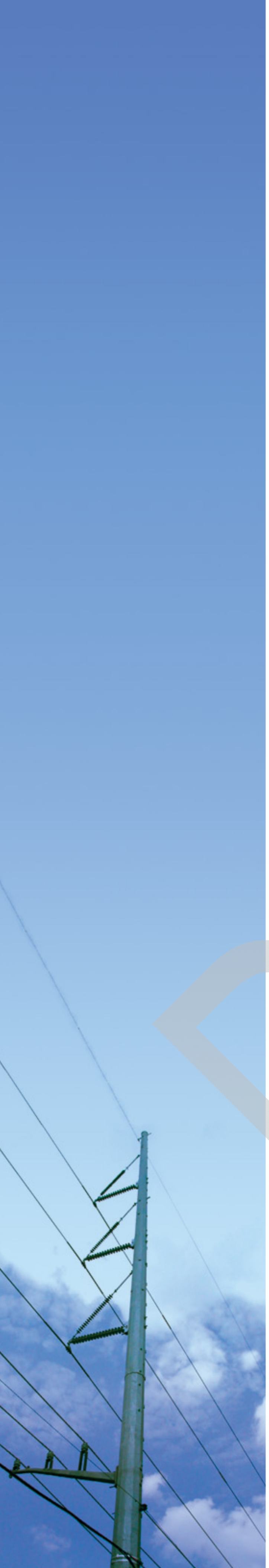

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SPP Priority Projects Report

MAINTAINED BY
SPP Engineering/Planning

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SPP Southwest Power Pool

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Introduction

With the ever increasing prominence that electric transmission is taking in the federal energy policy debate, the Southwest Power Pool (SPP) Board of Directors (BOD) formed the Synergistic Planning Project Team (SPPT) to develop recommendations for SPP to prepare for this national endeavor. This high level policy team was charged with providing sufficient direction to SPP Staff (Staff) and members to address comprehensive transmission planning and cost allocation methodologies. The members of the SPPT included:

- Paul Suskie; Chairman, Arkansas Public Service Commission
- Barry Smitherman; Chairman, Public Utility Commission of Texas
- Kelly Harrison; Vice President – Transmission Operations and Environmental, Westar Energy
- Ricky Bittle; Vice President – Planning, Rates and Dispatching, Arkansas Electric Cooperative Corp.
- Rob Janssen, President and General Manager, Dogwood Energy
- Ric Abel; Managing Director, Prudential Capital Group
- Carl Monroe; Executive Vice President and COO, Southwest Power Pool
- Mark Rossi, Accenture, facilitation and administration

In April 2009 the SPPT submitted its report and recommendations to the Markets and Operations Policy Committee (MOPC), the BOD and Regional State Committee (RSC). The report recommended Staff implement an Integrated Transmission Planning (ITP) process to create a robust, flexible, and cost-effective transmission network for the SPP footprint. The ITP process is currently being developed by Staff and stakeholders with a final proposal to be submitted to the MOPC, BOD, and RSC in October 2009.

In transitioning to the new ITP process, the SPPT also recommended that Staff evaluate and recommend to the RSC a list of Priority Projects within six months for approval by the BOD. The Priority Projects are intended to capture near-term opportunities associated with the heightened focus of electric transmission expansion. In conjunction with the evaluation of the Priority Projects, the SPPT recommended the RSC select an existing cost allocation methodology or a new "highway-byway" cost allocation methodology to be used for approved Priority Projects.

This report describes the development of the Priority Projects, the scope of analysis performed on the projects by Staff and consultants, and the results of that analysis. Staff respectfully submits this report to stakeholders, the MOPC, the RSC, and the BOD for consideration.

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Background

Perspective on Transmission Planning

The Southwest Power Pool (SPP) and its Members are transitioning from a historical planning perspective based solely on reliability and a shorter-term focus, to a process that considers reliability, economics, and possible future's scenarios such as renewable energy development, increasing environmental focus and longer-term strategic plans. This transition continues to move incrementally and appropriately away from shorter-term, least-cost planning toward planning and projects that provide the most cost-effective solutions. These two starkly different perspectives lead to differing patterns of congestion on the system that are not recognized or solved in the traditional, capacity-based snapshot planning process.

In light of the highly successful Energy Imbalance Services (EIS) Market and the ongoing strategic effort to develop and implement a Day Ahead market design, it is imperative that transmission planners capture and account for these market structures in the planning processes used for the Regional Transmission Organization (RTO). A least cost, incremental reliability analysis fails to provide solutions for some of the most costly and highly congested corridors that are impeding flows for the market of today and of the future. Though the existing process has provided improved regional solutions and transmission expansion, this unintended consequence can be mitigated by applying economic or energy-based planning which maintains reliability standards as a top down optimal approach. Clearly that is very different than a bottom up, capacity-based snapshot approach that addresses reliability mandates and then attempts to identify incremental economic opportunities.

As SPP transitions its planning process into the ITP process, the focus will be to incorporate economic planning with reliability planning and differing future's scenarios in order to capture a longer-range plan for the transmission grid. The ITP process starts with long range 20 year physical models and 40 year financial assessments to create an expansion plan based on scenarios that frame the grid's needs to enable transactions, and then works back to address reliability mandates to manage the two requirements of an efficient and reliable bulk power system. This process combines reliability planning with economic planning to determine the optimal solution for all the transmission system needs of the footprint.

Again, this type of planning is a paradigm shift, moving away from the traditional incremental, least-cost planning methodology toward a value-based approach more able to meet the needs of the transmission grid. Allowing planners to derive future solutions for the grid through consideration of all variables that affect system performance rather than a minimalistic approach should result in the development of transmission plans that leverage efficiencies between transmission projects from a regional perspective and greatly reduce the need for incremental upgrades to the transmission system. This strategic approach to transmission planning should alleviate the risk associated with stranded investments built as incremental solutions for a near-term future. Planners will be able to develop less costly planning solutions from a long-term perspective as well as provide greater benefit to the grid

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as a whole. This is particularly important in the SPP renewable energy-rich region; i.e. the "Saudi Arabia of wind".

As a first step in the transition to the ITP process, the Synergistic Planning Project Team has recommended the analysis of Priority Projects to identify near-term opportunities to relieve congestion on existing flowgates and to better integrate SPP's eastern and western transmission systems. Many regional transmission highway studies have been performed by Staff as detailed in subsequent sections of this report. These prior studies all point to the same results for the long-term transmission grid solutions. The primary objective of the Priority Project analysis is to determine the first steps necessary to implement this plan for the grid.

Consequently, the Balanced Portfolio analysis is a first step and an important discussion. This analysis determined what projects would be needed on the system from a congestion standpoint for today's system seeking to attain "balance" and a Benefit to Cost (B/C) ratio that was greater than one (1) over a ten year study period. This analysis met the needs of today based upon the limited set of assumptions known when the analysis was conducted. The Balanced Portfolio starts the development of the collector system that will work in conjunction with the EHV backbone system for the footprint. Projects like Woodward District EHV – Tuco and Spearville – Knoll – Axtell were developed to provide a collector system once the EHV backbone is in place.

SPP and its members are focusing on long-term needs, leveraging existing approved projects and insuring these and future solutions are sized correctly for the intended application in the development of Priority Projects. Also, thoughtful consideration of Balanced Portfolio 345 kV projects in the plains gives rise to the question surrounding Rights-of-Way (ROW). There are concerns associated with the acquisition of the very few "best" paths between EHV backbone nodes. Should that acquisition occur as part of this development of Priority Projects in order to mitigate potential future risk of causing significant issues with affected landowners and local officials? This openness and transparency regarding long-term needs to acquire sufficient, adjacent ROW during the approvals for these collector facilities may prove invaluable. These collector systems cannot be expected to meet the long-term needs of the transmission system for the possible future scenario of high wind energy penetration, and it is not unreasonable for these collector systems to be split long term to double the capacity of these network elements in terms of integrating renewable resources in these prime wind development regions of the US.

It has been opined that we cannot get to the future by doing what we have done in the past. A Smart Grid in SPP cannot be a static network, but must be flexible to allow configuration to optimize economics. Flexibility is not a product of traditional capacity-based reliability plans, and although it may increase costs in the near-term, more importantly it provides benefits to address future needs that are unknown or not "etched in stone". A next step and objective of the Priority Projects process is to determine what the first steps to implementation of the EHV backbone should be in order to work in tandem with this collector system from the Balanced Portfolio.

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Past Transmission Studies

Over time, many studies have been performed by Staff and independent consultants to evaluate how an EHV transmission system can facilitate the reliable and economic transfer of power within the SPP footprint. The process has been evolving and updated for each study. Many of the assumptions have changed over time to reflect the most recently known data for the footprint. Even so, in the study reports that have been conducted for the SPP region, the analysis has resulted in very similar recommendations. In these reports, the consensus is that looped 765 kV network overlays in SPP provide the most cost-effective, efficient means to serve the transmission expansion needs in the SPP region when considering high wind energy scenarios.

The following briefly describes each of these studies. A link will also be provided to the full report associated with each study.

1st SPP EHV Overlay Report (Revision 2)

This study leveraged the previous EHV Overlay Study analysis by Quanta Technologies, Inc. (Quanta) and PowerWorld Corporation to evaluate the effect of increasing the wind injection for the footprint to match the updated development activity for the SPP system.

This updated EHV Overlay Study provided Quanta's evaluation of a 345 kV alternative build-out for the SPP EHV Overlay. To conduct this analysis, the same model and assumptions that were used in the previous 765 kV design were used, and an alternative plan was developed that used the same transmission corridors. Using the cost estimates from the previous study, the transmission line-only cost estimate for the 345 kV package was $3.29B. Compared to the $3.25B cost estimate for the transmission lines used for the 765 kV design and considering the advantages of each plan, the preferred option was 765 kV plan over the inferior massive build out of the 345 kV transmission alternative.

Link to full report: 1st SPP EHV Overlay Report (Revision 2)

Oklahoma Electric Power Transmission Task Force (OEPTTF)

Staff performed a comprehensive transmission expansion study at the request of the Oklahoma Electric Power Transmission Task Force (OEPTTF) in order to identify the bulk power transmission expansion needs to integrate and deliver wind resources to customers based on approved projects in the SPP Transmission Expansion Plan 2008-2017 and current projections for wind development in the central and south plains of the SPP region.

The study was divided into analyses for 2010 and 2020 and considered nominal wind and high wind injection scenarios for both years of study. The level of wind development ranged from a 2010 base level of 4 GW (nameplate) to a 2020 high wind level of 15 GW (nameplate).

Transmission expansion alternatives for the OEPTTF Study considered 345 kV connectivity and expansion. As higher wind levels were analyzed, that assumption shifted to consideration of a 765 kV network. The study results indicated that for wind levels of 15 GW, 345 kV expansion is more costly than 765 kV, due primarily to the significant amount of Right-of-Way (ROW) acquisition.

Link to full report: OEPTTF Report

2nd SPP EHV Overlay Report

This study was conducted by Staff to quantify the benefits of a 765 kV EHV Overlay expansion for the SPP footprint. This study focused on the economic impact of the 765 kV EHV Overlay, going beyond the original reliability impact and feasibility studies completed previously.

The study considered three futures of wind expansions in SPP's region - a low, expected, and high wind scenario for the years 2017 and 2027, respectively. For each of these scenarios, adjusted production cost analysis was used to determine the expected benefit of transmission expansion projects. Benefit to Cost (B/C) ratio was calculated for each scenario by dividing the adjusted production cost savings by the cost of transmission expansion projects.

The conclusion was that the 765 kV EHV Overlay build out has a positive return as a package of upgrades. The report shows that the group of 765 kV transmission expansion projects that accommodate 13.5 GW of wind integration in the 2027 expected wind scenario provides a B/C ratio of 1.36. A project was required to have a B/C ratio of greater than 1 in order to provide a positive return.

