Date: May 17, 2018

Via web portal at www.utc.wa.gov/e-filing and email to Commission's Records Center at records@utc.wa.gov.

Steven V. King
Executive Director and Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, WA 98504-7250

RE: Comments of EQL Energy, LLC U-161024, Rulemaking for Integrated Resource Planning, WAC 480-1-238, WAC 480-90-238, and WAC 480-107

Dear Mr. King,
EQL Energy is a consultancy involved in Western DER planning, and program implementation. We have commented in previous sections of U-161024, once for a group of vendors called Pacific Northwest DER Parties. In this filing we are offering comments as consultants interested in seeing utilities, communities, and ratepayers benefit from the accelerating capability and cost declines in distributed energy resources, internet of things, data and associated analytics and control, as well as customer preferences for higher reliability, clean energy, and low costs.

We appreciate the opportunity to share our comments in response to the request in the Washington Utilities and Transportation Commission's ("Commission") Notice of Opportunity to Submit Written Comments issued in Docket UE-161024.

EQL has participated in NPCC 7th Plan development, Demand Response Advisory Committee, the PSE 2015 and 2017 IRP advisory group, Washington state's Distribution System Collaborative (DisCo) organized by Toni Usibelli and Dave Warren and numerous legislative and state utility commission proceedings in Washington, Oregon, Nevada, and California. Our areas of interest include:

1. Distributed energy resources (DER), e.g., energy efficiency, demand response, dispatchable standby generation, solar, storage, EV charging, CHP,
2. Distribution resources planning,
3. Integration of transmission and distribution planning/costs into the utility least cost planning process,
4. Resource adequacy modeling and methods (e.g., EUE expected unserved energy),
5. Reliability in IRP, Transmission Planning, and SAIFI/SAIDI statistics, as well as scenario and sensitivity analysis.

EQL has five objectives in providing these comments.

1. Appropriately include distributed energy resources (CHP, demand response, energy efficiency, storage, solar, etc.) in least cost planning for all utility investments and costs, including transmission and distribution level costs.
2. Create utility policy and programs that distinguish customer preferences for types of power, level of reliability, and use of distributed resources.
3. Promote integration of transmission and distribution planning into IRP, including the capacity, value, and technical constraints to integrate DERs onto portions of the grid.
4. Ensure data sharing, procurement and incentives for DERs reflect their value to utility, customers, and all ratepayers.

5. Support rates, programs, and incentives to promote Customer DERs.

A. General:

1. *Should the Commission propose parallel natural gas distribution planning rule language, similar to the draft rules in WAC 480-100-238 for electric utilities, with the exception of subsection (3)(c) "Distributed energy resource integration"?*
    a. *How should distribution system planning rule requirements for WAC 480-90-238 be similar to that of the electric utilities?*
    b. *How should the requirements be different?*

NO Comment

2. *In the draft rule, electric utilities would be required to form a separate advisory group to assist the utility as it develops its distribution system plan, in addition to the usual IRP advisory group. Regarding the distribution system advisory group:*
    a. *Should the distribution system advisory group be required, or should it be optional?*
    b. *What should be the extent and scope of the distribution system advisory group?*
    c. *Should the advisory group review the modeling methods, inputs, economic assumptions, cost estimates, and other factors that affect the selection of best options, or just review the results of transmission and distribution analysis?*
    d. *Is the draft description of the distribution planning advisory group's membership appropriate?*
    e. *Is a distribution advisory group necessary for the natural gas utilities? If yes, what should be the extent and scope of the advisory group?*

I recommend WUTC consider a ratepayer funded independent consultant (hired by WUTC) to coordinate or run the DSP process utilities providing data and perspective. This would allow experts in the field to collect utility data, identify data gaps, provide an independent analysis of the DSP and load forecasts that may include DER penetration scenarios. Many commissions in the US are either appointing independent IRP analysts (e.g., Montana) or coordinators for DRP (e.g., Washington D.C.). Some commissions have mandated DRP and integrated capacity analysis for DERs, e.g., California. In all of these cases the commission is seeking independent analysis or verification.

