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February 16, 2018

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY,
Draft Storage Potential Evaluation
Docket Nos. UM 1856

Dear Filing Center:

Please find enclosed the Opening Testimony and Exhibits of Dr. Benjamin Fitch-Fleischmann and the Direct Testimony of Daniel Crotzer on behalf of the Industrial Customers of Northwest Utilities and Northwest & Intermountain Power Producers Coalition in the above-referenced docket.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Haley M. Thomas
Haley M. Thomas

Enclosure

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 1856

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Draft Storage Potential Evaluation.	)
	)

OPENING TESTIMONY OF DR. BENJAMIN FITCH-FLEISCHMANN

ON BEHALF OF THE

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

AND THE

NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

February 16, 2018

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THE OPENING TESTIMONY OF DR. BENJAMIN FITCH-FLEISCHMANN**

EXHIBIT LIST

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Benjamin Fitch-Fleischmann. My business address is 121 Hickory Street, Missoula, Montana 59801.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a Senior Economist with Ecosystem Research Group, LLC. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU") and the Northwest and Intermountain Power Producers Coalition ("NIPPC"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including customers of Portland General Electric Company ("PGE" or the "Company"). NIPPC is a membership-based advocacy group representing electric market participants in the Pacific Northwest more generally. ICNU and NIPPC are also co-sponsoring the testimony of Daniel Crotzer.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at ICNU/101.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of this testimony is to describe several concerns that ICNU and NIPPC have with PGE's proposed investments in energy storage assets. NIPPC only joins in sections I, III and VI. Both ICNU and NIPPC are concerned with the degree to which PGE proposes to allow for participation in the projects by non-cost-of-service customers and third-party providers. ICNU and NIPPC are generally supportive of efforts to learn more about the potential for energy storage systems to provide benefits to customers. However, given the rapidly changing technological landscape, it is particularly important to move forward deliberately and in a way that builds on the experiences of other utilities and regulatory commissions.

Q. DO YOU HAVE ANY CONCERNS WITH PGE'S PROPOSED STORAGE POTENTIAL EVALUATION?

A. ICNU and NIPPC are aware that parties have expressed many concerns with PGE's proposed Storage Potential Evaluation in previous workshop discussions. ICNU and NIPPC do not have any substantial comments at this time on PGE's draft Storage Potential Evaluation but may provide comments after that evaluation is finalized for the April 2, 2018 deadline.

Q. DO YOU HAVE ANY GENERAL CONCERNS WITH PGE'S PROPOSED INVESTMENTS IN ENERGY STORAGE?

A. ICNU and NIPPC share concerns with the overall costs of PGE's proposal, which will ultimately be borne by PGE's ratepayers. Taken as a whole, PGE proposes to make up to $190 million in capital investments to learn about battery storage while more affordable options may be available from the competitive market. For example, it is not clear whether PGE considered alternative ownership structures, or technologies like pumped hydro storage. PGE should also justify the location of its projects, including mitigating future transmission and distribution infrastructure. Going forward, energy storage should be part of the utilities' integrated resources planning to make sure that utilities are identifying the least cost and risk options available to meet its ratepayers' needs.

Q. WHAT ARE ICNU'S ADDITIONAL CONCERNS WITH PGE'S PROPOSED INVESTMENTS IN ENERGY STORAGE?

A. ICNU is concerned that PGE's proposed projects risk offering little additional knowledge in return for costs that may greatly exceed not only their potential benefit but also the combined costs associated with all of PGE's other pilot projects (past and ongoing). ICNU also has particular concerns with PGE's proposed projects at the Coffee Creek Substation and Port Westward 2 Generating Station, as well as concerns with PGE's proposed cost-recovery mechanism.

Q. DOES YOUR TESTIMONY ADDRESS ALL OF THE ENERGY STORAGE PROJECTS PGE HAS PROPOSED?

A. No. My testimony only covers those ICNU and/or NIPPC considers the most significant. However, my silence with respect to a particular project should not be taken as support for or opposition to that project. To the extent other parties raise concerns with these projects, ICNU and NIPPC will review those and may respond.

II. ICNU'S BACKGROUND SUMMARY

Q. PLEASE EXPLAIN THE BACKGROUND FOR PGE'S PROPOSAL.

A. The impetus for PGE's proposal is Oregon House Bill ("HB") 2193, which mandates that PGE acquire by 2020 at least 5 MWh of energy storage systems but not more than one percent of its 2014 peak load. PGE's proposals are for energy storage systems that are technically within these limits. However, ICNU is concerned that the proposed acquisitions are overly aggressive, as they could collectively add fully twenty to fifty times more energy than required by HB 2193. While ICNU generally agrees with PGE's interpretation that "the purpose is to optimize learning about energy storage,"[1/] ICNU is concerned that this goal has become secondary to simply moving forward with the acquisition and construction of new, utility-owned assets. The fact that the primary purpose of these projects is educational does not

[1/] Exh. PGE/101, Riehl-Brown/40.

absolve the Company of the need to pursue them in a least-cost manner. While there may be some experimentation required, the design of the projects should also draw heavily on the experiences of other utilities.

ICNU is concerned that the potential to learn from the experience of others has not been sufficiently considered in PGE's plans. While PGE's projects may represent new ground for PGE, ICNU believes that more consideration should be given to whether the results will simply replicate experiments conducted by others. To the extent PGE can learn in a cost-effective way from the experience of other utilities, it should do so. Furthermore, to the extent PGE has proposed projects that will provide incremental learning opportunities, it should competitively bid at least the most significant of these and it should consider non-utility ownership and tolling/lease agreements in order to ensure least-cost implementation and to gain experience contracting with third-party providers of new technologies, assuming the Oregon Public Utility Commission ("Commission") agrees these projects should move forward at all.

III. ICNU AND NIPPC'S CONCERNS WITH SPECIFIC PROJECTS

A. Microgrid Resiliency Project

Q. PLEASE EXPLAIN PGE'S PROPOSED MICROGRID RESILIENCY PILOT.

A. PGE is proposing to install between two and five microgrids at a combination of community and customer-specific sites. For customer-specific sites, the microgrid would work in conjunction with behind-the-meter generation and energy storage to provide reliability in the event of an outage, including a catastrophic event, and to provide capacity, energy, and ancillary services during periods of normal operation.

Q. WHAT IS YOUR OVERALL REACTION TO THE PROPOSED MICROGRID PILOT?

A. While this pilot, like most of the others, is not cost-effective, the variety of uses, benefits, and potential learnings from this pilot makes it an intriguing proposal. Not only would the microgrids provide system benefits, they would also protect critical business customers from outages. Meanwhile, they should provide educational opportunities in areas like energy storage, demand-side management, and distributed generation, and how these technologies can efficiently work together. Thus, I support PGE moving forward with the microgrid pilot.

Q. DESPITE YOUR SUPPORT FOR THIS PILOT, DO YOU HAVE ANY CONCERNS WITH IT?

A. Yes. The cost and lack of cost-effectiveness of this pilot suggests that PGE should lean more toward the lower end of its proposal than the higher end. It is not clear, for instance, that PGE would learn more from doing four or five microgrids than it would from doing two or three. Additionally, although not certain, it appears that PGE may intend to limit this pilot to fully bundled customers, cutting direct access customers out of the opportunity to participate.[2]

Q. WHY SHOULD DIRECT ACCESS CUSTOMERS BE ALLOWED TO PARTICIPATE IN THE MICROGRID PILOT?

A. Because PGE will achieve the same benefits and have the same educational opportunities from this pilot regardless of whether it is sited at a direct access or bundled service customer location. While direct access customers purchase their energy commodity from an energy service supplier ("ESS"), they are still connected to the Company's distribution and transmission system. Thus, there is no reason why these customers cannot contribute to PGE's energy, capacity, and ancillary services needs through generation and storage located behind

[2] Exh. PGE/101, Riehl-Brown/51 (noting that "[p]articipants will be encouraged to enroll in PGE's commercial and industrial automated demand response program"). This program is not available to direct access customers. PGE Schedule 26.

their meters just as effectively as a bundled service customer. This is evident from the fact that PGE's dispatchable standby generation ("DSG") program – participation in which is one of the criteria PGE is using to select eligible customer sites – is available to direct access customers.[3/] Indeed, PGE itself identifies DSG as a simple form of microgrid.[4/] Such customers may also perform the type of critical services and have the generation and distribution infrastructure the Company is looking for. These customers (and the critical services they provide) would benefit from the reliability of a microgrid in the event of a catastrophic event to the same extent as a bundled service customer.

Q. COULD A DIRECT ACCESS CUSTOMER'S CONTRACT WITH ITS ESS EFFECTIVELY PREVENT IT FROM PARTICIPATING IN THE MICROGRID PILOT?

A. That is possible. The microgrid system could allow a customer to self-supply a portion of its load and/or essentially net meter generation back to the grid. It is conceivable that this could conflict with provisions in a direct access customer's contract with its ESS. If that is the case, then clearly such a customer should not be allowed to participate.

However, simply because *some* direct access customers could potentially be ineligible is no justification for writing them *all* off. If a direct access customer proves to be a good candidate for the pilot, based on the Company's selection criteria, and there is no physical or legal obstacle to its participation, then there is no reason to exclude that customer from the program.

