Exh. JDD-1T

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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-20_____

DOCKET NO. UG-20_____

DIRECT TESTIMONY OF

JOSHUA D. DILUCIANO

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Joshua D. DiLuciano, and I am employed as the Director of Electrical Engineering for Avista Utilities (Avista or "Company"), at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I am a graduate of Washington State University (WSU), from which I earned a Bachelor of Science degree in Electrical Engineering. I also earned a Master of Science degree in Management and Leadership from Western Governors University and am a licensed electrical engineer in Washington State. I joined Avista in 2006 as an Engineer and have held a variety of technical engineering roles since. I have managed several groups, including the Electric Metershop, Engineering Technical Services, Clarkston Operations (both natural gas and electric), Enterprise Maximo, and Energy Delivery Projects. I was awarded my current position in 2017, where I have responsibility for Washington Advanced Metering Infrastructure (AMI), the Company's geographic information system (GIS) Refresh, Transmission Engineering, Distribution Engineering, Protection Engineering, Substation Engineering, Drafting and Edit, Maximo, and Engineering Technical Services.

I am a U.S. Navy veteran, and I currently serve on the board of the West Central Community Center. Additionally, I am an advisory member for the WSU Electrical Engineering and Computer Science department.

Q. Are you sponsoring any exhibits that accompany your testimony?

A. Yes. I am sponsoring Exh. JDD-2 which is the "Avista Utilities Advanced Metering Infrastructure (AMI) Project Report", hereafter referred to as the "Report", which was filed with the Commission on August 31, 2020. After filing the Report, and as the Company was accounting for revenue requirement offsets for avoided costs, Avista found an inadvertent error overstating the amount of savings achieved for manual meter reading in 2018. Financial benefits in the Report (on a nominal and net present value basis) have been adjusted accordingly, in addition to making several non-substantive grammatical edits. Those edits were filed in Docket Nos. UE-170327 and UG-170328 on or about October 30, 2020, and are reflected in Exh. JDD-2.

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

A. I am the witness primarily responsible for addressing the details contained within the Report (Exh. JDD-2) as sponsored by me. As such, I will address the history of our AMI Project ("Project") deployment, its rationale, and refinements made over time. Finally, I will speak to the <u>net</u> benefits to customers over time, even under the most conservative of assumptions. A table of contents for my testimony is as follows:

II. AVISTA'S AMI INVESTMENT

Q. Would you please recount the history of filings with the Commission relating to Avista's AMI Project?

A. Yes. Avista's initial proposal to deploy its advanced metering system was considered by the Commission as part of the Company's electric and natural gas general rate case in 2015 (Dockets UE-150204 and UG-150205, *Consolidated*). At the conclusion of that case, Avista's final estimate of net Project benefits was $3.5 million over its 21-year life. We also requested the Commission approve deferred accounting treatment for the undepreciated value of our electric meters to be replaced during deployment. The Commission determined that Avista's requests were not ripe for determination, and further discussed the refined analysis they would expect to see in support of the Project in a future proceeding.

In anticipation of presenting a revised business plan as part of its next general rate case, the Company filed an accounting petition (Docket UE-160100) requesting deferred accounting treatment related to the undepreciated net book value of its existing electric meters. The accounting petition, as amended, was subsequently approved by the Commission in March of 2016; however, it was not effective until the Company executed major vendor contracts for the Project. Avista's approved deferral accounting was again amended in 2017 to include the undepreciated net book value of retired natural gas meter registers.

In February of 2016, the Company filed a revised business case for its advanced metering Project as part of its next electric and natural gas general rate case (Dockets UE-160228 and UG-160229, *Consolidated*). Avista's estimate of the capital cost of implementation was increased to $166.7 million, with an anticipated operations and maintenance lifecycle cost of $123.4 million. The revised Project was expected to deliver <u>net</u> financial benefits of $26.6 million. The Commission offered Avista several recommendations related to the Project in its final Order, however, because it did not adjust Avista's revenue requirements in that case, they did not decide the issues raised in the case concerning the advanced metering Project.

Q. What concerns were expressed by the Commission and parties in connection with prior filings?

A. In the Orders discussed above pertaining to our advanced metering system, the Commission highlighted several areas of interest and concern and noted those raised by Staff and parties to the cases. In discussing these concerns, the Commission urged the Company to make progress resolving these issues, both before and during deployment of the system, in an effort to reduce the uncertainty and possible contention surrounding cost recovery. We have attempted to diligently address these key issues, as briefly described below.

Q. How has the Company addressed concerns over whether AMI investments are "used and useful"?

A. Multiple concerns were raised in the Company's 2015 general rate case over the 'guidance' requested of the Commission by the Company regarding its planned investment in an advanced metering system. Through the course of the 2015 and 2016 general rate cases the Commission stated its policies and practices governing its review and approval for recovery of utility investments. The advanced metering system is now[1] functionally used and useful, and well before the completion of this case.

Q. What about the level of certainty surrounding Project costs and customer benefits?

A. The Commission previously noted comments of Staff and the parties, as well as raising concerns of its own, regarding the planning level estimates of Project costs and benefits presented by the Company in its 2015 general rate case. Accordingly, we presented improved estimates of costs and benefits for the Project in our 2016 case. The refined estimates of Project costs included more known information, greater detail and a planning margin for remaining

[1] Only incidental portions of the natural gas metering need to be installed before the end of Q2 of 2021. The Company will update this information during the pendency of the case.

uncertainties to be experienced during implementation. We also refined our projections of financial benefits and estimated a range in potential variability for each area of benefit. With the Project now largely completed (98%), the net present value of the final capital and O&M costs (now known) will be <u>much less than</u> estimated in 2016. Likewise, the <u>net</u> financial benefits quantified today are nearly double our 2016 estimate.

