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ECONOMIC CONSULTING

MEMORANDUM

May 15, 2018

TO: JP Batmale
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Oregon Public Utility Commission Staff

FROM: Frank Mossburg
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SUBJECT: Review of PGE Redlines and Response to ALJ Questions

The purpose of this memo is to provide our review of Portland General Electric (PGE)'s updated draft 2018 Request for Proposals for Renewable Resources (RFP) filed on May 11, 2018 in Docket UM-1934. In addition, we respond to questions posed to the Independent Evaluator (IE) by the Administrative Law Judge.[1]

REVIEW OF REDLINES

Our first task was to review the updated draft RFP to determine if PGE had made the changes they pledged to make in their response filing in the RFP docket.[2] We found that PGE made most of the changes that it promised to make. Among these changes were;

- Transmission and interconnection requirements have been clarified and made less strict.
- Bidders now have the ability to offer conditional firm bridge service for two years.
- Credit requirements have been simplified and relaxed.
- Sensitivities have been added to measure the impact of different price and non-price weightings.
- The obligations of the Benchmark offer have been clarified.
- A Post-issuance bidders conference has been added.
- A best-and-final offer process has been added.

[1] Notice, In the Matter of Portland General Electric Company, 2018 Request for Proposals for Renewable Resources, Docket UM-1934, May 10, 2018.
[2] PGE's Reply Comments, Docket UM-1934, April 13, 2018.

We feel that the above changes were generally in line with what PGE promised to accomplish. However, there were two sets of changes that were discussed in PGE's Reply Comments that did not appear to be fully or clearly implemented in the redline edit.

Permitting Requirements

In our report we raised objections to the use of permitting status as a "threshold" obligation as it had the potential to screen out otherwise viable bids. In their response comments PGE agreed to remove permitting status as a threshold obligation while continuing to use permitting status as a non-price scoring element.[3] The main RFP document does indeed remove the discussion of permitting as a threshold obligation and instructs bidders to submit a plan listing all permits and schedule for obtaining the permits. The RFP further states at that PGE may reject bids that it determines cannot obtain the requested permits as designed.[4]

This generally matches the spirit of our recommendation and PGE's Reply Comments. However, the RFP then notes that "A complete list of the permitting threshold requirements can be found in Appendix H."[5] In that appendix, several items – mostly surveys - are listed as being required at the time of bidding and several more permits are required at award time. The former, in particular, would appear to contradict the main body of the RFP or, at minimum, cause confusion. We would suggest changing the permitting requirements in Appendix H to be guidelines instead – in other words, these represent what PGE considers to be proper timelines for the project. This way bidders would know what PGE expects them to have and that if they present a schedule which deviates from these timelines they risk both losing points on their non-price score and having their bid rejected outright.

We understand that projects seeking a late 2020 COD will likely need to have a large amount of work completed on the permitting front in order to have a chance of coming on line in time and PGE's requirements reflect this reality. However, while that is PGE's preference, the RFP allows for COD until the end of 2021. Projects which plan to come on-line at later periods may not be as advanced in their permitting but still could meet their proposed timelines, making it unfair to hold them to the requirements in Appendix H.

[3] PGE's Reply Comments, p 3.
[4] PGE's Redline Version of the Final 2018 Request for Proposals for Renewable Resources, Docket UM-1934, May 11, 2018, p 34. (PGE Redline Draft RFP)
[5] Ibid.

Credit Requirements

In our report we noted that credit requirements for all types of transactions should be relaxed. PGE did, indeed relax these requirements, reducing the APA/EPC pre-COD requirements from $200/kW to $100/kW and changing the post-COD PPA requirement from a "mark-to-market" approach to a flat $100/kW.[6] These are both welcome changes. One bit of confusion that remains is that, in their reply comments, PGE stated "We will also clarify that there is no requirement of a performance or payment bond for APA-only bids."[7] However, this requirement remains in the latest filed RFP. We would suggest the removal of this requirement, in line with our recommendation and PGE's comments.

RESPONSES TO ALJ QUESTIONS

In the May 10, 2018 Notice, the ALJ issued several questions to the IE. In this section we answer those questions.

