BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1667

In the Matter of PACIFICORP, dba PACIFIC POWER, 2016 Annual Smart Grid Report.	STAFF COMMENTS

The Public Utility Commission of Oregon Staff (Staff) files these comments in response to PacifiCorp's (PacifiCorp or Company) fourth annual smart grid report (2016 Smart Grid Report).

In 2012, the Public Utility Commission of Oregon (Commission) adopted smart-grid reporting requirements for PacifiCorp, Portland General Electric, and Idaho Power Company to "ensure that utilities are systematically evaluating promising smart-grid technologies and applications, that the Commission is kept apprised of utilities' progress, and that stakeholders, Commission Staff, and the Commissioners have an opportunity to provide input into utility evaluations of smart-gird technologies and applications, as well as their plans for smart-grid investments."[1]

At a minimum, the utility's Smart Grid Report must include:

1. Smart-grid strategy, goals, and objectives.
2. Status of smart-grid investments the utility plans to take in the next five years and of projects already underway.
3. Smart-grid opportunities and constraints.
4. Targeted evaluations of technologies and applications pursuant to Commission approved stakeholder recommendations.
5. Related activities such as investment to address physical-and cyber-security, privacy, customer outreach and education, etc.[2]

[1]Order No. 12-158 at page 1, Docket No. 1460, May 8, 2012.
[2] Order No. 12-158, at 6.

The Smart Grid Guidelines specify that each utility's first report must include all smart grid reporting elements identified in Order No. 12-158. Subsequent reports need only include incremental additions and updates of all elements in the first report and information that may be required by the Commission in a previous order.[3]

In Order No. 15-367 the Commission accepted PacifiCorp's 2015 Smart Grid Report, with the inclusion of the following recommendations:

1. Include a high-level table summary of all stakeholder informal comments and corresponding Company responses as an appendix in future smart grid reports.
2. Continue to provide updates to the Commission regarding AMI evaluation as it pertains to the Company's Oregon service territory, including status updates of necessary IT and customer systems.
3. Continue as planned to report on West-of-Populus's possible results In the Company's 2016 Smart Grid Report, and if no update is available, provide a full explanation as to why that is the case.
4. Provide an update regarding the Company's use of thermal replicating relays at the Soda Springs area and any other location the Company may determine in the interim in the 2016 Smart Grid Report.
5. Provide the ensuing 2017 IRP analysis of specific transmission lines that PacifiCorp considers DLR as an alternative to traditional infrastructure upgrades.
6. Continue to report on any working relationship developments with WECC and Peak Reliability as well as providing comprehensive qualitative and quantitative analysis regarding the utilization of PMU data for transmission system model validation that the Company plans to detail in the 2016 Smart Grid Report.
7. Provide the results of the feasibility assessment for the irrigation load control pilot under consideration for Oregon, including methodologies and both qualitative and quantitative components of the analysis.
8. Include a comprehensive and exhaustive evaluation of each candidate circuit discussed in the Company's reply comments, including methodologies, assumptions, and sources that identify all potential benefits and costs of CES as appendices in its 2016 Smart Grid Report.
9. Include the update on the feasibility of Fuse Saving device implementation with the accompanying methodology and qualitative and quantitative data in the Company's 2016 Smart Grid Report.
10. Include a status update, including any benefits, of the implementation of capacitor bank, recloser, and regulator bank controls.
11. Provide a summary of ongoing efforts of completing a cost-benefit analysis of CFCIs, including alternative communication technologies such as AMI, in case the cost-benefit analysis is not ready for the 2016 Smart Grid Report.

[3] Order No. 12-158, p. 4.

12. Provide an update, including milestones, of its planned transition to a new, more powerful circuit analysis application. PacifiCorp should also provide an evaluation of the expected impact of the new circuit analysis on the potential for CVR application.
13. Describe in the 2016 Smart Grid Report how lessons learned from the irrigation TOU program can be applied to the other TOU programs offered by the Company.
14. Provide a quantitative and qualitative comparison of the Cool Keeper program's performance before and after the efficiency improvements in the 2016 Smart Grid Report.
15. Provide a comprehensive analysis, including methodologies, and qualitative and quantitative data of possible benefits and costs, of the Company's collaborative analysis of DER integration.

Below are Staff comments on each of PacifiCorp's responses to the Commission recommendations adopted in Order No. 15-367 as well as an analysis of PacifiCorp's new AMI implementation project.

Recommendations

Recommendation 1: Include a high-level table summary of all stakeholder informal comments and corresponding Company responses as an appendix in future smart grid reports.

The Company sent out its draft report to stakeholders on July 5, 2016 and requested that draft comments be submitted by July 15. Both Staff and the Oregon Department of Energy (ODOE) provided informal comments, which the Company reproduced in Table 6 in Appendix B of its 2016 Smart Grid Report. The Company also provided responses to each comment in the table with corresponding page numbers.[4]

Recommendation 2: Continue to provide updates to the Commission regarding AMI evaluation as it pertains to the Company's Oregon service territory, including status updates of necessary IT and customer systems.

See the section below entitled "PacifiCorp AMI Implementation."

Recommendation 3: Continue as planned to report on West-of-Populus's possible results In the Company's 2016 Smart Grid Report, and if no update is available, provide a full explanation as to why that is the case.

The West-of-Populus project is a dynamic line rating (DLR) project. "Line" in this context refers to a transmission line, and the rating signifies the highest current that a line can transfer without violating safety codes, impairing transmission apparatuses, or impeding network reliability. Traditionally, line ratings have been

[4] See pages 49-52 of PacifiCorp's 2016 Smart Grid Report.

static (fixed) with worst-case-scenario assumptions about thermal capacity conditions (e.g., low wind and high temperature). Because capacity is inversely related to the temperature of a transmission line's conductors, the goal of DLR is to attempt to calculate the thermal capacity of transmission lines in real time (as opposed to fixed assumptions) to optimize energy supply.[5] The West-of-Populus DLR project refers to a DLR system the Company has installed in Southeast Idaho.[6]

The Company has provided an update in the 2016 Smart Grid Report, asserting that information regarding the West-of-Populus project is difficult to retrieve due to low line loading. As a result, the transmission line has not approached the thermal capacity of the line. The Company explains that this has led to irregular line ratings, making it difficult to draw any conclusions about the effectiveness of the Company's DLR program.[7] The Company states that it will continue to monitor the line loading in its West-of-Populus DLR project.[8] Important to note is that the Company has previously identified the West-of-Populus line as being thermally constrained.[9]

Staff requests that the Company explain in its reply comments why the West-of-Populus site was originally chosen for a DLR project, what the initial appeal of the site was, and any insight as to why the line no longer appears to be thermally constrained/is reporting back irregular line ratings.