3/ PGE Schedule 200.
4/ Exh. PGE/101, Riehl-Brown/46.

B. Coffee Creek

Q. PLEASE EXPLAIN PGE'S PROPOSED COFFEE CREEK SUBSTATION PROJECT.

A. PGE proposes to build a 17-20 MW energy storage system at its Coffee Creek Substation, with a total capacity of 68-80 MWh. The project would provide capacity, energy, and ancillary services during normal grid conditions, and would mitigate outages during periods of grid interruption.

Q. IF PGE PROCEEDS WITH COFFEE CREEK, DO YOU HAVE ANY SUGGESTED MODIFICATIONS TO THE PROJECT?

A. Yes. While I do not believe that PGE has made a persuasive case in favor of this project, several modifications might be made to make it more cost-effective and serve ratepayers better. PGE states that it does not intend to allow bids that do not include utility ownership of storage assets.[5/] Given the rapidly evolving storage market, as well as significant changes to battery technology, I believe that PGE should allow parties to submit projects that include third-party ownership. Allowing such bids might actually enhance PGE's learnings – not only would it learn lessons regarding contracting for and constructing utility-scale storage, it would develop a better understanding of procuring energy storage systems owned by third parties. As shown in the testimony in this docket provided by Mr. Daniel Crotzer, of Fractal Energy Storage Consultants, this is a fairly common model in the energy storage sector. For example, SCE's Pomona Battery Storage project, which I discuss below, is owned and operated by AltaGas.[6/] I believe the most valuable lessons that PGE could get from this project are likely to come from gaining experience interacting and contracting with third-party providers of new technologies.

[5/] Exh. ICNU-NIPPC/102 at 12 (PGE response to ICNU DR 009).
[6/] https://www.altagas.ca/our-infrastructure/operations/pomona-energy-storage

Additionally, current forecasts show battery storage prices falling dramatically in the next few years.[7/] Mr. Crotzer's testimony offers more details on pricing, which suggest that continued price declines are likely in the near future and there is therefore value in proceeding slowly and incrementally.

Q. IF COFFEE CREEK IS NOT COMPETITIVELY BID, SHOULD THE COMMISSION REJECT IT?

A. Yes. I believe that energy storage will play an important role in PGE's operations in the future – but waiting a few years to procure these resources will save ratepayers millions of dollars, especially if they are competitively procured. Of course, PGE must make at least some investments now to comply with HB 2193, but all reasonable efforts should be taken to ensure that those investments maximize potential educational opportunities while minimizing cost to customers. PGE's Coffee Creek project does not meet these criteria.

IV. ICNU's CONCERNS WITH SPECIFIC PROJECTS

A. Coffee Creek

Q. PLEASE EXPLAIN ICNU'S SPECIFIC CONCERNS WITH THE COFFEE CREEK PROJECT.

A. ICNU has several additional concerns with PGE's Coffee Creek project. First, the sheer cost of the proposal is concerning – at over $30 in overnight capital cost, this single project is over half the cost of PGE's entire pilot proposal.[8/] I believe that PGE's proposed learnings with this technology do not justify such a significant cost.

Second, the project is not really a "pilot": it is just as big as some of the country's largest battery storage projects. In fact, its cost far exceeds the total cost of *all* pilots PGE has

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7/ https://www.lazard.com/media/450344/lazard-releases-annual-levelized-cost-of-energy_2017.pdf
8/ Exh. PGE/101 Riehl/Brown/12.

conducted in the last five years—which have combined costs of under $10 million—by a factor of over 3.[9/] Regardless of the merits of this project, its cost is not consistent with my understanding of what a "pilot" project should be. Historically, PGE's pilot programs have been small and relatively inexpensive.[10/] I do not think PGE should be allowed to deem the acquisition of such a major resource a "pilot."

I am not aware of any Commission rules or guidelines that suggest what the appropriate size or cost of utility pilot programs should be, but given the rapidly changing technological landscape and the size of the projects PGE has proposed, I recommend that the Commission consider establishing guidelines for pilot programs. This would help give stakeholders, the utilities, and ratepayers common expectations about the amount of money and time that the Commission believes utilities should allocate to gaining hands-on experience with new technologies. Such guidelines should start from the premise that a pilot project is intended to evaluate the feasibility, cost, and performance of new technologies and, therefore, should be small-scale and inexpensive unless a compelling reason justifies its expansion.

Q. CAN YOU ELABORATE ON YOUR CONCERNS ABOUT THE SCALE OF THE COFFEE CREEK PROJECT?

A. Coffee Creek is a large, fully-developed project, similar in size to some of the largest storage projects built elsewhere in the country. For example, Coffee Creek's size is almost identical to a project recently completed by Southern California Edison ("SCE"). That utility's Pomona Energy Storage Facility, a 20 MW, 80 MWh battery system, was the largest battery storage

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9/ Exh. ICNU-NIPPC/102 at 3-9 (ICNU DR 002 Attachment A). The calculation of a combined cost of approximately $10 million from the pilots identified in this attachment excludes revenues earned from the Automated Demand Response pilot and assumes PGE will spend the full $2.25 million identified for 2018 for the MFR Water Heater Program.

10/ Exh. ICNU-NIPPC/102 at 3-9 (ICNU DR 002 Attachment A).

system in the country when it was completed.[11/] In fact, the Coffee Creek Project is not much smaller than the country's largest battery storage project, San Diego Gas & Electric's ("SDG&E") Escondido plant, a 30 MW, 120 MWh project completed last year.[12/] While I realize that PGE anticipates learning certain things from this project (supporting an entire substation load during an outage, operating and constructing utility scale energy storage, etc.), I do not believe it is appropriate to deem a project of this size a "pilot." As compared to other operational storage projects, Coffee Creek is a very large asset.

Finally, I think it is worth comparing the size of Coffee Creek relative to HB 2193's legislative mandate to how other utilities have responded to their states' mandates. The various California projects discussed above were built pursuant to a *500 MW* storage mandate, spread across California's three largest investor-owned utilities.[13/] SDG&E's Escondido project, currently the largest in the nation, is less than 20 percent of that utility's mandated target of 165 MW. In contrast, Coffee Creek independently exceeds PGE's 5 MWh legislative mandate by 13 to 16 times.[14/]

SDG&E is working to meet its mandate, but it is not planning any more storage than legally required.[15/] In light of Mr. Crotzer's testimony on the rapidly declining cost of energy

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[11/] https://www.altagas.ca/sites/default/files/2017-06/daa982ef-7a30-43fa-872b-d8b063d9a2fe.pdf. A few storage projects have since eclipsed Pomona in size since it was completed in early 2016, but it remains one of the largest in the country.

[12/] https://www.windpowerengineering.com/business-news-projects/meet-north-americas-largest-lithium-ion-battery-storage-facility/

[13/] Cal. AB 2868 (2016), Order Instituting Rulemaking to consider policy and implementation refinements to the Energy Storage Procurement Framework and Design Program (D.13-10-040, D.14-10-045) and related Action Plan of the California Energy Storage Roadmap, Rulemaking 15-03-011, Decision 17-04-039, P. 66 (Cal. PUC April 27. 2017).

[14/] HB 2193 § 2(1), Exh. PGE/10 at 13:2. Oregon's legislation mandates megawatt hours of storage, whereas California requires a certain number of megawatts.

[15/] Rob Nikolewski, Utilities meet tight energy storage deadline, *San Diego Union-Tribune* (Sep. 13, 2016), available at http://www.sandiegouniontribune.com/business/energy-green/sdut-energy-storage-deadline-2016sep13-story.html.

storage, this is a reasonable approach to balancing regulatory obligations and ratepayer interests. In contrast, PGE's proposal far exceeds its legislative mandate, which will unnecessarily increase costs for ratepayers.

Q. IS THIS PILOT NECESSARY FOR PGE TO ACCOMPLISH ITS PROPOSED LEARNINGS?

No. PGE states that it hopes to learn "how to integrate and utilize a large-scale storage device into our dispatch and balancing authority." Additionally, PGE hopes to "gain learnings around the best practices for implementation and integration of energy storage."[16/] While these may be new concepts for PGE, they are not new for utilities elsewhere in the country. While battery storage technology is still developing, many utilities have deployed similar systems as part of their resource mix to meet their needs. I believe that, unless PGE can demonstrate incremental learnings from Coffee Creek, it should rely on peer utilities' experiences instead of constructing what would otherwise be an expensive, unnecessary project.

B. Generation Kickstart

Q. PLEASE EXPLAIN PGE'S PROPOSED GENERATION KICKSTART PROJECT.

A. PGE proposes to integrate a 4-6 MW battery storage system in its Port Westward 2 generation facility at an overnight capital cost of between $6 and $8 million. This battery storage system would be utilized the same way that spinning reserves are and would allow a reciprocating engine to remain shut off until the battery is exhausted.[17/]

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE GENERATION KICKSTART PROJECT.

16/ Exh. PGE/101, Riehl-Brown/73.
17/ Exh. PGE/100, Riehl-Brown/16.