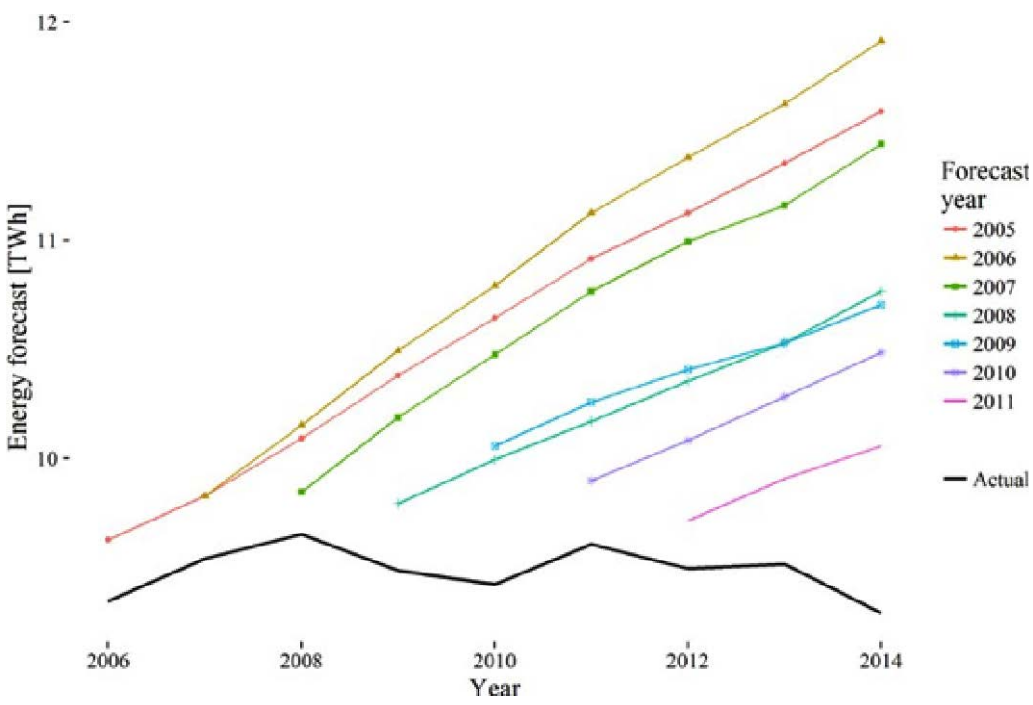
This group when done with the preliminary work, can report back to an advisory group which includes the utility. At this stage the stakeholder or advisory group can query both consultant and utility on the DSP. I imagine that the advisory group would meet 2 to 3 times over the course of a year planning horizon (timeline may be adjusted depending on the scope of work).

Why add load forecasting? Utility forecasting, especially in the Pacific Northwest has been very poor for both energy (MWh) and capacity (MW). There are consulting firms that could work with utility to provide an independent and informed opinion on the forecast. The current process has led to overbuilt and poor timing on generation, transmission, and distribution. LBNL's 2016 report on how IOUs exaggerate load forecasts. A comparison of forecasts to actual energy use and peak demand reveals that all but one of the Load Serving Entity (LSE) overestimated energy consumption growth over planning periods

beginning in the mid-2000s and ending in 2014, and that eight of the eleven LSEs that forecast peak demand also over-estimated this quantity.

https://emp.lbl.gov/sites/all/files/lbnl-1006395.pdf

Graph below are average load forecasts in IRPs for western utility load forecasts. Avista, Xcel Energy(Colorado), Idaho Power Company, LADWP, NV Energy, NorthWestern Energy, PacifiCorp PacifiCorp, PGE, PNM, Puget Sound Energy, Seattle City Light.



3. *The draft rule uses a new term, "major distribution capital investment," which is not tightly defined by a dollar value or otherwise. This definition is intended to provide separation of routine traditional maintenance of poles and other components from more significant capital expenditures that often have the potential for more than one solution. In those cases, a major distribution capital investment would call for analysis of all potential distributed energy resource options that satisfy the identified distribution need.*

I would modify this to read

> **"In those cases, a major transmission or distribution capital investment would call for an RFP of all potential distributed energy resources options that satisfy the identified distribution need."**

In New York, The commission articulated its vision for NWAs (Non-Wire Alternatives), stating it "does not want the utilities to contemplate necessary infrastructure upgrades and then issue RFPs to resolve the underlying system needs, but rather to "consider the procurement process earlier and more broadly incorporate system design into NWA solutions."

a. *Would it be useful to include a dollar limit in the definition of "Major distribution capital investment"? For instance, the rule could state a cutoff using an estimated capital cost of over $1 million. Are there other, better, criteria that the Commission should consider?*

Using cost over $1MM for anything that is not a direct replacement or maintenance item is good criteria to undergo a Distributed Resource Plan and a Non-Wires Alternative procurement process.

b. *Is there a need to define a major distribution capital investment for natural gas utilities? If yes, should the criteria be the same as for electric utilities? How should it be different?*

No Comment

4. *Distributed energy resources include a broad suite of evolving technologies. Electric utilities are learning through experience and experimentation how to efficiently integrate and value these resources. In recognition of this changing landscape, the Commission wants to encourage significant and creative progress in the prudent adoption and implementation of distributed resources without being too prescriptive in rule. Given that context:*

Customers will pursue DERs, clean energy, improved reliability, evolving technologies, and lower cost regardless of utility planning and programs. If Washington wishes to unleash these consumer preferences AND benefit the utility franchised system for ratepayers and community, then WA needs an independent DSP coordinator to identify the many consumer technologies and identify rates that would attract customers and benefit system. Vendors have a global breadth of market, have ability to discriminate on price, and understand fickle customer preferences.

a. *Is there a recommended structure for organizing the distribution system plan that allows future flexibility as well as engendering significant near-term progress?*

Utilities should share feeder load and reliability data with DSP coordinators and DER providers.

