NORTHERN TIER
TRANSMISSION GROUP

Description of Meeting:	**NTTG Quarter 6 Public Stakeholder Meeting**
Meeting Date:	**June 30, 2015**
Meeting Notes Prepared By:	**Amy Wachsnicht**
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Agenda:

- **Welcome and Agenda Review**
  - NTTG Milestone and Schedule Overview – Sharon Helms
- **NTTG Draft Final Regional Transmission Plan: Project Selection**
  - NTTG Planning Process: Hurdles, Lessons Learned and Key Accomplishments – D. Angell
  - NTTG Draft Final Regional Transmission Plan: Process Overview and Report
    - Setting the Stage: Q1 thru Q5 Overview – C. Quist
    - NTTG Q5-Q6 Additional Studies – C. Quist, G. Coulam
    - New Alternative Project Identification – C. Quist, G. Coulam
    - Draft Final Regional Transmission Plan Report – D. Angell
- **NTTG Draft Final Regional Transmission Plan: Cost Allocation**
  - Cost Allocation Scenarios and Study Plan – S. LaBray, J. Leland
  - Cost Allocation Scenario Base Case Development – G. Coulam
  - Cost Allocation Analysis – J. Leland
  - Cost Allocation Next Steps – S. LaBray
- **Interregional Coordination** – D. Angell
- **Next Steps**
  - What's Coming Up and Stakeholder Opportunities - S. Helms
- **Round Table/Other Business**
- **Adjourn**

Welcome and Agenda Review (Presented by Sharon Helms)

- Sharon Helms welcomed attendees and reviewed the agenda. There were no additions or modifications to the agenda.
- NTTG Milestone and Schedule Overview
  - Sharon Helms presented this overview.

NTTG Draft Final Regional Transmission Plan: Project Selection – NTTG Planning Process (Presented by Dave Angell)

- NTTG Planning Process: Hurdles, Lessons Learned and Key Accomplishments
  - With the intent to serve the constituents of the NTTG footprint and to produce the most efficient or cost effective solutions for transmission, NTTG creates a study plan that outlines the work to be completed by NTTG, its committees and work groups. From this study plan, an Initial Regional Plan is developed, then further refined into a Draft Regional Transmission Plan and finally into a final Regional Transmission Plan. This process is completed on a biennial planning cycle.
  - Data from transmission providers is used with a base case. The base case selected for this planning cycle was the TEPPC 2024 Common Case. It was discovered that this 2024 case did not have the most recent data as received from the transmission providers. This is a result of the differing data submission deadlines for the different entities involved in planning in the West. This disparity in timing provided a lesson learned for the need for more alignment of these differing deadlines.
  - With the project selected, the study plan is carried out through power flow analysis and capacity analysis. Those results then assist the subsequent cost allocation analysis.
  - During the analysis inclusive of the submitted data it was determined that the footprint would not be able to meet the capacity needs for 2024.

- The study plan was then updated and approved by the NTTG Steering Committee to adjust for gaps in methodology during the studies for reliability and load service.
- NTTG is now evaluating modifications to Attachment K to include the lessons learned from this process. The intent is to get the revised Attachment K filed and approved by the next planning cycle.

NTTG Draft Final Regional Transmission Plan: Process Overview & Report (Presented by Craig Quist & Gil Coulam)