<u>Recommendation 4: Provide an update regarding the Company's use of thermal replicating relays at the Soda Springs area and any other location the Company may determine in the interim in the 2016 Smart Grid Report.</u>

In the 2016 Smart Grid Report, the Company explains that it found an alternative to its original relaying scheme. The Company had estimated the cost of a thermal replicating relay and a DLR system in the Soda Springs area to be around $1.4 million, whereas the alternative project, a remedial action scheme, is only estimated to be $115,000.[10] Staff appreciates the update and the Company seeking lower-cost options to enhance transmission network operations. Staff anticipates an update to this project in the 2017 Smart Grid Report.

Staff requests that the Company add more specifics about the redundant relays in its Reply Comments. What, if any disadvantages are there to redundant relays as opposed to the thermal replicating relays? What, if any advantages are there to redundant relays (other than cost)?

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[5] USDOE. Dynamic Line Rating Systems for Transmission Lines: Topical Report. Pages 2-5. Available at https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf.
[6] PacifiCorp 2016 Smart Grid Report, p. 15.
[7] PacifiCorp 2016 Smart Grid Report, p. 16.
[8] PacifiCorp 2016 Smart Grid Report, p. 17.
[9] PacifiCorp 2015 Smart Grid Report, p. 9.
[10] PacifiCorp 2016 Smart Grid Report, p. 16.

Recommendation 5: Provide the ensuing 2017 IRP analysis of specific transmission lines that PacifiCorp considers DLR as an alternative to traditional infrastructure upgrades.

The Company has not yet filed its 2017 IRP, and Staff is unaware of DLR-specific analysis reported through the IRP stakeholder process. PacifiCorp has previously requested clarification from Staff on this recommendation, which Staff has included as Attachment 1. Staff requested a status update on 2017 IRP analysis of specific transmission lines.

Staff requests that the Company provide in its Reply Comments information (if any) as to additional analysis that is occurring via the 2017 IRP process. Staff also anticipates an update to this project in the 2017 Smart Grid Report.

Recommendation 6: Continue to report on any working relationship developments with WECC and Peak Reliability as well as providing comprehensive qualitative and quantitative analysis regarding the utilization of PMU data for transmission system model validation that the Company plans to detail in the 2016 Smart Grid Report.

According to the US Department of Energy,

> Synchrophasors are time-synchronized numbers that represent both the magnitude and phase angle of the sine waves found in electricity, and are time-synchronized for accuracy. They are measured by high-speed monitors called Phasor Measurement Units (PMUs) that are 100 times faster than SCADA. PMU measurements record grid conditions with great accuracy and offer insight into grid stability or stress. Synchrophasor technology is used for real-time operations and off-line engineering analyses to improve grid reliability and efficiency and lower operating costs.[11]

PacifiCorp has been involved in a project with WECC since 2013, where the Company and other participating energy companies have been streaming synchrophasor data to WECC for a number of years.[12] The Company links to two webpages from Peak Reliability to ease data entry from participating companies. The Company has stated that these webpages will be available by early 2017.[13]

The Company has not commented on whether it plans to utilize the PMU data for comprehensive analysis.

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[11] USDOE. Synchrophasor Applications in Transmission Systems. Accessed at https://www.smartgrid.gov/recovery_act/program_impacts/applications_synchrophasor_technology.html.
[12] PacifiCorp 2016 Smart Grid report, pg. 17.
[13] PacifiCorp 2016 Smart Grid Report, p. 18.

Staff requests that the Company state in its reply comments how it plans on utilizing the PMU data once it is available. Staff anticipates an update to this project in the 2017 Smart Grid Report.

<u>Recommendation 7: Provide the results of the feasibility assessment for the irrigation load control pilot under consideration for Oregon, including methodologies and both qualitative and quantitative components of the analysis.</u>

The Company reports that the median curtailed load dispatch was 141 MW for seven events that the irrigation load control program was dispatched for in 2015.[14] Since these seven events, the Company is expecting to implement a new, similar pilot program in the Klamath Basin, which OPUC Staff recently approved.[15] Staff is still exploring the particulars of the new pilot program and may add additional comments about it in its Public Meeting Memo.

Staff requests that the Company provide in its reply comments load curtailment data for all seven events and explain why the program was not dispatched more often.

<u>Recommendation 8: Include a comprehensive and exhaustive evaluation of each candidate circuit discussed in the Company's reply comments, including methodologies, assumptions, and sources that identify all potential benefits and costs of CES as appendices in its 2016 Smart Grid Report.</u>

In its 2015 reply comments, the Company describes a phone call it had with Staff regarding three studies conducted by PacifiCorp, NV Energy, and MidAmerican Energy.[16] In that phone call, Staff and the Company agreed that the Company would provide PacifiCorp's study. To Staff's knowledge, the Company has not provided the PacifiCorp study, and it is unclear whether the NV Energy and MidAmerican Energy studies will be provided.

Staff requests that the Company provide an update in its reply comments as to the provision of these studies.

<u>Recommendation 9: Include the update on the feasibility of Fuse Saving device implementation with the accompanying methodology and qualitative and quantitative data in the Company's 2016 Smart Grid Report.</u>

The Company states in its Smart Grid Report that it does not yet have enough data to do a quantitative or qualitative benefit analysis of the Fuse Saving devices. However, the Company mentions that it "launched an investigation to determine the feasibility and cost of establishing communications with Fuse Saving devices."

