SPP Southwest Power Pool

Transmission Network Economic Modeling & Methods

Prepared by SPP Staff
SPP Engineering Planning

As approved by the EMMTF: April, 2006

Table of Contents

1 Introduction

In the Federal Energy Regulatory Commission ("FERC") Order Granting RTO[1] Status Subject to Fulfillment of Requirements issued February 10, 2004 (the "Order Granting RTO Status"), FERC directed the Southwest Power Pool ("SPP") to be the Planning Authority and to plan for projects needed for economic reasons as well as those required to maintain compliance with reliability criteria. Pursuant to the SPP Open Access Transmission Tariff ("Tariff"), SPP is responsible for developing the SPP Transmission Expansion Plan (the "Plan"). To develop the Plan, SPP performs transmission planning studies to:

- Assess the reliability and economic operation of the SPP Transmission System;
- Identify Base Plan Upgrades; and
- Identify elective upgrades that have potential economic benefit to the SPP Region, but are not required for reliability reasons.

This document describes how models will be developed to identify upgrades that have potential economic benefit ("economic upgrades") and how such economic upgrades will be evaluated. This document does not address cost allocation for economic upgrades.

1.1 Background

In the SPP planning process, the upgrades required to support the transmission system are categorized as either reliability upgrades or economic upgrades. Identification of reliability upgrades is based on power flow studies that are performed on the power system for snapshot hours, including seasonal on-peak and off-peak periods. The generation that is used in these studies takes into consideration the dispatch order for Designated Network Resources ("DNRs") to meet the load of each Load-Serving Entity ("LSE"). However, the substitution of lower-cost power from other generating resources (economic transactions) is not taken into account in these reliability studies.

Identification of economic upgrades is based on modeling that includes both power flows and the substitution (re-dispatch) of lower-cost generation for more expensive generation where the secure limits of the transmission system allow such substitution to take place. These economic studies apply the same or highly similar network detail that is included in the reliability studies. Moreover, the emphasis of economic upgrade studies is on projected loadings of present and potential flowgates; i.e., elements of the transmission system that are likely to be operated at or near their capacity limits. The economic studies include simulation of unit commitment and security-constrained economic dispatch ("SCED") across the SPP region and a first tier of areas external to SPP, with less detailed modeling of an additional one or two tiers of areas beyond.

[1] Regional Transmission Organization ("RTO").

Having an independent assessment of benefits and costs related to proposed economic upgrades as performed by the SPP is important to State Regulators when they are evaluating whether or not project sponsorship by a jurisdictional utility is in the public interest or not detrimental to the public interest. As with any utility participation in resource acquisition, whether generation, transmission or in this instance, the impact of transmission on generation costs, State Regulators will want to have reasonable estimates of how the resource will likely impact the rates of retail customers, as well as an understanding of the uncertainties involved with ultimately realizing the expected benefits.

1.2 Creation & Purpose of the SPP EMMTF

The SPP Economic Modeling & Methods Task Force ("EMMTF") was established by the SPP Transmission Working Group ("TWG") to advise and assist SPP Staff in the determination of the appropriate data, sources, models, timing, applications and economic parameters to be used in the development and evaluation of economic upgrade alternatives for the next increments of the Plan. As part of its scope, the EMMTF was also charged with reviewing the economic planning process used by SPP Staff and offering proposals for the improvement of the process. The EMMTF addressed the following:

1. Data requirements – Determination of the necessary data required to model, study, and evaluate economic upgrade alternatives.
2. Solution techniques – Review of the solution techniques used in the prior Plans and provision of recommendations for improvement and/or alternatives.
3. Definitions – Definition, as necessary, of any terms used in the economic planning process, data, or assumptions in a way that provides clear understanding.
4. Assumptions – Review and revision, as appropriate, of the economic assumptions to be used in the development of the economic phase of establishing the Plan.
5. Methodologies – Review and modification, if appropriate, of the methodologies for overall quantification of economic impacts and the break-out of such impacts to individual market participants.

The scope of the EMMTF included the following deliverables for which the task force was responsible:

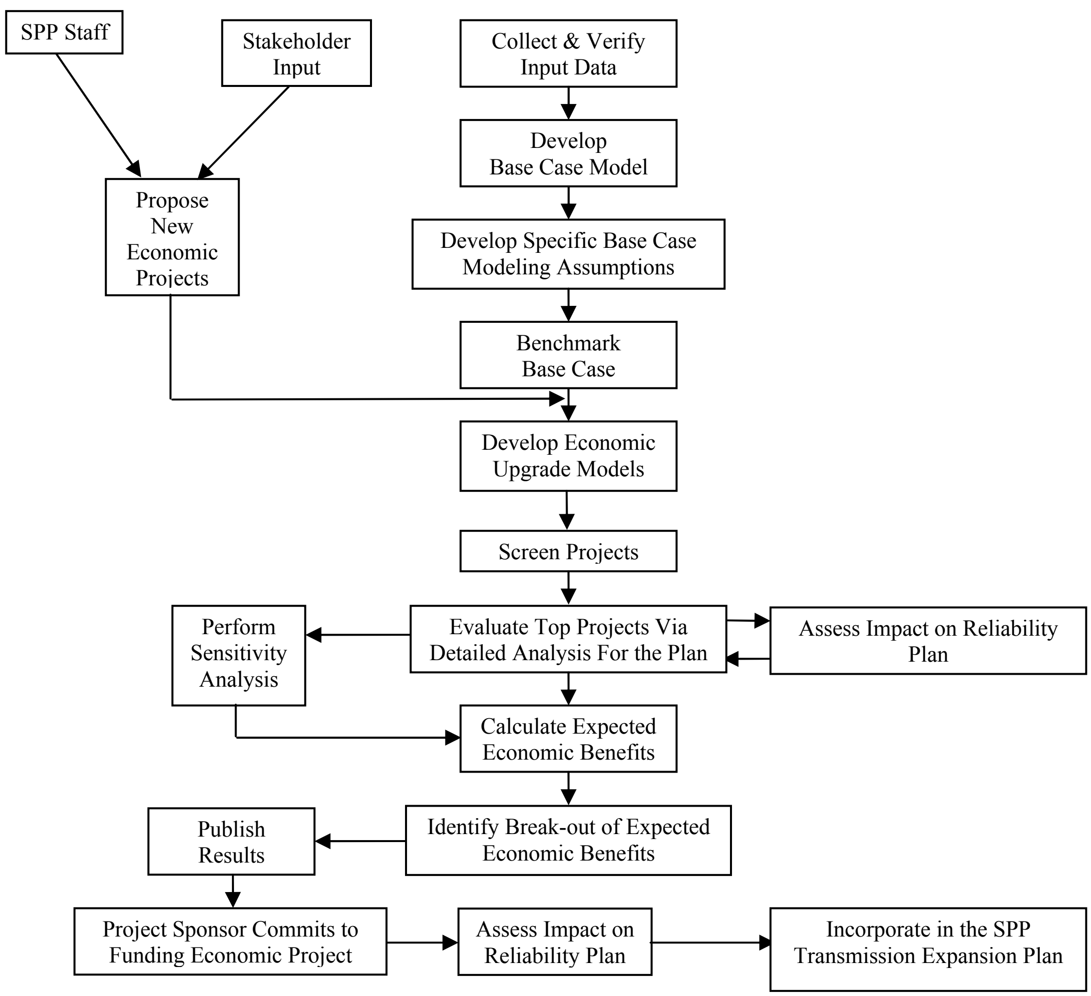
1. Documentation describing the data necessary to conduct the economic studies.
2. Templates to be used in supplying the necessary data.
3. Recommendations regarding assumptions to be used by SPP Staff in future economic analyses.

4. A glossary containing the definitions of terms used in assumptions, data and the economic planning process.
5. Recommendations regarding improvements to modeling/solution techniques and the economic planning process.
6. Papers or other discussions describing methodologies applied.

Another responsibility of the EMMTF was to assist SPP Staff in the determination of the scope of individual economic upgrade alternative studies; i.e., SPP Staff will principally focus on SPP region-wide metrics, with the individual members continuing to evaluate and provide expertise on many of their own specific geographical areas of interest, as well as providing SPP with regional guidance.

1.3 Economic Upgrade Analysis Process Diagram

The following diagram provides an overview of the economic upgrade model development and analysis process.



2 Transmission Planning Economic Upgrade Process Overview

2.1 Reliability & Economic Planning Process

As indicated in the Order Granting RTO Status, SPP is responsible for planning and directing or arranging transmission expansions, additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and to coordinate such efforts with the appropriate State authorities under Sections 2.1.5(b) and 2.1.1(j) of the Membership Agreement. Also, FERC recognizes that SPP is assigned the responsibility of designing a process to encourage open participation for market-motivated solutions to relieve long-term congestion; developing a streamlined queuing process for both generating unit interconnection and transmission service requests; and developing a pro forma generating unit interconnection agreement.

2.1.1 Reliability Planning Process

Attachment O of the SPP Tariff covers the Transmission Planning and Expansion Procedures used for reliability upgrades and to respond to requests for new transmission service. Since this document is focused on economic upgrades, there is no additional detail on reliability upgrades provided in this document.

2.1.2 Economic Planning Process

The economic planning process focuses on quantifying the economic benefits and costs of transmission expansion projects. The economic benefits of transmission expansion are driven by the impact on overall regional transmission congestion. The studies conducted by SPP estimate the overall impact on congestion across the modeled geographic footprint, and also identify which specific sub-regional areas and market participants will likely benefit from the quantified congestion reduction.

2.2 Quantifying Impacts on Transmission Network Congestion

The SPP economic studies and this document apply the term congestion in the most straightforward context – this being the amount that the cost of producing electric energy is impacted by constraints on transfer of energy across the bulk power transmission system. SPP applies a set of multi-regional simulation models to estimate the impact of network expansion and upgrade projects on generating unit dispatch and associated cost of producing electric energy across the modeled geographic footprint. A straightforward interpretation of the "societal impact" of reducing congestion is the ability to produce a dispatch of supply resources to serve electric loads which is closer to pure economic merit order.[2]

[2] If the analyses were to attempt an estimate of price elasticity (i.e., response of consumer loads to prices), the societal impact would include a "value" component associated with the change in use of electricity.

In some situations the simulations and analysis will be expanded to include the potential impact on generating unit commitment and associated costs. However, at present, the SPP geographic footprint includes 17 separate control areas which do not have a centralized generating unit commitment.

As is true for most economic cost/benefit analyses conducted in the industry, SPP analyses focus on marginal-cost based assessments. Sensitivity analysis may be performed to assist in addressing the impact of specific assumptions regarding pricing during scarcity conditions on the distribution of the projected benefits to sub-regional areas and market participants.

The simulations used to conduct the economic analysis consist of a multi-step process with the following characteristics:

- The simulations represent sub-regional area-based generating unit commitment and regional security-constrained economic dispatch (e.g., a feasible dispatch solution).
- The economic upgrade simulations reflect incremental transmission upgrades and the resulting change in security-constrained economic dispatch.
- The studies focus on the energy production cost differential between an economic upgrade case simulation and the base case simulation.
- The simulations identify which specific generating units are likely to experience change in dispatch as a result of the transmission upgrade. These generating units effectively utilize the additional transfer capabilities derived from the transmission upgrades. The marginal prices at the specific generator locations are later applied to estimate the value of the additional or reduced generation.

2.3 Screening Analysis

During the creation of each Plan, SPP Staff analyzes a wide variety of possible transmission upgrades identified by SPP Staff or suggested by stakeholders. The purpose of the screening analysis is to identify those potential upgrades most likely to produce positive net benefits and which, therefore, will be subject to more detailed analysis as described in this document.

For each potential economic upgrade, SPP estimates the construction cost of the upgrade and estimates the ten (10) year savings based on the net present worth of the total production cost savings. The potential economic upgrades are ranked in decreasing order based on the ratio of the estimated ten (10) year savings to the estimated construction costs. In the ranking of the projects, adjustments may be made to the estimated savings to take into account construction lead times. The projects with the highest ranking are then evaluated using the detailed analysis described in this document.

2.4 Quantification of Benefit-to-Cost

After performing the screening analysis, SPP evaluates the top projects via detailed analysis. This detailed analysis includes quantification of benefit-to-cost which is a two step process. The first step is the determination of whether there are positive net benefits associated with the transmission upgrade. The second step is to break-out the expected economic benefits by sub-regional area or market participant to provide to the stakeholders for informational purposes only. Details of these two steps are provided in Sections 7 and 8.

2.5 Sensitivity Analysis

Part of the analysis for each of the top projects includes an analysis of the sensitivity of the economics of the project to changes in assumptions. Examples of typical sensitivities include, but are not limited to, fuel prices, electric load growth rates, etc. SPP will solicit input from the stakeholders regarding the appropriate sensitivity analyses to be performed.

2.6 Reporting Requirements

Results will be published for the top projects that are evaluated using the detailed analysis described in this document. The published results will include:

- Study input assumptions (including data sources) including but not limited to:
  - Generating unit fuel price forecasts
  - Future generating unit expansions modeled as available for commitment and dispatch
  - Future generating unit retirements modeled
  - Electric load forecasts
  - Generating unit parameters (heat rates, forced outage rates, start-up costs, ramp rates, variable O&M, must-run status, maintenance outages)
  - Operating reserve requirements
  - Commitment and dispatch hurdle rates applied
  - Violation costs caps applied for exceeding flow limits
  - Transmission system network topology
  - Geographic modeling footprint
  - Impact of emission costs on dispatch cost where emission trading markets exist
  - Inflation rates applied to costs that are not specifically forecast
  - Discount rates applied

- Expected economic benefits (production costs + violation costs) over at least a 10 year period
- Break-out of expected economic benefits by sub-regional area or market participant
- Flowgate shadow prices (i.e., marginal value of additional transfer capability)

In all reporting activities, SPP Staff will take all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the SPP Tariff (i.e., Sections 17.2(iv) and 18.2(vii); Attachment V (Section 13.1 and Article 22 of Appendix 6); Exhibit 1 (Section 2.3); Attachment AJ (Section 8); and Attachment C-One (Clause 7)).

2.7 Ongoing Economic Modeling & Methods Process

2.7.1 Interaction with Other SPP Data & Modeling Activities

The transmission network models applied to transmission project/upgrade economic analyses are derived from underlying seasonal power flow cases as constructed and managed by the SPP Model Development Working Group ("MDWG"). SPP has developed specific procedures for converting underlying MDWG power flow cases for interface with the simulation models applied for network economic analyses.

For efficiency of activities within SPP, the same or similar transmission network models and simulation models are also applied to other market simulation and analysis activities within the SPP organization.

2.7.2 Review of Modeling Assumptions with Generator Owners

As part of the process of performing the first economic upgrade analysis phase of establishing the Plan, SPP Staff made some initial assumptions regarding modeling data for generating units. SPP Staff then worked with the individual generator owners to verify and refine the modeling data. The primary source of the initial modeling data was the database from *Global Energy Decisions*. This modeling data was cross referenced against the limited data that SPP had in-house. In March 2005, as part of a data verification process, SPP provided each generator owner with the modeling assumptions for its generating units; and requested verification of and corrections to the modeling data. In July and August of 2005, SPP Staff held discussions and corresponded with each generator owner to resolve any open issues.

Going forward, SPP Staff will review modeling assumptions for particular generating units or generating unit types with the individual owners of the generating units on a periodic basis as part of the process for the economic upgrade analysis phase of establishing future Plans. SPP will require the owners to provide updates to the generating unit modeling data via templates supplied by SPP. If generating unit modeling data changes between required updates, the owners should submit any revised data to SPP according to instructions posted on the SPP website. Also, at some point during the interconnection process for new generating units, SPP will require the generator owner to provide modeling data for the new generating unit to be used in the economic upgrade analysis phase of establishing future Plans.

2.7.3 Updates of Economic Modeling & Methods Document

SPP Staff will coordinate with the TWG to ensure that it is using the most appropriate economic models and methods in its analysis of economic upgrades. Material revisions to the economic models and methods applied by SPP will be submitted to the TWG for review and approval and will be reflected within future versions of this document.

3 Data Requirements

SPP Staff will periodically provide templates to be used in the provision of the data required to analyze potential economic upgrades in accordance with this document.

3.1 Confidentiality of Data

In addition to the treatment with respect to reporting requirements in Section 2.6, in all other activities SPP Staff will take all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the SPP Tariff (i.e., Sections 17.2(iv) and 18.2(vii); Attachment V (Section 13.1 and Article 22 of Appendix 6); Exhibit 1 (Section 2.3); Attachment AJ (Section 8); and Attachment C-One (Clause 7)).

3.2 Eastern Interconnection Network Representation

The network representation includes detailed network transmission models as developed by the SPP MDWG and described in Section 2.7.1.

3.3 Eastern Interconnection Market Database

Conducting multi-regional simulations of the wholesale marketplace requires the application of a broad range of parameters which are not readily available to or can be reasonably estimated or efficiently collected by SPP. This includes daily and intra-seasonal patterns of electric loads, and a host of fundamental generating unit parameters such as heat rates and non-fuel operating costs. SPP Staff starts with market data for the SPP footprint and multiple tiers of control areas outside of SPP from a vendor database.[3] SPP Staff reviews and modifies the market data as described in this document.

---

[3] As of this version of the document, the market database vendor is *Global Energy Decisions*; and the market database is referred to by the vendor as the *MARKETSYM/EMSS North America* database.

3.4 Load Forecast Assumptions

Electric utility monthly peak load and energy forecasts are based on the SPP Energy Information Administration ("EIA") report 411 ("EIA-411") and other information analyzed and documented by the market database vendor. SPP will, when capable, import database revisions based on the SPP EIA-411 reports and other filings recently published.

Summer and winter peak loads are modeled based on total internal demand as reported by the utilities. Hourly load shapes are based on 'typical year' representations derived by the market database vendor from multiple years of historical data. This data inherently reflects a peak load coincidence factor of about 97% for the SPP region.

Direct load control and interruptible loads as reported in EIA-411 are modeled as dispatchable resources in the simulation models.