A. My primary concern with Generation Kickstart is that it is similar to existing projects elsewhere in the country and therefore unlikely to produce knowledge that PGE could not gain at lower cost by learning from the experience of other utilities. As I understand it, HB 2193 was intended to encourage Oregon's utilities to develop expertise deploying storage assets, while balancing the costs of construction and operation with the potential value to ratepayers and utility operations.[18/] In my view, the "potential value to ratepayers" is primarily the knowledge that PGE gains, as these projects are not cost-effective. In the case of Generation Kickstart, the knowledge gained as a result of the project is minimal – other utilities have already developed nearly identical proposals, so it is clear that such a project is technically feasible. I do not believe ratepayers should be asked to shoulder millions of dollars in costs associated with pilot programs when equivalent projects have already been completed elsewhere in the country.

Q. CAN YOU IDENTIFY A PROJECT SIMILAR TO GENERATION KICKSTART?

A. Yes. As PGE acknowledges, Generation Kickstart closely resembles SCE's Hybrid Gas-Storage plant in Norwalk, California. There, the utility and General Electric added a 10 MW, 4.3 MWh battery to an existing gas peaker plant.[19/] This battery allows the natural gas turbines to remain off, while the battery serves spinning reserve purposes.

Q. DO YOU HAVE OTHER EXAMPLES?

A. Yes. Similar technology is already commercially available. General Electric produces an upgrade for its popular LM-6000 turbine that integrates battery storage.[20/] While PGE's Port

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18/ HB 2193 § 3(3)(a)(B).

19/ https://www.insideedison.com/stories/sce-unveils-worlds-first-low-emission-hybrid-battery-storage-gas-turbine-peaker-system

20/ https://www.gepower.com/services/gas-turbines/upgrades/hybrid-egt

Westward 2 uses a different type of generator, the existence of largely equivalent, commercially available technology makes me question what "learnings" PGE might accomplish that are not already well-known throughout the industry.

Q. GIVEN THAT THIS PILOT WOULD MIMIC EXISTING, IN-SERVICE TECHNOLOGY, WHAT DO YOU RECOMMEND?

There is no reason to conduct a "pilot" program when the electricity industry has already determined that similar technology can be deployed without any significant problems. I have no reason to doubt that projects similar to Generation Kickstart will ultimately be cost-effective, and I believe that PGE should revisit this project at that time.

V. COST RECOVERY

Q. HOW IS PGE PROPOSING TO RECOVER THE COSTS OF ITS ENERGY STORAGE PROGRAM?

A. PGE states that it "plans to modify its Schedule 122 Renewable Resources Automatic Adjustment Clause tariff ["RAC"] to add energy storage as eligible resources for cost recovery."[21/] The Company has not specified how it proposes to allocate the costs of these programs across its various customer classes. In response to a data request, however, PGE stated "[i]t is likely that PGE would recover based on generation revenues, as done in PGE's Schedule 137 [Customer-Owned Solar Payment Option Cost Recovery Mechanism]."[22/] This allocation method also would be consistent with the Company's RAC, which provides that "[c]osts recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule."[23/]

21/ Exh. PGE/101, Riehl-Brown/142.
22/ Exh. ICNU-NIPPC/102 at 1 (PGE Resp. to ICNU DR 001).
23/ PGE Schedule 122, Second Revision of Sheet No. 122-3.

Q. DO YOU HAVE ANY CONCERNS WITH PGE'S COST RECOVERY PROPOSALS?

A. Yes. First, I disagree that the costs of PGE's energy storage program are appropriately recoverable through the RAC. Second, I disagree that the costs of all of the projects proposed in this program should be recovered from customers on a generation basis.

Q. PLEASE EXPLAIN WHY THE RAC IS INAPPROPRIATE FOR RECOVERING THE COSTS OF PGE'S ENERGY STORAGE PROGRAM.

A. The RAC exists pursuant to Oregon's renewable portfolio standard law. Prior to 2016, ORS 469A.120(2) provided that the Commission "shall establish an automatic adjustment clause … [to recover] costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission." SB 1547 amended this statute to include "costs related to associated energy storage." Thus, while I am not a lawyer, it seems clear from this language that in order for an energy storage system to be eligible for inclusion in the RAC under this statute, the energy storage system must be "associated" with "facilities that generate electricity from renewable energy sources."

Q. ARE THE PROJECTS PGE PROPOSES ASSOCIATED WITH RENEWABLE GENERATION?

A. No, and it seems that only one of them – the Baldock Mid-Feeder, which is a proposed storage system that connects to the Baldock Solar array in Aurora, OR – could arguably be considered as associated with renewable generation.

The other proposed projects have little, if anything, to do with renewable generation. The Coffee Creek Substation project is a reliability project intended to mitigate the impacts of a transmission outage. The Company testifies that this project will enable it "to test the ability of the energy storage system to support the entire substation load during different transmission outage scenarios …. [I]f the primary transmission source sustains an outage, then an energy storage system could be used to ride through the outage while the scheme transfers to the secondary transmission source."[24/] This is unrelated to renewable energy.

Similarly, the proposed microgrid projects are reliability-driven. Their purpose is to isolate a customer or a community in the event of an outage to maintain service to this area, not to support or enhance renewable energy.

Generation Kickstart is intended to enhance the efficiency and effectiveness of Port Westward 2, which is a gas-fired generating station, not a renewable energy source.

The Residential Storage Pilot proposes to install battery inverter systems in residences. PGE states that this will provide reliability benefits for program participants, and will promote a more flexible grid. While PGE identifies increasing renewables penetration as necessitating this more flexible grid, it is nonetheless the case that the battery systems it proposes are not "associated" with any particular renewable generation.

Finally, the controls and administration/evaluation portions of the program are not energy storage at all. The former is software intended to "capture the benefits associated with the use cases identified in PGE's Energy Storage Potential Evaluation report,"[25/] while the latter is simply overhead related to the energy storage program.

Q. PLEASE EXPLAIN YOUR CONCERN WITH HOW PGE PROPOSES TO ALLOCATE THE COSTS OF ITS ENERGY STORAGE PROGRAM TO CUSTOMER CLASSES.

A. PGE has proposed a diverse array of energy storage projects, yet the Company suggests using a uniform method for recovering the costs by using an equal cents per kWh basis based on

24/ Exh. PGE/100, Riehl-Brown/14.
25/ Exh. PGE/100, Riehl-Brown/37.

generation revenues. This does not reflect basic principles of cost-causation. It stands to reason, for instance, that the costs of a residential storage program should be borne by residential customers, as they are the ones who directly benefit. Other projects may more appropriately be considered primarily as transmission or distribution investments because they are intended to provide a reliability backstop in the event of an outage on one of these types of facilities. For instance, in response to data requests, the Company admits that not a single customer on its industrial schedules 89, 90, 485, or 489 are served out of the Coffee Creek substation, and only 2% of the total load served from this substation is industrial load,[26/] yet its cost allocation proposal would assign a significant percentage of the costs of its Coffee Creek energy storage project to industrial customers.

The diversity of the projects PGE proposes demonstrates that its analogy to Schedule 137 as a means of recovering costs from customers is not appropriate. That tariff recovers costs associated with a volumetric incentive rate for solar generation systems. In other words, the tariff is dedicated to recovering costs that are exclusively related to generation. This is not the case for the Company's energy storage programs. Additionally, the range of projects is a further indication that the RAC is not an appropriate vehicle with which to recover the costs of the energy storage program. PGE states that it intends only to update the RAC to include "energy storage as an eligible resource[] for cost recovery." If PGE is allowed to do this, however, then all energy storage costs recovered through the RAC will necessarily be recovered based on generation revenues because Special Condition 1 of this tariff requires that result.

26/ Exh. ICNU-NIPPC/102 at 10-11 (ICNU DRs 006 & 007).

Q. WHAT DO YOU RECOMMEND?

A. PGE is correct that HB 2193 authorizes it to recover "all costs prudently incurred … in procuring one or more qualifying energy storage systems under this section, including any above-market costs associated with procurement."[27] Thus, the Commission may allow PGE to defer eligible costs for later recovery in rates, rather than authorizing their recovery through the RAC. This has the added benefit of allowing parties to address issues related to how the costs of the energy storage program should be allocated to various customer classes at the time PGE requests to amortize those costs into rates, rather than adjudicating those issues in this docket.

Q. SHOULD PGE BE ALLOWED TO DEFER ALL OF THE COSTS OF ITS ENERGY STORAGE PROGRAM?

A. No. The law ensures PGE of recovery only of costs prudently incurred in "procuring one or more qualifying energy storage systems …." Thus, the costs PGE anticipates incurring related to Controls and Administration/Evaluation should not be eligible for deferral because they are not "qualifying energy storage systems."

