Regional State Committee / Southwest Power Pool, Inc.

COST ALLOCATION WORKING GROUP MEETING

January 30, 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) .... Keith Tynes
2. RSC Meeting Discussion (20 min) .... SPP Staff
    a. Concepts Paper on Economic Upgrades
    b. Wind Generation Base Plan Funding Policy
    c. EDE & AEP Waivers
    d. 2008 Work Plan
3. BPGTF White Paper on Cost Allocation of Network Upgrades due to ineffective Transmission Operating Directives (45 min).. Keith Tynes

LUNCH, 12:30

4. Board of Directors Update (10 min)... Les Dillahunty and Keith Tynes
    a. STEP & Appendix B, "Notifications to Construct"
    b. Other items
5. DNR Cost Allocation Approach (60 min) ....Larry Holloway & others
    a. Review of any proposed alternatives
    b. SPP proposal

6. Revenue Crediting of Economic Projects .... Dennis Reed

BREAK, 15 min

7. Economic Portfolio: Project Selection Process (45 min) .... Charles Cates

Base Plan Guidelines Task Force Request for Review

RTWG Meeting

Dallas, TX

January 3, 2008

BPGTF Current Task

MOPC Action Item

- **Consider Base Plan Upgrade classification for upgrades due to ineffective Transmission Operating Directives (TODs)**
  - **Determine cost to replace all Operating Directives**
- **Consider Base Plan Upgrade status for upgrades meeting NERC TPL-003 Reliability Standards**

BPGTF Recommendation "Agreement Points"

- **BPGTF recommended a list of 8 "Agreement Points" (March 2007)**
  1. **If a Transmission Operating Directive (TOD) is in place and a Transmission Owner (TO) unilaterally withdraws the TOD before the TOD becomes ineffective, any consequences (upgrades) lie with the TO.**
  2. **SPP Staff (transmission planning and tariff administration) to determine when a TOD is ineffective.**
  3. **"TOD Planning Effectiveness Standards" should be developed by SPP Staff and endorsed by the TWG and ORWG.**
  4. **TOD must be on file with the SPP.**

Agreement Points Cont.

5. **If a TOD is "effective", it will continue to be used in evaluation of TSRs.**
6. **Upgrades associated with new TSRs associated with DNRs that cause a TOD to become ineffective will be classified as Base Plan Upgrades.**
7. **TODs that are identified to be ineffective using the most current MDWG base case models will not result in Base Plan Upgrades. (**
8. **TODs that are identified to be ineffective using the transaction scenario models based on the most current MDWG base case models (in the Transmission Expansion Planning Process) will result in Base Plan Upgrades.**

MOPC Response

- **Conditionally accepted BPGTF recommendation**
- **Directed SPP staff to develop white paper explaining agreement point #7 and #8**
- **Directed SPP staff to share white paper with RTWG and solicit opinion and report back to MOPC.**

"MOPC Action Item #7. The BPGTF recommendation for approval of eight agreement points dealing with Transmission Operating Directives and Base Plan Upgrades was passed unanimously with the exception of Agreement Point #7 ("the TODs that are identified to be ineffective using the most current MDWG base case models will not result in Base Plan Upgrades") and the CAWG is requested to review and comment on Agreement #7 and provide feedback to the MOPC prior to the April, 2007 MOPC meeting."

BPGTF Response

- BPGTF met recently and made amendments to the Agreement Points replacing #7 and #8 with a new recommendation.
- As stated in the white paper…
  - TF Simplified by removing dependency on models
  - Core issue, maintaining reliability.
  - Cost of system reinforcements are minor relative to overall system expansion $$

7

White Paper Conclusion

- Network Upgrades as a result of an ineffective Op Guide necessary to maintain system reliability will be categorized as a reliability upgrade, according to procedures of Attachment O

8

Staff Request

- Staff requests that RTWG review the white paper and provide some or all of the following by the next RTWG meeting…
  - General Comments
  - Expert tariff implementation opinion
  - If possible, formal acceptance of BPGTF white paper position

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SPP Southwest Power Pool

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General Inquiries: 501-614-3200

Wind and Base Plan Funding

Larry Holloway
Kansas Corporation Commission

Issues

- Treatment of wind generation under the current tariff
- Why wind may be different
- Alternatives for consideration

III.B, Attachment J of the Tarrif

Network Upgrades, with a cost that exceed $100,000, associated with new or changed Designated Resources shall be classified as Base Plan Upgrades if the Designated Resource or the associated upgrades (as applicable) meets each of the following conditions:

- 1. The Transmission Customer’s commitment to the Designated Resource has a duration of at least five years;
- 2. In the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer’s existing Designated Resources plus the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer’s projected system peak responsibility determined pursuant to SPP Criteria 2; and
- 3. The cost of Network Upgrades associated with the new or changed Designated Resource is less than or equal to $180,000/MW times the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity (the “Safe Harbor Cost Limit”).

III.B.2 of Attachment J is the Issue

(emphasis added)

- “In the first year the Designated Resource is planned to be used by the Transmission Customer, the ***accredited capacity*** of the Transmission Customer’s existing Designated Resources plus the ***lesser of***: (a) the ***planned maximum net dependable capacity*** applicable to the Transmission Customer ***or*** (b) ***the requested capacity***; shall not exceed 125% of the Transmission Customer’s projected system peak responsibility determined pursuant to SPP Criteria 2;

Where did this Provision come from?
(as I recall it)

- During the development and negotiations for the initial Cost Allocation Plan (CAP) the following items were considered for Base Plan Funding (BPF):
  - Cost allocation of reliability upgrades to the constructing zone
  - Regional cost allocation of high voltage upgrades
  - Using some type of economic model to allocate the costs of all reliability upgrades
  - Regional cost allocation of all upgrades
  - Etc.

Why the Compromise CAP?

- Concerns with various proposals
  - Either a total zonal or a total regional allocation was perceived to have free riders
    - Also did not provide any incentive to locate generation with any consideration to costs of transmission upgrades
    - Did not recognize the need for Load Serving Entities (LSEs) to jointly own or purchase generation
  - Some cost allocation schemes could cause members to leave SPP
    - Far less consensus and commitment on the part of members at that time
  - A more socialized cost allocation scheme was perceived as creating problems for state commission approval.

Is Access to new or changed DNRs an Economic or a Reliability Concern?

- Many argued at the time that access to new or changed DNRs was actually an economic concern, since generation decisions relied on the purchasers economic evaluation
  - However, it was decided that making sure all firm generation capacity could be used on a firm basis by network customers in SPP was a reliability concern
  - The rational is that it does nothing to satisfy reliability criteria for the overload, etc, if LSE's cannot access their required capacity margin
  - The 125% of peak load requirement represents a ***<u>20%</u>*** capacity margin
    - G = 125% L and CM = (G – L) / G, then
    - CM = (1.25L – L) / 1.25L = 0.25L / 1.25L = 20%
  - **<u>This is not that large of a margin, when the minimum is 12%!!</u>**
  - **<u>This represents accredited capacity because it is based on the capacity margin.</u>**

III.A.2 Appendix J, the CAP for BPF Upgrades

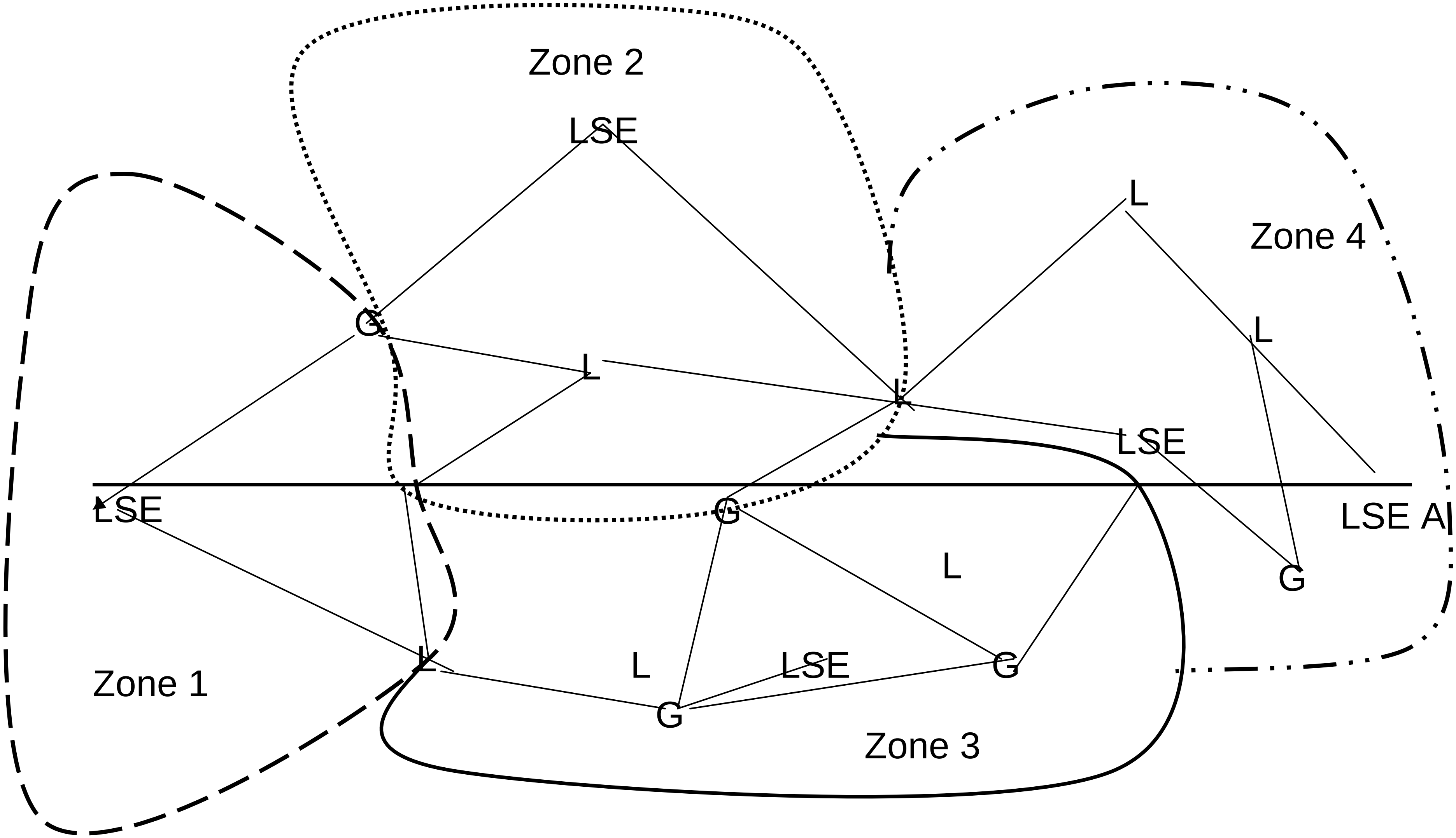
- 2. If the cost of a Base Plan Upgrade is greater than $100,000, then:
- i. X% of the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Base Plan Region-wide Charge. The initial value of X shall be 33%.
- ii. (100-X)% of the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and recovered through the Base Plan Zonal Charge. This portion of the annual transmission revenue requirement for each Base Plan Upgrade shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of specific Zones based on the Zones' share of the incremental positive MW-mile benefits as computed in Section 4 of Attachment S to this Tariff. Each Zone with a benefit of at least 10 MW-miles from a given Base Plan Upgrade shall be allocated a portion of the Base Plan Zonal Annual Transmission Revenue Requirement for such upgrade based on its incremental positive MW-mile benefit divided by the sum of the incremental positive MW-mile benefits for all of those Zones with a benefit of at least 10 MW-miles from the upgrade, provided that such allocation represents an engineering and construction cost of at least $100,000.Qualified BPF costs are allocated under
- **<u>Basically 1/3 regionally and 2/3 zonally based upon zonal benefits perceived as incremental MW-miles of transmission capacity.</u>**