3.5 Generating Unit Characteristics & Representations

To the full extent identifiable, generating units modeled in the underlying power flow cases are mapped to generating units[4] represented in the vendor's market database. Most generating unit characteristics are as estimated by the vendor from analysis of publicly-reported data and other non-proprietary sources, but updated through the review process described in Section 2.7.2.

SPP has reviewed generating units/stations in the vendor's market database against SPP EIA-411 reports and made identifiable revisions, such that more than 95% of the total generating unit capacity modeled in the underlying power flow cases is explicitly identified in and mapped to the market database.

The market database vendor generally estimates the full load heat rate of each generating unit from data reported by generator owners, including Continuous Emission Monitoring System ("CEMS") data. For part-load heat rates, a generic profile as estimated for the associated class of generating unit (size and type) is applied. For some recently-installed simple-cycle and combined-cycle generating units, the database applies heat rate profiles obtained from the manufacturers.

Generating unit annual and capacity seasonal ratings are generally defined in the vendor's market database based on data reported in EIA-411 reports and other sources.

The vendor's market database includes estimates of non-fuel Operations and Maintenance ("O&M") costs (per MWh) for each generating unit from historical data and additional assumptions as applied by the vendor. The non-fuel O&M values can be characterized as 'short-term variable' cost estimates, based on assumptions regarding the

[4] Generating units are referred to as 'stations' in the vendor's market database.

portion of overall non-fuel O&M costs that are driven by hours of operation and associated MWh output.

Thermal generating unit Equivalent Forced Outage Rates ("EFOR") and Equivalent Scheduled Outage Rates ("ESOR") are estimated for 'classes' of generating units from North American Electric Reliability Council ("NERC") Generator Availability Data System ("GADS") data. SPP may adjust the EFOR and ESOR values to reflect the most recent historic or actual performance data available.

Additional generating unit characteristics such as minimum 'up time'/'down time', ramp rates, start-up fuel use, emission rates and others are also developed by the market database vendor, and impact the generating unit commitment and dispatch activities within the *PROSYM* model as well as the generating unit offer curves subsequently applied within the simulation models.

3.6 Generating Unit Modeling Data

Generating unit modeling data is required in order to perform detailed analysis of economic upgrades. As indicated in Section 2.7.2, as part of the process for the economic upgrade analysis phase of establishing the Plan, SPP Staff reviews modeling assumptions for particular generating units or generating unit types with the individual owners of the generating units on a periodic basis and may require the owners to provide updates to the generating unit modeling data via templates supplied by SPP. Data required to model generating units may include, but is not limited to:

- Maximum MW Output, net of station load
- Minimum MW Output, net of station load
- Operating constraints, such as
  - Reliability/must-run ("RMR") conditions
  - Minimum Up Time
  - Minimum Down Time
  - Ramp Rate
- Annual Equivalent Forced Outage Rate
- Annual Equivalent Scheduled Outage Rate
- Full Load and Part-Load Heat Rate Curves
- Start-Up Fuel Use
- Non-Fuel Start-Up Costs
- Short-Run Non-Fuel Variable O&M
- NO_x Emission Rate

- SO_2 Emission Rate
- Monthly Fuel Price Profiles
- Emission Prices
- Historic Energy Output for Hydro Generating Units (Storage and Run-Of-River)
- Historic Energy Output for Wind Generating Units

3.7 Reliability/Must-Run Conditions

Regional bulk electric power simulation models such as those being applied by SPP have limited capability to automatically commit generating unit capacity to address local reliability concerns, which are most often voltage support issues. SPP manually models estimated generating unit reliability must-run conditions based on known situations and as provided by transmission system owners and specific generating units owners.

3.8 Fuel Prices

For natural gas and fuel oil, an estimated monthly market price is applied to all generating units in the simulation footprint, adjusted for local prices adders as estimated by the market database vendor from historical data. The market price for natural gas is generally based on a forecast of monthly marginal prices indexed to the Henry Hub location, with application of small price adjustments to sub-regional locations throughout the modeled footprint. Fuel oil prices are similarly based on a forecast of monthly marginal prices. The EIA Annual Outlook report is applied as a source for deriving the annual average natural gas and fuel oil prices, and a monthly pattern is applied within the year.

For each coal-fueled plant, the vendor's market database generally applies an inflationary increase to the most recent available annual per-unit fuel price reported by the generator owner to EIA/FERC.

3.9 Generating Unit Offer Curves

The generating unit offer curves applied in the *Simulator* model are 'energy-only' (\$/MWh) prices, that exclude start-up costs/prices and so-called 'no-load' costs/prices. SPP presently applies Short Run Variable Costs ("SRVCs") to construct these offer prices, which reflect the following parameters:

SRVC = Incremental Heat Rate x [Fuel Price + Emission Cost] + Non-Fuel Variable O&M

For SO2 and NOX: Emission Cost = Emission Rate [per unit of heat input] x Emission Allowance Prices (where identified)

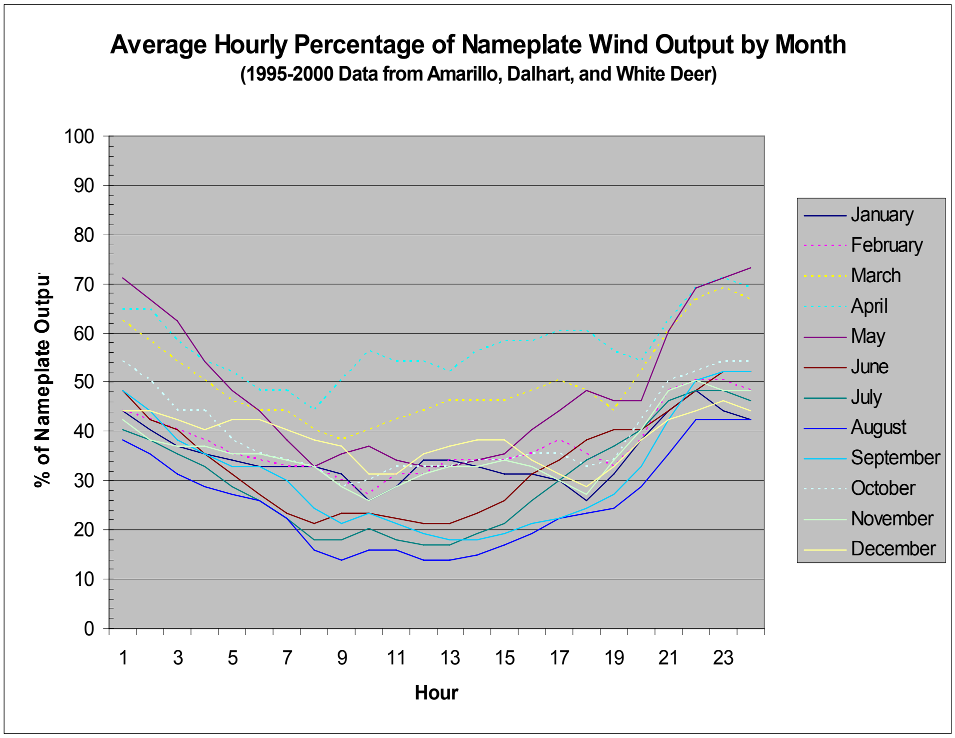
A key aspect of the SRVC pricing is the underlying assumption that the owners of generating units dispatching on the margin of a security-constrained economic dispatch (the 'price-makers') will not price significantly above their SRVC. Even in a relatively competitive market, this will not necessarily be so during periods of scarce capacity. However, analysis of 'price markups' above marginal cost is rather complicated and involves several key questions and issues, including appropriate price incentives to encourage new supply investment and market price mitigation. The techniques and implications of price markups are generally beyond the scope of SPP's immediate modeling activities, and in most cases are expected to have relatively small overall impact on differential economic analysis across modeled cases.

Implicit in the assumption of SRVC pricing is that the owners of generating units with dispatch costs lower than the marginal generating units ('price takers') do not price above the expected price-makers. The price-takers could actually price anywhere between their own SRVC and that of the price makers with essentially no impact on the economic Optimal Power Flow ("OPF") solution; i.e., the price takers are paid the same clearing price regardless. Thus, for the price takers, the assumption of SRVC offer prices is actually a modeling convenience, as these offer prices do not impact the dispatch solution or resultant locational prices.

The generating unit offer curves are constructed as piece-wise linear representations, generally with five dispatch segments for each generating unit.

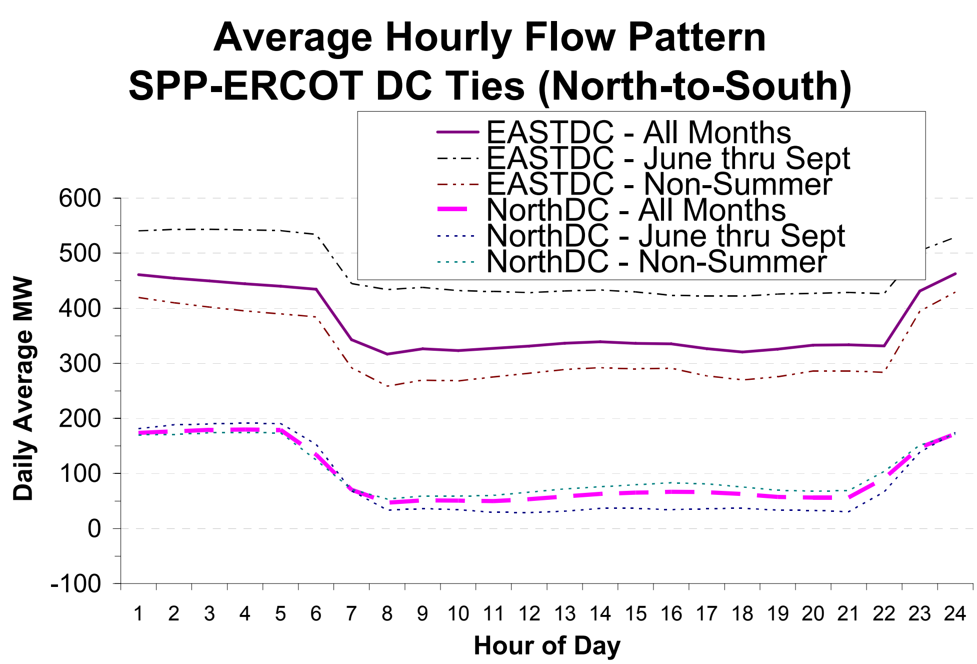
3.10 Wind Farms

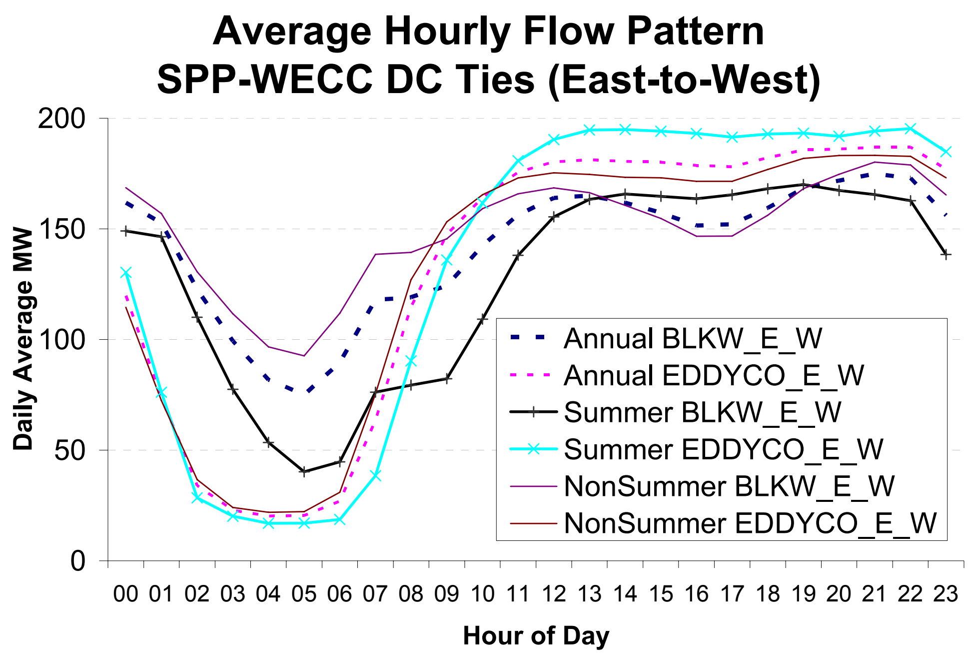
Daily wind farm profiles have been developed using actual data provided by the Alternative Energy Institute at West Texas A&M University, Canyon, Texas. An average hourly wind speed for each month was calculated from 1995-2000 data from three test sites: Amarillo, Dalhart, and White Deer. These wind speed values were then translated into MW values. The following monthly profiles are used to simulate wind farm impacts in economic analyses at SPP.



3.11 Interaction with ERCOT & WECC

SPP has a total of 800 MW of DC ties with the Electric Reliability Council of Texas ("ERCOT") and 610 MW of DC ties with Western Electricity Coordinating Council ("WECC"). The transfers modeled over the DC ties reflect historical data and recent patterns by time of day. The recent average hourly flow patterns are shown in the following graphs.





There are also approximately 3,000 MW of dual grid generating units that can feed into either the Eastern Interconnection or ERCOT. These generating units are modeled as primarily feeding into ERCOT. To accomplish this, a portion of this capacity is not included in the simulations; and hurdle rates are applied to the remaining portion of this capacity.

3.12 Modeling of Future Years

The cases used in the analysis of future years model future year facilities as follows:

- Committed reliability and economic upgrades will be included;
- Generating units known to be retiring will not be included; and
- New generating units that have signed interconnection agreements may be included in future year models. SPP will perform sensitivities to evaluate potential generating unit development scenarios.

4 Modeling Methods

4.1 Optimal Power Flow/Security-Constrained Economic Dispatch

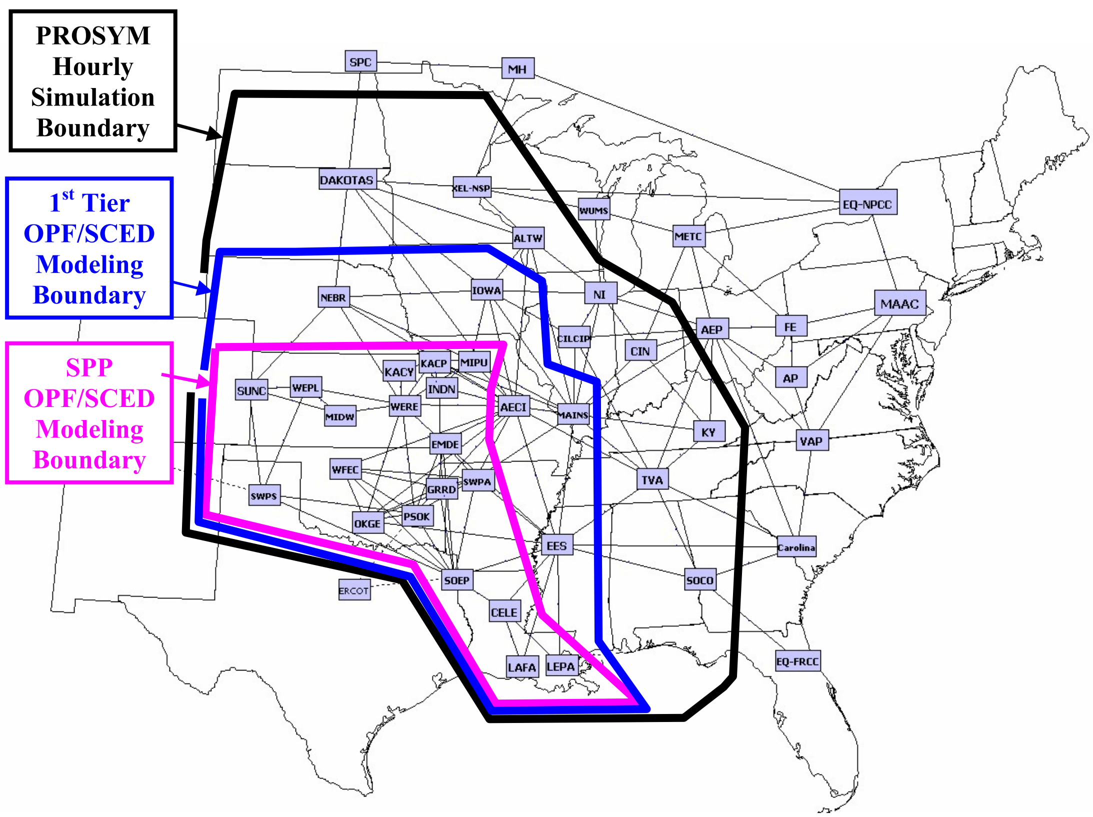
4.1.1 Market Simulation Tools

The market simulation models presently being applied by SPP Staff are the combined *MARKETSYM* LMP model from *Global Energy Decisions* and the *Simulator OPF* model from *PowerWorld Corporation*. The *MARKETSYM* model includes the

PROSYM simulation engine for generating unit commitment and preliminary "area-detail" dispatch. The area-detail dispatch applies a simplified representation of the regional transmission network which effectively models an aggregation of the individual transmission lines between each interconnected area as a transfer "link". The *Simulator OPF* model includes a security-constrained economic dispatch simulation process which iterates between an AC or DC power flow simulation and a piecewise linear dispatch simulation to arrive at a converged solution.