> ***"Does the wording of the revised RFP make clear that bids with a conditional firm transmission bridge would be allowed to bid? Can the IE recommend what amount of time (beyond 2 years) would be a reasonable amount to increase flexibility for bidders? How will conditional firm transmission impact a bidder's score? Will a conditional firm transmission bridge impact a project's capacity value, and does capacity value impact scoring?"***

We believe that the revised RFP is clear with respect to what the requirements are for conditional firm bridge service. In terms of additional extension of the service it is true that this might allow for more participants to bid, mainly those relying on longer-term upgrades. For example, if we refer to slide 12 on the attached BPA presentation we see that if the term is extended an additional year, then bids in the 2016 BPA Cluster study relying on the Montana to Washington Project, with an in-service date of fall 2023, could participate. If this is something parties desire we would recommend no more than another year be permitted. Extensions beyond this time would run the risk of not delivering on the requirement to be a firm resource.

In terms of scoring we would anticipate that PGE would add in the cost to carry additional reserves for the years of conditional firm delivery. This would impact the price score of the bid. As to the impact on capacity value we believe there would be

[6] PGE Redline Draft RFP, Appendix E.
[7] PGE Reply Comments p 19-20.

some impact but are open as to how this can be reflected. One thought would be to not consider it for the years under conditional firm service. Another way would be to reduce the capacity value by a factor (e.g. 50%) during the conditional years. The discount factor could be judged based on the conditions to the service curtailment and how likely they would be to occur.

"Will there be any difference in scoring between the benchmark resource and third party resources for balancing costs?"

Our read of the RFP is that there should be no difference between resources in terms of balancing costs for bidders outside of PGE's service territory. We assume that, per the RFP, any such bidders offering a PPA will include a fixed component that simply passes through balancing costs as incurred.[8] The benchmark and third-party APA/EPC bids will have this cost added to their bid as well. In the evaluation, then, both bid forms will have PGE's estimated future balancing costs added and therefore neither should be disadvantaged. The danger regarding these costs would come if a PPA bidder was not allowed to pass them through as incurred and instead had to guess as to what those costs would be for the next 20 years and include them in a fixed price bid. This would likely lead to PPA bidders placing additional risk premiums in their bid and would disadvantage the offer relative to a EPC/APA offer, which would not have to make such a calculation.

"Does the IE have any changes to its recommendations on specified energy?"

We have no changes to our recommendation regarding specified energy. We continue to believe that the concept should be removed from the PPA as it is not fair to PPA bidders and not consistent with what we understand as the general practice in contracting for renewable resources.

"Does the IE have a recommendation on whether redlines should impact non-price scoring?"

We believe that redlines which shift additional significant cost and risk to ratepayers should be penalized with lower non-price scores as this reflects the risk profile inherent in the bid.

[8] The RFP states, in part, "to allow for direct compensation for transmission costs, bidders are invited to propose power purchase agreements with both capacity and variable charges. Capacity charges may be escalated according to tariffed rate changes", PGE Redline Draft RFP, p 16.

"Parties raised concerns with these two issues, stating that PGE should remove language that prohibits capital additions. Parties have also asked that the damage cap be increased from $100,000 to $500,000. Does the IE have recommendations on these two issues?"

We note that the latest redline does have some additional language regarding increased output and the damage cap has been increased to $500,000, in line with parties wishes. We have no specific recommendations on these issues except to note that we believe parties understand the intent of the language in the PPA limiting delivery amounts and that, during contract negotiations, a reasonable compromise can be reached that achieves the goals of both parties.

2016 Transmission Service Request Study and Expansion Process (TSEP)

Cluster Study Results
Customer Briefing

June 14, 2017

Topics for Discussion

- Cluster Study TSR Overview/Pattern
- Cluster Study Areas
- Assumptions and Methodology
- Cluster Study Areas – Final Plans of Service
- Next Steps

Reminder – Process Overview

- TSR Study and Expansion Process (TSEP)
  - BPA’s process for conducting required studies (system impact and facilities) for incremental requests for service
  - Follows sections 19 and 32 of BPA’s tariff
  - Accomplishes BPA’s obligation to study, identify and ultimately complete transmission plans of service if customers elect to proceed

Elements of TSEP

Phase 1: Pre-Study

Pre-study:
- Customer TSR submittal and ATC assessment;
- Period between close of last TSR deadline and next TSR deadline for Cluster Study participation (typically June-May)
- $ - TSR deposit and processing fee

Phase 2: Cluster Study

Cluster Study:
- BPA tenders Study Agreements following TSR deadline;
- BPA commences and completes study (120-day study period);
- Results: preliminary plan of service scope, cost, and schedule;
- $ - Customer's pro rata share of costs by MW

Phase 3: Preliminary Engineering

Plan of Service Validation and Preliminary Engineering:
- Refinement of cost and scope of Cluster Study results;
- Estimation of Environmental Review scope and costs;
- $ - Customer's pro rata share of costs by MW

Phase 4: Environmental Review

Environmental Review:
- Required NEPA review of environmental impacts based on identified plan of service
- Includes Record of Decision on preferred route, and whether to build the project;
- $ - Customer's pro rata share of costs by MW

Phase 5: Project Construction

Project Construction:
- Construction and Energization of identified transmission project;
- $ - Customer secures its pro rata MW share of construction costs (letter of credit, etc.)

