**EXH. CAK-7 (Apdx. A)**
**DOCKETS UE-22___/UG-22___**
**2022 PSE GENERAL RATE CASE**
**WITNESS: CATHERINE A. KOCH**

**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**<br><br>**Complainant,**<br><br>**v.**<br><br>**PUGET SOUND ENERGY,**<br><br>**Respondent.** | **Docket UE-22____**<br>**Docket UG-22____** |

**APPENDIX A (NONCONFIDENTIAL) TO THE SIXTH EXHIBIT TO THE PREFILED DIRECT TESTIMONY OF**

**CATHERINE A. KOCH**

**ON BEHALF OF PUGET SOUND ENERGY**

**JANUARY 31, 2022**

PUGET SOUND ENERGY

# AMI Business Case

## November 2016

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# 1. Project Overview

The Advanced Metering Infrastructure (AMI) project will install a new standards-based mesh network, replace nearly 1.2 million electric meters and 800,000 gas Automated Meter Reading (AMR) modules with modernized metrology and meter reading technology, enable our IT systems with the interfaces and functionality to support this new technology and equip our employees with the tools, processes and training to effectively utilize AMI. The initial goal of this project is to ensure all capabilities currently available with the legacy AMR system are provided with the AMI system. These capabilities include meter reading for monthly billing electric and gas customers, remote meter diagnostics, outage notification and restoration verification services, and interval and instantaneous meter reads. PSE will also be pursuing one additional enhanced capability not available with the AMR system today: implementing voltage reads to enable the conservation voltage reduction program.

Once the foundational systems are in place through this initial project, PSE will build on this foundation to deliver additional AMI capabilities and derive additional benefits. These future initiatives are described in the following sections to provide context on the metering infrastructure vision but are not outlined in the project costs. Future business cases will be established to initiate these additional capabilities.

This project drives several objectives within the ISP, most notably the customer and processes and tools objectives. This project impacts business processes throughout PSE and touches nearly every PSE customer. PSE's meter is the company cash register and the mechanism to provide timely and accurate billing to our customers. AMI improves billing accuracy, broadens potential customer product offerings, and more robustly supports future metering, distributed resources, and automation requirements. A glossary of terms is provided in Appendix G.

# 2. Project Drivers

PSE's AMR system was initially installed in 1998-2001 and was designed for a 15 year life. As the system approached the 15 year life, PSE started planning for addressing the end-of-life of the AMR system. Between 2011-2015, a small team examined several scenarios for replacing the AMR system. The AMR service contract with Landis + Gyr ("L+G") provided several transition options that would allow for PSE to move to the current generation of meter reading systems, likely AMI.

AMI mitigates the risk of PSE's aging infrastructure and also provides a foundation for new capabilities[1] above what the PSE AMR system provides. These new capabilities, when implemented, will allow PSE to pursue new operational efficiencies, enhanced services to customers and implement new programs. In 2015, PSE initiated an amendment to the meter

[1] *Advanced Metering Infrastructure*. Electric Power Research Institute. Staff Report, February 2007 https://www.ferc.gov/CalendarFiles/20070423091846-EPRI%20-%20Advanced%20Metering.pdf

reading contract that provided an option for purchasing an AMI network and a migration path to allow for replacing aging meters and modules with modern metering technology.

PSE has three key business needs for AMI:

1. **ADDRESSING CORE BUSINESS CHALLENGES INHERENT WITH AMR TECHNOLOGY**: The AMR system is nearing end-of-life, is an obsolete technology, and is limited in its capabilities to drive PSE's strategic plan. Today several maintenance obligations with the AMR system are present or on the horizon such as expiring batteries in gas modules and increasing failure rates of the AMR equipment[2]. The AMR technology lies at the root cause of some of the problems PSE faces in the "meter-to-cash" processes--processes that are fundamental to timely and accurate bills[3] for all PSE customers. Furthermore, the AMR system performance is less than desired for advanced reads including net metering reads[4], load profile/15 minute interval reads[5] and demand reads[6]. Eliminating these problems will result in increased business performance including a reduction (up to 8%)[7] of calls to the customer access center.

2. **DRIVING OPERATIONAL EFFICIENCY**: AMR operations depend on many manual processes which could be improved through AMI implementation to drive operational efficiency and reduce costs[8]. For example the billing performance standard imposed by the WUTC has created more pressure on these manual processes such as disconnecting and reconnecting customers. Enabling the remote disconnect switch in AMI technology would allow customers moving in and out to be remotely disconnected or reconnected reducing truck miles driven[9] and significantly shorten the turn-around time for disconnecting and reconnecting customers. Additionally, although PSE can receive outage information utilizing the AMR technology[10], the poor reliability during storms and the lack of 2-way system means PSE cannot proactively communicate with the customer about their outage easily or effectively. A final example is the arduous

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[2] Attrition rate assumptions are described in Appendix B.
[3] 10/1/2015-9/30/2016 retro billing for stopped gas module problems is $1.36M.
[4] Any customer requiring kVARh delivered/received measurements must be fitted with a non-AMR solution.
[5] Load profile interval performance is less than the 99% performance standard. October 2016 recent performance for electric was 95% and gas was 94%.
[6] PSE and L+G must use a statistically-based correction algorithm today to estimate any missing demand intervals from AMR for customers who pay demand charges.
[7] The "Get to Zero" program estimated 8% of CAC calls were for billing problems which include retro bills, mixed and lost meters, and payment arrangements amongst some non-meter related issues.
[8] 2014 Smart Grid System Report, US Department of Energy, August 2014. Pgs. 4-5. http://energy.gov/sites/prod/files/2014/08/f18/SmartGrid-SystemReport2014.pdf
[9] *Operations and Maintenance Savings from Advanced Metering Infrastructure-Initial Results.* Smart Grid Investment Program. US Department of Energy. December 2012. Pg. iii. http://energy.gov/sites/prod/files/AMI_Savings_Dec2012Final.pdf
[10] While AMR technology does produce outage notifications, many of the outage notifications are never received by the network due to interference and lack of alternative paths for network redundancy. AMI technology utilizes a mesh network that contains redundant paths so most outage notifications will be received.

processes needed to analyze interval data which prevent activities that would proactively address equipment overloading conditions and combat energy diversion[11].

3. **ENSURE COMPETITIVENESS**: Over the next 5-10 years, PSE's customer and business needs will change with growing trends towards demand/response, distribution automation (DA), conservation voltage reduction (CVR), advanced outage notification and restoration verification, and prepaid billing. PSE's AMR technology does not enable[12] PSE to meet these future challenges.

## 3. AMI Project Costs

The AMI project costs include the material and installation of the AMI network, gas modules, electric meters, and system hardware and software as well as the business systems and business processes for enabling the foundational functionality with AMI. The project will also implement voltage readings to enable CVR and the costs and benefits of this capability are included in this business case. As AMI rolls out, there will be a reduction in the AMR system costs for the AMR meter, AMR module, and AMR network replacements, battery replacements and AMR software maintenance. These reductions are represented in the quantified benefits section of this business case. The rate of the project rollout affects the cost of the project because there are several fixed costs that are incurred for the duration of the project such as warehousing costs, customer service call center costs, and project management. Additionally, the costs of materials purchased from L+G will contractually increase annually based on the Consumer Price Index (CPI) so a faster rollout avoids some of this escalation.

Benefits from the project start accruing as soon as the capability is enabled, so a faster deployment can accrue more benefits than a slower one. As PSE evaluated these timing options, a six year meter deployment coupled with a two year readiness period, spanning 2016-2023, best balanced the desire for benefit realization with the cash flow realities. The AMI project costs relative to this timing are outlined below.