4.1.2 Geographic Modeling Footprints

The SPP SCED modeling footprint is generally the overall SPP reliability region. The overall SCED modeling footprint generally includes one tier of control areas external to the SPP reliability region. The modeling footprint for area-based generating unit commitment/dispatch within *PROSYM* and the AC/DC power flow solutions within *Simulator* extends out generally three (3) control area tiers external to SPP. These modeling footprints are illustrated below:



The SPP region is modeled with a break-out of approximately 20 transmission areas encompassing the 17 actual control areas. American Electric Power ("AEP")-West ("AEPW") is represented by two transmission areas dispatched as a single control area, and there is also an explicit transmission area for Midwest Energy ("MidW"). Oklahoma Municipal Power Authority ("OMPA") has been constructed as a "pseudo" control area, although actual OMPA loads are distributed within the Oklahoma Gas &

Electric ("OGE"), Public Service of Oklahoma ("PSO"), AEPW and Western Farmers Electric Cooperative ("WFEC") transmission areas. Arkansas Electric Cooperative Corporation ("AECC") loads are aggregated with other loads at buses within the Entergy ("EES") system, Southwestern Electric Power Company ("SOEP") and Southwestern Power Administration ("SPA").

4.1.3 Underlying Power Flow/Network Cases

SPP converts previous seasonal cases to support security-constrained economic dispatch nodal ('bus level') price modeling of an entire one-year span as follows:

- Spring case (applied March-May)
- Summer Peak case (applied June-August)
- Fall case (applied September-November)
- Winter case (applied December-February)

To construct a full year representation, each of the seasons listed above are generally simulated separately (and effectively in parallel on multiple PCs).

Bus, branch, load and generating unit modeling detail are effectively driven by the representations in these underlying power flow cases.

4.1.4 AC/DC Power Flow/OPF Simulations

SPP has built out its base modeling representations applying full AC power flow analysis, and presently applies full AC power flows within most of the SCED simulations. This was done in part to evaluate the tools being applied and interpret results in the more stringent environment of full AC solutions. Increased volume of studies and other modeling parameters will necessitate applying DC solutions to some extent from time to time.

In conducting OPF modeling across a wide range of load and generating unit availability situations to represent a full year time span, and particularly when conducting full AC simulations, there are inevitably some number of simulation hours that do not successfully solve. SPP generally experiences a better than 90% successful OPF solve rate for each of the seasonal cases. When comparing a base model case against a transmission expansion case, the hours for which both cases have solved are applied, which also generally exceeds 90 percent of the attempted simulation hours.

4.1.5 Method to Represent a Full Year & Multiple Years of Results

Most of the regional simulations are conducted based on simulating every other hour of a 'typical week' representation for each month of the year; i.e., 12 hours per typical day, 84 hours per typical week (and for each month), or 1,008 simulated hours for a full year. This reduces overall simulation run-times and data handling considerably in comparison to full 8,760 hour annual simulations.

Initial comparisons made by SPP indicate that relatively little accuracy or consistency is lost at the regional level or control area level when applying the modeling mode described above.

For economic upgrade studies that cover multiple years, not every year is explicitly simulated. SPP Staff models selected years, generally a near-term year and a mid-term year which is 4 to 5 years out from the near-term year. SPP interpolates between the near-term year and the mid-term year to estimate the annual savings of the intervening years and extrapolates to estimate the annual savings of the future years beyond the mid-term year.

The simulation tools being applied are highly scalable, depending upon the number of processors applied to the simulations, status of the network server, and effort applied to development of post-processing techniques.

4.1.6 Area-based Generating Unit Commitment & Dispatch Simulations

The *PROSYM* model conducts an hourly generating unit commitment and 'preliminary' dispatch, which is forwarded to the *Simulator* model for hourly network power flow and SCED analysis. Prior to conducting a thermal unit commitment/dispatch, *PROSYM* estimates a peak shave hydro dispatch. The hydro dispatch applies energy values for each month of the year based on an average of up to 20 years of values as reported by generator owners. The model applies an estimate of the portion of energy that is 'run-of-river' hydro for each month from the market database, and applies a 'peak-shave' dispatch to the remainder of monthly hydro energy. Wind generating units are modeled based on estimated hourly patterns of electric output.

To manage simulation run time and data volumes, SPP typically applies a 'converged Monte-Carlo' technique available within the simulation model, which constructs a generating unit forced outage forecast that is statistically similar at the control area level to what would result from a full ('multi-draw') Monte-Carlo simulation. The random outages exhibited at each specific location can still exhibit some bias on prices and other results relative to a full Monte-Carlo simulation, depending in part on how many total hours are simulated for each study.

For scheduled outages, a 'distributed outage' technique available within the simulation model is applied, whereby the outage hours for any specific generating unit are distributed across months of the year based on regional estimates of historical maintenance patterns. This reduces the bias that may result at specific locations associated with fixed period outages (e.g., March 1-March 15 for unit X) that might be otherwise constructed and applied in the simulations.

The models simulate a weekly thermal generating unit commitment that minimizes the total cost[5] for each weekly segment subject to generating unit modeling constraints applied by the user and described in Section 3 of this document. SPP is applying operating reserve commitment constraints to each control area as listed in the table below. Operating reserves are presently not being assigned to specific generating units – SPP will make such assignments as unit-specific information is received from SPP control areas. Operating reserves requirements are typically set in the range of approximately 7% of control area load in the simulations. The following table reflects typical values used for operating reserve parameters. As indicated in Section 2.6, the actual values used in the analysis of a specific project will be published as part of the reporting requirements.

Operating Reserve Parameter	**Value**
Spinning Reserve Requirement	2% of Load
Regulating & Load-Following Capacity Needed	3% of Load
Ready-Reserve (Non-Spinning) Requirement[6]	2% of Load

Within a 'strict' control area-based commitment simulation, designated generating capacity from within the control area or otherwise controlled by the area operator[7] would be required to be on-line to meet 100 percent of control area load, net of firm interchanges, plus operating reserve requirements. However, in reality, a portion of capacity to meet control area load is often effectively committed across control areas and from generators owned by independent power producers. SPP applies the *PRECOMMIT* logic available in the *PROSYM* model to simulate the dynamics of 'inter-area' generating capacity commitment.

The inter-area commitment of capacity can be impacted by several simulation parameters, such as a 'targeted' area load commitment multiplier as referenced in the following formula, and an 'inter-area' commitment hurdle rate.

Initial Minimum Area Capacity Committed = [Target Commitment (%) x Area Load +/- Net Firm Interchange] x [1 + Spin Reserve + Regulation/Load-Following]

The *PRECOMMIT* logic within *PROSYM* initially commits capacity within each area consistent with the above equation, while also enforcing an overall modeled footprint requirement that capacity meet or exceed total load plus total reserve requirements. The *PRECOMMIT* logic will then vary the area-based commitments to reduce overall

[5] The *PROSYM* commitment can also minimize prices from offer curves constructed by the user.

[6] To the extent that available 'fast start' capacity in the control area is less than this value, additional capacity must be spinning.

[7] Designated generating capacity from within the control area or otherwise controlled by the area operator are Designated Network Resources.

price of electricity while enforcing modeled transfer limits and also considering the cross-area commitment hurdle rates.

SPP generally models a control area unit commitment target at about 80% of the control area's firm demand. The generating units owned by Independent Power Producers ("IPPs") are excluded from the initial control area unit commitments, and are committed incrementally to the extent that the model estimates that committing these generating units would reduce total cost within the overall modeling footprint.[8]

The unit commitment logic is also impacted by additional generating unit constraints such as minimum 'up time'/'down time' values and hourly ramp rates as estimated for various groups of generating units.

The hourly unit commitment and 'initial' dispatch values developed by *PROSYM*, along with hourly control area load levels and generating unit 'offer curves', are forwarded to the *Simulator* model for application to the OPF simulations.

4.1.7 Flowgate Limit Monitoring & OPF Contingencies

Within the power flow and OPF simulations, all bus and branch elements >100 kV are monitored. Branch flows are limited to 100% of normal rating for each season, and buses are regulated to +/- 10% of nominal voltage.[9]

All flowgates within the SPP footprint are monitored within the OPF simulations, with monitored element post-contingency flows being limited to 100% of the total (firm plus non-firm) capacity rating of the flowgate.[10]

To gradually construct simulations that are verified to be fully consistent with 'n-1' SCOPF security analysis, SPP conducts contingency analyses to identify the branch outage contingencies most likely to constrain path elements within the market simulations, and applies this information to model additional post-contingency interfaces (i.e., potential flowgates). Also, potential flowgates or new congestion points are often addressed within specific transmission expansion studies.

The occurrence of branch flow limit violations necessitates the application of 'slack costs' in the *Simulator* OPF Linear Programming ("LP") solution. The slack cost

---

8 A minimum area generation level equal to 10% of load has also typically been specified for each control area to ensure that at least one generating unit is on-line for load regulation, although this requirement has not had a significant impact on the simulations.

9 Note that the PowerWorld *Simulator* OPF model does not presently have logic to explicitly clear bus voltage violations.

10 Consistent with SPP Criteria formula 4.5.10.4: Non-Firm Available Flowgate Capacity for Operating Horizon (NFAFC) = Total Flowgate Capacity – (b*TRM) – CBM – Non-Firm Base Loading; for most or all SPP Flowgates, b=0 and CBM=0 (total margin is incorporated within TRM), where TRM stands for Transmission Reliability Margin and CBM stands for Capacity Benefit Margin.

values are defined by the user, and effectively represent 'caps' on the re-dispatch cost the model will seek to clear violations. In any solution (short of setting the caps extremely and unrealistically high), there will be some small amount of un-cleared violation at some of the SPP flowgates. The un-cleared violations can be thought of as unassigned dispatch costs and are included within total production costs compared across case simulations. The change in violation cost across solved cases can represent a benefit of reducing un-cleared violations.

The following table reflects typical values used for flow limit violation cost caps in the regional modeling. The values are set high enough to reasonably capture re-dispatch which is likely to occur in the SPP market, without exaggerating the associated impact of any uncleared violations on locational prices. As discussed in Section 6.2, the SPP model benchmarking effort includes review of the frequency and magnitude of uncleared violations within the base model against recent actual loadings to verify that the simulations are reasonably consistent with recent actual conditions experienced on the regional network.

Type of Element	Operating Range	Penalty
SPP Flowgate	0-2% Above Total Capacity	$100 per MW per Hour
	>2% Above Total Capacity	$200 per MW per Hour
Branch or Transformer	Above Normal Rated Capacity	$30 per MW per Hour

As indicated in Section 2.6, the penalties applied in the analysis of a specific project will be published in the associated study report, as part of the reporting requirements. Variations in these values can be part of the sensitivity analysis, particularly for studies which result in significant impact on the simulated violations and associated costs.

4.1.8 Transfer of Load & Generating Unit Parameters to *Simulator*

The hourly control area loads, initial generating unit dispatch levels and generator offer price curves developed within the generating unit commitment simulation are applied within network-level security-constrained economic dispatch analysis. For each control area in the network simulations, loads are distributed to individual locations ('buses') in proportion to the distribution represented in the underlying power flow cases, after accounting for control area load losses and identified fixed-load (sometimes called 'non-scalable') buses. Hourly bus MVAR load values are estimated assuming non-varying power factor at each load bus.

To account for generating units/stations modeled in the unit commitment process that have not been mapped to specific generating units/stations of the network power flow cases, a scaling factor is applied to the MW dispatch value and maximum MW ('Pmax') of each generating unit. The scaling factor also accounts for any controllable/interruptible load 'resources' activated within the unit commitment model within a given hour.[11]

For control areas outside the simulated security-constrained economic dispatch footprint, generating unit dispatch levels of the underlying power flow case are scaled each hour to match the levels of the *PROSYM* simulation.[12]

4.2 Quantifying Cost of Regional Network Congestion

Whenever the most economic resource cannot be dispatched to cover the next increment of load due to constraints on the transmission system, network congestion is present, and associated congestion costs are incurred. As mentioned earlier, the most straight forward characterization of the cost of congestion the amount of additional production costs incurred due to the presence of network constraints. This can include the cost impact of committing generating units out of merit order in order to avoid or minimize network loading constraints or violations.

Quantifying the total cost of congestion across a region is largely an academic exercise, in that one would need to simulate region-wide dispatches, and to at least some extent region-wide unit commitments, which would be totally unencumbered by network constraints. The comparative cases constructed by SPP address the change in the amount of congestion from the base case to the upgrade case resulting from the transmission upgrade.

The shadow price of any flowgate or branch is the decrease in total system costs that would be achieved by increasing the rating of the flowgate or branch by 1 MW.

See Appendix B for an example of network congestion using an eight node model.

5 Base Case & Sensitivity Model Development

5.1 Base Case Model Development

5.1.1 Physical (vs. a Financial) Regional Simulation

The base case model for economic upgrades is derived from earlier analysis used to identify reliability upgrades as part of the reliability planning process and includes any committed reliability upgrades identified by that process.

The base case model reflects unit commitment primarily by control area and the SPP regional Energy Imbalance Service ("EIS") market implementation, including real-

11 The amount of reported dispatchable/interruptible load within each control area is relatively small in relation to total electric load, and is not explicitly identifiable by location for application within the dispatch simulations.

12 Scaling is applied because for most control areas external to SPP, a detailed generator mapping between *MARKETSYM* and *Simulator* generally does not exist.

time security-constrained economic re-dispatch. The base models are also set up for full AC power flow analysis.

The simulations reflect a physical commitment and dispatch of the regional bulk power system. The simulations in effect represent a large feasible solution of regional dispatch subject to security constraints. Most bilateral transactions do not affect the resultant physical dispatch solution, and are thus are not needed for SPP to estimate the impact on (physical) cost of production. An exception is owned/leased generating unit shares and other identified mid/long-term firm transactions that can significantly impact the generating unit commitment simulations.

5.1.2 Incremental Dispatch Levels & Associated "Transactions"

The SPP simulations focus on the differential change between two compared cases – i.e., the "base case model" and a case model reflecting transmission upgrades. The changes to dispatch (and possibly hours of commitment) of individual generating units inherently aggregate to changes in area dispatch levels and interchanges (i.e., transactions). However, as discussed more later in this document, SPP analysis focuses on changes in dispatch levels of individual generating units, and thus inherently the incremental "sale" and/or "purchase" of energy by those generating units at their respective locations, ultimately aggregating the results for generating units owned (or controlled) by specific market participants. However, as mentioned above, there is no attempt to assign bilateral interpretations of the associated incremental transactions.

5.1.3 Physical Transmission Rights

The SPP transmission market applies physical transmission schedules and associated rights. At present (i.e., prior to implementation of the SPP EIS market described immediately below), scheduling or interchange "imbalances" are subject to various bilateral agreements as to price and other procedures. Under the emerging SPP EIS market, all "imbalances" (real-time deviations from scheduled amounts) will be subject to locational marginal prices, specifically defined and referred to as Locational Imbalance Prices ("LIPs") in the SPP Market Protocols. Most deliveries (from generating units to loads) both within a control area and across control areas will effectively be "hedged" by associated physical transmission rights. However, an indeterminate amount of energy will be subject to locational price uncertainty due to advertent or inadvertent imbalance of generating unit-to-load schedules. The re-dispatch of generating units by the SPP regional SCED system is inherently defined as locational imbalance, priced at the LIP at each generating unit location.

5.1.4 Existing TLR Process for Reliability

Transmission Loading Relief ("TLR") is a reliability-based process for clearing transmission loading violations within the Eastern Interconnection. Most TLR events which impact the SPP region involve no curtailment or only curtailment of non-firm power (TLR levels 1-4). Since TLRs are effectively the "last-resort" of a coordinated transmission reservation and scheduling process to maintain security of the grid, they represent only a fraction of the total congestion experienced on the grid.

The market simulation models apply representations of security-constrained economic dispatch to clear and otherwise minimize violations, and are intended to represent the economic impact of congestion (and likelihood of violations) on the grid. For this reason, TLRs are not directly comparable to or simulated in the economic upgrade studies. However, as illustrated in Section 6.2, where base model simulations show significant violation of flowgate limits, SPP reviews the simulations against recent actual loadings, including TLRs, to help validate the models.

5.1.5 Operating Directives

SPP's Operating Directives may allow higher loadings for short-term emergency operations. These Operating Directives provide non-firm capability that is reflected in economic planning simulations to benchmark actual operations. These higher short-term emergency ratings can have a significant impact on the need for and savings associated with any transmission upgrades.

5.2 Specific Base Case Modeling Assumptions

5.2.1 Wheeling Rates

Because the SPP Tariff excludes the application of source-based wheeling rates within (most of) the SPP Region, no explicit wheeling rates are generally modeled directly between SPP control areas. Because there are "through and out" wheeling rates for both imports to and exports from the SPP boundary, wheeling rates are applied to transactions which cross the SPP boundary.

5.2.2 Commitment & Dispatch Hurdle Rates

The modeling tools inherently attempt to model a highly efficient marketplace, subject to the constraints presented. The model's underlying methodology is also consistent with the implicit assumptions of total price transparency and dispatch rationality (i.e., that market participants would not commit or dispatch resources higher in cost than other available resources within the modeling footprint).

In reality, no market is as perfect as the models would simulate without some representation of inefficiency and limited price/cost transparency. One way that market inefficiency can be modeled is by applying 'hurdle rates' within the SPP footprint (directly between SPP control areas) and between SPP control areas and non-SPP control areas. This approach effectively limits transactions to those that exhibit a price or cost differential higher than the hurdle rate.[13]

Specific hurdle rates are applied in the modeling for both generating unit commitment and security-constrained economic dispatch. For both commitment and dispatch, the hurdle rates modeled within the SPP footprint are lower than the hurdle rates between SPP control areas and non-SPP control areas, to generally reflect some amount of reduced knowledge and transparency across regional and market boundaries.

SPP attempts to quantify the hurdle rates within the base models so as to reasonably represent the transactions which have occurred or will occur in the market. This is a special challenge when modeling a marketplace which is emerging or revising underlying interactions/processes, such as introduction of security-constrained economic dispatch and other new market mechanisms.

The following table reflects values typically applied for hurdle rates in the regional modeling. These values are similar to values reported/applied within various studies of the Eastern Interconnection. Variations in these rates can be part of the sensitivity analysis within a specific study. As indicated in Section 2.6, the actual values used in the analysis of a specific project will be published in the associated study report, as part of the reporting requirements.

