Regional State Committee / Southwest Power Pool, Inc.
COST ALLOCATION WORKING GROUP MEETING
February 27, 2008
AEP Dallas Offices
Renaissance Towers
1201 Elm Street
• A G E N D A •

11am – 5pm
CAWG Participant Number and Code -
Toll: 203-320-8823
Participant: 113358

1. Open Admin Duties (10 min) ................................................................. Mike Proctor

2. Economic Portfolios – First Look (60 min) ........................................... Charles Cates

LUNCH, 12:30

3. SPP Updates (30 min) ........................................................................... SPP Staff
   a. Determination of Cost Allocation: Efficient Access Pricing vs. MW-mi
   b. Wind Penetration: Operating Limitations
   c. EHV Overlay Restudy Update

4. Transmission Planning Survey Results (15 min) ................................. Les Dillahunty

5. CAWG 2008 Work Plan (10 min) .......................................................... SPP Staff

BREAK, 15 min

6. Proposed Cost Allocation for the Costs of Upgrades in the Supply Zone for Designated Wind Resources (120 min) ................................................................. Mike Proctor
Economic Portfolios – First Look

A presentation detailing the initial results from the first subset of economic portfolios in SPP
Disclaimer

Material in this presentation is preliminary and not considered final. Material is provided for discussion purposes only.

Economic Portfolio Project Selection Process

- The project selection process in the Economic Portfolio is based off of the 2012 Spring and Summer economic project screening

- In general, projects with a higher individual B/C ratio were given preference over projects with lower B/C ratio

- SPP has assembled four initial portfolios and conducted adjusted production cost analysis for these portfolios

- Comprehensive analysis performed using PROMOD and is simulated for an entire year (3/1/2012 through 2/28/2013) on every hour
### All Projects from Economic Screen

#### Initial Economic Portfolio Project Groupings

<table>
<thead>
<tr>
<th>Project</th>
<th>Screening B/C Ratio</th>
<th>P1</th>
<th>P2</th>
<th>P3</th>
<th>P4</th>
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<tbody>
<tr>
<td>Tolk - Potter</td>
<td>7.20</td>
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<td>+</td>
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<tr>
<td>El Dorado - Longwood</td>
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<tr>
<td>Iatan - Neshua</td>
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<td>+</td>
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<tr>
<td>SWPS - Battlefield</td>
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<tr>
<td>Chesapeake XF</td>
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<tr>
<td>Tuko - Tolk - Potter</td>
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<td>+</td>
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<tr>
<td>Fairport - Sibley</td>
<td>1.31</td>
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<tr>
<td>Pittsburg - Ft Smith</td>
<td>1.17</td>
<td>+</td>
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<tr>
<td>Spearville-Mooreland/Woodward-Tuco</td>
<td>1.13</td>
<td>+</td>
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<tr>
<td>Seminole - Muskogee</td>
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<td>Monett XF</td>
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<tr>
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<td>Anadarko XF</td>
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<td>Turk - McNeil</td>
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<td>Mooremorland/Woodward - Wichita</td>
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<td>+</td>
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<td>(0.00)</td>
<td>+</td>
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</table>

- Portfolios shown are **initial and preliminary**
- Preference given to projects with high B/C ratio
- Additional consideration for projects that may have low B/C, but could have positive interaction with other projects
Initial Economic Portfolio - #1

- Projects selected based on > 0.9 B/C Ratio
- Mutually exclusive projects excluded (i.e. Tolk – Potter vs. Tuco – Tolk – Potter)
- Attempts to demonstrates the adjusted production cost savings if everything with stand alone benefit is grouped into a portfolio

Estimated Total Project Cost: $521M
## Initial Economic Portfolio - #2

### Project
- El Dorado - Longwood
- Iatan - Nashua
- SWPS - Battlefield
- Chesapeake XF
- Tuco - Tolk - Potter
- Pittsburg - Ft Smith
- Spearville-Mooreland/Woodward-Tuco
- Cleveland - Sooner
- Sunnyside XF
- Northwest XF

### Estimated Total Project Cost
- $371M

- Subset of Portfolio #1
- Projects that have expected shared benefit are removed
- Portfolio attempts to demonstrate the fact that many projects share a common benefit basis.
### Initial Economic Portfolio - #3

- Projects selected for Portfolio #3 based on an attempt to get a project into every zone.
- If a zone has more than one high B/C ratio project, the highest is used.
- Projects that cross many zones considered (e.g. Spearville – Mooreland/Woodward – Tuco).