Why wind may be different

- The productivity of wind generation is based upon the location of the resource
- Wind generation requires intensive land usage
  - A 1,000 MW wind farm would cover around 70 square miles – a magnitude of 10 times more than needed for a large coal or nuclear site
  - High productivity wind farms need unobstructed wind
    - The result is these are going to be commonly located at distances very remote to the load
    - These areas in SPP are in regions that currently have little transmission access.
- And, of course, the accredited capacity for wind is generally around 10% of nameplate
  - But to use and justify wind generation the load must have access to the production whenever it is available
- But necessary transmission upgrades for wind generation may be focused on the production zones
  - The zonal net positive MW-mile allocator has the potential to over-allocate the costs to the zones where transmission customers see little benefit.

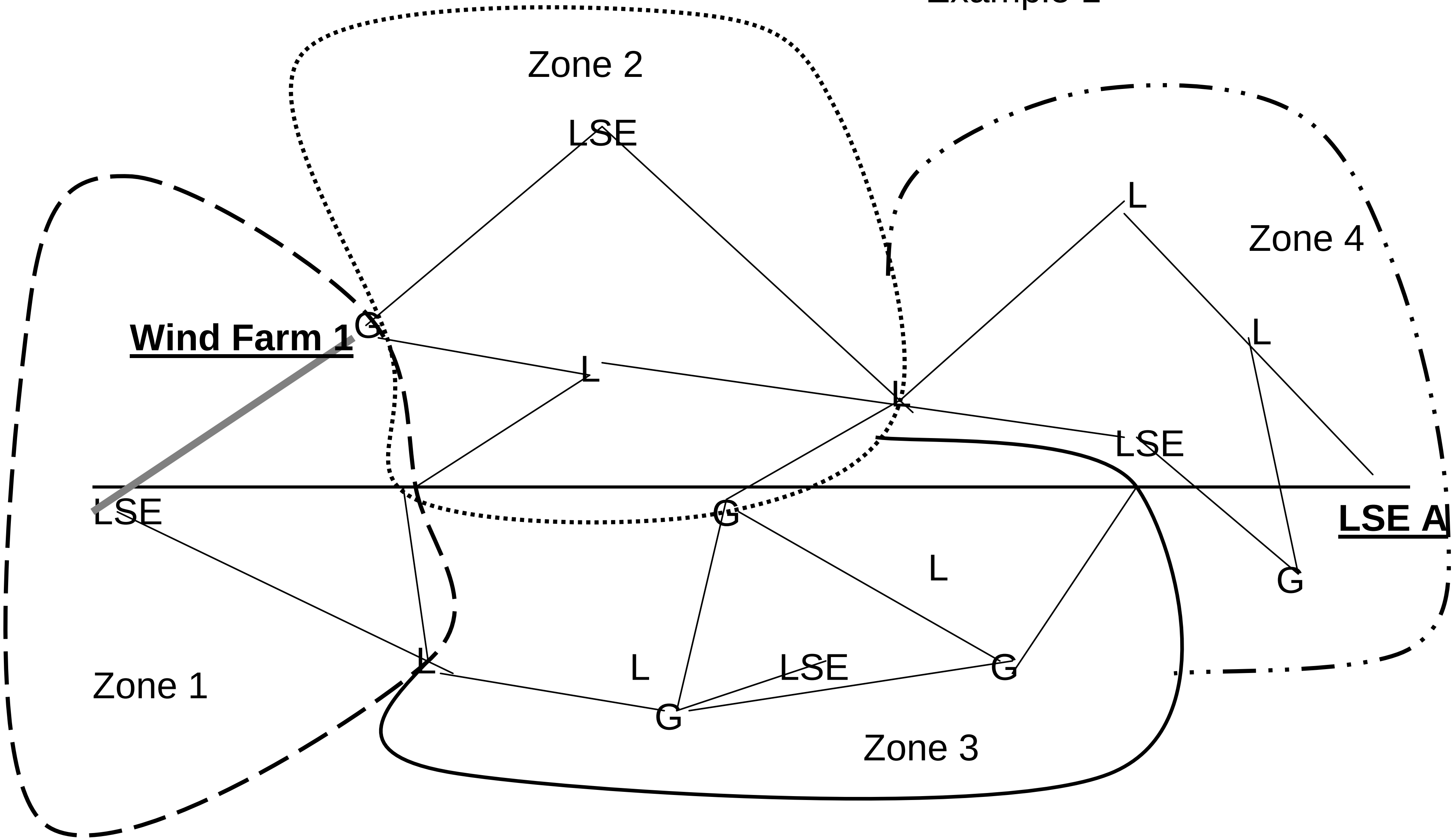
Why wind is different (cont)

- We could encourage wind by changing the qualification criteria of Appendix J III.B.2
  - This does not mean that the current language allows anything but accredited capacity, clearly that <u>**never**</u> was the intent.
    - This does mean that wind would be treated differently.
- This also does nothing to address the concerns with the zonal allocation, which <u>**must be addressed**</u> before wind can be treated differently.



