SOUTHWEST POWER POOL (SPP)
CONSOLIDATED PLANNING PROCESS TASK FORCE (CPPTF)
December 06, 2024, 9:00 a.m. to 4:00 p.m.
WebEx 2482 737 9441

MINUTES

AGENDA ITEM 1 – CALL TO ORDER AND ADMINISTRATIVE ITEMS

Chair Sunny Raheem called the meeting to order at 9:04 a.m., December 6, 2024, with a quorum present. Staff Secretary Ramunda Russell provided an overview of meeting procedures and read the antitrust statement. There were no proxies noted for this meeting. Chair Raheem reviewed the meeting agenda (Attachment A) and provided a high-level summary of the agenda items including all of the items requesting approvals. Steve Gaw (APA) moved to approve the agenda as presented. Heather Starnes (MEC) seconded, and the motion passed unanimously.

AGENDA ITEM 2 – CONSENT AGENDA

Chair Raheem reviewed the consent agenda item for the November 18, 2024, draft meeting minutes (Attachment B). John Krajewski (NPRB) moved to approve the motion for the consent agenda item. Heather Starnes (MEC) seconded, and the motion passed unanimously.

AGENDA ITEM 3 – NUC (ENTRY FEE) APPROACH DISCUSSION

Chair Raheem reviewed the two different approaches for the network upgrade contribution (NUC)/entry fee. He recommended considering a volume-based usage instead of a single snapshot. He explained that it could provide more valuable consideration that will avoid large swings in the initial entry fee. He summarized that the guiding principles are to keep it simple and based on benefit and commercial viability because it's an indicator of what customers are willing to pay. He reviewed the load and generation benefits that will be included in the benefit calculation-based approach. For future integration, he stated that we still need to look at the FERC Order 1920 benefits that could play into the entry fee. He explained that the difference in the two approaches is that we would apply a benefit-cost justification but it won't be a direct contribution to GI customers. The plan would be to use an energy utilization ratio rather than a precise measurement of benefits. One member commented that he prefers something simpler and more stable that can be justified. Another member agreed that keeping it simple is better but be able to ensure comparison of cost assignment versus benefits because FERC will require that, and it will be easier to get approved and in place. Chair Raheem reviewed the draft language and how to ensure that we are aligned on how the costs will flow under the different charge types under the CPP components. After Chair Raheem outlined the three buckets of the entry fee structure, there was discussion regarding unplanned generation, how utilities with retired assets would be treated, and a request to provide transparency about where to interconnect in the planned areas so customers can avoid planning to interconnect in unplanned areas. Chair Raheem stated that staff will screen for this in the 20Y assessments. One member asked if flows were excluded in the calculation, and an SPP member responded that it would be bi-directional. He also mentioned that these numbers don't include 69 kV (only includes 100 - 300kV) which aligns with the entry fee that is only 400 kV and above. Another member asked for clarification about taking into account sites with a generator that has paid for direct assigned upgrades and where there is extra generation capacity at that site but it's not accounted for in current agreements and another generator uses it, if there will be some accounting change for that. Chair Raheem responded that it depends on the concurrent revision request that establishes the amounts for grandfathered resources with rights before the process. If approved and established, it will simplify our entry fee approach because the generation sites load will be recognized and will only have to pay for load over the approved generation levels. The same member mentioned that we need to take into account the older sites that have extra capacity and that they are not assigned the same level of fees as a new greenfield site. Chair Raheem stated that planning for capacity at existing sites will be reviewed internally, and staff will provide a complete package of how that will work. After showing an example of an ERIS flat fee which calculated EHV and HV usage separately, Chair Raheem asked for thoughts on running additional analysis. He shared examples of what costs would look like under different options. Another member stated that is helpful to understand all of the impacts. He asked if there was an estimate from the limited affected systems study that provides additional costs on top of JTIQ. Chair Raheem responded that we assumed it to be zero because there is no way to determine this. He commented that this level of information will allow us to make progress, and analysis is helpful in supporting a conclusion that will help to get people on board. He stated that we will take a deeper dive in the January 2, 2025, meeting and determine if we are ready to have exploratory conversations with GIAG and get feedback from CAWG and the developer community. A third member asked if this was determined on a portfolio basis, zone by zone basis, or facility by facility basis. Chair Raheem responded that it would be on a portfolio basis, the EHV would be on a regional basis, and the subregional would be on a five pricing zone basis. He added that everyone would be paying the same EHV/regional fee but different fees will be paid on a subregional basis. A meeting participant asked when referring to historical contributions of GI customers, if the low values were because of non-firm interconnections and how viable the historical interconnection costs are. Chair Raheem mentioned that it is just a good reference point, but construction is based off the $7.7B portfolio. A member asked to explain at high level the drivers for the entry fee changing in Y5 vs. Y20 and how it relates to growth rates in terms of added incremental generation. Chair Raheem stated that there are 4-6 GW showing to be connected annually in the EMS and markets process. The member followed up with which is the right number to set the entry fee. Chair Raheem responded that this will be an achievable, reasonable entry fee over the 20Y study horizon, and we may need to look at transmission needs within the Y5 or Y10 assessment. He explained that Y5 doesn't have enough head room for the amount of load growth, so Y10 may be the better number for the cost per kW. He added that we need to evaluate a DP on which year forecast to base the NUC because Y5 seems too close. Another member stated that we may want to look at Y10 and compare to the Y5 and Y20 to see if enough is captured.