<table>
<thead>
<tr>
<th>Project</th>
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<tbody>
<tr>
<td>Tolk - Potter</td>
</tr>
<tr>
<td>El Dorado - Longwood</td>
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<tr>
<td>Iatan - Nashua</td>
</tr>
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<td>Chesapeake XF</td>
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<td>Spearville-Mooreland/Woodward-Tuco</td>
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<td>Cleveland - Sooner</td>
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<tr>
<td>Spearville - Stilwell</td>
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<tr>
<td>Anadarko XF</td>
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</table>

**Estimated Total Project Cost:** $347M
Initial Economic Portfolio - #4

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<tr>
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<tr>
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</tr>
<tr>
<td>Fairport - Sibley</td>
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</tr>
<tr>
<td>Spearville-Mooreland/Woodward-Tuco</td>
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<tr>
<td>Cleveland - Sooner</td>
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<tr>
<td>Northwest XF</td>
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<tr>
<td>Turk - McNeil</td>
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<tr>
<td>Mooreland/Woodward - Wichita</td>
<td></td>
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<tr>
<td>Mooreland/Woodward - Northwest</td>
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</tbody>
</table>

- Portfolio #4 attempts to select projects that could have positive interaction

Estimated Total Project Cost: $608M
Adjusted Production Cost Results and B/C Ratios

<table>
<thead>
<tr>
<th>Project</th>
<th>Total 2012 Adjusted Production Cost (APC)</th>
<th>SPP OATT APC</th>
<th>SPP RE APC</th>
<th>Tier1 APC</th>
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<tbody>
<tr>
<td>Portfolio 1</td>
<td>($122,746,000)</td>
<td>($100,356,000)</td>
<td>($101,076,000)</td>
<td>($21,668,000)</td>
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<td>Portfolio 2</td>
<td>($111,476,000)</td>
<td>($92,332,000)</td>
<td>($92,710,000)</td>
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<td>Portfolio 3</td>
<td>($170,969,000)</td>
<td>($131,985,000)</td>
<td>($133,524,000)</td>
<td>($37,446,000)</td>
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<tr>
<td>Portfolio 4</td>
<td>($170,969,000)</td>
<td>($131,985,000)</td>
<td>($133,524,000)</td>
<td>($37,446,000)</td>
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</tbody>
</table>

Initial Findings

- All portfolios screened had a > 1 B/C ratio
- All portfolios screened demonstrated a > 1 B/C ratio for both SPP RE and SPP OATT
- Portfolios 3 & 4 have identical results (details as to why on next slides)
What’s the deal with Portfolio 3 & 4??

• Portfolios 3 & 4 demonstrated identical adjusted production cost savings – Why?
  
  • Economic analysis is based on a set of monitored conditions, termed flowgates
  
  • Currently, SPP is simulating all known flowgates as they exist today for the Eastern Interconnect (i.e. NERC Book of Flowgates)
  
  • Portfolios 3 & 4 eliminate the same subset of existing flowgates, as such, they return the same benefit (see graph)
  
  • This does not mean that “all congestion is gone” – this demonstrates importance of evaluating the next limits
PROMOD Congestion Report for SPP (Linear)

Flowgate Loading Profile, per Portfolio

- Base
- Portfolio 1
- Portfolio 2
- Portfolio 3
- Portfolio 4

Flowgate Name

WWW.SPP.ORG
Project Interaction

- Project interaction plays a very significant role in the final outcome of benefits