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[14] PacifiCorp 2016 Smart Grid Report, p. 32.
[15] See http://edocs.puc.state.or.us/efdocs/UBA/adv242uba162659.pdf.
[16] See Staff Attachment 1.

Staff requests that the Company provide additional details in its reply comments as to what is needed to establish communications with Fuse Savings devices and existing barriers to integrating Fuse Savings devices with the SCADA Monarch energy management system.

<u>Recommendation 10: Include a status update, including any benefits, of the implementation of capacitor bank, recloser, and regulator bank controls.</u>

In a clarification to this recommendation, Staff responded to the Company as follows:

> Staff response: Staff is looking for updates on the smart grid capabilities of these devices, be it from devices already installed and said capabilities activated, or for new devices installed. Staff expects the Company to describe circumstances under which smart grid functionality can be activated for these devices if such functionality is not readily available upon installation. [17]

In the Smart Grid report, the Company says that "the communication protocols for the control devices of reclosers and regulators were evaluated," [18] but details of the evaluation are not revealed apart from being DNP 3.0 ready. There does not seem to be additional information apart from this, though the Company states that these controls "will be evaluated" upon AMI implementation.

The Company has not adequately addressed this recommendation.

Staff requests that the Company provide more insight in its reply comments as to the benefits clarified by Staff in Attachment 1.

<u>Recommendation 11: Provide a summary of ongoing efforts of completing a cost-benefit analysis of CFCIs, including alternative communication technologies such as AMI, in case the cost-benefit analysis is not ready for the 2016 Smart Grid Report.</u>

The Company has provided a status update, stating that "[i]mplementation of CFCI data is expected to occur in 2016 and outage event data is possible for analysis and inclusion in the 2017 Smart Grid Report."[19] In addition, "an evaluation of the backhaul of fault detector data over the AMI communication network is ongoing."[20] There is no mention of a cost-benefit analysis.

Staff requests that the Company provide in its reply comments additional information or update to Recommendation 11.

[17] See Staff Attachment 1.
[18] PacifiCorp 2016 Smart Grid Report, p. 27.
[19] PacifiCorp 2016 Smart Grid Report, p. 26.
[20] PacifiCorp 2016 Smart Grid Report, p. 26.

Recommendation 12: Provide an update, including milestones, of its planned transition to a new, more powerful circuit analysis application. PacifiCorp should also provide an evaluation of the expected impact of the new circuit analysis on the potential for CVR application.

PacifiCorp provides a description of a new distribution system analysis application called CYME, which was installed late 2015. Staff appreciates the Company's excitement about the program and is pleased to see some qualitative benefits of the program. Some of the benefits are listed, such as the ability to incorporate additional details into CYME that were incompatible with the previous model, ABB FeederAll. Though Staff found this update useful, the Company did not relate CYME to conservation voltage reduction (CVR) potential. The report also does not provide specific milestones of the CYME phase-in. It remains unclear as to whether CYME is going to be utilizing new AMI data. The installation of the new system also raises the question of whether PacifiCorp's transition to CYME may have rendered certain existing applications or hardware obsolete.[21]

Staff requests that in its reply comments the Company outline a complete and comprehensive list of benefits of utilizing CYME as opposed to ABB FeederAll in its Reply Comments.

Recommendation 13: Describe in the 2016 Smart Grid Report how lessons learned from the irrigation TOU program can be applied to the other TOU programs offered by the Company.

The Company discusses some interesting lessons it learned regarding TOU programs, on page 35 of the Smart Grid Report. In addition to these updates, the Company addressed why its residential TOU participation rate was so much higher in Idaho than it is in Oregon and Utah. Staff is satisfied with the update and anticipates any additional updates in the 2017 Smart Grid Report, especially as it pertains to AMI implementation.[22]

Recommendation 14: Provide a quantitative and qualitative comparison of the Cool Keeper program's performance before and after the efficiency improvements in the 2016 Smart Grid Report.

The Company provided one quantitative comparison in this program—namely, that the controllable load measured up to about 115 MW as a result of the program. In addition, the Company lists a number of analytical applications for the data it receives from the program, including event validation and customer segmentation.

Staff found the data applications useful.[23]

[21] PacifiCorp 2016 Smart Grid Report, p. 28-29.
[22] See PacifiCorp 2016 Smart Grid Report, pp. 35 – 37.
[23] There was also a clarification to Staff recommendation 14. See Staff Attachment 1.

Staff requests that the Company explain in its reply comments whether it regularly runs the analytics it describes in the Smart Grid Report and whether it was able to garner additional quantitative comparisons from the data.

Recommendation 15: Provide a comprehensive analysis, including methodologies, and qualitative and quantitative data of possible benefits and costs, of the Company's collaborative analysis of DER integration.

In the 2015 Smart Grid Report, the Company stated that it started a pilot study for comparative analysis of DER resources.[24] In the 2016 Smart Grid Report, the Company gave an update to this project, stating that it realized it needed a tool for transmission and distribution planners that would help them compare DER to alternative solutions. The Company has created this tool, but this seems to have held up the DER study. The Company states it will update its data and has since commissioned a new study that will be complete by the end of 2016.[25]

Staff requests that the Company provide an update to the DER study in its 2017 Smart Grid Report.

PacifiCorp AMI Implementation

PacifiCorp Smart Grid Background

The most significant update in PacifiCorp’s 2016 Smart Grid Report is the Company’s intention to install Advanced Metering Infrastructure (AMI) technology. PacifiCorp reports the core components of PacifiCorp’s AMI project as replacing its existing meters with smart meters and implementing a communications network.[26]

The Smart Grid Report itself does not contain much detail about the AMI rollout. The Company provides a list of potential benefits,[27] a list of the new capabilities its meters will possess,[28] brief descriptions of the components of its communications network,[29] a list of AMI applications that are beyond the scope of its project,[30] and an anticipated timeline for deployment.[31] Staff submitted discovery requests about the AMI rollout and explains below some of its concerns and what it perceives as deliverable benefits from the AMI rollout.

