State-Provincial Steering Committee

2011 Study Request to the Western Electricity Coordinating Council

January 31, 2011

The State-Provincial Steering Committee (Steering Committee or SPSC) requests that the Western Electricity Coordinating Council (WECC) conduct the following transmission expansion study as part of the Transmission Expansion Planning Policy Committee's (TEPPC) 2011 work plan.

The Steering Committee anticipates that TEPPC will continue to build studies around a reference case, and makes our recommendations for the 2011 study cycle under the assumption that there is justification for developing a reference case on an annual basis in order to provide ongoing updates. Our reference case recommendations add new elements beyond those offered for the 2010 study cycle.

In 2010, the Steering Committee recommended a **Breakthrough Technology Case** for the years 2020 and 2030. This study request was accepted. Subsequently, the Steering Committee modified its request to apply only to 2030, in order to encompass a broader scope of new technologies. We reiterate our request for the **Breakthrough Technology Case** in conjunction with the availability of the long-term planning tool.

TEPPC also accepted the Steering Committee's request for a **Carbon Reduction Case** that had targets for 2020 and 2030. We appreciate the work underway in evaluating the 2020 study case and reiterate the importance of this case as we look to the 2030 study.

The Steering Committee requests that WECC examine several new scenarios in the 2011 study cycle. Our recommendations for the Reference Case and the specific scenarios are described below. The DSM study requests refine and expand upon the DSM study request made in 2010. The Steering Committee and its work groups will provide TEPPC with more detailed assumptions and information during the study cycle to model these scenarios.

The Steering Committee supports the Western Governors' Association's request for a 10-year and 20-year prolonged drought and climate change study.

1. Reference Case: Utility IRPs and Plans

The Steering Committee recommends that the Reference Cases for the 10- and 20-year studies be guided by existing utility integrated resource plans (IRPs), other utility-level information, and current state, provincial and federal policies, with appropriate review from state/provincial policy makers and regulators.

In 2010, SPSC submitted a request for a Reference Case that would be based on current utility integrated resource plans (IRPs) or related utility plans. The SPSC's DSM Work Group reviewed the 2020 load forecasts from Balancing Areas (BAs) and found that many forecasts did not incorporate all federal and state DSM policies. The DSM Work Group developed state-adjusted loads and these load forecasts were applied in the 2020 Reference Case, as distinguished from the original BA load forecasts used in the 2020 Base Case.

This proposed 10-year Updated Reference Case would add new information from the most recent IRP or other resource plans, and updated load forecasts for BAs that fully accounts for demand-side policies of energy efficiency, demand response, and distributed generation (DG). A new element to this request would be the addition of distributed generation policies.

The Updated Reference Case would incorporate the following assumptions:

- Current state/provincial laws and policies related to resource development
    - Current state/provincial RPS requirements and policies (including distributed generation policies)
    - Performance standards for emissions
- Load growth would be based on balancing area load forecasts consistent with state/provincial and federal policies on energy efficiency, DSM, and demand response

The SPSC intends to engage and collaborate with utility resource planners through the Resource Planners Forum. We expect this will serve to better refine the IRP assumptions for accuracy and reasonableness for purposes of the final modeling scenario.

<u>What we hope to learn from this scenario</u>:

1. Update the Reference Case modeled by TEPPC to ensure it is using the most current and updated information available.
2. Ensure that load forecasts reflect existing DSM policies and new information on distributed generation.
3. The transmission needed to support the proposed future load growth and generation needs that are projected by the regional utilities.

2A. Scenario DSM-1: West-Wide High DSM/DG Scenario

The Steering Committee requests both a 10-year and 20-year high demand-side management (DSM) and high distributed generation (DG) scenario that reduces loads to specified levels relative to the Reference Case, reflecting implementation of aggressive DSM and DG policies throughout the Western Interconnection. The load forecasts developed for this scenario will also be incorporated into the 20-year Technology Breakthrough case.