Between Control Areas	**Commitment Hurdle Rates**	**Dispatch Hurdle Rates**
SPP Control Areas	$4 to $5/MWh	$2/MWh
SPP and Non-SPP Control Areas	$6 to $8/MWh	$2 to $5/MWh

6 Base Case Model Benchmarking

Once the base model is built as described under Section 5 utilizing the assumptions and input data described under Sections 3 and 4, SPP makes several preliminary analysis runs for the first year of the study for the purposes of comparing the model output results against actual data from an historical year to ensure that the results that are being produced from the base case model are reasonable. The following sub-sections provide a description of the benchmarking process.

6.1 Short- and Long-Range Load & Resource Balance

SPP constructs the EIA-411 report for submittal to the U.S. Energy Information Agency in April of each year. This report includes a compilation of 10 year forecasts of electric load growth and existing/planned supply resources provided by each reporting electric utility within the SPP region. From this and additional related information, SPP

[13] Since most market simulation models do not include a separate modeling variable for hurdle rates, they are applied via the wheeling rate variable; i.e., modeled "wheeling rate" = explicit wheeling rate + hurdle rate.

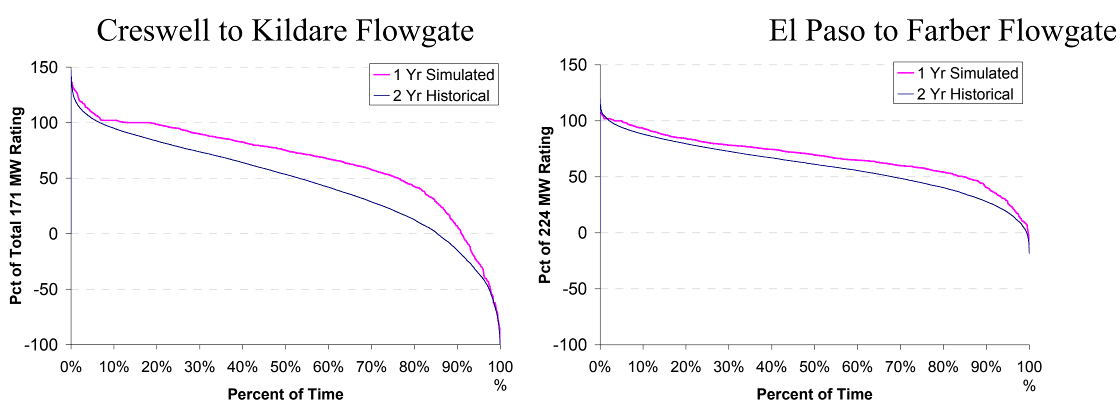
constructs 10 year forecasts of regional demand and supply within the region, which are a source for construction and application of future year modeling representations.

SPP also compares area electric loads and resource outputs for peak-hour simulations from the base model against the SPP seasonal (peak-hour) power flow cases to validate consistency of underlying assumptions**.**

6.2 Flowgate/Network Loadings

As part of base case model benchmarking, SPP compares the simulated flowgate loadings to the historical flowgate loadings of key flowgates. For example, below are graphs comparing the simulated flowgate loadings to the historical flowgate loadings for two flowgates: the Creswell to Kildare flowgate and the El Paso to Farber flowgate.

Flowgate Loading Comparison



The Creswell-Kildare flowgate was the most constraining element within SPP for 2005. El Paso-Farber is another flowgate in SPP that is in series with Creswell-Kildare and can limit north to south transfers from Kansas to Oklahoma for an outage of the Wichita-Woodring 345 kV line. SPP analyses to date to benchmark the simulated loadings on these facilities compared to actual performance show a high level of consistency regarding the hours that loadings exceed the flowgate ratings. Actual flowgate loadings that exceed Total Flowgate Capacity will often reflect hours that TLR level 1 or higher would be in effect for the flowgate. Also, for some flowgates, including El Paso-Farber, the use of dynamic ratings will impact the comparison of loadings against published ratings.

The simulated results of the base model often exhibit somewhat higher flowgate loadings than those experienced in historical operations for a majority of hours across the year, including for the flowgates shown above. SPP believes this generally reflects improvement in multi-area generating unit dispatch which will be realized from the SCED mechanism being implemented within the SPP EIS market.[14]

[14] A general reference is the *Cost-Benefit Analysis Performed for the SPP Regional State Committee* (of the SPP EIS market) by Charles River Associates, published (in revised form) on July 27, 2005.

6.3 Area/Resource Energy Production

For each SPP control area, total generating unit production and the output of individual generating units is compared to historical production figures. To the extent that significant differences exist, SPP will modify the base case input assumptions and address any differences.

6.4 Area Net Scheduled Interchange

In addition to Area/Resource Energy Production comparisons, SPP also compares net scheduled interchange values produced by the model against actual values for each SPP control area. These net scheduled interchange values are directly impacted by the results described under Section 6.3 along with modeling assumptions relating to firm scheduled transactions.

6.5 Review by Stakeholders

SPP provides preliminary Area/Resource Energy Production results and Area Net Scheduled Interchange results to the controls areas within SPP for review. SPP incorporates stakeholder feedback as to the reasonableness of results and makes adjustments to the base assumptions, as appropriate, to correct any identified significant differences.

7 Calculation of Net Expected Economic Benefits

Once a particular transmission upgrade project has passed the screening analysis described under Section 2.3 (operating cost savings are expected to exceed construction cost of upgrade), more detailed economic benefits associated with that particular transmission upgrade are calculated based upon the expected reduction in operating costs within the SPP region that may be realized through reduction in re-dispatch costs and violation costs made possible by the particular transmission upgrade. Operating cost savings are generally estimated over a 10 year period to represent a desired 10 year payback of the construction costs associated with a particular upgrade.

7.1 Operating Cost Reduction

The economic upgrade cases, when compared to the base case, will provide a measure of the economic benefit of reduced congestion from a proposed set of transmission upgrades. As mentioned earlier, the most straightforward way to measure the benefit of congestion impact for the entire modeled geographic footprint is to quantify the differential (Δ) of total electric production costs across the respective cases. Expressed as an equation, this would be as follows:

Overall Congestion Reduction Benefit
= Expected Operating Cost Reduction

$$= \Delta\textbf{Production Costs} + \Delta\textbf{Violation Costs}$$

Violation Costs are defined in Section 4.1.7. Removal of the violation costs through an economic transmission system upgrade is included in the overall economic benefit calculation. Operating directives, which are discussed in Section 5.1.5, will often determine procedures to apply when loadings exceed published limits, sometimes including emergency actions to be undertaken if a network outage occurs simultaneous with a high loading. From this perspective, a reduction or elimination of flowgate loading exceedances (i.e., "violations") for a flowgate might often be interpreted as reflecting a reliability improvement by reducing the necessity of a possible emergency action in response to experiencing an outage on the grid.

7.2 Expected Economic Benefits & Net Benefits

Estimates of Operating Cost Reductions under Section 7.1 are calculated by SPP using the modeling methods described in this document for the base year of the analysis and one future year, generally 5 years out from the base year (i.e., model runs are not made for every year of a 10 year analysis period). Annual Operating Cost Reductions are then estimated for the remaining years within the 10 year analysis period through interpolation and extrapolation of the model run results. Once the Operating Cost Reductions of each year of the 10 year analysis period are obtained, SPP then calculates an Expected Economic Benefit over the 10 year analysis period, as reflected in current dollars, by discounting the Operating Cost Reduction values back to the base year of the analysis and summing the results. As a final step, the discounted 10 year Expected Economic Benefit is then compared to the projected construction cost of the particular upgrade to ensure that Expected Economic Benefit exceeds the expected construction cost.

8 Break-out of Expected Economic Benefits

Once the economic benefits for the overall modeled footprint have been calculated as described under Section 7, the regional benefits are estimated for market participants to provide information that is meant to help those participants in making decisions about project sponsorship. In regard to estimating benefits for market participants, it is important to note that considering only changes in generation costs is not sufficient. Moreover, a transmission upgrade that reduces congestion costs implies that more expensive generation is decreased, less costly generation is increased, and for this to result in cost savings to customers, there will be a resulting change in energy transactions among market participants.

8.1 Estimating Generating Unit Re-dispatch Net Benefits by Market Participant

Net benefits of the generating unit re-dispatch are estimated for each market participant based on an aggregation of the generation resources controlled by each market participant. Note that this application of the 'market participant', as used in Section 8, is not limited to market participants in the SPP market footprint. For example, generators in the 1st tier control areas external to SPP would be represented in this equation as a market participant. However, the representation of market participants outside the SPP region may be somewhat more generalized than within SPP, due to somewhat less detailed identification of specific generator owners within those modeled areas.

Changes in purchases and sales of electricity among market participants are estimated by looking at the change in generation at the generator nodes and summing the changes across all generating units controlled by each market participant. Absent congestion between a market participant's generators and loads, an increase in generation at a node represents an increase in sales from that generator into the market[15] and a decrease in generation at a node represents an increase in purchases for the load associated with that generator. For example, at a specific generator node, if generation increases, the generation costs will increase, but there will also be a marginal increase in revenues from sales of that generation equal to the change in generation multiplied by the Nodal Price. Alternatively, if generation decreases, the generation cost will decrease, but there will also be a marginal increase in costs from purchases to replace that generation equal to the change in generation multiplied by the Nodal Price. The following equation is used by SPP to capture the net impact of changes from purchases or sales and changes from generation dispatch costs.

Congestion Impact Break-Out by Market Participant – Generating Unit Re-Dispatch

$$= \sum_{\substack{All \\ Hours}} \sum_{\substack{GenUnits \\ foreachParticipant}} \left[\left(\Delta MW \; x \; Nodal \; price_F \right) - \Delta \Pr oduction \; cost \right]$$

ΔMW refers to the change in real output of each generating unit from the "Base Case" simulation (before expansion/upgrade) to the "Change Case" simulation. Nodal Price refers to the $/MWh locational price at each associated generating unit location of the Change Case solution, deriving from offer prices assumed in the modeling.

This calculation addresses the economic impact of generating unit re-dispatch that is observed across comparable market simulation cases. These changes in dispatch implicitly represent incremental bulk power transfers that can be achieved as a result of removing or at least reducing certain congestion barriers. To the extent that there is no unhedged congestion between the generation and load of each market participant, this calculation should capture the direct economic impact of congestion reduction occurring from improved dispatch of generating units across the modeled footprint. The qualifier of no unhedged congestion between each market participant's generation and load is equivalent to assuming that each market participant has scheduling rights that provide for this hedge.

[15] If congestion exists between a generator and the load it serves (an internal congestion within the market participant's area), it is possible for a transmission upgrade to eliminate this internal congestion , in which case the increase in generation does not represent a sale by the generator to the market.

It is also important to note that violation costs are excluded from this calculation of Net Benefits among market participants. Moreover, changes in violation costs may or may not be assumed to be distributed to each market participant in proportion to the net participant benefits being calculated.

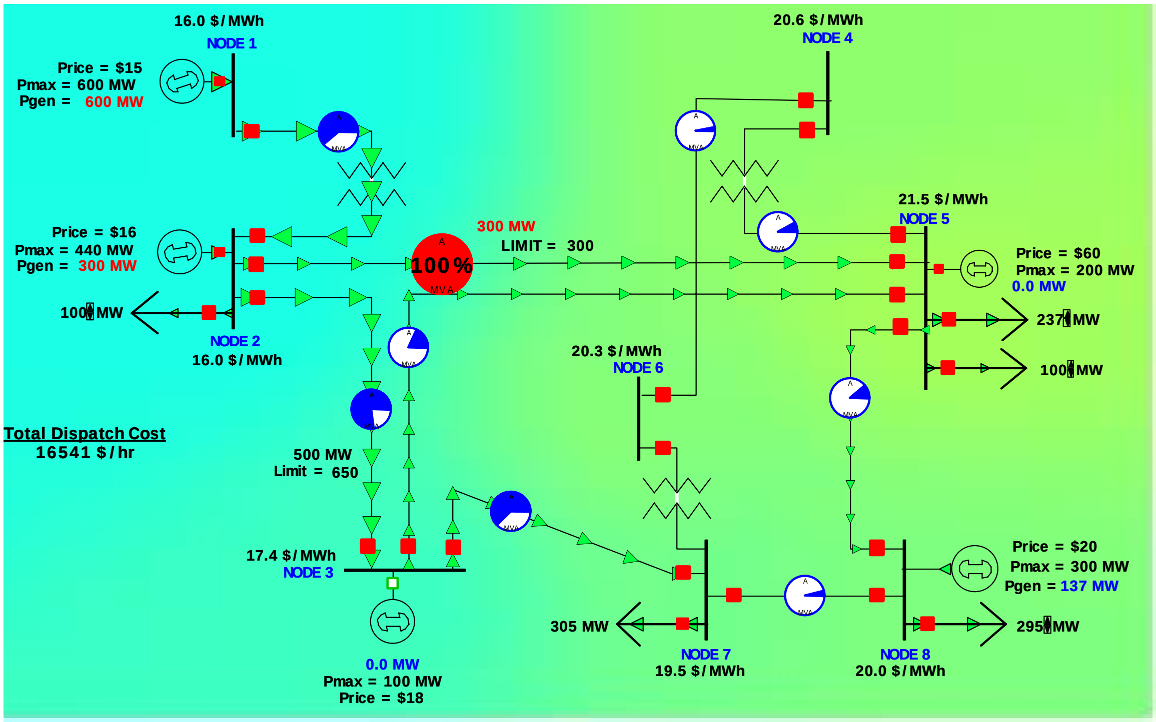
Example: Application of Generating Unit Re-Dispatch Equation

The following example represents an eight-node simplified OPF network model and the computations and one-line diagrams were constructed using *Simulator*. For the simplified examples presented here (see Appendix B for a more detailed version of these examples), it is assumed that generator owners offer into the market at marginal cost of their generating units. As such, in these examples the only impediment to achieving the optimal or "least-cost" dispatch is network congestion.

The initial congested case is illustrated in Figure 1, reflecting a transmission network branch from Node 2 to Node 5 that is limited to 300 MW transfer. The generating unit output and network flows are consistent with an optimal achievable dispatch, showing that the network branch would become fully loaded, effectively creating an "export constraint" on the left side of the network and an "import constraint" on the right side of the network.

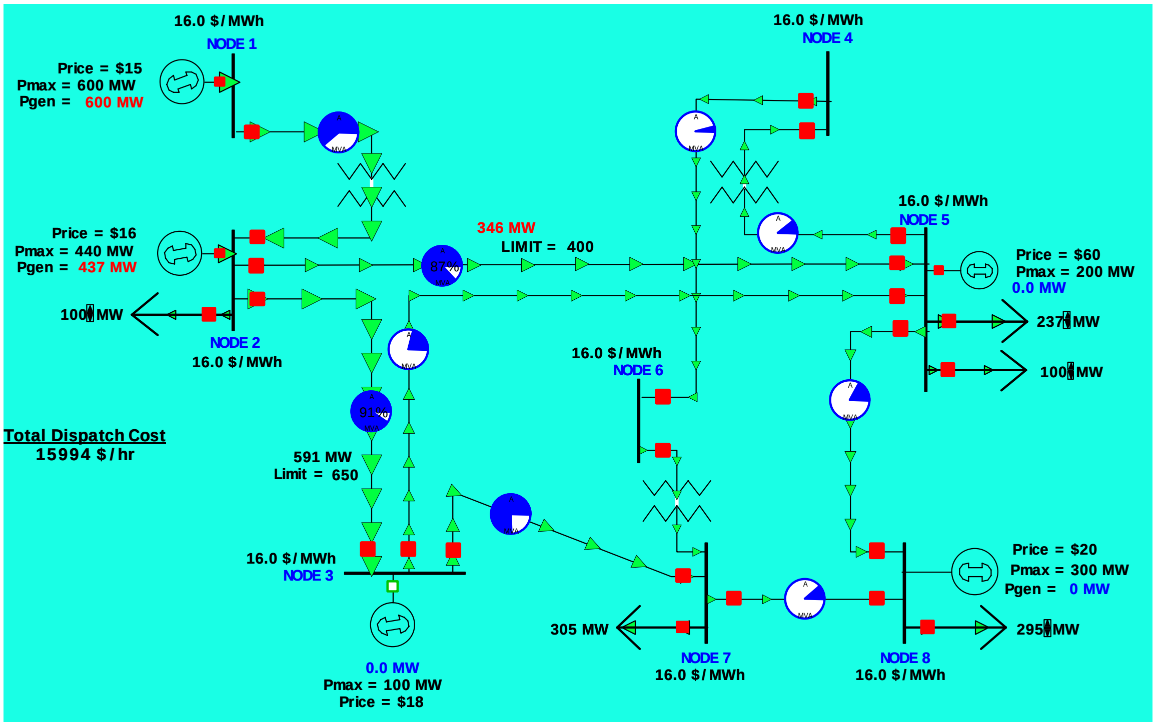
In Figure 1, the lowest-priced generating unit at Node 1 ($15/MWh) is fully dispatched. The next merit-order priced generating unit at Node 2 ($16/MWh) is capable of producing 440 MW, but is limited to 300 MW output by the transfer constraint. Conversely, the generating unit at Node 8 is producing megawatts only because the transfer constraint is present. A generating unit at Node 3 priced at $18/MWh is presently assumed to be out of service for maintenance. A generating unit at Node 5 is sufficiently high priced so as to not impact the situation. The LMPs range from $16/MWh at the left-most nodes, to a high of $21.50/MWh at Node 5.

Figure 1: Initial Congested Case



A visual perspective of removing the transfer constraint is shown in Figure 2, indicating that indeed in comparison to Figure 1, the generating units have "re-dispatched" as reflected in the constructed schedules. Comparing the computed total dispatch cost of $15,994 shown on Figure 2 to the value of $16,541 shown on Figure 1, the saving is $547. Also, Figure 2 shows that the marginal prices are now identical at all the nodes, consistent with the ability to now deliver the next megawatt of load anywhere on the network from the "merit order" generating unit at Node 2 (again $16/MWh).