They also do not qualify for deferral more generally because their anticipated costs do not rise to the level that justifies a deferral. The general deferral statute requires, at a minimum, that a deferral will minimize the frequency of rate changes or match appropriately the costs borne by and benefits received by ratepayers.[28] Even if the costs in question meet one of these criteria, they must also be at least material.[29] PGE anticipates that the combined first year revenue requirement impact from the Controls and Administration/Evaluation

[27] HB 2193 § 2(3).
[28] ORS 757.259.
[29] Docket No. UM 1071, Order No. 04-108 at 8-9 (Mar. 2, 2004)

projects will equal $800,000, an amount that clearly is *im*material compared to a total revenue requirement of over $1.8 billion.[30/]

This is not to say that if the Commission authorizes PGE to go forward with the Controls and Administration/Evaluation portion of its energy storage program, the Company should be denied recovery of these costs. Rather, it simply means that PGE should be required to recover them through traditional regulatory mechanisms, such as a rate case, after prudency is reviewed and determined.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[30/] Docket No. UE 319, PGE Revenue Requirement Revision to Final Update at 1 (Dec. 4, 2017).

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OF OREGON

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EXHIBIT NO. ICNU-NIPPC/101

QUALIFICATION STATEMENT OF DR. BENJAMIN FITCH-FLEISCHMANN

Q. **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. I received a B.A. in economics and government from Claremont McKenna College in 2005, an M.A. in economics from the University of Montana in 2009, an M.S. in economics from the University of Oregon in 2012, and a Ph.D. in economics from the University of Oregon in 2015. I am currently Senior Economist with Ecosystem Research Group, LLC, where I work as a consultant for public agencies and private clients on environmental, economic, and regulatory compliance issues. From 2016 to 2017 I was a Senior Economist with the Oregon Public Utility Commission. Prior to that, from 2015 to 2016, I was an Assistant Professor of Economics and Environmental Studies at Oberlin College. From 2012 to 2015 I was an instructor and Ph.D. candidate in economics at the University of Oregon. From 2006 to 2008, I was a consultant for ICF International working on projects for the U.S. Department of Energy, the U.S. Environmental Protection Agency, and other governmental entities. I have taught undergraduate courses on microeconomics, macroeconomics, econometrics, environmental economics, and behavioral economics.

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EXHIBIT NO. ICNU-NIPPC/102

PGE DATA RESPONSES

February 6, 2018

TO: Benjamin Fitch-Fleischmann
Riley Peck
Tyler Pepple
Davison Van Cleve, PC

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1856
PGE Response to ICNU Data Request No. 001
Dated January 23, 2018

Request:

Please explain how PGE intends to allocate pilot costs on a per-class basis. If costs for each of the distinct pilot proposals will be allocated differently, please explain how each distinct pilot's costs will be allocated on a per-class basis.

Response:

PGE has not yet determined how it will allocate pilot costs for cost recovery. However, most of the benefits appear to be generation related. It is likely that PGE would recover based on generation revenues, as done in PGE's Schedule 137. Special Condition 1 in Schedule 137 reads:

> Costs recovered through Schedule 137 will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis.

February 6, 2018

TO: Benjamin Fitch-Fleischmann
Riley Peck
Tyler Pepple
Davison Van Cleve, PC

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1856
PGE Response to ICNU Data Request No. 002
Dated January 23, 2018

Request:

Please identify every pilot PGE has conducted in the last five years. What were the costs of these pilots, on a program-by-program basis? Of those costs, how much has either been collected from ratepayers or deferred for later recollection, again on a program-by-program basis?

Response:

Attachment 002-A provides the information requested.

In 2015 we started the Pricing Pilot and Direct Load Control. We deferred costs and began collecting from customers in January 2018 through Schedule 105.

In 2017 we started three pilots: Residential Water Heater (Schedule 4), Non-residential Direct Load Control (Schedule 25), and Non-residential Demand Response (Schedule 26). We deferred costs and began collecting from customers in January 2018 through Schedule 135.

The ADR Pilot started in January 2014 and was completed by November, 2017. The balance in the account was transferred to Schedule 25-26 (Non-residential Direct Load Control/Non-residential Demand Response).

Direct Load Control
(AWO 1000004433)

DESCRIPTION OF THE DEFERRAL: UM1708 Order NO. 15-203 dtd 06.23.2015. Deferral of expenses associated with demand resonse pricing and direct load control pilots. The 'Pricing Pilot' is composed of three different rate structure offerings - a peak time rebate rate design and two different Time of Use rate designs. The 'Direct Load Control Thermostat (DLCT) Pilot' is a direct load control program involving responsive thermostats.

JE Ref: JRV75Z

Month		**Accrual / Deferral**	4073001 **Amortization**	4210010 **Interest**	1823002 **Balance**
Beginning Balance:					
December	2015	29,075.93		$92	$29,168
January	2016	28,790.59		$273	$58,231
February		39,589.23		$488	$98,308
March		22,104.12		$684	$121,097
April		22,273.98		$828	$144,198
May		9,387.48		$932	$154,517
June		60,300.98		$1,156	$215,974
July		49,475.07		$1,506	$266,956
August		16,582.15		$1,722	$285,260
September		(37,000.29)		$1,669	$249,929
October		65,331.45		$1,768	$317,029
November		9,630.78		$2,014	$328,674
December		45,871.29		$2,200	$376,746
January	2017	7,950.01		$2,383	$387,078
February		25,728.29		$2,503	$415,309
March		7,325.01		$2,622	$425,256
April		35,753.07		$2,773	$463,782
May		2,450.01		$2,910	$469,142
June		2,800.47		$2,945	$474,887
July		(0.85)		$2,972	$477,858
August		(26,915.43)		$2,906	$453,849
September		9,250.24		$2,869	$465,968
October		312.50		$2,917	$469,198
November		107,575.49		$3,273	$580,046
December		146,802.82		$4,089	$730,938
January	**2018**		(18,331.05)	**$1,756**	**$714,363**
February				$1,738	$716,102
March				$1,743	$717,844
April				$1,747	$719,591
May				$1,751	$721,342
June				$1,755	$723,097
July				$1,760	$724,857
August				$1,764	$726,621
September				$1,768	$728,389
October				$1,772	$730,161
November				$1,777	$731,938
December				$1,781	$733,719
	Totals	**680,444.39**	**($18,331)**	**$71,606**	**$733,719**

UM 1856 - PGE Response to OPUC DR 002

Attachement 002-A
Page 2

Direct Load Control
(AWO 1000004433)

DESCRIPTION OF THE DEFERRAL: UM1708 Order NO. 15-203 dtd 06.23.2015. Deferral of expenses associated with demand resonse pricing and direct load control pilots. The 'Pricing Pilot' is composed of three different rate structure offerings - a peak time rebate rate design and two different Time of Use rate designs. The 'Direct Load Control Thermostat (DLCT) Pilot' is a direct load control program involving responsive thermostats.

JE Ref: JRV75Z

Month		Accrual / Deferral	4073001 Amortization	4210010 Interest	1823002 Balance
	2015	$29,076	$0	$92	$29,168
	2016	$332,337	$0	$15,241	$347,578
	2017	$319,032	$0	$35,161	$354,193
	2018	$0	($18,331)	$21,112	$2,781
	Totals	**$680,444**	**($18,331)**	**$71,606**	**$733,719**

UE 283 Cost of Capital - 2015	**7.562%**
UE 294 Cost of Capital - 2016	**7.510%**
Approved Blended Treas Rate (UM-1147)_2018	**2.920%**

Pricing Pilot
(AWO 1000004385)

DESCRIPTION OF THE DEFERRAL: UM1708 Order NO.15-203 dtd 06.23.2015. Deferral of expenses associated with demand resonse pricing and direct load control pilots. The 'Pricing Pilot' is composed of three different rate structure offerings - a peak time rebate rate design and two different Time of Use rate designs. The 'Direct Load Control Thermostat (DLCT) Pilot' is a direct load control program involving responsive thermostats.

JE Ref: JRV75Z

Month		Accrual / Deferral	4073001 Amortization	4210010 Interest	1823002 Balance
Beginning Balance:					
December	2015	392,588.02		1,236.90	393,824.92
January	2016	-		2,464.52	396,289.44
February		6,080.67		2,498.97	404,869.08
March		120,675.62		2,911.23	528,455.93
April		22,046.66		3,376.02	553,878.61
May		25,473.67		3,545.83	582,898.11
June		30,458.25		3,743.03	617,099.39
July		58,828.09		4,045.83	679,973.31
August		23,476.31		4,328.67	707,778.29
September		81,152.44		4,683.14	793,613.87
October		59,238.83		5,151.73	858,004.43
November		31,047.99		5,466.47	894,518.89
December		290,318.22		6,506.22	1,191,343.33
January	2017	23,212.17		7,527.96	1,222,083.46
February		40,996.28		7,775.97	1,270,855.71
March		34,380.30		8,060.48	1,313,296.49
April		186,876.94		8,803.23	1,508,976.66
May		14,497.70		9,488.41	1,532,962.77
June		34,017.36		9,699.59	1,576,679.72
July		9,423.31		9,896.22	1,595,999.25
August		39,014.64		10,109.71	1,645,123.60
September		36,244.20		10,408.45	1,691,776.25
October		(9,749.86)		10,556.49	1,692,582.88
November		-		10,592.04	1,703,174.92
December		220,582.68		11,348.52	1,935,106.12
January	2018		(40,801.36)	4,659.12	1,898,963.88
February				4,620.81	1,903,584.69
March				4,632.06	1,908,216.75
April				4,643.33	1,912,860.08
May				4,654.63	1,917,514.71
June				4,665.95	1,922,180.66
July				4,677.31	1,926,857.97
August				4,688.69	1,931,546.66
September				4,700.10	1,936,246.76
October				4,711.53	1,940,958.29
November				4,723.00	1,945,681.29
December				4,734.49	1,950,415.78
	Totals	**1,770,880.49**	**(40,801.36)**	**220,336.65**	**1,950,415.78**

Pricing Pilot
(AWO 1000004385)

DESCRIPTION OF THE DEFERRAL: UM1708 Order NO.15-203 dtd 06.23.2015. Deferral of expenses associated with demand resonse pricing and direct load control pilots. The 'Pricing Pilot' is composed of three different rate structure offerings - a peak time rebate rate design and two different Time of Use rate designs. The 'Direct Load Control Thermostat (DLCT) Pilot' is a direct load control program involving responsive thermostats.