**Budgetary Requirements:**

| Project Costs | (2016-2023) Nominal $M |
|---|---|
| **Capital** | **$456** |
| **O&M** | **$17** |
| **TOTAL** | **$473** |

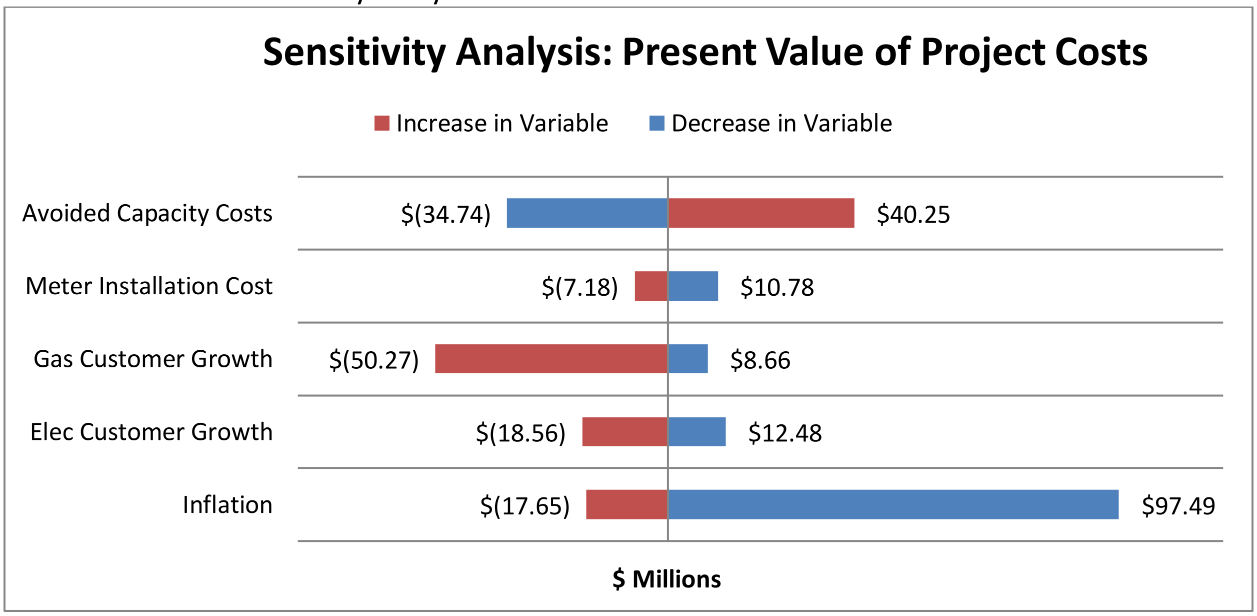
[11] See supra note 8
[12] 3rd *Annual Grid Modernization Index*, Gridwise Alliance. January 2016. pg. 33. http://www.gridwise.org/report_download.asp?id=17

**Sensitivity Analysis**

These costs above correspond to assumptions around five key variables shown below. For each of these variables, PSE performed a sensitivity analysis to determine how a change in the assumption would impact the cost and benefits of the project. The high and low assumptions used in this sensitive analysis are shown below.

| Variables | Current Assumption | High Assumption | Low Assumption |
|---|---|---|---|
| 1. Avoided Generation Capacity (Benefit) | $190 | $270 | $116 |
| 2. Meter Installation Costs | $26.34 | $32 | $20 |
| 3. Annual Gas Customer Growth | 1.5% | 3% | 1.25% |
| 4. Annual Electric Customer Growth | 1.25% | 2.5% | 0.5% |
| 5. Inflation | 3% | 3.5% | 1% |

The results of the sensitivity analysis are shown in the chart below.




The sensitivity analysis indicates that inflation is the largest influencer of the project costs of all variables examined. While the project is using a 3% inflation rate, recent history indicates that inflation has been lower than 3%, even dipping below 1% in the last couple of years. Should inflation hold at 1% for the duration of this project, the costs of the project would be nearly $100 Million less expensive on a PV basis.

**Financial Analysis**

The financial analysis of this investment considers the project costs, the quantified benefits, the revenue requirement and income tax and depreciation. This financial analysis evaluates both the cost to customers and the Net Present Value of the project with the revenue requirement. A summary of this financial analysis is presented below. The detailed financial analysis is found in Appendix A.

| | **(2016-2037) $M** |
|---|---:|
| **NPV of project, with revenue requirement** | **$8** |
| **Cost to Customers of AMI Project** | **$258** |

## 4. Quantified Benefits

Benefits from the AMI technology and strategic implementations are captured in this business case and in the Get-to-Zero (GTZ) roadmap[13]. Because several of the GTZ benefits would be expected as part of any AMI deployment, we have characterized these benefits in Appendix E but the benefits are actually aligned to the GTZ roadmap.

The quantified benefits[14] to PSE's operations associated to the investment in AMI are summed over a 20-year horizon, starting when the first AMI modules are deployed. The time horizon was selected to correspond to the 20-year design life of AMI technology. Most of the benefits accrue in the years following the project completion.

For this business case, PSE is not quantifying all anticipated benefits.  The following benefits are quantified for two primary reasons: (1) the magnitude of the values of the benefit associated to the capabilities below are large and (2) the company possessed empirical data from our operations and from industry studies that supported and allowed for quantifying these benefits. Details on the benefit assumptions and analysis are found in Appendix A.

| | **(2017-2037) Nominal $M** |
|---|---:|
| **Total Quantified Benefits of AMI Project** | $668 |

Quantified benefits from the AMI system include the following (2017-2037):

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[13] GTZ roadmap version 68, 10/26/2016 :
http://team/sites/SGP/AMI/Projects/+AMI%20Implementation/1.%20Project%20Management/CSA/2016%20CSA%20+%20Bus%20Case/Business%20Case/GTZ_Roadmap_v68.xlsm
[14] See Appendix A for detailed benefit breakdown.

| Capability | Benefit Value $M Nominal | Benefit Description |
|---|---|---|
| **CVR**[15] | $436[16] | Lowering customers' energy bills through reduction in supply voltage |
| | | Reducing supply-side resource requirements |
| **Distribution Automation**[17] | $1.5 | Avoid the investment and maintenance needs for a separate distribution automation network |
| **Avoided AMR investment**[18] | $230[19] | Reduce maintenance obligations for AMR gas module batteries, AMR network nodes and AMR software through a refresh of our aging meter reading infrastructure |
| | | Reduce capital investments in AMR modules, meters and network nodes required to sustain customer growth and equipment attrition |

PSE has a small pilot program in place with AMI meters to enable end-of-line voltage monitoring for CVR. Starting in 2013, PSE has installed approximately 150 AMI meters to capture the voltage reads from customers near the end of feeder lines on 6 substations. Information from these meters are used to compute the energy savings impact of CVR as well as to ensure customers receive a delivery voltage that is within the 114V-126V ANSI limits. The results of this pilot have been used as a basis for estimating the benefits of CVR as it is deployed a wider-scale. PSE utilizes the Northwest Council Regional Technical Forum's protocol for assessing the value of CVR.

## 5. Non-Monetized Benefits

**AMI Project Non-Monetized Benefits from AMI**

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[15] The CVR estimated in PSE's business case is built on the technique of End-of-Line monitoring using AMI meters to record the voltage load profile. The protocol for assessing the value of CVR is provided by the Regional Technical Forum https://nwcouncil.app.box.com/s/llu2rhtdqd167t2t53hj6udq6gsm3lqk.

[16] Number different from November BoD presentation which showed net benefits (Benefits-Costs). Assumptions updated since November BoD presentation on the rate of roll-out.

[17] PSE estimated the DA benefit utilizing the average fixed and reoccurring cost of cellular radio technology which is often used as the transport for command and control of distribution grid assets at PSE. The AMI mesh radio network can be utilized for this transport in lieu of cellular radios.