Q. How have "disconnects" for nonpayment been addressed?

A. In both our 2015 and 2016 general rate cases, the Commission and some of the parties expressed concern over the potential that the use of the remote service switch could negatively impact customers by increasing the long-term rate of service disconnections for non-payment. Throughout our history we have always taken care to ensure our customers have multiple opportunities to make a payment or payment arrangements to avoid having their electric service disconnected. Taking advantage of the savings offered by advanced metering and based on our experience in Idaho for even a longer period of time, we began using the remote service switch for these cases in our Pullman service area in 2012. Because we were still concerned about any potential that use of the remote switch could result in a long-term increase in service disconnections, we carefully monitored these results as well as any potential customer complaints associated with remote disconnections. During the 2016 case we showed that customer disconnects had not statistically increased in our Pullman service area since the deployment of advanced metering and reported that we had received no Commission complaints as a result of this practice.

As contemplated by the Commission in 2016, Avista, Staff and the parties engaged in a rulemaking to address various consumer protection issues related to the deployment of AMI, including remote service disconnection (Docket U-180525). This rulemaking process concluded on July 29, 2020 with the issuance of General Order R-600, which amended and permanently adopted new rules in both WAC 480-100 and WAC 480-90.

Q. How did Avista address the Commission's rules related to remote service disconnection in its Report and in this case?

A. Avista believes the Commission's adoption of new restrictions on use of remote service for some service disconnects does not fundamentally alter the net financial benefits presented in the Report. When Avista made the decision to proceed with AMI in Washington the net benefits were based on what was known at the time, including, in part, the elimination of staffing and related costs for manual service disconnects and reconnects. That changing conditions in the future may either increase or decrease the actual financial savings achievable with AMI does not alter the Project costs and benefits that were known at the time Avista made its decision to proceed, and which provide the basis for the determination of prudence. With the Commission's ruling in July 2020, the Company will add four employees to meet the requirements of the new rule, at an estimated incremental cost of approximately $271,000 per year. Accordingly, witness Ms. Andrews has reduced the estimated reduction in revenue requirement for AMI included in this case by that amount, while the Project net benefits remain as stated in the Report.

Q. Why is continued use of the Interruption Cost Estimator (ICE) Model for calculating outage costs still appropriate?

A. The Commission noted the extensive concerns expressed by Public Counsel in our 2015 general rate case regarding the efficacy of the Interruption Cost Estimator (ICE) model developed by the Lawrence Berkeley National Laboratory for assessing customer costs related to electric service outages. The approach used in the model for estimating the cost to customers for electric service outages has been compared with alternative approaches and found to provide results that are superior to other methods, in a paper sponsored by the National Association of Regulatory Utility Commissioners (NARUC).[2] The concern for Public Counsel focused on a sampling methodology used to estimate outage costs *for only residential customers*.[3] Unfortunately, the Public Counsel witness conflated this methodology with the "actual cost" surveys used to estimate financial losses for commercial and industrial customers.[4] This confusion even found its way into the Commission's Final Order where it referred to the interruption calculator as based on what "…customers would pay to avoid an outage."[5] The contingent value sampling method challenged by the witness, however, was used to estimate <u>less than three percent</u> of the financial costs that are associated with only residential customer outages, while greater than 97% of the estimated costs are based on the actual financial costs experienced by commercial and industrial customers during an outage.

Q. Have customer "opt-out" policies been addressed?

A. Yes. In our 2016 general rate case, the Commission anticipated there would be customers who would want to opt-out of receiving service from an advanced meter and stated its interest in having the Company present a plan and tariff proposals to provide for the same. After a year of informal discussions, the Commission initiated an inquiry process (Docket U-180117) related to customer choice for advanced meter installation. Avista actively participated

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[2] Evaluating Smart Grid Reliability Benefits for Illinois. National Association of Regulatory Utility Commissioners, A Report for the Illinois Commerce Commission funded by the U.S. Department of Energy. 2011.
[3] Contingent valuation or "willingness to pay" survey methods derive an attribute value by determining a price representing what someone would pay to avoid, in this instance, an electric outage.
[4] Actual cost surveys, gathered through individual customer interviews, document the direct financial losses that are experienced by commercial and industrial customers due to a service outage.
[5] Washington Utilities and Transportation Commission v. Avista Corporation, Dockets UE-150204 and UG-150205 (Consolidated), Final Order 06, at para. 183, January 6, 2016.

with the parties in a workshop established by the Commission and filed applicable comments. The inquiry culminated with the publication of a Commission Policy and Interpretive Statement in April 2018. Avista subsequently filed a proposed opt out tariff pilot (Docket UE-180418) and again participated with the Staff and the parties in a subsequent Commission Open Meeting to discuss the Company's proposal. Avista's amended tariff pilot was subsequently approved by the Commission with an effective date of August 2, 2018.[6] Among other stipulations in the pilot tariff, which included modifying our request to meet customer needs such as allowing customers to keep their existing meters, Avista is required to track the actual costs for manually reading meters for opt-out customers as a basis for potential amendment of these tariffed costs long term.

Q. Have customer privacy concerns been addressed?

A. Yes. In its Final Order in our 2016 general rate case the Commission expressed its interest in promoting Avista's careful consideration of customer privacy and protection of personal and proprietary information. We understand the critical nature of protecting our customers' information and interests in every aspect of the conduct of our business, including new technology platforms like AMI. Through the course of deployment, we have taken the necessary steps to address these issues as discussed in Avista's Report. We also have the benefit of recently-enacted rule changes (WAC 480-100-153) on July 29, 2020, governing customer privacy protections.

Q. How has the Company addressed cyber security?

A. In its 2016 Order, the Commission also reiterated its interest in requiring the

[6] Washington Utilities and Transportation Commission v. Avista Corporation, Dockets UE-180418 and UG-180419, Order 01, July 30, 2018.