It was primarily through discovery that Staff understood the particulars of the Company’s implementation, which Staff has included as various attachments to

[24] PacifiCorp 2015 Smart Grid Report, p. 16.
[25] PacifiCorp 2016 Smart Grid Report, pp. 21-22.
[26] PacifiCorp 2016 Smart Grid Report, p. 11.
[27] PacifiCorp 2016 Smart Grid Report, p. 10.
[28] PacifiCorp 2016 Smart Grid Report, p. 11.
[29] PacifiCorp 2016 Smart Grid Report, p. 12.
[30] PacifiCorp 2016 Smart Grid Report, p. 13.
[31] PacifiCorp 2016 Smart Grid Report, p. 13.

its comments. As a bit of historical background, the Company has previously characterized smart grid implementation as being potentially leveraged by the following capabilities:

- An expansion of non-firm demand response (i.e., time-based rates);
- Outage management;
- Fault detection, isolation, and restoration; and
- Integrated volt/VAr optimization.[32]

In previous versions of the smart grid report, the Company has cited low population density within its service territory as an obstacle to AMI implementation.[33] The Company has also explained that "key AMI functionalities, including dynamic pricing, demand response programs, and outage management, could not be gained without significant upgrades to the existing customer information system and other information technology (IT) applications,"[34] and "when full consideration is given to an overarching replacement strategy to address future obsolescence of IT supporting programs, such as the customer information system, an economic and compelling business case cannot be made for implementing AMI."[35]

Despite these findings, in 2015, the Company was encouraged that its AMI analysis presented a marginally positive business case.[36] Since the 2015 Smart Grid Report filing, the Company has revealed that it has submitted a new request for proposal (RFP) for an AMI rollout. The results differ from what the Company has previously stated in terms of cost-effectiveness. The Company presents the 2016 AMI proposal as having a positive business case,[37] and the Company now plans on installing approximately 590,000 smart meters in its Oregon service territory.[38]

Customer Benefits

The Company offered a workshop on September 28, 2016 on customer benefits. Staff appreciates the Company's move in reaching out to stakeholders and addressing their concerns. The workshop primarily revolved around common customer perceptions about smart grid implementation, such as increases in bills, health and safety concerns, and privacy concerns. The Company also explained its considerations around collections and billing.

[32] PacifiCorp 2014 Smart Grid Report, p. 24.
[33] PacifiCorp 2013 Smart Grid Report, p. 33.
[34] PacifiCorp 2015 Smart Grid Report, p. 21.
[35] PacifiCorp 2015 Smart Grid Report, p. 1.
[36] PacifiCorp 2015 Smart Grid Report, p. 21.
[37]PacifiCorp 2016 Smart Grid Report, p. 9.
[38] PacifiCorp 2016 Smart Grid Report, p. 11.

In Order 12-158, the Commission provides an exhaustive list of policy goals and objectives with regard to smart grids. Staff believes that PacifiCorp's current AMI implementation will incorporate some of these benefits. In particular, Staff believes PacifiCorp's AMI project could be consistent with the following Commission policy goals:

- Reduce costs of meter reading;
- Reduce costs and improve customer service through more efficient notification of and response to outages, more efficient detection of theft and broken meters, more effective handling of service orders, and improved billing, credit, collection, and connection/disconnection practices; and
- Reduce billing errors and call center transactions.[39,40]

The workshop on September 28th revolved around these issues. Of the benefits Staff found to be most relevant is the outage restoration time upon bill payment. The Company discussed expanding the locations of its pay stations, and because of AMI remote connection/disconnection functionality, the Company explained it would be possible for customers to receive service much more quickly than before, possibly within minutes.[41] In the workshop, the Company also cited quicker outage detection as a result of its AMI rollout.

At the workshop, stakeholders raised concerns about informing customers of the AMI rollout. The Company stated a respect for customer concerns, including privacy, but also expressed some uncertainty about the best approach to inform its customers. The Company explained its preference on cutting costs to AMI implementation by installing meters earlier than the proposed rollout date, during routine meter replacements, for example. However, the question of customer consent arose among Staff and other stakeholders. The Company expressed interest in an early AMI implementation notification filing. Staff believes customer concerns over AMI rollout are outside the scope of the smart grid docket, but Staff appreciates the Company's concern over its customers. Staff believes the Company should continue to work with Staff and stakeholders to flesh out some of the customer issues raised in the September 28th workshop.

Staff requests that the Company provide a clear explanation in its reply comments of the quicker response time functionality, reconnection functionality, and outage detection functionality. Staff also would like PacifiCorp to provide a cost and benefit estimation of these functionalities.

[39] Order No. 12-158 , p. 3.
[40] Refer to Staff Attachment 2 for the Company's explanation of how it defined customer benefits. Staff Attachment 2 refers to OPUC DR 55.
[41] This comment was made orally.

AMI Functionality and Capability

At Staff's request,[42] the Company submitted a confidential financial analysis of its AMI implementation as an attachment to the 2016 Smart Grid Report. The attachment did not contain much detail, and Staff found it confusing to interpret. The Company was able meet with Staff via a phone call on September 27th, 2016, to go over the attachment and other discovery requests pertaining to the financial analysis. Staff is very appreciative of the Company's willingness to meet with Staff and answer questions about the analysis. It clarified a number of aspects of the AMI rollout. Through this process and through the Smart Grid Report, Staff believes that, other than the provision of customer benefits described above, the key deliverables of the project are primarily lower O&M and labor costs and increased revenues to the Company.[43,44]

The Company has been direct about the deliverables it does not expect to achieve with its current AMI implementation:

- Integration with the CADOPS outage management system.
- Critical peak pricing or prepaid pricing capabilities.
- Limited tariff billing functionality aimed primarily at distributed energy generation.
- Integration with the SCADA and DMS systems.[45]
- Functionality that provides customer data to a home area network (HAN).
- Capability to automate interactive volt/VAr optimization (IVVO).
- Various distribution automation capabilities (DA).
- Demand-side management (DSM) functionality and programs.
- Load planning capabilities and integration.[46]

Although Staff appreciates the Company's frankness about the capabilities that are outside the scope of the current AMI rollout, Staff believes this list of non-deliverables diminishes AMI's overall value.