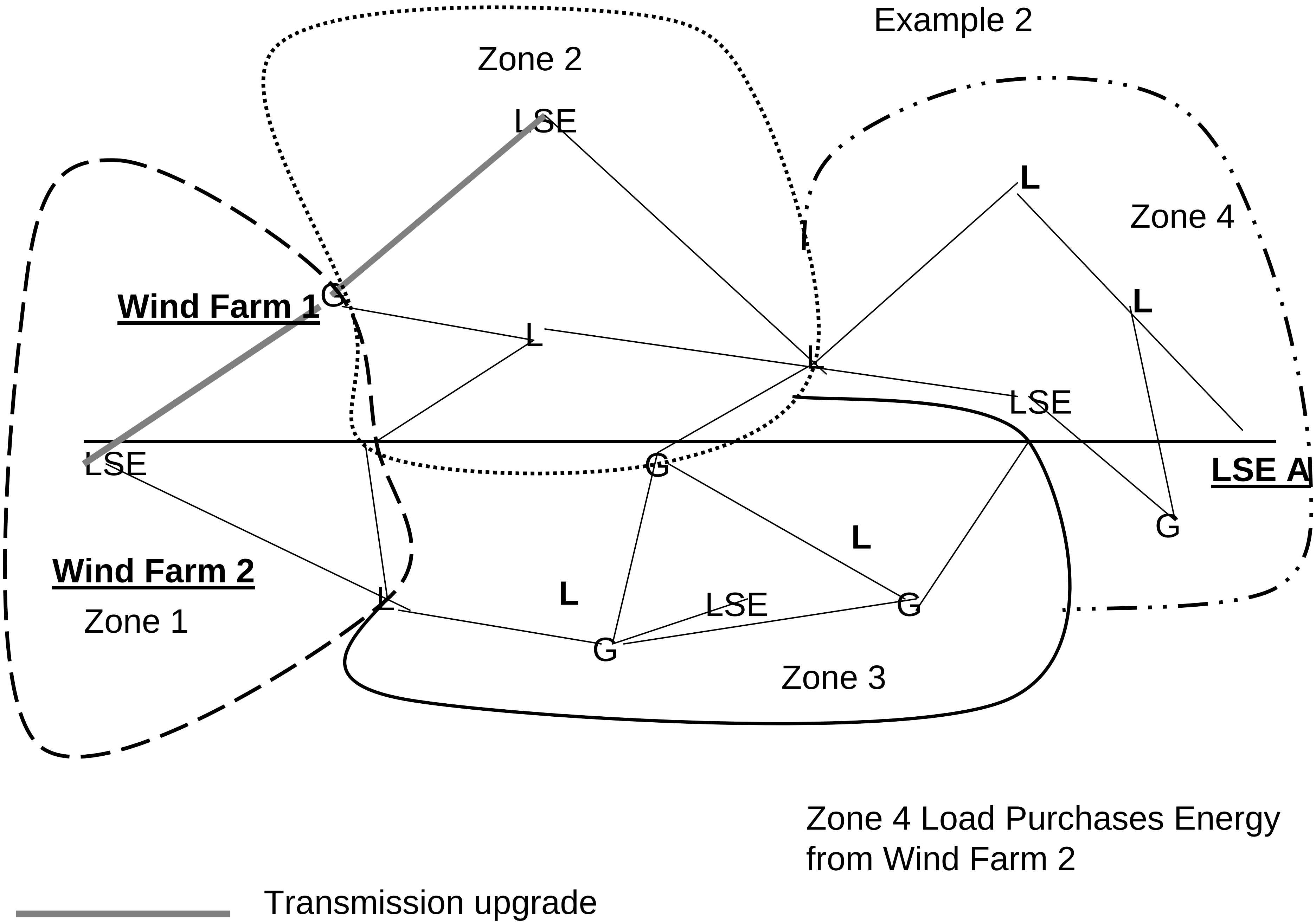
Example of the Basic System

Example 1

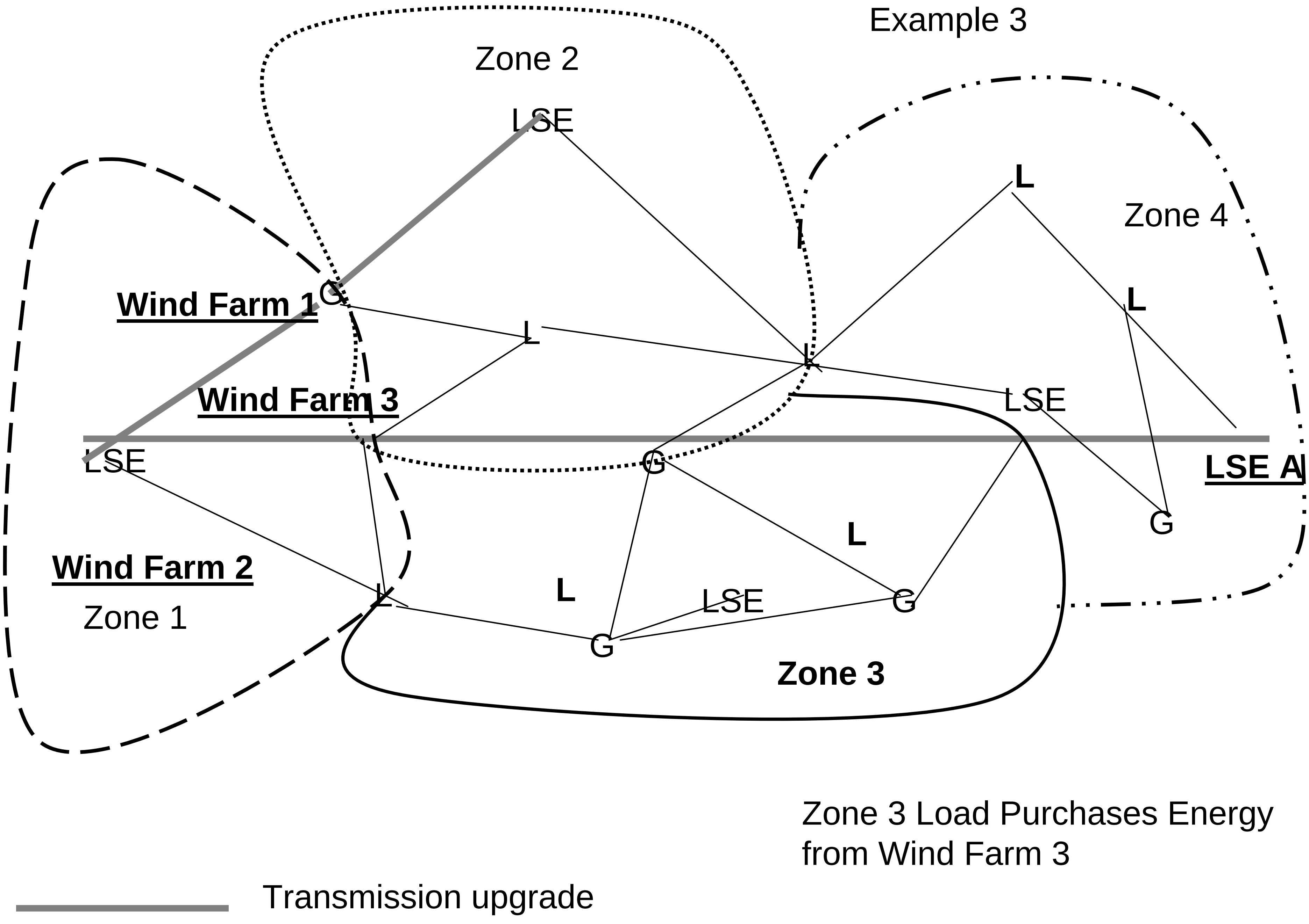


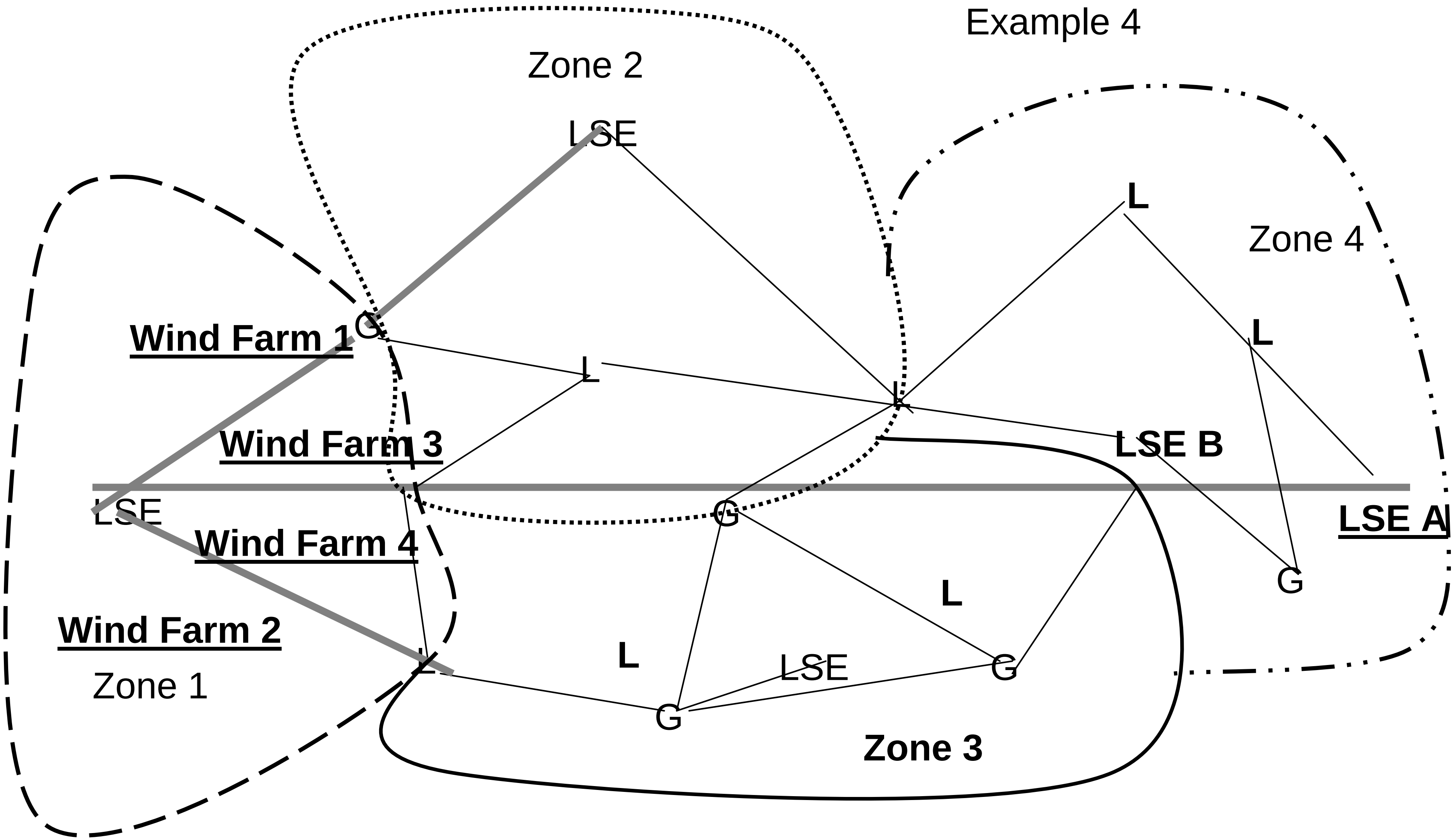
LSE A Purchases Energy from Wind Farm 1

Transmission upgrade



Example 2
Zone 2
LSE
L
Zone 4
Wind Farm 1
G
L
L
L
LSE
LSE
G
LSE A
G
L
Wind Farm 2
L
L
Zone 1
LSE
G
G
Zone 3
Zone 4 Load Purchases Energy from Wind Farm 2
Transmission upgrade


Example 3
Zone 2
LSE
L
Zone 4
L
Wind Farm 1
G
L
L
Wind Farm 3
LSE
LSE
G
LSE A
L
G
Wind Farm 2
L
L
LSE
G
Zone 1
G
Zone 3
Zone 3 Load Purchases Energy
from Wind Farm 3
Transmission upgrade