Company to continue to advance its capability to shield customer data and utility infrastructure from continuing cyber security threats associated with the potential vulnerability of advanced metering technology. Through the course of deployment, we have continued to advance our cyber security capabilities and strategies to protect every aspect of our business from cyber security threats, including our advanced metering system.

Q. Did the Commission Staff express its views with respect to Puget Sound Energy's (PSE) AMI program?

A. For its part, Commission Staff, in response to PSE's recent request to recover its AMI investments, noted that PSE reasonably determined that it needed to replace AMR infrastructure, reasonably selected AMI from available alternatives, reasonably involved its board and management, and adequately documented its decision-making process. (See PSE Order at para. 139.) Likewise, Avista has also methodically investigated and implemented its AMI system, with active management oversight and documentation, as discussed in the Report.

While much of Avista's Report has focused on the costs and customer benefits of our advanced metering system, we believe it's important to restate how our decision to undertake this deployment serves our customers' overall interests and meets the Company's obligations under the Commission's prudence standard.

Q. Was there a timely need for this Project?

A. Yes. In Section 1 of the Report, we describe how our industry and business model are changing and why we believe AMI is essential to the delivery of service to our customers. As just one example, we explain how this system plays a central role in our achievement of a range of new energy conservation savings and how it will enable the implementation of new demand response strategies called for in our current Integrated Electric

Resource Plan. Indeed, our obligation to acquire new cost-effective capacity resources through measures such as variable peak or time of use pricing would be unachievable without the capabilities of our advanced metering system. Similarly, our requirement to focus more on distributed energy resources and non-wire solutions in electric distribution planning are significantly enabled by AMI. Across the Country, utilities responding to these multiple needs for the capabilities of advanced metering are expected to have well over 107 million meters deployed by the end of this year. As recently noted by Puget Sound Energy and the Commission, moving to an advanced metering platform has become the industry metering "standard" and the operational decision to install AMI now is prudent.

Q. Did the Company evaluate reasonable alternatives?

A. Yes. The industry's move to adopt the AMI metering standard makes the prima facie case that there is no reasonable alternative technology or combination of technologies that perform the key functions of advanced metering at a similar or lower cost. In our initial business case, we looked at the capabilities of other metering technologies, such as an automated meter reading system (AMR) combined with other applications, as a potential alternative to advanced metering infrastructure. But there was no combination of applications or technologies, even then, that performed the functions of AMI at a comparable cost. Today, advanced metering is more robust and reliable with expanded capabilities such as the "edge" computing features of the Itron Riva system. More recently in the case of Puget Sound Energy, some parties cited presumed alternatives to AMI for capturing individual customer benefits, such as conservation voltage reduction, or automated meter reading through AMR, but no other technology alone or in combination provides the central platform essential to meeting our future service needs or cost effectively integrates the multiple range of benefits accomplished by AMI.

Q. Was Avista's Senior Management appropriately involved?

A. Yes. As noted throughout the Report, Avista's senior executives that compose the Executive Technology Steering Committee, which includes among others Avista's President and Chief Operating Officer, have maintained active involvement in the Project from its inception. Their involvement included approval of the Project scope, the capital and operating budgets, and presentation of the planned capital investment to the Company's Board of Directors for approval. As described in the Report, the Executive Steering Committee was updated each month by Project management staff, which updates included review and approval of analyses of Project status, challenges, risks and responses, incremental changes in scope and cost, and recommendations related to technology challenges, such as maturity of the metering hardware and software systems, and any changes in deployment schedules. As noted below, these reviews and approvals have been well documented, and they demonstrate a robust record of the engagement, management, review and approvals of the Company's senior leadership.

Q. Was there sufficient documentation of the decision-making process?

A. Yes. Avista Project management staff has kept detailed records of key decisions made during the course of the Project, including factors leading to key decisions, the associated risks and consequences, and support for why these decisions represented the best interests of our customers and the Company. These include records of meetings of Project staff for each of the major phases (e.g. communications infrastructure or meter data management system), and meetings for the overall management of the AMI Project. Documentation shows how issues identified at the Project-level were elevated for review and approval by the Executive Steering Committee. These records document the topics discussed, and decisions made as appropriate, and include records of proposed changes in Project scope and budget, including documentation of the review and approval of the Executive Steering Committee. Project documentation also includes regular refreshes and updates to forecasts of Project costs made during deployment, and updates to estimates of Project benefits. In summary, Avista's Project documents provide a detailed and comprehensive record of the many key decisions made through the course of deployment by Project-level staff and the Company's senior leaders, attesting to the prudence of each decision and the Project overall.

Q. What are some of the forces driving changes in the utility industry?

A. From Avista's perspective, these underlying forces can be aggregated into three groups:

- Clean Energy and Conservation: A societal, and indeed, a global response to changes in climate and the desire to significantly and quickly reduce CO2 emissions. Among responses to this call for action has been the societal and legal shift to require a greater percentage of our electricity supply be provided by renewable resources. There are also calls now to actively shift current energy uses met by fossil fuels to clean electricity. The cost of these changes is putting greater price pressure on customers and will continue to drive an ever greater need to use electricity more efficiently. Conservation measures, including pricing strategies that were historically not viable because of Avista's low electric rates, will be ever more important. For example, Washington has new building codes that require drastic reductions of energy consumed in buildings going forward. With our AMI investment, we have the tools and insights that allow building owners and managers to understand where and when their energy demands are occurring, and then take action to reduce that consumption.
- Enabling Technologies: The rise and maturing of new technologies are changing the electricity landscape. These include significant reductions in the cost and availability of customer-owned renewable electricity generation, and control and storage, coupled with regulatory changes promoting investment in distributed

energy resources. The digitization of massive volumes of customer data is now combined with complex, interoperative and integrated control systems, allowing new market players to provide traditional utility customers with a range of energy services their utility provider may not offer, at price that's ever more competitive.