Link to full report: 2nd SPP EHV Overlay Report

Joint Coordinated System Plan 2008 (JCSP'08)

This analysis offered a conceptual transmission and generation system plan for a large portion of the Eastern Interconnection in the United States and was developed with the participation of most of the major transmission operators in the Eastern Interconnection. The initial effort looked at two scenarios (a reference scenario and a 20% wind energy scenario) that expanded transmission and generation opportunities between 2008 and 2024.

This analysis resulted in conceptual transmission overlays for the reference scenario that included three 765 kV lines, one double circuit 345 kV line, and one single circuit 345 kV line for the SPP region. For the 20% wind energy scenario, the conceptual transmission overlay includes twenty 765 kV lines, no double circuit 345 kV lines, and two 345 kV lines for the SPP region. The final recommendation stated that a substantial increase in wind generation will necessitate a significant increase in the need for transmission, including a strong 765 kV transmission system for SPP.

Link to full report: JCSP (click on Report tab)

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Quanta Technologies, Inc. - Long Range Analysis for SPS

In May 2009, Quanta developed a report for Xcel Energy that summarized the development and performance of transmission alternatives that are designed to collect new wind generation within the Southwestern Public Service (SPS) territory and export the power to external systems. This study analyzed the 2023, 2018 and 2013 summer peak conditions and documented the key transmission topology assumptions, wind generation projections and interconnection buses at SPS, SPP systems and wind export levels.

The analysis began with the development of five transmission alternatives for the 2023 base case and evaluated their performance considering the total amount of wind generation projects on the SPS territory estimated by 2023. According to the study, the alternative with the largest number of 765 kV lines exhibited the best performance under extreme wind generation levels (i.e., 80% for 2023 scenario) and was determined to be the most robust with the ability to accommodate a higher level of wind penetration than the other alternatives.

Link to full report: Quanta Long Range Analysis for SPS

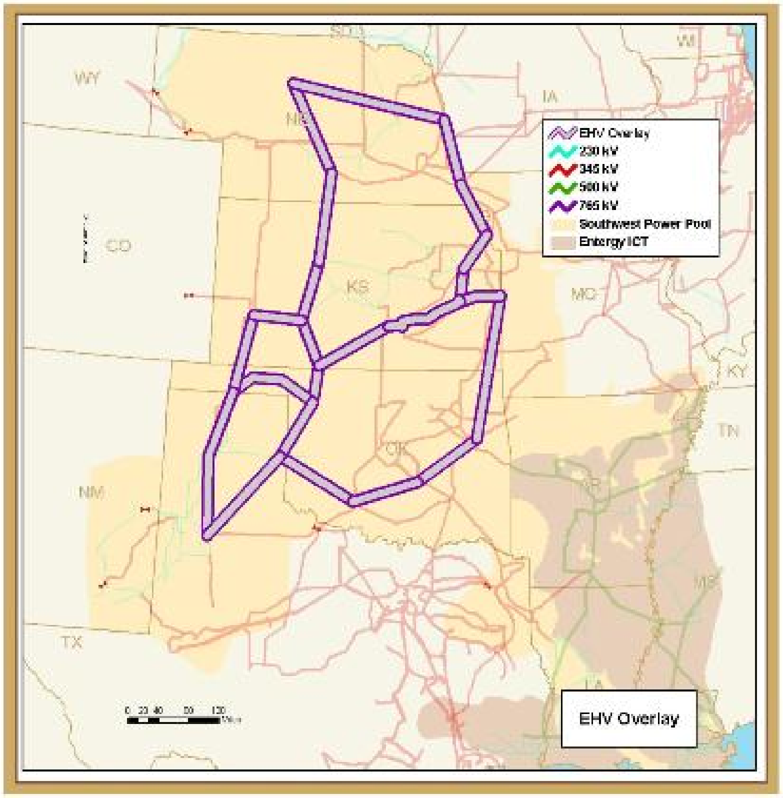
Feasibility Cluster Study for Generation Interconnection Requests (FCS-2009-001 (June 2009))

This study analyzed multiple generation interconnection requests associated with new generation totaling 14.9 GW nameplate which would be located within several transmission systems. The primary objective of this study was to identify the system constraints associated with connecting new wind generation in seven clusters while evaluating each cluster at nameplate capacity with all other clusters at 20% of rated output to the regional transmission system. This cluster study resulted in an effective expansion plan to integrate approximately 5 GW of aggregate new wind generation into the approved SPP Transmission Expansion Plan.

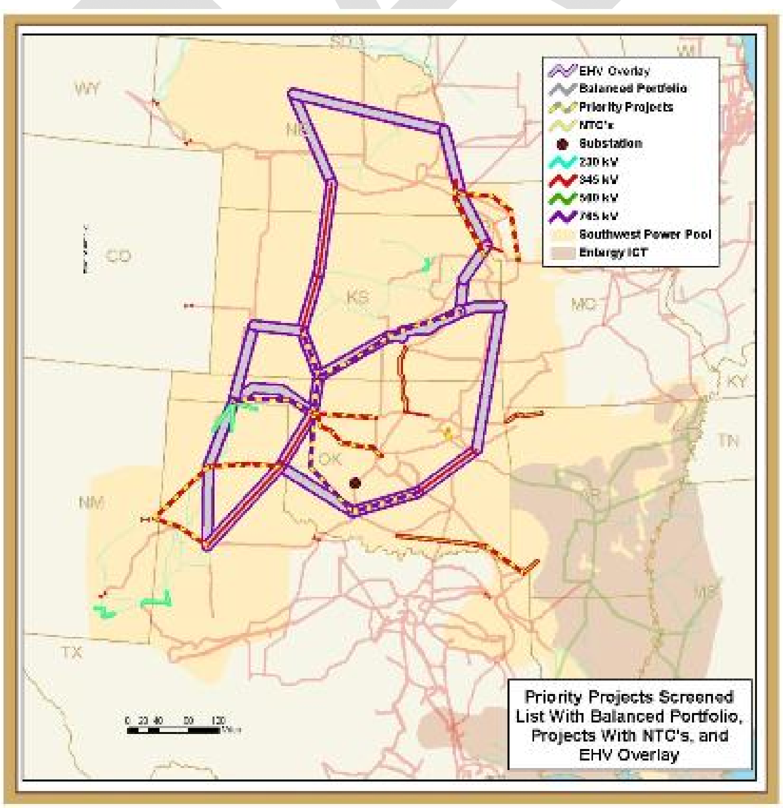
The cluster groups have varying system constraints associated with the generation interconnection requests. Many of these constraints are mitigated by 765 kV line upgrades. The full report includes a description of the constraints and mitigations for each of the cluster groups studied.

Link to full report: FCS-2009-001 (June 2009)

In summary and as an introduction to the discussion of the development of the Priority Projects, two maps are shown below. One of the more robust EHV Overlays proposed has been coined the 'Figure 8' and is useful for comparison to the list of Priority Projects. Though the development of the specific list of these Priority Projects is not described until the next section of this report, a snapshot of the final Priority Projects in conjunction with the 'Figure 8' is provided below to create insight.



SPP EHV "Figure 8" Overlay



Final Priority Projects compared to SPP EHV "Figure 8" Overlay

Development of the Priority Projects

Objectives

The Priority Projects are intended to help SPP transition from its current planning processes to the new ITP process and to capitalize on the current focus related to electric transmission expansion. The SPPT encouraged Staff to consider projects that demonstrated a near-term need to relieve flowgate congestion that routinely showed up as needed in the Aggregate (AG) Studies and Generation Interconnection (GI) Cluster Studies, improved interconnections, and improved transfer capability between western and eastern sections of the region.

Stakeholder Interaction

SPP's Value Propositions include being relationship-based and member-driven. These ideals have been utilized throughout the Priority Project process. As illustrated extensively in this report, Staff has depended on the input of stakeholders to help develop the initial list of projects, to review the screening of the projects, and to develop the assumptions used by Staff for the analysis. This has been accomplished through numerous face-to-face meetings, teleconferences, phone calls, and email communications. Some key points of stakeholder interaction are:

- May 21, 2009 – Spring Transmission Planning Summit, Staff presented the initial overview of Priority Projects
- May 29, 2009 – Stakeholders are solicited through email to submit proposals for Priority Projects
- June 10, 2009 – Staff distributes the first draft of Priority Project Criteria and Metrics
- June 16, 2009 – Staff publishes the initial list of Priority Project candidates
- July 7, 2009 – Staff publishes the "screened" list of projects and the revised draft of Criteria
- July 14, 2009 – The screened list of projects is presented and discussed at a MOPC pre-meeting seminar
- August 4, 2009 – Economic Studies Working Group (ESWG) approves initial metrics as developed by the Benefits Analysis Techniques Taskforce (BATTF)
- August 14, 2009 – MOPC approves initial metrics as developed by the ESWG used to assess Priority Projects
- August 20, 2009 – Stakeholders are updated on Priority Projects at ITP Stakeholder Meeting
- September 29, 2009 – SPP Priority Projects Workshop, The stakeholders and BOD are updated on the initial results of the Priority Project analysis
- October 13, 2009 – MOPC review and consideration of project list
- October 26, 2009 - RSC review and consideration of project list

Continuing interaction and support from stakeholders is necessary in order to present Priority Projects to the BOD for approval and ultimately for construction.

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Initial List

As recommended by the SPPT, Staff began to compile a list of projects to be considered as Priority Projects prior to the Spring Transmission Planning Summit on May 21, 2009. Internally, Staff began by assessing which projects appeared repeatedly in the Aggregate Study and Generation Interconnection processes or projects that were not approved in the Balanced Portfolio process but were identified as needed to relieve congestion in the SPP footprint.

In addition to projects identified by Staff, a request was sent to stakeholders on May 29, 2009 for any projects they would like to see considered for the Priority Project process. Stakeholder responses to this request far exceeded Staff's expectation. The initial list of Staff and stakeholder proposed Priority Projects exceeded 100 – many more than Staff could evaluate given the deadline for project approvals in October 2009. The initial list of proposed Priority Projects is provided in Appendix A.

Screening and Refinement

With a large number of projects proposed and an aggressive timeline for evaluating them, Staff developed a screening process to reduce the number of projects to be analyzed to a more manageable number. Projects included in the Priority Project list needed to be cost-effective, demonstrate a near-term regional need, and improve upon the robustness of the existing regional system. To insure the projects met these conditions, Staff developed a scoring methodology to screen the projects. The scoring process assigned a point value from 1 to 5 for each project that provided benefit in a particular category. The points were added across all categories for each project to calculate a total project score. The categories assessed and the scoring methodology is outlined in the following table:

Criteria	5 points	4 points	3 points	2 points	1 point
Congestion Relief (C)	$170K - $100K	$99K - $50K	$49K – $20K	$19 - $8K	$7K - $0K
TSR Impact (T)	300 – 100	99 – 50	49 – 19	18 – 10	9 – 0
GI Impact (G)	1600 – 1300	1299 – 1000	999 – 700	699 – 400	399 – 0
Economic Benefit (E)	Above 1.2	1.19 – 0.9	0.89 – 0.65	0.64 – 0.4	0.39 - 0
West - East Transfer (W)	765kV	500kV	345kV	230kV	Under 230kV

Where:

Congestion Relief (C) - The congestion relief value was calculated by multiplying the average hourly shadow price as provided by the SPP markets group by the total number of intervals breached or binding for an affected flowgate.

TSR Impact (T) - The TSR impact value was calculated by taking reservation Transfer Distribution Factors (TDFs) and multiplying by the Mega Watts requested to obtain a total Mega Watt Impact (MWI) value. MWI values for each reservation were then summed together to get a total. The numbers used to obtain this sum were taken from the last five aggregate studies. ((R1: TDF1 x MW1=MWI1), (R2: TDF2 x MW2=MWI2), etc (MWI1 + MWI2 = Total))

GI Impact (G) - The GI impact value was calculated as the sum of all positive incremental flow impacts on such upgrades. (PTDF x MWrequested = GI Impact)

Economic Benefit (E) - The value for economic benefit attributed to each project was a Benefit to Cost (B/C) ratio as identified in recent economic studies.