The West-wide High DSM/DG scenario will build upon the 10-year High DSM scenario modeled within the 2010 TEPPC study program by:

- Incorporating additional load impacts associated with high penetration of DG
- Solar photovoltaic (PV) technology would be part of the DG resource portfolio
- Extending energy efficiency and demand response potential estimates out to 20 years
- Refining the underlying assumptions used to estimate energy efficiency and demand response potential

<u>What we hope to learn from this scenario</u>

1. Further improve TEPPC's capacity to model energy efficiency, demand response, and distributed generation resources within both the 10-year and 20-year modeling platforms.
2. Assess changes in congestion patterns and needs for new transmission capacity if future loads throughout the Western Interconnection are reduced through aggressive DSM and DG policies.
3. Characterize differences in the implications of a high DSM/DG future for transmission congestion and capacity needs between 10-year and 20-year time horizons; this issue is of particular importance given the high reserve margins under the 10-year High DSM scenario within the 2010 TEPPC study.

2B. Scenario DSM-2: Geographically Targeted High DSM/DG Scenarios

The Steering Committee requests <u>a set</u> of 20-year scenarios in which High DSM/DG resources are placed only in those specific regions where it would likely alleviate transmission congestion identified within the Reference Case. Developing the specific scenarios would consist of:

- Identifying the most congested paths in the 20-year Reference Case scenario
- Selecting a manageable number of those paths (three to five) in which higher levels of DSM and DG could be expected to mitigate the congestion
- Run a separate case for each path, in which the high DSM/DG load forecast would be assumed for the region downstream of the congestion; for all other regions, the Reference Case load forecasts would be assumed

<u>What we hope to learn from these scenarios</u>

1. Better understand the extent to which targeted deployment of DSM and DG resources in the Western Interconnection could reduce congestion costs and/or obviate the need for specific transmission capacity additions.
2. Identify those regions in which high DSM and DG has the greatest potential and value for relieving transmission congestion.

3. Alternative California Import and Westwide REC Trading Policy Scenarios

Under current policies, California's 33% RPS requirement accounts for about two-thirds of the incremental renewable generation expected to be needed to meet all RPS requirements across the Western Interconnection by 2020. California strategies to meet its RPS goals could have a profound impact on future imports or delivery of power into California, and the corresponding demand for new transmission. TEPPC's 2019 Base Case and the 2020 Base and Reference Case assumed California's incremental renewable imports amounted to about 20% to 25% of the net short of energy needed to meet 33% RPS.

This study request explores the transmission implications if decisions in California lead to three different approaches to meeting RPS requirements:

(a) Policy makers change the RPS statute to limit new qualifying renewable energy to instate resources.
(b) California utilities find that out-of-state renewable resources are cost competitive such that imports rise to 45% to 50% of the RPS net short requirement, and state policy requires the power be delivered into the state.
(c) Policy makers across the Western Interconnection adopt a policy to accept unbundled renewable energy credits (RECs) to meet RPS targets, and thereby remove the need to deliver renewable power to specific markets.

Option (a) assumes the state RPS is limited to instate renewable energy resources and then there would be less development of out-of-state resources for imports to California. The drop in imports to California would likely reduce the demand for transmission to deliver that power.

Option (b) assumes the polar opposite with an increased demand for imports coupled with the need to deliver the power into the state. The potential areas with the best and lowest cost options for California may be informed by TEPPC's 2019 geographic relocation cases. These cases shifted 12,000 GWh of renewable energy (about equal to 3000 MW of wind capacity) out of California into 8 different locations across the West. Additionally, two aggressive wind cases to be run this year shift 24,000 GWh of energy out of California to Wyoming and Montana. This study would seek to identify a cost-effective portfolio of potential renewable imports.

Option (c) inquires about the implications of allowing REC trading to meet RPS requirements without requiring the physical delivery of the power. If policy makers across the Western Interconnection approved unbundled RECs for RPS compliance, utilities could purchase RECs from out-of-state resource rich areas without the need for new transmission to deliver the power. This could promote increased development in areas with high quality renewable resources and low loads, further complicating the operational challenges of integrating variable generation.

What we hope to learn from this scenario

1. Potential implications for transmission if California pursues a renewable energy strategy that deviates from recent TEPPC Reference Case assumptions.
2. An unbundled REC policy could put significant pressure on the development of areas with high quality renewable resources and exacerbate the operational challenges of integrating high levels of variable generation in such areas.