b. *Is there specific language that would optimize the combined goals of flexibility and timely implementation?*

If WUTC chose a DSP coordinator to run the process, I imagine they could work with utility to address flexibility and timely implementation. Doing a detailed DSP, or a comprehensive DRP (like California IOUs) can add lots of cost. We recommend that DSP Consultant and Utilities prioritize areas of the system that might demonstrate cost effective NWA, or increase DER penetration.

c. *How should pilot and demonstration projects be encouraged in rule?*

Ratepayer funded pilot projects should expect to be cost effective within 4 years. DSPs should lead to extra locational benefits of DER program procurements and avoided costs. Pilots may be considered cost effective on a locational basis, but not on a system basis.

d. What criteria should the utility use to evaluate when there is a need for a pilot or demonstration project as opposed to programs ready for full-scale implementation?

Pilot Criteria

1. **Locationally cost effective pilots. If the procurement process yields locations that are cost effective for DERs, then role out programs in "pilots" for these areas. In other words, the program will not be available to all customers. Likely areas of system where solar is more beneficial than others.**

2. **Customer Driven pilots. Certain areas of utility service territory, DER adoption is being driven by customer demand. In these cases, the cost effectiveness may be easier to attain for because customers will be installing solar, storage, EV chargers, etc. All the utility needs to do is create a program that provides system value (e.g., rates tied to certain technology)**
3. **Technology Pilots. Target certain technologies that can support grid and renewable integration. Utilities should also be working on evaluating rate programs to manage load in a beneficial way. Rates plus technology to respond to rates should be tied together.**

Full scale implementation Criteria:

1. **Market Transformation opportunity (e.g., Electric water heat, EV Chargers, thermostats, heat pumps, advanced solar inverters, storage, etc.). The best time to engage customers is when they are acquiring certain energy using technology. Northwest Energy Efficiency Alliance should be funded by utilities to expand market transformation efforts in the many technologies that can provide grid benefits, beyond energy efficiency. Once someone buys the water heater, solar inverter, or EV Charger that does not include communication and control, then it may never be cost effective to have that device support the grid.**

2. **Cost effective for the general system. Any DER program that is considered cost effective in a term no less than 20 years should be pursued. Most problems with DER cost effectiveness is comparing a short NPV for DER with 30 year NPV for traditional asset.**

5. *Recognizing that utilities are at various stages of modernizing their distribution systems, should the rule identify specific assumed fundamental requirements for enabling a modernized grid, such as:*

   a. a two-way distribution communication system,

   b. a distribution management system (DMS) that provides centralized and automated monitoring and control of the utility's distribution system,

   c. a distributed energy resources management system (DERMS) that aggregates, monitors and controls distributed energy resources as dispatchable resources, or,

   d. other physical infrastructure and software needed to manage and control a modernized grid?

   e. Are the fundamental requirements the same for electric and natural gas utilities? If no, what fundamental requirements should be used for natural gas utilities?

YES

6. *When utilities submit biennial energy conservation reports to the Commission, they are required to provide an independent third-party evaluation of their conservation program achievements (See WAC 480-109-120(4)(b)(v)). Should a similar periodic independent review and evaluation of distribution plan results be required? If not, please explain why this should not apply.*

YES

7. *Should the distribution plan conclude with an action plan? If so, what should be the time horizon for the action plan?*

Action plan should have timelines for data, e.g., Integrated Capacity Analysis, Location Value Analysis, and planned DER pilots and procurements. If done well, this should lead to programs and resources that will be cost effective in 3-4 year time frame. Procurements should be done for at least 10 year terms with off ramps for poor performance.

8. *For the organization of WAC 480-100-238, would it provide greater clarity to reorganize the rule into smaller sections, maintain the same organization and numbering structure, or add a new rule section?*

NO Comment

Appendix A: Original comments in U-161024, November 14, 2016. WRITTEN COMMENTS

1. The Commission has identified a broad scope of issues to evaluate in its inquiry. Are there other issues or topics that should be addressed? What type of schedule would best lend itself to a proceeding of this scope?

PNDERP Response:

"Integrated Utility Planning" instead of Integrated Resource Planning. We suggest a change the naming convention from Integrated Resource Planning (IRP) to Integrated Utility Planning (IUP).The 2003 docket UE-030311 was referred to as "electric least cost plan" (WAC 480-100-238). During this proceeding the description changed from "Least Cost Plan" to "Integrated Resource Plan" in order to include various risk elements into the analysis, which we support. The use of the term Integrated Resource Plan, however, has also been interpreted to be restricted to just resources. We think the intent of the law is lowest reasonable cost for all utility investment decisions, including transmission and distribution. In our comments, PNDERP will use the term "Integrated Utility Planning" to represent lowest reasonable cost goal for all major utility investments, and reflects the fact that electric power resources will: 1) come from a variety of locations, 2) provide a variety of power related services, and 3) can compete or displace not only power resources, but other utility assets related to transmission and distribution.

