NORTHERN TIER
TRANSMISSION GROUP

NTTG Draft ESR Report: 2019 Economic Study Request
Stakeholder Comment Form

Open Comment period August 28, 2019 through September 6, 2019

Please submit comments to info@nttg.biz

Commenter Contact Information

Date September 6, 2019
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Stakeholder Comments

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All	All	Please see the joint parties comments below.

Joint Parties Comments on the 2018-2019 NTTG Economic Study Request

Draft: August 28, 2019

[Draft NTTG 2019 Economic Study Request Report]

- General
  - The joint parties appreciate the efforts of the NTTG Technical Work Group (TWG) to perform this economic study request (ESR). To date, there have not been any publicly available transmission planning studies that have evaluated the potential for lower cost transmission alternatives relative to the Energy Gateway West and South proposed projects. This ESR addresses that gap and provides valuable information for stakeholders. Given the magnitude of the costs for major new transmission expansions, it is important to sufficiently evaluate reasonable alternative solutions.
  - However, while the joint parties appreciate all of the technical analyses that were performed, some analyses and statements in the draft ESR report appear to go well beyond the scope of the study plan. Many statements in this draft report discuss concerns that extend well beyond the 10-year planning horizon and the eight test cases that have been evaluated by NTTG during its regional transmission planning process. Some of these statements seem misleading rather than informative or system reliability based. The joint parties offer the following questions and comments in an attempt to help clarify the results.

- Pg. 1, Lines 3:9 – Executive Summary
  - The initial sentence of the Executive Summary indicates that the ESR transmission showed acceptable performance for all of the NTTG stressed power flow cases, at a lower cost than the dRTP transmission.
  - The estimated capital cost difference is over $1.9 Billion and the estimated annual revenue requirement savings is $271 Million per year.[1] The significant magnitude of the cost savings for the ESR[2] transmission relative to the dRTP[3] transmission is a key takeaway from this report. Given the significance of this cost difference, the joint parties request that these figures be included in the executive summary.
  - The initial sentence caveats the conclusion that the ESR transmission configuration performs reliably at a lower cost by explaining that there are increased costs due to transmission congestion and dumped energy in Wyoming. The joint parties point out that these estimated increased costs only offset a small fraction of the overall total cost savings and request that the Executive Summary make that clear.

- Pg. 1, Lines 10:15 – Executive Summary

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[1] NTTG 2019 ESR Report_Draft V1.2_08-28-2019, p. 16.

[2] ESR transmission configuration includes the transmission elements listed on pg. 2 of the draft ESR report. It does not include Energy Gateway West or Energy Gateway South.

[3] The dRTP transmission configuration includes a majority of the Energy Gateway West and Energy Gateway South segments.

- The joint parties comment that the estimated increase in costs resulting from the change in dispatch referenced in this section only offsets a small fraction of the total cost savings of the ESR transmission configuration.
- Please explain what is meant by the statement on line 15 that the PCM simulation dispatches generation in Utah "without consideration of economics."

- Pg. 5 – Figure 16 is labeled Heavy Summer Case with ES Configuration, but it appears that this is actually the High Aeolus West/South Case, which is Case I. Please confirm.

- Pg. 5-6, Lines 99:101
  - The draft report states that "[t]he highlighted violations in the ESR configuration are the result of slight post contingency overloads in the 138 kV Path C system similar to those that occur in Case E."
  - Please confirm that these reliability violations referenced in this statement for Case E and Case I are limited to the Path C underlying 138 kV system. If not, please explain.
  - To provide some context, the joint parties would like to note that the cost of potential solutions to mitigate overloads on the 138 kV system, such as reconductoring, would likely be only a small fraction of the estimated $1.9 billion capital cost difference between the ESR and dRTP transmission configurations.

- Pg. 6-7 – Figure 17 and 18.
  - Please explain what these graphs are intended to represent.
  - In Figure 19, the gray line appears to represent values that are larger than the difference between the orange and blue curves. Please confirm that this accurately represents the difference between the curves.
  - The orange curve is labeled Ph2-V2. Is this intended to represent flows in the dRTP configuration?