- Customer Empowerment: Utility customers have a growing ability to exercise greater choice and control over their traditional monopoly utility service. This includes use of technology to help manage and reduce their energy costs, the use of distributed energy resources to reduce reliance on the serving utility, and the growing opportunity to sell their electricity to others outside the utility's control, while otherwise relying on the utility's dedicated infrastructure. Finally, the falling price of electricity storage and management systems, coupled with onsite generation, may soon provide traditional customers a real option to bypass their service utility altogether. Through all of this, the utility must stand ready to serve.

Q. What are the conservation use cases for AMI?

A. The potential for energy conservation, aided by smart metering, is substantially expanded from the initial model. As noted earlier, The American Council for an Energy-Efficient Economy, in their recent article "Leveraging Advanced Metering Infrastructure to Save Energy,"[7] presents multiple energy efficiency use cases, summarized below, designed to more effectively leverage the value of the AMI platform in helping the utility and its customers reduce energy consumption and lower costs. <u>Avista has already expanded plans from its initial business case for AMI and has either implemented or is actively developing conservation initiatives ***for each use case*** described in the report.</u> Below we summarize each conservation use case described in the report, followed by a brief overview of Avista's efforts, explained in

[7] Leveraging Advanced Metering Infrastructure to Save Energy. Rachel Gold, et al. The American Council for an Energy-Efficient Economy (ACEEE). January 2020.

more detail in Sections 4 and 6 of the Report.

- Targeting Strategies involve leveraging AMI-based load disaggregation or using profile clustering to focus the utility's conservation engagement on customers most likely to take action to reduce their consumption.
- Energy Use Feedback involves using the advanced metering system to provide customers access to their near-real time energy use to help them better understand and manage their energy use. This use case provided the initial energy conservation push for advanced metering.
- Behavioral Feedback Programs involve providing customers with personalized insights based on their interval data to help motivate them to take actions to reduce their energy consumption. The report authors note that these tailored reports are a common application of behavioral feedback in the industry.
- Measurement and Verification of conservation savings is made more accurate and timelier by the ability to use smart metering data.
- Energy Pricing Strategies allow customers to select how and when they use energy to lower their bill. As an example, smart metering enables the utility to better understand the usage profile of each individual customer and offer rate plans that meet that customer's need, while at the same time saving them money on their utility bill. Examples of this include demand response (DR) events or time-of-use rates that align with the customer's need. "A demand response company can provide more actionable feedback on customer energy usage to help the customer save money while benefitting all customers by reducing the system's peak demand."[8]
- Grid-Interactive Efficient Buildings to expand the role of flexible, controllable electricity loads to improve energy efficiency, system capacity and lower infrastructure costs. Buildings consume 40% of the nation's energy, and approximately 70% of our electricity is used for heating, lighting and motors, etc.

[8] Ibid.

- Pay for Performance Models that reward customer energy savings on a going-forward basis rather than providing up-front payments for conservation investment.
- Conservation Voltage Reduction programs can be made more effective by relying on voltage measurements taken at the customer's service point to help lower the overall voltage level on the feeder. This is an effective approach that reduces the cost of serving electric customers.

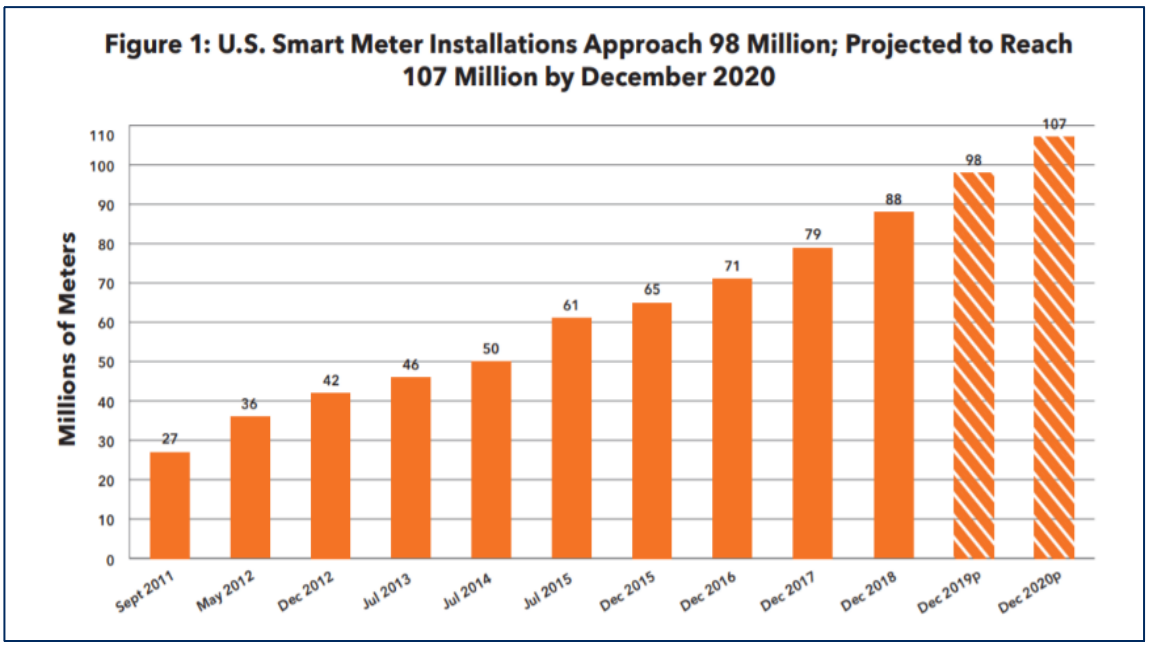
Q. Does AMI also serve to address needs at the "Edge of the Grid"?