[18] PSE estimated avoided AMR investment using expected future failure and attrition rates of electric meters, gas modules and network equipment based on historical and statistical forecasts. Specific rates are detailed in the key assumptions in Appendix B.

[19] Number different than November BoD presentation due to inaccuracy on the cost of some maintenance activities which is now updated. Further AMI equipment failure rates have since been updated with L+G's November 2016 assessment.

The non-quantified or non-monetized benefits to PSE's customers and PSE's operations associated to the investment in AMI are provided. Most of the benefits below are likely to have some monetary value to PSE. For many of these benefits, PSE lacks empirical and/or industry data required for robust quantification today. For some of these benefits, the likely value is small and the effort to develop a robust analysis was not justified. Once the AMI project is implemented, the data from the new operational processes may lead PSE to estimate or compute the benefit achieved from the capabilities below.

The following benefits will be pursued with the AMI technology and are aligned to the AMI Business Case.

| Capability | Benefit |
|---|---|
| **CVR** | Reduced capacity constraints will result in greater operational flexibility on the distribution grid. |
| | Deferring or avoiding capacity upgrades on circuits experiencing load growth.[20] |
| | Reduction in $CO_2$ emissions, estimated at 123,000 tons through 2024. |
| **Avoided AMR investment** | Reducing PSE's Billing Exceptions work processes and resulting call volume due to AMR meter issues |
| **Billing Exceptions** | Eliminate zero-consumption based retro-bills caused by the AMR defect in gas modules. |
| | Reduce the number of estimated bills due to missing reads. The AMI read performance is expected to exceed that of AMR and require fewer manual reads and better read fidelity from the interval data. |
| | More accurate demand billing due to the ability to retrieve missing demand intervals from the AMI meters. With the AMR system, missing demand reads cannot be recovered. |
| | Reduction in lost and mixed meters as deployment process validates location for each new device installed. |
| **Demand/ Response** | Metering platform can enable dynamic or time-of-use rates. |
| | Reduce infrastructure investment for standing up a direct load control program by leveraging the AMI network for command and control of appliances. |

Finally, the AMI meter technology provides the foundation to address the following as the future unfolds:

[20] While PSE can calculate the avoided cost of additional capacity that CVR can capture, the specific location of capacity constraints and load growth can be widely varied among its population of distribution circuits.

- Microgrids and other smart city attributes like street light controls
- Distributed generation integration with utility
- Electric vehicle integration with utility
- Customer home-area network interface

# 6. Project Schedule

**High Level Schedule**

Project development and design began in 2015 and initial installation of the AMI network and IT Systems development and integration began in 2016. Meter deployment is targeted to begin in Q4 2017, following the completion of the IT Systems development and integration effort. PSE will transition approximately 16% of its customers to AMI meters per year after 2017. Additional AMI capabilities will be introduced in subsequent stages of the project, driven by initiatives such as GTZ.

| Stage | Years | Key Deliverables |
|---|---|---|
| Stage 1: Network Deployment, System and Organizational Readiness | 2016-2018 | • AMI Network installed<br>• AMI Head-End System implemented<br>• All essential business processes for meter-to-cash processes designed and implemented<br>• IT system development and integration for meter-to-cash processes<br>• Back-end system integration for CVR program. |
| Stage 2: Meter/Module Deployment | Q4 2017-2023 | • 100% AMI Electric Meter and Gas Module Deployment<br>• Accurate and timely bills<br>• End of Line monitoring CVR program implementation<br>• Timely area retirement of parallel AMR system |
| Stage 3: Capability Enhancements, driven by GTZ initiative or other programs. | 2018-2023 | • Remote Connect/Disconnect enabled<br>• Prepaid Metering enabled<br>• CVR business processes enhanced for more benefits<br>• Distribution Automation implemented over AMI Network |

| | | |
|---|---|---|
| | | • Enhanced outage response integration<br>• Data Lake for meter data to support advanced analytics<br>• Advanced analytics capabilities<br>• OMS integration for outage management |
| Stage 4: Possible Extension of Capability Enhancements | 2019 or beyond | • Demand Response<br>• Internet of Things |

**Stage 1 Network Deployment, System and Organizational Readiness**

The Stage 1 objectives are primarily to enable the new AMI system with all existing AMR functionality including the ability to perform end-of-line voltage monitoring to support the on-going CVR program. The pre work[21] for installing the AMI network will begin 2016-2017 with installation of the AMI network [22] between 2016 and 2018. This first stage will not include the installation of meters and modules, but rather the system integration, processes and preparation required to ready the organization for the first meter/module installation. A diagram of the system is provided below.

[21] See AMI scope document for specific high level tasks: SharePoint link
[22] *AMI Network Options*, PSE Decision Document, 6/29/2016. http://team/sites/SGP/AMI/Projects/+AMI%20Implementation/1.%20Project%20Management/Decisions/1.%20AMI%20Network/AMI%20Network%20options.docx

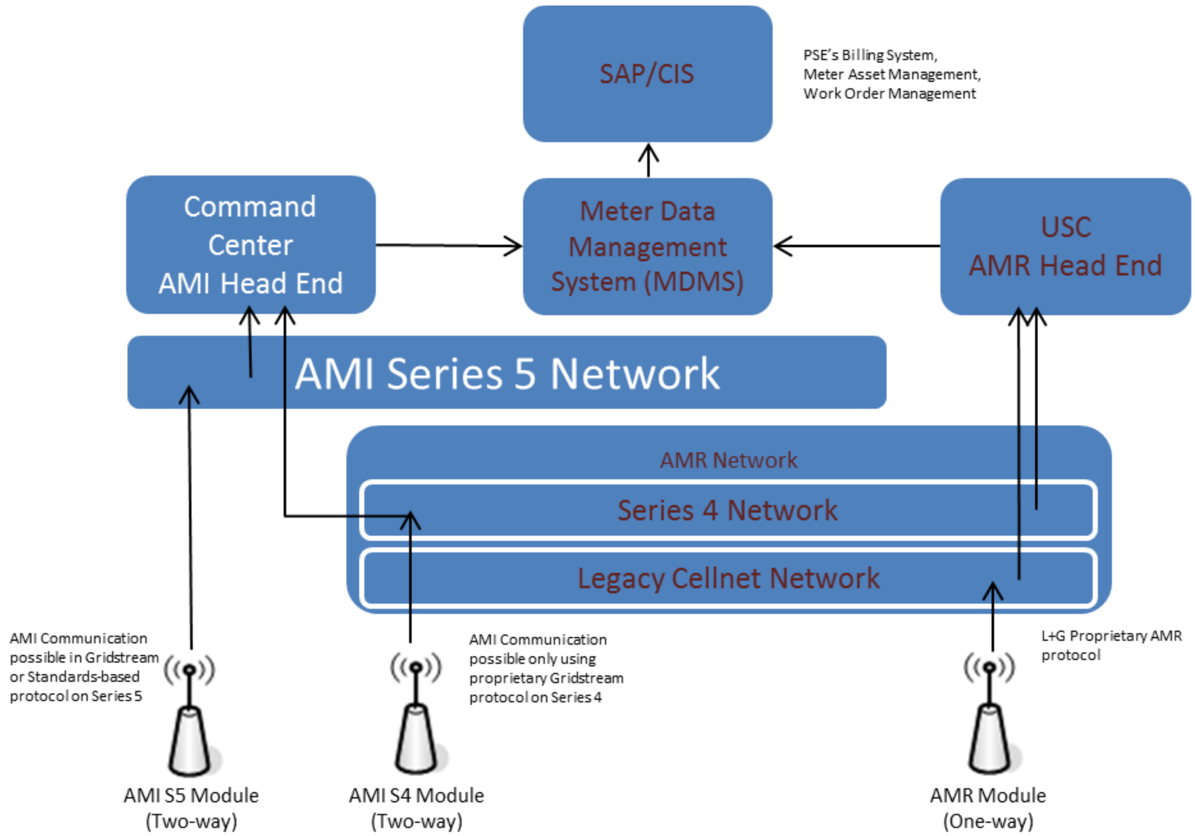


**Figure 1: PSE's AMR and AMI system diagram**

**Stage 2 Meter/Module Deployment**

The Stage 2 objectives include deploying the gas modules and electric meters to refresh the AMR infrastructure. The initial focus will be on installing the AMI technology in those locations that will have the greatest benefit. The gas module deployment is scheduled for five year targeting starting in Q2 2017, at an approximate rate of 150,000 modules/year. The electric meter deployment is scheduled for 6 years targeting starting in Q3 2017 at an approximate rate of 200,000 meters/year.