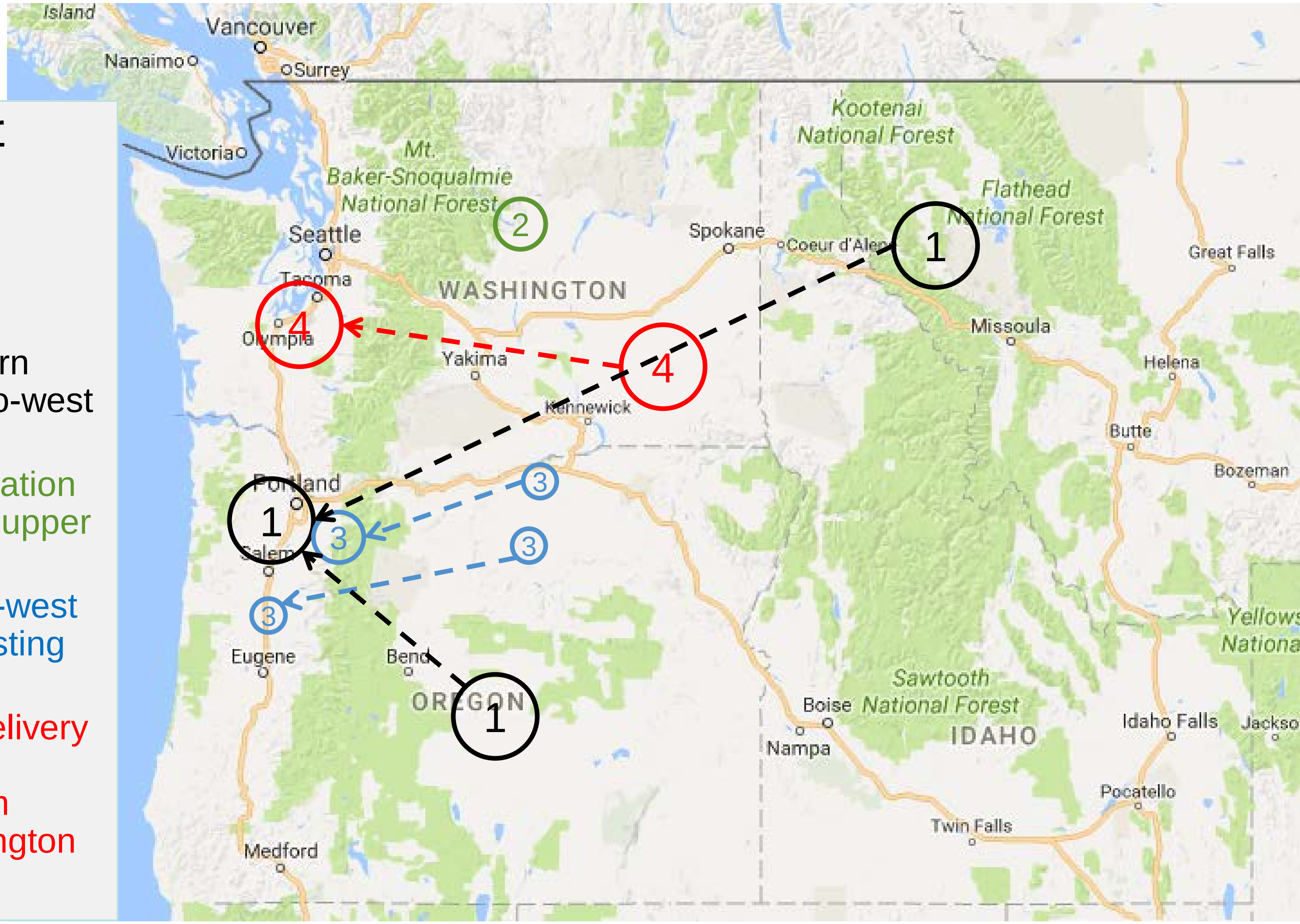
2016 Cluster Study: TSR Overview

	MW Studied	# TSRs
Total	***2,042***	***51***
Point-to-Point Service	**1,802**	**50**
New Service	1,547	46
Redirected Existing Service	255	4
NT Service	**240**	**1**