In Staff's view, the Company has created a distinction between AMI "functionality" and AMI "capability." "Functionality" to Staff indicates the Company's AMI operations by the time the meters are fully deployed in 2020. The Company has indicated that there are deliverable benefits as a result of AMI "functionalities," such as faster connection/reconnection times, for example.

[42] See Staff Informal Comments on page 49 of the PacifiCorp smart grid report.
[43] See Staff Attachment 2. Staff Attachment 2 refers to OPUC DR 55.
[44] PacifiCorp 2016 Smart Grid Report, p. 10.
[45] See Staff Attachment 3. Staff Attachment 3 refers to OPUC DR 48.
[46] PacifiCorp 2016 Smart Grid Report, p. 13.

In contrast, "capability," seems to indicate technological latency or potential for implementation. Important to note is that capability does not necessarily translate into implemented functionality. That is, the meters may be able to handle the non-deliverable applications as listed above, but at additional cost and technology augmentation. At present, the Company is not pursuing the additional functionality. When Staff asked PacifiCorp about some of these non-deliverable capabilities, the Company indicated that they are still under review.[47]

The Company has stated that full AMI capability exceeds the initial phase of implementation, which it highlights as comprised of meter reading and disconnect/reconnection.[48] While the Company has stated that the non-deliverable applications "may be pursued in the future,"[49] Staff cautions that some of the non-deliverables appear to fall under the umbrella of what previously was considered as leveraging AMI technology.[50]

The Company does not appear to have a clear plan for utilizing the full list of capabilities offered by the meters and data. In particular, Staff believes that the Company's responses to discovery on demand response,[51] load curtailment,[52] integrated resource planning,[53] and data management,[54,55] lacked substance and did not indicate whether the Company even intends to pursue these applications.

As a result, Staff is concerned that the Company's AMI rollout will not eventually transition "capabilities" to "functionalities," and thus customers may not ever receive the full level of potential smart grid benefits.

Technology Obsolescence

Staff is also concerned with smart grid technology obsolescence. Staff views this as being conceptually similar to other types of information technology obsolescence, where computer software and electronic devices evolve over time and require significant or frequent upgrades as technology matures. This renders incumbent technology obsolete. While the Company references technology obsolescence in a series of "necessary strategies" for implementing a smart grid,[56] Staff has not found much more detail in the report concerning the specifics of such a strategy. In addition, in the 2015 report, an expansion of non-firm demand response (i.e., time-based rates) and integrated volt/var optimization were applications rendered uneconomic because of the risks of IT

[47] See Staff Attachments 4, 5, and 6. These refer to OPUC DRs 39, 42, and 43, respectively.
[48] See Staff Attachment 4. This refers to OPUC DR 39.
[49] PacifiCorp 2016 Smart Grid Report, p. 13.
[50] See above statements regarding the 2014 Smart Grid Report.
[51] Max DR 17
[52] Max DR 17,
[53] OPUC DR 43.
[54] OPUC DR 39.
[55] OPUC DR 42.
[56] PacifiCorp 2016 Smart Grid Report, p. 5.

obsolescence.[57] These have been highlighted by the Company in the 2016 Report as non-deliverables. Overall, Staff is concerned that the potential capabilities of smart grid, such as the non-deliverables the Company has cited, may never be realized.

Staff does not dispute that there is a need to be aware of the potentially high costs of technology obsolescence in relation to achieving smart grid policy goals, but the Company should demonstrate a more detailed case for how it intends on mitigating the risk of obsolescence.

Staff requests that the Company further address in its reply comments how it plans on addressing the technology obsolescence risk.

Additional Investigation

Staff cautions that not all of the original smart grid policy goals will be met with this particular AMI implementation. However, Staff recognizes that PacifiCorp has taken a cautious approach to smart grid implementation and believes the Company has demonstrated some benefits to the rollout, particularly with its promise of faster reconnection times.

It is important to note that some of the Company's responses to Staff's recommendations from the 2015 report are "folded in" to AMI implementation. For example, see PacifiCorp's responses to Recommendations 10 and 11.The AMI implementation section of the 2016 Smart Grid Report contains little evidence that the Company is prepared to utilize such data for those purposes. Staff is concerned that the Company is postponing research into the benefits of various smart grid projects it has already installed.[58]

As stated above, the Company clearly states the deliverables it will **not** provide in this particular phase of AMI deployment.[59] Regular updates, either through future smart grid reports or otherwise, will be helpful in tracking the progress of benefits and goals. Staff is considering the possibility of requesting that the Company provide data available upon request both for future updates and prudence review. Staff is interested in establishing clarity around the delivery of future functionality. In particular, Staff wants to understand which of the current non-deliverables the Company plans to implement in the future, and which ones it expects to never implement.

Staff believes that a thorough review of PacifCorp's AMI project is not possible in this report given the relatively short timeline for this filing. The Company did

[57] PacifiCorp 2015 Smart Grid Report, p. 1.
[58] In addition, there were several areas of the report where the Company postponed publishing results in favor of reporting on them in the 2017 Smart Grid Report. See PacifiCorp's responses to Staff recommendations 11 and 15, pp. 21, 22, and 26 of the 2016 Smart Grid Report. Staff also notes that this has historically been an issue with PacifiCorp's Smart Grid Report. See also Staff's 2015 Report in UM 1667.
[59] PacifiCorp 2016 Smart Grid Report, p. 13.

submit a confidential AMI project plan, which Staff received through discovery, but Staff does not believe that the project plan or the 2016 Smart Grid Report provide enough detail and clarity to address Staff's concerns. In particular, Staff remains concerned about mitigating the risk of technology obsolescence and wants to fully understand the Company's future goals of AMI implementation beyond reduction in labor costs, increased Company revenues, and the limited customer benefits mentioned above. Staff believes AMI to be a major resource and infrastructure investment. How the Company defines AMI and its capability and investments will define smart grid development for decades to come and will lock ratepayers into major investments now and in the future.