- Portfolio 2 provides 91% of the same benefit as Portfolio 1, yet with ‘comparable’ projects removed, it is only 71% of the cost

- Portfolio 3 & 4 show very similar benefit, yet it can be seen that the inclusion of Tolk – Tuco element did not provide any additional relief**

- Between Portfolio 3 & 4, it appears that El Dorado - Longwood and Turk - McNeil share similar root benefits **

**NOTE: Based on existing flowgates only, subject to change when new constraints found

Issues

- Next limit analysis (i.e. reliability analysis) needs to be conducted to determine the ‘next limit’ potential flowgates after portfolios would be active

- Balance…… with the exception of Portfolio #3, balance has not been considered as a criteria for project grouping
Additional Concerns

- Tie-ins with existing SPP studies:
  - EHV Overlay
  - OEPTTF
  - SPP Transmission Expansion Plan

- Economic Portfolio should be integrated and evaluated for interaction with the above studies

- Project timing and implementation

Next Steps

- Develop further year cases for analysis: 2012, 2017, 2022

- Develop futures cases (e.g. high wind, carbon regulation, etc)

- Finalize group of portfolios to use for the above analysis

- Stakeholder buy in and feedback
Questions?

Southwest Power Pool

Charles Cates
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ccates@spp.org
Efficient Access Transmission Pricing

Steering between the whirlpool (postage stamp rates) and the rock (distance-sensitive pricing), efficient access pricing tends to discourage actions that increase loadings on the bulk power transmission system and encourage actions that reduce loadings. And it does so without the harm to competition that other approaches might cause.

Paul Hassink and Steve Jones

I. The Paradox of Transmission Pricing

Transmission systems are undergoing a profound redefinition. Once regarded simply as the facilities necessary to connect generation to load within individual control areas and to connect individual control areas with each other, transmission systems are increasingly viewed today as essential facilities needed to enable competitive, wholesale bulk power markets within each synchronous interconnection. As the purpose of the transmission system is redefined to fit this competitive model, pricing of transmission services must also change.

A natural companion to a fairly constructed market-driven bulk power market must be a new transmission pricing concept—one which recognizes parallel flows, accounts for all impacts on transmission facilities and allocates cost burdens equitably within a region. This is essential because participants will need to make the economic and reliability
tradeoffs between generating costs and transmission. To prevent transmission users from gaining an uneconomic competitive advantage, it is also essential that they pay the transmission costs associated with their use.

A paradox of transmission pricing, however, is that any distance-sensitive pricing method that recognizes parallel flows will also tend to restrict the scope of the bulk power market, because parallel flows tend to multiply with distance. When this happens, the price of transmission service under most power flow-based pricing methods will also increase, resulting in a corresponding decrease in the economic feasibility of distant transactions.

An obvious solution to this problem is to ignore it and pretend that parallel flows either do not exist or that they are not as important as other objectives. One logical outcome of this approach would be to adopt a region-wide postage stamp rate. This would eliminate the pancaking that is involved in traditional contract path—postage stamp pricing, when multiple control areas are in the contract path. On the negative side, postage stamp pricing also eliminates what little distance-sensitive pricing the traditional method, long permitted by the Federal Energy Regulatory Commission, does provide.

Fortunately, a better method is available that will permit vigorous bulk power competition in a region, but also recognize and resolve the parallel flow problem.

II. The Theory of Efficient Access Pricing (EAP)

From time to time, transmission systems have been compared to lakes or reservoirs: Water is injected into the reservoir at certain points and withdrawn at other points. Since paths between points of injection and points of withdrawal cannot be identified within the reservoir, the implication of this approach is that all injections and withdrawals impact the reservoir equally and cost responsibility for the use of the reservoir can be assigned accordingly. But since injections and withdrawals from a transmission system do not impact that system equally, a better analogy is needed to properly identify and define transmission impacts.