Based on the initial capabilities available from Stage 1, the deployment focus will be on avoiding liabilities accruing from the AMR system include expiring gas module batteries, gas modules causing zero-consumption and lost/mixed meters. Approximately 300,000 gas modules are projected to have expiring batteries around the time that the AMI solution is available. While some of these batteries will require replacement in 2016 and 2017 before the AMI solution is available, there will be opportunities to address a portion (up to 125K) of gas modules with expiring batteries through replacement with an AMI module. The results of the geographic analysis indicate that the largest AMR liabilities lie in urban King County (Bellevue, Federal Way, Seattle), southern Snohomish County and eastern Pierce County. The initial deployment focus will be getting gas modules deployed in these areas. Where PSE serves electric and gas, the focus will also be on establishing the mesh network with electric meters to allow gas module deployment.

Meters will be deployed by region, in a contiguous fashion to optimize installation operations. The regions selected for deployment will be prioritized by benefit value available. The benefits evaluated will consider the capabilities that are available on the meters, the customers in the area requesting those capabilities and the operational benefits available from deploying meters to those regions.

Deployment vendors will be required to provide deployment analytics to bolster the meter-to-cash process integrity. As these assets are deployed, analytics will detect faulty meters/modules and sockets, customer bill issues, false alarming, communication gaps, and installation mix-ups. These are common problems with deployments and these tools can detect and diagnose these issues in a timely fashion.

**Stage 3/4 Capability Enhancements**

The Stage 3 objectives are focused on enabling many of the modern capabilities available with AMI technology. Many of the objectives for Stages 3/4 are being pursued through the GTZ roadmap. The project schedule for Stage 3 and beyond is not developed. It will be added once it is ready.

# 7. Strategic Plan

**Integrated Strategic Plan**

The primary Integrated Strategic Plan (ISP) objectives that AMI drives are the Processes and Tools and Customer objectives. AMI will mitigate projected liabilities of AMR asset failure and replacement rates that are a risk with the aging AMR solution and provide a technology foundation to streamline processes through the enhancement of existing and application of new tools and capabilities and enable opportunity to enhance customer service and offerings.

**Project Strategy**

The AMI project strategy is to deploy both the meters and the system capabilities in stages with consideration to the customer bases and regions that most strongly benefit[23]. A base set of capabilities are required before the first meter or module can be deployed in the field. Below are the business objectives, by stage and the associated strategies.

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[23] *Heat Map for Benefits*, PSE Internal Study.2016. http://team/sites/SGP/AMI/Projects/+AMI%20Implementation/1.%20Project%20Management/CSA/2016%20CSA%20+%20Bus%20Case/Business%20Case/Heat%20Map%20for%20Benefits.JPG. PSE has evaluated the zip code locations for where the quantified benefits are estimated to occur.

| Business Objectives | Project Strategy | Stage |
|---|---|---|
| Address core business challenges inherent with AMR technology | Deliver the core meter reading, diagnostics and alerts and work management capabilities we have with AMR through the AMI solution. Drive timeline to prevent escalating maintenance obligations | 1/2 |
| Drive Operational Efficiency | Obtain voltage readings for CVR for program implementation. This program was designed to expand by 3-9 substations annually, growing to enable CVR on 164 substations. With a large-scale AMI deployment, this program will group the candidate substations into regions to complement and drive the regional deployment of meters and network. | 1/2 |
| Ensure Competitiveness | Future proof AMI technology to ensure future use through the use of a standards-based network design. The AMI network selected is designed as a mesh communication network that is capable of transmitting either a standards-based IPv6 protocol or L+G’s proprietary Gridstream protocol. | 1/2 |
| Drive Operational Efficiency | AMI solution integrated to drive outage call reduction and outage management efficiency. Because this service is available from both AMR and AMI meters, the strategy is to integrate these systems to the OMS for speedier and more comprehensive outage notification and restoration verification capability across our entire service area. | 3 |
| Drive Operational Efficiency | The AMI network is also our distribution smart grid network. In 2015, PSE implemented a new DA control system to automatically identify and sectionalize faults and reconfigure distribution circuits to restore power to affected customers. This system relies on telecommunications to monitor and control the distribution switches. The AMI network will be used for this telecommunications equipment, allowing PSE to save on purchasing a separate radio network for DA and other distribution smart grid capabilities. | 3 |
| Drive Operational Efficiency | PSE meters can be remotely disconnected/reconnected to save on truck rolls and retro bills. The key strategy here will be to implement disconnect/reconnect for move in/out use cases first. This will allow PSE to eliminate electric UEU in locations where there are AMI meters | 3 |

| | | |
|---|---|---|
| | deployed. The focus for this will be in multifamily residences that have historical high turnover. In parallel, we will begin using this technology to address disconnects for non-payment and reconnections when balances are paid. | |
| Drive Operational Efficiency | Provide analytics for theft/tamper detection through AMI solution Aligning with the energy diversion team through the Be Excellent initiative, PSE will use the AMI meter data to proactively inform the detection of theft and tamper. Further, as the new meter technology is rolled out in Stage 2, PSE will ensure that the deployment vendor has appropriate protocols in place to discover and report probable energy diversion situations that are encountered in the field. This effort will mitigate revenue losses and address safety hazards as energy diversion is eliminated. | 3 |
| Ensure Competitiveness | Provide communications past the customer side of the meter. Currently, PSE does not have a roadmap item to introduce this type of demand response or dynamic rates; however the IRP forecasts the viability of these programs in future years. The strategy here is to put the capabilities on the roadmap to ensure that system architectures and business processes for this capability are considered as the earlier stages are implemented. | 4 |

# Appendix A –Financial Analysis-Costs and Benefits of AMI Project

The detailed AMI project costs and benefits are provided below.

AMI Project Costs

The financial analysis with impacts on revenue and customer costs of these project costs and benefits is provided below.