- Pg. 5-7
  - The language on these two pages suggests that increased flows on Path C is a problem. The joint parties request that it be clarified why increased flows across Path C is being highlighted as an issue rather than improved utilization of existing facilities and recent investments (i.e. Populus-Terminal 345 kV lines). Making better use of existing transmission assets can be considered a positive economic outcome in many situations.
  - Page 7 states "Path C limitations are resulting in increased flows through Colorado as well as increased Utah area generation dispatch." Again, the report should frame alternate transmission paths and alternative sources of generation to serve Utah load as a positive economic outcome of the ESR configuration instead of a "limitation."
  - Further, Table 1 on Page 10 identifies only $568,026 of congestion per year on Path C. The joint parties believe this section (Pages 5-7) discussing the increased Path C congestion is misleading and does not provide context relative to the $271 million per year in annual savings from the ESR transmission configuration.

- Pg. 10, Table 1
  - Please identify the PCM simulation that was used to simulate these congestion costs.

- Table 1 has changed significantly relative to the [08-01-2019 draft of the ESR report]. The congestion costs have changed. In some cases, the congestion costs in this draft of Table 1 are multiple times larger than the congestion costs from the 08-01-2019 version. Further, additional congestion areas have been added to the table.
- Please reconcile the differing congestion values between this draft and the 08-01-2019 draft.
- Was a different PCM simulation used to determine these new numbers? If so, why?
- Table 1 shows that the ESR configuration increases congestion costs on P20 Path C by $568,026. Please confirm that these are the resulting increase in congestion costs across Path C under the ESR configuration.
- Please confirm what the "Total Congestion Cost ($)" values are representing. How are they developed? What assumptions are part of the PCM that influence congestion costs? How do these PCM based congestion costs relate to the actual operation of the transmission system on a contractual and network load servicing basis?
- Please confirm that the congestion costs in Table 1 refer to WECC wide congestion costs, not an increase in costs that would be borne solely by customers in the NTTG footprint.
- If known, please identify what the cost impact would be for each path for customers within the NTTG footprint.

- Pg. 10, Lines 138:140 – the draft report states "[m]ost significantly, congestion costs almost double in the ESR configuration on the ties into Colorado from Dave Johnston when compared to the already congested amount in the dRTP configuration."
  - The joint parties believe this statement is misleading. In the 08-01-2019 draft of the ESR report, the congestion costs are shown to increase by about $900,424 per year on this path. In context, these congestion costs do not appear to be significant, relative to a revenue requirement difference of $271 million per year between the different transmission configurations.
  - Please identify the increase in congestion costs on the ties into Colorado from Dave Johnston in the revised Table 1.

- Pg. 11 – Table 2
  - Please identify the PCM simulation that was used to simulate these thermal dispatch costs.
  - Please explain why the operating costs of fixed dispatch and hydro resources were excluded from this tabulation, "as those resources are included at zero cost in the PCM model".
    - If the exclusion of fixed dispatch and hydro resources is not anticipated to impact the tabulation, why were they excluded?
  - Please explain how these results would differ if the operating costs were not limited to thermal resources? i.e. What would the results be if fixed dispatch and hydro resources were included in this tabulation? Joint parties request inclusion of the PCM dispatch cost results with fixed dispatch and hydro resources included.

- Pg. 11, Lines 149-150.
  - Please explain what is meant by "dump energy?"
  - What is the cost impact to customers in the NTTG region from "dump energy?"

- Pg. 11 Table 3 appears to be duplicated.