- Setting the Stage: Q1 thru Q5 Overview
    - Craig Quist reviewed NTTG's 8 quarter process.
    - NTTG has set a high bar for a committed project. This requires perfected right of ways. It was determined that Q2 submittals qualified as non-committed projects due to not meeting the committed project requirements.
    - NTTG considered Attachment K as the lead document if there were any discrepancies between the study plan and Attachment K.
    - Power flow analysis done in Q3 included 5 stress cases using the TEPPC Production Cost Modeling case. This included all common case transmission assumptions as well as NTTG submitted projects and Full Funder local transmission plans. These constitute the Initial Regional Plan.
        - Q4 change cases were developed by removing the non-committed projects. In searching for a more efficient or cost effective transmission plan, NTTG identified the need for the unsponsored project (Alternative Project) as part of the transmission reliability analysis. The Alternative Project facilities cover 500 kV transmission line located between southeast Idaho (Downey, Idaho) and southeast Wyoming (Carbon County). Interconnection points of this project to the PacifiCorp transmission system include: Populus 345 kV, Bridger 345 kV and Freezeout – Shirley Basin 230 kV line
            - Shown as an unsponsored 500kV Alternative Project from Aeolus (So. WY) to Anticline (SW WY) to Populus (So. ID) in the presentation.
        - Also completed in Q4 was the Draft Regional Transmission Plan report comprised of work and results to date in the current planning cycle.
    - Lessons learned included the projected load for PacifiCorp was significantly lower than the Q1 submittals that were in the TEPPC case. Another lesson learned was that the original study plan did not consider transmission needs and available transmission capacities.
    - The study plan was revised and was approved on March 9, 2015. This allowed for additional studies and added transmission needs and available transmission capacities. Q5 also incorporated data submission updates from Q1 submittals.
- NTTG Q5-Q6 Additional Studies
    - The load forecast for 2024 did not change between Q1 and Q5 submittals, but allowed for updating the TEPPC case data.
    - The resource forecast for 2024 saw a significant increase including approximately 1000MW of new resources in Idaho submitted later in Q5.
    - Due to time constraints, the Technical Work Group chose to conduct two high level studies with these new resources using the summer case only.
    - Gil Coulam reviewed the results of the Q5-Q6 additional studies incorporating the updated loads and resources and also discussed the results of the transmission needs and capabilities analysis.
    - There was a public policy consideration study requested that resulted in an additional study of replacing Colstrip 1 and 2 with wind generation at Broadview.
        - This met Order 1000 and Attachment K criteria. Results are included in the draft regional transmission report.
- New Alternative Project Identification

  - To meet a more efficient and cost effective solution for the draft transmission plan, the Q4 Alternative Project consisting of a 500 kV line from Aeolus to Anticline to Populus was studied with the updated loads and resources.
  - The Q4 alternative project had N-0 and N-1 violations with the updated loads and resources from Q5. By adding a new transmission 230 kV line section and upgrading existing transmission in Wyoming, and by adding a new 500 kV line from Aeolus to Mona, Utah and 345 kV line from Anticline to Bridger to the Aeolus to Anticline to Populus 500 kV line, these violations were eliminated.
- Draft Final Regional Transmission Plan Report
  - The sponsored project of Boardman to Hemingway, and the new unsponsored Alternative Project added to the current transmission, results in meeting the service needs of the NTTG footprint for 2024.
  - The new unsponsored Alternative Project consisted of a new 230 kV line from Windstar to Aeolus and reinforcements to existing underlying system in Wyoming, a new 500 kV line from Aeolus to Anticline to Populus in southern Idaho, a new 500 kV line from Aeolus to a new substation near Mona, Utah and a 345 kV line from Anticline to Bridger.

➢ **Question:** *Johanna Bell, Idaho PUC -* Regarding the transmission service updates submitted by Idaho Power in Q5, were they committed or non-committed? I am assuming they were committed.
  - **Answer:** *Dave Angell, Idaho Power -* What was submitted by Idaho Power in Q5 was additional detail around the transmission requirements in order to facilitate our integrated resource plan. So this is the integrated resource plan that was published for 2013 with their 2014 update. (We will be publishing today a brand new 2015 integrated resource plan.) And so those numbers identify two components. One – the capacity that the integrated resource planning process assumes will be available out there in that period of time with the Boardman to Hemingway transmission project in service. And then two – the capacity split of 500/200 for Idaho Power summer/winter and the capacity of 550/250 for Bonneville Power Administration winter/summer are based on permitting contracts for the Boardman to Hemingway transmission project.

➢ **Question:** *Johanna Bell, Idaho PUC -* Did any other NTTG members provide similar types of updates in Q5?
  - **Answer:** *Dave Angell, Idaho Power -* No.

➢ **Comment:** *Johanna Bell, Idaho PUC -* My understanding is that the Boardman to Hemingway additional capacity in addition to BPA that PacifiCorp is also going to be utilizing that.
  - **Response:** *Dave Angell, Idaho Power -* Yes. They are also members of the permitting project. They did not submit any capacity requirements.