Primary Study Drivers/Generation Trends

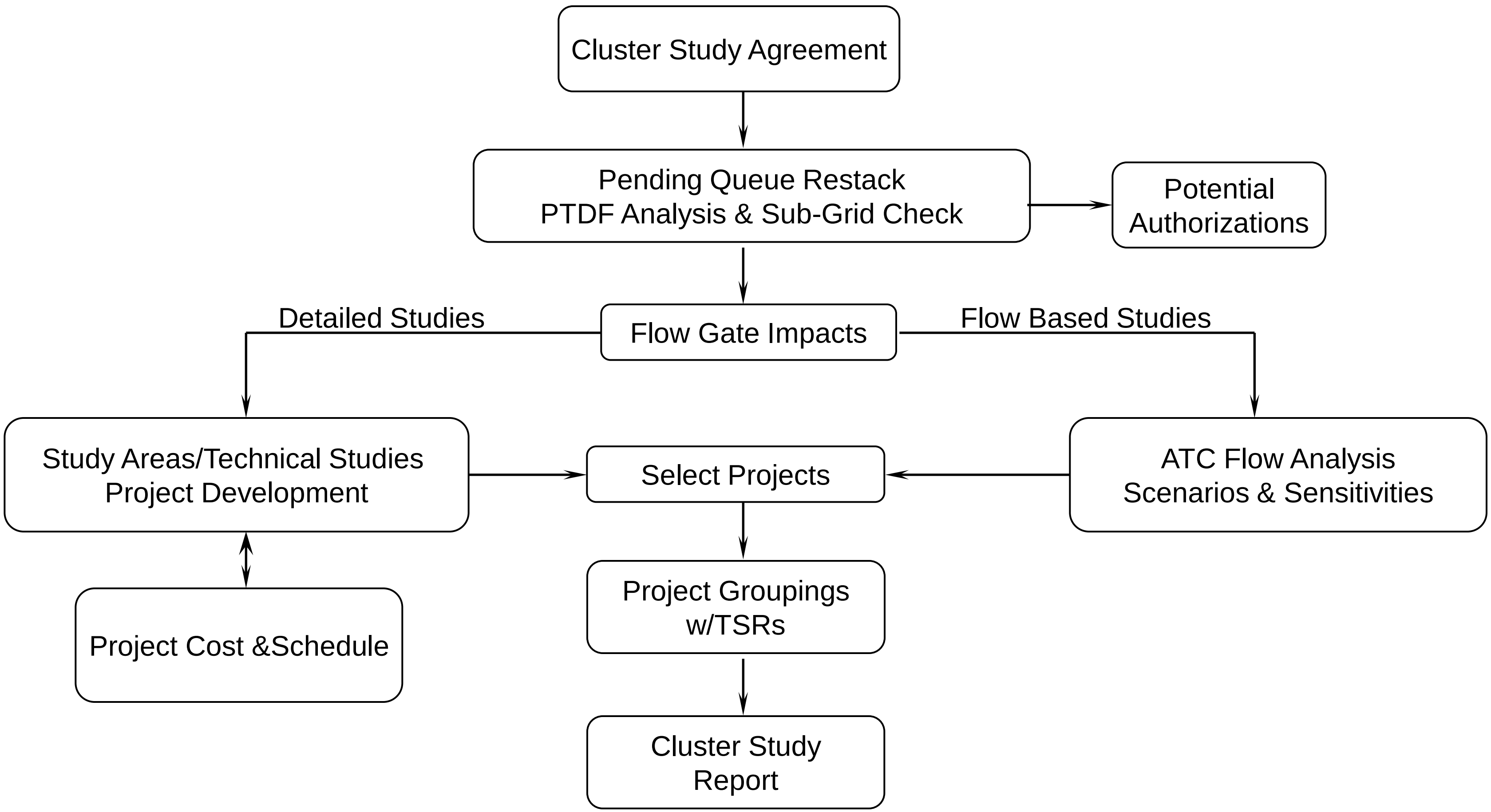
Primary Customer Behaviors

1. Potential new resource development in Montana and Central/Southern Oregon (east-to-west transactions)
2. Potential generation increase in the upper Columbia area
3. Certain east-to-west redirects of existing generation
4. East-to-west delivery of additional generation from eastern Washington