West – East Transfer (W) – Each project received a value based on the kV level of the proposed solution that improved power transfers between West and East regions of SPP.

After using the above methodology, Staff proposed a list of the top 20 projects to a group of stakeholders at a MOPC pre-meeting seminar that was held on July 14, 2009. The screened list of projects presented to stakeholders is listed below and provided in three maps following:

1. Hitchland – Woodward District EHV (345kV)
2. Spearville – Comanche – Medicine Lodge – Wichita (765kV)
3. Comanche – Woodward District EHV (345kV)
4. Woodward District EHV – Elk City West (765kV)
5. Potter – Grapevine – Beckham (345kV)
6. Tatonga – Northwest #2 (345kV)
7. Woodward District EHV – Tatonga #2 (345kV)
8. Fairport – Sibley (345kV)
9. Potter – Mid-Point reactor station on the Tuco – Woodward District EHV345kV line (345kV)
10. Sunnyside – LES (345kV)
11. Valliant – Texarkana (345kV)
12. Extension of the already approved Woodward District EHV/Mooreland 765kV – Hitchland 765kV line for 40 miles to Cimarron County, Oklahoma
13. Elk City West – LES (765kV)
14. LES – Seminole (765kV)
15. Northwest Wichita – Wolf Creek (765kV)
16. Roosevelt – Tolk – Tuco (345kV)
17. Potter – Roosevelt (similar to Tolk-Potter) (345kV)
18. Chesapeake Tap & Transformer (345kV/161kV)
19. Riverside Station 138kV– Tulsa Power Station (Rebuild) (138kV)
20. Jeffrey (KS) – Sheldon (NE) (345kV)

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List of Priority Projects for Analysis

Stakeholders at the MOPC pre-meeting seminar recommended Staff combine some proposed projects and eliminate others. The resultant list of projects to be considered in the Priority Project process and rigorously analyzed by Staff is listed below and provided in the following map:

1. Hitchland – Woodward District EHV (765kV/Run at 345 kV)
2. Spearville – Comanche - Medicine Lodge – Wichita (765kV/Run at 345 kV)
3. Comanche/Medicine Lodge – Woodward District EHV (765kV/Run at 345 kV)
4. Woodward District EHV – Elk City – LES - Seminole (765kV/Run at 345 kV)
5. NW Wichita – Wolf Creek (765 kV)
6. Woodward District EHV – Woodring (345 kV)
7. Valliant – NW Texarkana (345 kV)
8. Stateline – Potter – Roosevelt – Tuco (345 kV)
9. Riverside Station – Tulsa Power Station (Add Reactor) (138 kV)[1]
10. Cooper – Maryville – Sibley (345kV) OR
    Nebraska City – Stranger Creek (345 kV)[2]

Based upon the current scarcity of transmission between the western and eastern portions of the SPP system and past Staff analysis, some of the projects were studied in conjunction with other projects to reduce the number of study cases evaluated. The project groupings studied are as follows:

- Spearville – Comanche – Medicine Lodge – Wichita
  Comanche/Medicine Lodge – Woodward District EHV

- Hitchland – Woodward District EHV
  Spearville – Comanche – Medicine Lodge – Wichita
  Comanche/Medicine Lodge – Woodward District EHV
  Woodward District EHV – Elk City – LES – Seminole

- Hitchland – Woodward District EHV
  Spearville – Comanche – Medicine Lodge – Wichita
  Comanche/Medicine Lodge – Woodward District EHV
  Wichita – Wolf Creek

All other projects listed were studied independently.

[1] This project was initially presented as a rebuild of the 138kV line, but AEP suggested a reactor could be added as a much lower cost solution. Staff made an assessment to verify the reactor as a viable solution and concurs with AEP's recommendation that the reactor be considered for Priority Projects instead of the line rebuild.

[2] The stakeholder recommendation from the MOPC pre-meeting seminar was to assess a solution to the Cooper South flowgate. Affected stakeholders were asked to submit their recommendations and asked Staff to consider Cooper – Maryville – Sibley (345kV) or Nebraska City – Stranger Creek (345kV) as the solution.

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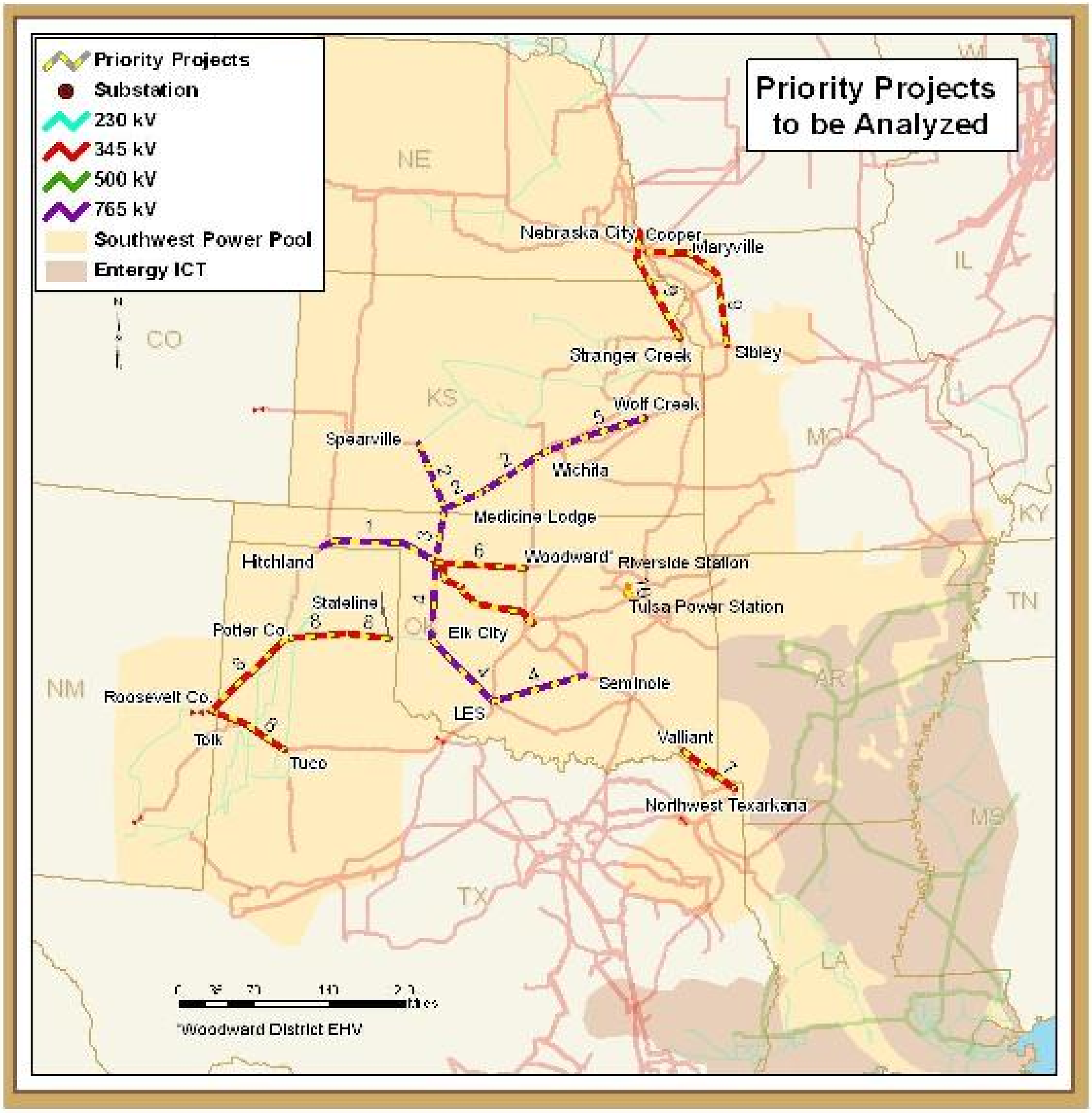

Projects for Detailed Analysis

Scope of Analysis

Study Assumptions

The assumptions used in the modeling and analysis of the Priority Projects were vetted through the SPP stakeholder process. The majority of the assumptions were developed by the Benefits Analysis Techniques Task Force (BATTF) and approved by the ESWG. See the Benefit Analysis for Priority Projects report in Attachment 1 for further information. For the Priority Project analysis, PROMOD software was utilized to model 8760 hours representing a full year of system-wide commitment and dispatch of resources.

- **Time Frame** – The BATTF directed that a ten-year time frame be used to analyze the benefits for the Priority Projects. Three years were modeled and the benefits for the years in between were calculated using a linear progression. The total of the ten-year benefit was then used to create the Net Present Value (NPV). The three modeled years are 2009, 2014, and 2019. Additionally, a terminal value will be used to represent the final B/C of the project from the last year of analysis (i.e. 2019). Additionally, considering the scope and lifetime of some of the projects, a 20 and 40 year financial result will be shown as extrapolated from the data used in the 10 year analysis.

- **Fuel Prices** – The gas price was determined by using the Henry Hub NYMEX ten-year price with an additional adder for the panhandle. Other fossil fuel prices used generic assumptions and publicly-available data.

- **Wind Modeling** – The wind amounts and locations were developed using data from the Wind Integration Task Force (WITF). The model assumes that wind generators are paid the zonal market marginal price. Wind profiles were developed using historical data and are grouped according to queue position. The sequence for the requests is: Interconnection Agreement (IA) fully executed/commercial operation (2877 MW), IA fully executed/on schedule (1479 MW), facility study completed (1464 MW), facility study in progress (755 MW), impact study completed (635 MW), impact study in progress (635 MW) and feasibility study completed (4826 MW). This was based on the status of the generation interconnection queue in February 2009.

  Also included are interconnection requests in Nebraska totaling 1312 MW. The point of interconnection and the output for these requests were provided by the Nebraska entities as SPP was not coordinating interconnection requests in the Nebraska entities' interconnection queue in February 2009. No interconnection request with IA on suspension or with pending status was included. However, the exclusion of these requests is not thought to be material in that the included interconnection requests represented a similar geographic distribution of wind generation as those requests that were excluded.

  Three levels of wind energy penetration were analyzed for the three years modeled. Level 1 assumptions are 3 GW wind energy penetration (5%) in 2009, 7

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GW (10%) in 2014, and 14 GW (20%) in 2019. Level 2 considered a delayed progression of 3 GW in 2014 and 7 GW in 2019. Level 3 considered an advanced progression with 7 GW in 2009 and 14 GW in 2014. More detail has been provided in Appendix C concerning wind energy penetration levels and the specific wind generation modeled.

- **Study Footprint** – The study footprint contains SPP, Entergy, TVA, MAPP, MISO (Ameren, MEC, et al), PJM, Southern Companies, WAPA, Basin Electric, Big Rivers Electric Company, and East Kentucky Power Cooperative.

- **DC Ties** – Historical DC Tie profiles were used to simulate best known profiles for all DC Ties in the SPP region.

- **Environmental Costs** – The emission cost for SO_2 and NO_x were approximated using data from the Chicago Climate Exchange. The price of CO_2 was not input on the front-end of the modeling. All CO_2 analysis was done as a post processing technique according to the amount of carbon deferred from the transmission plans and various generation scenarios modeled. The CO_2 analysis used a low and high carbon pricing; these costs are $15 and $54 per ton. Mercury was not addressed due to the lack of valid market information.

- **Resource Forecast** – Only plants with firm transmission service and signed agreements or plants that were currently under construction were included in the analysis. The exception is wind generation that is required to meet wind scenarios modeled for the analysis detailed in Wind Modeling section above.

- **Plant Outages** – The data for outages and maintenance was taken from the ESWG data collection effort earlier this year. This data was provided by the stakeholders through this effort. Forced outage rates were taken as a single draw and locked for the change and the base cases to eliminate biased results due to different outage schedules. Similarly, maintenance outages were also locked down from a single scheduled pattern. These outages were plant specific.