- Pg. 12, Lines 153-160 and Table 4
  - The joint parties comment that the description and calculation of "Bottled Energy Costs" appear to represent fictitious costs. To the extent that PacifCorp does not have firm contractual transmission arrangements on certain transmission paths, does not automatically result in a cost equal to $23.13/MWh for every MWh of energy that is simulated to flow across those segments. "Consistent with operating practices", uncontracted flows in the Western Interconnection are not assigned costs equal to $23.13/MWh, otherwise there would be little to no uncontracted flows anywhere in the system which operational practice indicates not to be the case. Uncontracted flow is an inherent part of a path rated network system. It is a misrepresentation to suggest that every incremental uncontracted flow on the interconnection be assigned a cost equal to some average clearing cost or even a portion of uncontracted flows. Alternatively, the cost to purchase a corresponding amount of transmission service based on existing transmission assets could be identified and quantified.
  - Have "bottled energy costs" ever been considered in prior NTTG transmission plans? If so, please reference the analysis.
  - What is the basis for assigning a cost to "non-contracted flows"? It appears that NTTG assumes that any change in *physical* power flows from the dRPT are non-contracted flows. What made the dRPT-derived flows "contracted"? In actual system operations, it is routine for power to flow down transmission lines that do not align with the way transmission contracts are managed. There is no reason to assign a cost to these flows.
  - Is "bottled energy" the same thing as dump energy?
  - Is it a coincidence that the Wyo Spill in Table 4 is equal to the total "dump energy" in Table 3? Or is the Wyo Spill bottled energy calculated to be equal to the total "dump energy" for the NTTG footprint?
  - Please explain how the amount of "bottle energy" is calculated for each path.
  - Please explain why annual bottled energy costs were estimated using the a $23.13/MWh Utah Average clearing cost of energy?
    - Why wasn't the "bottled energy" cost estimated using OATT approved transmission rates?
  - Is there any overlap between bottled energy and the PCM dispatch costs in Table 2? Please explain why or why not.
  - Bottled energy costs are already captured in the production cost results such that a separate calculation of "bottled energy" results in a double counting of these costs. Please explain how "bottled energy" costs are not already being captured in PCM results.
  - The difference in thermal dispatch costs are tabulated in Table 2. Please explain why this concept of "bottled energy" should be considered an additional cost that is not captured by the cost of generation dispatch?

- Pg. 12, Lines 168-172
  - The draft report states "[c]onsidering that a large portion of the Utah generation south of Path C is from coal (over 2900 MW) and assuming that those coal resources will be retiring beyond the 10 year study timeframe, it is possible that the Utah system will see increased constraints with

the ES configuration compared to the dRTP. Replacing those coal resources with renewable wind and solar resources will likely be the preference."

- Please identify the generation resources that make up 2900 MW+ that is being referred to in this statement.
- According to PAC's 2017 IRP Update, the Hunter coal units 1, 2 and 3 in Utah are planned to be retired in 2042 and the Huntington coal units 1 and 2 in Utah are planned to be retired in 2036. Combined, these units account for over 2000 MW of capacity in Utah. These planned retirement dates are 8-14 years beyond the NTTG planning horizon.
- Is this section intended to indicate a concern that these coal units in Utah may retire sooner than the planned retirement dates?
    - If yes, what are the anticipated retirement dates?
- Were any future scenarios assessed for either the dRTP or the ESR transmission configurations that assumed that these Utah coal resources would be offline?
    - If yes, please explain.

- Pg. 12, Lines 174-176
    - The draft report states that the "ES configuration could result in significant dispatch changes with increased must run resources within the state of Utah, potentially adding yearly cost to the overall cost of the transmission upgrades proposed in the ESR."
    - Is this statement referring to the dispatch changes that could occur during the 10-year 2018-2019 RTP planning horizon? Or dispatch changes that could occur outside of 10-year planning horizon?
    - Would this statement still be true with increased zero dispatch cost solar resource additions in and around southern Utah?
    - Is the suggestion that there could be increased must run resources within the state of Utah based on the assumption that no improvements are made to address the 138 kV underlying Path C area and that no additional solar or other resources are added in Utah?
    - The joint parties comment that changes to the dispatch of units in Utah and elsewhere is not necessarily a bad thing. The dispatch of low cost resources in the future could result in economic benefits.

- Pg. 12-13, Lines 179-184
    - The draft report states "[w]hile the ES configuration showed acceptable performance in the selected power flow hours considered, the capability of the ES configuration is less than the dRTP. For example, for outages in the Wyoming 345 kV segments will result in the remaining system to be at its thermal capacity, indicating the ES configuration is at its capability while the 500 kV dRTP configuration has further capability beyond the conditions studied."
    - Please explain which outages are being referred to in this statement.
    - During these specific outages, how much additional capability does the 500 kV dRTP configuration provide?
    - The footnote to this section implies that the increased capability is due to the increased operating voltage and an additional conductor necessary to mitigate radio noise and corona issues. Please specify the additional conductor in the dRTP that provides the excess capability.
    - What is the estimated of cost of this segment of conductor?