Figure 2: Effect of Removing the Congestion



Applying the Generating Unit Re-dispatch portion of the congestion benefit break-out equation to the congested ("Base") and non-congested ("Change") cases shown on Figures 1 and 2 results in the following:

"Benefit at" Gen Node 2 = [137 MW x $16 (nodal price)] - [137 MW x $16 (dispatch cost)] = $0

"Benefit at" Gen Node 8 = [-137 MW x $16] - (-) [137 MW x $20] = +$548

Thus, in this example, the owner of the generating unit at Node 8 is effectively the beneficiary of the $548 benefit ($1 rounding difference due to small loss factors). The benefit to the generator owner is that it could buy the energy more cheaply that it could have produced the energy itself, assuming its dispatch price for its generating units roughly reflects its generating units' SRVCs.

Please see Appendix B for a more detailed description of how the Generating Unit Re-dispatch equation is applied and for additional examples.

8.2 Load Impact Sensitivity Equation

Within SPP, almost 90% of generating unit capacity is owned by vertically-integrated electric utilities. These utilities generally own sufficient transmission rights to deliver energy from affiliated generating units to native loads and other obligated (firm) loads.

These deliveries are scheduled via a combination of network transmission service within metered control areas and point-to-point service across control areas. Loads served by the scheduled deliveries are effectively "hedged" from the effects of changes in locational marginal prices beyond those inherent in the re-dispatch computations (i.e., these scheduled deliveries should not experience a nodal price charge or congestion cost charge in the marketplace).

However, some portion of loads will inevitably be "unhedged" in the markets. For example, in the upcoming SPP EIS market, any load that is not scheduled beforehand (Imbalance Energy) will pay a locational marginal price (i.e., LIP). More generically, a certain amount of "unhedged" spot transaction activity is inevitable in any market due to uncertainties such as generating unit/transmission outages, weather conditions, and over time, load growth.

The second line of the congestion reduction benefit break-out equation is intended to capture the impact of changes in nodal prices on loads that not hedged in the marketplace, and is referred to herein as the "unhedged load" impact. The equation is:

Congestion Impact Break-Out – Unhedged Load Impact =

$$-\sum_{\substack{All\\Hours}} \sum_{\substack{Each\\Participant}} \left[\Delta Load\ wtd\ price\ x\ Load\ x\ \langle Pct\ load\ in\ mkt \rangle\right]$$

The ΔLoad-Wtd Price refers to the change in load-weighted locational price for a specific market participant. Multiplying this value by the associated Load is equivalent to aggregating the product of load and change of price at each location. The Pct "Unhedged" Load component refers to the portion of load that is not protected from nodal price fluctuations.

Example: Application of Unhedged Load Impact Equation

In the previous examples it was implicit that all load was hedged against "incidental" nodal price impacts via generating unit/transmission rights and associated scheduling to load. What if the examples discussed in Section 8.1 assumed that 10 MW of the load at Node 2 and also 10 MW of the load at Node 5 were unhedged (i.e., no scheduled deliveries), and thus deliberately or incidentally experience the changes in nodal price as congestion is reduced?

Applying the Unhedged Load Impact portion of the congestion benefit break-out equation to the congested ("Base") and non-congested ("Change") cases shown on Figures 1 and 2 results in the following:

"Benefit at" Load Node 2 = -[$16 (nodal price Figure 1) - $16 (nodal price Figure 2)] * 10 MW (load x Pct load in mkt) = $0

"Benefit at" Load Node 5 = -[$16 – $21.50] x 10 MW = +$55

Thus, in this example, the owner of the load at Node 5 realizes a $55 benefit for its 10 MW of unhedged load.

Please see Appendix B for a more detailed description of how the Unhedged Load Impact equation is applied and for additional examples.

8.3 Combined Allocation of Benefits to Generator Owners & Load

For sensitivity purposes only, SPP estimates the combined generator owner and load benefits for each area within the SPP region utilizing the equations specified under Sections 8.1 and 8.2. The combined formulation is shown below:

Congestion Impact Break-Out Equation

$$= \sum_{\substack{All\\Hours}} \sum_{\substack{GenUnits\\foreachParticipant}} \left[\left(\Delta MW \; x \; Nodal \;\; price \right) - \Delta \Pr oduction \; cost \right]$$

$$- \sum_{\substack{All\\Hours}} \sum_{\substack{Each\\Participant}} \left[\Delta \, Load \; wtd \; price \; x \; Load \;\; x \; \langle Pct \; "unhedged" \; load \rangle \right]$$

However, due to the challenges of estimating future levels of unhedged load relating to market activity, the percentage of load to apply in the equation is problematic. Therefore, SPP also calculates the allocation of benefits, again for informational purposes, utilizing the Generating Unit Re-dispatch portion of this equation, as described under Section 8.1.

For both calculations, the equations are applied to each identified market participant within and external to the SPP region. Areas with positive results are summed and each market participant's percent contribution to this summation is calculated. These percentages are then used to calculate expected dollar benefits for each market participant based upon the total expected benefits for the modeled footprint.

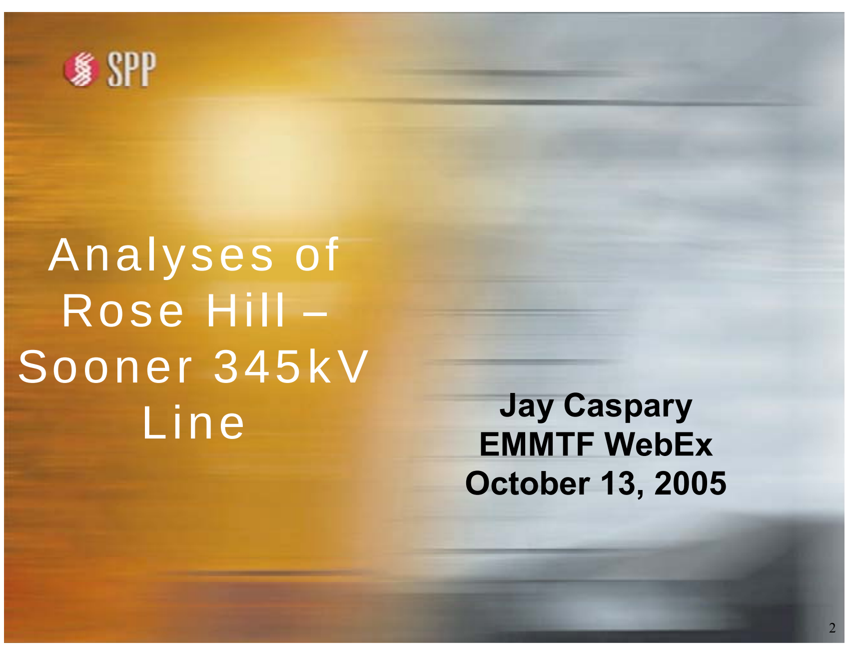
Please see Appendix A for an example of how these calculations were applied to develop results relating to an actual economic transmission expansion study.

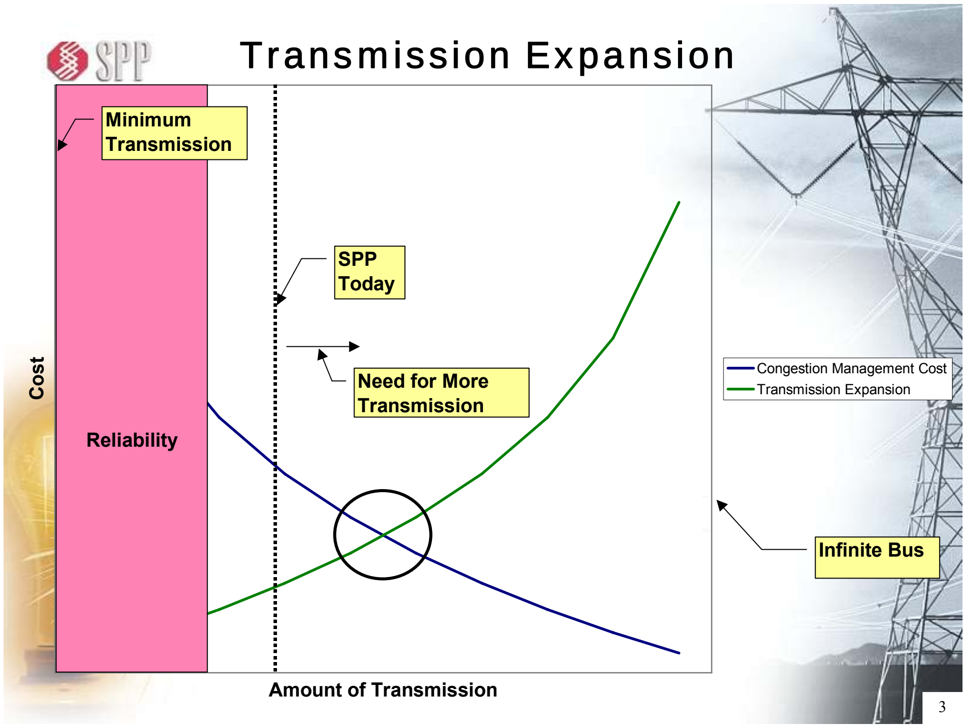
Appendix A

EXAMPLES OF PROJECT ANALYSIS & RESULTS FOR ROSE HILL-SOONER

USING THE 'BASE' AND 'SENSITIVITY' MODELS

Appendix A is based on the 2005 - 2010 SPP RTO Expansion Plan ("SREP") report. It is included in this document for reference purposes only, and represents a historical snapshot of the terms and assumptions used at the time the SREP was prepared. This appendix should not be used to draw conclusions regarding the potential savings for particular areas, the possible allocation of costs of projects to areas, or the potential benefits to generators or loads.





Screening Process

- Ran MarketSYM base typical week July 2005
- Made change cases and reran MarketSYM run for the typical week July 2005
- Compared total production savings (dispatch savings + violation savings) to the base case

4

Screening Process

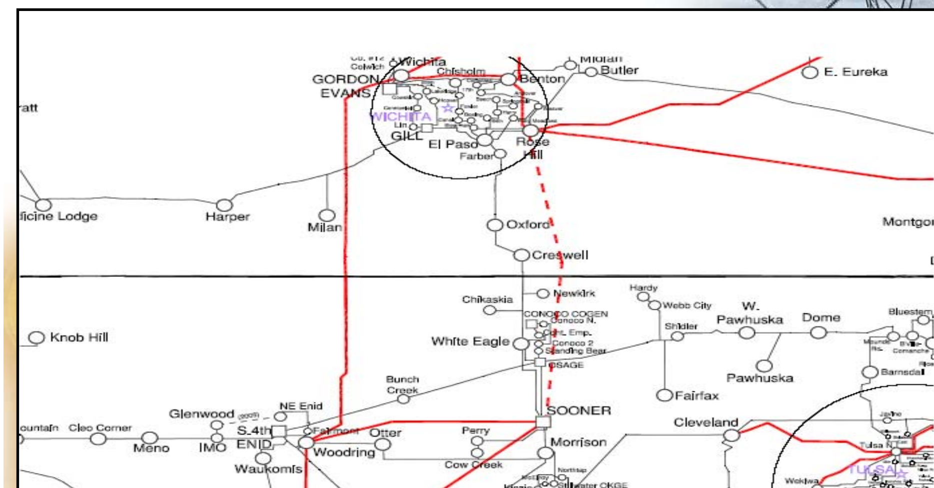
- Estimated ten year savings based on total production savings
- Made ratio of estimated ten year savings to estimated construction cost
- Multiplied the ratio times 100

5

Project Ranking			
Project Name	Project Cost million $	Dispatch Savings 10 year Estimate Cost Savings	Ratio x 100
N.E Oneta Tie N.E GRDA	8.0	9.4	117.50
Tolk-Potter	29.5	25	84.75
Cleveland-Sooner	18.0	14.57	80.94
Tuco-Tolk-Potter	44.5	25.23	56.70
Rose Hill -Sooner 345 kV	43.5	19.68	45.24
SWPS-Battlefield	3.0	1.047	34.90
Fair Port-Sibley 345 kV	32.0	9.92	31.00
Potter-Clovis	98.5	27.45	27.87
Super X-Plan	493.5	136.884	27.74
Pauline-Knoll-Spearville-XF 345 kV	119.0	32.24	27.09
Modified X-Plan	449.0	119.966	26.72
Pauline-Knoll-Spearville 345 kV	114.0	29.74	26.09
JEC-Swisvalle 345 kV	27.0	6.29	23.30
Valliant Tie	3.3	0.702	21.60
Original X-Plan (Plan-A)	419.0	84.35	20.13
Original X-Plan (Plan-B)	410.0	81.9	19.98
Swisvalle-JEC-Moore 345 kV	86.5	14.68	16.97
Tuco-Tolk	17.0	2.52	14.82
Flint Creek-ISES	143.0	20.688	14.47
S.Dierks-Murfressboro	7.3	0.914	12.57
S.Fayetteville-Osage	17.3	1.851	10.70
JEC-Moore 345 kV	59.5	5.9	9.92
NW Texarkana-McNeil	28.0	2.68	9.57
Chaves XFR 2	7.0	0.667	9.53
Wolf Creek-Lang	22.0	1.31	5.95
NW Texarkana-McNeil+Dolet Hills	52.3	2.952	5.64
Lacyne-Montrose-Callaway	105.0	3.95	3.76
Moore-Pringle	20.0	0.704	3.52
SPS 115 Lines & XFR	35.0	0.946	2.70
Potter-Northwest	132.0	1.98	1.50
Muskogee-VBI	38.3	0.38	0.99
Dolet Hills Tie	24.3	0.051	0.21
HaleCounty-PlantX	27.0	0.025	0.09

6

Rose Hill – Sooner 345 kV



7

Detail Market Analysis

- All four seasons
- Sensitivity to fuel cost and load growth
- Dispatch cost savings
- Generator benefits
- Load benefits

8

Rose Hill-Sooner Annual & 10 Year Savings

	Production Cost savings + violation costs	
	Rose Hill-Sooner	Rose Hill-Sooner
	2005	2010
Spring	$1,961,617	$1,630,577
Summer	$1,905,147	$1,705,158
Fall	$1,775,775	$1,187,216
Winter	$1,143,109	$904,225
Total	$6,785,648	$5,427,176
Estimated 10 year Savings	$41,840,778	

9

The 10-year savings calculates the net present value using an 8% discount rate. The calculation assumes annual savings of $6,785,648 for years 2005-2009 and annual savings of $5,427,176 for the years 2010-2014. Note that while this analysis starts in the year 2005, the Rose Hill-Sooner line did not come into commercial operation that year and will not for several years after that.

Production Cost Savings

- Production Cost Savings do not equal Generator Benefits
- Production Cost Savings equal expected economic dispatch savings plus violation cost savings

10

Generator & Load Benefits

Generator Benefits

$$\sum_{\substack{All\\Hours}} \sum_{\substack{Each\\Area}} \sum_{\substack{Gen\\with\\\Delta\ MW}} \left[\left(\Delta\ MW\ x\ Nodal\ \ price\right) - \Delta\ Dispatch\ \ \text{cost} \right]$$

Load Benefits

$$\sum_{\substack{All\\Hours}} \sum_{\substack{Each\\Area}} \left[\Delta\ Load\ \ wtd\ \ price\ \ x\ Load\ \ x \left\langle Pct\ \ \text{“}unhedged\text{”}\ load \right\rangle\right]$$

11

Rose Hill-Sooner Annual Savings

	Year 2005	Year 2005			Year 2010	Year 2010
	Generator Benefits	10% load Benefit Normalized			Generator Benefits	10% load Benefit Normalized
CELE	13,822	110,432		CELE	5,289	69,743
EMDE	17,670	(28,231)		EMDE	16,747	(6,449)
GRRD	(0)	146,195		GRRD	3	94,818
INDN	28,572	(66,117)		INDN	13,828	(51,699)
KACP	50,440	(986,490)		KACP	45,025	(671,235)
KACY	21,102	(161,633)		KACY	16,358	(113,499)
LAFA	(39)	31,531		LAFA	115	17,340
LEPA	31	12,914		LEPA	0	8,149
MIDW	0	(53,106)		MIDW	0	(27,309)
MIPU	26,049	(403,430)		MIPU	28,505	(323,414)
OKGE	159,202	2,943,603		OKGE	163,543	1,770,614
PSOK	56,683	1,366,973		PSOK	47,200	913,138
SOEP	71,260	743,026		SOEP	52,244	465,385
SPPIPP	2,349	0		SPPIPP	2,275	0
SPRM	10,476	(62,056)		SPRM	6,497	(40,276)
SUNC	587	(47,009)		SUNC	(435)	(10,405)
SWPA	2,636	(17,543)		SWPA	2,093	(10,325)
SWPS	52,183	1,432,390		SWPS	44,454	1,098,007
WEPL	(828)	(148,765)		WEPL	(448)	(73,178)
WERE	475,208	(3,291,564)		WERE	252,411	(2,145,724)
WFEC	149,851	642,156		WFEC	80,762	374,022
WINDSPP	0	0		WINDSPP	0	0
	0	0			0	0
	0	0			0	0
Subtotals	1,137,252	2,163,275		Subtotals	776,466	1,337,703
	0	0			0	0
AECI	17,878	(114,962)		AECI	13,042	(100,575)
IOWA	7,221	(453,634)		IOWA	1,071	(221,292)
MAINS	7,467	(1,017,516)		MAINS	2,028	(647,631)
NEBR	8,775	(730,772)		NEBR	3,805	(472,843)
EES	(79,011)	720,296		EES	(33,393)	499,115
EESIPP	5,001	0		EESIPP	1,802	0
	0	0			0	0
	0	0			0	0
Subtotals	(743,771)	(2,316,884)		Subtotals	(312,190)	(1,442,341)
	0	0			0	0
Totals	393,482	(153,608)		Totals	464,275	(104,637)
Violation Cost Savings	2,664,830			Violation Costs Savings	1,278,927	
Dispatch Savings	4,120,817			Dispatch Savings	4,148,248	
Dispatch + Violation Savings	6,785,647			Dispatch + Violation Saving	5,427,175	

12

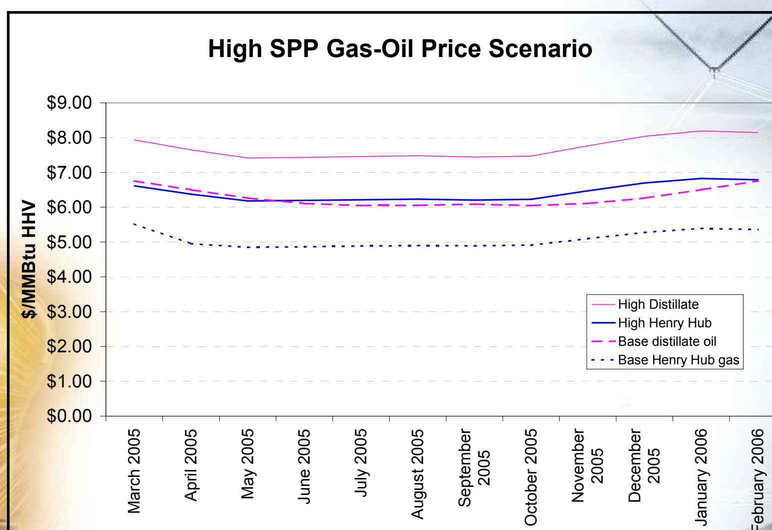
Rose Hill-Sooner Allocation

	Generator Benefits Plus 10% load Benefits	Allocation Generator Benefits
CELE	4%	3%
EMDE	0%	2%
GRRD	2%	0%
INDN	0%	2%
KACP	1%	5%
KACY	0%	2%
LAFA	0%	0%
LEPA	0%	0%
MIDW	0%	0%
MIPU	0%	3%
OKGE	31%	20%
PSOK	15%	6%
SOEP	8%	6%
SPPIPP	0%	0%
SPRM	0%	1%
SUNC	0%	0%
SWPA	0%	0%
SWPS	18%	5%
WEPL	0%	0%
WERE	4%	31%
WFEC	7%	10%
WINDSPP	0%	0%
	0%	
AECI	0%	2%
IOWA	0%	0%
MAINS	0%	0%
NEBR	0%	0%
EES	8%	0%
EESIPP	0%	0%
	0%	0%
Totals	100%	100%

13

The estimation of benefits was calculated two different ways. The first estimate is based on positive benefits for 10% load benefits plus positive generator benefit. The second estimate is based on just the positive generator benefits.