We also suggest a language change to Lowest Reasonable Cost definition in WAC 480-100-238 highlighted in red. "Lowest reasonable cost" means the lowest cost mix of resources determined through a detailed and consistent analysis of a wide range of commercially available sources. At a minimum, this analysis must consider resource cost and location, transmission and distribution cost, market-volatility risks, demand-side resource and load uncertainties, resource dispatchability, resource effect on system operation, the risks imposed on ratepayers, public policies regarding resource preference adopted by Washington state or the federal government and the cost of risks associated with environmental effects including emissions of carbon dioxide.

Utility Performance Incentives and return on investment. PNDERP would like Commission to include discussion of performance incentives for utility acquisition of DERs, or other mechanisms that remove the preference IOUs have for capital projects over expenses.

Investor Owned Utility's (IOU) receive a rate of return on capital investments and can lead to a utility preference for capital projects over utility expenses or customer incentives. This is an underlying cause for many of the disputes that arise during the utility stakeholder planning and procurement processes. This rulemaking is a good place to find a mechanism to address the shareholder incentive in utility planning and procurement.

There are a number of methods being used in the US to address this utility preference gap. One solution is to allow utilities to earn a return (incentive) on expenses based on defined performance metrics. This practice is being done in several state utility jurisdictions. In a recent order, California's IOUs will be able to earn 4% on DER expenses as part of their Distribution Resources Planning and DER procurement process.[1] This incentive is part of a pilot and other incentive mechanisms are being discussed, e.g., providing utility a full return on the avoided

[1] Page 49. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M169/K669/169669077.PDF

investment. In New York state, Central Hudson Gas and Electric is working on a non-wires alternative project that is sharing 30% of cost savings with utility shareholders.[2]

While we don't think rate design should be part of the IRP rulemaking, we wish to acknowledge that current rates and net metering may also discourage utilities from acquiring some DERs.

Another solution to this preference gap, and on the other side of the spectrum, is to completely separate utility owners from utility operation and planning role. In many jurisdictions, transmission operations and planning are performed by Independent System Operators (ISO) or Regional Transmission Operators (RTO) that are not controlled directly by the transmission owner (investor). There have even been industry leaders recommending the development of Independent Distribution System Operators (IDSO) to address the conflicts that may lead to a vertical utility to discourage resources on the customer side of the meter. In early 2016 the City and County of Maui sponsored a report that suggested an IDSO as best means to meet government and ratepayer objectives for electric utility service on Maui.[3] We are not calling for IDSOs in the state of Washington.

We think that if the Commission can find an IOU financial incentive mechanism for DERs and grid modernization that many of the preference gaps and issues will shrink.

B. Energy storage

1. The Commission has already engaged in an investigation regarding energy storage technologies and their treatment in IRP documents (Docket UE-151069). The Commission is considering merging that investigation with this proceeding, then issuing a straw proposal and soliciting one more round of comments before issuing a policy statement on the topic. Do the parties have any concerns with this approach? Is there any information relative to modeling energy storage that has not been presented in the existing docket?

PNDRP Response:

Energy storage should be included and compared among other resources and grid infrastructure in IRPs. Several reasons for this.

1. Many of the benefits and use cases of energy storage are common among DERs. It is efficient and logical to include all the avoided costs and values among all DERs into one least cost planning process.
2. Storage can address transmission and distribution constraints and reduce/defer transmission and distribution costs, similar to other DERs, e.g., demand response, CHP, EV Charging, and dispatchable standby generation (PGE's 100MW program).
3. Storage will often be combined with other resources, e.g., solar and backup power, so the combined resource should be considered together.
4. Storage can be used as a customer backup or reliability device, as well as a grid resource.

[2] http://www.transmissionhub.com/articles/2016/07/n-y-psc-adopts-revised-nwa-project-cost-allocation-recovery-methodology-proposed-by-central-hudson.html

[3] http://mauinow.com/files/2016/01/Analysis-of-Alternative-Forms-of-Ownership-and-Alternative-Business-Models-for-Maui-Countys-Electric-Utility-Company.pdf

5. Storage may exist on either the utility or customer side of meter. Customer side resource may lead to lower cost for ratepayers and must be considered along with utility grid connected storage. For instance, customer wants reliability during high risk storm outage and utility wants it for peak load reduction. In least cost utility planning, utility can examine appropriate incentive/investment levels to place storage on customer sites versus on distribution system only.
6. EIM pricing may assist in valuing storage and other DER flexibility.

C. Requests for proposals

1. WAC 480-107-015 requires any utility that files an IRP identifying a generation capacity shortfall within the next three years to issue a request for proposals (RFP) within 135 days of filing its IRP. In recent IRP cycles, utilities have frequently requested waivers of this rule, generally citing the cost and complexity of the RFP process and stating that the IRP selected market purchases as the low cost, preferred approach to meeting short-term capacity needs. Given the frequent requests for waivers of this rule, should the Commission change it? What type of changes would parties recommend to make the rule more broadly applicable and reduce the need for waiver requests?