- **Operating Reserves** – SPP's current reserve sharing program (as of 2008) was used in the simulation for operating reserves.

- **Hurdle Rates** – A dispatch hurdle rate of $5/MW and a commit hurdle of $8/MW was used to commit resources across regional boundaries.

- **Load Forecasts** – In early 2009 stakeholders submitted load forecasts for 2012, 2017, and 2022. To determine the load for our study years of 2009, 2014, and 2019 an escalation rate of 1.29% per year was used.

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- **Market Structure** – The simulation was conducted considering a single balancing authority and a day-ahead market structure for the SPP region.

Value Metrics

Adjusted Production Cost

Adjusted production cost is a measure of the impact on production cost savings by node (LMP), accounting for purchases and sales of economic energy interchange. This benefit metric is typically simulated by a production cost modeling tool accounting for 8760 yearly hourly profiles of commitment and dispatch modeling, taken over the course of the study period.

Nodal modeling is aggregated on a zonal basis using weighted LMPs. There is concern that modeling the border points will not be accurate without additional Eastern Interconnection points. For example, the border LMPs will have significant impact on the adjusted production cost within SPP. If there are lower LMP prices outside SPP there will be no transfers from the western portion of SPP. The BATTF recommended the modeled footprint be broadened to include Southern Companies, Basin Electric, WAPA, TVA, PJM, MISO (Ameren, MEC, et al), and the DC ties (using the recent historic patterns) at a minimum when running the model to assess the impact on the borders.

Gas prices are based on Henry Hub NYMEX ten-year, plus a panhandle basis difference. For other fossil fuel prices, publicly-available data should be used.

The nodal analysis will aggregate on a zonal basis using the following formulation highlighted. The calculation, performed on an hourly basis, will be:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases
Where:
Revenues from Sales = MW Export x Zonal $LMP_{Gen\ Weighted}$
and
Cost of Purchases = MW Import x Zonal $LMP_{Load\ Weighted}$

Tools used for this analysis includes standard assumptions and modeling using PROMOD.

The rationale for using this methodology is as follows:

- This formula was previously approved by stakeholders, the MOPC, and the BOD as part of the Balanced Portfolio analysis.

- The formulation represents the broad impact of new transmission projects in changing LMP costs (energy, congestion and losses cost) to rate payers within the SPP footprint. It, therefore, represents much of the savings/benefits or additional cost to rate payers for specific transmission projects.

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The total adjusted production cost for a project is calculated using the adjusted production cost value of a project in three different years. The years that are studied, and subsequently have an adjusted production cost value, are 2009, 2014, and 2019. The benefits of the in between years (i.e. 2010, 2011, etc.) are calculated linearly using the benefit values from the two years that were studied (i.e. 2009 and 2014). The sum of the adjusted production cost benefits for each of the 10 years is the total adjusted production cost.

Impact on Losses - Energy

Lower impedance transmission lines provide a loss savings to the transmission grid. The energy component of the loss savings is captured as part of the adjusted production cost analysis. It is possible that losses will increase since generation sources will be remotely located from load centers.

Impact on Losses – Capacity

While the energy component of losses is captured in the adjusted production cost analysis, the capacity component is not. Capacity savings associated with a loss change are determined by looking at the selected hourly loadflow models to determine the loss change associated with a transmission upgrade. The BATTF has established standard capacity prices to capture capacity savings. Formulation will be based on a Combustion Turbine (CT) replacement, currently priced around $750 per kW installed (based on the expected cost to install various types of machines used by BATTF members).

There is a fixed O&M cost component based of $650,000 per year (average expected cost experienced by BATTF members). This is an additive benefit component for capturing the capacity component of that energy typically passed on to rate payers through Ancillary Service charges. This is variance in quantity of energy (capacity). The energy component of losses is captured in the formulation below:

- Capacity Savings at Coincidental Peak = ((Capacity requirement at Peak (base case) – Capacity requirement at Peak (with projects upgrades included)) x (CT replacement cost)).

  This would be a straight savings estimate of the capacity, since the CT installation would be a one-time cost when the upgrade was energized.

- There is a fixed O&M cost savings associated with this calculation, usually captured in the Ancillary Services fee.

  It should be calculated as Fixed Cost Benefit = (Capacity savings (as determined from above per 150 MW) x $ 650,000/yr), escalated by the rate of inflation as reported in Bureau of Economic Analysis.

- The price differential would be calculated on an annual basis from the point the proposed upgrade would be energized to the end of the defined 20-year period. There should be no additional accommodation for savings after 20 years, because a CT has an estimated 20-year life span.
- This formulation is the estimated benefit or cost Impact of Losses.

Environmental Impacts

The pricing for SO_2 and NO_X is approximated using data from the Chicago Climate Exchange; this represents our best estimate of current market prices. The BATTF discussed at length the merits of CO_2; the assumption is that the high price in the long term (20 years) is determined by 100% sequestration currently valued at between $80 and $102 per ton ($91 per ton average) from the Mountain Air Plant DOE project. The low price is based on the current price of CO_2 from the Chicago Climate Exchange.

The current price of CO_2 is escalated up to $91 per ton in year 20, based on unknowns with government regulation as it relates to carbon emissions. Emissions values are based on a range that reflects the maximum and minimum from various sources, using a high case and low case probability.

The BATTF determined that the CO_2 calculation is viewed as a less definitive, but still quantitative, formulation. Since Cap and Trade legislation is under discussion and there is no clear direction - but a higher probability - that a higher price bias exists, the BATTF also recommended using a 60-40 weighting. This weighting represents a belief that there will be federal legislation; there is a 40% chance the lower price case will happen and 60% chance the higher price case will happen. (There is also the possibility of the federal government spearheading transmission construction.) Using this formula, the value is calculated as (60% x $91/ton) + (40% x $0/ton) = $54/ton

It is assumed that as carbon prices increase, wind penetration will increase. Therefore, a linear interpretation of the carbon cost curve is a reasonable cost curve. The BATTF discussed running two carbon scenarios with a low and a high carbon value; both of which are needed to see what the impact will be on generation dispatch to provide the best determination of the impact of carbon on transmission projects. Without this type of modeling run, the CO_2 benefits for transmission projects will cause any transmission project to have benefits in excess of its cost if it displaces coal or gas generation. Due to the time constraints for this type of modeling and simulations, and given the current state of the model and the input and model development required, the BATTF determined this analysis would not be a part of this report. An approximation for the impact of CO_2 was determined by calculating the change in CO_2 output between the base and change cases. The change in CO_2 tons is then used to calculate the potential savings or costs using a price of $15 and $54 per ton.

Reliability Impact

Power Flow Analysis

As part of the Priority Project evaluation Staff conducted a study to evaluate both the impact of the Priority Projects on the reliability plan of the SPP transmission system and the reactive requirements for the Priority Projects. This study is not intended to justify any Priority Project based on deferred project cost; it is only intended to show the effects of the Priority Projects on the SPP reliability plan. An analysis was conducted on each Priority Project and proposed grouping of projects to determine the impact of these projects on the SPP reliability plan and on first tier third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in SPP's 2009 STEP 10 year Reliability Analysis.

An AC N-1 contingency analysis was performed using PSS/E. The analysis was performed using the 2009 STEP Build 3 models. Details of the analysis are as follows:

- Monitoring of Facilities
  - All facilities in the SPP footprint were monitored at 69 kV and above.
  - EES and AECI facilities were monitored at 100 kV and above.
  - All other first tier control areas were monitored at 230 kV and above.
- Cases
  - 2014 Summer Peak
  - 2014/15 Winter Peak
  - 2019 Summer Peak
  - Including all transaction cases
- Normal conditions and contingency analysis
  - Normal conditions
  - All N-1 single-element contingencies 69 kV and above in the SPP footprint were evaluated. These contingencies did not include manual transfer of load or manual switching.
  - All N-1 single-element contingencies 100 kV and above in EES, AECI, and all other first-tier control areas were evaluated.
  - Staff verified that all normal conditions and N-1 violations identified have corrective plans
- Use of Transmission Operating Directives (TOD)
  - Transmission Operating Directives were applied in the same manner they have been applied in the 2009 STEP

The analysis was performed using the 2009 STEP Build 3 models. Build 3 models were created in July 2009 to include revised load forecast information due to the recent economic downturn. Using the STEP models allows re-evaluation of STEP projects to determine if they can be deferred or eliminated due to the Priority Projects. Appendix B provides details of how the STEP models are built.

SPP's STEP 10 year Reliability Analysis is an open and transparent process allowing stakeholder input. This analysis of Priority Projects shares the study results in stakeholder public meetings using the same methodologies used in the 2009 STEP.

The scope used in this analysis originated from the 2009 STEP scope. The STEP scope was initially approved by the TWG in November 2008 then later updated in May 2009 to allow for changes related to the economic downturn. These changes included updated load forecasts and incorporation of Balanced Portfolio projects.

ACCC results for the Priority Projects are evaluated using input provided by stakeholders for the 2009 STEP. This allows projects to be evaluated in the same manner as the STEP. Projects are deferred based on the same justification as their original need. Similarly, mitigations are handled in the same manner as the STEP.

The preliminary report on the reliability impacts of the Priority Projects was submitted to the Transmission Working Group (TWG) on September 1, 2009. The TWG conducted a conference call to provide comments on September 8th pending endorsement on September 15th.

Reactive Requirements

The consideration of long EHV transmission upgrades (345 kV+) may require additional reactive compensation to maintain voltage during normal operating conditions and reduce voltage rise during line switching. During light load conditions the high voltage issue may exacerbate as there are less transmission line real power losses to offset capacitive line charging. The additional line charging increases voltage on the Bulk Electric System. In order to address this issue, shunt line reactors are typically used to counter or off set excessive line charging during light load conditions.

This high level screening study provides a calculated value for line shunt reactors required to support the addition of EHV transmission in Priority Project Pairs 1 through 10 under normal (no outage) and selected single contingency events.

The study method determines Reactive power (Q) requirements for different line voltages (V) to determine the magnitude of reactive compensation to maintain system voltages within acceptable limits. This analysis technique is commonly called "QV Analysis".

A QV, reactive compensation verses voltage analysis was conducted on each proposed grouping of Priority Projects to determine the impact of these projects on the SPP interconnection points and the amount of shunt compensation each segment of the project would require to maintain acceptable transmission voltages.

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The light load base cases representing 2014 light load conditions were prepared using PSS/E. The steps to build each model are in Table 1.

Table 1: Model building steps

1. Add Balanced Portfolio Projects to the base case
2. Add Priority Project Pair
3. Add line breakers as needed
4. Solve model

PowerWorld Corporation Simulator was used to perform an AC QV analysis. The total amount of line reactance to keep the system voltages around 1.01 PU[3] was determined for each Project Pairing line segment. The base case was analyzed. Each line segment was also tested for voltage rise at the open end while the other end remained closed into the network.

The following key study assumptions were applied:

1. This study does not include the effects of subsynchronous resonance (SSR). SSR is an electric power system condition where the electric network exchanges energy with a turbine generator at one or more of the natural frequencies of the combined system below the synchronous frequency of the system[4].
2. Light load conditions is the worst case scenario for high voltage conditions
3. The STEP 2010 Spring Peak model is included in the base case
4. Balanced Portfolio Projects are added to the base case
5. Priority Project Pairings 1 through 10 are analyzed to determine the amount of line shunts per line segment
6. Line reactors are sized by opening one end of line segment to determine reactive support to keep line end voltage around 1.01 PU.
7. Actual line reactors may be a combination of smaller units or FACTS devices to cover multiple system load conditions and operating points.
8. The study has not included additional shunts required to maintain safe voltage levels on locations other than the priority project pairing line segments.
9. The study is not a short circuit analysis and does not include the effects of reactors on line switching.
10. The study does not consider the effect of STEP 230 kV and above projects.