A. Yes. Avista has taken a number of steps over more than a decade to help us better optimize our utilization of the electric distribution system, to lower electricity costs for our customers, to maintain and uphold our system reliability in high-density service areas, to promote the development of electric transportation, and to learn more about how to effectively integrate, utilize, and optimize distributed energy resources. More recently, we have been systematically evaluating the interaction between new technology systems and emerging customer choices and markets at the grid edge through an internal employee team referred to as the Grid Edge Consortium. The goal of this group is to understand and anticipate industry trends as well as technology advancements so Avista can prepare to meet future customer demands and expectations 'ahead of the curve.' Avista's Grid Edge Consortium has identified a developing future state we referred to as the "shared energy economy", and has developed a comprehensive roadmap identifying technology, infrastructure, regulatory, and a range of other structural and process achievements necessary for its realization. As noted, the deployment of AMI is one of the first essential technology steps required to realize this vision.

Q. What are the trends in AMI implementation in the country and our region?

A. National trends in advanced meter deployment are a familiar topic in advanced metering business cases, and nationwide trends exceed projections included in the Company's earlier 2016 business case, as shown below in Illustration No. 1 below (included as Figure 1-1 in the Report). As of year-end 2018, electric utilities had installed more than 88 million smart meters, covering nearly 70 percent of U.S. households. Based on survey results and plans approved in 2019, estimated deployments were expected to reach 98 million smart meters by the end of 2019 and 107 million by year-end 2020.[9]

ILLUSTRATION NO. 1 - ACTUAL AND EXPECTED TREND IN DEPLOYMENT OF ADVANCED METERING IN THE UNITED STATES. EDISON FOUNDATION, 2019.[10]



Q. What has been the experience in Washington State?

A. While Washington State lags behind the West Coast in deployment of smart meters, several utilities are in the process of completing system installations, as shown in the Table No. 1 below.

[9] Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2019 Update). Edison Foundation, Institute for Electric Innovation. 2019.
[10] See Report at p. 27 (Exh. JDD-2), Figure 1-1

TABLE NO. 1. UTILITY DEPLOYMENTS OF ADVANCED METERING IN WASHINGTON STATE[11]

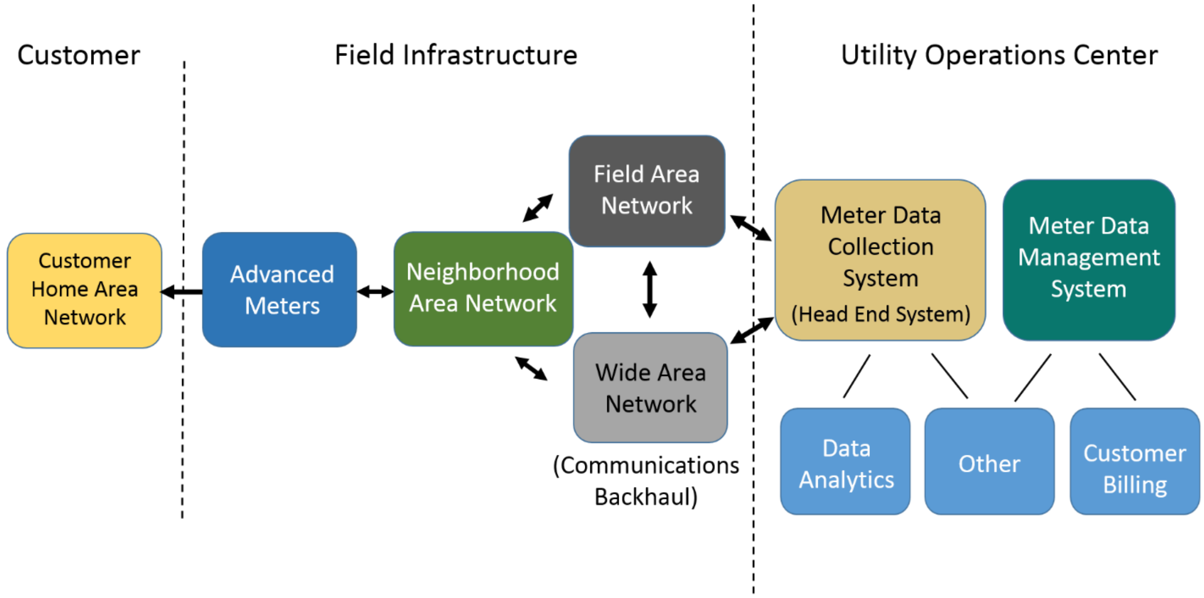
Company	Dates	Number of Meters Deployed
Puget Sound Energy (PSE)	2017-2023	1.1 million electric meters 800,000 natural gas modules (PSE, 2020)
Seattle City Light	2016-2019	461,496 electric meters (Seattle City Light, 2020)
Tacoma PUD	2018-2022	190,000 electric meters 110,000 water meters (Nhede, 2020)
Inland Power & Light	2013-2015	39,000 electric meters
Avista	2017-2020	249,391 electric meters 160,166 natural gas modules
Total		**Electric Meters: 2,039,887** **Natural Gas Meter Modules 960,166**

Q. Would you please describe the basic components of the AMI system?

A. While there is greater familiarity with advanced metering systems today than when the Company released its initial business case in 2016, we believe it is still helpful in this discussion to provide a brief overview. The diagram below (Figure 3-1 in the Report) represents the AMI system, including the advanced meters themselves, specialized communications hardware and software (neighborhood, field, and wide area networks) and the head end, meter data management, and data analytics systems. These key components are depicted in the following diagram and are briefly described below.

[11] See Report at p. 27 (Exh. JDD-2), Table 2-1.

ILLUSTRATION NO. 2 - DIAGRAM OF AMI INTERCONNECTION WITH CUSTOMERS.[12]



Each of these components is described in more detail at pages 29-30 of the Report (Exh. JDD-2).