Financial Model

# Appendix B – Risks, Key Assumptions and Measures for Success

## AMI Project Risks

The risks described below are high-level project risks. As the project team is established, an important responsibility will be to outline detailed project risks and mitigations.

| **Risk Description** *(List risks that could significantly impact funding and/or spend schedule)* | **Mitigation Plan** *(What are you doing to mitigate the risk? Are risk $s assigned?)* | **Risk Date Horizon** *(Date risk will no longer be a threat)* |
|---|---|---|
| 1. Costs to deploy may exceed estimate<br><br>*Impact = M and Probability = H* | Proactively engage stakeholders such as jurisdictions to identify issues that would increase or decrease installation and deployment costs.<br><br>Identify cost savings opportunities such as work bundling and contracting.<br><br>Lengthen installation timeframe to manage annual impact | 2021 |
| 2. Lack of bench strength in AMI domain<br><br>*Impact = M and Probability = H* | Leverage L+G expertise to fill the gaps<br><br>Hire external consultants to augment with expertise on PSEs backend system integration and implementation experience<br><br>Plan for on-going AMI system management effectively. | 2019 |
| 3. Failure to enable advance network and meter capabilities will limit the ability to remotely operate distribution devices and enhance service offerings.<br><br>*Impact = M and Probability = L* | Implementing AMI technology in a timely manner. Robust stakeholder engagement.<br><br>Front-load the project with implementing the solutions that provide the greatest benefits first.<br><br>Consider accelerating the 6 year deployment horizon of meters (decision implemented <date> from 10 year deployment) | 2023 |
| 4. Disputes arise from vendor contract<br><br>*Impact = L and Probability = L* | Facilitate transition with appropriate legal support. | 2023 |
| 5. Failure to deploy at rates per contract amendment will result in higher maintenance prices.<br><br>*Impact = H and Probability = L* | Include options for acceleration of deployment in meter installation vendor contract.<br><br>Prioritize budget dollars to allow acceleration of deployment to meeting penalty milestone goals. | July 1, 2023 |

| **Risk Description** *(List risks that could significantly impact funding and/or spend schedule)* | **Mitigation Plan** *(What are you doing to mitigate the risk? Are risk $s assigned?)* | **Risk Date Horizon** *(Date risk will no longer be a threat)* |
|---|---|---|
| 6. Poor communications during implementation; Incorrect customer bills; privacy considerations; customer acceptance. *Impact = M-H and Probability = L* | Having an effective communication plan and the necessary resources to support design, change management and community outreach. Build testing environments and quality assurance to ensure end to end process will function as intended. | 2023 |
| 7. The requisite AMI opt out option does not allow PSE to recover costs associates with non-AMI meters. *Impact = L and Probability = M* | Proactively engage with Commission Staff to develop a mutually acceptable Opt-out tariff. | 2023 |
| 8. Commission does not allow PSE to recover costs associated with network and module deployment, as well as other integration costs. *Impact = H and Probability = M* | Proactively engage with Commission and staff regarding investment, utilizing information available from Avista Rate Case, transcripts and testimony, to prepare for prudency. Ensure benefits and strategy is founded on strong data. | 2023 |

**AMR Risks**

**Maintenance Risk:**
The AMR system, network, gas modules, and electric meters are failing or requiring maintenance at increasing rates. The network equipment is now failing at a 4% rate. The gas AMR modules require a battery and PSE estimates 36% of the gas AMR batteries will reach end-of-life between 2016 and 2021 and will need replacement. The current commercial AMR gas modules have a failure rate above 11%[24]. Electric meters are failing at 1.6%. Through third-party study, PSE concludes that these failure rates are higher than industry average for AMR equipment. The total avoided AMR investment costs are estimated at $216 million over the 20-year life of the AMI asset[25]. Should assumptions regarding failure rates be low, the financial risk could increase due to the effort required to meet billing standards and the difficulty in scaling up the manual processes that address these maintenance obligations.

[24] See Appendix B Key Assumptions for failure and attrition rates.
[25] Note that AMR batteries are an O&M cost; whereas modules are a capital cost. The benefit amount is an avoided capex number which assumes that a module and battery are replaced together. In reality, there are times when only a battery is replaced; however, we have inconsistent historical data on battery-only replacement rates.

**Obsolescence Risk:** Equipment and support providers for PSE's AMR platform are limited as industry is moving to an AMI platform. There is an ever-increasing disparity between customer expectations and business needs and the capabilities of the AMR system. To scale up current programs and implement new programs PSE needs data and functionality such as 2 way information flow that does not exist in AMR technology. As vendors phase out and sunset AMR equipment, equipment options are diminishing creating supply chain interruption risk and in some cases no options at all[26] (i.e., 3 phase meter will not be manufactured beyond 2016).

**Performance Risk:** AMR suffers reliability issues with the communication network and meter modules. Between 50,000-60,000 meters must be manually read every month due to network interference, network dead spots, or failed modules. These causes result in increased manual intervention to detect, correct, and prevent meter related bill problems. Failure to perform effectively in light of the billing standard that became effective March 25, 2016 causes increased regulatory scrutiny if AMR performance causes increased billing issues for customers.

**Competition and Reputational Risk**: Delaying the implementation of AMI technology will also reduce PSE's ability to adapt to evolving customer service needs. Nationally, deployments are expected to reach 70 million AMI meters by the end of 2016[27] which amounts to more than 50% of the meters in the US. As neighboring utilities[28] implement AMI, PSE's customers and regulators may view PSE unfavorably due to less modernized infrastructure. The company will be less able to offer enhanced reliability and new products and services to its customers such as demand response, distributed resource integration, time of use rates, energy information feedback, and enhanced billing and payment options.

## Key Assumptions

Capital and O&M figures used in this business case are based upon pricing outlined in Fourth Amendment to Amended and Restated Network Meter Information Services Agreement between PSE and L+G. PSE assumptions on tax, growth, overhead, and CPI are applied to these figures. These figures are detailed in the key assumptions below.

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[26] A2 replacement options.docx, PSE summary. May 16, 2016. http://team/sites/SGP/AMI/Projects/+AMI%20Implementation/1.%20Project%20Management/CSA/2016%20CSA%20+%20Bus%20Case/Business%20Case/A2%20replacement%20options.docx
[27] Source: *Electric Company Smart Meter Deployments: Foundation for A Smart Energy Grid*. The Edison Foundation Institute for Electric Innovation (September 2016) pg. 2.
[28] Seattle City Light is deploying AMI meters beginning in 2017. Snohomish County PUD is currently exploring an AMI deployment beginning in 2018. Avista has already begun AMI deployment through the Northwest Smart Grid Demonstration Project and is initiating a full system deployment in Washington starting in 2016. Portland General Electric has a fully deployed AMI system.

| **Assumption Description** *(List assumptions you have made about your project such as cost, depreciation, head count assumptions)* | **Assumption has been confirmed by?** | **Assumption Date Horizon** *(Date assumption will no longer be a threat)* |
|---|---|---|
| 1. Customer growth rate of 2.0%[29] | Smart Grid Planning | At end of each forecasted year |
| 2. Failure/attrition rates of AMR and AMI electric meters with modules, gas modules and network equipment[30] | Smart Grid Technology, L+G, Purchasing | At end of each forecasted year |
| 3. Gas battery expiration rate (10 years) | IT-Meter Data Systems and Gas Standards & Commodities | 2020 (this is the end of the cyclical hump in battery replacements) |
| 4. Inflation rate of 3%[31] | Smart Grid Planning | Annually |
| 5. Depreciation rate of 15 years for AMI meters and Network Equipment | Property Accounting | 2016 (potential depreciation study) |
| 6. Tax rate of 10% | Procurement & Contract Services | At end of each forecasted year |
| 7. Asset Purchase Overheads (3% for network, meters and modules and 0% for software) | Property Accounting, Budget & Financial Performance Supervisor | At end of each forecasted year |
| 8. Materials Management Overheads (9.5% on meters and modules) | Materials Management Manager | At end of each forecasted year |
| 9. Headcount: For tasks which PSE is responsible to perform for this project, resources are a mix of PSE staff and contractor staff. Contractors will be heavily leveraged for this project. | Budget & Financial Performance Supervisor, Electric Meter Operations Manager | 2016 |
| 10. Pricing from L+G for: <br>• An enterprise license for the AMI head-end software (also known as Command Center) <br>• Material and installation services for AMR gas modules to address battery expiration. | Contract Management | 2026 (Contract end date) |