A better metaphor might be to conceptualize a bulk power system as a series of ponds, each representing a local transmission network: Water is injected into the local pond by local water sources (generators) and water is withdrawn from the pond to meet local water demand. For some ponds, local water sources (wells, springs or streams) may be adequate to meet local water demand. Other ponds may have inadequate local water sources to meet demand, or the local water sources may be more than adequate to meet local demand.

In order to balance the water supply across the region, an extensive canal system with multiple owners has been constructed to connect the ponds to a regional canal network. The network enables ponds with inadequate water supplies (resource deficient ponds) to import water from the canal network; ponds with surplus water (resource concentrated ponds) may export water through the canal network, thereby balancing water needs in the larger region.

The theory of EAP applies a similar concept to transmission systems and pricing, in which the canal network becomes a regional bulk transmission system serving resource deficient and resource concentrated localities. Resource deficiency occurs when local generation can’t meet local power requirements and power must be imported over the regional bulk power system. Resource concentration occurs when local generation capability exceeds local needs and the excess must be exported to other loads over the regional bulk power system.

While load and generation in a given area may be perfectly balanced and require no power imports or exports, most "ponds" will either be resource deficient or resource concentrated and will require imports or exports over the transmission system. Some areas may be only slightly out of balance and require only minimal imports or exports. At the other extreme, the imbalance may be severe and imports or exports considerable. Most situations will lie somewhere in between.
Efficient Access Pricing builds upon the theory of locational imbalance to determine the transmission cost responsibility (access fee) for each generator and load bus by identifying the impact each bus has on the bulk transmission system. Impacts will vary by bus depending upon the load-generation balance within the area where the bus is situated. Areas that are only mildly out of balance will have minimal impacts on the bulk power system, while areas that are severely out of balance will have major impacts.

The imports of load buses and generator buses are inversely related. Load buses situated in a resource deficient locality will have significant impacts, while the impacts of generator buses in the same locality will be de minimis because there is sufficient load in the vicinity to absorb the output of the generator without burdening the bulk power system. The opposite is true for resource concentrated localities. Generator buses will show major impacts while load bus impacts will be de minimis because there is more than sufficient generation in the vicinity to meet loads without burdening the bulk power system.

III. The Mechanics of Efficient Access Pricing

EAP is a power flow-based method which begins with the peak flow base case for any transmission region or interconnection in the country. After that base case has been established by some regional authority such as the regional reliability council or a regional ISO, EAP would unbundle the base case itself through line flow tracing to identify the transmission facilities that each load bus in the region requires to be served from local generation which can meet the peak load on that bus. The EAP load analysis program accomplishes the task of determining electrical paths between sinks and sources by identifying the load on each load bus and apportioning it among all incoming line flows. The flow is then followed to the next bus on each line and the process is repeated until the entire load finds a generator or generators in the vicinity with adequate capacity to serve that load. EAP is not a dynamic congestion pricing method, however. EAP can be combined with such methods to provide reasonably stable pricing signals through its calculation of annual transmission access fees.

Once the electrical paths for each unique pair of resource and load have been identified, the impact of the path is assigned equally to the resource (generator) and the load. In aggregate, all such paths will account for all loads on the system and all generator output to the system contained within the base case.

A. Megawatt-Dollars

Identification of each electrical path will also reveal the transmission facilities that create the path and the proportionate use of those facilities by each resource-to-load path. Load bus X may use 50 percent of line A, 20 percent of line B, and 5 percent of line C in order to access the output of generator Z under peak flow conditions. A pro rata portion of each of those facilities would be assigned to load bus X and generator Z. If all transmission lines were the same length, the same voltage, and the same vintage, impact assignment to the various buses would be relatively straightforward. However, since all lines are not equal in length or voltage, nor of the same vintage, EAP employs the concept of megawatt-dollars to assign impacts on lines to buses.