Q. Would you briefly describe the oversight exercised to deliver the AMI Project within budget?

A. One of the key factors supporting our successful deployment was the detailed forecasting and budgeting used to develop cost estimates for the initial business case. We understood the importance of developing estimates in our 2016 business case that would help give the Commission and parties greater confidence in the validity of the forecasts. In addition to having greater detail, the Project managers were attentive both individually and as a group to managing emerging issues and uncertainties and developing innovative ways to optimize solutions and costs. This provided good financial visibility and controls needed to effectively manage the budget across multiple programs and over the entire deployment period. In this

[12] See Report at p. 29 (Exh. JDD-2), Figure 3-1.

process funds were shifted as needed by Project and from year to year to best optimize Project costs in meeting milestones and schedules. Budgets developed for individual projects, as well as the overall Project budget were refreshed monthly, including the identification of emerging uncertainties, development of plans for managing them, and reforecasting the expected final cost. Any proposed changes in budgeted amounts were presented monthly to the Officer Enterprise Technology Governance Group. During this monthly review, the executive team was apprised of the status of each Project, considered and approved any recommended changes to individual Project budgets that would impact available contingency funds, and reviewed and approved other key decisions necessary to optimize delivery of the AMI system. The result of this continuous oversight and flexibility to adapt, was to bring the Project in <u>under</u> what was expected in 2016.

Q. What difficulties did Avista experience along the way?

A. In late 2014, Itron announced the launch of its Riva™ metering system. Beyond traditional smart metering capabilities, the Riva system was designed and equipped to support applications and computing capability installed in meters themselves (distributed computing power). Riva represented the next generation metering platform described as a new 'edge intelligence platform' supporting sensing technologies and dynamic applications at the device level. By embedding the operating system, applications and processor into field devices and sensors, the system also has the potential to reduce both the amount of traffic on the network and how much data needs to be retained at the corporate level. Edge computing has the potential of reducing the long term costs of the supporting infrastructure for AMI. In Avista's view, the value of this platform was its potential to support control and analytics for automated decision making at the edge of the grid, and key functionality supporting our Grid Edge roadmap.

Further, the Riva platform had the potential for integration of third-party devices into the network, creating the future opportunity to unlock the value of 'the internet of things' in support of utility operations and more importantly our customers directly. At the same time, Avista understood the initial releases of such new systems could be fraught with delays, setbacks and disappointments, all of which add costs to the Project.

Avista weighed the value of implementing the new system with enabling characteristics key to our Grid Edge strategy with the potential costs that could be incurred with delays in a first-generation system and elected in September 2016 to purchase the new Riva system from Itron. The RIVA system, unlike others, will allow Avista to maximize potential applications. The systems purchased by the Company included head end system hardware and software, communications systems hardware and software, the electric meters and natural gas communicating modules and operating software, and some of the data analytics applications implemented by the Company.

Q. Did these difficulties cause a delay in full implementation?

A. Yes. Avista experienced a delay in deliverables with the new system in March 2017, when Itron announced delays in the pending releases of system hardware and software. Combined with other head end and meter data management system challenges, Avista made the decision to delay the planned meter deployment and to extend the Project timeline by one year. This decision allowed us to reduce and manage risks to the Project while optimizing the cost impacts associated with the delay. We also used the additional time to continue testing and optimizing the overall advanced metering system and to develop our integrated AMI operations team to support the system once deployed in the field. Apart from the deployment challenges, the need to extend the schedule had a substantial impact on the value of the expected financial benefits (reduced by approximately 15%). Fortunately, these are more than offset by cost savings described elsewhere.

Q. How is the Riva system performing now?

A. Overall, the Riva system is performing well and is meeting the broad range of key business requirements, such as accurate metering and billing for Avista's customers, voltage monitoring and early notification of outage events. In each instance of these product challenges, Itron has worked with the Company to develop a plan of action to remedy the issues over the short and long term. Avista is continuing to work closely with Itron to ensure we timely achieve expected system performance. The impact of these remaining issues is reflected in the Company's current business case, both in terms of the cost impacts to the Project and in the timing and magnitude of benefits we expect to deliver to our customers. The key point is the level of ongoing proper oversight by management to address problems, discuss solutions, and choose final actions.

Q. How has the Company engaged with its customers to explain AMI?

A. As noted earlier, Avista understood the potential for the rollout of its advanced metering system to be derailed if customers were not somewhat familiar and comfortable with the technology. We knew from similar deployments gone awry, that the stakes were high, and the risks were real. Our customers may have already been exposed to negative media coverage from other AMI deployments across the Country and, being one of the largest capital projects in Avista's history, public acceptance was a critical element of the Program's success. From our experience communicating and working through complex issues with our customers, we proactively trained affected employees to engage, communicate, share information with and work through issues with the multiple internal and external stakeholders whose support would be key to a successful implementation. Appendix A to the Report contains a complete discussion of our communications initiatives, actions taken, materials produced and distributed and results of our efforts. Pages 44-48 of the Report also describe our customer outreach.

Q. Turning now specifically to the area of customer benefits, will you please describe the major categories, and how estimates have changed from 2016 to 2020?

A. Table No. 2 below (included in the Report as Table 4-1) provides such a summary:[13]

TABLE NO. 2 - FORECASTS OF ESTIMATED CUSTOMER BENEFITS FINANCIALLY QUANTIFIED IN THE COMPANY'S INITIAL BUSINESS CASE IN FEBRUARY 2016 AND IN AUGUST 2020.