PNDERP Response:

PNDERP would support a change to RFP section to require utilities to issue open all-source RFPs or auctions for DERs and other smart grid technologies when they have identified a need to invest in any capital item, including transmission or distribution infrastructure. The same California proceeding that is providing utilities a financial incentive to procure DERs is requiring Distribution Resource Plans (DRP) to identify portions of distribution system that would benefit from DER capacity and grid services. This DRP process leads to RFPs for DERs that meet distribution requirement. An open RFP for all investments and measures that could address the requirement could lead to lower cost solutions and hence lower rates. Transmission requirements are often larger investments, yet DERs are being procured as part of investment avoidance or deferral in New York, California, Minnesota[4], and Southwestern Washington (South of Allston non-wires RFO).[5]

RFPs for DER products/services are essential for several reasons. First, DER vendors understand a specific customer base – and are best equipped to market on all customer benefits, including non-energy benefits. Second, DERs mostly happen on customer side of meter where utility has less experience. Third, competing vendors help to get best price and service.

Regarding RFP cost and complexity, the RFP process can't be any more costly and complex than the current IRP process. RFPs are where the benefits of the IRP manifests themselves.

2. Utilities state that the RFP process is time-consuming and complex, and does not lend itself to a biennial cycle. Are there alternative means of meeting the rule's requirement? Would narrowly crafted solicitations that are tailored to the specific resource needs identified in the IRP

[4] http://www.utilitydive.com/news/as-xcel-pushes-non-wire-alternatives-solarstorage-pilot-sparks-utility-ow/414650/
[5] https://www.bpa.gov/transmission/CustomerInvolvement/Non-Wire-SOA/Pages/default.aspx

be an effective way of reducing administrative burden and costs, while still encouraging bidders to provide the utility with a range of resource options?

PNDERP Response:

PNDERP prefers open ended solutions, with utility focusing on defined power service reliability and requirement(s). Utility should focus on defining its requirement, e.g., winter peak hours, or Volt/VAR support. The RFP, on the other hand, should not be limited based on technology, application, or sector. For instance, an RFP for winter peak capacity should state likely times and hours needed and whether it needs to be dispatchable, but does not need to specify technology, or sector.

RFPs for most DERs should be for time periods greater than 10 years. It is difficult to get capacity cost down when time frames are shorter than the asset it is competing against.

3. In considering the waiver requests to this rule, Commission staff and utilities have been at odds whether the IRP actually identified a resource shortfall in the following three years. Staff has generally held that if the IRP model relies on market purchases for capacity needs, then the utility is short on capacity; utilities have generally held that if the model selected market purchases, then the resource need has been cost-effectively met. Is there a potential compromise on this issue? Could improved modeling of market risk in the IRP increase confidence in the model's determination? How might market risk be modeled?

PNDERP Response:

PNDERP recommends characterization of risk in ways that provide more information about the risk, e.g, MW, hours, and season, (EUE, Expected Unserved Energy) This allows planners to target the risk with specific resources or measures. This is preferred over LOLP (loss of load probability), which does not provide any risk details.

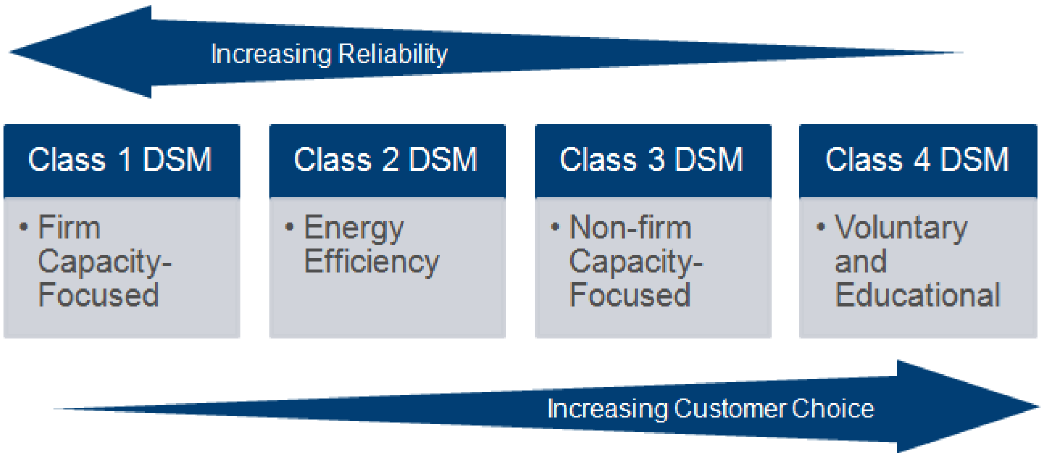
PNDERP recommends modeling option value of DERs and other resources that can defer larger investments. This option value can help address a variety of risks related to power market, load, weather, technology costs, etc. For instance, Idaho Power overbuilt gas combustion turbines in a low priced market and attempted to shut off their cost effective demand response programs. To address the risk of overbuilding, smaller resources will have an extra value of deferring large investments.