4. Lower Renewable Generation Scenario

Past TEPPC studies have specified renewable generation levels needed to meet RPS targets under current policies or specified a higher penetration level above the RPS targets. This study explores the transmission implication if future renewable development is less than the RPS targets anticipated from today's perspective.

Future renewable energy development may fall short of current RPS policies for the following reasons:

- The cost of renewable energy rises relative to other resources and cost cap provisions in state RPS statutes become binding over the next 10-years. At least five states have cost caps in their RPS statute (Colorado, New Mexico, Oregon, Utah and Washington).
- Federal tax incentives (production tax credit or investment tax credit) are eliminated by Congress. Without these incentives, it becomes significantly more expensive for utilities to purchase renewable energy and regulatory commissions decide against putting this cost on the ratepayers.
- State legislatures or regulatory commissions reverse the current RPS provisions.

Multiple factors may come into play to hinder the attainment of RPS statutes. For simplicity, this study request assumes that states with RPS requirements end up reaching 50% of their current respective RPS target.

This scenario will assume California will meet its 33% RPS target.

What we hope to learn from this scenario

1. Potential implications to transmission if a combination of factors serves to hinder renewable energy development below its expected development.

5. Alternative Southwest Solar Development Scenarios

Solar generation is potentially the biggest wildcard in the future build out of renewable resources and the corresponding demand for new transmission. Wind generation has experienced declining costs over the past two decades and is currently a cheaper option to solar. More recently, however, the cost of solar PV has dropped enormously in the last 2 years. Future technological innovation and economies of scale could lower the cost of PV further and bring down the cost of solar thermal. This proposed scenario examines the impact which widespread deployment of large-scale solar generation in the Southwest would have on the demand for and location of new transmission. An important take away from the Resource Planners Forum meeting last June was that utility resource planners are looking in their own backyard for renewables to meet their RPS requirements.

The same overall scenario, with opposite assumptions about the future cost competiveness of solar resources in relation primarily to wind resources, can be used to examine transmission needs in a future without significant large-scale solar resource development.

We request a scenario which examines the transmission impacts under the following assumptions:

- Concentrated solar power costs (i.e., thermal and/or PV) drop to a level where their development and delivery throughout the Southwest region is competitive relative to wind resources on an energy basis and for on-peak capacity.
- Large-scale solar deployment becomes very cost competitive and highly valued to meet peak loads, to an extent that at certain times solar generation is exported to other parts of the interconnection. (This could result in complementary flows of wind and solar generation over the transmission system.)
- Solar power costs do not drop relative to wind resources resulting in significant transfers of wind from the northern and eastern portions of the interconnection to the Southwest.

<u>What we hope to learn from this scenario</u>

1. Transmission needs associated with deployment of large-scale solar power resources to meet RPS requirements in the Southwest
2. Transmission needs if there is not widespread deployment of solar in the Southwest
3. Transmission needs if solar generation in the Southwest is exported to other parts of the interconnection.

6. Plant Retirements in the Low Carbon Cases

In 2010, SPSC requested a Low Carbon Scenario that specified two carbon targets: (a) 17% below 2005 levels by 2020; and (b) 42% below 2005 levels by 2030. SPSC's request identified the shutdown of coal fired generation resources as a potential mechanism to reaching these carbon reduction targets. The 2020 Low Carbon Case was modeled without adding additional coal plant retirements and the 2030 Low Carbon Case was not modeled in 2010.

The Steering Committee requests a follow up study of the Low Carbon Cases that incorporates potential coal plant retirement futures in 2020 and 2030 as follows:

a. 2020 coal plant retirements identified by: (i) state/provincial policy or regulation; and (ii) utility announcements or plans.
b. 2030 coal plant retirements identified by (a) above, and plants expected to face significant upgrades to meet air quality regulations for conventional pollutants currently being promulgated by the U.S. Environmental Protection Agency.