High Fuel Scenarios



14

SPP

Sensitivity to Fuel Cost

- Benefits of Rose Hill-Sooner 345 kV Line increased 20% with higher natural gas fuel prices
- Almost linear correlation between natural gas price and economic value of potential 345kV interconnection between KS and OK

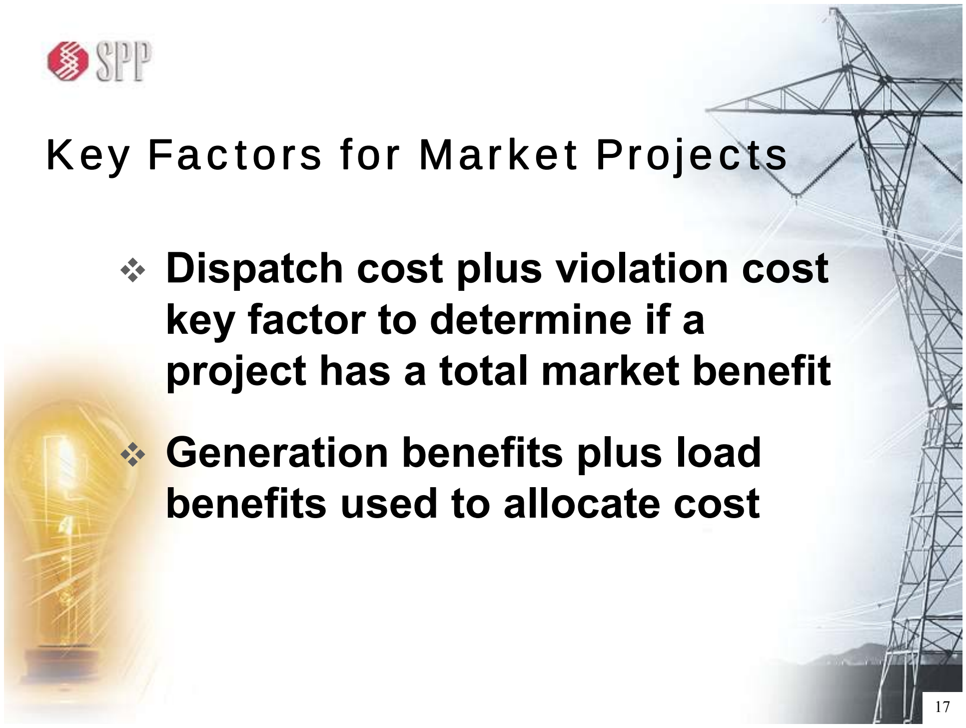
15

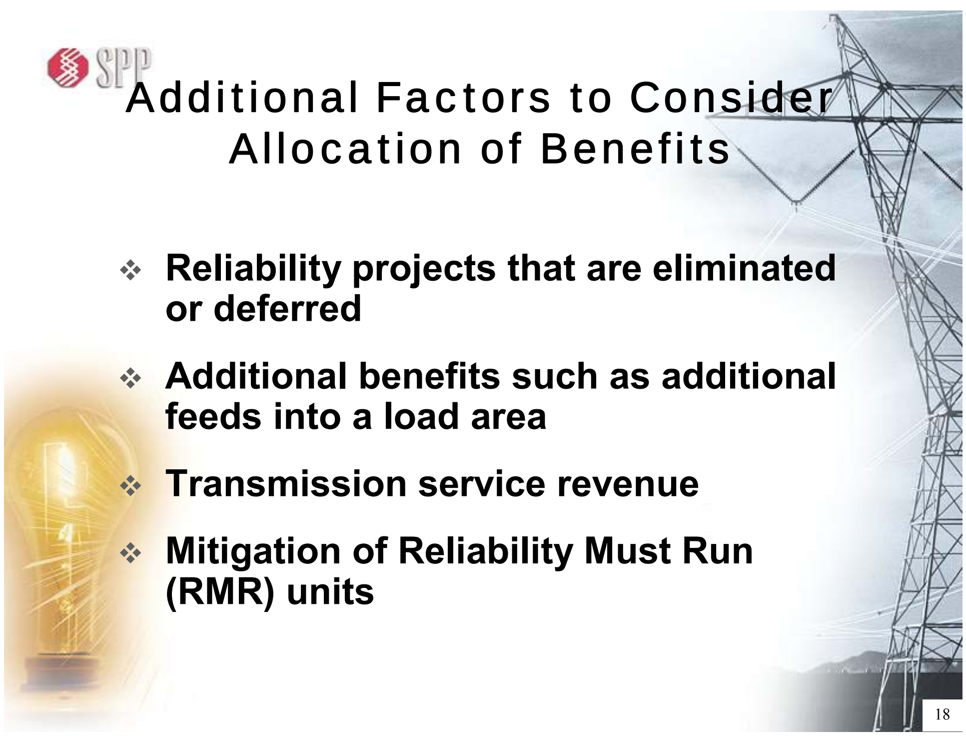
SPP

Violation Cost Reductions

- Benefits due to unloading key Flowgates
  - Creswell – Kildare
  - El Paso – Farber
    - Be careful to not double count benefits of constraints in series

16


SPP
Key Factors for Market Projects
❖ Dispatch cost plus violation cost key factor to determine if a project has a total market benefit
❖ Generation benefits plus load benefits used to allocate cost
17


SPP
Additional Factors to Consider Allocation of Benefits
❖ Reliability projects that are eliminated or deferred
❖ Additional benefits such as additional feeds into a load area
❖ Transmission service revenue
❖ Mitigation of Reliability Must Run (RMR) units
18

Appendix B

EIGHT NODE MODEL EXAMPLES – DECEMBER 2004 DRAFT

QUANTIFYING ECONOMIC BENEFITS OF ECONOMIC TRANSMISSION UPGRADES

1. Introduction

Among the challenges of quantifying the economic benefits of transmission upgrades is the estimation of impact on overall regional congestion and identifying which specific sub-regional areas and market participants will likely benefit from the quantified congestion reduction.

SPP applies a set of multi-regional simulation models to estimate the impact of network expansion and upgrade projects on regional resource dispatch and congestion. A straightforward interpretation of the "societal impact" of reducing congestion is the ability to produce a "closer to optimal" dispatch of supply resources to serve electric loads, resulting in reduced dispatch costs within and across regions. In some situations the analysis might be expanded to include the potential impact on generating unit commitment and associated costs. Specific assumptions regarding pricing can impact the likely distribution of these benefits to market participants.

To help identify how much sub-regional areas and/or individual market participants that might benefit from reduced congestion resulting from transmission expansion/upgrade projects, SPP has constructed the congestion reduction benefit break-out equation shown in **Equation 1**.

Equation 1: SPP Congestion Reduction Benefit Break-Out Equation

$$= \sum_{\substack{All\\Hours}} \sum_{\substack{Each\\Area}} \sum_{\substack{Gen\\with\\\Delta MW}} \left[\left(\Delta MW \ x \ Nodal \ \ price \right) - \Delta \ Dispatch \ \ cost \right]$$

$$- \sum_{\substack{All\\Hours}} \sum_{\substack{Each\\Area}} \left[\Delta \ Load \ wtd \ price \ x \ Load \ x \ \left\langle Pct \ "unhedged" \ load \right\rangle \right]$$

The first line of Equation 1 is referred to herein as the **"generator re-dispatch"** portion of the equation, because it addresses the economic impact of generator re-dispatch that is observed across comparable market simulation cases. These changes in dispatch implicitly represent incremental bulk power transfers that can be achieved as a result of removing or at least reducing certain congestion barriers. This component the equation should capture the direct economic impact of congestion reduction occurring from improved dispatch of generating resources across the modeled footprint.

Application of the generator re-dispatch portion of Equation 1 can be thought of as implicitly quantifying incremental transactions made possible by removing or reducing "blockages" within the network. The nodal prices reflect the marginal value of injecting (exporting) or withdrawing (importing) energy at the respective generator locations. The impacts of reducing congestion accrue to the owners of impacted generators and the load-serving entities receiving output from the generators.

Within SPP, almost 90% of generating capacity is owned by vertically-integrated electric utilities. These utilities generally own sufficient transmission rights to deliver energy from affiliated generators to native loads and other obligated (firm) loads. These deliveries are scheduled via a combination of network transmission service within metered control areas and point-to-point service across control areas. Loads served by the scheduled deliveries are effectively "hedged" from the effects of changes in locational marginal prices beyond those inherent in the re-dispatch computations (i.e., these scheduled deliveries should not experience a nodal price charge or congestion cost charge in the marketplace).

However, some portion of loads will inevitably be "unhedged" in the markets. For example, in the upcoming SPP EIS market, any load that is not scheduled beforehand (Imbalance Energy) will pay a locational marginal price (called a Locational Imbalance Price or "LIP"). More generically, a certain amount of "unhedged" spot transaction activity is inevitable in any market due to uncertainties such as generator/transmission outages, weather conditions, and over time, load growth.

The second line of Equation 1 is intended to capture the impact of changes in nodal prices on loads that not hedged in the marketplace, and is referred to herein as the **"unhedged load"** impact. Due to the challenges of estimating future levels of unhedged/spot market activity, the percentage of load to apply in the equation is problematic, and should perhaps be thought of as akin to sensitivity analysis.

More specifically within the equation, **ΔMW** refers to the change in real output of each generator from the "Base Case" simulation (before expansion/upgrade) to the "Change Case" simulation. **Nodal Price** refers to the $/MWh locational price at each associated generator location of the Change Case solution, deriving from offer prices assumed in the modeling. The **ΔDispatch Cost** refers to the change in total dispatch cost ($) of each generator across the two cases. As shown later, applying the Change Case nodal prices in the equation does not infer that Base Case prices are ignored – they are inherently reflected in the dispatch levels of the generators in the Base Case solution.

The **ΔLoad-Wtd Price** refers to the change in load-weighted locational price for a specific area or market participant. Multiplying this value by the associated **Load** is equivalent to aggregating the product of load and change of price at each location. The **Pct "Unhedged" Load** again component refers to the portion of load that is not protected from nodal price fluctuations.

2. Description of Eight Node Model

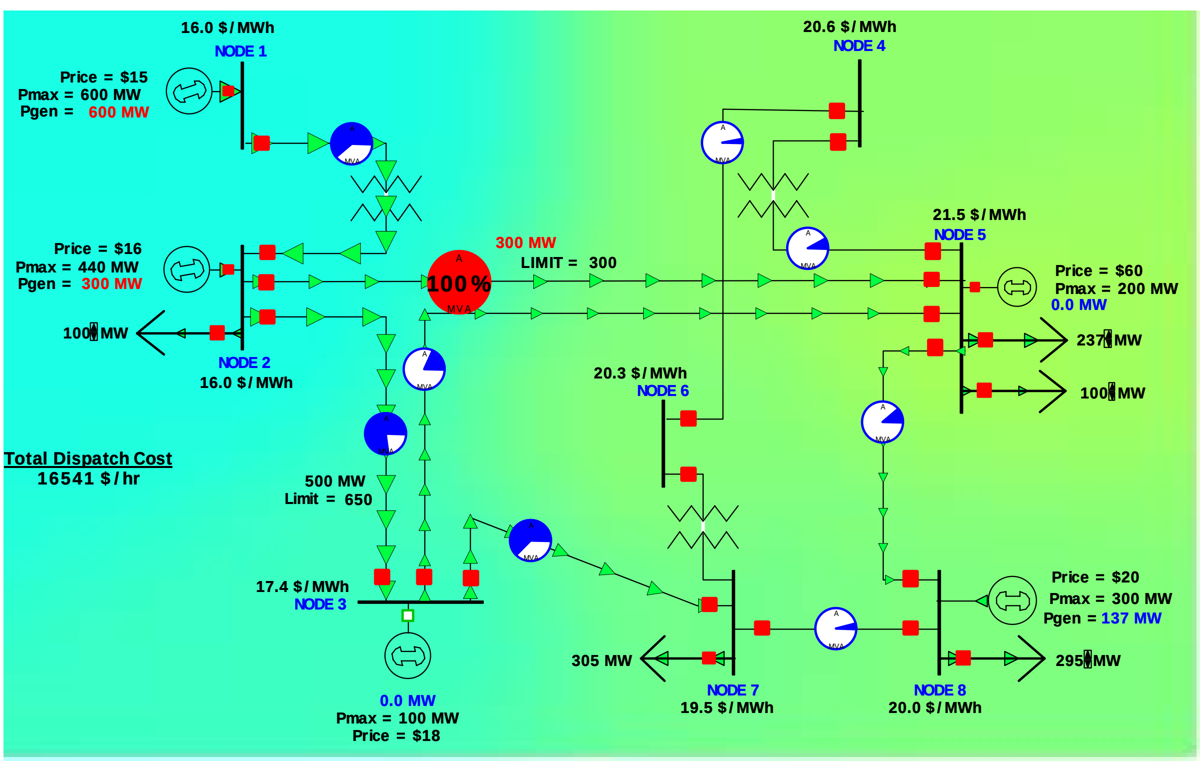
An eight-node simplified optimal power flow network model was developed to construct the examples in this Appendix B. The computations and one-line diagrams were constructed using the *Simulator®* model from *PowerWorld Corporation*. For the simplified examples presented here, it is assumed that generators offer into the market at marginal cost. As such, in these examples the only impediment to achieving the optimal or "least-cost" dispatch is network congestion.

3. Simplified Network Examples With and Without Congestion Present

The initial congested case is illustrated in **Figure 1**, reflecting a transmission network branch from Node 2 to Node 5 that is limited to 300 MW transfer. The generator output and network flows are consistent with an optimal achievable dispatch, showing that the network branch would become fully loaded, effectively creating an "export constraint" on the left side of the network and an "import constraint" on the right side of the network. For some of the examples which follow, it can be useful to think of the depiction as representing two utility control areas, each operated by vertically integrated utilities and with a border interface drawn right down the middle of the figure. However, a vertically integrated utility perspective is not necessary for the examples to be correct.

In Figure 1, the lowest-priced generator at Node 1 ($15/MWh) is fully dispatched. The next merit-order priced generator at Node 2 ($16/MWh) is capable of producing 440 MW, but is limited to 300 MW output by the transfer constraint. Conversely, the generator at Node 8 is producing megawatts only because the transfer constraint is present. A generator at Node 3 priced at $18/MWh is presently assumed to be out of service for maintenance. A generator at Node 5 is sufficiently high priced so as to not impact the situation. The locational marginal prices range from $16/MWh at the left-most nodes, to a high of $21.50/MWh at Node 5. It will become more obvious later why the marginal price at Node 5 exceeds the price of both the $16/MWh and $20/MWh "marginal" generators.