- Pg. 13, Lines 185-186
    - The draft report states “Power vs Voltage (P-V) and Var vs Voltage (Q-V) analysis was performed on Case I which had Path C loaded to 2214 MW in the ES configuration. The Q-V analysis shown in Figure 24 confirms that at the flow levels in the modified Case I there is adequate reactive margin for the critical N-2 contingencies. The P-V analysis shown in Figure 25 suggests that the ES configuration is significantly less capable of servicing future Utah loads. Voltages of the dRTP configuration with an additional 1200 MW schedule exceed that of the ES configuration with only a 400 MW additional schedule.”
    - The analysis performed on Case I had Path C loaded to 2214 MW in the ES configuration. Please confirm this loading is less than the 2250 MW Path C limit.
    - What was the Path C loading under Case I for the dRTP transmission configuration?
    - Were the P-V and Q-V analyses performed on Case I on the dRTP configuration, similar to the analyses discussed for the ES configuration?
        - If yes, what were the results?
        - If not, why not?
    - Figure 24 is explained to reflect reactive margin under a modified Case I. Please explain what modifications were made to Case I?
        - Was the dRTP also analyzed under the modified Case I conditions? If yes, what were the results?
        - Please explain the justification for the modifications to Case I.
    - The report states that under the modified Case I there is adequate reactive margin for critical N-2 contingencies. Please confirm this sentence is referring to the ESR configuration.
    - The report states that Figure 25 “*suggests*” the ES configuration is significantly less capable of servicing future Utah loads.
        - Please confirm that the ES configuration performs reliably under the 10 year forecasted conditions in Case I.
        - Please elaborate how Figure 25 suggests that the ES configuration is less capable of serving future Utah loads.
        - Please explain how the dRTP is more capable?
        - Please confirm that adding new resources (solar, wind, gas peaker, etc) south of Path C in Utah would mitigate the issue of servicing future Utah loads.
    - Please explain what is meant by the statement that “Voltages of the dRTP configuration with an additional 1200 MW schedule exceed that of the ES configuration with only a 400 MW additional schedule.”
        - Please explain how the 400 MW additional schedule and 1200 MW additional schedule sensitivities were tested?
        - Please explain why these additional sensitivity scenarios evaluating these additional schedules were performed.
        - Were these sensitivities identified in the ESR study plan?
        - This statement appears to indicate that the system operates reliably under the ESR configuration. Further it appears to indicate that the schedules can actually be increased by up to 400 MW, above and beyond the stress conditions in the NTTG test cases, before there are any voltage concerns.

        - Is this a correct interpretation of the report?
        - If not, please explain.
        - What was the starting flow level before the 400 MW schedule increase?
        - Where is the power being scheduled to and from and why?

- Pg. 14, Lines 196-197
    - The report states that "[t]o mitigate Path C overload concerns, an additional 345 kV circuit between Populus and Terminal was contemplated."
    - Please confirm that the only Path C overloads observed under the eight NTTG test cases were on the underlying 138 kV system.
        - If not, please identify the overloads and conditions.
    - This statement appears to refer to Path C overload concerns that would result from stress conditions that may or may not occur beyond the 10-year planning horizon. Please clarify what the "overload concerns" are and whether the concerns are in the 10-yr planning horizon or beyond.

- Page 18; line 250-254
    - The only segment of Gateway West that is scheduled for construction in the near term is D.2 and PacifiCorp could choose to re-permit the remaining Gateway West corridor for 345-kV transmission, as considered in this study. In a transmission planning process that has the goal of identify the most cost effective plan to meet the region, PacifiCorp and NTTG should not discount alternative configurations when there are reasonable actions that could be taken by members to implement them if they were deemed to be more cost effective options.
    - Please explain why it would take another "12 to 15 years" to re-permit the remaining Gateway West corridor for 345-kV.