LSE B Load Purchases Energy from Wind Farm 4

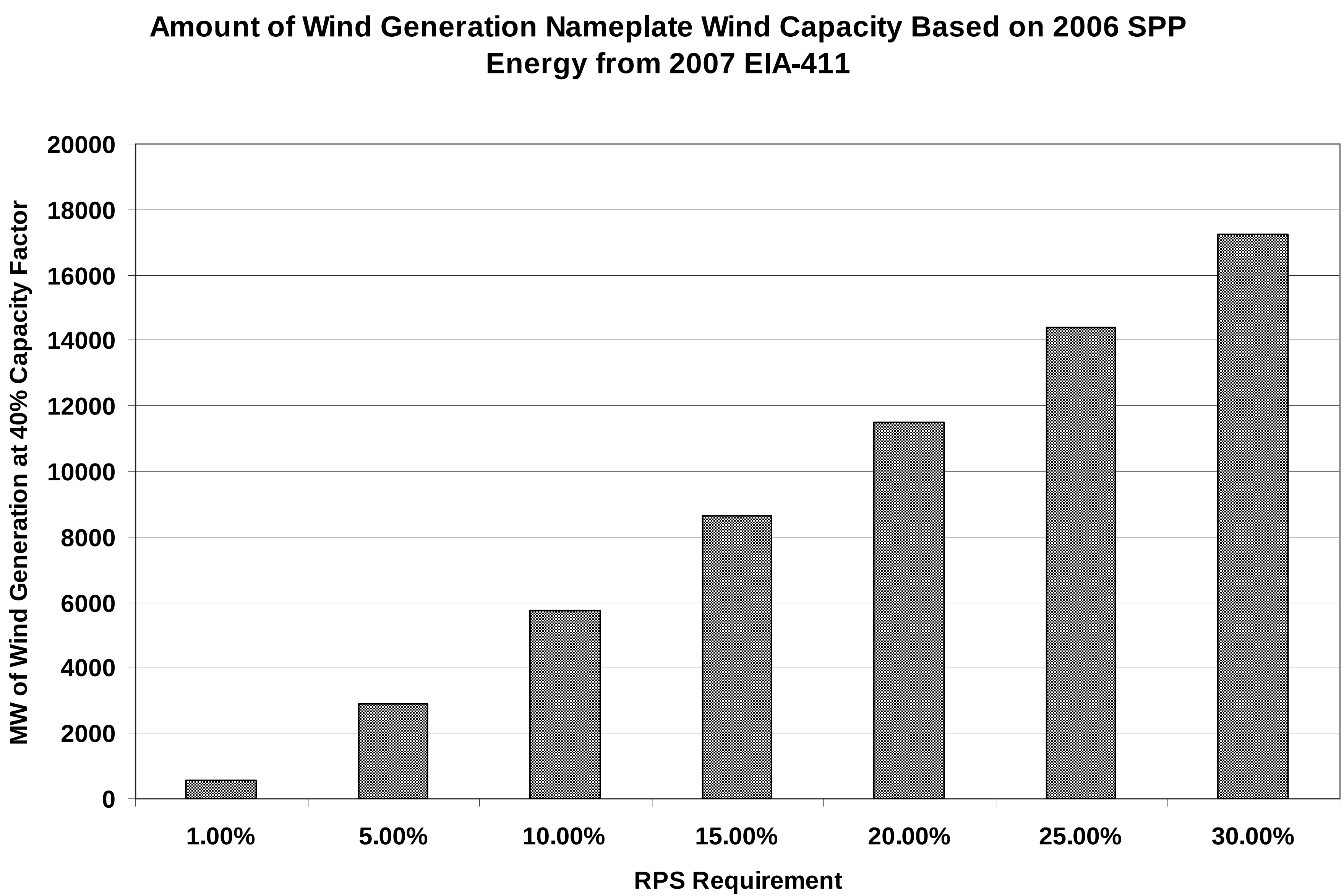
Transmission upgrade

Concerns – why wind is different

- Example 1 – Most of the zonal allocation goes to zone 1
- Example 2 – Most of the zonal allocation goes to zone 2
- Example 3 – Zonal allocation to all zones
- Example 4 – Zonal allocation to zone 1
- Result
  - Zone 1 and 2 rates go up substantially to benefit wind purchase by LSEs and Loads in Zone 3 and 4
- Big picture
  - This may be an unsustainable outcome
  - This does not support some sort of regional resource planning (that is supposed to be one of the focuses of the RSC)
  - Right now it looks like wind in the western part of SPP and baseload in the eastern part (2 new large coal units in Arkansas)
  - Few believe wind can reliably provide more than 25% of a utilities energy needs
    - But this requires about 30% nameplate of utility’s peak load and would almost all be installed in the Western Part of SPP – the result could be over 12,000 MW of wind just for SPP load – most of it installed in the western half of SPP.

SPP – potential internal wind requirements

- SPP 2006 results from SPP 2007 EIA-411
  - 42,882 MW peak load
  - 201521 GWH energy
- Results in about a 54% load factor
- How does this translate into amount of wind needed at different RPS levels?
  - Just for SPP alone – without exports.


Amount of Wind Generation Nameplate Wind Capacity Based on 2006 SPP Energy from 2007 EIA-411
MW of Wind Generation at 40% Capacity Factor
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
1.00%
5.00%
10.00%
15.00%
20.00%
25.00%
30.00%
RPS Requirement

Proposed Solution

- Requests for Wind still uses the same cost allocation for the accredited capacity
- If request does not exceed 125% peak load (using accredited capacity) that the accredited capacity from the wind project is allowed $180K/MW of BPF
  - Assuming 10% of nameplate this is $18K/MW of nameplate
- But, the remaining amount is allowed (within certain parameters) and allocated entirely regionally
  - (Nameplate – accredited) at $180K/MW regionally allocated
  - Only applies to amount not funded by current BPF
- Amount of wind that would qualify would be limited to 30% nameplate of the peak load.

Example A

- NITS customer has a 1000 MW peak load and 1200 existing DNRs
  - Proposes to purchase 200 MW of wind generation accredited at 20 MW
  - Full delivery requires $25 M transmission upgrades
  - 1200 + 20 = 1220 > 122% of peak load > qualifies
  - 20 MW ($180k/MW) = $3.6 M BPF
    - $1.2 M regional allocation, $2.4 M zonal allocation
  - Remaining (200 – 20) = 180MW ($180K/MW) = $32.4 million
    - Qualified funding = $3.6 M + $32.4 M = $ 36 M
    - $36M > $25M, so
    - $3.6M under current BPF, $25M - $3.6M = $21.4M regionally
  - Result is $2.4M allocated zonally, $22.6M ($21.4M + $1.2M) allocated regionally

Example B

- NITS customer has a 1000 MW peak load and 1200 existing DNRs
  - Proposes to purchase 200 MW of wind generation accredited at 20 MW
  - Full delivery requires $40 M transmission upgrades
  - 1200 + 20 = 1220 > 122% of peak load > qualifies
  - 20 MW ($180k/MW) = $3.6 M BPF
    - $1.2 M regional allocation, $2.4 M zonal allocation
  - Remaining (200 – 20) = 180MW ($180K/MW) = $32.4 million
    - Qualified funding = $3.6 M + $32.4 M = $ 36 M
    - $36M < $40M, so
    - $3.6M under current BPF, $32.4 wind regional allocation
  - Result is $2.4M allocated zonally, $33.6M ($32.4M + $1.2M) allocated regionally
  - Remainder – ($40M - $36M) $4M allocated to the customer

Example C

- NITS customer has a 1000 MW peak load and 1240 existing DNRs
    - Proposes to purchase 200 MW of wind generation accredited at 20 MW
    - Full delivery requires $25 M transmission upgrades
    - 1240 + 20 = 1260 > 126% of peak load > only 10 MW (or half) qualifies
    - 10 MW ($180k/MW) = $1.8 M BPF
        - $0.6 M regional allocation, $1.2 M zonal allocation
    - Remaining (100 – 10) = 180MW ($180K/MW) = $16.2 million
        - Qualified funding = $1.8 M + $16.2 M = $ 18 M
        - $18M < $25M, so
        - $1.8M under current BPF, $16.2 wind regional allocation
    - Result is $1.2M allocated zonally, $16.8M ($16.2M + $0.6M) allocated regionally
    - Remainder – ($25M - $18M) $6M allocated to the Customer

Example D

- NITS customer has a 1000 MW peak load and 1200 existing DNRs
  - Proposes to purchase 400 MW of wind generation accredited at 20 MW
  - Full delivery requires $60 M transmission upgrades
  - 1200 + 40 = 1240 = 124% of peak load > 40 MW 10 MW ($180k/MW) = $7.2 M BPF
    - $2.4 M regional allocation, $4.8 M zonal allocation
  - But 400 MW of wind is 40% of peak load so only 300 MW (30% of 1000 MW qualifies for remainder
  - Remaining (300 – 40) = 260MW ($180K/MW) = $46.8 million
    - Qualified funding = $7.2 M + $46.8 M = $ 54 M
    - $54M < $60M, so
    - $7.2M under current BPF, $46.8 wind regional allocation
  - Result is $4.8M allocated zonally, $49.2M ($46.8M + $2.4M) allocated regionally
  - Remainder – ($60M - $54M) $6M allocated to the Customer

Conclusions

- There may well be other methods or limits we can consider
  - Nonetheless we need to consider the fact that the wind will be developed primarily in only a portion of SPP
    - Many utilities will want access to the wind
  - This method does acknowledge the difference between wind and other generation resources
    - Fits into fuel diversity and other concerns RSC added to tariff language
  - Allowing nameplate wind capacity instead of accredited capacity under III.B.2 of Appendix J **is treating wind differently and is a consequence not intended or envisioned when the current cost allocation plan was developed** – alternate methods for wind related transmission upgrade cost allocation would establish a cost allocation scheme that **is not an unintended consequence** but is instead a deliberate approach

Revenue Crediting of Economic Projects

A position paper by

Westar Energy

January 30, 2008

Question at Hand

- Does the Wichita-Reno-Summit line qualify for Revenue Credits?