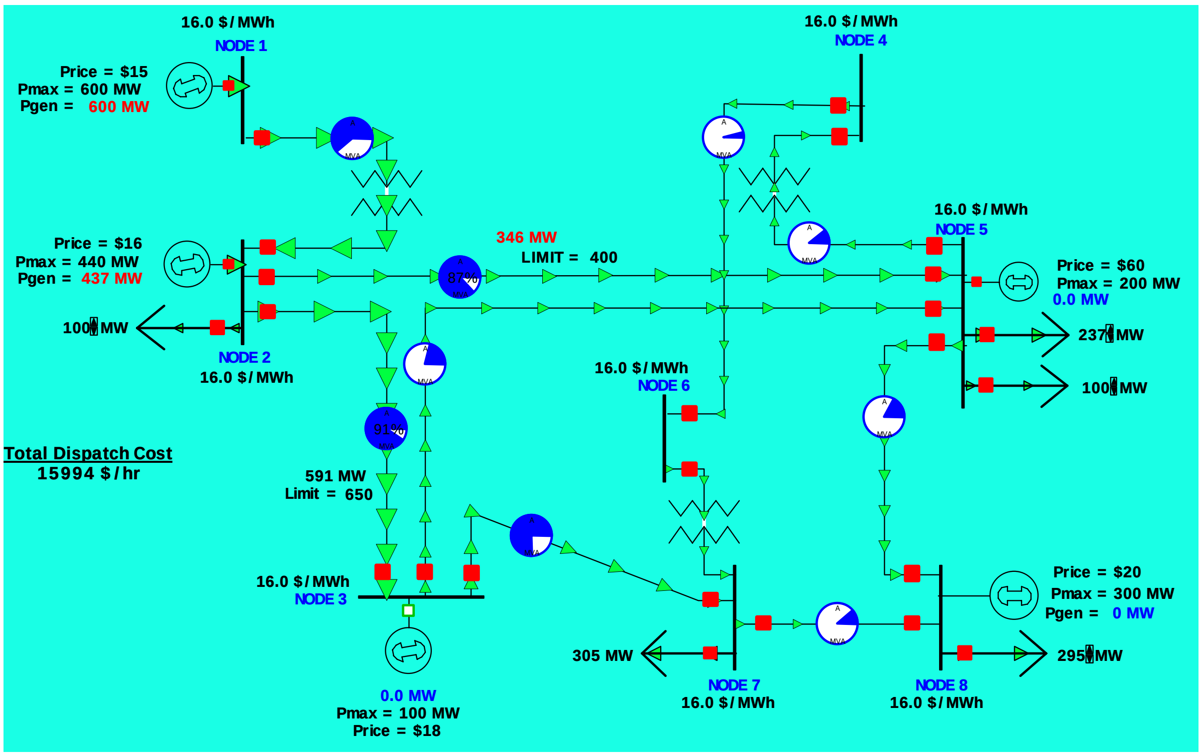
Figure 1: Initial Congested Case



A visual perspective of removing the transfer constraint is shown in **Figure 2**, indicating that indeed in comparison to Figure 1, the generators have "re-dispatched" as reflected in the constructed schedules. Comparing the computed total dispatch cost of $15,994 shown on

Figure 2 to the value of $16,541 shown on Figure 1, the saving is indeed $547 ($1 rounding error due to small loss factors). Also, Figure 2 shows that the marginal prices are now identical at all the nodes, consistent with the ability to now deliver the next megawatt of load anywhere on the network from the "merit order" generator at Node 2 (again $16/MWh).

Figure 2: Effect of Removing the Congestion



4. Scheduling Examples with the Congestion Present

To help understand the scheduling perspective, simplified scheduling examples were constructed for the congested situation depicted on Figure 1.

The first set of schedules constructed as shown on **Table 1** is consistent with a desired optimal dispatch of the lowest-cost resources, but is ignorant of the transfer limitation on the branch from Node 2 to Node 5. The prospect of overloading the branch makes this set of schedules infeasible. If these schedules were submitted to the transmission operator, a re-dispatch would be necessary to avoid overloading the transmission branch. The most efficient re-dispatch would again be consistent with Figure 1, effectively requiring that the output of the generator at Node 2 be dispatched 137 MW less than reflected in the schedules, and the higher-cost generator at Node 8 dispatched at 137 MW.

Table 1: Initial Set of Schedules Ignorant of the Congested Transmission Branch

Sched #	Transaction	Cumulative Loading on Branch Node 2 -> Node 5
1	305 MW from Generator at Node 1 to Load at Node 7	89 MW
2	295 MW from Generator at Node 1 to Load at Node 8	189 MW
3	100 MW from Generator at Node 2 to Load at Node 2	189 MW
4	237 MW from Generator at Node 2 to Load at Node 5	300 MW (fully loaded)
5	**100 MW from Generator at Node 2 to Load at Node 5**	**345 MW (OVERLOADED)**

Assume that the parties submitting schedules #1 through #4 in Table 1 collectively hold the full scheduling rights to the 300 MW transfer capacity on the branch from Node 2 to Node 5. In this situation, the party submitting schedule #5 would bear the cost of the re-dispatch. In a nodal price market, the cost of congestion would be calculated consistent with **Equation 2**.

Equation 2: Transaction-Based Congestion Cost Equation

$$\boxed{MW\ Transaction\ x\ (Nodal\ \Pr ice\ at\ Withdrawl - Nodal\ \Pr ice\ at\ Injection)}$$

Applying the nodal prices from Figure 1 to this equation yields the following cost of congestion, resulting in a value equivalent to the incremental cost of the forced re-dispatch.

100 MW x (\$21.50 - \$16) = \$548 (congestion cost calculation #1)

Other sets of schedules could be constructed to also yield the cost of congestion. For example, second set of schedules is shown in **Table 2**, with the further assumption that the parties submitting schedules #1 through #5 hold the scheduling rights to the congested transmission branch. The cost of congestion borne by the party submitting schedule #6 is quantified below, again yielding a consistent result.

158 MW x (\$19.50 - \$16) = \$548 (congestion cost calculation #2)

Table 2: Second Set of Schedules Ignorant of the Congested Transmission Branch

Sched #	Transaction	Cumulative Loading on Branch Node 2 -> Node 5
1	337 MW from Generator at Node 1 to Load at Node 5	157 MW
2	263 from Generator at Node 1 to Load at Node 8	246 MW
3	100 MW from Generator at Node 2 to Load at Node 2	246 MW
4	32 MW from Generator at Node 2 to Load at Node 8	257 MW
5	147 MW from Generator at Node 2 to Load at Node 7	300 MW (fully loaded)
6	**158 MW from Generator at Node 2 to Load at Node 7**	**345 MW (OVERLOADED)**

Any number of unique scheduling scenarios could be constructed to yield the cost of congestion in even this simplified network. However, consistent to each of them would be the underlying forced re-dispatch of the identified generators at Nodes 2 and 8 to avoid overloading the network branch. Thinking of it in this context, the cost of congestion reflected as a "direct transaction" between the affected generators would be calculated as follows:

137 MW x ($20 - $16) = $548 (congestion cost calculation #3)

5. Generator Re-Dispatch Equation

In a large network with multiple identified or potential congestion locations and associated re-dispatch at multiple generator locations, the scheduling scenarios that could be constructed to calculate the cost of congestion would be virtually infinite. However, consistent to each of them would be the underlying re-dispatch of generators as forced by the network congestion.

Implicit within a "Base Case" market simulation exhibiting congestion is an underlying set of schedules supporting the (sub-) optimal dispatch of that case. A "Change Case" with reduced network congestion would reflect incremental dispatch of low-cost/priced resources.

The generator re-dispatch calculation of the congestion reduction benefit break-out equation in effect assumes distribution of the incremental scheduling rights to the owners of the re-dispatched generators. In the context (most) of these generators being associated with integrated electric utilities, the scheduling rights would then effectively impact the price of scheduled deliveries to loads on those utility systems. This has the practical implication that incremental schedules made feasible by the elimination or reduction of congestion will most likely directly impact the "nearby" loads.

As an example of this, assume that Nodes 4 through 8 of Figure 1 or 2 (including the generator at Node 8) represent a small utility system, and the utility obtains the full scheduling rights associated with the improved (fully optimal) re-dispatch resulting from removal of the network congestion. The utility can then apply the scheduling rights to schedule lower-cost energy to effectively reduce congestion anywhere on the utility system, as shown within congestion cost computations #1 and #2 for scheduling to Node 5 or Node 7.

This break-out methodology does not represent a unique distribution of transmission scheduling rights, or even a "most appropriate" distribution (if there were one). However, the methodology should present a straightforward "initial" distribution of benefits based again on direct participation by owners of the generators impacted by the re-dispatch. Once again, to the extent the generators are part of a utility or control area network system, the benefit should effectively impact cost of delivery to loads within that system.

The congestion reduction benefit break-out equation should also appropriately capture the impact of re-dispatch that does not translate to scheduled transactions. For example, if a "must-run" constraint is impacted within a control area, the nodal prices of the changes in generation should capture the internal value of injecting/withdrawing energy at the impacted generator locations (e.g., no net impact if no congestion within the area), as well as the change in production costs.

6. Applying the Congestion Reduction Benefit Break-Out Equation to the Previous Examples

Applying the generator re-dispatch portion of Equation 1, the congestion reduction benefit break-out equation, to the congested ("Base") and non-congested ("Change") cases shown on Figures 1 and 2 results in the following:

"Benefit at" Gen Node 2 = [137 MW x $16 (nodal price)] - $2,192 (dispatch cost) = $0

"Benefit at" Gen Node 8 = [-137 MW x $16] - (-) $2,740 = +$548

Thus, in this initial situation, the owner of the generator at Node 8 is effectively the beneficiary of the $548 benefit. One subtlety of this result is that the marginal price (marginal value of injecting generation) at Node 8 decreased, while the marginal price remained unchanged at Node 2.

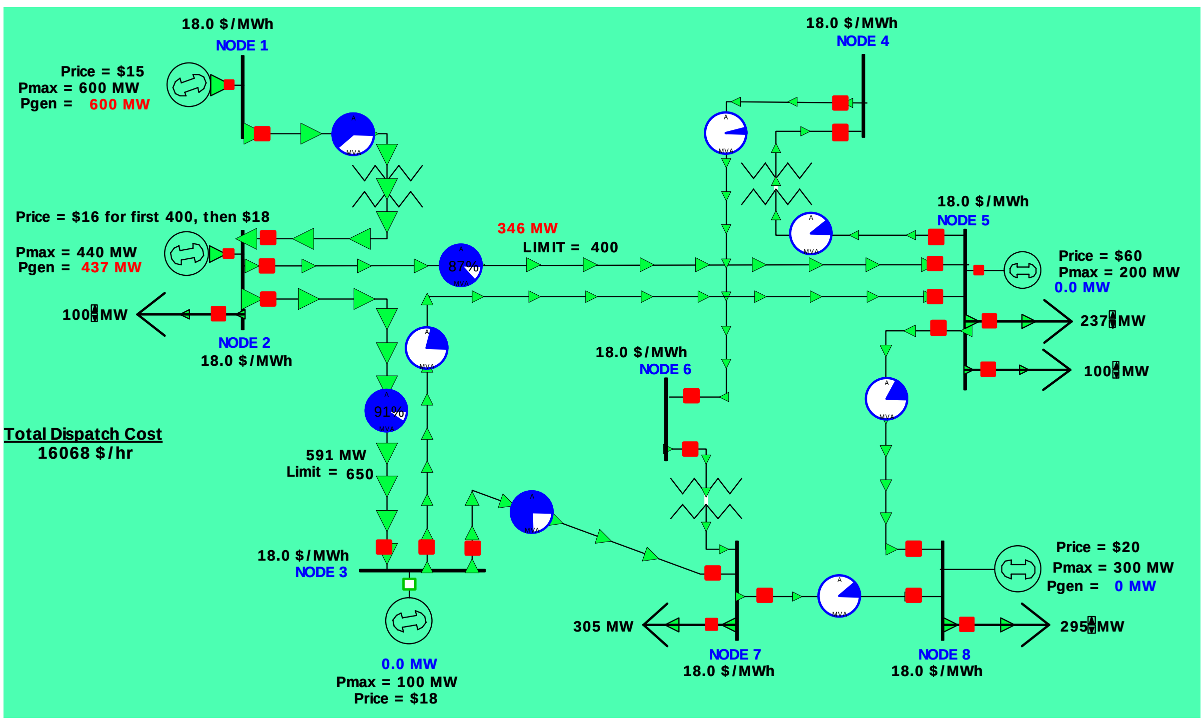
Changing the situation slightly, assume that the generator at Node 2 has a “two-part piecewise linear” offer price as follows:

First 400 MW is offered at (and the marginal cost is) $16/MWh

Remaining 40 MW is offered at (and the marginal cost is) $18/MWh

The above change would not affect the congested case of Figure 1, but the non-congested result would now look like the depiction in **Figure 3**.

Figure 3: Non-Congested Case with Two-Part Offer Curve for Generator at Node 2



The (non-congested) marginal price at all nodes is now $18, and the re-dispatch impact of removing the congestion is as follows:

[100 MW x $16] + [37 MW x $18] + [-137 MW x $20] = -$474 (i.e., reduced congestion)

Apply the generator re-dispatch portion of the congestion reduction benefit break-out equation to the new situation depicted here, with the congested case again representing the Base and the non-congested case representing the Change, results in the following:

“Benefit at” Gen Node 2 = [137 MW x $18 (nodal price)] - $2,266 (dispatch cost) = +$200

“Benefit at” Gen Node 8 = [-137 MW x $18] - (-)$2,740 = +$274

In this example about 58% of the benefit is assigned to the owner of the generator at Node 8. The marginal prices have changed significantly at both the exporting node and the importing node.

In both of the previous examples, the generator at Node 8 reduces output, and we state that "the owner of this generator … benefits". Does it make sense that the owner benefits when generating less?

There are two perspectives on this question, depending on whether the generator is owned (or otherwise under the control of) a vertically-integrated utility, or is owned by an Independent Power Producer ("IPP"). When assuming utility ownership, it is clear in this simplified example the utility would benefit by importing energy at a lower price than the incremental cost of generating, as depicted in the example. It is not quite as straightforward to interpret this situation for IPP ownership. However, it would be expected that if the IPP owner could effectively replace a scheduled delivery from a high-cost source with equivalent delivery from a lower-cost source, an incremental margin could be achieved.

7. Unhedged Load

In the previous examples it was implicit that all load was hedged against "incidental" nodal price impacts via generation/transmission rights and associated scheduling to load. What if for the examples discussed earlier it was instead assumed that 10 MW of load at Node 2 and also 10 MW of load at Node 5 were unhedged (i.e., no scheduled deliveries), and thus deliberately or incidentally experience the changes in nodal price as congestion in reduced?

To interpret the impact of the unscheduled load, it is perhaps best to review the changes in both load charges and overall generator revenues between a congested case and a non-congested case. **Table 3** shows the nodal price charges to the unscheduled loads for the comparative cases, based on the two-part price assumption for the generator at Node 2 as applied in the previous section. The unscheduled load at Node 2 experiences a $20 increase of charges with elimination of the congestion, due to the increase in nodal price at that location (from $16/MWh to $18/MWh). Conversely, and the unhedged load at Node 5 experiences a $35 decrease of charges due to the reduction of nodal price at that location (from $21.50/MWh to $18/MWh).

Table 3: Charges for Total 20 MW Unscheduled Load

	Load at Node 2		Load at Node 5		
	Unscheduled	Charges	Serving	Serving	Total
Congested Case	10.0 MW	$160	10.0 MW	$215	$375
Non-congested Case	10.0 MW	$180	10.0 MW	$180	$360
Change of Gen Revenue		$20		-$35	Net Change **-$15**

Table 4 shows in relative detail a calculation of the change in revenues and expenses for the two generators from the congested case to the non-congested case, with a break-out of portions attributable to both the scheduled and unscheduled loads. The change in revenue is calculated for both scheduled and unscheduled components as "ΔMW x nodal price", since this is consistent with both the generator re-dispatch portion of the congestion reduction

benefit break-out equation for scheduled loads, and how the "spot price" output would be priced. For the expense calculations, dispatch costs for the "final MW" of output were applied against the unscheduled loads, since this is consistent with how dispatch would effectively be impacted.

Table 4 yields net benefit for each generator consistent with the result for the example at the beginning of the previous section, including an overall saving of $474.

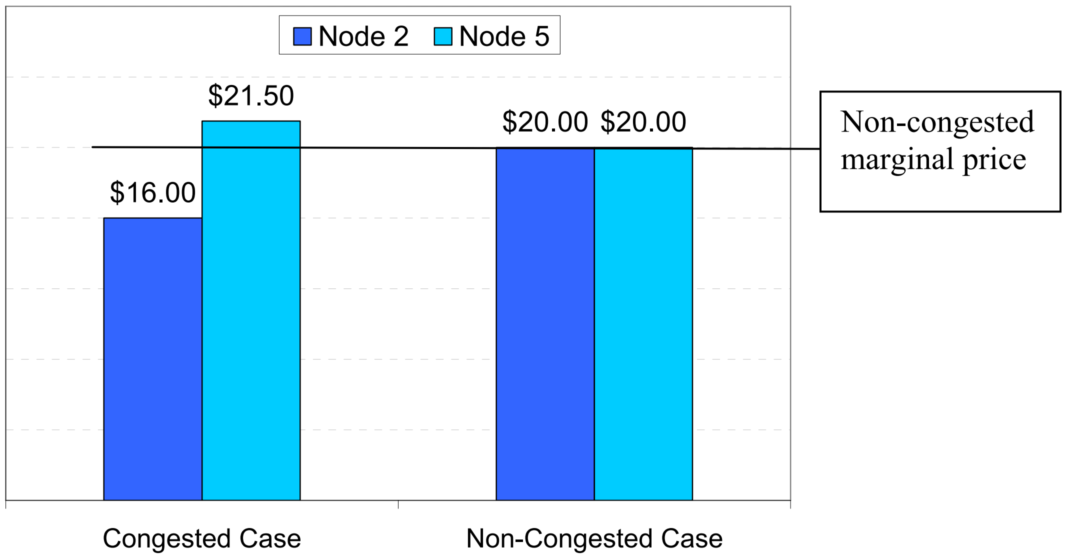
It is worthwhile to note that $15 of the overall benefit is identified with the unscheduled load. From this and other examples yielding a consistent result, it would appear the NET reduction in charges to unscheduled loads across simulated cases effectively overlaps with the quantification of benefit derived from the generator re-dispatch portion of Equation 1.