[3] All EHV lines (345 kV+) are operated between 0.98 and 1.04 p.u. For the study purpose, an average 1.01 pu operating voltage was chosen.

[4] Subsynchronous Resonance in Power Systems, Paul M. Anderson, B. L. Agrawal, J. e. Van Ness, IEEE Press, 1990

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Local Economic Benefits

Quanta Technology is working with the Brattle Group to determine the local economic benefits from both wind development and transmission line construction for states in the SPP footprint. These states are: Kansas, Oklahoma, Texas, New Mexico, Nebraska, Missouri, Arkansas, and Louisiana.

Wind Development

The economic benefit from wind development is calculated by using the Department of Energy's (DOE) "Job and Economic Development Impact" (JEDI) model. JEDI was developed for DOE by an independent consultant to assess the potential economic impact of developing certain wind projects in a state. Given certain project parameters, including cost structures, the model uses economic multiplier data (from the Minnesota IMPLAN Group/Model) to estimate the job and economic impact (including the rippling effect of income and indirect economic activities and effects) of particular projects.

The key inputs for the JEDI model are the following:

- Project Location (State)
- Year of Construction
- Total Project Size - Nameplate Capacity (MW)
- Turbine Size (KW)
- Installed Project Cost ($/KW)
- Operations and Maintenance Cost ($/kW)

In addition, an assumption is made of the construction material purchased within the state, and these material costs are also factored into the economic benefit calculation.

Quanta Technology has provided this information to Brattle by state for the 3 GW, 7 GW and 14 GW wind levels.

Transmission Line Development

The economic benefit from transmission line development is calculated by using the IMPLAN model to assess economic impacts of proposed telecommunications projects. Brattle will utilize IMPLAN to model transmission projects that fall outside the scope of the JEDI model framework. Specifically, Brattle will take spending on transmission (or other) projects broken out by NAICS code and evaluate the direct and indirect employment, value added and economic activity associated with such spending.. These impacts are estimated on a state by state basis.

For each priority project, the following inputs will be provided for the IMPLAN model:

- Project Location (State(s))
- Construction Period (Year(s))
- Total Project Size, Capacity and Distance of Transmission Lines
- Various Financial Parameters (e.g., debt/equity ratios, interest rate, ROE)
- Tax Parameters
- Land Lease Parameters

Deliverability of Capacity and Energy to Load

The BATTF suggested that the shadow prices at flowgates be used to measure the deliverability of capacity and energy to load. This metric will determine which lines reduce the most congestion. A change in deliverability is reflected as a change in shadow prices which represents, in part, the cost of congestion. The deliverability is captured using the following formulation:

Total System Congestion Before Upgrade – Total System Congestion After Upgrade = Improved Deliverability Benefit.

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Assumptions for Design Standards

Staff understands that SPP will be building a strong, robust transmission system that enables more efficient use of the grid. With this goal in mind, SPP needs to build the components of the backbone system as strong, flexible and reliable parts of the whole backbone. Although Staff currently has not proposed design standards, SPP in concert with the new ITP process will work on the development of design standards for new EHV transmission facilities. Therefore, Staff utilized 3000 amp capacity on 345 kV lines in the analysis of the Priority Projects:. Staff believes that to best build a robust transmission system 3000 amp capacity lines are essential to the future expansion of the SPP grid. Today, the transmission utility industry provides ample 345 kV equipment for 3000A operation. With the abundant wind potential in SPP, the 3000 amp capacity design standard is a key component to building a robust collector network in SPP.

Staff also utilized a standard for 765 kV lines. To build a robust backbone in the SPP system, high capacity lines are necessary. However, 765 kV transformers and terminal equipment are typically created at 4000A capacity or less, with some options at 5000A. As there are not many industry-wide choices to build 765 kV facilities at 5000A capacity, Staff utilized 5000A capacity for the analysis of 765 kV lines in the Priority Projects; however the associated terminal equipment is constructed to 4000A capacity

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Appendices

Appendix A – Initial List of Priority Projects

Project	Supported By	Voltage	Project	Supported By	Voltage
EHV Facilities					
Spearville - Comanche - Medicine Lodge - Viola	Staff/Westar Energy/Sunflower/ ECRNA	765	Potter - Mid-Point reactor station on the Tuco – Woodward District EHV 345kV Line	E.ON Climate & Renewables North America Inc. (ECRNA)	345
Tallgrass 765 Transmission Project	OGE	765	Tuco - Woodward	Staff/ECRNA	345
Extension of the already approved Woodward/Mooreland - Hitchland 765kV line for 40 miles to Cimarron County, Oklahoma	Windstar Energy	765	Crossroads - Hobbs Plant - Midland - Borden - Grassland - Jones - Tuco	Xcel	345
Woodward District EHV-Elk City West 765	AEP/OGE/Wind Coalition	765	Woodward District EHV - Woodring EHV 3000 Amp capacity 345kV; R/W for 765kV	OGE	345
Elk City West-LES 765	AEP/OGE/Wind Coalition	765	Beckham County 345kV Sub	Staff/OGE	345
LES-Seminole 765	AEP/Wind Coalition/OGE	765	Beckham County - Anadarko 345kV (same corridor as Elk City to Cimarron)	Staff/OGE/OMPA	345
Seminole - Muskogee	AEP/OGE	765	Elm Creek-to-Summit 345-kV	Sunflower	345
Muskogee-AR Border 765	AEP/OGE	765	Northwest Wichita - Summit	ECRNA	345
Muskogee-KS Border 765	AEP/OGE	765	Fairport - Sibley	Staff	345
Northwest Wichita - Wolf Creek	Wind Coalition	765	Chesapeake Tap & Transformer (345/161)	Staff	345
Fort Smith - Tontitown	Staff	500	Redbud - Horseshoe Lake	Staff	345
Fort Smith - NW Texarkana	Staff	500	Muskogee-Horseshoe Lake 345 kV line w/new HSL 345 switch station	OMPA	345

Comanche - Woodward	Staff/Wind Coalition	345	Muskogee - VBI 345kV	OGE	345
Hitchland - Woodward	Staff/Wind Coalition/OGE/ECRNA	345	Northwest Transformer (345/138)	Staff	345
Tatonga - Northwest #2	Staff	345	Chamber Springs - Osage Creek	Staff/AEP	345
Woodward District EHV- Tatonga #2	Staff	345	Flint Creek-Shipe Road-Osage Creek 345 kV	AEP	345
Woodward District EHV- Lawton Eastside	Wind Coalition	345	Brookline - Summit and Brookline Transformer (345/161)	Staff	345
Cimarron - Northwest (Replace CTs)	Staff	345	Iatan - Stranger Creek (Voltage Conversion 161 -> 345)	Staff	345
Cimarron (Replace Circuit Breaker)	Staff	345	Arcadia-HSL 345 kV line w/new HSL 345 switch station	OMPA	345
Mingo - Knoll	Staff/Sunflower	345	Arcadia Transformer and Breakers (345/138)	Staff	345
Spearville - Viola	Staff	345	Sunnyside - LES	Staff	345
Spearville - Comanche	Staff	345	Sunnyside Transformer (345/138) (NTC)	Staff	345
Spearville - Northwest Wichita	ECRNA	345	Grapevine - Beckham	Staff	345
Woodward District EHV- Spearville	ECRNA	345	Grapevine - LES	Staff	345
Medicine Lodge - Wichita	Staff	345	Beckham County - Lawton ES 345kV	OGE	345
Comanche - Medicine Lodge	Staff	345	GEN0740 - Conestoga	Staff	345
Hoyt - Cooper	Westar Energy	345	GEN0740 - Comanche	Staff	345
Jeffrey(KS)-Sheldon(NEB) 345 kV line	OMPA	345	Beaver County - Conestoga	Staff	345
Cooper - Jeffrey Energy Center	Central Transmission	345	Beaver County - Woodward	Staff	345
Tulsa East 345kV Switching Stations	Staff	345	Beaver County - Hitchland	Staff	345

North Platt 345kV Switching Stations	Staff	345	Stranger - W Gardner	Westar Energy	345
Turk - McNeil 345 (or 765)	AEP	345	Wolf Creek - Emporia	Westar Energy	345
Roosevelt - Tolk - Tuco 345 kV	Xcel/Wind Coalition/ECRNA	345	Hitchland - Wheeler (Stateline) 345 kV	Xcel	345
Potter- Roosevelt 345 kV (similar to Tolk - Potter)	Staff/Xcel/Wind Coalition	345	345kV Tap at Monet to Table Rock	Empire	345
Potter - Grapevine	Staff	345	Dolet Hills - Messick	Central Transmission	345
Lower Voltage Facilities					
Messick Transformer (230/115)	Staff	230	Siloam City - Siloam Springs (Rebuild)	Staff	161
East Manhattan - Jeffrey Energy Center (Raise Structures)	Staff	230	Substation M #2 Transformer (161/69)	Staff	161
Auburn Road Transformer (230/115) (NTC)	Staff	230	OPPD Line 34: Sub 1226 - Tekamah (Rebuild)	OPPD	161
SWPS - Battlefield	Staff	161	Line 642 Tap - Livonia Bulk - Wilbert	Staff	138
3rd St - Arkoma (Terminal Upgrades)	Staff	161	Gill Energy Center West - Waco (Rebuild)	Staff	138
Calico Rock - Norfork (Substation Upgrades)	Staff	161	Riverside Station - Tulsa Power Station (Rebuild)	Staff	138
Hancock - 5 Tribes - Pecan Creek (Reconductor & Sub Upgrades)	Staff	161	SE Loop 138	AEP	138
Chamber Springs - Farmington (Rebuild)	Staff	161	OklaUnion-Altus Jct 138 kV line	OMPA	138
St Joe - Woodbine (Reconductor)	Staff	161	Broken Bow - Bethel - Nashoba - Clayton - Sardis - Lone Oak (Rebuild)	Staff	138
St Joe - Everton - Harrison East - Summit	Staff	161	Ashdown West - Craig Junction (Rebuild)	Staff	138

Trumann West - Hergett	Staff	161	Mooreland - Morewood SW (Reconductor)	Staff	138
Dardanelle - Russellville South (Substation Upgrades)	Staff	161	Okmulgee-Weleetka 138 kV (Rebuild)	AEP	138
Jones - Jonesboro	Staff	161	BPU - City of McPherson - Johns - Manville - E. McPherson SS (Rebuild)	Staff	115
Fisher Tap - Keystone Dam			Lyons - Whetland (Rebuild)	Staff	115
Little Spadra-ANO 161 kV line	OMPA	161	Concordia - Jewell - Beloit (Rebuild)	Staff	115
Prairie View-Dardanelle 161 kV line/in conjunction with Massard-Branch 161 kV line	OMPA	161	Spearville - N. Kinsley	Staff/Midwest Energy	115
Stateline - Jopline - Reinmiller (Voltage Conversion 69 -> 161)	Staff	161	N. Kinsley - Edwards - St. John (Rebuild)	Staff	115
Sub 376 - Monett City South Transformer (161/69)	Staff	161	St. John - Huntsville - Hutchinson Energy Center (Rebuild) (NTC)	Staff	115
Sub 383 - Monett - Sub 376 - Monett City S.	Staff	161	Tecumseh Energy Center - Tecumseh Hill (Terminal Upgrades)	Staff	115

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Appendix B – STEP Model Construction

The reliability analysis uses 2014 Summer Peak, 2014/15 Winter Peak and 2019 Summer Peak cases with updates from nearby regions and entities. The STEP load flow cases were built using 2009 series MDWG Models On Demand (MOD) process. The load and capacity forecast for the flow cases have included the impact on load of the existing and planned demand response resources. Due to the recent economic downturn, SPP provided an opportunity for its members to change their load forecast information. The 2009 STEP Build 3 models were created to include this new forecast information. These models were completed in June 2009

- Treatment of Transmission Owner-Initiated Projects
  - Transmission Owner-Initiated Projects as determined by the Transmission Owner were included.
    - MOD Type – Reliability
    - MOD Status STEP (with Notice to Construct (NTC))
    - Planned Projects
- Treatment of previous SPP Transmission Expansion Plan Projects
  - All projects that have either a Letter of Authorization (LOA) or NTC are included in the model except projects requested for removal through the stakeholder review process.
    - MOD Type- Reliability
    - MOD Status STEP (with NTC)
    - TO Planned
  - Due to the economic downturn requiring new load forecast and a short lead time to complete the STEP, stakeholders could request projects with NTCs to be re-evaluated if the request was received by June 1, 2009.
  - Balanced Portfolio projects with NTCs were included in the June models. Projects with NTCs that have been identified as impacted by the Balanced Portfolio were re-evaluated.
- Treatment of SPP Aggregate Study (Attachment Z) Projects
  - All projects that have either an LOA/NTC are included in the model except projects requested for removal through the stakeholder review process.
    - MOD Type TSR
    - MOD Status w/NTC (Approved)
- Treatment of transmission interconnection facilities of new generation
  - Include the interconnection facilities with executed agreements not on suspension
  - MOD Type LGIP
    - MOD status GIP.
- Include all MOD projects that have been energized
  - MOD Type Network
  - MOD type Energized
- Include all MOD projects that change network topology status
  - Constructed facilities that are out-of-service or normally open
    - MOD Type Outage
    - MOD Status Outage
- Include all MOD projects that update network data

- MOD Type Network
- MOD Status Update.