9-min break until 10:50a

AGENDA ITEM 4 – 2026 ITP/CPP TRANSITION STUDY SCOPE UPDATES

a. Objectives & Outcomes - Chair Raheem mentioned that we want to layout the policy on the approvals. He explained that, for the scope, we want to identify the policy items that are critical for the CPP assessment to continue work for model development and the start of the assessment. He stated that there are two phases for scope approval - phase 1 is for approvals for the high-level framework for the technical assessment in January, and phase 2 for scope approvals will be in July. He explained that we will also be laying out the workplan for the CPPTF, which will be shared in the January 21, 2025, meeting. He reviewed the model development scope approvals as well as the technical assessment scope approvals being requested. He stated that we will be using the scope as a vehicle to get policy decisions made to use as the starting point for ITP manual redlines in 2025.

b. SCRIPT C3 Common Model Recommendations - Eddie Watson provided an update on the C3 common model progress. He reviewed the background of addressing the common model activities. He provided detailed explanations of each segment (C3.1 - C3.5). He outlined additional modeling needs and provided an overview of the ITP, CPP, and GI modeling options included in the technical assessment. Eddie reviewed the recommendation that is being brought to the group today. One member stated that he is supportive of the 10.3 waiver but asked about next steps with the MPM. Eddie responded that there will be internal discussions and will bring a response back to the working groups. There was continued discussion about an MPM delay and waiver request. Chair Raheem stated that we need to layout a workplan on when requested items will be brought back to CPPTF. Another member had general questions on the models outlined and what would be needed from a deliverable standpoint in the deliverability areas, specifically if the models provide insight into whether there is sufficient deliverability to provide load to meet the modeled requirements. An SPP staff member responded that the T-GEM construct will set the structure for where we will be from the deliverability aspect. Two members brought up points about this being presented to the primary working groups first. Chair Raheem stated that we need to modify the recommendation slide to state that the CPPTF approval is contingent upon the MDAG and TWG approval.

Jared Cooley (SPS) moved to approve the motion as presented on the screen:

CPPTF approves the policy direction for the SCRIPT C3 Common Model CPP Transition modeling policy recommendations for the 2026 ITP & CPP Transition Assessments scope document, as follows:

- **SCRIPT C3.1: The deadline for submitting Section 10.3 model change requests will be July 31, 2025**
- **SCRIPT C3.2: Common Model Set Dispatch Assumptions as outlined on slides 10-11**
- **SCRIPT C3.3: A waiver for the ITP Manual, Section 2.3.2, for the MPMs**

Derek Brown (Evergy) seconded, and the motion passed unanimously.

Chair Raheem stated that the recommendation is now ready to go to the TWG/ESWG and the MDAG for approval. Eddie shared that it would go before TWG/ESWG on 12/11/2024 and MDAG on 12/12/2024 for their respective items.

Chair changed the order of the next two presentations due to presenter availability.

d. Short Circuit Ratio Screening - Doug Bowman explained key points about system strength and short circuit ratio (SCR). He summarized the purpose of the short-circuit ratio (SCR) screening. He defined the SCR metric which measures the relative strength of the bus at the inverter-based resources (IBR's) point of interconnection (POI) and identifies weak points close to IBR's. He stated that for the purpose of the scope, we are using the value of 3.0, and an SCR below this value will be considered during solution evaluation and development. He asserted that this value is also being used for electro-magnetic transient (EMT) analysis. He explained that the weighted SCR will also be evaluated, and this metric considers a high penetration of IBR's in a general area. He clarified that the value of 3.0 will be used in this instance as well. He explained the benefits of using the grid strength assessment tool (GSAT) that SPP will be utilizing. One member asked how detailed this will be when using it in CPP. Doug stated that there were two ways to use the GSAT tool – to look at existing IBR's in the system and calculate what the SCR of the bus will be and then assess how much short-circuit maximum available power (SCMVA) is at the location so a generation resource can look at the assessment to determine that there is not enough available where they want to interconnect. He stated that this would be used for customers that want to interconnect at a certain POI to be able to evaluate the information. The same member asked if this information that can be provided about the general grid can pinpoint how to make the area more secure. Chair Raheem clarified that whether this information should trigger added transmission will be part of the scope approvals coming in phase 2. The same member added that it would be useful to use this tool to forecast where there may be future areas of issue within generation siting. Chair Raheem offered that we could run a model with the CPP in mind. An SPP staff member added that from a long-term assessment standpoint where we don't have customer data, this could be used to select better locations and proxy potential transmission upgrades. Another member asked if this assessment would be tied into the 20Y model that is driving the network upgrades to help drive siting generation and transmission buildout in the right areas. Chair Raheem responded that we would use this in the 20Y assessment and do a deeper dive in the annual assessment to screen for EMT and have GI customer data for a transient stability look as well.