[29] Based on PSE's F2014 Load Forecast Summary.
[30] Approximately 300,000 gas modules are projected to have expiring batteries in 2016-2020, based on a 10 year battery life. These battery replacements plus the failure rates for gas modules yield an annual module attrition rate between 8.5%-20% for 2016-2020. Historical annual attrition rates for electric meters are near 1.6% and AMR network equipment is near 4%. AMR Gas Module and Electric Meter/Module historic replacement rates are provided by PSE's Purchasing department. The forecast for future gas module failure rates is based on a PSE-commissioned study: *PSE Gas AMR Gas Module Weibull Analysis*, Sept. 30, 2014. http://team/sites/SGP/AMI/Archive/AMR%20Failure%20Rate%20Analysis/PSE%20Gas%20AMR%20Gas%20Module%20Weibull%20Analysis%20Results-Final.docx.
AMI hardware annual replacement/failure rates are based on manufacturer's failure analysis (0.31% for AMI gas modules 0.34% for AMI Electric meters, 0.91% for AMI GAP Collectors, and 0.43% for AMI routers).
[31] PSE Procurement Department assumption for all contract forecasts

| **Assumption Description** *(List assumptions you have made about your project such as cost, depreciation, head count assumptions)* | **Assumption has been confirmed by?** | **Assumption Date Horizon** *(Date assumption will no longer be a threat)* |
|---|---|---|
| • AMI network equipment and associated installation services<br>• Project management services for installing the AMI network<br>• AMI gas and electric modules and AMI electric meters | | |
| 11. AMR Electric meter mass asset depreciation will be fully realized. | Property Accounting | 2020 |
| 12. Network, module and meter deployment rates are uniform throughout the deployment period. | Smart Grid Technology | 2023 |

## Measures for Success

| **Measure for Success**<br>*(List measures for success)* | **Measured by?**<br>**(How do you plan to measure?)** | **Measure Date Horizon**<br>*(Date measurement will be available)* |
|---|---|---|
| 1. Low budget variance | Project controls | Monthly |
| 2. Low schedule variance (no penalties incurred) | Project controls | Monthly |
| 3. Defined requirements for network, meters, and applications | Requirements review forum, attended by key vendor partners. | 2016 |
| 4. Enterprise Project Management processes utilized and phase gates adhered to | Deliverables completed; appropriate approvals through phase gates; effective change control process | 2016 |
| 5. Few scope changes | Quantity of scope change incidents | 2019 |
| 6. Customer engagement | Quantity of customer complaints related to AMI project and effect of these complaints on cost/schedule/scope of project | 2019 |
| 7. Gas module quality | Count of recalls, failures as a percentage of total deployed population. Goal is <0.5% recall/failure rate. | Annually after gas module deployment begins |
| 8. Reduced AMR maintenance costs on meters and network | Annual costs of AMR meter and AMR network expense. | Annually after AMI equipment deployment begins |
| 9. AMI system performing to requirements. | Contracted performance metrics met or exceeded. | 2017 or once meter installation begins. |
| 10. CVR program rollout rate accelerated and benefits achieved. | CVR benefits achieved; number of substations included in CVR. | Year over year measurement showing growth. |
| 11. New automation projects rely on AMI network for telecommunications | Number of DA projects using AMI network for data transport | Year over year measurement |

# Appendix C – Application of Prudence Standard

Using the Commission's guidance regarding prudence that was highlighted through several proceedings, most recently the proceeding associated with PSE's acquisition of the Lower Snake River wind generation facility (Docket UE-111048, Order No. 8 dated May 7, 2012), this section applies the 4 elements described for testing reasonableness; 1) the need, 2) evaluation of alternatives, 3) communication with and involvement of the Board of Directors, and 4) adequate documentation.

**Determination of Need for AMI**

The Project Drivers described in Section 2 outlines the chief reasons PSE is pursuing an AMI solution. In arriving at the determination that these key business drivers were best satisfied with a technology refresh, PSE developed a base case by analyzing the alternatives associated with maintaining its AMR network through an entire theoretical AMI project time horizon. PSE also estimated changes in viability with a dynamic model that compared maintaining the AMR system with any combination of deployment start date, deployment pace, and ownership model scenarios.

**Evaluation of Alternatives**

PSE has evaluated metering possibilities for several years. It continues to feed its cost/benefit analyses with the most current information available to the company from a variety of sources, including negotiated pricing under contract, budgetary pricing from vendors, conversations with peer utilities, information from utility user group presentations, and published business and use cases.[32]

*Initial Analysis*

Per the 2011 contract with L+G, PSE was to take ownership of the AMR assets on April 1, 2016. Because of this approaching obligation, PSE initiated a feasibility study of key alternatives to managing its existing AMR system as well as migrating to AMI technology over 10-15 years (CSA dated November 1, 2013). Three scenarios for managing the *AMR system* were considered which were augmented by 4 *AMI system* scenarios. The analysis of qualitative risks and benefits and estimated costs showed 2 AMI scenarios worth evaluating for feasibility; 1) take ownership per the contract and then utilize L+G technology to build out AMI over 10 years and 2) take ownership per the contract and then utilize L+G technology for electric AMI and a different vendor for gas AMI. Full deployment of AMI with a new vendor was estimated to be higher and brought financial and technology uncertainty. An L+G proposal at the time for AMI envisioned a managed service delivered with O&M funding which was not preferred. This analysis and feasibility activities performed in 2013 and 2014 provided the direction for the 2016 decision.

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[32] Of particular note within reference sources are the Department of Energy's Smart Grid Investment Grant reports. The DOE requires federal grant recipients to publicly report on project progress, costs, and results. These reports provide project data, lessons learned as well as alternative approaches considered by utilities of similar size.

In terms of AMR and AMI data, PSE uses its own experience with AMR costs, extant contract costs and cost escalation rates, actual costs from its AMI pilot program supporting conservation voltage reduction, and third party and vendor projections of product life and availability. The compilation of these data points help form the basis of PSE's internal assumptions. To ensure its assumptions were suitable, in 2014 PSE commissioned a consultant review of its AMR replacement strategy to identify business case components to improve. It also commissioned a third party analysis[33] in 2014 to establish AMR gas module end-of-life assumptions.

*Project Alternatives*

1. **AMI-2023**: Wait until the Q1, 2023 expiration of L+G AMR managed service contract. Address AMR obsolescence for 3-phase meters and net meters by installing non-AMR meters and then manual meter reading. Transition to AMI technology at completion of current contract, starting deployment in 2023 and finishing in 2027 (5 years). Readiness for deployment will begin in 2022.

2. **AMI-10yr**: Initiate transition to AMI technology in 2016. Roll out AMI meters over 10 year horizon, starting in 2018 and finishing full AMI deployment in 2027. In the first two years of AMI roll-out new AMR equipment for growth and attrition will need to be purchased but the removed AMR equipment can be refurbished or used for spare parts once enough units have been removed to meet the volumes. Obsolescence for 3-phase and net meters will be addressed by this refurbished stock where available. Some manual meter reading may be required if refurbished supply does not meet the need.

3. **AMI-6 yr**: Initiate transition to AMI technology in 2016. Roll out AMI meters over 6 year horizon, starting in 2018 and finishing full AMI deployment in 2023. This alternative was added once the AMI vendor pricing was available as the impact of costs over time can benefits accrual was more clearly an opportunity to consider. In the first two years of AMI roll-out new AMR equipment for growth and attrition will need to be purchased but the removed AMR equipment can be refurbished or used for spare parts once enough units have been removed to meet the volumes. Obsolescence for 3-phase and net meters will be addressed by this refurbished stock where available. Some manual meter reading may be required if refurbished supply does not meet the need.

4. **Revert to manual meter reading** as AMR system fails. While an alternative, it is not worth pursuing for reasons relative to the services PSE provides today for operational excellence and customer satisfaction that rely on AMR data including load research, energy efficiency programming, 120-hour guarantee, no cost off-cycle meter reading, outage notification and restoration verification, troubleshooting for billing and operations, etc.