- Scenario cases
  - Staff developed six scenario cases for each season for the steady state evaluation
    - The "Zero case" had the same dispatch as the MDWG cases with the exception that generation that does not have a signed interconnection agreement and generation that does not have transmission service is also removed. The exception to this is in later years when generation load and interchange does not match the shortfall is made up of units that are in-service.
    - The "West to East" scenario 1 case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact West to East flowgates with ERCOTN HVDC Tie South to North, ERCOTE HVDC Tie East to West, SPS exporting, and SPS exporting from the Lamar HVDC Tie.
    - The "East to West" scenario 2 case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact East to West flowgates with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC Tie.
    - The "South to North" (Scenario 3) scenario case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact South to North flowgates with ERCOTN HVDC tie South to North, ERCOTE HVDC tie East to West, SPS exporting, and SPS exporting to the Lamar HVDC Tie.
    - The "North to South" (Scenario 4) scenario case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact North to South flowgates with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC tie.
    - The "All transactions" scenario 5 case is the same as the zero scenario case with the dispatch changed to include all transmission service sold with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to the Lamar HVDC tie

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Appendix C – Wind Siting for Priority Projects

The Priority Projects have defined several levels of wind penetration to be studied in the SPP footprint. For each level (Base Case (5%), 10% and 20% Energy Penetration), a set of generators was included in the studies. The Priority Projects Cases and their respective amounts of wind generation are shown in Table 1 below:

Base Case (5%)		***10% Case***		***20% Case***	
State	**Installed Nameplate Wind Capacity (GW)**	**State**	**Installed Nameplate Wind Capacity (GW)**	**State**	**Installed Nameplate Wind Capacity (GW)**
KS	1.05	KS	1.24	KS	2.64
MO	0.00	MO	0.00	MO	0.10
NE	0.18	NE	0.57	NE	0.74
NM	0.20	NM	0.15	NM	0.21
OK	0.85	OK	0.48	OK	1.75
TX	0.71	TX	1.41	TX	1.39
Total	**3.00**	**Total**	**6.84**	**Total**	**13.67**

Table 1 - Wind Generation Levels in Priority Projects

The amount of wind generation placed in the models (nameplate MW capacity) was based on wind energy penetration levels studied. The WITF looked at base case, 10% wind energy penetration, and 20% wind energy penetration levels. It was determined that typical annual energy sales in SPP in a certain year totaled 236,000 GW-hours. For wind to serve 10% of these energy needs, SPP would need at least 23,600 GW-hours of energy from wind throughout the course of the year.

To serve 23,600 GW-hours using a fully dispatchable resource at 100% nameplate would take a resource of 2.69 GW (23,600 GW-hours / 8760 hours). Assuming the Class 3 and 4 wind zones throughout the SPP footprint, it was estimated that annual capacity factor from wind generation would average 40% of installed nameplate capacity. This calculation required the installation of approximately 6.8 GW of wind generation throughout the SPP footprint (2.69 GW/ 40%).

The ESWG Members voted following a conference call on August 10, 2009 to use the wind locations used for the Base (5%), 10% and 20% cases from the WITF in the Priority Projects study. A detailed list of these wind sites is included as Appendix D – Wind Generation in Priority Projects. These wind levels are illustrated on the maps below:

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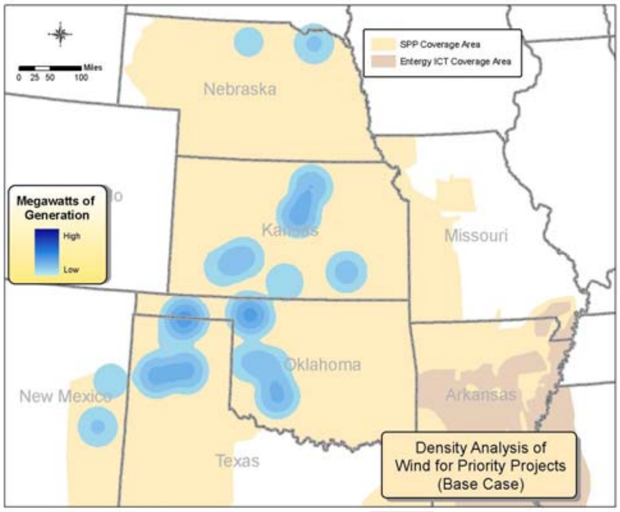

Figure 1 – Base Case (5%) Wind Location Map

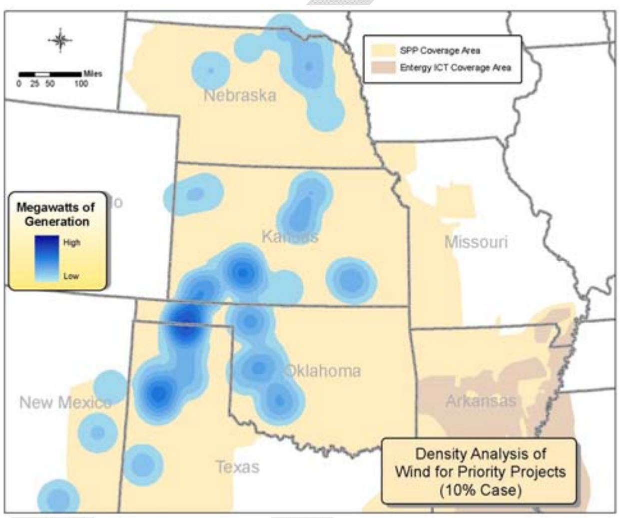

Figure 2 – 10% Case Wind Location Map

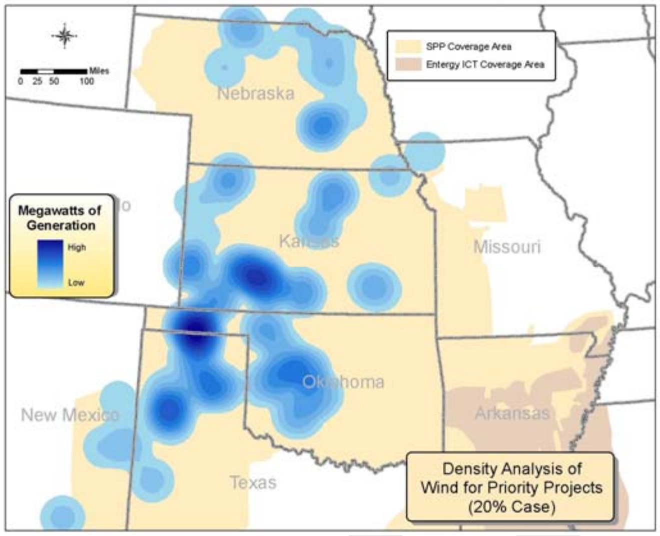

Figure 3 – 20 % Case Wind Location Map

When modeling this wind generation, it was noticed that several of the generators do not have the point of interconnection bus modeled in PowerBase. In order to expedite the analysis, the wind was modeled at the nearest bus, using the following assumptions:

- For any wind farm to be tapped on a certain line, it was added at one of the terminal buses of the line.
- For any wind farm to be added on a certain bus which was not modeled, it was modeled at a >=100kV bus in the county listed in its interconnection request.

The wind modeled in the footprint for the Priority Projects were connected to the locations related to the Generation Interconnection (GI) queue details submitted. Wind plants will be dispatched according to actual wind profiles. Wind data taken from the operations of the grid, representing an expected wind profile for each farm, will be used to simulate the future profiles for the same farm. Where no wind data is available, the nearest wind location was used as a proxy in lieu of actual wind generation profiles.

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Appendix D – Wind Generation in Priority Projects

The Wind Integration Task Force (WITF) grouped the wind following a sequence, where the requests with a higher position in the generation interconnection queue were used first to compose the study cases. The sequence for the requests is: IA fully executed/commercial operation (2877 MW), IA fully executed/on schedule (1479 MW), facility study completed (1464 MW), facility study in progress (755 MW), impact study completed (635 MW), impact study in progress (635 MW) and feasibility study completed (4826 MW). This was based on the status of the generation interconnection queue in February, 2009. Also, the task force included interconnection requests in Nebraska totaling 1312 MW. The point of interconnection and the output for these requests were provided by the Nebraska entities as SPP was not coordinating interconnection requests in the Nebraska entities' interconnection queue in February 2009. The WITF did not include interconnection requests whose interconnection agreement had been placed on suspension or interconnection requests with IA pending status. However, the exclusion of these requests is not thought to be material in that the included interconnection requests represented a similar geographic distribution of wind generation as those requests that were excluded.

WITF GROUP	GI REQUEST	Capacity	AREA	COUNTY	STATE	Status
B	AINSWRTH	60	NPPD	BROWN	NE	
B	CRFTNHLS	42	NPPD	KNOX	NE	
B	ELKHRNRDG	81	NPPD	KNOX	NE	
B	GEN-2001-014	96	WFEC	HARPER	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2001-026	74.25	WFEC	COMANCHE	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2001-033	120	SWPS	CHAVES	NM	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2001-036	80	SWPS	QUAY	NM	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2001-037	102	OKGE	WOODWARD	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2001-039M	110	WERE	WICHITA	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2002-004	75	EMDE	BUTLER	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2002-004	75	EMDE	BUTLER	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2002-005	114	WFEC	ROGER MILLS	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2002-009	80	SWPS	HANSFORD	TX	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2002-022	160	SWPS	OLDHAM	TX	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2002-025A	100.5	KACP	FORD	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2003-004	100	WFEC	CADDO	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2003-006A	110	WERE	CLOUD	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B		110	EMDE	CLOUD	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2003-019	100	MIDW	ELLSWORTH	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B		150	MIDW	ELLSWORTH	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2003-020	80	SWPS	CARSON	TX	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2003-022	120	AEPW	CUSTER	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2004-020	27	AEPW	CUSTER	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2004-023	20.6	WFEC	CADDO	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2005-003	30.6	WFEC	CADDO/KIOWA	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2005-008	130.5	OKGE	HARPER	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION

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WITF GROUP	GI REQUEST	Capacity	AREA	COUNTY	STATE	Status
B	GEN-2006-021	110	WERE	BARBER	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	GEN-2006-024S	18.9	WFEC	HARPER	OK	IA FULLY EXECUTED/COMMERCIAL OPERATION
B	LLANOEST	80	SPS	CARSON	TX	Operational
B	MONTE	110	MKEC	MONTEZUMA	KS	Operational
B	SPSDIST	10	SPS	MOORE	TX	Operational
B		10	SPS	MOORE	TX	Operational
B		10	SPS	MOORE	TX	Operational
B		10	SPS	MOORE	TX	Operational
B		10	SPS	SHERMAN	TX	Operational
B		10	SPS	SHERMAN	TX	Operational
B		10	SPS	HANSFORD	TX	Operational
B		10	SPS	TEXAS	OK	Operational
B		10	SPS	TEXAS	OK	Operational
B*	GEN-2002-008	240	SWPS	HANSFORD	TX	IA FULLY EXECUTED/COMMERCIAL OPERATION
Base Case Capacity Subtotal		2,997.35				
10%	ANTELOPECO	111	NPPD	ANTELOPE	NE	
10%	BOYDCO1	124.5	WAPA	BOYD	NE	Operational
10%	BUTLERCO	105	NPPD	BUTLER	NE	Operational
10%	COOKERCO	108	NPPD	COOKER	NE	Operational
10%	GEN-2002-006	150	SWPS	TEXAS	OK	IA FULLY EXECUTED/ON SCHEDULE
10%	GEN-2002-022	80	SWPS	OLDHAM	TX	IA FULLY EXECUTED/COMMERCIAL OPERATION
10%	GEN-2002-025A	49.5	KACP	FORD	KS	IA FULLY EXECUTED/COMMERCIAL OPERATION
10%	GEN-2003-005	100	WFEC	CADDO	OK	IA FULLY EXECUTED/ON SCHEDULE
10%	GEN-2003-020	80	SWPS	CARSON	TX	IA FULLY EXECUTED/COMMERCIAL OPERATION
10%	GEN-2005-012	250	SUNC	FORD	KS	IA FULLY EXECUTED/ON SCHEDULE
10%	GEN-2005-016	150	WERE	ELK	KS	IA FULLY EXECUTED/ON SCHEDULE
10%	GEN-2006-006	205.5	MKEC	FORD	KS	FACILITY STUDY IN PROGRESS
10%	GEN-2006-020S	19.8	SWPS	HANSFORD	TX	IA FULLY EXECUTED/ON SCHEDULE
10%	GEN-2006-034	81	SUNC	SHERMAN	KS	IA FULLY EXECUTED/ON SUSPENSION
10%	GEN-2006-040	100	SUNC	THOMAS	KS	IA FULLY EXECUTED/ON SCHEDULE
10%	GEN-2006-043	99	AEPW	BECKHAM	OK	FACILITY STUDY COMPLETED
10%	GEN-2006-044	65	SWPS	HANSFORD	TX	IA FULLY EXECUTED/ON SCHEDULE
10%		139	SWPS	HANSFORD	TX	
10%		196	SWPS	HANSFORD	TX	
10%	GEN-2006-045	240	SWPS	RANDALL	TX	IA FULLY EXECUTED/ON SUSPENSION
10%	GEN-2006-046	130	OKGE	DEWEY	OK	IA FULLY EXECUTED/ON SUSPENSION
10%	GEN-2006-047	240	SWPS	RANDALL	TX	IA FULLY EXECUTED/ON SCHEDULE
10%	GEN-2006-048	150	SWPS	EDDY	NM	WITHDRAWN
10%	GEN-2006-049	141	SWPS	SEWARD	KS	FACILITY STUDY IN PROGRESS
10%		139	SWPS	SEWARD	KS	
10%		120	SWPS	SEWARD	KS	

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WITF GROUP	GI REQUEST	Capacity	AREA	COUNTY	STATE	Status
10%	GEN-2007-004	150	SWPS	TERRY	TX	WITHDRAWN
10%	GEN-2007-005	200	SWPS	HUTCHINSON	TX	IMPACT STUDY COMPLETED
10%	MADISONCO	120	NPPD	MADISON	NE	
10% Case Capacity Subtotal		6,840.65				
20%	CHERRYCO	272	NPPD	CHERRY	NE	
20%	GEN-2007-006	200	OKGE	BLAINE	OK	IA FULLY EXECUTED/ON SUSPENSION
20%	GEN-2007-008	300	SWPS	GRAY	TX	IMPACT STUDY COMPLETED
20%	GEN-2007-010	200	SWPS	CASTRO	TX	IMPACT STUDY COMPLETED
20%	GEN-2007-011	135	SUNC	HAMILTON	KS	IA FULLY EXECUTED/ON SCHEDULE
20%	GEN-2007-012	300	SUNC	RAWLINS	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-013	99	SUNC	WICHITA	KS	FACILITY STUDY COMPLETED
20%	GEN-2007-015	129	WERE	NEMAHA	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-017	101	MIPU	NODAWAY	MO	FACILITY STUDY COMPLETED
20%	GEN-2007-019	187.5	SWPS	HAMILTON	KS	IMPACT STUDY COMPLETED
20%		187.5	SWPS	HAMILTON	KS	
20%	GEN-2007-021	201	OKGE	DEWEY	OK	IMPACT STUDY COMPLETED
20%	GEN-2007-025	300	WERE	BARBER	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-026	130.2	SWPS	DEAF SMITH	TX	WITHDRAWN
20%	GEN-2007-027	60	SWPS	CURRY	NM	IMPACT STUDY COMPLETED
20%	GEN-2007-028	200	MKEC	CLOUD	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-030	200	SWPS	GRAY	TX	IMPACT STUDY COMPLETED
20%	GEN-2007-032	150	WFEC	CUSTER	OK	IMPACT STUDY COMPLETED
20%	GEN-2007-033	100	SWPS	HUTCHINSON	TX	IMPACT STUDY COMPLETED
20%		100	SWPS	HUTCHINSON	TX	
20%	GEN-2007-034	150	SWPS	ROOSEVELT	NM	IMPACT STUDY COMPLETED
20%	GEN-2007-036	200	SUNC	FORD	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-037	200	SUNC	FORD	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-038	200	SUNC	FORD	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-040	500	SUNC	GRAY	KS	IMPACT STUDY COMPLETED
20%	GEN-2007-041	600	SWPS	TEXAS	OK	IMPACT STUDY COMPLETED
20%	GEN-2007-042	360	SWPS	HANSFORD	TX	IMPACT STUDY COMPLETED
20%	GEN-2007-043	300	OKGE	GRADY	OK	IMPACT STUDY COMPLETED
20%	GEN-2007-044	300	OKGE	BLAINE	OK	IMPACT STUDY COMPLETED
20%	HAMILTONCO	301	NPPD	HAMILTON	NE	
20%	PIERCECO	171	NPPD	PIERCE	NE	
20% Case Subtotal		13,674.85				

B*   PARTIAL BASE CASE DISPATCH-DISPATCHED FULLY IN 10% CASE

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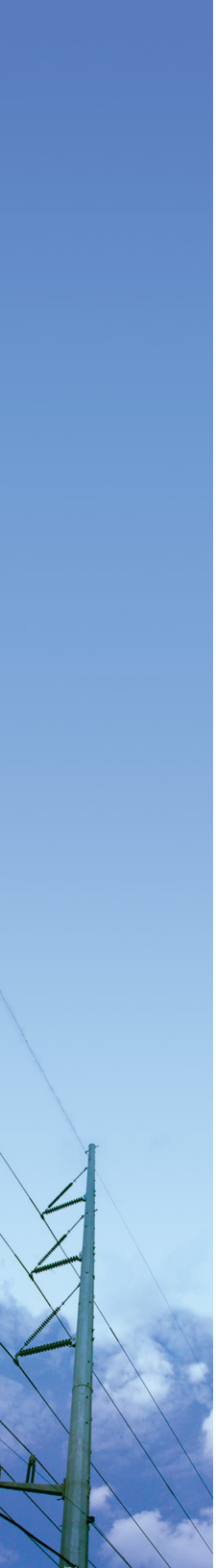
Attachment 1 – BATTF Report



Benefit Analysis for Priority Projects

July 24, 2009

Disclaimer: This report is for Priority Project evaluation only. No reference for cost allocation is implied or intended.

Southwest Power Pool

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Introduction

By recommendation of the Synergistic Planning Project Team (SPPT), the Economic Studies Working Group (ESWG) was asked to develop benefit analysis techniques for transmission planning with the goal of creating a robust, flexible, and cost-effective transmission system. The ESWG is currently developing the metrics to be used in the Integrated Transmission Planning (ITP) process.

The Benefit Analysis Techniques Task Force (BATTF) was created as a quick response team to address the immediate need to determine the formulation of the metrics to support Priority Project analysis, an interim measure specified by the SPPT until the ITP process is functional.

Significant time is required to fully develop the metrics for the ITP and integrate the existing transmission planning processes. This document and the metrics contained within will be a “living document”, subject to change as the process matures and develops.

This document is presented as a working draft of the benefit metrics to be used primarily for Priority Projects and as a starting point for the ITP benefit metrics calculations. The final list of Priority Projects and the ITP process will be presented to the SPP Board of Directors for approval in October 2009.

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Scope of Work and Metrics for Formulation

The scope of the BATTF effort is to standardize formulation and analysis techniques for SPP study metrics so Priority Projects are evaluated on a consistent basis. Another goal of the BATTF is to develop a standard reporting format to maximize market participants' and stakeholders' understanding of the results.

If approved by the ESWG, results of the BATTF's efforts will be utilized as a starting point for future ITP process evaluation and will be incorporated into the ESWG's Economic Studies Manual.

The BATTF was asked to consider and formulate for use with Priority Projects the following metrics:

1. **Adjusted Production Cost** (APC) – Projects will be screened to determine their individual APC benefit for SPP. This benefit metric is typically simulated using a production cost modeling tool accounting for 8760 yearly hourly profiles of system-wide commitment and dispatch modeling taken over the course of the study period.

2. **Environmental Impacts** – SO_2, NO_X, CO_2, and mercury can be modeled in a study for the fuel type used in the generating units. Once stakeholders determine a value per ton for the emissions, the cost of emissions can be calculated for the units. Transmission upgrades can then be used to determine the net impact on emission pricing.

3. **Reliability Impact** – Economic transmission upgrades can have an impact on reliability. This benefit is seen when reliability projects are deferred or displaced through construction of more efficient, regional projects. The advancement of reliability projects must also be considered when determining the total overall impact of a collection of economic expansions.

4. **Deliverability of Capacity and Energy to Load** – Projects will be assessed on their ability to provide or act as enablers for power to be delivered from firm designated resources to respective loads. These projects are typically associated with transmission service requests for new designated resources, but could also be bulk EHV projects for regional transfer capability.

5. **Impact on Losses** – Lower impedance transmission lines provide a loss savings to the transmission grid. The energy component of the loss savings can be captured as part of a production cost analysis tool. Capacity savings associated with a loss reduction can be determined by looking at select hourly models to determine loss reduction.

6. **Local Economic Benefits** – Transmission construction provides local economic development and job creation benefits. These benefits will probably reside in the state where each project is constructed.

Results of the BATTF Efforts

The BATTF recommends using the Net Present Value (NPV) over 10 years with a terminal value rather than a benefit to cost ratio for the Priority Projects. This rationale is based on the following:

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- The time frame for determining the Priority Projects is very short and there is currently no existing model that has a greater than 10-year time frame. Unless the Board directs the ESWG and SPP staff to develop a 20-year or greater model, a current model must be used.

- A positive NPV over 10 years is a fair indicator of determining a project's priority. This is not a decision to implement a project, just an indicator of the priority of a project. A project with a higher NPV may have a higher cost, so other metrics should be used when evaluating whether a Priority Project should be implemented. Conversely, if a project has a negative NPV, it can be eliminated from the list.

- The logical assumption is that after 10 years, if there is a positive NPV, then a BC ratio of more than 1.0 is more probable.

- If a cost benefit indicator over 10 years is used, the ESWG will need to determine what assumptions should be addressed beyond the 10-year horizon. This will require additional study and will not meet the projected delivery date of October 2009.

- The BATTF is unsure whether the cases for evaluation have adequate data and background beyond 10-year analysis, or whether or not they should be vetted with stakeholders before implementing them into a long-term model.