45-min lunch break until 1:00p

c. CPP Technical Assessment Discussion - Kelsey Allen reviewed the CPP transition study scope document to show where we are with the model development portion (section 3) of the technical assessment. He explained setting the B-GEMs as the baseline for the transfer assessment. He mentioned the use of load assumptions and recommended including these to plan appropriately. He stated that there would be twelve base models, and the B-GEMS would be used to build the transfer models from there. He explained that the model set will consist of two scenario types. He reviewed the dispatch methodology of the inter- and intra-deliverability areas transfers - using economic dispatch for conventional generation and scaling for renewables. Kelsey mentioned that we could treat all resources as NRIS and ERIS types. The NRIS+ service would require twelve models, and the ERIS service would require seventy-two models (sixty for HVER and twelve for LVER). He explained that we would have a steady-state version of the models. He outlined that for the year 20 models, they would be developed from the 10Y summer and winter sets. Kelsey asked for direction on general scope approval. One member stated his support for the general models but has a question about pulling this into the scope which means pulling this into the annual NERC requirement. There was a question about whether this will satisfy annual TPL requirements. An SPP staff member responded on the sensitivity models and how they will be used for TPL. Kelsey stated that this is written to expand, and the TPL scope goes above and beyond. The same member responded that ITP and TPL are linked, and the base model assumptions are the same. He was basically suggesting that the common model should be the base and not the B-GEM/T-GEM. Chair Raheem commented that we can add a table to the scope to spell out which model sets are used for what purposes to address the concern. The same member suggested having more in-depth discussion about if stability studies are needed to support the entry fee, which goes into scope development in the models which ties to compliance.

Derek Brown (Evergy) moved to approve the motion as presented on the screen:

SPP Staff recommends CPPTF approve the policy direction outlined below, and as described in the 2026 ITP & CPP Transition Assessment scope, for the CPP Transition Assessment (20YR) model framework & recommendation, as well as the technical analysis and framework.

Model Framework & Recommendation:

Recommendations for building L-GIM, B-GEM, and T-GEM models to streamline the protection of NRIS+ (B-GEM), set the foundation for resiliency conditions (T-GEM), and evaluate local generator interconnection constraints (L-GIM)

Incremental CPP Models (~90 models per Future)

- **Local GI outlet: Local Generation Interconnection Models (L-GIM)**
- **Base assessment: Base Generation Expansion Models (B-GEM)**
- **Transfers assessment: Transfers Generation Expansion Models (T-GEM)**

Technical Analysis Framework:

Recommendations for use of CPP model framework under the Invest, Connect, and Manage (ERIS) and Deliver (NRIS+)

GI and ITP Grid Strength Evaluation through Short Circuit Ratio (SCR) screenings to identify potentially "weak" areas of the transmission system.

(refer to Recommendations slide for detail layout)

Heather Starnes (MEC) seconded, and the motion passed.

An SPP staff member added that we will meet Monday to get the purpose table created and included in the scope document for TWG/ESWG review next week.

e. Scope Update and Document Review - Sherri Maxey updated on where we are with the scope development. She shared that she revised the schedule to capture each of the identified scope items. She outlined the items going to January and July MOPC meetings for approval. Following schedule review, she stepped through each section of the scope document. She reminded the group that we will be requesting approval for this scope document in the January 2, 2025 joint meeting and requested that the group provide any comments or feedback as soon as possible.

10-min break until 2:10p

AGENDA ITEM 5 – DISIS TRANSITION TO CPP UPDATE

Caitlin Shank reviewed the current plan for transitioning DISIS into CPP. She outlined the three options developed for the transition approach. She explained that the first option is the cleanest approach and the preference for CPPTF to consider. She then explained the next two options. She highlighted that option three would be the most difficult alternative to achieve just because of the levels of difficulty involved. She outlined the different items to consider. She provided the recommendation for CPPTF to approve option one and to remove options two and three for varying reasons. One member stated that option one generally reflects what people have stated is easier to manage, but he asked what would be done regarding potential harm if someone leaves during this time. He also asked for clarification about removing the harm test. There was significant group discussion around the specific details of options one and two. The same member commented that we are going in the right direction with option one as long as we don't go into too much detail with alternative 1b. Another member restated for clarification that after the first restudy, customers can go to the decision point (DP) and then make a real decision because staying in past DP2 will make it hard to get the deposit back from a restudy later. He asked if staff was ok with withdrawals up to DP2 but not after, and staff response was yes. He then asked what the next steps would be. Caitlin responded that a revision request (RR) would be necessary. Chair Raheem emphasized that the penalty-free withdrawals were purposely staged to encourage early withdrawal, so we can make adjustments going forward with CPP studies.

Steve Gaw (APA) moved to approve the motion as presented on the screen:

CPPTF Recommendation - CPPTF supports option 1 and the exploration of the development of provisions limiting restudies, and the removal of options 2 and 3.