JE Ref: JRV75Z

Month		Accrual / Deferral	4073001 Amortization	4210010 Interest	1823002 Balance
	2015	392,588.02	-	1,236.90	393,824.92
	2016	748,796.75	-	48,721.66	797,518.41
	2017	629,495.72	-	114,267.07	743,762.79
	2018	-	(40,801.36)	56,111.02	15,309.66
	Totals	**1,770,880.49**	**(40,801.36)**	**220,336.65**	**1,950,415.78**

UE 283 Cost of Capital - 2015	**7.562%**
UE 294 Cost of Capital - 2016	**7.510%**
Approved Blended Treas Rate (UM-1147)_2018	**2.920%**

Sch.25 "Nonresidential Direct Load Control Pilot" and Sch.26 "Nonresidential Demand Response Pilot"
AWO - 1000003228

Advice No.17-23 UM 1514 Compliance Filing for Sch.25 "Nonresidential Direct Load Control Pilot" and Sch.26 "Nonresidential Demand Response Pilot Program, dated 10.27.2017, with effective date 12.01.2017.
Amortization schedule for sch.25 & 26 was submitted to OPUC as part of the OPUC Advice filing No. 17-29, dated 11.13.2017. Effective date is 01.01.2018.
The incremental costs related to this pilot are to be recovered through Sch.135 "Demand Response Cost Recovery Mechanism".
The schedule below is not based on actual numbers and is used for 2018 budget.
The schedule will replace ADR program that is using AWO 1000003228. The ADR program ended on 11-30-2017, with ending regulatory liability balance of $(544,687.37) on account 2420008, AWO 1000003228. That AWO will continue to be used for this new pilot, and the balance will be transferred into the new pilot.
The purpose of these schedules is to help grow a resilient and flexible demand response portfolio to create a program able to meet PGE's goals of greater than 27 MW of peak load reduction by 2021.

Month	Year	*1823002* Deferral	*4073001* **Sch.135** Amortization	*4210010* Interest on Avg Balance	**JRV85D** *1823002* Balance
November		Balance transfer from an obsolete ADR Program (same AWO)			($544,687.37)
December	2017	$1,210,256.59		$119.87	$665,689.09
January	**2018**	**#REF!**	**(53,976.61)**	**#REF!**	**#REF!**
February			0.00	#REF!	#REF!
March			0.00	#REF!	#REF!
April			0.00	#REF!	#REF!
May			0.00	#REF!	#REF!
June			0.00	#REF!	#REF!
July			0.00	#REF!	#REF!
August			0.00	#REF!	#REF!
September			0.00	#REF!	#REF!
October			0.00	#REF!	#REF!
November			0.00	#REF!	#REF!
December			0.00	#REF!	#REF!
January	2019		0.00	#REF!	#REF!
	Totals	#REF!	($53,976.61)	#REF!	#REF!
	2017	1,210,256.59	(544,687.37)	119.87	665,689.09
	2018	#REF!	(53,976.61)	#REF!	#REF!
	2019	0.00	0.00	#REF!	#REF!
	Totals	#REF!	($598,663.98)	#REF!	#REF!

Blended Treasury Rate - UM 1147	2.380%	January 1,2017
Blended Treasury Rate - UM 1147	2.920%	January 1,2018

PGE
Schedule 4 Residential Water Heater
Balancing Account
Account 1823002, AWO - 3000001057 "MFR Water Heater Program"

Schedule 4 was submitted to OPUC in Advice filing No. 17-09 (UM 1827), dated 04.19.2017. Pilot effectice date 07.01.2017. The pilot to go till 12.31.2019.
Sch.4 amortization was submitted to OPUC as part of the OPUC Advice filing No. 17-29, dated 11.13.2017. Amortization effective date is 01.01.2018.
The incremental costs related to this pilot are to be recovered through Sch.135 "Demand Response Cost Recovery Mechanism".
PGE Proposed $2.25mm amortization in 2018: $1.50mm for Sch.25&26, and $0.75mm for Sch.4.
This implies that actual amortization should be split as 1/3 for Sch.4 and 2/3 for Sch.25&26.
The schedule below is not based on actual numbers and is used for 2018 budget. The deferral for the nonresidential demand response programs is docket UM 1514. The residential water heater pilot deferral is docket UM 1827.
The schedule 4 has its own AWO 3000001057.
The pilot is designed to quantify the energy consumption that can be shifted to different times of day using water heaters equipped with communication intefaces that support direct load control events. During the pilot, PGE will test different technologies while implementing different demand response dispatch strategies. PGE plans to use 3rd party providers for 4G LTE and radio coverage for communicating direct load control events.

Month		*4073001* **Sch.135 Amortization**	*1823002* **Deferral**	*4210010* **Blended Treasury Rate Interest**	*1823002* **Ending Balance**
December	2017		60,583.33	60.08	60,643.41
January	**2018**	**(26,988.31)**	**#REF!**	**#REF!**	**#REF!**
February		-		#REF!	#REF!
March		-		#REF!	#REF!
April		-		#REF!	#REF!
May		-		#REF!	#REF!
June		-		#REF!	#REF!
July		-		#REF!	#REF!
August		-		#REF!	#REF!
September		-		#REF!	#REF!
October		-		#REF!	#REF!
November		-		#REF!	#REF!
January	2019	-		#REF!	#REF!
	Totals	(26,988.31)	#REF!	#REF!	#REF!
	2017	-	60,583.33	60.08	60,643.41
	2018	(26,988.31)	#REF!	#REF!	#REF!
	Totals	(26,988.31)	#REF!	#REF!	#REF!

Interest = [Prior Month Balance + (Current Month Accrual/2) + (Current Month Amortization/2)] x %/12 months

Blended Treasury Rate - UM 1147	**2.380%**	January 1,2017
Blended Treasury Rate - UM 1147	**2.920%**	January 1,2018

PGE
Sch. 135 Automated Demand Response
Balancing Account
AWO - 1000003228

Source:		*12M Rev Report 4560002*		*JRV85D*	*AWO Activity*	*JRV85D*	*JRV85D 4310002*		
			Sch 135 Revenues		**Sch 135 Expenses**		**Blended Treasury Rate**	**Balance**	
Month		**Deferred**	**Amortized**	**Net**	**Deferred**	**Amortized**	**Interest**	**1823002 / 2420008**	
January	2013				-		0.00	-	
January	2014	(184,443.75)		(184,443.75)	6,316.28		127.36	(2,591.76)	
January	2015	(214,429.91)	-	(214,429.91)	-	-	(5,364.01)	(3,447,717.23)	
January	2016	4.36	(11,749.25)	(11,744.89)	(11,749.25)	11,749.25	(4,586.28)	(2,512,067.42)	
February		28.27	154,980.74	155,009.01	154,980.74	(154,980.74)	(4,463.37)	(2,361,521.78)	
March		0.65	10,813.83	10,814.48	10,813.83	(10,813.83)	(4,319.54)	(2,355,026.84)	
April		-	130,304.78	130,304.78	130,304.78	(130,304.78)	(4,198.10)	(2,228,920.17)	
May		-	8,408.26	8,408.26	8,408.26	(8,408.26)	(4,078.65)	(2,224,590.55)	
June		-	149,371.14	149,371.14	149,371.14	(149,371.14)	(3,941.49)	(2,079,160.90)	
July		588.09	1,917.49	2,505.58	1,917.49	(1,917.49)	(3,809.50)	(2,080,464.82)	
August		-	18,569.16	18,569.16	18,569.16	(18,569.16)	(3,797.16)	(2,065,692.83)	
September		-	(9.45)	(9.45)	(9.45)	9.45	(3,787.11)	(2,069,489.39)	
October		-	232,416.81	232,416.81	232,416.81	(232,416.81)	(3,581.02)	(1,840,653.59)	
November		(0.30)	211,881.64	211,881.34	211,881.64	(211,881.64)	(3,180.31)	(1,631,952.56)	
December		-	113,998.57	113,998.57	113,998.57	(113,998.57)	(2,887.41)	(1,520,841.41)	
January	2017	-	97,616.19	-	97,616.19	(97,616.19)	(2,919.53)	(1,426,144.75)	
February		-	204,464.34	204,464.34	204,464.34	(204,464.34)	(2,625.76)	(1,224,306.17)	
March		-	161,641.50	161,641.50	161,641.50	(161,641.50)	(2,267.91)	(1,064,932.58)	
April		-	-	-	-	-	(2,112.12)	(1,067,044.70)	
May		-	112,491.81	112,491.81	112,491.81	(112,491.81)	(2,004.75)	(956,557.64)	
June		-	-	-	-	-	(1,897.17)	(958,454.81)	
July		-	(6,371.40)	(6,371.40)	(6,371.40)	6,371.40	(1,907.25)	(966,733.46)	
August		0.17	-	0.17	-	-	(1,917.35)	(968,650.65)	
September		-	-	-	-	-	(1,921.16)	(970,571.81)	
October		-	(110,131.16)	(110,131.16)	(110,131.16)	110,131.16	(2,034.18)	(1,082,737.15)	
November	**2017**	0.45	539,661.59	539,662.04	539,661.59	(539,661.59)	(1,612.26)	(544,687.37)	**This deferral is complete as of 11.30.2017, and is replaced by Sch.25&26 starting 12.01.2017. The remaining balance will continue on AWO 1000003228 and will become part of the new Sch.25&26 pilots.**
	Totals		(390,853.29)			-	(153,834.08)	(544,687.37)	
	2013	-	-		170,150.70	-	5,257.65	175,408.35	
	2014	(3,851,170.30)	646,025.56		475,874.86	(646,025.56)	(28,036.21)	(3,403,331.65)	
	2015	(215,213.00)	1,008,606.17		1,008,606.17	(1,008,606.17)	(61,206.12)	732,187.05	
	2016	621.07	1,020,903.72		1,020,903.72	(1,020,903.72)	(46,629.94)	974,894.85	
	2017	0.62	999,372.87		999,372.87	(999,372.87)	(23,219.46)	976,154.03	
	Totals		(390,853.29)			-	(153,834.08)	(544,687.37)	