- The BATTF is assuming there is a limit on the amount of money for Priority Projects and will have to choose from projects with positive NPVs (the "low hanging fruit" projects). Other indicators will need to used to adequately pick the best projects based on the metrics that the group has identified below.

Based on conversations with the ESWG, the BATTF has been asked to concentrate its efforts on the following metrics:

Adjusted Production Cost

Adjusted production cost is a measure of the impact on production cost savings by node (LMP), accounting for purchases and sales of economic energy interchange. This benefit metric is typically simulated by a production cost modeling tool accounting for 8760 yearly hourly profiles of commitment and dispatch modeling, taken over the course of the study period.

Nodal modeling is aggregated on a zonal basis using weighted LMPs. There is concern that modeling the border points will not be accurate without additional Eastern Interconnection points. For example, the border LMPs will have significant impact on the Adjusted Production Cost within SPP. If there are lower LMP prices outside SPP there will be no transfers from the western portion of SPP. Therefore, the BATTF recommends the model should broaden the footprint to include Southern Companies, Ameren, Basin, WAPA, TVA, PJM, MISO, and the DC ties (using the recent historic patterns) at a minimum when running the model to assess the impact on the borders. The group recognizes the increased run time required and the short time for analysis of the Priority Projects.

The BATTF recommends that gas prices should be based on Henry Hub NYMEX ten-year, plus a Panhandle basis difference. For other fossil fuel prices, publicly-available data should be used.

The BATTF recommends that wind in the models be at a rate of $6.00 per MWH, based on the variable Operation and Maintenance (O&M) cost of a wind farm for the first three years of operation. The BATTF recommends using the same rate for other renewables that was used in the Balanced Portfolio analysis.

A nodal analysis will be completed that aggregates on a zonal basis using the following formulation highlighted. The calculation, performed on an hourly basis, will be:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases
Where:
Revenues from Sales = MW Export x Zonal $LMP_{\text{Gen Weighted}}$
and
Cost of Purchases = MW Import x Zonal $LMP_{\text{Load Weighted}}$

Tools used for this analysis will include standard assumptions and modeling using PROMOD, PowerWorld, or equivalent production cost software.

The rationale for using this methodology is as follows:

- This formula was previously approved by stakeholders, the Market and Operating Policy Committee, and the SPP Board as part of the Balanced Portfolio analysis.

- The formulation represents the broad impact of new transmission projects in changing LMP costs (energy, congestion and losses cost) to rate payers within the SPP footprint. It therefore represents much of the savings/benefits or additional cost to rate payers for specific transmission projects.

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Impact on Losses

Lower impedance transmission lines provide a loss savings to the transmission grid. The energy component of the loss savings is captured as part of the above production cost analysis tool. It is possible that losses will increase since generation sources will be remotely located from load centers.

Capacity savings associated with a loss change are determined by looking at the selected hourly loadflow models to determine the loss change associated with a transmission upgrade. The BATTF has established standard capacity prices to capture capacity savings. Formulation will be based on an aeroderivative Combustion Turbine (CT) replacement, currently priced around $750 per kW installed (based on the expected cost to install of various types of machines used by BATTF members).

There is a fixed O&M cost component based on $650,000 per year (average expected cost experienced by BATTF members). The energy component of losses is captured in the formulation above. This an additive benefit component for capturing the capacity component of that energy typically passed on to rate payers through Ancillary Service charges. This is variance in quantity of energy (capacity).

The calculation:

- Capacity Savings at Coincidental Peak = ((Capacity requirement at Peak (base case) – Capacity requirement at Peak (with projects upgrades included)) x (CT replacement cost)).

  This would be a straight savings estimate of the capacity, since the CT installation would be a one-time cost when the upgrade was energized.

- There is a fixed O&M cost savings associated with this calculation, usually captured in the Ancillary Services fee.

  It should be calculated as Fixed Cost Benefit = (Capacity savings (as determined from above per 150 MW) x $ 650,000/yr), escalated by the rate of inflation as reported in Bureau of Economic Analysis.

- The price differential would be calculated on an annual basis from the point the proposed upgrade would be energized to the end of the defined 20-year period. There should be no additional accommodation for savings after 20 years, because a CT has an estimated 20-year life span.

- This formulation is the estimated benefit or cost Impact of Losses.

Environmental impacts

The BATTF's primary assumption is that SO2 and NOX will be approximated using pricing curves from the Chicago Climate Exchange; this represents our best estimate of current market prices. Mercury will not be addressed in this metric due to the lack of valid market information. The BATTF discussed at length the merits for CO2; our assumption is that the high price in the long term (20 years) is determined by 100% sequestration currently valued at between $80 and $102 per ton ($91 per ton average) from the Mountain Air Plant DOE project. The low price is based on the current price of CO2 from the Chicago Climate Exchange.

Our assumption is to escalate the current price up to $91 per ton in year 20, based on unknowns with government regulation. Emissions values should be based in a range that reflects the maximum and minimum from various sources, using a high case and low case probability. Example: the high case could be current prices times 3 and the low case could be current prices times 0.5. The base case should be established using the ESWG's opinion of future scenarios (based on current information). Therefore, the reference future will be based on the latest information from sources such as legislative outlooks, technology improvements, state regulations, and other data sources.

The BATTF determined that this calculation is viewed as a less definitive, but still quantitative, formulation. Since Cap and Trade legislation is under discussion and there is no clear direction - but a higher probability - that that a higher price bias exists, we recommend using a 60-40 weighting. The BATTF believes there will be federal legislation; there is a 40% chance the lower case will happen and 60% chance the high price case will happen. (There is also the possibility of the federal government spearheading transmission construction.) Using this formula, we get (60% x $91/ton) + (40% x $0/ton)= $54/ton

The BATTF discussed whether modeling should reflect year 1, year 5, and year 10 evaluation points. It is the BATTF's opinion that as carbon prices increase, wind resources will increase. Therefore, a linear interpretation of the carbon cost curve is a reasonable cost curve. The BATTF discussed running two carbon scenarios with a low and a high carbon value; we need both of these to see what the impact will be on generation dispatch to provide the best determination of the impact of carbon on transmission projects. Without this type of modeling run, the CO2 benefits for transmission projects will cause any transmission project to have benefits in excess of its cost if it displaces coal or gas generation. Due to the time constraints for this type of modeling and runs, and given the current state of the model and the input and model development required, this analysis will not be delivered by October 2009. An approximation for the impact of CO2 can be to have the model produce the amount of tons of CO2 from the Base Case minus the amount of tons saved from the addition of the transmission projects and show a potential range of CO2 prices for comparative purposes. A table can be calculated as follows:

Case Description	Tons of CO2 Produced	Reduction from Base Case at $15/Ton	Reduction from Base Case at $54/ton
Base Case		N/A	N/A
All Priority Projects Priority Project 1			
Priority Project 2			
Priority Project 3			
Priority Project 4			

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Priority Project 5			
Priority Project 6			
Priority Project 7			
Priority Project 8			
Priority Project 9			
Priority Project 10			

Based on the above discussion, the BATTF recommends that SO2 and NOX be evaluated for Priority Projects and CO2 be evaluated as a post analysis based on tons of CO2 produced at $15 and $54 per ton.

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Increased Reliability

The advancement/expedition of SPP Board-approved reliability projects must be considered to determine the total overall impact of economic upgrades. The formula would be based on SPP Transmission Expansion Plan (STEP) reliability projects deferred or advanced, and the benefit would be linked to the dollar impact on the NPV of Annual Transmission Revenue Requirements (ATRR) savings for the deferral/advancement.

The recommended benefit calculation should be:

$\sum$ (STEP Projects Deferred ATRR - STEP Projects Advanced ATRR), taken for years deferred/advanced

Note: If a STEP Project is eliminated, the ATRR for the 40-year life of the asset would be calculated based on the year in which the upgrade was scheduled to go into service.

Local Economic Benefits

Local economic development, job creation, etc. fall under the umbrella of local economic benefits. These benefits will most likely reside in the state where the each project is constructed. The task force recommends using an SPP or consultant model for economic studies to describe local economic impact, which can then be endorsed by the ESWG for ITP benefit analysis. Preliminary discussion suggests this calculation will be difficult to qualify on a multi-county or multi-jurisdictional basis. Historically, economic analysis for local economic benefits has taken 7-10 days per construction project. A more realistic calculation would be a formula based on standard economic impact analysis to provide analysis for the SPP region.

The BATTF recommends not using a detailed local economic impact calculation for Priority Project evaluation. The economic impact calculation should be part of the ITP process. This metric should be developed in conjunction with economic experts/consultants to provide the true local economic impact. For Priority Projects, the BATTF recommends using project construction costs instead of the full local economic impact on the project's location. The cost of the project needs to be framed and explained to avoid cost allocation issues.

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Deliverability of Capacity and Energy to Load

A change in deliverability should be reflected in more or less variation in the LIP or LMP prices across the SPP footprint. If deliverability is improved, it would be reflected as a decrease in variation. Since variation and its statistical metrics are difficult to explain, the following metric has been developed using the capabilities of ProMod or a similar nodal modeling tool.

The LMP price at each node is the sum of three price components:
(1) the energy price component
(2) the price component for losses
(3) the congestion price component

All of these component prices are added to make the LMP price at each node. During each hour of the year, each node across the SPP footprint has an associated LMP price and quantity of energy injected (generation) or withdrawn (load) from the system. Generation or injected energy carries a positive sign (+) and loads or withdrawn energy is negative (-).

The congestion component of those LMP nodes will change as a new transmission line is added to relieve congestion. The sum congestion cost within the region will change as new transmission lines are added, providing an effective measure of the impact on deliverability. If the assumption is made that deliverability is the inverse of congestion, we now have a way to measure deliverability in dollars rather than using statistical terminology. These dollars are not additive to the APC metric, since doing so would mean congestion costs are being double counted.

The metric will determine which lines reduce the most congestion. It can also be seen as a variance in price.

The BATTF recommends capture deliverability using the following formulation:

> Congestion Cost at baseline – Congestion Cost with new project = Improved Deliverability Benefit[5]

An alternative formulation:

> Total System Congestion[6] Before Upgrade – Total System Congestion After Upgrade

SPP's PROMOD function has the capability to divide LMP points into energy, congestion, and loss components. The focus of this metric would be on the congestion component.

[5] losses must be fixed and captured separately before congestion cost can be calculated
[6] potentially shown as shadow prices

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Additional Recommendations

1. The ESWG needs to determine the assumptions to be used in developing a 20-year model.

2. The ESWG needs to develop, with support of SPP staff, a 20-year model for the ITP Process.

3. To meet the October 2009 deadline for recommending Priority Projects, assumptions in the modeling and analysis need to be simplified:
   a. Use the existing Balanced Portfolio model as the primary model for benefit analysis.
   b. Assumptions used in the Balanced Portfolio for wind generation, or as recommended by the ESWG, should be used for analysis. This is a critical piece of data to begin modeling.

4. Another possible metric for consideration by the ESWG would be a Return on Investment (ROI) to capture those projects that yield better returns for the footprint.

5. Value at risk concepts can be applied directly to hourly LMP time series. We cannot use this metric to produce a dollar value that has value at risk meaning in a traditional sense. We would need to use Monte Carlo simulation and look at the problem hourly for this to work. However, we can still get a good look at the standard deviation, and make an ordinal decision regarding which project provides more benefit along the variance dimension. Here is how we would work the mathematics:

   a. Calculate LMP's for both the base case and change cases (e.g., run the cases).

   b. Calculate the LOAD weighted LMP for these cases for the entire SPP region for each hour. This will give us 8760 load weighted observations for each case.

   c. Calculate the natural log differences between the sequential hourly weighted LMPs for each case. That is, LN(HR2) - LN(HR1), etc.

   d. Calculate the standard deviation of these log differences for each case.

   e. If a project reduces congestion, the standard deviation of the change case will be lower than the base case. The greater the difference, the better the project is.

We are already using "other" metrics to evaluate our positive NPV projects given a budget constraint. This would be another good one.

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