What Does the OATT say?

- Two different types of transmission facilities:
  - Existing Facilities
    - Facilities built or required prior to Oct. 1, 2005
    - All costs are paid by local Zone
  - Network Upgrades
    - Facilities built after Oct. 1, 2005
    - Costs allocated according to Attachments J & Z

Network Upgrades

- Four types of Network Upgrades - Today
  - Base Plan Upgrades
  - Economic Upgrades
  - Requested Upgrades
  - Generation Interconnection Upgrades
- Four types approved but not filed:
  - Base Plan Upgrades
  - Sponsored Upgrades
  - Service Upgrades
  - Generation Interconnection Upgrades

Westar's Position

- The line qualifies as an Economic/Sponsored Project under the OATT
- The line is not:
  - An "Existing Facility"
  - Related to an LGIA, nor
  - Related to a Request for transmission service

Does the Line have Regional Benefits?

- 123 transmission request from the last four Ag. Studies – 4967 MW of Trans. Service.
  - Westar = 7 requests @ 758 MW
  - Power Not sourcing or sinking in WR BA
    - 11 entities, 38 requests, 3030 MW
  - MIDW = 58 requests, 310 MW
  - Non-WR Entities inside Westar Zone:
    - 2 Entities, 12 Requests, 257 MW
  - Exports: 10 Entities, 14 requests, 812 MW
  - Imports: 4 Entities, 8 requests, 683 MW

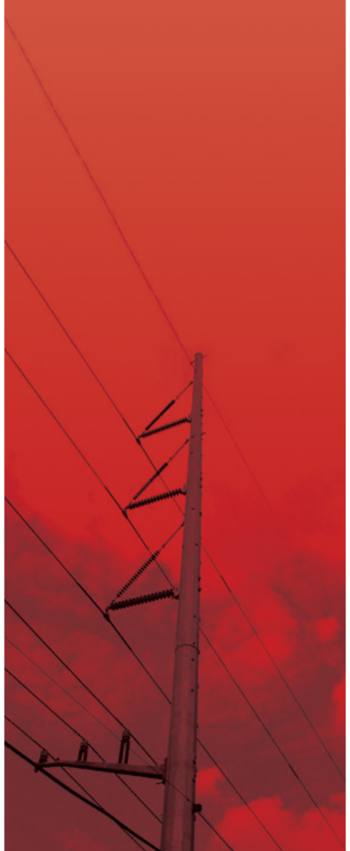
The Mechanics

- Credits from PTP transactions:
  - Take care of themselves
    - Increase In WR Rev. Req. (50% of allocation)
    - Change in mw-mile impacts (50% of allocation)
- Credits from NITS
  - Need Credits from new designated Network Resources
    - 90 requests (estimated), 2205 MW would otherwise use the line without paying for it.
    - This only occurs on facilities classified as “Existing”

Request:

- Westar is asking the CAWG & RTWG to agree with Westar's position on:
  - The Wichita-Reno-Summit line is an Economic Project
  - Is eligible for credits pursuant to Attachments J and Z

SPP Southwest Power Pool



Helping our members work together to keep the lights on…

today & in the future

Portfolio Project Selection

A presentation detailing the process for selecting projects in the economic portfolio

Disclaimer

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

Economic Portfolio Project Selection

- **The project selection process in the Economic Portfolio is based off of the 2012 Spring and Summer economic project screening**
- **The intent of the project selection is to develop a balanced portfolio with a relatively high B/C cost ratio**
- **Projects with a higher individual B/C ratio were given preference over projects with lower B/C ratio**
- **SPP has developed a set of 3 initial portfolios to begin analysis**

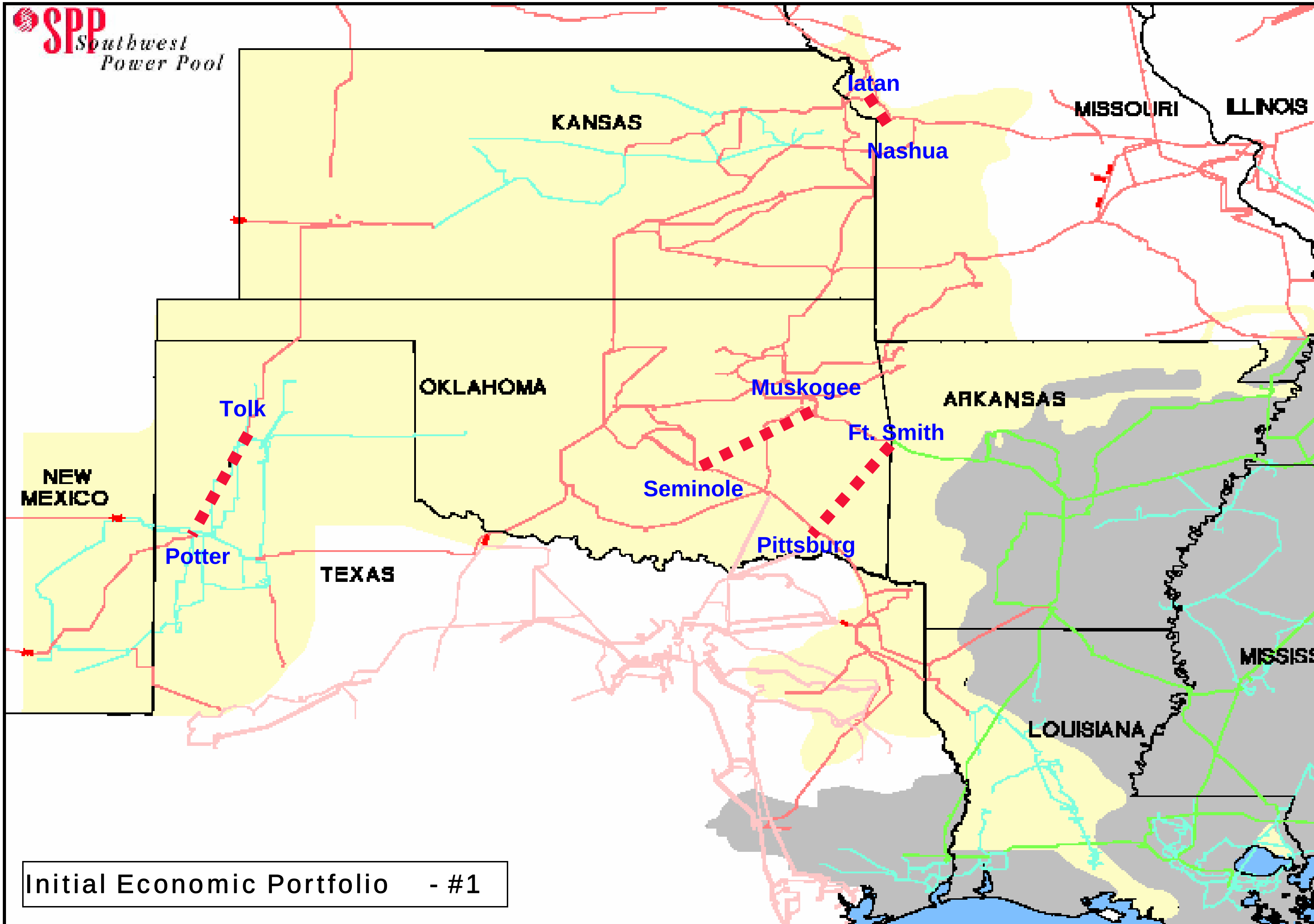
Initial Economic Portfolio - #1

- **Tolk – Potter**
- **Iatan – Nashua**
- **Pittsburg – Ft. Smith**
- **Seminole – Muskogee**

Total Cost: $217M

SPP Benefit	Tier 1 Benefit
79.1%	20.9%

Note: Benefit shown is for illustrative purposes only and is based on algebraic sum of individual project screening results and not portfolio analysis