7. Increased Utilization of the Existing Grid Scenario

The Steering Committee requests a study of the transmission impacts from an improved utilization of the existing grid. The study would examine the combined effect of evolving operational efficiency gains and advanced grid technologies, such as deployment of new transmission technologies such as synchrophasers, and volt-var optimization/conservation voltage that serve to reduce loads and line losses, and institutional reforms that reduce friction in the system through an Energy Imbalance Market or the proposed Joint Initiatives.

TEPPC relies on a production cost model to evaluate 10-year cases. Under current practices, the production cost model generally assumes a perfect dispatch in a frictionless world. There are no institutional barriers, bilateral contracts, or imperfect information to inhibit the selection of the least cost solution to meet loads for every hour over an entire year. In order to use the production cost model to evaluate the gains from innovations that improve the operation of the system, it will be necessary to model the system with its current institutional rigidities or friction. This type of work is currently being pursued to evaluate the benefits of an energy imbalance market, balancing area consolidation, and other changes.

This scenario supposes that the following technology and operational changes have been implemented across the Western Interconnection by 2020:

- **Energy Imbalance Market –** creation of a voluntary energy imbalance market with intra-hour scheduling across much of the West. This can be simulated by modifying dispatch patterns and lowering hurdle rates between production and load zones.
- **Joint Initiatives**– widespread implementation of dynamic scheduling and a transaction accelerator (I-TAP).
- **Synchrophasor Technology –** widespread use of phasor measurement units for transmission system monitoring, in conjunction with advanced synchrophasor applications for system planning and operations, that enable greater throughput and improved reliability across existing (and new) transmission assets. This can be modeled by increasing path limits on the many transmission paths that are presently constrained by conservative thermal and voltage limits, and possibly some that are now stability-limited as well. Throughput on many of these paths could potentially increase by as much as 3-5% when managed using real-time phasor data and grid conditions. This could be modeled by raising the path limits on numerous individual major western transmission paths to reflect more tailored operational (thermal, voltage, stability) constraints informed by synchrophasor technology.

- **Volt-var optimization and conservation voltage reduction** leveraging distribution automation – current utility pilots of the impacts of volt-var optimization and conservation voltage reduction suggest that these distribution-level techniques could reduce loads by 1-2% (potentially higher during peak periods) and reduce line losses (again, with greater beneficial impact during peak loads). While it is not clear how these technologies would interact and net out relative to load-targeted end use energy efficiency, it is worthwhile to examine the potential impact of uniformly lower demands. This could be modeled by assuming that VVO and CVR are implemented by utilities within all of the major load centers of the West (i.e., assuming that it is cost-effective to implement these techniques within concentrated metro area loads, but not within areas with sparser loads), and reduce demand levels in those urban load areas by 1.5%.

This scenario would be run against the study year Reference Case; all modeling changes would affect supply side conditions (transmission path limits and hurdle rates), with limited changes to demand levels to reflect the demand-lowering impacts of Volt-var optimization and conservation voltage reduction.

<u>What we hope to learn from this scenario</u>

1. The potential cost savings from more efficient grid operation
2. The potential effect on resource development patterns and transmission flows from more efficient grid operations
3. The impact of these changes upon generation and congestion costs
4. The impact of these changes upon ability to meet state RPS requirements
5. The impact of these changes upon carbon emissions.

8. Variable Generation Integration Analysis

The Steering Committee requests that WECC develops a screening tool to evaluate the technical feasibility and cost of integrating generation assumed in cases with substantial variable generation. The evaluation should identify measures to mitigate technical and cost hurdles. This integration screen would be analogous to the reliability analysis that subregional planning groups will be doing on current case studies.

TEPPC's current modeling efforts are being validated using improved data on loads and generation assumptions, historical analysis of transmission flows, and analyses of load and resource balances. However, we currently do not have a tool to evaluate the capability of the system to integrate high levels of variable generation.

The SPSC will collaborate with the National Renewable Energy Laboratory to assist WECC in developing a tool to evaluate the feasibility of integrating high levels of variable generation. NREL has been evaluating how to measure the flexibility of the power system and has begun to identify features of such an evaluation tool. Depending on how long it takes to develop the tool, it could be tested against some 2010 study cases as well as 2011 study requests that include large amounts of variable generation.