John Krajewski (NPRB) seconded, and there was discussion about including this language in the current CPP tariff RR language that is in development for early 2025 approval and timing in general. Following the discussion, the motion passed.

A different member had a concern about potential delay of the RR language development and how it could impact generators being able to make adjustments. The first member added comments regarding the timing. Another member wants to ensure that there is a way to limit restudies. Chair Raheem agreed that we are taking analytical information from the generator interconnection (GI) study, and it could impact CPP on-going. He stated that we will have more specific provisions to limit restudies to bring to this group at the next meeting.

AGENDA ITEM 6 – CPP TARIFF RR PATH FORWARD

Staff Secretary Russell recapped prior discussions and feedback received that influenced staff's decision to re-evaluate the original timeline that was previously provided to aim towards an April MOPC approval for the revision request. She shared and reviewed the newly revised plan and timeline that would target obtaining July MOPC approval with a September 2025 FERC filing goal. She outlined the requested review and approval dates for CPPTF as well as each of the impacted stakeholder groups. One member shared that we need to set the stage for CPP being a new way of doing business and reflecting that in the tariff language. He added that with the new FERC filing date, if there would be plans to incorporate FERC Order 1920 language and prepare for a single filing. SPP staff members responded that this is still in consideration, but there is no path forward to moving in that direction at this time because the impact of the FERC response to MISO is unknown. The member shared that it could be a relevant consideration into the equation.

AGENDA ITEM 7 – WRAP UP, ACTION ITEMS, AND FUTURE MEETINGS

Staff Secretary Russell reviewed the action items from the meeting and discussed upcoming meeting dates:

- Staff will provide a complete package of how to plan for existing gen sites that have extra capacity (item 3)
- Staff to evaluate a decision point on which year's forecast to base the NUC - will bring slides back to the group next meeting (item 3)
- Staff to lay out the workplan for the scope approvals coming to CPPTF, which will be shared in the 1/21 meeting (item 4a)
- Staff to lay out a workplan on when requested items will be brought back to CPPTF on the model recommendations (item 4b)
- Staff to add a table to the scope to spell out which model sets are used for what purposes in ITP & TPL (item 4c) = complete

ADJOURNMENT

Chair Raheem adjourned the meeting at 3:22 p.m.

Attachments: Agenda, 11/18/24 Minutes, Attendance List

SOUTHWEST POWER POOL, INC.
CONSOLIDATED PLANNING PROCESS TASK FORCE (CPPTF)

December 6, 2024: 9:00 a.m. to 4:00 p.m. CT
WebEx: 2482 737 9441 | Password: 5mnQHKtDJ26
This meeting will be recorded. By attending the meeting, you are consenting to be recorded.

AGENDA

1) **Call to Order and Administrative Items** (10 mins.)
   a) Administrative Items .... Ramunda Russell & Sunny Raheem
   b) Agenda (Approval) .... Sunny Raheem

2) **Consent Agenda** (5 mins.) .... Sunny Raheem
   a) Meeting Minutes - November 18 (Approval)

3) **NUC (Entry Fee) Approach Discussion** (60 mins.) .... Sunny Raheem

Break (5-15 mins)

4) **2026 ITP/CPP Transition Study Scope Updates** (225 mins.) .... SPP Staff
   a) Objectives and Outcomes (10 mins.) .... Sunny Raheem
   b) SCRIPT C3 Common Model Recommendations (45 mins.) .... Eddie Watson
      i) ITP Manual Sect. 10.3 Deadline (Approval)
      ii) ITP Manual Sect. 2.3.2. MPM Waiver (Approval)
   c) CPP Technical Assessment Discussion (90 mins) .... Kelsey Allen
      i) Model Framework & Recommendation (Approval)
      ii) Technical Analysis Framework (Approval)
   d) Short Circuit Ratio (SCR) Screening (20 mins.) .... Doug Bowman
   e) Scope Update & Document Review (60 mins.) .... Sherri Maxey

Lunch Break (30-60 mins)

5) **DISIS Transition to CPP Update** (Approval) (45 mins.) .... Caitlin Shank

Break (5-15 mins)

6) **CPP Tariff RR Path Forward** (15 mins.) .... Ramunda Russell

3) **Wrap-Up, Action Items, and Future Meetings** (10 mins.) .... Ramunda Russell

Future Meetings

Thur, Jan. 2, 2025 (10a-5p)..WebEx
Tue - Wed, Jan. 21 - 22, 2025 (12p-5p / 8a-12p EST)....................................Juno Beach, FL
Wed, Feb. 19, 2025 (9a-4p) .... WebEx
Wed, Mar. 19, 2025 (8a-5p) ....Little Rock, AR

SOUTHWEST POWER POOL (SPP)
CONSOLIDATED PLANNING PROCESS TASK FORCE (CPPTF)
November 18, 2024, 9:00 p.m. to 4:00 p.m.
WebEx 2497 833 6035

MINUTES

AGENDA ITEM 1 – CALL TO ORDER AND ADMINISTRATIVE ITEMS

Chair Sunny Raheem called the meeting to order at 9:04 a.m., November 18, 2024, with a quorum present. Staff Secretary Ramunda Russell provided an overview of meeting procedures and read the antitrust statement. Heather Starnes was noted as a proxy for John Krajewski. Chair Raheem reviewed the meeting agenda (Attachment A) and provided a high-level summary of the agenda items. Heather Starnes (MEC) moved to approve the agenda as presented. Commissioner French (KCC) seconded, and the motion passed unanimously. It was noted that approvals were not being recommended for items 4.d. or 6 at this time, but they will be brought back to the December 6 meeting.