Area of Benefit	Expected NPV 2016	Expected NPV 2020
Meter Reading and Meter Salvage	$75,920,112	$73,685,330
Remote Service Connectivity	$24,332,683	$22,010,615
Outage Management	$40,331,781	$53,723,041
Energy Efficiency	$59,384,914	$33,686,230
Energy Theft and Unbilled Usage	$28,880,881	$23,395,770
Billing Accuracy	$10,648,127	$11,406,347
Utility Studies	$2,201,905	$2,050,632
Total	**$241,700,403**	**$219,957,965**

Q. Have you prepared a more detailed tabulation of benefits under each of these broad categories?

A. Yes. The complete tabulation of benefits that includes subcategories under each of these areas of benefit is contained within the master table of benefits, Table 1-4 in the Report, and is reproduced in full below.[14]

[13] See Report at p. 49 (Exh. JDD-2)
[14] See Report at pp. 8-9 (Exh. JDD-2)

<u>**TABLE NO. 3 - FORECASTS OF ESTIMATED CUSTOMER BENEFITS FINANCIALLY QUANTIFIED IN THE COMPANY'S INITIAL BUSINESS CASE IN FEBRUARY 2016 AND IN AUGUST 2020.** *MAJOR AREAS OR CATEGORIES OF BENEFITS AND THEIR RESPECTIVE FINANCIAL TOTALS ARE SHOWN IN BOLD FONT. INDIVIDUAL BENEFITS COMPRISING EACH MAJOR AREA ARE INDENTED BELOW. (STATE OF WASHINGTON ELECTRIC AND NATURAL GAS)*</u>

Area of Benefit	Expected NPV 2016	Expected NPV 2020	Cross-References to Report
Meter Reading and Meter Salvage	**$75,920,112**	**$73,685,330**	**Pages 52-57**
Eliminate Regular Meter Reading	$68,939,150	$59,045,423	
Reduce Special Meter Reading	$445,092	$372,120	
Net Metering	$4,567,870	$4,627,144	
Customer Meter Base Repairs	Not Included in Initial Case	$6,302,323	
Natural Gas Meter Module Refresh	Not Included in Initial Case	$3,190,319	
Meter Salvage Value	$148,000	$148,000	
Local Economy Jobs	$1,820,000	Not Included in Current Case	
Remote Service Connectivity	**$24,332,683**	**$22,010,615**	**Pages 57-58**
Account Open/Close/Transfer	$11,756,573	$10,352,917	
Credit Collections/Connections	$12,180,323	$11,326,484	
After-Hours Fees	$395,786	$331,214	
Outage Management	**$40,331,781**	**$53,723,041**	**Pages 59-69**
Earlier Outage Notification	$32,817,495	$28,009,803	
More Rapid Restoration	Not Included in Initial Case	$18,673,199	
Reduced Customer Calls	$1,421,119	$1,277,163	
Avoided Single Lights Out	$2,935,025	$2,730,472	
Reduced Major Storms Cost	$3,158,142	$3,032,403	
Energy Efficiency	**$59,384,914**	**$33,686,230**	**Pages 69-77**
Conservation Voltage Reduction	$55,014,844	$18,494,601	
Customer Energy Efficiency	$4,370,070	$3,655,286	
Behavioral Energy Efficiency	Not Included in Initial Case	$8,927,226	

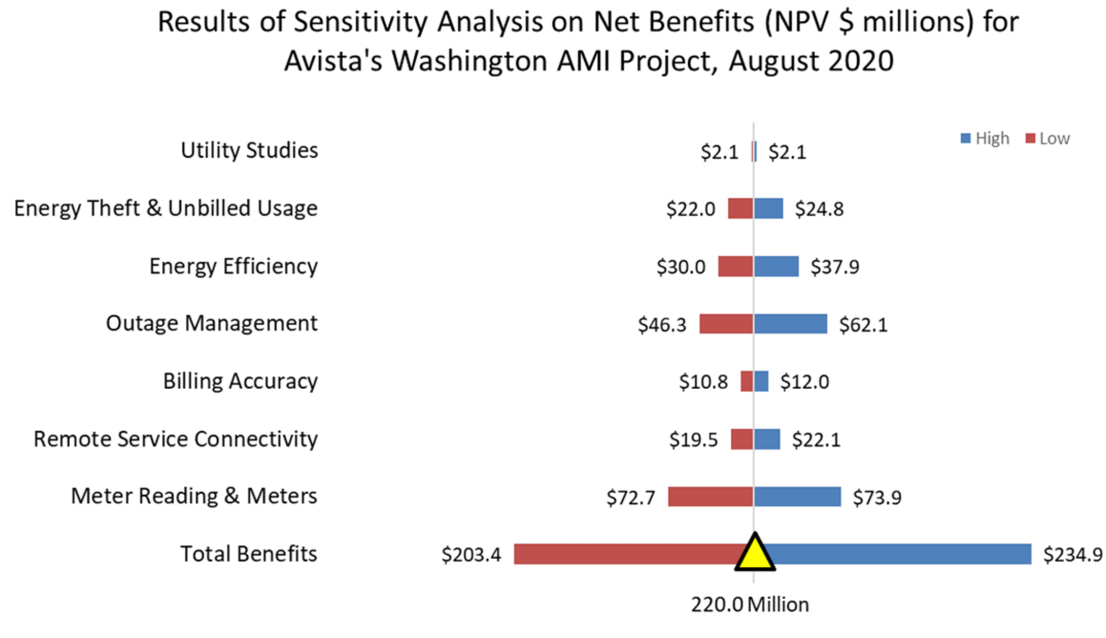
Grid-Interactive Efficient Buildings	Not Included in Initial Case	$2,609,116	
Energy Theft and Unbilled Usage	**$28,880,881**	**$23,395,770**	**Pages 77-81**
Theft and Diversion	$19,768,167	$4,499,424	
Unbilled Usage	$1,912,078	$1,951,970	
Slow/Failed Meters	$4,319,220	$3,995,883	
Stopped Meters	$2,881,416	$3,558,176	
Loss of Phase	Not Included in Initial Case	$9,390,317	
Billing Accuracy	**$10,648,127**	**$11,406,347**	**Pages 81-84**
Estimated Bills	$5,608,610	$6,783,166	
Bill Inquiries	$2,951,711	$2,472,821	
Billing Analysis	$1,387,734	$1,138,569	
Rebilling	$700,072	$1,011,791	
Utility Studies	**$2,201,905**	**$2,050,632**	**Pages 84-85**
Retail Load Analysis	$1,154,805	$979,467	
Meter Sampling	$1,047,101	$1,071,165	
Totals	**$241,700,403**	**$219,957,965**	

Q. Have you performed a sensitivity analysis around the ability to achieve projected savings?

A. Yes. Nearing completion of the deployment phase, we have gained knowledge and experience allowing us to better understand and reduce much of the uncertainty around achievement of these benefits. Our current estimates of the potential variability for each benefit category are presented in the figure below.[15]

[15] See Report at p. 50 (Exh. JDD-2), Figure 4-1.