Under the megawatt-dollar approach, the MW impact of a bus on a line is multiplied by the original cost of that line to capture differences in length, voltage and vintage. EAP uses the original cost of a line only for purposes of assigning impacts to a given bus, and not to assign costs to that bus. However, the presence of original cost impact in the calculation should substantially account for differences in length, voltage and vintage because a line with a higher original cost will either be longer, newer, rated at a higher voltage or represent a combination of all three factors. Buses that impact high original cost facilities will receive a higher impact as-
assignment than a bus which impacts a low original cost line. Megawatt-dollar approaches should permit resolution of the “either/or” pricing controversy that has bedeviled the FERC over the last several years. Under “either/or” pricing, a transmission customer at the margin pays either the cost of new facilities associated with transmission service to that customer, or embedded cost, whichever is higher. Under EAP-megawatt-dollars, no new facility is directly assigned to a single customer (more precisely, the load bus or buses owned by that customer). Only that portion of the line impacted by the customer is assigned to that customer, with the balance of the impact on the new line assigned to whomever else impacts it under base case (peak) flow conditions.

The next step in the process is to determine the megawatt-dollar impact of loads and generators depending upon their megawatt-dollar usage. If the electrical system consisted of only one generator, one load and one line connecting the two, and the load in the base case was 10 MW, the line loading would be 10 MW (ignoring losses). Since this electrical path is the only path using the line, 100 percent of the line would be assigned to the path and that loading would be multiplied times the line’s original cost ($100) to yield a megawatt-dollar value of $1000, half of which would be allocated to the load and the other half to the generator.

The mechanics of EAP complete the process by converting the megawatt-dollar impacts of each electrical path into embedded transmission cost-of-service dollars (real dollars) using the ratio of each path’s megawatt-dollar impact to the total megawatt-dollar impact of all electrical paths. For instance, assume a utility’s transmission cost-of-service is $1000 and the utility’s megawatt-dollar impact for all of that utility’s electrical paths is 10,000 megawatt-dollars. The path in the example above which was allocated 1000 megawatt-dollars would represent 10 percent of total system megawatt-dollars and it would be responsible for $100 of system cost, $50 assigned to the load and $50 to the generator.

Up to this point, the examples assume only a single transmission-owning utility in a region. Where a regional transmission system has many owners, determining megawatt-dollar impacts and access fees becomes more complex, but only because a given electrical path may use facilities owned by more than one utility. Hence, the identification of paths and the allocation of impacts must take into account multiple ownership by means of a regional matrix that calculates the cost responsibility of each load and generator bus owner for the transmission costs of each regional transmission entity.

The end product of this process is a table listing each load and generator bus, the transmission costs assigned to that bus, the load on the bus and the $-per-kW-year access fee for the bus (obtained by dividing the load on the bus by the costs assigned to it).² As a check on the accuracy of the process, the allocated flows on each line are added to verify that they equal the base case flows.

### B. Transmission Line Losses

EAP is also capable of determining line losses and allocating them to loads and generators. The program will identify the losses on each path and which party is responsible for them (the agents for or owners of each load and generator bus). This capability could provide the basis for a loss compensation (“PAYG,” or pay as you go). Under PAYG, a matrix is developed for hourly load levels that indicates which loads and which generators are responsible for line losses associated with a given load level. This information would be available in advance and each generator would then produce loss compensation power to cover the losses on its electrical path. This would substantially reduce or eliminate cash loss compensation payments.

### IV. The Case for EAP

EAP has the ability to resolve the paradox of transmission pricing described above, because the access fees and loss determina-
tions it derives can be characterized as a middle-of-the-road pricing method that produces the “right” price for transmission service. The “right” price promotes efficient tradeoffs between generation siting and transmission upgrades, while also fostering opportunities for trade across broad geographic regions. The definition of “region” could mean a single regional reliability council such as ERCOT or an entire interconnection such as the Eastern Interconnection.