Order No. 12-158 states that smart grid planning documents are reporting requirement dockets, not planning documents.[60] Staff cautions that complying with a reporting requirement in this docket, and subsequent Commission acceptance of the 2016 Smart Grid Report, should not be interpreted as pre-approval of AMI implementation for cost recovery. However, Staff does believe that including PacifiCorp's intent to implement AMI is appropriate for the smart grid report.

In the 2016 Smart Grid Report, the Company has forecasted certain customer benefits. Given such a large project as AMI, Staff believes realization of those benefits should be tracked for prudence review and consistency. Staff is still exploring what those tracked benefits should be and how they might be tracked for future reference. There will be additional details on this issue in Staff's Public Meeting Memo.

This concludes Staff's Comments.

Dated at Salem, Oregon, this 7th day of October, 2016.

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[60] Order No. 12-158, p. 2.

Recommendation #5:

1. Does this recommendation suggest an additional requirement for the 2017 IRP?

   Staff response: No.

2. Given DLR is traditionally considered for thermally constrained lines, is an analysis for non-thermally constrained lines expected?

   Staff response: No – Staff expects PacifiCorp to provide any DLR analysis conducted in relation to the 2017 IRP.

3. Given data may not be available for 2016 report, can reporting on recommendation be deferred to future smart grid reports, when data is available?

   Staff response: Yes, when an analysis becomes available, the Company can report it in the next Smart Grid Report. Regardless of analysis availability, Staff would like a status update in the 2016 Smart Grid Report on ongoing DLR analysis.

Recommendation #8

1. Given one circuit has been identified where a "CES solution could potentially offset the need for a traditional capital investment," is an analysis of other circuits expected in 2016 report?

   Staff response: Staff clarifies that it was referring to the three "studies" conducted by PacifiCorp, NV Energy, and MidAmerican Energy that are mentioned on the bottom of page 19 of the Company's reply comments. The Company indicated during the Nov. 30, 2015 phone call that it would provide the PacifiCorp study in the interim, which Staff finds sufficient.

2. Is the intention of Recommendation 8 to direct PacifiCorp to provide an evaluation of the identified circuit in Redmond, Oregon in the 2016 report, as PacifiCorp stated it would provide in its reply comments?

   Staff response: No, the intention of this recommendation is described above.

Recommendation #10

1. Devices listed in Recommendation 10 are traditional equipment upgrades and/or deployments within the "progressive network." Is staff looking for an update on number of equipment installed, or only update when smart functionality is utilized?

   Staff response: Staff is looking for updates on the smart grid capabilities of these devices, be it from devices already installed and said capabilities activated, or for new devices installed. Staff *expects the Company to describe circumstances under which smart grid functionality can be activated for these devices if such functionality is not readily available upon installation.*

Recommendation #14

1. Additional information regarding the upgrade to the two-way communication network within the Cool Keeper program was provided within PacifiCorp's reply comments. Given no further upgrades to the Cool Keeper network are planned, what supplementary information and/or analysis is requested by Staff for the 2016 report?

   Staff response: Staff would like the Company to provide any quantitative data that demonstrate changes in program operations due to the upgrades, such as increased utilization of the program (e.g., the upgrades resulted in XX additional megawatts of program load reduction per event), cost savings (or increases), changes in program dispatchability, or changes in customer opinion of the Cool Keeper program.)

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

October 5, 2016

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Oregon Public Utility Commission
201 High St. SE
Salem, OR 97301-3612
puc.datarequests@state.or.us (C)

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RE: OR Docket No. UM 1667
OPUC Data Request (39-58)

Please find enclosed PacifiCorp's 1st Revised Redacted and Confidential Response to OPUC Data Request 55. The information designated as confidential is commercially and competitively sensitive and is provided as confidential under Order No. 13-279 and may only be disclosed to qualified persons as defined in that order.

If you have any questions, please call me at 503-813-6583.

Sincerely,

Natasha Siores/ANM

Natasha Siores
Pacific Power Regulation

OPUC Data Request 55

Please see Confidential Attachment A of the 2016 Smart Grid report.

a. Please explain what each of the rows mean on both pages of the attachment– (e.g., explain the text and how the values were calculated).
b. On the very last line of the first page of Confidential Attachment A, there is a number. How does this number correspond with the information from OPUC Data Requests 16 and 17 (the data requests which Staff analyst Max St. Brown earlier submitted as DRs 9 and 10)?
c. Will AMI technology improve reductions in actual power losses/energy losses?
d. On the second page of the Confidential Attachment, the Company separates the information into two different columns. Please explain the difference between the two columns.
e. See the second page of Confidential Attachment A. Please explain how these numbers correspond with what was projected in OPUC Data Request 16 (the data requests which Staff analyst Max St. Brown earlier submitted as OPUC DR 9).
f. What time frame does the second page of Confidential Attachment A encompass? Is each of the rows within the same timeframe?
g. Please see the second to last row on the second page of Confidential Attachment A. What years does this include? Is this an average?
h. Please see the last row on the second page of Confidential Attachment A. What years does this include? Is this an average?

1st Revised Response to OPUC Data Request 55

The Company's original response dated, September 15, 2016, included confidential information that was inadvertently not marked as such. This response replaces the original, in its entirety.

The Company assumes that the OPUC staff meant to reference the second page of the attachment rather than the first page, and vice versa

a. Eliminate Meter Reading Operating Costs—Fully automating all of the electric meters in Oregon will eliminate employees that are currently utilized to manually read meters.

   Eliminate Collection Operating Costs—All self-contained residential and small commercial single-phase meters will be equipped with a disconnect switch in the meter. This will enable the capability to remotely disconnect customers for non-pay, and re-connect upon payment, which will eliminate employees that are currently used for these functions.

   Eliminate Journeyman Metermen Operating Costs—Replacing the entire meter population in Oregon with new meters will reduce the number of field orders, primarily for maintenance purposes. This will reduce journeyman metermen positions.

Eliminate Service Coordinators Costs—The decrease in fieldwork orders from meter reading, collections, and meter maintenance will reduce the amount of work for service coordinators. This will reduce service coordinator positions.