ILLUSTRATION NO. 3 - RESULTS OF SENSITIVITY ANALYSIS FOR QUANTIFIED BENEFITS (NPV $MILLIONS) ESTIMATED IN AUGUST 2020.

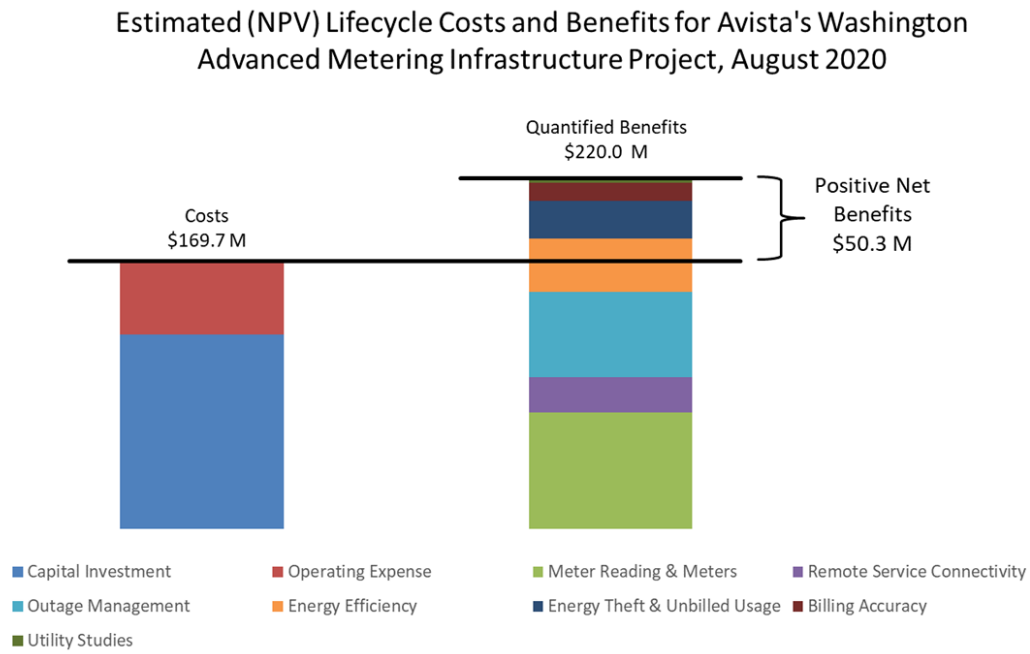


As expected, the potential range in benefits for each category, and the range in total, is reduced from our initial estimates. Even if Avista were to only achieve the extreme lower end of the range in variability in benefits ($203.4 million), the Project would still produce positive net benefits exceeding $33 million. And this would not even count any new financial benefits, nor many other "non-quantifiable" (but real) benefits such as safety, power quality, convenience, and service.

Q. Would you please conclude with a comparison of Project costs and benefits?

A. Yes. Descriptions of Project costs in the Executive Summary and in Section 3 of the Report include the actual capital and operating expenses incurred and the expenditures planned over the remaining Project lifecycle. By the close of the deployment phase in 2021 we anticipate the total capital cost to reach $156.6 million, well under the initial cost of $166.7 million estimated in 2016. Likewise, our estimated operations and maintenance costs are now forecasted to total $101.7 million over the Project lifecycle, well below our 2016 estimate of $123.4 million. The net present value of the current lifecycle capital and operating costs is $169.7 million, as shown below in Illustration No. 4, which represents more than a 20% reduction from the same estimate made in 2016 ($215.1 million).[16]

ILLUSTRATION NO. 4 - ESTIMATED LIFECYCLE CAPITAL AND O&M COSTS AND QUANTIFIED FINANCIAL BENEFITS, ON A NET PRESENT VALUE BASIS, FOR AVISTA'S ADVANCED METERING SYSTEM.



Quantified financial benefits described in Section 4 of the Report includes a point estimate of the expected net present value when fully realized (in 2016 dollars), based on the timeline anticipated for achievement of the full value of each benefit. In cash value, these benefits are expected to reach $496.5 million over the Project life, compared with a total estimated in 2016 of $510.7 million. On a net present value basis, current benefits total $220.0 million as shown above in Illustration No. 4, compared with an estimate of $241.7 million in

[16] See Report at pgs. 10 and 98 (Exh. JDD-2), Figure 7-1.

2016. Though the net present value of currently estimated benefits is roughly 10% less than estimated in 2016, the lifecycle net benefits are $50.3 million, as shown above in Illustration No. 4 (and Figure 7-1 of the Report - Exh. JDD-2 at pgs. 10 and 98), nearly double the net benefit of $26.5 million estimated in 2016.

Q. Finally, what are the net benefits under the lower end of our sensitivity analysis?

A. Even if one was to assume net benefits based on the lowest end of the current sensitivity analysis (see discussion at Section 4(A)(1) of the Report), the worst case would still produce net benefits exceeding $33 million, before including financial benefits yet to be included or quantified. Though we believe the prudence of our investment in advanced metering should be judged on the merits of all customer benefits provided by the system (both quantified and unquantified benefits), our current case clearly demonstrates the cost-effective value delivered for our customers based on the financial net benefits alone.

Q. Does this conclude your direct testimony?

A. Yes, it does.