AGENDA ITEM 2 – CONSENT AGENDA

Chair Raheem reviewed the consent agenda item for the November 1, 2024, draft meeting minutes (Attachment B). Heather Starnes (MEC) moved to approve the motion for the consent agenda item. Alan Myers (ITC) seconded, and the motion passed unanimously.

AGENDA ITEM 3 – 2025 MEETINGS

Staff Secretary Russell recapped the previous meeting dates as listed. One member offered his thanks for all the work on the meeting dates. There was some group discussion about other meeting conflicts later in the year. The group discussed who would like to host this group for in-person meetings, and there was discussion on piggybacking on SAWG and partnering with TWG/ESWG for joint meetings. Chair Raheem reminded the group that we needed to have more meetings earlier in the year due to approvals needed from MOPC by Q3 and listed target locations for Q1 to get finalized.

Heather Starnes (MEC) moved to approve the 2025 meeting schedule dates as displayed on the screen.

Steve Gaw (APA) seconded, and the motion passed unanimously.

Chair Raheem mentioned that staff will follow up by end of week to confirm the in-person locations for Q1.

AGENDA ITEM 4 – 2026 ITP/CPP TRANSITION STUDY SCOPE UPDATES

a. Sherri Maxey reviewed the updated scope schedule. She outlined which items were approved in the TWG/ESWG meetings and have approved scope language to add into the document. She outlined what topics would be included in each section. She laid out the plan for requesting approvals in upcoming meetings. Chair Raheem recapped that there is a lot of work going on, and the scope will include models to begin drafting language in the siting manual and ITP manual. He summarized that the scope document will be posted next week.

b. Colton Stanton reviewed the siting zone allocations. He mentioned that the six LOLE zones will be the same as identified in the FERNS study to use for subregional siting direction in the CPP transition study. He explained that we would use the GI queue data and compare it to the FERNS study data. He explained the GI queue data sets to be used and how the numbers compared across the different zones. He discussed the solar additions (load percent by zone) and compared the FERNS average data to the 2025 ITP siting values and FCITC limited GI requests. One member mentioned that we should look at this from the standpoint of creating additional capacity for interconnection due to what people consider (where demand would be and where open capacity is on the system). He stated that we need to think about how we want to see capacity developed over the 20-year period to give us more cost-effective locations for where generation will be added. Chair Raheem mentioned that we discussed internally to split this evaluation for year 10 and year 20. He stated that the FCITC and generation siting review will help us. One meeting attendee asked what the reason was to do the Kansas split for the transition. Chair Raheem agreed that we should consider Kansas as one generation zone during the CPP transition study. An SPP staff member chimed in that we should see better transfer capability for the upgrades. Colton pointed out that the dashed red line is the load ratio share of each zone in the footprint to see how much generation is being added compared to the current look to use as a reference. Colton then discussed the storage additions with the same comparison. He also discussed the wind additions and showed that there was quite a bit of variance across the data sets. He explained that due to cost restrictions (lower interconnection costs and upgrade costs), there was a lot of load projected for the Southeast zone. One member asked about stability from the Northeast perspective. Chair Raheem mentioned that the FERNS study doesn't have projections of the stability limits in the Northeast. Colton explained the approach to calculate the FCITC limited GI requests. He outlined the options discussed in the ESWG meeting and requested input on assumptions to bring forth as recommendations. Another meeting attendee mentioned that option one made more sense because developers in the area have done due diligence, so keep it close to the GI queue instead of using the FERNS study data. One member agreed with the attendee to identify the right transmission buildout to facilitate the transmission on the system because it has already been vetted. Another member asked for meeting material to involve during this discussion. Colton mentioned that discussion will continue at the special joint TWG/ESWG meeting being held the following day. He then outlined the siting process changes - two repository postings and new ranking methodology to be developed. Chair Raheem asked if the numbers should be presented at the December GIAG meeting, and one member noted that we should look at this. Chair Raheem summarized that next steps would be to take this to the TWG, ESWG, and GIAG for feedback.