Interest = [Prior Month Balance + (Current Month Accrual/2) + (Current Month Amortization/2)] x %/12 months

Approved Cost of Capital - UE 215	**8.033%**	January 1, 2013
Blended Treasury Rate - UM 1147	**1.770%**	January 1,2014
Blended Treasury Rate - UM 1147	**1.930%**	January 1,2015
Blended Treasury Rate - UM 1147	**2.200%**	January 1,2016
Blended Treasury Rate - UM 1147	**2.380%**	January 1,2017

February 12, 2018

TO: Tyler Pepple
Riley Peck
Davison Van Cleve, P.C.

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1856
PGE Response to ICNU Data Request No. 006
Dated January 23, 2018

Request:

Please state the number of customers served under schedules 89, 90, 485, and 489 by the Coffee Creek substation, providing a specific number for each schedule.

Response:

There are no customers on the listed schedules served by the Coffee Creek Substation.

February 13, 2018

TO: Benjamin Fitch-Fleischmann
Riley Peck
Tyler Pepple
Davison Van Cleve, PC

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1856
PGE Response to ICNU Data Request No. 007
Dated January 30, 2018

Request:

Please refer to PGE/Exhibit 101, page 71, which provides the breakdown of the number of customers, by customer type, served by the Coffee Creek Substation. Please provide the breakdown of the composition of the average load at this substation by customer type. If similar information is available for peak load, please also provide it.

Response:

The average load by customer type at Coffee Creek Substation is identified in the table below.

Customer Type	Average Load	Percent
Residential	856 kW	9.9%
Commercial	7,603 kW	88.1%
Industrial	171 kW	2%
Total Average Load:	**8,630 kW**	

The breakdown of the peak load by customer type is not available, however it is expected that the ratios will be close to the same as the average load. The Coffee Creek Substation has a historical peak load of 13.6MW in the winter and 15.4MW in the summer.

February 13, 2018

TO: Benjamin Fitch-Fleischmann
Riley Peck
Tyler Pepple
Davison Van Cleve, PC

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1856
PGE Response to ICNU Data Request No. 009
Dated January 30, 2018

Request:

Will PGE allow bids into the RFP for the Coffee Creek project that do not include utility ownership of the storage assets?

Response:

No, PGE owns the underlying property and substation assets at the Coffee Creek site. In order to maximize the learnings from the testing and subsequent evaluation of the energy storage system, PGE is proposing to own and operate the energy storage assets at Coffee Creek.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1856

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
Energy Storage Proposal	)

DIRECT TESTIMONY OF

DANIEL CROTZER

ON BEHALF OF

NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

AND

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

February 16, 2018

**TABLE OF CONTENTS TO
THE OPENING TESTIMONY OF DANIEL CROTZER**

I. INTRODUCTION

Q Please state your name and address

A My name is Daniel Crotzer with Fractal Energy Storage Consultants. My business address is 8305 W HWY 71, STE 255, Austin, TX 78735

Q Please describe your background, experience and expertise.

A I am President at Fractal Energy Storage Consultants. Fractal is a specialized energy storage and renewable energy consulting firm that provides technical design and financial analysis of energy storage and renewable energy projects[1]. Fractal focuses on the technical and business needs of electric utilities to help decrease costs and improve reliability. Fractal's experience includes consultant services of over a GW of battery storage, 402 MW mechanical storage and 662 MW of solar and wind. Fractal is a member of the Smart Electric Power Alliance and is active in the Energy Storage Working Group[2]. In addition, Fractal has drafted and/or managed several energy storage procurements for utility clients, including:

(1) CPS Energy 10 MW / 10 MWh (solar+storage)
(2) Ishikari Project 70 MW / 130 MWh (wind+storage)
(3) Pedernales Electric Coop 2 MW / 4 MWh (storage only)
(4) Kingdom of Jordan 30 MW / 60 MWh (storage only)
(5) Singapore Power 2 MW / 2 MWh (storage only)

Formerly, I was the Operations Center Manager at Younicos (Xtreme Power), where I directed the operation of 77 MW of energy storage systems across the world. This included maintenance, monitoring (24/7) and marketing (operated the first batteries in

[1] https://www.energystorageconsultants.com/
[2] https://sepapower.org/community/member-committees-and-working-groups/energy-storage-working-group/

PJM and ERCOT ancillary markets). While at Xtreme Power, I led the creation of the first power trading platform using battery energy storage. Prior to Xtreme Power, I completed an MBA from the University of Texas at Austin. I was a Surface Nuclear Propulsion Officer for the US Navy onboard the USS George Washington (CVN-73) and led a 25-man team that operated the nuclear reactors. In addition, I was the Reactor Controls Division Officer for Reactor #1. I also have a B.S. in Civil Engineering from the UT Austin.

Q On whose behalf are you testifying

A I am testifying on behalf of the Northwest and Intermountain Power Producers Coalition ("NIPPC") and the Industrial Customers of Northwest Utilities ("ICNU").

II. <u>SUMMARY</u>

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

A The purpose of my testimony is to address the proposal from Portland General Electric Company ("PGE") for its Energy Storage Proposal ("Proposal"), which was filed with the Public Utility Commission of Oregon ("OPUC" or "Commission") November 1, 2017, and which was docketed in UM 1856. Specifically, my testimony will focus on two points: 1) demonstrate that if the solicitation were open to tolling/lease agreements, PGE could procure the storage with less cost and risk to its customers, and 2) reveal that the Controls and System Integration project ($3.1 million) is an unnecessary software platform.

Q Please summarize your recommendation for the Commission.

A In light of the high cost estimates provided by PGE, I recommend that energy storage RFPs allow tolling/lease agreements with independent power producers ("IPPs"). The implied cost of the PGE Proposal is $17,538/MW-month, while the market rate is $14,108/MW-month[3], as shown in Table 1. This means that PGE ratepayers would pay almost 25% more if PGE owned the projects.

Table 1 - Cash Flow Analysis of Costs

Year	Fractal Benchmark	PGE Low-Cost Estimate
0	$26,470,000	$30,400,000
1	$887,244	$6,700,000
2	$887,244	$821,053
3	$887,244	$821,053
4	$887,244	$821,053
5	$887,244	$821,053
6	$887,244	$821,053
7	$887,244	$821,053
8	$887,244	$821,053
9	$887,244	$821,053
10	$887,244	$821,053
11	$887,244	$821,053
12	$887,244	$821,053
13	$887,244	$821,053
14	$887,244	$821,053
15	$887,244	$821,053
16	$887,244	$821,053
17	$887,244	$821,053
18	$887,244	$821,053
19	$887,244	$821,053
20	$887,244	$821,053
Gross Cost	$44,214,880	$52,700,000
Present Value (7% WACC)	$35,869,476	$44,592,587
Annual Payment ($/MW-yr)	$3,385,825	$4,209,225
Monthly Payment ($/MW-mo)	$14,108	$17,538

Secondly, the Controls and System Integration project is unnecessary. Energy storage software is normally included at no extra charge. Most software includes the ability to remotely monitor, schedule and integrate with existing fleet controllers. The

[3] Market costs from Fractal's management of energy storage RFPs with a 7% hurdle rate

included energy storage controllers can be integrated with existing infrastructure at no extra cost.

III. <u>THE ENERGY STORAGE MARKET</u>

Q What are the typical overnight capital costs for a storage project?