Initial Economic Portfolio - #1

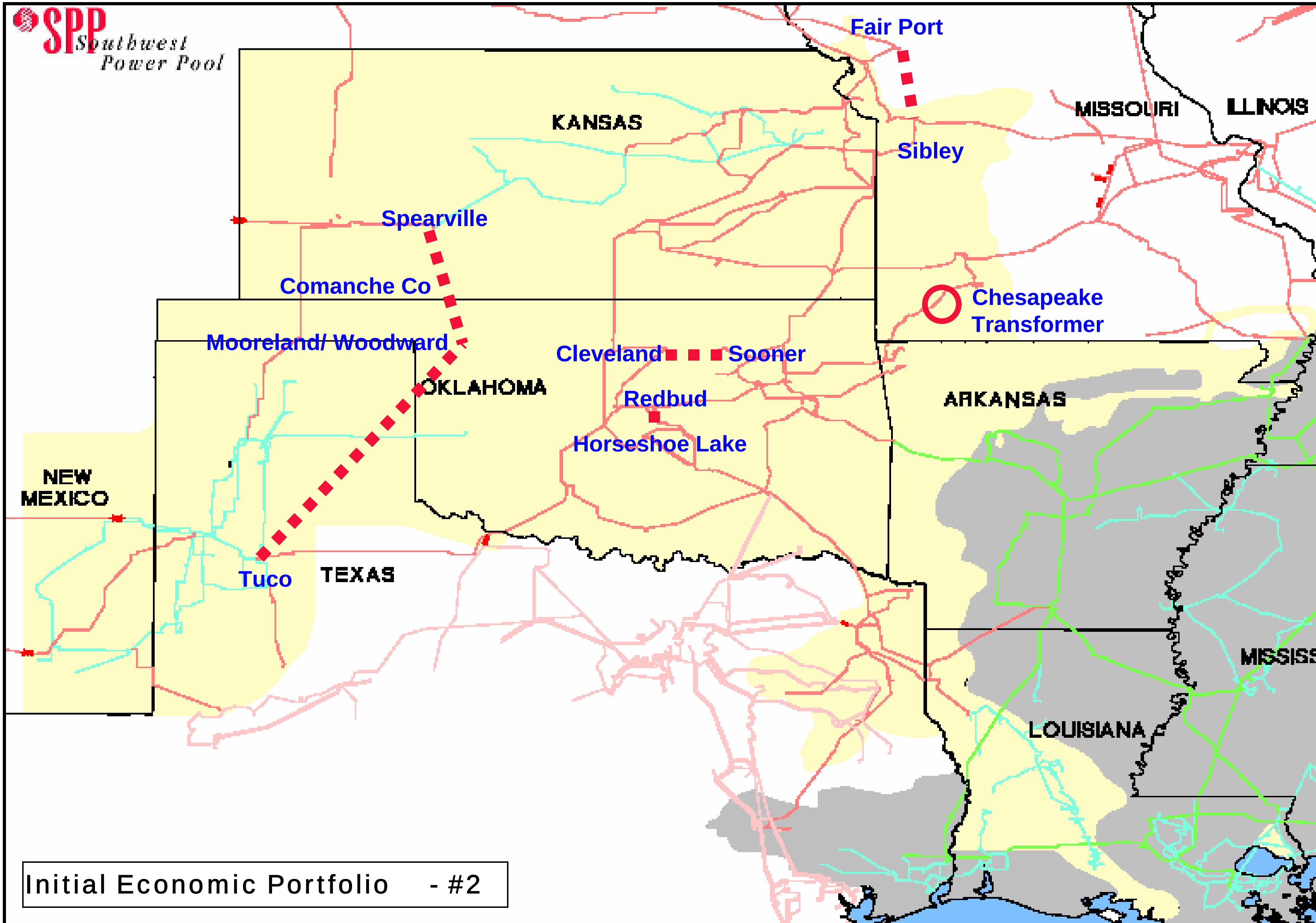
Initial Economic Portfolio - #2

- **Fairport – Sibley**
- **Spearville – (Comanche Co)- Mooreland/Woodward – Tuco**
- **Redbud – Horseshoe Lake**
- **Cleveland – Sooner**
- **Chesapeake Transformer**

Total Cost - $240M

SPP Benefit	Tier 1 Benefit
81.7%	18.3%

Note: Benefit shown is for illustrative purposes only and is based on algebraic sum of individual project screening results and not portfolio analysis



Initial Economic Portfolio - #2

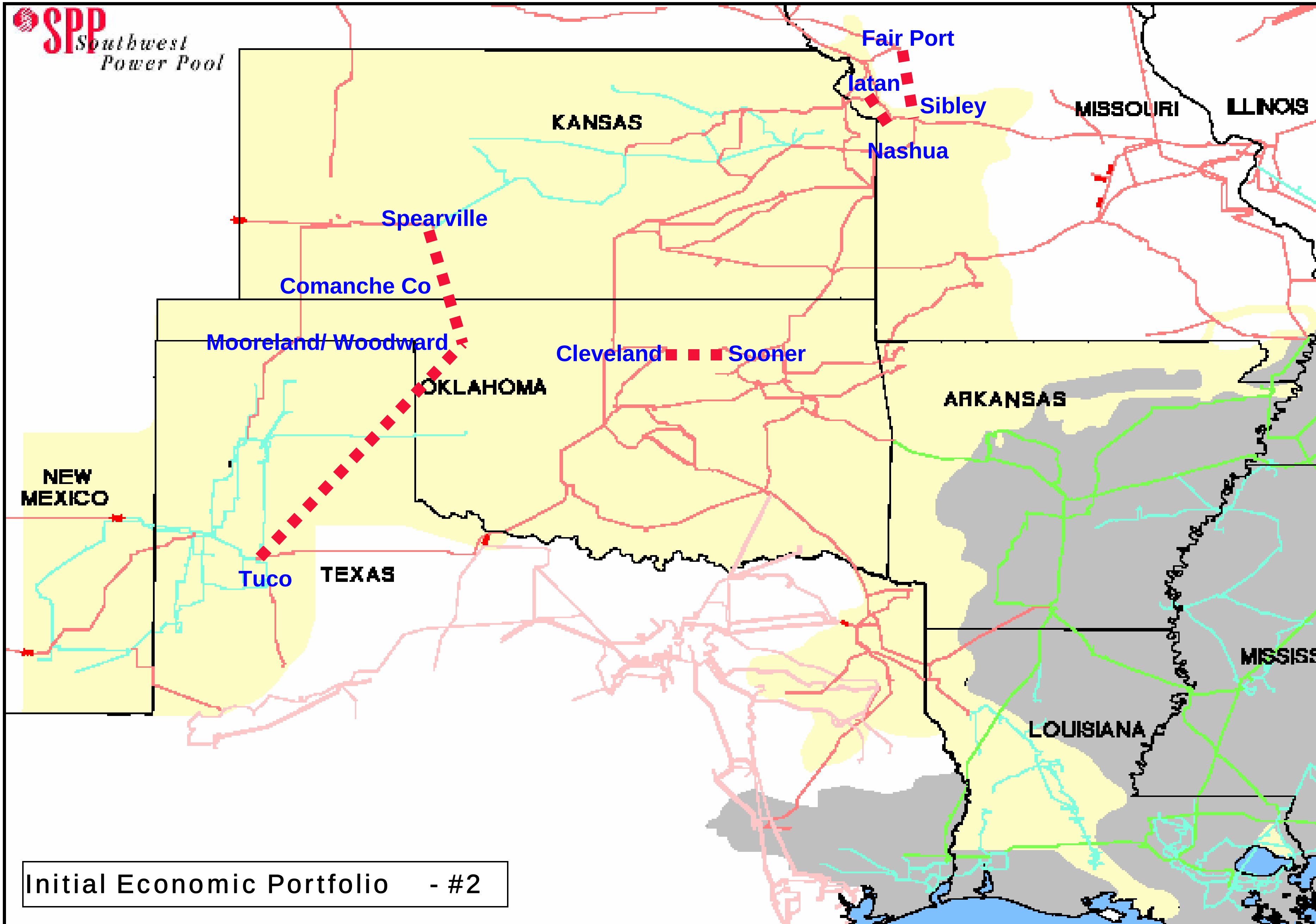
Initial Economic Portfolio - #3

- Iatan - Nashua
- Fairport - Sibley
- Spearville – (Comanche Co)- Mooreland/Woodward - Tuco
- Cleveland - Sooner

Total Cost - $249M

SPP Benefit	Tier 1 Benefit
80.6%	19.4%

Note: Benefit shown is for illustrative purposes only and is based on algebraic sum of individual project screening results and not portfolio analysis



Initial Economic Portfolio - #2

Project Benefit by Zone

	P1	P2	P3
AREC	1.7%	3.0%	3.1%
CELE	0.0%	0.1%	0.1%
AEPW	12.6%	8.7%	7.2%
EMDE	0.7%	2.0%	2.1%
GRDA	1.2%	1.5%	1.6%
INDN	0.5%	0.9%	1.6%
KACY	0.3%	0.0%	0.0%
KCPL	3.0%	4.9%	8.4%
LAFA	0.4%	0.5%	0.5%
LEPA	0.1%	0.2%	0.3%
MIDW	0.3%	2.0%	1.8%
MIPU	1.5%	3.6%	5.3%
OKGE	16.7%	18.7%	17.2%
OMPA	2.0%	1.4%	1.2%
SPRM	0.1%	0.5%	0.1%
SUNC	0.3%	0.4%	0.6%
SWPA	2.2%	0.8%	0.2%
SWPS	42.6%	30.5%	25.9%
WFEC	8.7%	8.5%	7.1%
WEPL	0.9%	1.2%	1.8%
WERE	4.0%	10.6%	14.1%

Note: Benefit shown is for illustrative purposes only and is based on project screening results and not portfolio analysis

- **Benefit shown for portfolio grouping is based on project screen totals**
- **Percentages shown are for percent of SPP benefit, not total**
- **Ideally, benefit will be close to allocation percentage of the portfolio**
- **Benefits subject to change (in either direction) due to project interaction when portfolio analysis is complete**

Issues -

- Certain portfolio groupings tend to heavily benefit SWPS
- Project interaction may lead to drastically different results, thus the need for iterations through portfolio analysis to attain balance and overall high B/C ratio
- Portfolio analysis will be conducted on 8760 over multiple years, so benefits could shift

Next Steps

- SPP is currently working on running the analysis for the given portfolios

- Initial portfolio B/C results to be presented to the CAWG in February meeting
  - Further analysis will likely be required to achieve portfolio balance

- Sensitivity analysis to fuel and other future scenario need to be conducted following baseline analysis

Questions?

Southwest Power Pool

Charles Cates
Planning, Engineer II
501-614-3551
ccates@spp.org

Revenue Crediting for Transmission Projects

Background:
Westar is building a 100 mile, 345kV line from Wichita to Hutchinson to Salina (Wichita-Reno-Summit line) as an Economic project under the tariff. The line is supported by all the customers within the Westar Zone and the KCC. The line will help eliminate significant constraints for power flows between east and west Kansas, and throughout the SPP. Economic studies have shown that the existence of the line will help lower power costs throughout Kansas and the SPP. Because the line will be considered "used and useful", it will be automatically included as part of Westar's formula rate calculation as each phase of construction is completed.

SPP has also recognized that the line significantly lowers constraints on the system. Currently there are 123 transmission requests from the last four aggregate studies (2006-AG2-AFS4b through 2007-AG3-ASIS1) that have identified the Wichita-Reno-Summit line as needing to be completed prior to the start of their service. This represents 4967 MW of requests. Of these 123 requests, requests from Westar only make up 7 of them totaling 758 MW. 38 of the requests do not source or sink in Westar and represent 3,030 MW of the 4967 MW of transmission service.