➢ **Question:** *Johanna Bell, Idaho PUC -* As you are looking at your lessons learned and Attachment K, will the definition of committed vs. non-committed projects be re-examined? For example, will that threshold question of perfecting the right of way and all of the permitting to be secured, will that be changed at all or proposed to be changed?
  - **Answer:** *Dave Angell, Idaho Power -* It hasn't been brought to our attention to need to change it. It is not one of the items that we are tracking at the moment.

➢ **Question:** *Bela Vastag, Utah Office of Consumer Services -* This is a follow up with what Jamie Austin was talking about earlier with the increase in PacifiCorp loads from Q1 which was based on TEPPC data, which she said was one year lagging and that those loads from 2012-2013 were still recessionary loads and the updated loads are up significantly. I'm currently reviewing the PacifiCorp 2015 IRP and I'm trying to reconcile the two statements. The IRP shows the loads are down from 2013 to 2014, so the loads that Jamie was referring to must not be PacifiCorp retail loads – they're other load servicing entities on the PacifiCorp system. Is that what went up?

- **Answer:** *Jamie Austin, PacifiCorp* - Comparing the loads in the TEPPC 2024 CC for PACE (LRS 2013 load submittal that reflects the 2012 load forecast) to that submitted to NTTG in Q1 and Q5 (PAC's load submittal to LRS in 2014, reflecting the 2013 load forecast) you'll find an increase in the load forecast, close to a 1700MW; this discrepancy also includes 600MW of inadvertent omission of the Southeast Idaho BPA load that is part of the PACE BAA. . And the rest of it is actually a difference in the load growth. The PACE area load has increased and the numbers are consistent with what you would find if you look at the LRS submittals to WECC.

- **Question:** *Bela Vastag, Utah Office of Consumer Services* - That last load increase is from other load serving entities like UAMPS? I am just trying to reconcile what I see in the PacifiCorp IRP which shows loads down from the last IRP update and you're saying loads on the transmission system are up.
  - **Answer:** *Jamie Austin, PacifiCorp* - I don't think you are comparing the two forecasts that are being discussed here because the most recent 2015 IRP has in it a one year newer forecast. So what we are talking about here is we are comparing the last 2 older load forecasts as opposed to the most recent one.

- **Comment:** *Dave Angell, Idaho Power* - So the comparison that you are looking at is September 2014 vs. the forecast from September 2013 which would have been used in this planning cycle. That is compared with a September 2012 forecast which had missed the Southeast Idaho load in the balancing area.

- **Question:** *Ray Brush, NorthWestern Energy* - In the study where you replaced the Colstrip Units, was the wind put in at the same capacity or did you put in enough to meet the total energy?
  - **Answer:** *Chelsea Loomis, NorthWestern Energy* - The wind was put in at the same capacity.

- **Question:** *Dmitry Batishchev, The Energy Authority* - What is the capacity for Unit 1 and 2 of Colstrip vs. the wind capacity that was used in your study?
  - **Answer:** *Chelsea Loomis, NorthWestern Energy* - We didn't address capacity. We did a one for one replacement. So we turned off 610MW of coal at Colstrip and replaced it with 610MW of wind at Broadview. We understand that in a real life scenario the chances of the wind actually generating at 610MW are slim, but we tried to stress the system and go to a worst case or best case scenario depending on your perspective.

NTTG Draft Final Regional Transmission Plan: Cost Allocation Scenarios and Study Plan (Presented by Shay LaBray and John Leland)

- The Cost Allocation Committee has met regularly and worked through Order 1000 requirements as it pertains to the regional transmission plan and cost allocation.
- The LS Power/SWIP North project pre-qualified and was subject to the 2014-15 NTTG regional transmission plan process but was not eligible for cost allocation.
- The new unsponsored Alternative Project identified in the Draft Final Regional Transmission Plan was selected for cost allocation.

NTTG Draft Final Regional Transmission Plan: Cost Allocation Base Case Development (Presented by Gil Coulam)

- The initial cases were updated with Q5 submissions. From there four cost allocation scenarios were created. These four cases were created for both the Initial and Draft Final Regional Transmission Plan. These could then be compared for a direct comparison of economic metrics, such as capital costs, losses and for robustness of the Draft Regional Transmission Plan.
  - The change case is the Draft Final Regional Transmission Plan. The term change case is in Attachment K so for consistency this term is used.