We also urge IRP attention to natural gas pipeline and capacity to serve regional plants and customers. One of the big shortfalls in 2001 Western Power Crisis was natural gas pipeline capacity, storage, and constraints. Natural gas power plants are the marginal build for the next 5 years and access to firm gas supply should be evaluated as part of the IUP.

4. Conservation is currently included in WAC 480-107-015. Should the Commission require utilities to issue RFPs for conservation measures and programs on a regular basis? If so, should RFPs be issued in conjunction with the IRP cycle or the biennial conservation planning cycle described in WAC 480-109-120?

PNDERP would like to see regular RFPs and consistent programs for all cost effective Customer Demand Side Management ("DSM") which would include programs such as conservation, price and behavioral efficiency, demand response, EV Charging, and solar/storage. PacifiCorp's IRP is a good example of a utility that is targeting DSM, not just conservation. PacifiCorp separates DSM into 4 classes, many of which are acquired through RFPs that lead to 3 year contracts with 2 year extensions.[6] Figure 1 below shows the 4 DSM classes in relation to Customer Choice and Reliability.

Figure 1: PacifiCorp's DSM Classes (2015 IRP)



Utilities should be consistently offering cost effective DSM and programs that can achieve system and locational energy and capacity savings. These programs may change their incentives or other details dependent on changes in avoided cost relative to all utility related costs (generation, transmission, and distribution). For instance, a utility offering a combined energy and capacity reduction program may want to spend more in areas that could avoid transmission upgrades.

It is important for customer focused DSM programs to be consistent and persistent. Even if new vendors are brought in, or incentives levels change, it is important that the brand and messaging remain consistent. Customer DSM programs should not be acquired only when a need is identified in an IUP, but should be consistently offered in a cost effective manner.

This rulemaking is a good place to discuss how all demand side resources are evaluated and procured. Regarding timing of DSM RFPs, we think some resources, e.g., DR, requires longer terms in order to recover recruitment and setup costs. Once DR programs become more mature, then it may be possible to reduce contract terms. For Conservation three (3) year contract period with two (2) year extensions makes sense.

Using PacifiCorp's Class description, we think it is possible for several of the Class DSM categories can programmatically be acquired simultaneously, while providing different services to utilty. For instance, a smart thermostat program can achieve both energy and capacity savings, or combined solar with storage, combines customer renewable energy and reliability with DER value of capacity and Volt/VAR support from advanced inverters.

---

6 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSM_Potential_Vol_1_Executive_Summary_FINAL_Jan30-2015.pdf

D. Avoided costs

1. *Avoided costs are used by utilities in multiple applications. They are used for determining rates for qualifying facilities in compliance with the Public Utility Regulatory Policy Act (PURPA), they are used for identifying cost-effective conservation measures, and they are used in determining the incremental cost of resources used for complying with the state's renewable portfolio standard. Despite their ubiquitous use, however, avoided costs can be difficult, if not impossible, to identify in current utility planning. Would it be feasible and beneficial for the utilities to transparently report their avoided costs in the IRP document? What obstacles exist that would complicate such a report? Would it be possible to create a generic avoided cost calculator that could be used to generate avoided costs for various applications? Should the included elements of avoided costs be different for different applications? Is the avoided cost methodology different for natural gas distribution utilities?*

PNDERP Response:

Utilities should provide avoided cost for energy and capacity needs to defer or avoid investments in all utility costs, including transmission and distribution. Because of the locational nature of transmission and distribution, avoided costs and hence resource value will likely be different based on location. See discussion below under Transmission and Distribution modeling. DERs can provide other power services besides capacity and energy. Therefore avoided costs need to be considered for frequency regulation, balancing service, operating reserves, Volt/VAR support, etc.

Utilities should use transparent DRP and current GIS mapping to allow stakeholders to see the avoided cost values in different areas. It is commonplace to use heat maps and other graphical tools to demonstrate DER value changes.

E. Transmission and distribution modeling

PNDERP believes that while the language in WAC 480-100-238 addresses transmission and distribution (T&D), more discussion and clarity from the Commission is needed so that all utility costs and alternatives are properly addressed, and lowest reasonable cost can be attained. A large portion of utility ratebase, and therefore rates, lies in transmission and distribution investments and costs. If there are resources and measures that can defer or avoid these, then it would be just and reasonable to do so, and to do so in a more transparent stakeholder setting and open RFP process.

Integrated Utility Planning is the best place to add this modeling effort. We recommend adding DERs to the transmission and distribution models and look at scenarios where DER and smart grid investments can address T&D requirements. In California's Distribution Resource Plans (DRP), the IOUs were asked to model all substations and feeders and provide capacity analysis to add DERs and value analysis to suggest the value to utility (i.e., locational avoided cost).