Eliminate Meter Manager Operating Costs—With the significant reduction of field full time equivalent (FTE) employees, the associated management of these employees will no longer be required to operate the business. Metering manager positions will be eliminated.

Eliminate Overtime (Metering and transmission and distribution (T&D))—The advanced metering infrastructure (AMI) system will eliminate the need to drive to customer locations to perform manual reading and reconnect functions after normal business hours. This will reduce the amount of existing overtime that is currently being spent to meet company objectives.

Avoided Handheld Maintenance and Repair—With an AMI system, the need to maintain new handheld equipment for meter reading purposes will be eliminated.

Billing Suspends Reduction—Access problems and meter failures create estimated bills for customers resulting in manual reviews by call center agents of bills prior to rendering the bills to customers.

New AMI Operating Costs—In order to operate and maintain an AMI system, PacifiCorp will incur additional annual costs for employees to support AMI technology, software, cellular fees, firmware upgrades, licenses, security, web portal services, and maintenance costs.

Theft Reduction—The Company will identify and stop theft during the process of physically exchanging meters.

Reduced Power Losses—An AMI system will give the ability to read the meter in near real-time and disconnect the service between tenants. Performing this disconnect will prevent the loss of unbilled kWh's currently occurring.

Revenue from Added Meters with VARs—AMI functionality will allow us to charge power factor penalties on those sites that are operating less efficiently, which will result in increased company revenue.

System Energy Loss Reductions—All electric meters require a small amount of current flow before they begin to measure the power flow. Mechanical meters require 24 watts of power before they start to register consumption, while electronic meters require only five watts. Additionally, mechanical meters consume 0.70 watts of power to operate compared to 0.46 watts for an electronic meter. The new AMI meters are more efficient than mechanical meters, which will result in more revenue generated per customer per year, based on the meter registering more kWh use.

Revenue Recovery on Unaccounted for Energy—PacifiCorp's meter test program has shown that newer electronic meters are more accurate than older mechanical meters. Meters tend to register less usage (drift) as they age, making them less accurate.

Reduction in Write-offs—The added functionality of the AMI system gives the ability to remotely disconnect customers for non-payment. Delinquent customers will be disconnected sooner, thus reducing the amount of company write-offs.

Avoided Meter Purchases—The Company is replacing almost all of the current Oregon meters with new AMI meters. As a result of this PacifiCorp will experience a significant decrease in the amount of meter failures following the implementation.

Avoided Load Study Costs—The new AMI system will provide data used in load studies eliminating the need for future load studies in Oregon. The Company will extend the life of existing load study meters during project implementation and begin using interval data delivered through AMI post project completion. This will eliminate the need to install between 100 – 175 new meters per year.

Avoided Handheld replacement costs—The need to purchase new handheld equipment for meter reading purposes will be eliminated.

Total Project Costs—The total initial cost to implement an AMI solution in Oregon, which includes both capital and operating and maintenance (O&M) costs.

Implementation Capital Costs—The initial capital costs to implement an AMI solution in Oregon.

Implementation O&M Costs—The initial O&M costs to implement an AMI solution in Oregon.

Ongoing Annual O&M Costs—The additional annual costs to run and support the AMI system after implementation.

Net Annual Project Benefits—The net annual project benefits including O&M savings, additional revenue and capital cost savings of the AMI project after implementation.

Net O&M Annual Savings—The net annual project O&M savings of the AMI project after implementation.

Internal Rate of Return—The discount rate that makes the net present value of all cash flows from a particular project equal to zero.

Net Present Value—A calculation that compares the amount invested today to the present value of the future cash receipts from the investment.

Revenue Requirements—The amount of money that a utility must receive from its customers to cover its costs, operating expenses, taxes, interest paid on debts owed to investors and a reasonable return.

Present Value of Revenue Requirements—A calculation that compares the revenue requirement to the present value.

Payback Period—The length of time required to recover the cost of an investment.

Please refer to Confidential Attachment OPUC 17 1st Supplemental, which includes the formulae as to how the values are calculated.

[redacted]

[redacted]

[redacted]

c. Yes, AMI technology will reduce power/energy losses in the following ways:

- Theft Reduction—The Company will identify and stop theft during the process of physically exchanging meters.
- Reduced Power Losses—An AMI system will give the ability to read the meter in near real-time and disconnect the service between tenants. Performing this disconnect will prevent the loss of unbilled kWh's currently occurring.
- System Energy Loss Reductions—All electric meters require a small amount of current flow before they begin to measure the power flow. Mechanical meters require 24 watts of power before they start to register consumption,

while electronic meters require only five watts. Additionally, mechanical meters consume 0.70 watts of power to operate compared to 0.46 watts for an electronic meter. The new AMI meters are more efficient than mechanical meters, which will result in more revenue generated per customer per year, based on the meter registering more kWh use.

- Revenue Recovery on Unaccounted for Energy—PacifiCorp's meter test program has shown those newer electronic meters are more accurate than older mechanical meters. Meters tend to register less usage (drift) as they age, making them less accurate.

d. The Pre-Contract financials were those used at the time the Company approved implementation of an Oregon AMI project in March of 2016. The Post-Contract Financials are those that reflect the Company choosing a vendor and negotiating contract terms in May of 2016.

[redacted]

[redacted]

[redacted]

f. The timeframes vary depending on the specific line items:

The first three rows (Total Project Costs, Implementation Capital Costs and Implementation O&M Costs) are during the implementation portion of the project, which starts in 2016 and goes through 2019.

The Ongoing Annual O&M Costs, Net Annual Project Benefits and Net O&M Annual Savings will begin in 2020 after project implementation is complete and go throughout the duration of the project.

The Internal Rate of Return, Net Present Value, Revenue Requirements, Present Value of Revenue Requirements, Payback Period, Net Annual Project Benefits, and Net O&M Annual Savings are the financial calculations for the duration of the entire project.

g. The Net Annual Project Benefits listed are the rounded benefits from the year starting in 2020. These benefits will increase annually due to inflation and projected salary increases.

h. The O&M Net Annual Savings listed are the rounded benefits from the year starting in 2020. These benefits will increase annually due to inflation and projected salary increases.