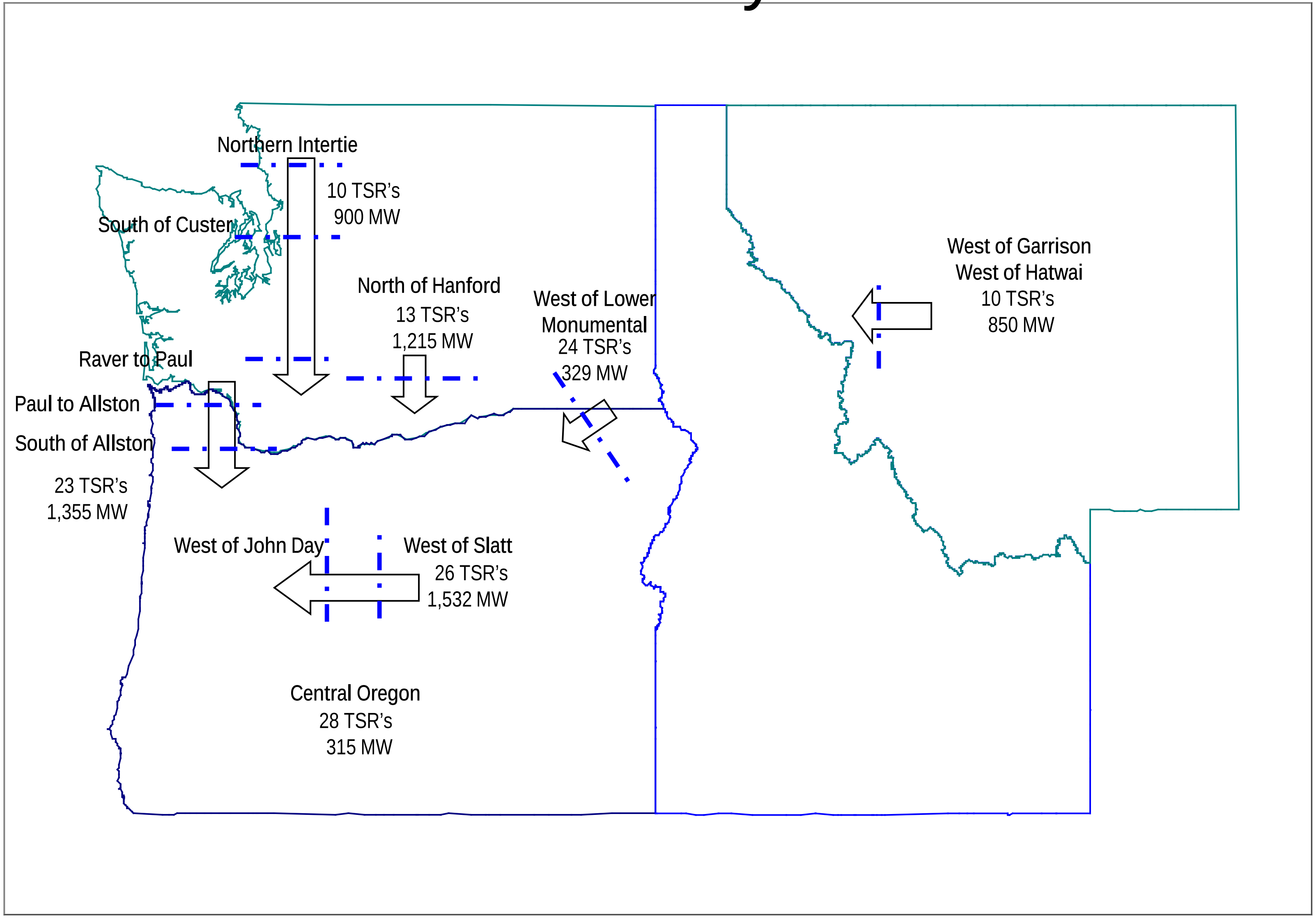


Pre-Decisional. For Discussion Purposes Only.

TSEP Cluster Study



Cluster Study Areas



NOTE: Demand from the study areas cannot be added to achieve the cumulative requests in the 2016 TSEP CS.

Assumptions & Methodology

- **Hydro Scenarios**

  Includes three scenarios:

  – Each zonal stress pattern provides for the nameplate less expected generation outages all of the FCRPS projects in a zone for the appropriate season. The zones include the Upper Columbia, Lower Columbia and Lower Snake.

- **Wind Scenarios**

  Includes two scenarios:

  – 100 % Wind Generation in the NW was modeled at the lesser of nameplate or demand.