15-min break until 11:00a

c. Joshua Norton reviewed what was presented and approved at the ESWG meeting on the futures data. He outlined the data sources that were used in developing the scenarios. He then reviewed the different scenarios. He outlined the futures in the scenarios and compared them to previous studies. He outlined the next steps for the ESWG approval and plans to take to the January MOPC meeting for approval. One member asked if we already have numbers related to siting zones instead of just percentages to share in order to make a better decision. Joshua mentioned that he could work with Colton on this.

d. Kelsey Allen presented a streamlined version of the presentation that he gave in the last CPPTF meeting. He recapped the discussion and asked the group to consider what needs to be documented for guidance to get approvals from the working groups. He highlighted the policy items for consideration in the technical design. He reviewed the holistic assessment option of the three assessment types (base ITP/regional planning, consolidated regional planning and GI, and base GI/initial reliability). He detailed the consolidated regional planning and GI (CPP) option. One member agreed that this aligns with what was discussed on deliverability areas and transfer capability and wanted to confirm that we are getting ahead of planning reserve margin (PRM) changes on the GI side. He also asked if targeting megawatt amounts will be included in scoping the CPP transition study. Kelsey responded that there is work in the resiliency space that has not yet been included in this concept. He added that he will look at transfers across the system to generate values for inclusion in the technical assessment design. Kelsey showed graphical representations of the study zones to better demonstrate the transfer generation expansion model (T-GEM) and base generation expansion model (B-GEM) plan. He mentioned that we want to limit the number of models used in the analysis and determine if it meets our objective. Kelsey explained the technical assessment overview and cost responsibility diagram showing the three assessment types. He showed the listing of optimization ranking analysis. One member mentioned that he had a struggle with the CPP option because of the cost sharing. Kelsey agreed that there will be a lot of work to determine what cost sharing will look like in this CPP bucket construct. He stated that there will be co-optimization across the portfolio. Another member summarized for clarification that if we have economic and reliability projects, then the base ITP would reflect firm service for load; the CPP bucket would show the generation & load that would be needed to maintain inter- and intra- availability, and this option would serve multiple reliability needs; the GI bucket would be reliability as well which is the interconnection customers. Kelsey agreed with the member that we need to find the right nomenclature as well as the right optimization ranking. That member responded that we need to know which customers to target in each. He also mentioned that we need to define what we are trying to preserve and the limits we are trying to maintain. He ended with a suggestion to add ERIS resources and load in the CPP bucket. A third member stated that he is having trouble with digesting this information because he is unclear about what the ranking references (needs, cost sharing, etc.). He also had a question on the optimization ranking and if it is an indication of solving the problem or just the order of coming up with how to solve the needs. Kelsey responded that it is a preference of solutions, but the ranking alone will not be the selection criteria. Kelsey outlined the poll questions for which he is requesting group input.

53-min lunch break until 1:00p

After returning from lunch, Kelsey provided a recap of the questions for which he wants group feedback. Voting ended with thirteen responses to the questions. Kelsey asked for voting rationale feedback from those that voted.

We returned to agenda item 4a to get approval for the scope development schedule plan.

Steve Gaw (APA) moved to approve the motion as presented on the screen:

SPP staff recommends the CPPTF approve the planned schedule for scope development shown on slides 3-4, as presented.

Heather Starnes (MEC) seconded, and the motion passed unanimously.

e. Caitlin Shank recapped that FERC approved DISIS waivers to extend the close of DISIS 2024 cluster window to 3/1/2025 and delay the start of phase 1 until 9/1/2025. One member asked what would be impacted by the 5/1/2026 dates. Caitlin responded that DISIS 2023 and prior would fall under the current DISIS process, and starting with 2024 DISIS will be the transition point into CPP. She explained that Decision Point 2 (DP2) would be delayed because of expecting a delay of the network upgrade contribution (NUC). A meeting attendee asked that if there is a delay of DP2 past 5/1/2025, will the options still be the same. He asked if there could be clarity of words added to the slide. Another meeting attendee commented that clarity is needed on the options if the DP2 date gets delayed. He also asked if there is an option to stay in the original 2024 DISIS without being forced into the CPP study. Caitlin responded that remaining in the DISIS will be agreement to transition to CPP. Chair Raheem explained that we will look at sites from the study to then look at the queue of customers and also look at siting to estimate the network upgrades. He explained that if DISIS is not ready by the effective date of CPP, then the customers will have the option (or requirement) to move over to CPP. The first meeting attendee commented that having it voluntary is needed at this stage in the decision. One member agreed with both meeting attendees and pointed out that we need to think through consequences from a legal perspective. He stated that we need to understand what answers are needed to mitigate risk of voluntary transition to CPP. Caitlin agreed that allowing clusters to diverge will make things complicated. The member then asked what the decision timeline is to come up with a plan of action to address this. Chair Raheem responded that we need this to be able to develop the tariff revision request. The same member asked if we could show what the risks are of doing this in 2024 compared to other options. Another member had additional concerns about the timing of this because people entered into 2024 DISIS with the plan of getting interconnection quicker and if transitioning could add one year to the plan, then it could cause an issue. A third meeting attendee asked if the 2024 DISIS DP1 and DP2 will happen as usual. A third meeting attendee stated that this is helpful to SPP because we get more data but it doesn't incentivize customers to enter into the queue request, so the attendee is asking for more information to make a more informed decision. Caitlin responded that an incentive is that customers would take the points of interconnection (POI's) for the 5-year models, and 2026 DISIS and beyond would take the optimal POI slots which would be to look at using the planning horizons as the queue. Another member reiterated that in order to stop the restudies, you will need to have a transition. He suggested that staff should develop the transition procedures to hold people harmless and provide the same level of certainty. Chair Raheem responded that part of POI demands includes DISIS 2024 as we know it today and will get updated as we finalize the queue next year. A different meeting attendee had concerns regarding timing and wants to know why transition can't occur at the start of 2025 and just complete DISIS 2024 as planned. Chair Raheem responded that the purpose of the transition is to reduce the restudies from 2024 but it would be a cleaner transition to enter into 2025 or 2026. One member asked how we would handle customers who drop out of the 2024 DISIS and if it was worth the risk of the other factors. Caitlin resumed with explaining the queue priority. She also outlined a list of risks under the voluntary approach for joining CPP. Chair Raheem mentioned that we should lay out responses to two options for next meeting. For the option showing a transition to 2024 DISIS, we need to show an example of what would happen to the remaining two customers and how the cost certainty would be determined.