The information designated as confidential is commercially and competitively sensitive and is provided as confidential under Order No. 13-279 and may only be disclosed to qualified persons as defined in that order.

UM 1667/PacifiCorp
September 15, 2016
OPUC Data Request 48

OPUC Data Request 48

See page 26 of the 2016 Smart Grid Report, regarding the Communicating Faulted Circuit Indicators.

a. What does the Company expect to achieve by commissioning the new SCADA Monarch system?
b. The Company states, "In addition, an evaluation of the backhaul of fault detector data over the AMI communication network is ongoing." Please elaborate on the scope of this evaluation and when the Company plans to complete it.

Response to OPUC Data Request 48

a. The Supervisory Control and Data Acquisition (SCADA) Monarch system is a replacement energy management system of the legacy SCADA energy management system at the Company.

b. The scope of the evaluation of retrieving fault detector data over the AMI network includes determining the compatibility of the Silver Spring Networks communication hardware with the communicating faulted circuit indicator hardware, testing the communications between the communicating faulted circuit indicator and the advanced metering infrastructure (AMI) meter data management system, then determining the feasibility of integrating the collected data into either the SCADA energy management system or the outage management system where system operators can utilize the data in operation of the system. The evaluation will also help determine in which system the collected data will reside based on the ease of integration and most efficient use for system operators. The evaluation is not anticipated to be complete until the end of 2018.

UM 1667/PacifiCorp
September 15, 2016
OPUC Data Request 39

OPUC Data Request 39

See page 10 of the 2016 Smart Grid Report.

a. The Company provides a list of customer benefits. What is the Company referring to by the first bullet point, "Cost savings over the life of the investment?"
b. Please elaborate on what the Company means by "Aids future rate design that gives customers rate plan options to include applications related to net metering, electric vehicles, and dynamic pricing programs."
c. Refer to Staff Data Request 39 b. How is this consistent with the Company's statements on page 13 of the Smart Grid Report about projects outside the scope of AMI? If future rate design is outside the scope of AMI, why does the Company consider this application a benefit to customers (see page 10)?
d. Has the Company outlined a plan for how it plans to use data to "manage the network for system operations efficiently" as stated on page 10? If so, please outline.
e. Has the Company done any carbon reduction analysis pertaining to the environmental benefit of AMI as stated on page 10? If so, please provide.

Response to OPUC Data Request 39

a. The advanced metering infrastructure (AMI) project provides the Company with operations and maintenance (O&M) savings, additional revenue and capital cost savings throughout the duration of the life of the asset (from completion of the project through life asset as compared against 2016 financial and workforce actuals).

b. Interval consumption data obtained through AMI provides the opportunity to develop additional rate plan options for customers.

c. The AMI project has clear deliverables for phased implementation. Its capabilities exceed the initial phase (meter read, connect/disconnect application). Additional teams and phases will be designated to take full advantage of the application. Rate design could be one of those phases.

d. The organizations that require and will use the data to improve network performance and customer interaction will develop the plan and template for data management. The design and development will continue in 2017 and leverage other utility and vendor best practices to improve reliability and response performance.

e. Vehicles are (on average) 8 years old, travel 12,336 miles annually and burn 948.9 gallons of unleaded fuel (approximately 13 miles per gallon). Each gallon burned emits 20 pounds of greenhouse gas (GHG) (per www.fueleconomy.gov).

   948.9 x 20 = 18,978.5 pounds (9.489 tons)

UM 1667/PacifiCorp
September 15, 2016
OPUC Data Request 42

OPUC Data Request 42

See page 12 of the 2016 Smart Grid Report. Does the Company have a plan for how it intends to use the data it collects from the Meter Data Management System (MDMS)? If so, please outline.

Response to OPUC Data Request 42

The organizations that require and will use the data to improve network performance and customer interaction will develop the plan and template for data management. The design and development will continue in 2017 and leverage other utility and vendor best practices to improve the Company's reliability and response performance.

The Company is also benchmarking how other utilities leverage the data in areas such as customer information and billing inquiries.

UM 1667/PacifiCorp
September 15, 2016
OPUC Data Request 43

OPUC Data Request 43

See page 13 of the 2016 Smart Grid Report.

a. The Company states that load planning capabilities and integration are outside the scope of the Oregon AMI project. Does this mean that the Company does not intend to use AMI data for resource planning purposes? If not, what are the obstacles to using AMI data for planning purposes?
b. For each of the capabilities listed that are outside the scope of AMI, does the Company mean to say that the Company's anticipated AMI technology is the primary obstacle to achieving those capabilities? In other words, is the incapacity of the smart meters the primary obstacle? If it is not the smart meters, what are the primary obstacles?

Response to OPUC Data Request 43

a. The Company is currently reviewing how the advanced metering infrastructure (AMI) meter data can be utilized for applications beyond the metering/billing functionality that will be part of the initial AMI deployment.

b. The Company is currently in the process of reviewing how the AMI data can be utilized for other business purposes beyond customer billing. It has not been determined what, if any, obstacles exists. However, it is unlikely that the AMI technology will be an obstacle, but rather only provide potential up-side.

Smart Meters / PacifiCorp
May 23, 2016
OPUC Data Request 17

OPUC Data Request 17

Max St. Brown – 503-378-6681
Smart Meters - *Appendix E – Smart Grid* on page 83 of the Company's 2015 IRP states, "smart metering and home area networks … enable consumer response to price fluctuations and load curtailment requests".

(a) Does the Company plan to use smart meters to enable consumer response to price fluctuation? If yes, please describe.

(b) Does the Company plan to use smart meters to enable consumer response to load curtailment requests? If yes, please describe.

Response to OPUC Data Request 17

The early stages of deployment and integration do not fully enable demand response pricing and load control.

(a) The Company will continue to evaluate future smart meter capabilities, but the current advanced metering infrastructure (AMI) project plan will not fully enable this functionality.

(b) The Company will continue to evaluate future smart meter capabilities, but the current advanced metering infrastructure (AMI) project plan will not fully enable this functionality.