There are several examples of utilities considering DERs, smart grid technology, and locational value of resources to avoid or defer certain transmission and distribution costs. In 1996 the region deferred and eventually stopped plans for a cross-Cascade transmission line into the

Puget Sound area.[7] The transmission investment was avoided by targeting energy efficiency and upgrades to existing transmission infrastructure. Currently, BPA is procuring resources and generation redispatch commitments to defer or avoid the I-5 Transmission corridor project in Southwestern Washington. In New York state, both ConEd and Central Hudson have Non-wire alternative projects underway.[8] In California, all the IOUs are doing DRPs to provide avoided costs and hence value of procuring DERs and smart grid projects. This process is identifying where DERs have more value and can be procured with higher incentives. Regulatory Assistance Project has reported on many more projects that are using conservation and DER to avoid T&D project costs.[9]

Most utility IRPs include T&D cost adders onto resources in order to compare the actual cost of serving load. While this is valuable, the next step in Integrated Utility Planning is to include transmission and distribution models that evaluate resources by location and time that can reduce cost of transmission and distribution, increase reliability, minimize outages, improve power quality, and reduce emissions. Transmission models are mature and improving relative to new resources, and distribution models are getting more sophisticated in modeling DERs, e.g., Synergi (DNVGL)[10], CymeDist (Cooper), and DEW (EDD).

Separating transmission and distribution planning from resource planning is not consistent with the unique obligations of a public utility that has been granted monopoly status by the state of Washington and provides bundled service to its customers. For a number of reasons Washington retained vertical integration for investor owned utilities. Because investor owned utility customers in Washington receive bundled service, they stand to benefit from integration of generation and transmission cost structures such that the lowest reasonable cost service is delivered. If utilities were to build a transmission or distribution project that could have been avoided by a targeted resource procurement decision, then bundled retail rates may not be just and reasonable absent such a process to target resource procurement to optimize total transmission, distribution, supply-side, and demand-side resource cost.

In Washington, PacificCorp's 2015 IRP demonstrates how transmission costs are integrated into IRP process.[11] PacifiCorp began using this transmission modeling approach in its IRP process over 10 years ago.

Purpose of IRP is to examine all cost effective solutions that reduce cost of service to all ratepayers. A large part of utility cost of service is transmission and distribution. As more DERs, grid modernization tools, and capacity resources become available and cost effective, it becomes more important to include transmission and distribution investments and local reliability into the least cost planning process.

---

7 http://energy.gov/sites/prod/files/2015/04/f22/EIS-0160-FEIS.pdf

8 http://www.transmissionhub.com/articles/2016/07/n-y-psc-adopts-revised-nwa-project-cost-allocation-recovery-methodology-proposed-by-central-hudson.html

9 http://www.raponline.org/wp-content/uploads/2016/05/rap-neme-efficiencyasatanddresource-2012-feb-14.pdf

10 https://www.dnvgl.com/publications/synergi-electric--14903

11 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

1. The IRP rule requires utilities to conduct "an assessment of transmission system capability and reliability" and "a comparative evaluation of energy supply resources (including transmission and distribution) …." How are utilities currently meeting these requirements in their IRPs? Has modeling software advanced in a way that might allow for a more detailed analysis of transmission and distribution systems?

<u>PNDERP Response: Location, Location, Location</u>

It appears that utilities in Washington have a narrow interpretation of IRP related to T&D. PNDERP supports a move to Integrated Utility Planning that will include transmission and distribution planning. Standard practice today is to add the cost of transmission and distribution onto new resources that are far away from load, or subtracting it from cost of conservation. They have never considered adding transmission and distribution planning to IRP, and the only resources considered to assist in transmission planning are consultant reports on assessment of non-wire alternatives.

For example, PSE's 2015 IRP considers transmission cost in two narrow aspects:

1. Costs associated with importing Montana wind
2. Gas Plant location – build in eastern Washington instead of inside PSE service territory.

Currently transmission and distribution planning is a utility endeavor that does not receive Commission approval until the project has been built and is being requested for inclusion in rates. This lack of stakeholder involvement and commission review is becoming a larger utility and ratepayer risk as the number of alternatives of avoiding T&D costs is increasing fast and decreasing in cost. We have seen some utility transmission plans hire consultants and go through a non-wires assessment. Unfortunately, these assessments are paid for by the utility, with utility assumptions and data, and do not reflect an open RFP or stakeholder process.

Modeling software has advanced to demonstrate more accurately where transmission constraints are occurring, and distribution system could use a variety of services related to energy, capacity, ancillary service, Volt/Var management, and reliability. Transmission models, e.g., Plexos, can incorporate a host of different resource types, load shapes and evaluate sub hourly variations and flexibility.

Most of our work is related to the distribution system and we know the following tools can include DERs: Synergi (DNVGL)[12], CymeDist (Cooper/Eaton)[13], and DEW (Electrical Distribution Design - EDD)[14], LoadSEER[15], others we have less experience with include PSS (Siemens), Digsilent, and Aspen DistriView.

2. To what degree are utilities currently planning for distribution system impacts such as electric vehicles, changes in end uses, and distributed generation? Are there opportunities for utilities to improve their modeling related to these issues without overly burdening the planning process?