Issue:
Westar is building the Wichita-Reno-Summit 345 kV line, which it believes is an Economic Project under the terms of the SPP OATT. Upon completion, the cost of the line construction will be included in Westar's zonal rates. It is Westar's belief that the line is eligible for credits under Attachments J and Z. SPP staff is concerned that since the line will be part of the zonal revenue requirements that it is not eligible for credits.

Discussion:
Under the SPP OATT, there are two major classifications of transmission facilities, 1) Existing Facilities and 2) Network Upgrades. By the definition of Transmission in Attachment AI, existing facilities are those in existence (or needed) prior to October 1, 2005. Transmission facilities after October 1, 2005 are classified as Network Upgrades.

Pursuant to Attachment J, there are four types of Network Upgrades, 1) Base Plan Upgrades, 2) Economic Upgrades, 3) Requested Upgrades and 4) upgrades related to generation interconnections (Attachment V upgrades)[1]. Since the line is being built after October 1, 2005, it can not be considered an "existing facility". It must be classified as one of the four possible Network Upgrades.

Jay Caspary of the SPP staff testified in the line siting hearings for the Wichita-Reno-Summit line affirmed the fact that the line has broad regional impacts will provide many economic benefits not only to Kansas, but to the SPP region more generally[2]. As such the line could easily be classified as an Economic project under the tariff and thus receive credits. Attachment J, Section IV, states: "The Project Sponsors shall receive transmission revenue credits in accordance with Attachment Z to this tariff".

In essence, the line is an economic project, built by the host TO with the overall cost of the project being paid for by the Westar Zonal customers. SPP's own analysis shows that many regional customers' transmission requests rely on this line being built. The Westar Zonal customers should receive compensation for the use of the additional, unused, ATC created on the SPP system due to the existence of the line. Credits received from SPP through these additional transactions will be passed through to the Westar Zonal customers by lowering the zonal revenue requirement.

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[1] Attachment J.II, Southwest Power Pool, FERC Electric Tariff, Fifth Revised Volume No. 1, Original Sheet No. 226.
[2] Direct Testimony of P. Jay Caspary, Before the State Corporation Commission of the State of Kansas, Docket No. 07-WSEE-715-MIS, page 4.

Revenue Crediting

SPP staff is also concerned about the possibility of “double payment” of credits due to the increase in the allocated revenue from PTP customers. Westar is agrees that the change in revenue distribution between Transmission Owners for PTP service accurately reflects the correct crediting mechanism for PTP service. However an analysis of the 128 requests for transmission service shows that as many as 90 of the transmission requests, which total 2205 MW, are related to NITS service and would be utilizing the line without compensating those entities inside Westar’s zone for use of the line.

Westar’s position is consistent with the SPP OATT and reflects a similar process that happens today under the SPP OATT for PTP service. When SPP sells PTP service, it collects the money from the transmission customer and allocates it to each Transmission Owner. The revenue distributed to Westar from SPP for the Point-to-Point transactions sold by SPP become a revenue credit in its transmission formula, thereby reducing its total revenue requirement.

Nothing in the SPP tariff prohibits this arrangement for Economic Projects. The fact that the line will be included in Westar’s zonal revenue requirement does not change the fact that SPP should be assessing charges to all customers utilizing the line. By not assessing the appropriate charges to those transmission requests utilizing the line and not paying the credits to Westar, it becomes the equivalent of SPP granting “free” transmission service across the line to all customers outside the Westar Zone.

Proposal:
Westar is asking the CAWG and RTWG to agree with its view that the SPP tariff allows SPP to collect and pay Westar (and ultimately its zonal customers) credits for transmission service sold that require the existence of the Wichita-Reno-Summit line pursuant to Attachments J and Z.

Submitted by:

Dennis Reed
Director Transmission Services
Westar Energy

P1	P2	P3	Project	2012 Summer Total Adjusted Production Cost	2012 Spring Total Adjusted Production Cost	Summer + Spring	Yearly Estimate (1.5 x Sum + Spr)	Project Cost	B/C Ratio
√			Tolk - Potter	($11,347,000)	($20,021,000)	($31,368,000)	($47,052,000)	$44.3	7.2
			Eldorado - Longwood	($1,797,000)	($1,506,000)	($3,303,000)	($4,954,500)	$10.0	3.4
√		√	Iatan - Nashua	($5,286,000)	($2,979,000)	($8,265,000)	($12,397,500)	$28.5	2.9
			SWPS - Battlefield	($1,062,000)	($117,000)	($1,179,000)	($1,768,500)	$4.5	2.7
	√		Chesapeake XF	($1,433,000)	($235,000)	($1,668,000)	($2,502,000)	$7.5	2.3
			Tuco - Tolk - Potter	($9,871,000)	($1,506,000)	($11,377,000)	($17,065,500)	$66.8	1.7
	√	√	Fairport - Sibley	($3,514,000)	($2,678,000)	($6,192,000)	($9,288,000)	$48.0	1.3
√			Pittsburg - Ft Smith	($1,043,000)	($6,651,000)	($7,694,000)	($11,541,000)	$66.8	1.2
	√	√	Spearville-Mooreland-Tuco	($4,337,000)	($11,744,000)	($16,081,000)	($24,121,500)	$145.0	1.1
√			Seminole - Muskogee	($3,059,000)	($5,212,000)	($8,271,000)	($12,406,500)	$77.7	1.1
			Monett XF	($1,175,000)	($57,000)	($1,232,000)	($1,848,000)	$12.0	1.0
	√		Redbud - Horseshoe Lake	($1,176,000)	($14,000)	($1,190,000)	($1,785,000)	$12.0	1.0
	√	√	Cleveland - Sooner	($1,153,000)	($1,257,000)	($2,410,000)	($3,615,000)	$27.0	0.9
			Sunnyside XF	($276,000)	($379,000)	($655,000)	($982,500)	$7.5	0.9
			Northwest XF	($674,000)	$21,000	($653,000)	($979,500)	$7.5	0.9
			Messick XF	($573,000)	($396,000)	($969,000)	($1,453,500)	$13.9	0.7
			Swissvale - Stilwell	($191,000)	($469,000)	($660,000)	($990,000)	$10.0	0.7
			Iatan - Nashua - Thomas Hill	($5,330,000)	($3,151,000)	($8,481,000)	($12,721,500)	$129.0	0.7
			Spearville - Viola	($530,000)	($5,872,000)	($6,402,000)	($9,603,000)	$106.0	0.6
			Anadarko XF	($128,000)	($229,000)	($357,000)	($535,500)	$7.5	0.5
			Fort Smith - Tontitown	$156,000	($4,016,000)	($3,860,000)	($5,790,000)	$84.8	0.5
			Turk - McNeil	($1,403,000)	($1,205,000)	($2,608,000)	($3,912,000)	$57.8	0.5
			Lang - Wolf Creek	($365,000)	($642,000)	($1,007,000)	($1,510,500)	$23.7	0.4
			JEC - Swissvale	($359,000)	($1,312,000)	($1,671,000)	($2,506,500)	$47.3	0.4
			Spearville - Wichita	$1,033,000	($4,445,000)	($3,412,000)	($5,118,000)	$118.2	0.3
			Redbud - Sooner	($950,000)	($540,000)	($1,490,000)	($2,235,000)	$53.4	0.3
			Spearville - Knoll - Axtell	($1,988,000)	($2,580,000)	($4,568,000)	($6,852,000)	$168.0	0.3
			Midland - Pentagon	($30,000)	($578,000)	($608,000)	($912,000)	$25.4	0.2
Total	**Total**	**Total**	Reno Co. - Auburn Rd	$185,000	($1,675,000)	($1,490,000)	($2,235,000)	$77.5	0.2
$ 217	$ 240	$ 249	East Centerton - Beaver	($358,000)	($213,000)	($571,000)	($856,500)	$33.0	0.2

AREC	CLECOU	CSWSPP	EMDE	GRDA	INDN	KACY	KCPL	LAFA	LEPA	MIDW	MIPU	OKGE	OMPA	SPCIUT	SUNC	SWPA	SWPS	WEFA	WEPLKS	WRI	
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	4%	24%			6%	3%	38%
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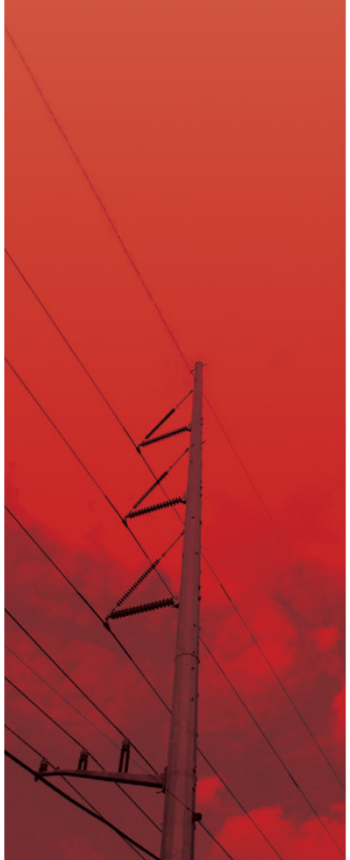
SPP Southwest Power Pool