*Analysis and Selection*

[33] See Supra Note 30

Cost, yearly expenditures, feasibility, benefit realization timing, impact to enabling GTZ and non-monetized benefits, and risks are the factors that were evaluated with each alternative. PSE used the financial model to assess the net present value of the project and the cost to customers for each of the alternatives.

These figures include the full AMI project costs as well as the incremental costs for operations and maintenance of the AMR system above the AMI-6 year alternative, net of the benefits aligned to this business case that are realized by the rollout of the AMI technology. The benefits in this analysis do not include monetary benefits accounted for through the GTZ initiative. While benefits can be realized for all three of these options as the AMI technology is rolled out, the faster the AMI technology is rolled out, the sooner benefits are realized. Additionally, delay on the AMI deployment will also delay the realization of GTZ benefit streams which have a dependency upon AMI technology, such as the use of the remote connect/disconnect switch.

| Alternative | Years evaluated | NPV, with Revenue Requirement $M | Cost to Customers $M |
|---|---|---|---|
| AMI-2023 | 2016-2037 | $7.4 | $225 |
| AMI-10yr | 2016-2037 | $7.3 | $134 |
| AMI-6 yr | 2016-2037 | $7.8 | $128 |

*Risk Considerations*

The three alternatives considered provide different levels of risk mitigation. For those risk categories outlined in Appendix B, the likelihood of occurrence is evaluated:

| | Likelihood of Residual Risk Occurrence with Alternative Selected (High, Med, Low) | | | | |
|---|---|---|---|---|---|
| | Obsolescence | Aging Infrastructure | Technology Limitation | Financial | Competition and Reputational |
| AMI-2023 | High | High | High | High | High |
| AMI-10yr | Med | High | High | Med | Med |
| AMI-6yr | Low | Med | Med | Med | Med |

*AMI-2023 Option Analysis*

AMI-2023 has the largest incremental cost in nominal dollars and the largest cost to customers due to the need to maintain and service the AMR system through 2027. Further, AMI-2023 also carries an overall high risk and has the largest obsolescence risk; a risk that is likely to occur. This risk is difficult to mitigate efficiently and if it occurs will impact some of our most engaged and highest consumption customers. For these two primary reasons, PSE has decided not to pursue this alternative.

*AMI-10yr Option Analysis*
AMI-10yr option is the least aggressive spend rate due to the lengthy deployment however AMR operations that must be maintained for 10 years which adds complexity. Feasibility-wise, this option is equivalent to the AMI-6yr option for the system readiness phase of the project; however it lengthens or delays PSE's ability to realize benefits. This option has a modest increase to customer cost over the AMI-6yr option with a lower NPV with revenue requirement so financially is slightly less attractive than the AMI-6yr option.

*AMI-6yr Option Analysis*
The AMI-6yr option provides the greatest mitigation from the outlined risks of all of the alternatives considered and also presents the highest NPV with revenue requirement. Further, this option offers the lowest cost to customers. Because the meter technology is installed sooner than either of the other options, PSE and its customers will have the opportunity to leverage the technology to realize the benefits from this system sooner.

With the factors consider, PSE's best option is the AMI-6yr and as such 2017 Corporate Spending Authorization Requests were developed and submitted with this plan.

**Contract Strategy**
PSE's AMR system was installed and managed by L+G since installation began in 1998. In 2011, PSE updated its contract with L+G, providing a business arrangement for the contractor to support PSE's metering through 2023. Associated with this Agreement were penalties for early termination and other contract rights for performance for both parties. Additionally this contract outlined the transition of asset ownership that would take place in 2016.

PSE's need to move to an AMI system in advance of predicted performance issues had to be weighed with termination and performance terms of the existing contract. Accordingly, PSE began discussions with L+G to understand the AMI products, services, and implementation parameters, and in parallel began an evaluation of the contract risks. An amendment was signed to set forth provisions regarding the AMI products, services, and implementation, without obligating PSE to any specific purchases or timelines.

Over time there have been different contracting strategies considered. The following outlines those with the conclusions noting PSE is unique as it must operate an AMR system in parallel with embarking on an AMI transition and that management of that service is currently with L+G.

| Concern | Approach | Action taken | Conclusion |
|---|---|---|---|
| Pricing Competitiveness | Exploit Favored Nation Clause if proof of lower costs paid by | Pricing comparison | L+G pricing is competitive |

| | | | |
|---|---|---|---|
| | similarly situated utilities for similar order quantities. | performed through RFI | |
| | Terminates L+G contract for cause or convenience and bids out AMI project.[34] | Reviewed termination penalties | |
| Meter/modules technology limitations | See action taken | Transition with ability to move to Open Protocol standard | Allows any meter technology to be used |
| Performance | See action taken | Own equipment<br><br>Increase contractual expectations of managed service | Contract to be signed has added requirements |

With the result of this analysis, PSE has carried the terms of amendment forward into a contractual restatement which also resulted in enhanced contractual benefits. In doing this PSE has also extended the contract until 2026 with the right to terminate for convenience without penalty at any time after 2023. PSE anticipates signing this agreement before year end after the appropriate reviews and approvals are completed.

*Reevaluation*

At every major decision and project stage gate, PSE will examine all reasonable alternatives. Before meters and modules are installed, the project sponsors should evaluate the merits of continuing onto the meter deployment, where the bulk of the costs for this project lie. The rate of AMI meter/module deployment can be increased or decreased in later years to complement other PSE long-term goals

**Officer and Board Engagement**

PSE has reviewed the AMI project and contractual elements of the L+G relationship at the executive level and with the Board of Directors over the course of the development of this project and the conclusions that provided the current direction. A final presentation was made to the Board on November 3, 2016.

**Adequate Documentation**

[34] The Agreement allows for either Termination for Cause or Termination for Convenience. Termination for Cause is only allowed if specific factors occur. Termination for Convenience is allowed with proper notice although termination penalties may apply.

PSE has captured the supporting documentation for the analysis and decisions in the AMI SharePoint and AMI binder located with Sponsor Director.

# Appendix D - Regulatory Implications

**Regulatory Approvals if applicable**

a) Regulatory approvals required

While regulatory requirements have spurred the development of AMI deployments in many states, in the Northwest, regulators have been relatively silent on the issue of smart grid and AMI deployment. Currently under review with the WUTC is Avista's rate case which includes AMI investments. Investments in this technology are expected to be recovered through rates and hence will require inclusion in a rate case.

Regulatory stakeholder engagement and approval is anticipated for the prepayment and remote disconnect programs along with any tariff changes including customer opt-out provisions.

b) Time frame expected

The amount the deployment will impact the 2017 GRC is still being analyzed. Most of the expense of this project is outside of the time window ending Sept. 30, 2016, for the 2017 GRC. The major project cost will align with subsequent rate cases. See part d) below.

Certain tariff changes such as customer opt out provisions will be pursued in 2017 prior to meters installation in Q4. Regulatory stakeholder engagement for the prepayment and remote disconnect programs anticipated after initial installation in 2018.

c) Process for approvals

General rate case

Tariff changes will follow routine process.

d) Expected probability to achieve the approvals

PSE will study the treatment of the Avista AMI investments coming from its 2015 rate case. It is expected that the WUTC will provide rate adjustments for the investment in the basic AMI technologies. Approvals relative to prepayment and remote disconnect programs is still an unknown.