Other transmission pricing methods tend to fall at the extremes. Distance-sensitive methods typically identify a specific transaction as the change case to the base peak flow case. As the distance associated with such transactions grows, so do the parallel flows and impacts on all transmission systems in the region, until the price of transmission service becomes prohibitive. At the other extreme, postage stamp rates ignore parallel flows and the transmission cost-causing impacts of loads and generators on the bulk power transmission system. EAP represents a balance between the extremes because it is location-sensitive, thereby identifying the impacts of loads and generators on the bulk power system. However, it is not distance-sensitive because access fees are determined by the location of loads and generators, not the distance between them.

A new generator negotiating to serve a growing load in Maine could conceivably locate in Kansas if its location were in a resource deficient area and the economics of the site were otherwise favorable. If the site in Kansas is resource deficient, the new generator will serve load buses in the immediate area, reducing their impact on the bulk power system in Kansas and the access fees they pay under EAP. The new generator would also pay a modest access fee because its output is being absorbed locally and not burdening the bulk power system in Kansas, even though its output is contracted to a load in Maine.

Though the Kansas generator and the load-serving entity in Maine cannot completely ignore constrained transmission conditions that may exist in intervening areas, the transaction will, in many cases, have only a minimal impact on these constrained facilities because the Kansas generator will serve loads in Kansas and the Maine load will continue to be physically served by generators in Maine or New England.

The growing load in Maine may pay a higher access fee under EAP if it is in a resource deficient location. This is because the growth may require greater use of the Maine bulk power system to reach more distant generators in Maine or New England.

In response to this signal, the generator could decide to locate near the load, thereby incurring a smaller access fee and lowering the access fee paid by the load that it intends to serve.

V. Conclusion

Theoretically, if all localities were perfectly balanced electrically, there would be no flows on the bulk power transmission system and no parallel flow problems. The strength of EAP going forward is that it will tend to discourage events that increase loading on the bulk power transmission system and encourage events that reduce such loadings, like the Maine generator above. Obviously, generator siting decisions are influenced by other economic and non-economic factors that may overrule transmission cost considerations. EAP’s strength is that it can make transmission cost causation explicit so this factor can be taken into account when siting new loads or generation.

Endnotes:
2. Central and South West has produced such a table for all load and generator buses in the Southwest Power Pool and ERCOT that contains the access fees which every load and generator bus in those regions would pay under EAP.
3. ERCOT has approximately 300 generator buses and 4300 load buses and the complete tables show access fees for all 4600 buses.
EHV Overlay Restudy

- Report being finalized with few alternatives
- Analysis of Alt 5 from original study does not support 345 kV build out
- Communication plan being developed
- Performing comprehensive economic analyses of alternatives in new several weeks
- Results expected first quarter 2008

New Wind in EHV Overlay Restudy

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<thead>
<tr>
<th>State</th>
<th>MW</th>
<th>%</th>
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<td>750</td>
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<td>New Mexico</td>
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<td>Oklahoma</td>
<td>8,550*</td>
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<tr>
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<tr>
<td>TOTAL</td>
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* Includes 4,450 MW in Oklahoma Panhandle
Summary Findings

- Collect & deliver 15 GW of new wind in SPP with 6 GW to SPP loads, 3 GW to WECC via HVDC, 3 GW to northeast and 3 GW to southeast
- Roughly $8B at $2M/mile E&C plus $65,000/mile for ROW
  - 2,250 Miles of 500 and 765 kV in SPP
  - Almost 600 miles of 765 kV in new interconnections and connectivity in neighbors
- Identifying phasing of build outs for alternatives
- Long term EHV Overlay rebuild would include Knoll — Swissvale rebuild from 230 to 765 kV and extend new 765 kV from LaCygne KS – Sedalia MO – MISO Labadie MO – PJM Sullivan IN
1. Policy for Cost Allocation for Economic Upgrades and Portfolio Development

2. Review and enhance the SPP Tariff provisions that govern the amount of accredited capacity available for Base Plan funding for wind resources.