- Idaho Power had the largest amount of increase change in 3 of the scenarios (A-C) with PACE having the largest increase change in the final scenario (D).
- The results of the analysis showed that all four studies produced acceptable results and no new transmission additions were needed.
  - For the final Draft Regional Transmission Plan the cost allocation result showed that only the comparison of the Initial Regional Plan with the change case has a change in capital costs, that all losses were annualized and monetized for use in the Cost Allocation workbook (available on the NTTG website) and that there were no reserve benefits found.

- **<u>Question:</u>** *Dave Angell, Idaho Power -* The only thing tested was higher loads than the levels in the Draft Final Regional Transmission Plan, right?
  - **<u>Answer:</u>** *Gil Coulam, NTTG* We wanted to see if we changed the futures in these scenarios would we need more or less transmission than what had been identified as the new alternative project. We did a test on Scenario B (subtract 1000MW) to see if we would get acceptable results if we didn't build the new line section from Aeolus to Clover. The results were unacceptable.

NTTG Draft Final Regional Transmission Plan: Cost Allocation Analysis (Presented by John Leland)

- John Leland reviewed the graphs produced by the cost allocation analysis.
- A workbook was developed from the work done by the Technical Work Group and analysis by the Cost Allocation Committee.
- The cost analysis began with the results from the Planning Committee calculations of a capital cost metric, loss metric and reserve metric.
- The non-committed project portion with no cost allocation in the graphs represent the Boardman to Hemingway project.
- The benefit identified between the Initial Regional Plan and the Draft Final Regional Transmission Plan was $1.93Billion. The beneficiaries were the existing Wyoming generation (30.5%) and the new Wyoming wind generation (19.7%) that was now dispatched, along with Q6 incremental PAC BAA LSEs (49.8%). These beneficiaries then have cost allocated appropriately for the non-committed alternative project.
- It should be noted that the identified beneficiaries have ownership-like rights on the alternative project.

- **<u>Comment:</u>** *Jamie Austin, PacifiCorp -* Re: Slide 46, The bar on the left hand side under Initial Regional Plan has the non-committed projects of Energy Gateway and Boardman to Hemingway. So in essence that particular set has a totally different deliverable than what you have in the middle column under Draft Regional Transmission Plan because the Gateway project is needed to serve PacifiCorp loads east and west. And the Boardman to Hemingway is serving the Idaho needs. In the middle column you have the alternative project in essence not serving the full requirement of the non-sponsored project. I believe the comparison is unfounded and not a comparison of apples to apples for benefits. Something is missing. It's not a straightforward comparison of benefit accrued because you have a lesser construction.
  - **<u>Response:</u>** *John Leland, NTTG -* Taking a look at that from a regional perspective and that is the intent of this because we have to take this at the regional perspective. The charge is there a more efficient or cost effective alternative. And our process to do that was using a technical analysis that either showed through power flow studies that you were able to get the energy out of the Wyoming area and also serve the load that was instilled in the study without any additional overloads or thermal problems. And that was accomplished.
    - If you are saying that the alternative project and the Gateway project comparable, no they're not. And that wasn't the charge. They are different projects. The Energy Gateway project does take the power through a line that goes all the way from Wyoming to basically the New Point area and the

  - Boardman to Hemingway project gets it up to the Northwest. So the alternative project is getting power to the Northwest. Likewise when you take the alternative project basically to Wyoming to eastern Idaho there's a gap between eastern Idaho and Western Idaho. That's the existing system. And so what happened and it's probably part of a study and this is part of our lessons learned too, but we were able to dispatch the system to meet all the load including the additional 1800MW of new load in the Wyoming area without any problems.
  - That was the analysis that was done. Now I will say it was not the full technical analysis that one would do in a particular siting study or if you were going for a rate case. It's not intended to do that. It did not have dynamics or anything like that.

- **Comment:** *Craig Quist, PacifiCorp*: On the depiction on slide 46 with the draft final regional plan and if you took a ruler and went across it would imply that the cost of the Initial Regional Plan were identical to the final regional transmission plan and we know that they are not because the Draft Final Regional Transmission Plan does not have system improvements between Hemingway and Populus. I think we know what you are trying to do, but it's a little misleading because it makes it sound like both plans have identical dollars in them.
  - **Response:** *John Leland, NTTG* - That goes to what Jamie is saying. They are not. The real comparison is between the top bar for the initial plan and the sum of the bottom two stacked bars in that middle column.