## Appendix E – AMI-related Benefits from Get To Zero Program

The GTZ initiative will leverage AMI to capture several benefits. Those quantified benefits are based on the use of the disconnect switch in the AMI electric meter. Several unquantified benefits drive better communication with customers in support of GTZ. A holistic understanding of the value of this AMI technology is needed to fully appreciate the benefits for PSE and customers. AMI-related efforts driven by GTZ and captured in the GTZ roadmap are described below.

| | (2017-2037)<br>Nominal $M |
|---|---|
| **Total Quantified Benefits of GTZ Project** | $428 |

The descriptions of the quantified benefits that GTZ has captured in their roadmap are below.

| Capability | Benefit Value $M Nominal | Benefit Description |
|---|---|---|
| **Disconnects for Move in/move out** | $179 | Reduce truck rolls for disconnecting/reconnecting electric meters by toggling the switch in the meter remotely and likely through an automated process |
| | | Eliminate the lost revenue and retro-billing arising from unbilled energy usage. Today, many customers who move out do not get physically disconnected from the power system so often the premise is still using energy after the move-out date. This usually results in a retro bill or unbilled energy usage. |
| | | Improvement to cash flow |
| **Disconnects/ Reconnects for Delinquent Accounts** | $249 | Reduce truck rolls for disconnecting/reconnecting electric meters by toggling the switch in the meter remotely and likely through an automated process. |
| | | Decrease the APUA obligations that come with customer non-payment by disconnecting customers sooner as their accounts become arrear, while the deposit amount will still cover the arrearage. |
| | | Improvement to cash flow |

In the financial analysis, the benefits for both the AMI project and GTZ were considered. The GTZ benefits do not make a significant impact on the NPV with the revenue requirement shown in Section 3 because there is only a minor increase in capital investment and much of the benefit comes in the form of O&M cost savings which provides no earning opportunity. However, the cost of the project to customers is impacted significantly as these two benefit sources are layered on. The cost to customers of the GTZ project actually returns money to customers and when combined with the AMI project cost to customers described in Section 3, reduces the customer cost to $90M.

| | (2016-2037)<br>Present Value $M |
|---|---|
| **Cost to Customers for GTZ Project Capabilities enabled by AMI** | -$168 |

GTZ will be seeking to improve the customer experience and operational efficiencies through the AMI technology and several benefits have been explored through GTZ planning that have not yet been quantified due to lack of empirical and/or industry data required for robust quantification today. These benefits are described below.

| Capability | Non-Monetized Benefit |
|---|---|
| **Move in/move out** | Providing more flexibility and speed to customers' move-in and move-out process. When customers move away, electric meters can automatically be disconnected to turn off power to the premise and when new electric customers establish service, the reconnection can be performed remotely, likely within minutes of the customer initiating a new account. |
| **Disconnects/ Reconnects for Delinquent Accounts** | Improve safety and security for PSE field staff during disconnection transactions by reducing exposure to arc flash risk and negative customer interactions. |
| | Ability to do quicker reconnection once payment has posted |
| **Prepay Metering Services** | Increased cash flow from payments upfront before electricity is used |
| | Reduction in the number of delinquent payments |
| | Reduction in the cost and frequency of manual service disconnection and reconnection |
| | Customer benefits arising from no deposit requirement, no late fees, no monthly bills, no disconnect/reconnect fees and better energy use information for both money management and conservation goals. |
| **Outage Management** | Quicker situational awareness of an outage through incorporation of meter power-out messaging into the OMS. |
| | Outage predictions without customer calls, leading to prompter restoration possibly before customers know they are out. |
| | Higher reliability and confidence from meter pings due to AMI network architecture's increased redundancy and resiliency. |

| | |
|---|---|
| **Advanced Analytics** | Increased visibility to system loading on distribution lines and equipment which allows for proactive mitigation of overload conditions and better information to inform prioritization for maintenance planning. |
| | Increased intelligence on tamper events and energy diversion to reduce losses/increase revenue. |
| | Higher-fidelity customer usage data for rate studies, capacity planning, conservation and energy efficiency program implementation and evaluation, and billing investigations |
| | Ability to troubleshoot customer to transformer mapping errors within GIS without field visit by using voltage signature data from meters. |
| **Customer Engagement** | Higher fidelity information for customers to troubleshoot high bills, select energy efficiency measures, or engage in other PSE programs/services. |
| | Detailed information from meters to allow PSE to proactively notify customers of outage, forecast monthly billing, issue high bill alerts. |

# Appendix F – Business Case Development and Review

The following people contributed to the development and review of this business case:

| Contributing Team Member | Organization |
|---|---|
| Laura Feinstein | Smart Grid Technology Planning & Analysis |
| Spencer Jones | Smart Grid Technology Planning & Analysis |
| Sylvia Gard | Contract Services |
| Heather Brickey | Project Management |
| Susan Free | State Regulatory Affairs |
| Karen Fulmer | Contract Management |
| Patrick Moore | Customer Care |
| Mitch Droz | Budgeting and Financial Performance |
| Ryan Redmond | Contract Services |

**Review**

| | |
|---|---|
| Cathy Koch | Director Steering Committee |
| Harry Shapiro | Director Steering Committee |
| Mike Richardson | Director Steering Committee |
| Wayne Gould | Director Steering Committee |
| Dan Koch | Director Steering Committee |
| John Mannetti | Director Steering Committee |

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# Appendix G – Glossary

| Term | Definition |
|---|---|
| 1. AMI | Advanced Metering Infrastructure: Meter reading system with enhanced capabilities that include two-way communication and command and control capabilities. |
| 2. AMR | Automated Meter Reading: Meter reading system with basic capability to read meters, provide outage information. PSE's system is characterized by a point-to-point network that is uni-directional down to the meter. |
| 3. APUA | Accumulated Provision for Uncollectible Accounts: used to reserve for the potential impairment of accounts receivable on the balance sheet, and must be large enough to cover all receivables within electric and gas, invoices for customers who have been designated as bankrupt and residential customers who have been identified as Prior Obligation. |
| 4. CVR | Conservation Voltage Reduction: The act of reducing the voltage on a circuit to induce less power consumption by end-users. AMI meters are used to measure the voltage levels on the line to ensure that minimum levels are maintained. |
| 5. DA | Distribution Automation: A technology-based approach to detecting faults, isolating them, and restoring as many customers as possible customers on faulted circuits through automated switching. |
| 6. GTZ | Get-to-Zero: A PSE initiative intended to improve upon and reduce customer interactions with PSE by providing self-service solutions as well as addressing poorly functioning processes that cause customers to call in. |
| 7. L+G | L+G is the abbreviation for Landis + Gyr, PSE's vendor partner for meter reading equipment and services. |
| 8. MDMS | Meter Data Management System: PSE's longitudinal database that stores meter reads and all diagnostics, validation, estimation, edits made to these reads. |
| 9. OMS | Outage Management System: PSE's control system for managing system outages and switching/clearances. |
| 10. Retro bill | An energy bill that is sent for unbilled past usage that occurred prior to the current billing period. |
| 11. TOU | Time of Use is a rate structure that charges different rates for different time of day when energy is used. |
| 12. UEU | Unbilled Energy Usage: Energy that is used at a premise that has no customer assignment. This occurs when a customer |

| Term | Definition |
|---|---|
| | moves out and terminates service with PSE but physical disconnects are not performed. The next tenant may not establish service back to the move-out date of the previous tenant so any energy used during that period is UEU. |

# Appendix H –Change Log

| Revision | Date | Submitted by | Change Summary |
|---|---|---|---|
| 1.2 | 6/17/16 | Laura Feinstein | Incorporate feedback from GTZ |
| 1.3 | 10/17/16 | Laura Feinstein | Update benefits to reflect AMI project and GTZ project benefits distinctly. |
| 1.4 | 10/20/16 | Laura Feinstein | Added in Alternatives analysis figures. |
| 1.5 | 11/4/16 | Laura Feinstein | Presented net benefits; included additional references. |
| 1.6 | 11/7/16 | Laura Feinstein | Added sensitivity analysis |
| 1.7 | 11/11/16 | Laura Feinstein | Updated financial analysis |