3. Waiver Reviews

4. Initiate the tariff required regional allocation factor and zonal allocation review.


6. Interpretation and clarification of Base Plan Funding, the use of Operating Directives, etc.

7. Review of STEP/EHV/OEPTTF and other special studies.


11. EIS market performance.

12. EHV Cost Allocation.
Proposed Cost Allocation for the Costs of Upgrades in the Supply Zone for Designated Wind Resources

Mike Proctor
CAWG Meeting
February 27, 2008

Context: Two Distinct Cost Assignments/Allocations

1. **Aggregate Studies** assign costs to requestors based on **MW impact** for ALL upgrade facilities required by the study requests.
   - A request for a new wind resource can be assigned costs from many different upgrades, not just the upgrades in the supply zone.
   - The purpose of the Aggregate Study assignment is to determine how much of these assigned costs are eligible for **base-plan funding (BPF)** and what is directly assigned to the requestor.

2. **MW-mile allocations** are made individually for each upgrade that comes out of the Aggregate study based on the % of those costs eligible for BPF.
   - Any solution to the supply zone problem **should focus on upgrades in the supply zone** that would not otherwise be required “but for” requests for wind as designated resources.
   - The solution **should not focus on the other costs assigned to requestor in the aggregate study process**. These costs can include upgrades made throughout the SPP system, and in particular can include upgrades made within the zone of the requestor.
     - For example, the requestor’s zone may have limited import capability so that any new or changed DR located outside the zone would require the same upgrades to increase import capability as would be required by a wind resource.
     - These upgrade costs should not receive special treatment simply because wind was the designated as a resource.
Focus is on $ from upgrade 3 made in zone S because of request C and then allocated to zone S via MW-Mile.

The difference $37.6 - $20.15 = $17.35 is directly assigned to the Requestor.

The 15% that goes to neighbors via the MW-mile allocation can also be a part of the problem.
Initial Thoughts About Changing the Allocation for Wind DRs

A. $180,000 per MW of requested transmission service as safe-harbor for designated wind resources
   - “But for” upgrades within the supply zone are not included in safe harbor calculation
   - Up to 12.5% of total peak demand

B. Dollars allocated from positive MW-mile impacts to Alternative 1: the supply zone / Alternative 2: all zones from upgrades made within the supply zone to meet the request for a designated wind resource are allocated:
   - 25% Postage Stamp
   - 75% Direct Assignment to Requestor who is then eligible for revenue credits from subsequent users of the upgrade.

Example Allocation with Modifications for Upgrades in the Supply Zone

Only showing MW-mile allocations for the supply zone upgrades.

The alternative eliminates the MW-mile allocation of the costs from the supply zone.
Alternative Approach: All Upgrade Costs from Supply Zone Are Included

• In the alternative approach, the allocation will always be 1/3 postage stamp and 2/3 direct assignment of the cost of the upgrade(s) in the supply zone.
  
  \[
  \frac{1}{3} \text{ is postage stamp from BPF} \\
  \frac{1}{4} \text{ of } \frac{2}{3} \text{ is postage stamp from proposal} \\
  \Rightarrow \frac{1}{3} + \left(\frac{1}{4}\right)\left(\frac{2}{3}\right) = \frac{1}{3} + \frac{1}{6} = \frac{2}{6} + \frac{1}{6} = \frac{3}{6} = \frac{1}{2} \\
  \text{or 50% Postage Stamp.}
  \]

Alternative Made Simple

Apply KISS principle

Remove cost of the supply zone from BPF calculations and therefore from the assignment process of the Aggregate Study, and directly allocate these costs via:

- 50% Postage Stamp
- 50% Direct Assignment

Similar to the Allocation method adopted by MISO for Large Generator Interconnections of Generators that are designated as network resources.
Adding Interconnection Costs