- **Comment:** *Jamie Austin, PacifiCorp* - I just want to set the record straight that that analysis is not what you would typically do for full blown economic analysis. And also that the approval of the project is not the same. So ultimately it's not a straight forward apples to apples comparison. And eventually the benefit being calculated, I know they are limited to the metrics that NTTG uses with losses, reserves and capital costs. This doesn't give any regard to the net worth and there are benefits to other connected systems. This is very limited, crude, high level type of analysis.
  - **Response:** *John Leland, NTTG* - And Dave (Angell) did mention that what we are going to be taking a look at is how we can do this with improvement in the future. These are the kinds of things we need to think about. It is an opportunity to implement the case with the Attachment K criterion mentioned – losses, reserves and capital costs, and there was no additional benefits or cost allocation beyond what Attachment K mentions.

- **Question:** *Clay MacArthur, Deseret Power* - The studies that were done are based largely on a TEPPC model with assumptions on the retirement of units across WECC. Retirement of units can be a significant driver in this analysis. I don't think a scenario was done on retirement. Is that correct?
  - **Answer:** *John Leland, NTTG* - Scenario 4 was done with some replacement of coal. It could have been that they weren't retired. It could be that they were just re-dispatched. But that would be something that is similar to that.
    - We did have that public policy, but that of course was not a cost allocation scenario.

- **Question:** *Clay MacArthur, Deseret Power* - But the delay of a retirement or something like that was not contemplated?
  - **Answer:** *John Leland, NTTG* - No.

- **Question:** *Clay MacArthur, Deseret Power* - I think all of the scenarios currently are kind of equally weighted, even though some may be perceived as more likely outcomes. Is that correct?
  - **Answer:** *John Leland, NTTG* - Basically the way this works is you average the results of the scenarios. So with capital costs you average the four capital costs, and from losses you take the average of those, and it's that average you are using to allocate the benefits and cost. There was no weighting on those.

    - One way to look at it is what are we really doing in this analysis and what we're trying to take a look at through the cost allocation scenarios themselves is what are potential futures, but without changing the decision path you are on today. That is you have a decision that says, in this case, the alternative project and the Boardman-Hemingway. Without changing that decision path, but what if the future in 10 years does look different. So Scenario A is 1000 more MW of load, Scenario B is 1000 less load, and Scenario C with wind/solar and Scenario D with coal. We could have done things with weighting, but with the way we did the analysis and how it was specified in Attachment K the way we looked at it, it had to be averaged.
    - And again this can be something we look at for the future and with Attachment K.

- **Question:** *Clay MacArthur, Deseret Power* - One last question. On the benefit to the PACE BAA LSEs, is that primarily in the form of reduced losses?
  - **Answer:** *John Leland, NTTG* - No, what happened is that we had a project that started in Wyoming, ended in western Idaho and then went to the Northwest. We took a section out of that middle so it stopped in eastern Idaho. We still had the same amount of generation, but what happened to draw that generation out was1800MW of new load in the PacifiCorp BAA. So basically what happened is that the load was increased and the generation was increased and it served that. So that's how it happened. And that's a key important concept. That's one of these planning concepts. Because if this were to receive cost allocation at some point in time and nothing changed – everything remained exactly the same, the LSEs would have to be acquiring just like the plan suggested. It has to come from Wyoming, it has to use this new line, so if an LSE is in their planning and end up going someplace else then that criteria has failed for allocation and you have an argument that could say I shouldn't be receiving this allocation because the assumptions that were used are not fulfilled.

- **Comment:** *Jamie Austin, PacifiCorp* - I just wanted to add with regard to plant retirement within the TEPPC case. If you are doing analysis of just power flow, this is one hour and the power flow is kind of limited to a view of dispatch or re-dispatch because of retirement outside of the region, all you would see in regard to the NTTG footprint would be the transfer in and out. I don't know that there was an exerted effort to reflect retirements so all of that would not be transparent unless you run the production cost model and have other measures such as total production cost, etc. to actually see the impact.
  - **Response:** *John Leland, NTTG* - This is again a lessons learned. We need to start thinking of what we are going to do with the Attachment K to not have this kind of an issue. We could have gone in to a lot more detail with respect to the production cost models, but there was a decision made early on that we would not use that. We wanted to go with power flow analysis. But I and others are encouraged to perhaps think of different approaches to some of these things.