Table 4: Generator Revenues and Expenses with 20 MW Unscheduled Load

	Gen at Node 2		Gen at Node 8		Total	
	Serving Scheduled Load	Serving Unscheduled Load	Serving Scheduled Load	Serving Unscheduled Load	Sched	Un Sched
Congested Case	293.7 MW	6.3 MW	123.3 MW	13.7 MW		
Expense	$4,699	$101	$2,466	$274	$7,165	$375
Non-congested Case	417.0 MW	20.0 MW	0.0 MW	0.0 MW		
Expense	$6,706	$360	$0		$6,706	$360
Net Above Expense	$2,007	$259	-$2,466	-$274	-$459	**-$15**
Change of Revenue (ΔMW x nodal price)	$2,219	$247	-$2,219	-$247		
Net Benefit	$213	-$13	$247	$27	$459	**$15**
	$200		$274		**$474**	

There is another aspect to the impact of congestion reduction on the nodal prices paid by unscheduled loads. The examples applied herein exhibit the classic expectation that marginal prices on the exporting side of a congestion point are lower than would be observed in the non-congested situation or a "less-congested" situation, and prices on the importing side of a congestion point are conversely higher. **Figure 4** visually shows the perspective that the reduction of congestion is eliminating the differential impact imposed on unscheduled loads in the market.

Figure 4: Nodal Prices Experienced by the Unscheduled Loads



8. Example with All Loads and Generators Exposed to Nodal Prices

The next set of examples applies the assumption that all loads incur charges based on their specific locational nodal prices and all generators are paid based on their specific locational nodal prices. These assumptions are consistent with assuming that no loads or generators effectively own or apply network transmission/transaction scheduling rights.

Table 5 summarizes generator revenues and load charges of the original congested case shown on Figure 1 assuming all loads pay the marginal nodal price and all generators are paid the marginal nodal price. The computed total charges incurred (by loads) exceed the computed total payments (to generators) by a significant amount (about 20%). This differential is a representation of the impact of congestion, based on the marginal prices of the particular solution state represented in Figure 1.

Table 5: Load Charges and Generator Revenues Based Only on Nodal Prices

Paid BY Loads					
Node 2:	100	MW paying at	$16.0	=	$1,600
Node 5:	337	MW paying at	$21.5	=	$7,242
Node 7:	305	MW paying at	$19.5	=	$5,935
Node 8:	295	MW paying at	$20.0	=	$5,900
					$20,677

Paid TO Generators					
Node 1:	600	MW paid at	$16.0	=	$9,600
Node 2:	300	MW paid at	$16.0	=	$4,800
Node 3:	0	MW paid at		=	$0
Node 8:	137	MW paid at	$20.0	=	$2,740
					$17,140

Amount Paid by Loads less Amount Paid to Generators:	$3,537

To understand the above effect, the first point to remember is that the marginal prices of a given "snapshot" are directly applicable only to the next increment of load at each location [1 MW in our models]. It should not be surprising that due to changing marginal prices at varying load levels, the application of a "single snapshot" of prices will inevitably produce a "mismatch" of charges paid in and revenues paid out if applied to all load and generation within the network. The larger the portion of overall network loads and generation to which the assumption is applied, the larger the transactional "mismatch" will almost certainly be.[16]

The type of unscheduled generator/load congestion $$ mismatch illustrated here does happen in real markets – although to a much lesser degree than exhibited in this example and undoubtedly with some offsetting impacts across hours. In actual markets, if a significant amount of "mismatch" accumulates over time, it will likely be distributed to all or a group of market participants by means of an "uplift" allocation mechanism.

Additional insight to the values calculated in Table 5 can be obtained by application of Equation 2, the transaction-based congestion cost equation.

Applying Equation 2, the transaction-based congestion cost equation, to the set of transaction schedules created in Table 1 of this document yields a computation of congestion costs shown in **Table 6**. It is worthwhile to note that the congestion cost for schedule #5 ($548) equals our earlier calculation for this scheduled transaction back in **Section 4**. Consistent with our earlier discussion, if schedules #1 through #4 all have scheduling rights to the loading of the transmission branch from Node 2 to Node 5, the associated congestion costs would be nullified, as indicated in **Table 7**. The only remaining congestion cost is that associated with schedule #5, which is not supported by scheduling rights.

Table 6: Congestion Costs Computed from the Set of Schedules in Table 1

1	From Node 1 gen to Node 7 load	305	x (	$19.5	-	$16.0	) =	$1,056
2	From Node 1 gen to Node 8 load	295	x (	$20.0	-	$16.0	) =	$1,180
3	From Node 2 gen to Node 2 load	100	x (	$16.0	-	$16.0	) =	$0
4	From Node 2 gen to Node 5 load	237	x (	$21.5	-	$16.0	) =	$1,301
5	From Node 2 gen to Node 5 load	100	x (	$21.5	-	$16.0	) =	$548
		1,037						$4,085

[16] Referencing back to the previous example, with only 20 MW of unscheduled load (10 MW at each of two locations) the unscheduled revenue-charge "mismatches" were zero – i.e.., in both the congested case and the non-congested case the charges incurred and revenues received matched (at $375 in the congested case and $360 in the non-congested case).

Table 7: Effect of Applying Transmission Rights to the Congestion Charges

1	From Node 1 gen to Node 7 load	305	x (	$19.5	-	$16.0	) =	~~$1,056~~
2	From Node 1 gen to Node 8 load	295	x (	$20.0	-	$16.0	) =	~~$1,180~~
3	From Node 2 gen to Node 2 load	100	x (	$16.0	-	$16.0	) =	~~$0~~
4	From Node 2 gen to Node 5 load	237	x (	$21.5	-	$16.0	) =	~~$1,301~~
5	From Node 2 gen to Node 5 load	100	x (	$21.5	-	$16.0	) =	$548
		1,037						$548

9. "Hidden" Dispatch Cost Savings

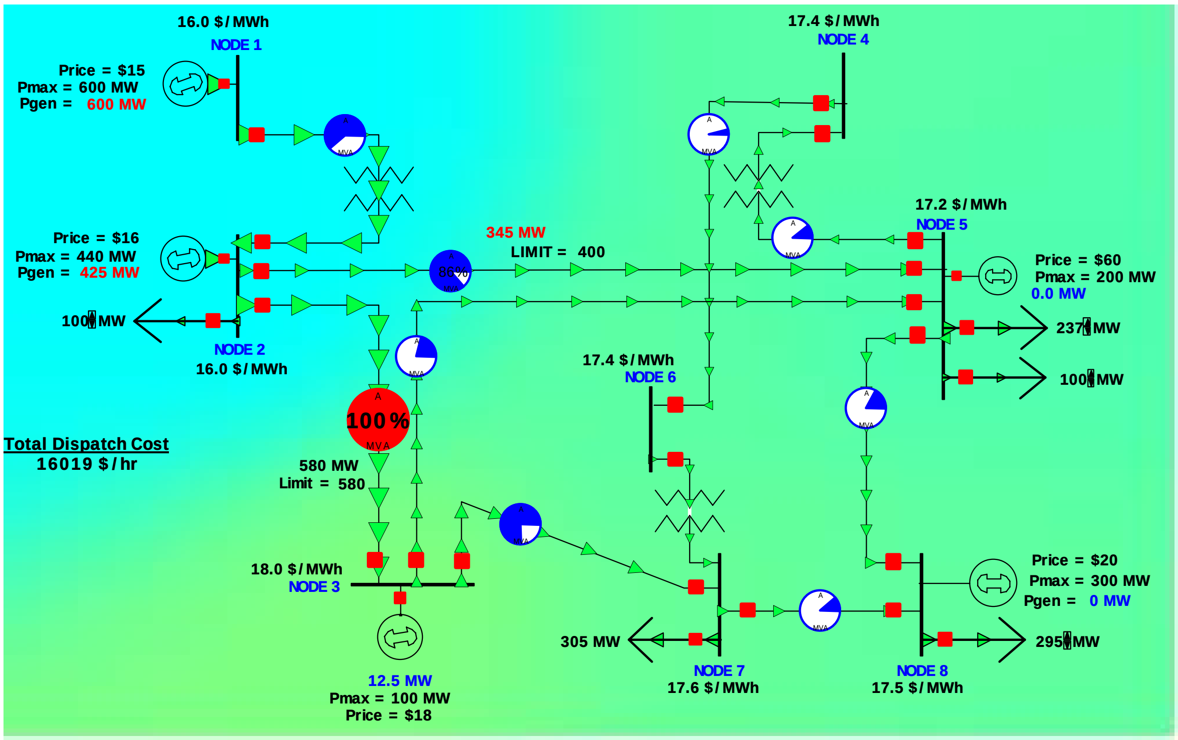
To illustrate a situation where congestion is being reduced but not eliminated, another set of cases was constructed. The congested case depicted in Figure 1 was revised assuming the network branch between Node 2 and Node 3 is rated 580 MW. It was also assumed the generator at Node 3 is available and priced at $18/MWh. These revisions had no impact on the generator dispatch or marginal prices of the original congested case.

The impact of upgrading the original congested branch (Node 2 to Node 5) such that it is no longer a congestion location is illustrated on **Figure 5**. We note that the transmission branch from Node 2 to Node 3 is now congested.

Very similar to the earlier example, eliminating the branch from Node 2 to Node 5 as a congestion location resulted in the generator at Node 2 ramping upward and the generator at Node 8 going off-line. However, in this newer situation the generator at Node 3 dispatches to 12.5 MW. The marginal price at Node 8 reduces to $17.50/MWh (rather than dropping to $16/MWh as previously observed). A total dispatch saving of **$522** [$16,541 - $16,019] is observed from Figure 5 in comparison to Figure 1.[17]

[17] It is worthwhile to note that the dispatch cost reduction of this example ($522) is almost as large as for the original example of Section 3 ($548).

Figure 5: Reduced Congestion Case with 2nd Congested Branch



Applying the generator re-dispatch portion of Equation 1, the congestion reduction benefit break-out equation, to these cases shows the following:

"Benefit at" Gen Node 2 = [124.5 MW x [$16 (nodal price)]] - $1,992 (dispatch cost) = $0

"Benefit at" Gen Node 3 = [12.5 MW x [$18]] - $225 = $0

"Benefit at" Gen Node 8 = [-137 MW x [$17.5]] - (-) $2,739 = **$342**

In this example, the equation is only capturing 66% of the net dispatch saving. Where is the other **$180** dispatch saving hiding? Actually, this computation is a result of the "new" congestion location preventing the marginal prices from equalizing.

Applying Equation 2, the transaction-based congestion cost equation, to a pair of transactions consistent with the incremental transfers yields the following computations. These values were straightforward to calculate in this situation, since there are only two incremental "exporting" locations (generators at Nodes 2 and 3) and only one "importing" location (the generator at Node 8).

From generator at Node 2 to generator at Node 8: 124.5 MW x ($17.5 - $16) = $187

From generator at Node 3 to generator at Node 8: 12.5 MW x ($17.5 - $18) = -$7

$180

Although the above computed congestion cost should not negate any of the overall dispatch cost reduction observed ($522), it is still not obvious how this computation impacts the overall distribution of savings. To carry this example a step further, **Table 8** lists a set of assumed schedules that are identical to those of Table 1 (except that the MW listed for schedules #4 and #5 have been reallocated to emphasize the point at which the transmission branch from Node 2 to Node 3 would now congest).

Table 8: A Set of Schedules Ignorant of the "Newly-Congested" Transmission Branch

Sched #	Transaction	Cumulative Loading on Branch Node 2 -> Node 3
1	305 MW from Generator at Node 1 to Load at Node 7	216 MW
2	295 MW from Generator at Node 1 to Load at Node 8	411 MW
3	100 MW from Generator at Node 2 to Load at Node 2	411 MW
4	316 MW from Generator at Node 2 to Load at Node 5	580 MW (fully loaded)
5	**21 MW from Generator at Node 2 to Load at Node 5**	**591 MW (OVERLOADED)**

Application of Equation 2, the transaction-based congestion cost equation, to the above schedules and nullifying the computations for schedules protected by available scheduling rights (schedules #1 through #4) yields a congestion cost of $24, as shown on **Table 9**. This value is consistent with that the dispatch cost penalty observed by comparing dispatch costs of Figures 2 and 5 ($15,994 and $16,019 respectively).

Table 9: Congestion Costs Calculated from the Above Set of Schedules

1	From Node 1 gen to Node 7 load	305	x (	$17.6	-	$16.0	) =	~~$489~~
2	From Node 1 gen to Node 8 load	295	x (	$17.5	-	$16.0	) =	~~$440~~
3	From Node 2 gen to Node 2 load	100	x (	$16.0	-	$16.0	) =	~~$0~~
4	From Node 2 gen to Node 5 load	316	x (	$17.2	-	$16.0	) =	~~$382~~
5	From Node 2 gen to Node 5 load	21	x (	$17.2	-	$16.0	) =	$24
		1,037						$24

Unfortunately, the resultant impact on the ultimate distribution of benefits may not be resolved until reviewing which parties have rights at the newly-congested path. If these rights are not owned by the owner of the generator at Node 8, it would appear this market participant would effectively be limited to the $384 benefit, and the remaining $180 would effectively accrue to one or more newly-identified market participants.

10. Relevance of the Above Examples to Large-Scale Market Simulations Conducted by SPP Staff

The network congestion situations presented and examined herein are simplified representations of what is occurring in the large scale (8,000 network bus) optimal power flow simulations being conducted by SPP Staff. In particular, several specific observations can be noted and some key points reinforced from these examples in relation to the larger-scale cases.

A. In the examples of **Sections 6 and 9**, no "net benefit" is quantified for the exporting generator(s). In the small-scale cases, this is occurring because: 1) offer prices are implicitly modeled as being equal to incremental dispatch costs; and 2) the nodal prices are not changing at the exporting generator location(s). For essentially the same reasons, the large scale simulations recently conducted by SPP show relatively little "incremental margin" for the generators that are dispatching more after a reduction of network congestion.

Within the large-scale simulations, SPP has been applying market offer prices equal to short-run variable cost for several reasons: 1) SPP has not conducted independent analysis of "offer price strategies" and possible impacts on prices and generator/market participant profitability/margins; 2) A driving perspective when building the models was "cost-driven (i.e., societal) economic modeling"; 3) It is not clear how the application of specific "price markup" assumptions in SPP studies might be interpreted by market participants and others; and 4) from a more technical perspective, the *PowerWorld Simulator* model does not directly support separate computation or accumulation of costs and prices (although a reasonable work-around should be feasible).

Somewhat generic assumptions regarding price margin or markup would have a significant impact on the distribution of generator re-dispatch benefits. For example, if 100,000 MWh of area-to-area transfer were observed annually, a \$2.00/MWh margin would result in about \$200,000 additional benefit to exporters and an offsetting impact to importers (via higher purchased prices).

B. The "hidden" dispatch benefit observed in the example of **Section 9** are also typically observed for large scale simulations conducted by SPP Staff when applying the generator re-dispatch portion of the congestion reduction benefit break-out equation. This is undoubtedly happening for the same reason discussed in that section (i.e., the computational impact of congestion that continues to exist in the Change case solutions).

An important point to draw from the example of **Section 7** is that the appropriate measure of societal economic benefit of the reduced congestion is the region-wide reduction of dispatch costs, including reduced branch/interface limit violation costs. The portion of benefit that is not revealed in the net total of the generator re-dispatch portion of the congestion reduction benefit break-out equation can accrue to market participants if they own or receive sufficient transmission rights to nullify the congestion charges.

This discussion underscores the importance of consistency between the methodology of identifying/assigning quantified benefits for funding purposes and the ultimate assignment of incremental transmission/transfer rights. To the extent that the "hidden" benefits are assigned to specific market participants for funding purposes, it is important to verify that existing or new transmission rights accrue to the same market participants.

However, any attempt to construct "incremental schedules" as applied in the example would be computationally challenging due to the amount of transactional activity inherent in the large-scale simulations, and in any event would not produce a unique or definitive result.

C. The unscheduled load example of **Section 7** indicates there is a small overlap between the "generator re-dispatch" and "unhedged load" portions of the congestion reduction benefit break-out equation, to the extent that a net change in unscheduled load charges is applied. This seems intuitively correct from the perspective that unscheduled loads are then (in their aggregate) experiencing a portion of the economic impact of the generator re-dispatch that is occurring in the market.

D. The discussion at the end of **Section 7** and highlighted by Figure 4 raises the perspective that perhaps it is reasonable to conclude that unhedged loads experiencing lower marginal prices due to network congestion are not truly being "penalized" when nodal prices rise toward the non-congested ideal as a consequence of the reduction of network congestion. This would imply the exclusion of some or all areas experiencing increased nodal prices in the "unhedged load" portion of the congestion reduction benefit break-out equation.

E. Applying the concepts discussed in paragraphs B-D above might result in detailed application of the congestion benefit break-out equation similar to that presented in **Table 10**.

Table 10: Possible Detailed Application of the Congestion Reduction Benefit Break-out Equation Components

Total Identified Dispatch Cost Reduction =	**DCR**
Violation "Slack" Cost Reduction =	**VCR**
(i.e., unidentified dispatch cost reduction)	

Area Calculation Part 1: Area Benefit Quantified from Generator Re-Dispatch Equation	
1st Area =	$\mathbf{AGR_1}$
2nd Area =	$\mathbf{AGR_2}$
:	:
Last Area =	$\mathbf{AGR_l}$
	$\sum \mathbf{AGR_X}$

Area Calculation Part 2: Δ Area Nodal Charges to "Unhedged Load"	
(each based on an assumed percentage of total load being unhedged)	
1st Area =	$\mathbf{ANC_1}$
2nd Area =	$\mathbf{ANC_2}$
:	:
Last Area =	$\mathbf{ANC_l}$
	$\sum \mathbf{ANC_X}$

Application of Area Calculation Parts 1 & 2	
1st Area =	$\mathbf{AGR_1}$ - $\mathbf{ANC_1}$**(if <0)**
2nd Area =	$\mathbf{AGR_2}$ - $\mathbf{ANC_2}$**(if <0)**
:	:
Last Area =	$\mathbf{AGR_l}$ - $\mathbf{ANC_l}$ **(if <0)**
	$\sum \mathbf{AGR_X}$ - $\mathbf{ANC_X}$**(if <0)**

Remaining Unassigned Portion of Benefit =	**DCR + VCR -** $\sum \mathbf{AGR_X}$ **-** $\sum \mathbf{ANC_X}$