Helping our members work together to keep the lights on…

today & in the future

SPP's Transmission Planning Survey Results

November 30, 2007
DRAFT

Overview

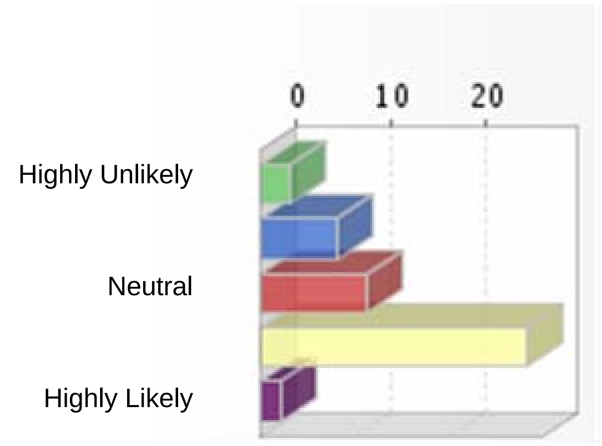
- Purpose
  - Solicit feedback from a broad range of stakeholders on key issue related to transmission planning
  - Asked for responses in two time frames
    1. Short Term – between now and 2010
    2. Long-term – by 2020
  - Use results to shape key input assumptions
- Main Topic Areas
  - Supply & Demand
  - Fuel & Environmental Constraints
- Distribution
  - SPP Members
  - Regulators
  - Other related organizations

Supply Side Related Responses

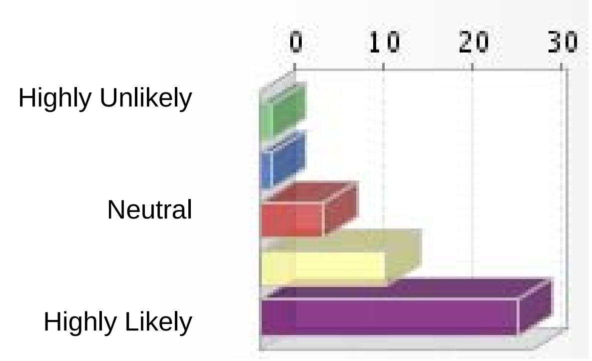
Renewable Portfolio Standards

- Most believed that some form of federal or state-mandated RPS would be in place in by 2020
  1. 76% thought some form of state mandate would be in place by 2020
- Amount
  - <10% in short term
  - Between 10% and 15% in long term

Short Term (2010)



Long Term (2020)



Treatment of Wind Resources

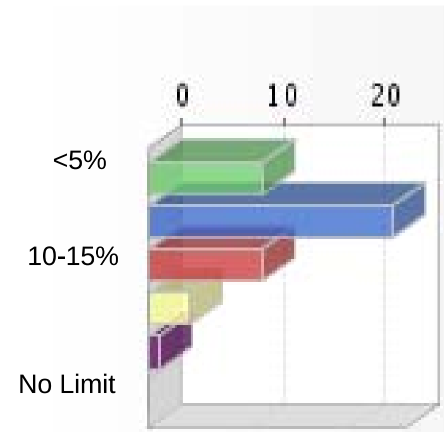
Majority recognize increase in wind resources from today's 3%

- **68% say it could be as high as 10% in short term**
- **72% see potentially 15% in long-term**

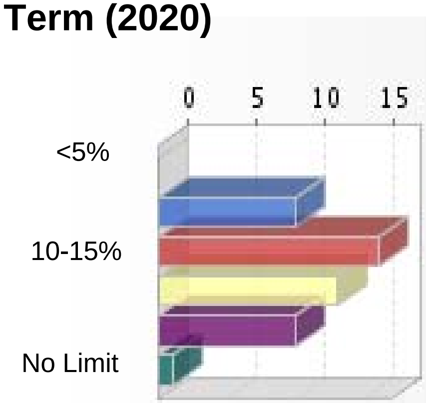
Transmission needs to support new wind generation

- **67% believe study should model transmission expansion to support export of wind generation**
- **74% see increase in net exports in long-term**

Short Term (2010)



Long Term (2020)

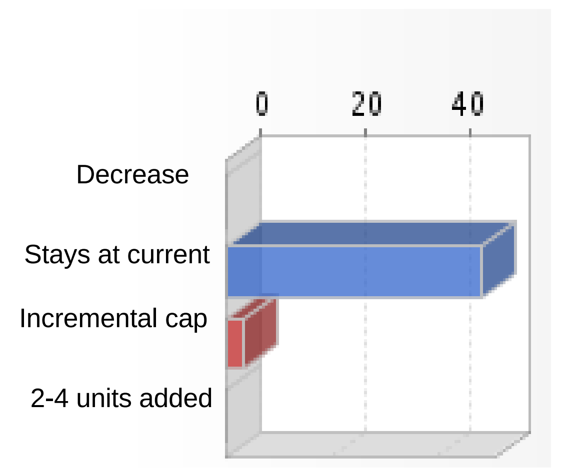


Nuclear Generation

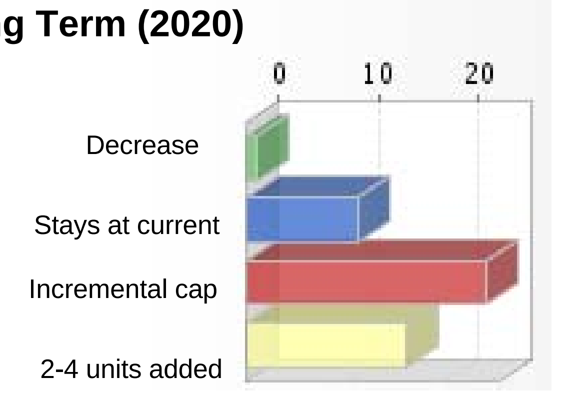
- Short term outlook - overwhelming majority see no change in short term

- Long-term outlook – 77% see at least some incremental capacity being added

Short Term (2010)



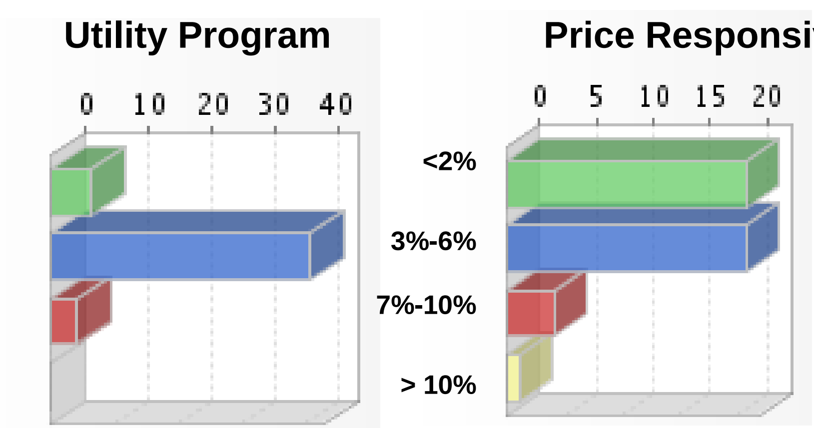
Long Term (2020)



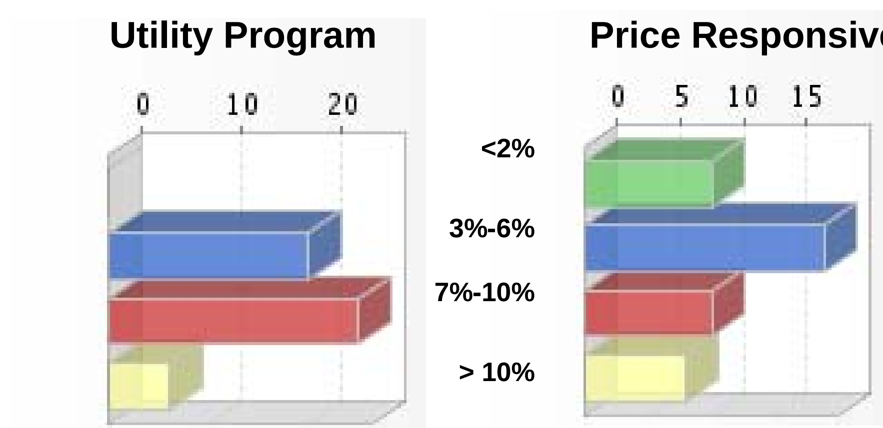
Demand Side Responses

- Scope of questions included utility demand programs, price responsive load, and energy efficiency
- Summary across all three areas
  - Short term outlook – overwhelming majority (80.4%) see current levels of demand response capability (3%-6%) being roughly maintained
  - Long-term outlook
    - Increase in utility demand response programs could be in the 7%-10% of load
    - Price sensitive load remains in same range of 3%-6%

Short Term (2010)



Long Term (2020)



Fuel & Environmental Constraints

- **Emissions Constraint Policies**
  - **81% see cap and trade system being put in place**
  - **Majority see price of emissions credits increasing at (31%) or greater (58%) than rate of inflation**

- **Fuel Prices**
  - **Natural Gas prices**
    - **upward pressure on prices at or greater than rate of inflation**
    - **78% see prices rising greater than inflation in long-term forecast**
  - **Coal prices**
    - **Prices increase at a pace slower than rate of change in natural gas prices**

Interpreting the Results

- Supply & Demand Areas
  - An RPS standard will be in place in the long term that could be as high as 10% or more
  - Wind resources
    1. Could make up as much as 10%-15% of the region's capacity
    2. Transmission to support exports of these resources to the Eastern Interconnection should be evaluated
  - Nuclear Generation in the future will remain constant in the short term with the potential for incremental capacity in the long term
  - Demand side resources
    1. will continue to be in the 3-6% range in the short term
    2. Utiliities will increase the amount of demand side programs to as much as 10% in the long-term
  - Imports/Exports
    - SPP will continue its current pattern although an increase in export capability should be evaluated
- Fuel & Environment
  - Emissions constraints
    1. A cap and trade system will be in place
    2. The value of emissions credits is expected to increase at a rate at or above inflation
  - Fuel Price Forecasts
    - Natural gas prices will increase at or above the rate of inflation
    - Coal prices will increase at a rate below that of natural gas prices

Questions?

SPP Southwest Power Pool

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