- The workbook contains the calculations used for the resulting allocations.
- John Leland reviewed the four key steps in the cost allocation analysis process, as understood by the Cost Allocation Committee pursuant to Attachment K.

- **Question:** *Sharon Helms, NTTG* - You mentioned that if it had been higher than the 150% you would have had to reset it. What does that mean – you would have to reset it? What does that mean?
  - **Response:** *John Leland, NTTG* - Attachment K does not describe that. It just says this is a cap and if it is outside that cap you would have to set it at the cap. My thought is that if we had something that was over or under the cap, we would bring it up to the cap level and then allocate pro rata.

- Final result was that since all project costs cannot be allocated to beneficiaries (as caps were reached per Attachment K) and there is not an Applicant to accept the remaining costs of the unallocated cost of the project,, this alternative project is not eligible for cost allocation at this time.

- **Question:** *Dave Angell, Idaho Power -* The Initial Regional Plans were not accepted because there is a really high bar about the perfection of the right of ways. But now what you are saying is we go through this, the group identified a project, and the draft regional plan has no cost allocation. And even though there's no right of ways that have been perfected by these projects that have come out of this, they will remain in the plan? Or do they have to go back into the plan because there are no right of ways for them?
    - **Answer:** *John Leland, NTTG -* What we have done here does not change the committed or uncommitted status of the project. It remains uncommitted at this point in time. And the alternative project remains just that – it does not have a right of way or anything of that nature. But it was selected to the plan. So it would have to go through the process again, it would have to be re-selected and all of that. It could be displaced.

- **Question:** *Dave Angell, Idaho Power -* So it would need to be re-selected?
    - **Answer:** *John Leland, NTTG -* Yes. It is carried over from this plan into the next cycle because this is our regional plan, but it will be re-evaluated.

- **Comment:** *Sharon Helms, NTTG -* Every year the first task that the Technical Work Group does is to assess what projects in that Initial Regional Plan are committed. And those that are committed are set aside and they are not subject to re-evaluation, but every other project is. And then they also consider projects that were submitted by stakeholder or other merchant transmission developers.

- **Comment:** *John Leland, NTTG -* As a committed project, they have milestones that they have to establish. If they fail to meet those milestones then there has to be a decision of: are they still in the plan as a committed project or not?

- **Question:** *Bill Hosie, TransCanada* - What is the process for these projects that acquire a sponsor?
    - **Answer:** *John Leland, NTTG -* The process would be that whoever would like to sponsor this they would have to submit this project with the information in Q1 of this next planning cycle. If they are going to go for cost allocation then they would have to pre-qualify starting in Q8 of this year. Whether you want to be selected for cost allocation or you just want to be selected for the plan in any event you would have to submit information in Q1 and cost allocation would have to start a little earlier in the last quarter of this year for sponsor qualification just to show you have the where-with-all to sponsor a project of this magnitude.

- **Question:** *Bill Hosie, TransCanada -* What if there are two organizations that put a submission in?
    - **Answer:** *John Leland, NTTG -* They would have to come through the process and would be evaluated whether to go forward or not.

- **Question:** *Bill Hosie, TransCanada -* And what basis would they be evaluated on?
    - **Answer:** *John Leland, NTTG -* Currently if Attachment K is to stay intact as it is, they'd have to go through the planning process, they would have to go through the power flow analysis and so forth. We'd use the capital cost, the losses and the reserve metrics, and then we'd select the project that is in the plan after that. So first they'd have to meet the reliability criteria. If they did meet the reliability criteria and the metrics, then it would be about the cost.