AGENDA ITEM 5 – NUC (ENTRY FEE) APPROACHES

Chair Raheem resumed discussion from the last meeting. He stated that we would preview the types of cost sharing between generation and load. He requested feedback on the EHV flat fee approach and benefit-to-cost (B/C) uplift approach. He summarized a good indicator of what customers would pay historically. He reiterated that the $125/kW is a good ceiling but average costs are $65/kW, and one-third of the customers are connecting at or below $15/kW. He depicted a scattered plot that equates to decisions at the time of NUC commitment. He explained that there was a wide cost range, and the average cost is around $46/kW. One member asked if a similar snapshot was being created for phase two. Chair Raheem stated that at DP2, we are seeing higher costs ($65 - $85/kW) but they are due to other requests dropping out or some other reason. He mentioned that we could bring the DP2 cost snapshot back to the group. He then showed a visual of how much contribution is expected for different types of upgrades. The thought was that the displayed cost assignment would be mostly assigned to load. The transfer assessments would be a combination of GI contribution customers. The B/C measures would continue in the CPP approach. For projects that don't meet the B/C ratio = 1.0, it would need to be determined if GI customers can contribute the cost needed to bring the B/C ratio up to 1.0. A meeting attendee asked for clarification that if load in the ITP study has a greater than 1.0 B/C ratio, then the upgrade would be paid for by the customer. Another member still had questions about how to co-optimize and where the cost sharing comes into play. A third member asked about EHV vs. HV designations on the GI side. Chair Raheem responded not to make it so dependent on the usage. He explained how to calculate using the ERIS EHV flat fee approach and outlined the inputs used in the calculation. He then explained the justification for using the ERIS EHV flat fee. A meeting attendee asked if the flows (7.7%) are firm resources delivering to firm load or if there is a price difference and non-firm energy flows is included. Chair Raheem explained that this was done in ProMod and includes both firm and non-firm load. One member asked if the flows associated with load is demand combined with resources assigned to load in other models. Chair Raheem responded that this usage looks at all future generators in the resource plan and their utilization on the system. Another member asked if there was a breakout into smaller regions. Chair Raheem responded that EHV was not broken down into small subregions. The same member then asked how the concept for the EHV flat fee drives developers to find the most economical and beneficial generation locations. Chair Raheem responded that this is included in the NUC and would be added to incremental upgrades needed if a generator is trying to interconnect at a suboptimal location. These would be the guardrails included in the entry fee components. Chair Raheem stated that there should be another slide describing what a suboptimal cost looks like. He then asked if there were thoughts on this approach. A meeting attendee asked if there is more low-cost generation that SPP would like to access, then the standard flat rate wouldn't apply so how is this taken into account. Chair Raheem stated that this was trying to justify a cost from a regional perspective to show use from generators on how they utilize the EHV system from an 8760 simulation. He stated that we would discuss this internally. Another member mentioned that it would be beneficial to estimate a proxy in each category that would show an interconnection cost in the area including the JTIQ number. Chair Raheem reminded that the future benefit for GI customers must be realistic.

AGENDA ITEM 6 – SCRIPT C3 COMMON MODEL

Eddie Watson provided an overview of the SCRIPT C3 model description. He summarized the common base model set configuration and explained the proposed changes. He explained what has been completed and what is currently in progress in a status update.

AGENDA ITEM 7 – CPP TARIFF RR REVIEW - ATTACHMENT O REVIEW

Staff Secretary Russell summarized the progress on the Attachment O language revisions. She explained that the language changes were developed in alignment with the current tariff format. The request was made to get staff's feedback on the redlines made to date. She then provided the gameplan for getting the language developed, bringing it to the group for review, and outlining next steps to get this to the MOPC for approval to initiate the FERC filing in mid-2025. She reported that a month-by-month schedule will be built with target dates to share in the December 6 meeting.