  – Wind Generation modeled offline.

- **Canadian Entitlement Return Scenarios**

  Includes two scenarios

  – FCRPS Hydro Generation dispatched to meet current obligations without CER.

  – FCRPS Hydro Generation increased to dispatch CER and deliver to Canada.

Item	2016 TSEP
Basecase	Summer Case: WECC 2020HS Winter Case: WECC 2020HW
Load	Expected 1-in-2 peak
Hydro	-Three high generation scenarios: Upper Columbia, Lower Columbia, and Lower Snake -Mid-C remained at assumed contract level
Thermal	-All thermal in Northwest set to 100% of contracted/requested demand -All gen participated in basecase balancing
Wind	-All wind in Northwest set to 100% of contracted/requested demand and 0%. -All gen participated in basecase balancing
Solar	-All solar in Northwest set to 100% of contracted/requested demand -All gen participated in basecase balancing
COI/PDCI	4,800/3,220 Summer
Northern Intertie	Contracted demand in N>S direction for summer incremented for requested service from previous NOS; Canadian Entitlement Return for Winter
Montana>NW	Set at agreed to levels from ATC Methodology and incremented for requested service
Idaho > NW	Set at agreed to levels from ATC Methodology

Proposed Plans of Service

- **South of Custer (Northern Intertie Westside)**
  - Upgrade Monroe-Novelty 230 kV to 80° C plus
  - Third party impact to Puget Sound Energy (PSE) transmission – Second Portal Way 230/115 kV Transformer required plus additional fixes on PSE system. Final plan of service to be determined based upon discussion with PSE.
- **Raver to Paul Project**
  - South Tacoma-St. Clair 230 kV line sag upgrade
- **Harney Project**
  - Harney SVC
  - Redmond-Brasada 115 kV line sag upgrade
  - Brasada 115 kV shunt capacitor
  - Ponderosa-Brothers Tap 230 kV line (~46 miles) and substation
  - Third party impact to Idaho Power Company (IPC) transmission – Upgrade Hines 138/115 kV Transformer required on IPC's system. Final plan of service to be determined based upon discussion with IPC.
- **La Pine Project**
  - Shunt capacitors
  - La Pine 230/115 kV transformer upgrades
  - La Pine-Fort Rock 115 kV #2 line addition

Proposed Plans of Service

- **Walla Walla Project**
  - Tucannon River-Hatwai 115 kV line addition (~8 miles)
  - At Hatwai Substation a new 115 kV yard with a New bay, PCB, 230/115 kV transformer and a new 230 kV bay and PCB
- **Montana to Washington Project (M2W)**
  - The M2W project includes upgrading reactive compensation between Garrison, Hatwai and Bell substations
  - The M2W project refers to only upgrades on the BPA Network – facilities west of BPA’s Garrison Substation plus BPA’s share of harmonic filtering at the Colstrip Generating Station
- **Garrison to Ashe Project**
  - New 500 kV single circuit AC transmission line between Garrison Substation and Ashe Substation, through Bell Substation (~430 Miles)
  - Addition of a new 500 kV substation between Taft and Hot Springs substation
  - Three 500 kV series capacitors
  - Facilities identified here exclude any additional facilities that may be required between Colstrip and Garrison substations, and any other reinforcements east of Garrison needed to deliver generation associated with the requests to BPA’s Network

Estimated Costs and Projected Energization Date

Project Description	Estimated BPA Direct Cost ($M)	Projected Energization Date*
Montana to Washington Project	$119	Fall 2023
Garrison to Ashe Project	$1,042	Fall 2029
Harney Project†	$56	Fall 2024
La Pine Project	$65	Fall 2022
South of Custer Project†	$1.8	Fall 2021
Raver to Paul Project	$0.5	Fall 2021
Walla Walla Project	$12	Fall 2022

* Projected energization date based on construction feasibility, and do not account for BPA's NEPA obligations or Integrated Program Review/Capital Investment Review processes
† Third Party projects are not included in these project estimates

Next Steps

- Staff are currently working to perform initial financial analysis on the identified plans of service
  - Anticipate completing this in August
- We are developing customer letters providing additional detail on the immediate next steps for each TSR
  - Includes TSRs that have been studied in prior BPA cluster studies (since 2008)
  - Following the financial analysis, BPA will tender to customers the relevant next phase agreement (Preliminary Engineering, Environmental Study Agreement, e.g.)
- Staff are available to have individual meetings with customers to discuss results and next steps, as necessary
  - Please contact your Transmission Account Executive for more information