- **<u>Question:</u>** *Bill Hosie, TransCanada* - But this project is not in the plan because there is no mechanism for it to go ahead?
  - **<u>Answer:</u>** *John Leland, NTTG* - Well it is carried forward at this point in the plan. This was a startup cycle so we couldn't follow our normal process. So next cycle we will have a prior regional biennial plan so that is in the mix. Then we'll have the roll up of the transmission providers – if they have any new projects or additional projects. Likewise we could have sponsors come in. So in Q1 we could have a host of things that is going to be a lot larger than what we need to meet the regional need. So at that point in time that's where we have to go into the Q3 and Q4 analysis to weed out which one of those is the best.

- **<u>Comment:</u>** *Jamie Austin, PacifiCorp* - So what this suggests is that you may have to pick your projects.
  - **<u>Response:</u>** *John Leland, NTTG* - And that would be through Q3 and Q4. We would go back and rebuild this draft plan. It could be what was submitted, it could be what comes out of this current plan, it could be modified as a result of sponsored, but uncommitted projects or it could be something that was submitted.

- **<u>Comment:</u>** *Bill Hosie, TransCanada* - So it sounds like if after the submissions of a large customer wanted to go ahead they have to wait two years to have this evaluation done.
  - **<u>Response:</u>** *John Leland, NTTG* - We are on a biennial cycle.
  - **<u>Response:</u>** *Dave Angell, Idaho Power* - We are looking at a 10 year planning horizon so what we are studying is 10 years out and there could certainly be many cycles as projects develop both resource-wise and transmission-wise. We are not looking in the next couple of years.

NTTG Draft Final Regional Transmission Plan: Cost Allocation; Next Steps (Presented by Shay LaBray)

- A project is subject to re-evaluation until it is committed so it may go through multiple cycles.

- **<u>Question:</u>** *Clay MacArthur, Deseret Power* - If this project rolls forward and stays in the plan, and then in the next cycle maybe an independent transmission developer submits an identical project doesn't that create a bloat to the Initial Regional Plan?
  - **<u>Answer:</u>** *John Leland, NTTG* - Yes. Assuming they all qualify that would put it in the Q3/Q4 analysis. We would go through and figure out which one meets the needs in the most efficient and cost effective option.

- **<u>Question:</u>** *Dave Angell, Idaho Power* - That bar chart with the Initial Regional Plan and the benefit being calculated as the delta between the Initial Regional Plan and the final Draft Regional Transmission Plan, would that still be calculated as the benefit and would those applicable benefits be allocated? Or will it be a modified benefit in the next cycle?
  - **<u>Answer:</u>** *John Leland, NTTG* - It will be whatever the plan turns out to be. So we'll ultimately have an initial plan (whatever that runs out to be) and then we'll have a draft final plan.

- **<u>Comment:</u>** *Bill Hosie, TransCanada* - In the next cycle, will the initial transmission plan be this alternative plan that you have just created? If so, you go through the evaluation again and the plan turns out to be the same as what you've come up with this time then there is no benefit.
  - **<u>Answer:</u>** *John Leland, NTTG* - I've thought about what to do in that case and I think this would have to be thought through a lot and we'd have to modify Attachment K because it really doesn't address this, but you have to step back and say what is the benefit of that project? And it's not one project in this plan and another project is another plan, you

are going to have to somehow figure out what's the benefit of the project in that plan. It's a good question and one that we need to work through and think about.

Interregional Coordination (Presented by Dave Angell)

- On June 25, 2015 there was an interregional coordination stakeholder meeting.
- Exchange of information and base case identification processes for use in all the regions are currently being developed. The milestone for having these processes defined is October 1, 2015.
- Another definition being developed is what constitutes an interregional project. Each region has tariff language concerning its own regional processes, but details around interregional projects and how the regions collectively work on them is still to be determined.

- ➢ **Question:** *Jerry Maio, Utah PUC* - How does that coordination work generally? Do you all work from a common database? And who resolves conflicts with the database or the numbers as you are doing your coordination?
    - **Answer:** *Dave Angell, Idaho Power* - That is exactly what we are fleshing out. We have a couple meetings next week where we are going to try and work through these specific details. As for databases, we all pretty much start with WECC databases as the initial starting point. However each region may modify those databases quite substantially in order to stress paths or in the production cost side of it maybe they have some information they want to incorporate as to what they think the future is going to look like. So in our discussions this next week we will be exploring how to better coordinate and harmonize so, to use a terms used by FERC. So when one is in harmony it doesn't mean you are exactly the same, but you do work or sound well together.