A Energy storage has experienced tremendous price reductions in the last five years. For instance, lithium ion batteries in 2013 cost $800 per megawatt hour ("MWh"), today the cost is $275/MWh. Two years ago inverters were $0.15 per watt ("W"), today tier 1 inverters cost $0.08/W. Figure 1 shows the implied cost of a 20 MW / 80 MWh system using 17 different proposals from RFPs managed by Fractal. It is important to note that almost half of the costs are lower than PGE's "Low-Cost Estimate" for its Coffee Creek pilot.[4]

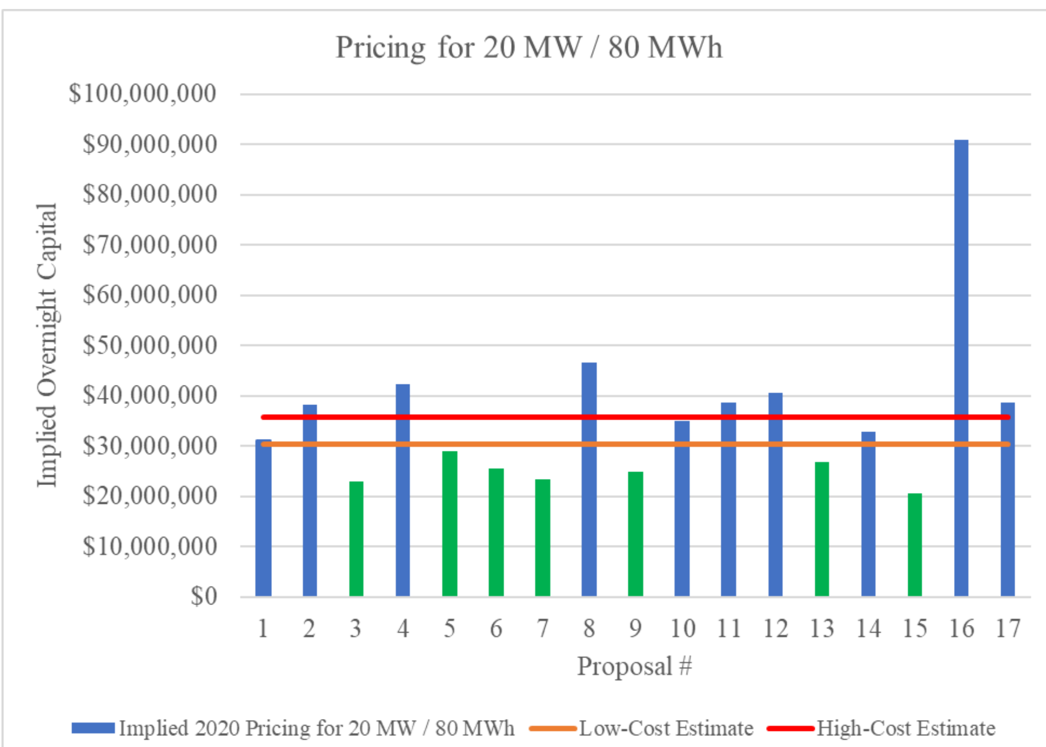

Figure 1 - Indicative Pricing for 20 MW / 80 MWh

[4] PGE/101, page 79.

The implied pricing shown in Table 2 is based on a January 1, 2020 commercial operation date ("COD") with the following reduction in costs compared to a Q1 2018 installation[5]:

(1) 20% reduction in battery

(2) 30% reduction for the enclosure

(3) 10% reduction for inverters

(4) All other costs are assumed to remain the same

Fractal's estimated overnight capital cost (terminology used by PGE to reflect upfront CAPEX) is $26.5 million, this is significantly lower than PGE's "Low-Cost Estimate" of $30.4 million for the Coffee Creek 20-year project.[6]

Table 2 – Fractal's Estimate for Overnight Capital Costs

Capital costs		
Batteries & BMS	$18,480,000	$220.00 $/kWh
Enclosure and thermal management	$2,940,000	$35.00 $/kWh
Inverters, bi-directional	$1,400,000	$70.00 $/kW
Balance of Plant	$2,000,000	$100.00 $/kW
Labor, Legal, and Engineering	$1,000,000	$50.00 $/kW
5 yr Warranty	$250,000	$5.00
Battery hard cost	$26,070,000	
Battery soft cost	$400,000	$20.00 $/kW
Total battery cost	$26,470,000	$330.88 $/kWh

To illustrate the impact overnight capital costs have on a storage project, Figure 2 shows internal rate of return for a similar sized project. PGE's "Low-Cost Estimate" is 15% higher than Fractal's estimate, as a result the higher cost would significantly reduce net benefits to PGE customers.

[5] Using Fractal's data on energy storage procurements
[6] PGE/101, page 79.

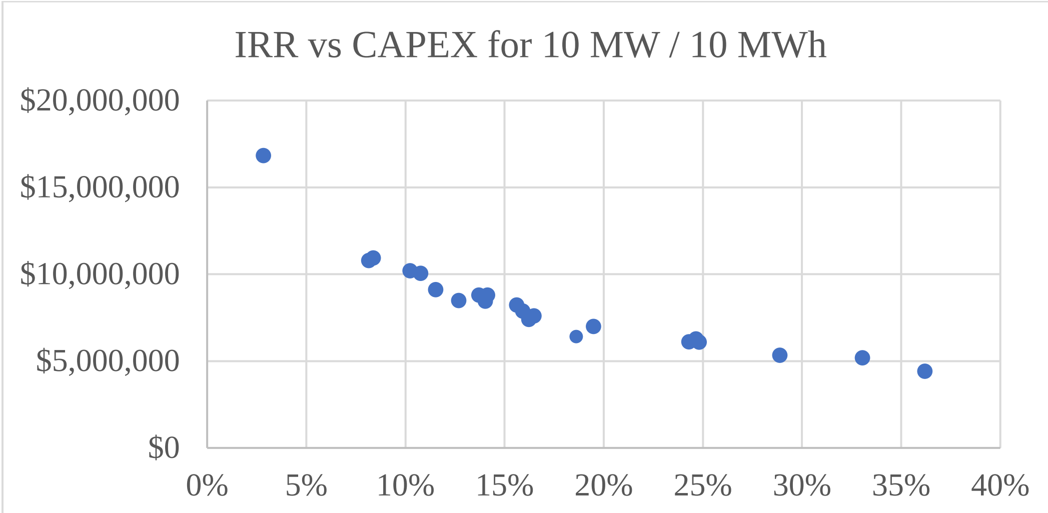

Figure 2 - Results of 10 MW / 10 MWh RFP Managed by Fractal

Q What are the typical operational expenses for a storage project?

A In our experience in operating storage and managing procurements, we have found that OPEX is considerably less than the PGE estimates. For example, in a 10 MW / 10 MWh (1-hr) energy storage project, the average operations and maintenance ("O&M") cost was approximately $90,000 per year (see Figure 3).

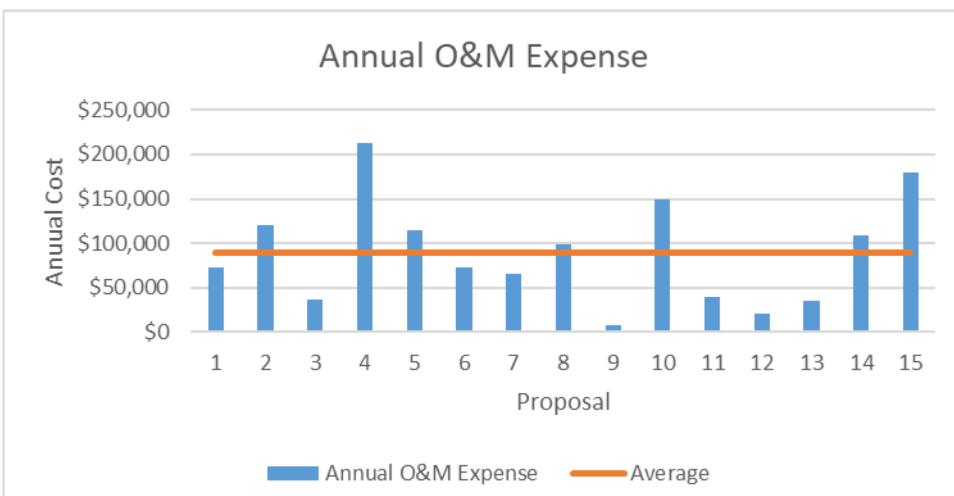

Figure 3 - Annual O&M Expenses from a Fractal Managed RFP

Figure 4 shows the footprint of a generic 20 MW / 80 MWh project, which is roughly equal in size to PGE's Coffee Creek project. This generic project would require approximately ½ acres for equipment and ½ acres for parking, access and setbacks. Assuming an annual lease rate of $1.50/sf, the land costs for storage are relatively small ($65,340/yr).