<u>PNDERP Response:</u>

[12] https://www.dnvgl.com/publications/synergi-electric--14903
[13] http://www.cyme.com/software/cyme/BR917058EN-CYME72-NewFeatures.pdf
[14] http://www.edd-us.com/dewism/product/
[15] http://www.integralanalytics.com/products-and-services/spatial-growth-planning/loadseer.aspx

Because distribution planning is not transparent, we do not know what any utilities in Washington are planning related to DERs. This was one of the reasons California required in 2015 for utilities to share the results of distribution resource plans. It provides a way for utilities to get the DERs they need, at a price they would be willing to pay, and allows vendors to understand the economics of selling DERs to customers.

We've heard Avista is working on distribution planning that incorporates certain DERs, but have no details.[16]

3. The Commission's rule requiring smart grid reports, 480-100-505, is scheduled to sunset this year absent an order from the Commission requiring utilities to consider filing the reports. What has the experience of utilities been in filing these reports? Would there be value in extending this requirement? Is there a way to address the Commission's desire for information on this topic through the IRP?

PNDERP Response:

We are not familiar with these smart grid reports. Will provide comment later in rulemaking.

4. The natural gas IRP rule requires plans to include "an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources," but is silent on distribution system modeling. To what degree are gas utilities currently engaged in modeling their distribution system? Would it be beneficial for utilities to further engage in distribution system modeling? If so, is there commercially available software that is capable of meeting these modeling needs?

PNDERP Response:

We are focused on electric utility planning. Will may provide comment later in rulemaking.

5. In recent years, other states have required or considered requiring utilities to engage in full-scale distribution system planning. What are the costs and obstacles associated with such a requirement? What are the benefits? Is detailed distribution planning feasible now, and if not, what is needed for it to become so?

PNDERP Response:

We believe utilities in Washington are already investing in distribution modeling tools, training, grid modernization, smart grid technology, interconnection evaluation, and various DER assessment, e.g., conservation, demand response, storage, etc. In California, all the IOUs are doing DRPs to provide avoided costs and hence value of procuring DERs and smart grid projects. This process is identifying where DERs have more value and can be procured with higher incentives.

[16] https://www.greentechmedia.com/squared/read/how-spokane-is-building-a-smart-city-from-the-ground-up-with-transactive-en

The three primary reasons California utilities are engaging in a transparent distribution resource planning process are: 1) reduce utility ratebase and rates (rates), 2) enable GHG reductions through increased renewable integration (environment), and 3) provide DER vendors the utility incentive and pricing information they need to market, sell, and service their customers (economic development).

We know that PG&E added two people to manage DRP process, but unsure of the costs.

DRP is feasible and being done at both large and smaller scales. In Washington, it could be done on a selective area or project basis.

F. Flexible resource modeling

1. Current IRP models balance load and resources on an hourly basis over a 20-year period, generating more than 175,000 data points for the model to solve. Many of the new resource alternatives that utilities consider, however, operate on a sub-hourly basis and therefore generate benefits that cannot be captured in the IRP's hourly modeling. These benefits promise to increase over time as the penetration of variable generation increases and the need for flexibility from fast-moving resources grows. Prime examples of this type of resource are energy storage, reciprocating engines and the Energy Imbalance Market. How are utilities accounting for sub hourly resources in current IRP models?

See response in transmission and distribution modeling.

2. Are there readily available means of using sub-hourly IRP models? For example, if the model ran in 15-minute increments over 20 years, it would generate more than 700,000 data points – four times as many as current models. But if it ran in 15-minute increments for just 10 years, it would only double the number of data points, to about 350,000. Would it be possible to adapt current IRP models to operate in that way? Are there commercially available alternatives for sub-hourly modeling? Do utilities or other parties have experience in operating those models?

G. Procedural improvements

1. Should the commission clarify its treatment of confidential information in IRP and RFP dockets? If so, how?

<u>PNDERP Response:</u>

We would like treatment of confidential information in Integrated Utility Planning (IUP) discussed and clarified in this rulemaking. We think any restrictions to information should be a very high bar. One of the challenges in Washington's unilateral IRP and transmission planning processes is stakeholder access to data and assumptions, and the use of utility sponsored consultants. Utilities should explain/clarify what information is considered Critical Energy Infrastructure Information (CEII) and provide instructions for stakeholders to receive necessary approvals. CEII can too easily be a reason to keep IUP stakeholders from gaining access to important data and assumptions. We don't want to see any confidentiality restrictions for IUP.

2. Should the commission outline more specific requirements for public involvement, like identification of meeting time and location on the workplan, and the identification of the date a draft will be available for public review?

3. How can the commission increase the transparency of IRP models? Is there a way to allow commission staff and other stakeholders to independently access company modeling software and test assumptions, without violating proprietary agreements or confidentiality, as is done with power cost models?

<u>PNDERP Response</u>

Commission could hire consultants qualified to operate models, share inputs and data, and work with utility staff to populate and run all stakeholder scenarios.

4. Are there any improvements that could be made in the IRP reporting or review process? Staff will ensure rule language is simplified and written in terminology that promotes clarity and understanding for all stakeholders. Rules that are written in Plain Talk are easier to understand and implement consistently.