- Sharon Helms mentioned that there is a document posted to the NTTG website that contains discussion points that were reviewed at last week's stakeholder meeting and that comments are welcome. Any comments can be submitted to regionaltransmission@caiso.com.
- The next stakeholder meeting is scheduled for August 18, 2015 and will be hosted by WestConnect in Denver, CO at the Tri-State offices.

Next Steps (Presented by Sharon Helms)

- Q7 is when stakeholder review id solicited for the Draft Final Regional Transmission Plan. Comments are welcome from July 6-24, 2015. The next NTTG stakeholder meeting will be in Bozeman, MT on September 29, 2015.
- A technical writer will be engaged and a comprehensive report will be finalized to be submitted to the NTTG Steering Committee with final approval slated for Q8.
- If entities are interested in getting pre-qualified, this takes place in Q8 of the NTTG planning cycle.
- October 1, 2015 also marks the effective date of Order 1000 Interregional Coordination.
- CAISO and WestConnect were invited to give an update on their regional activities.
    - Gary DeShazo with CAISO mentioned that they are in Phase 2 of their process where CAISO begins to run their analysis for their current annual planning cycle. Results will be released in September 2015. Their economic and public policy analysis will begin with results shared in November 2015. Their draft transmission plan will be released in January 2015 for review.
    - Charlie Reinhold with WestConnect mentioned that WestConnect is doing an abbreviated planning cycle for 2015. Their full biennial cycle will begin January 2016. WestConnect is currently in the process of developing any regional needs following completion of their transmission model which is a power flow model only in this abbreviated cycle. In this cycle WestConnect will be looking at only reliability needs, whereas in their full biennial cycle this will expand to reliability, economic and public policy needs. A presentation of the needs assessment to their Planning Management Committee is scheduled for July 22, 2015. Preliminary results are that there are no reliability needs in this cycle. Collection of projects to meet identified needs would then occur and move on to cost allocation processes.

- Sharon on behalf of NTTG thanked and wished Ron Schellberg congratulations on his retirement which is effective today.

Round Table/Other Business

- There were no additional comments.

Hearing no additional comments the meeting was adjourned.

Attendees in Person:

Name	Company
Dave Angell	Idaho Power
Jamie Austin	PacifiCorp
Johanna Bell	ID PUC
Gil Coulam	NTTG
Jared Ellsworth	Idaho Power
Sharon Helms	NTTG
Belinda Kolb	WY Office of Consumer Advocates
Shay LaBray	PacifiCorp
John Leland	NTTG
Clay MacArthur	Deseret Power
Craig Quist	PacifiCorp
Mary Ellen Stefanou	PacifiCorp
Jim Tucker	Deseret Power
Amy Wachsnicht	NTTG
Courtney Waites	Idaho Power
Richard Walje	PacifiCorp
Curtis Westhoff	Idaho Power
Matt Wiggs	ID Office Energy Resources

Attendees via WebEx:

Name	**Company**
Travis Allen	Enbridge
Dmitry Batishchev	The Energy Authority
Rich Bayless	NTTG
Ray Brush	NorthWestern
Bob Decker	MT Public Service Commission
Brian DeKiep	NW Power & Conservation Council
Gary DeShazo	CAISO
Marshall Empey	UAMPS
Jennifer Galaway	Portland General
Fred Heutte	NW Energy Coalition
Bill Hosie	TransCanada
Rhett Hurless	Absaroka Energy
Don Johnson	Portland General
Amy Light	Portland General
Chelsea Loomis	NorthWestern
Jerry Maio	UT Public Service Commission
Kim McClafferty	NorthWestern
Carla McLane	Morrow County
Ken Neal	Naturener
Marci Norby	WY Public Service Commission
Larry Nordell	MT Consumer Council
Patel, Kishore	PacifiCorp
Natalie Propst	FERC
Charlie Reinhold	WestConnect
Adam Richins	PacifiCorp
William Schubert	NorthWestern
Phil Solomon	Deseret Power
Jaime Stamatson	MT Consumer Council
Monica Taba	FERC
Henry R. Tilghman	Tilghman & Associates
Bela Vastag	UT Office of Consumer Services
Dave Walker	WY Public Service Commission
Lawrence Willick	LS Power