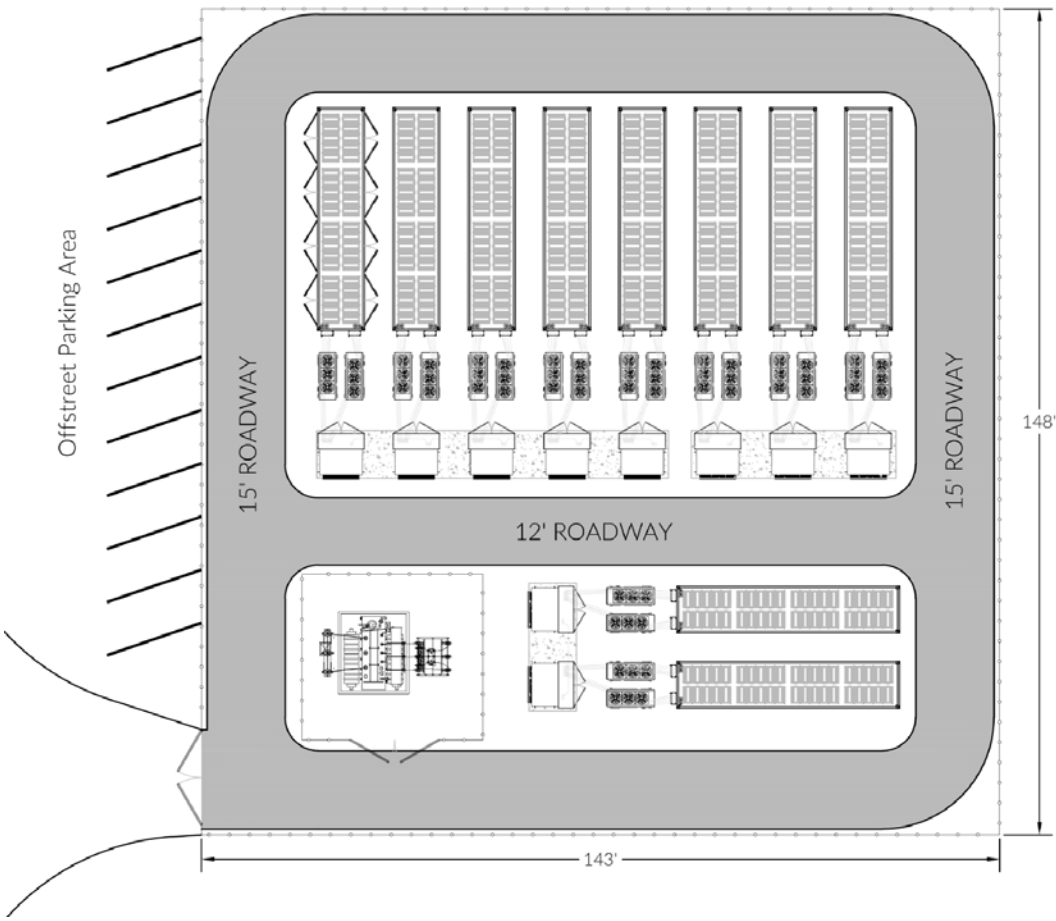

Figure 4 - Site Layout for 20 MW / 80 MWh

Table 3 shows Fractal's estimate for total OPEX, which is equivalent to PGE's "Year 1 Rev. Req."[7] The costs in Table 3 are comprehensive and include items that are often overlooked. These figures indicate that the annual OPEX for Coffee Creek should be

[7] PGE/100, Riehl-Brown/7

approximately $890,000 per year. This is exponentially different than the PGE "Low-Cost Estimate" of $6.7 million.[8]

Table 3 - Breakdown of Operating Expenditures (OPEX)

Annual OPEX			
Insurance	$52,140	0.2	% of hard costs
O&M (24/7 monitoring and maintena	$200,000	2.5	$/kW or $/kWh
QSE cost	$53,156	2.0%	of revenue
Aux load	$132,164		based on HVAC
Roundtrip Efficiency Loss	$119,745		based on $30/MWh
Land Lease	$65,340		0.5 acres
Property Tax	$264,700	1.0%	of Overnight Capital
Total Annual OPEX	$887,244		

Q What are the costs and functionality of existing Controls and System Integration software?

A Energy storage site controllers provide the following capabilities: programmable dispatch, SCADA integration and remote control, dashboard controls, remote real-time monitoring and cloud-based reporting. Table 4 lists leading ESS suppliers that provide site control software. In most cases the control platform cost is included[9]. This means that the functionality proposed for the Controls and System Integration project ($3.1M) is normally included at no extra cost with energy storage site controllers. Also, in Fractal's experience, it takes deep industry expertise and years to develop energy storage software. It would be prudent to use existing platforms that leverage years of experience and already possess the proposed capabilities.

[8] PGE/101, page 79. This PGE estimate is for a 20-year asset. The Company estimates that a 10-year asset would have a first-year revenue requirement of $6.5 million.

[9] Observed from Fractal's RFP management, but when not included the annual fee ranges from $10,000-$200,000 per site

Table 4 - Comparison of ESS Controls

Vendor	Control System	Dashboard	Remote Monitoring and Programmable Dispatch	Integrates with Generation and SCADA	Reports and Analytics
Younicos	Included	Y	Y	Y	Y
Powin	Included	Y	Y	-	Y
Indie Energy	Included	Y	Y	Y	Y
AMS	Included	Y	Y	-	Y
NEC	Included	Y	Y	Y	Y
Greensmith	License Fee	Y	Y	Y	Y
Landys+Gyr	Included	Y	Y	Y	Y
IHS	Varies	Y	Y	Y	Y
Tesla	Included	Y	Y	-	limited
AES	Included	Y	Y	Y	Y
RES	Included	Y	Y	Y	Y

Q How often are tolling/lease agreements used for energy storage procurements?

A They are used often. In order to reduce technical and financial risk, most of the storage procured by the three California investor owned utilities were procured through a tolling/lease agreement. Xcel Energy (Colorado) had a request for offers that attracted 430 responses, of which 141 included storage. Most of those proposals offered storage services under a tolling/lease agreement. The 28 stand-alone battery storage proposals offered a median price of $11,300/MW-month. Although the median price is influenced by system size and duration, this recent price test shows that IPPs are offering battery storage solutions at prices vastly below that estimated by PGE.

Table 5 - Summary of Xcel RFP Responses[10]

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11		$/MWh
Biomass	1	9	1	9		$/MWh
Total	430	111,963	238	58,283		

Q Should utilities be playing a role in energy storage?

A This is a vital question. From my experience, it takes two to three years before new developers and owners of storage have a grasp on operations and costs. Before owning storage, utilities may benefit from interacting with storage on a contractual basis while learning technology and O&M from an experienced storage developer and operator.

Q Should utility commissions be considering utility investment and/or mandates in energy storage infrastructure?

A Implementing mandates and/or allowing storage to be included in rate cases must be balanced with the overall cost to the system (cost to ratepayers and to existing infrastructure). California has singlehandedly fueled the energy storage industry, but the mandates on the three investor owned utilities raised the price of Resource Adequacy payments from $20/kW-yr to over $90/kW-yr. On the other hand, market driven

[10] Limited bid price details offered by Xcel Energy. Image: Xcel Energy

incentives, such as Reg-D in PJM, have encouraged storage adoption while reducing customer costs.[11]

Storage technology continues to advance in accordance with market opportunities, and while in certain instances top-down investment directives have resulted in temporarily inflated service costs, the overall price curve is overwhelmingly positive. Storage costs continue to decrease while performance continues to improve. At this point, there is enough installed storage to understand its value. As a result, I would advise commissions to require utilities to study the feasibility of storage, but I would not recommend encouraging uneconomical projects as a result of mandates.

IV. PROPOSAL

Q Do you recommend the Commission's approval of the Proposal?

A On one hand, I would like to encourage wider storage development, but on the other hand, I want to make sure that projects are economical. I do not recommend approving the Proposal as filed. I recommend modifying the proposal to include competitive bidding to secure the lowest cost and least risk.

Q What are your recommendations for modifying the Proposal?

A I strongly recommend:

(1) Re-evaluating the estimated operational expenses or encouraging PGE to procure storage through a tolling/lease agreement

(2) Dropping the Controls and System Integration project since it is unnecessary.

My testimony shows that Overnight Capital should be significantly lower than PGE's estimates, and PGE admits as much: "These costs were calculated based on the request

[11] https://www.eenews.net/assets/2017/03/10/document_pm_06.pdf

for information (RFI)[8] that was issued and may not reflect current market prices or prices that we will see when we issue a RFP."[12]

Even more revealing, is that OPEX can be reduced significantly. PGE ratepayers could enjoy the benefits of storage at a much lower cost ($14,108/MW-month vs $17,538/MW-month) if the recommendations are implemented.

Q Should the Commission approve the Proposal, how should it take additional action to explore a longer-term vision for energy storage?

A Encouraging adaption of new technology is difficult. Storage is even more difficult because it is multidimensional (e.g. charge, discharge, state of charge, C-rate, degradation, etc.). Before approving the purchase of any particular storage project, it would be prudent to:

(1) Benchmark proposals to current market prices

(2) Analyze lifetime performance using a combined technical and financial model

(3) Perform due diligence on the "bankability" of warranties and guarantees

V. CONCLUSION

Q Does this conclude your testimony?

A Yes.

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[12] PGE/100, Riehl-Brown/7