AGENDA ITEM 8 – WRAP UP, ACTION ITEMS, AND 2025 MEETINGS

Staff Staff Secretary Russell reviewed the action items from the meeting and discussed upcoming meeting dates:

- Staff secretary to find out how long meeting recordings are stored in Webex = complete
- Staff secretary to reach out to Jason Tanner for hosting 1/21-1/22/2025 meeting in FL = complete
- Josh and Colton to work on developing numbers related to siting zones vs. load percentages to share for the group to be able to make a decision (item 4c)
- Kelsey and staff to create a better version of slide 12 in upcoming war room session that more clearly outlines the objectives (item 4d)
- SPP staff to provide what the risks are of voluntary transition in 2024 compared to other options (item 4e)
- SPP staff to develop the transition procedures to hold people harmless and provide the same level of certainty (item 4e)
- SPP staff to develop an additional slide describing what a suboptimal cost looks like (item 5)
- SPP staff requested to develop a table/chart to show proxy estimations in each category that would show an interconnection cost in the area, including the JTIQ number (item 5)
- SPP staff to follow-up and include model set approval in the scope item (item 6)
- Ramunda to build a month-by-month revision request schedule with target dates to share in the Dec. 6 meeting (item 7)

ADJOURNMENT

Chair Raheem adjourned the meeting at 4:01 p.m.

CPPTF ATTENDANCE LIST, DECEMBER 6, 2024

Attendance list from WebEx registration & In-Person. Symbols: * denotes CPPTF Member and † denotes proxy.

#	Name	Organization
1	Sunny Raheem (Chair)*	SPP
2	Alan Myers*	ITC
3	Adam McKinnie*	PSC
4	Andrew French*	KCC
5	David Mindham*	EDPR
6	Derek Brown*	Evergy
7	Heather Starnes*	MEC
8	Jarred Cooley SPS*	SPS
9	John Krajewski*	NPRB
10	Michael Wise*	GSEC
11	Steve Gaw*	APA
12	Steve Hohman*	OPPD
13	Ramunda Russell (Secretary)*	SPP
14	Aaron Stemplewicz	EJ
15	Adam Schieffer	OPPD
16	Adam Snapp	OG&E
17	Afshin Salehian	SPP
18	Ahmed Magdi	EPE
19	Alyssa Culver	SPP
20	Andrew Daro	NPPD
21	Angela Sartori	SPP
22	Annie Minondo	NRDC
23	Austin Baccus	SPP
24	Bernie Liu	XCEL
25	Brad Lafler	CES
26	Brian Rounds	AESL
27	Bridget Sparks	AES
28	Britney Lloyd	SPP
29	Caitlin Shank	SPP
30	Call-in User_2	
31	Call-in User_4	
32	Call-in User_5	

33	Calvin Daniels	WFEC
34	Casey Cathey	SPP
35	Charles Locke	SPP
36	Chris Davis	SPP
37	Chris Jamieson	SPP
38	Christine Aarnes	Sunflower
39	Clifford Franklin	Sunflower
40	Conf 1F Room 117	SPP
41	Conor McKenzie	AEU
42	Dana Shelton	Stone Pigman
43	Danny Johnson	SWPA
44	Dennis Reed	MWRC
45	Diana Gastelum	GPISD
46	Don Frerking-SPP	SPP
47	Doug Kouskouris	AEP
48	Dugan Marieb	PGR
49	Eddie Watson	SPP
50	Eric Henderson	SPP
51	Erynn Kuehl	Evergy
52	Greg Wannier	Sierra Club
53	Hannah Jones - EPE	EPE
54	Jake Chapman	Sisung
55	Jason Mazigian	BEPC
56	Jay Caspary	TGA
57	Jennifer Swierczek	SPP
58	Joe Price	Samsung
59	John O'Dell	SPP
60	Joshua Norton	SPP
61	Joshua Pilgrim	SPP
62	Justin Grady	KCC
63	Katherine Rogers	SPP
64	Kelsey Allen	SPP
65	Ken Wei	NextEra
66	Lee Elliott Invenergy	INVENERGY
67	Lisa Tormoen Hickey	Interwest
68	Marisa Choate	SPP
69	Mark Whitson	SPP
70	Mateusz Neska	StromPower
71	Maya Nevels	APA
72	Megan Damron	SPP

73	Michael Wegner ITC	ITC
74	Natasha Henderson	SPP
75	Naved Khan	SPP
76	Nick Parker	SPP
77	Nicole Wagner	SPP
78	Nigel Dunham	ACE
79	Paul Antony	GA
80	Ray Ward	WAPA
81	Regan Fink	PGR
82	Rishabh Gupta	PST
83	Robert Pick	NPPD
84	Ryan Tuter	OMPA
85	Shawnee Claiborn-Pinto	PUCT
86	Sherri Maxey	SPP
87	Spencer Magby	SPP
88	Susanna Padilla	SPP
89	Tom Michelotti	NWE
90	Tyler Berton	AES