• If Wind Resources interconnect as energy resources that are deliverable to the SPP market, then:
  1) Most if not all of the upgrades to deliver energy to the SPP market will occur in the supply zone; and
  2) All upgrades to the supply zone required for designating wind as a resource would already be included for delivery to the SPP market.
• When wind is designated as a network resource by a load within the SPP, all of the network upgrades associated with the interconnection of wind as an energy resource would be included in the 50% PS / 50% Direct Assignment (DA) to Requestor allocation.
• This simplifies the process to three steps:
  – Step 1: Interconnect Wind as an energy resource deliverable to the SPP market.
  – Step 2: When designated as a resource by a load, allocate all network upgrades from the interconnection costs on a 50% PS / 50% DA basis.
  – Step 3: Wind deliverable as a DR goes through the aggregate study process and follows the current BPF formulas using Megawatts of Transmission Service. All interconnection costs are excluded from the BPF calculations.

Interconnection Alternatives for Wind Resources

Wind interconnections have three options

1) Interconnect with no deliverability requirements
   ✓ Would require SPP to perform the second study for purposes of information on costs eligible for 50% cost allocation at the time that it is designated as a resource.
   ✓ Until designated as a resource, the wind resource would incur no additional network upgrade costs beyond its basic interconnection costs. When designated as a resource ⇒ 3) below.

2) Interconnect with deliverability into the SPP energy market
   ✓ SPP would perform the deliverability study at the time of the interconnection and all network upgrade costs would be eligible for 50% cost allocation at the time it is designated as a resource.
   ✓ The wind resource would initially incur all network upgrade costs, including those beyond its basic interconnection costs. When designated as a resource, those cost would transfer to the 50% cost allocation.

3) Interconnect with deliverability to a load as a designated resource
   ✓ SPP would need to separate out those upgrades necessary for deliverability to the SPP market from those necessary for deliverability to a specified load.
   ✓ The cost of network upgrades necessary for deliverability to the SPP market would be eligible for the 50% cost allocation and the wind resource would incur no network upgrade costs.
What if Deliverability to the SPP Market Results In Upgrades Needed Beyond the Supply Zone?

- The calculation of deliverability of energy to the SPP market is made in the power flow studies by increasing the output of the proposed new interconnection to its maximum level and decreasing the output from every other generator by the same total amount using an equal percentage decrease from each generator.
  - With the decrease, it is unlikely that problems in non-supply areas will occur.
    - Export issues from the supply zone should show up.
    - Import issues into zones should be handled by the decrease in generation within the zones.
    - Transport issues from the supply zone to all the other load zones should also be handled by the decrease in generation throughout the footprint.

- However, if this is not the case: Non-supply zone upgrades required for the transport of energy from the supply zone to the SPP market may also be included in the 50% PS / 50% DA allocation. However, upgrades required to increase the import capability into any of the load zones should be excluded from this allocation.
  - Costs associated with upgrades needed to increase the import capability into load zones should be included in the Aggregate Study process and be subject to normal BPF.

Why Limited to 12.5% of Peak Load?

The primary concern is the operational problems that can result from adding too much wind:

1. Regulation: If the wind suddenly stops generating, the power grid will need to rapidly pick up lost generation through generators on automatic generation control. Too much wind that can simultaneously stop generating will result in a significant increase in % regulation.

2. Minimum Generation Operating Levels: If wind blows at night and injects too much power into the grid, this will result in problems for base load units that must operate at minimum levels to stay on line.

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<th>Calculations</th>
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<tr>
<td>1,000 MW</td>
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<td>125 MW</td>
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Divided by Peak
Attachment Z Implications

- The requestor would be eligible for revenue credits on the assigned costs.
  - A new wind power interconnection requestor without a DR could also require deliverability into the SPP market as a project sponsor, and would be responsible for upgrade cost on previously upgraded facilities.
  - Subsequent requests for transmission service (PTP or DR) through the Aggregate Study that have a MW impact on these previously upgraded facilities would be responsible for MW percent (MW share of capacity) of upgrade cost on these facilities.

- Funding for revenue credits would come 50% PS and 50% DA to requestor