Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 24th, 2014

Web Conference

• SUMMARY OF ACTIONS TAKEN •

1. SPP Staff will develop a methodology to select Economic Needs.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 24th, 2014

Web Conference

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:35 a.m., welcomed those in attendance. (Attachment 1 – Attendance List)

There were 46 web conference participants representing 10 of 11 members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP staff) requested proxy statements. No proxies identified.

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. The agenda was approved unanimously. (Attachment 2 – Agenda)

> **A motion to approve the proposed agenda was made by Kurt Stradley (LES) and seconded by Paul Dietz (Westar). The motion was approved unanimously.**

After approving the agenda Juliano Freitas (SPP Staff) asked members if they decided to approve the methodology proposed by SPP Staff to select Economic Needs (For further details check the April 10, 2014 Minutes). Members did not have a final decision and asked SPP to develop a methodology to calculate the benefit of adding these needs in the 2015 ITP10 Study. Members decided to make a motion to approve the methodology that will be developed by SPP Staff, due to a limited amount of time to have the ESWG vote before the next face to face meeting. SPP Staff will post the methodology as soon as possible.

> **A motion to approve the methodology to select economic needs to be developed by SPP Staff was made by Leon Howell (OGE) and seconded by Kurt Stradley (LES). The motion was approved unanimously.**

ACTION ITEM: SPP Staff will develop a methodology to select Economic Needs.

Agenda Item 2 – Metrics Review

Antoine Lucas (SPP staff) continued presenting the metrics review, the focus of his presentation in this particular web conference is on metrics that have received more attention from stakeholders during the ITP process and also in the previous RCAR. The main metrics approached in the presentations were: Assumed Benefit of Mandated Reliability Projects, Public Policy Benefits, Mitigation of Transmission Outages, Increased Wheeling Through and Out Benefits and Marginal Energy Losses Benefit. For each metric Antoine explained the methodology options currently under evaluation to calculate these metrics and allocate benefits. ESWG members asked for more time to review the methods proposed before having a final decision. (Attachment 3 – Metrics Review)

Agenda Item 3 – DPP – Projects Selection Methodology

Juliano Freitas (SPP staff) presented the methodology developed by SPP Staff to select economic and policy projects to be included in the final 2015 ITP10 portfolio. The process consists of three phases; the intention is to select the optimal projects in order to have a robust transmission plan. In Phase one, projects will be evaluated on an individual basis, with the selection being made considering the economic and/or policy performance of each project. In phase two, the projects performance will be measured as part of a grouped portfolio, evaluating first the reliability projects, and then on top of that policy projects, and finally the last group to be added will be the economic projects. Phase three consists of a consolidation methodology combining the final groupings from both futures. The DPP project submittal window will begin after assessments are complete. ESWG members requested SPP Staff to review the B/C ratio to select economic projects in Phase 1, as members expressed opinions that the proposed values are too high (Attachment 4 – DPP – Projects Selection Methodology)

Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 11:38 a.m.

Respectfully Submitted,

Juliano Freitas,

Secretary

Name	Email	Attendance
Adam Mummert	amummert@burnsmcd.com	Webex
Al Tamimi	atamimi@sunflower.net	Webex
Alan Myers	amyers@itcgreatplains.com	Webex
Antoine Lucas	alucas@spp.org	Webex
Ben Roubique	broubique@pwrsol.biz	Webex
Bennie Weeks	bennie.weeks@xcelenergy.com	Webex
Bill Leung (NPRB)	bleung@bjleung.com	Webex
Bruce Walkup (AECC)	bruce.walkup@aecc.com	Webex
Caitlin Shank	cshank@spp.org	Webex
Cory Blair (RES Americas)	cory.blair@res-americas.com	Webex
David Treichler	david.treichler@oncor.com	Webex
Deral Danis (Clean Line)	ddanis@cleanlineenergy.com	Webex
Don Le	don.le@nexteraenergy.com	Webex
Eric Burkey (Ameren)	eburkey@ameren.com	Webex
Gayle Freier (SPP)	gfreier@spp.org	Webex
Jason Shook	jason.shook@gdsassociates.com	Webex
Jason Spear	jspear@spp.org	Webex
Jeff Knottek	jeff.knottek@cityutilities.net	Webex
Jerry Bradshaw (CUS)	jerry.bradshaw@cityutilities.net	Webex
Jim Jacoby	jwjacoby@aep.com	Webex
Joe Lang	jlang@les.com	Webex
Jon Iverson	jiverson@oppd.com	Webex
Jon Shipman (OPPD)	jeshipman@oppd.com	Webex
Josh Ross	jross@spp.org	Webex
Juliano Freitas	jfreitas@spp.org	Webex
Kaustubh Deshmukh	kdeshmukh@itctransco.com	Webex
Kelsey Allen	kallen@spp.org	Webex
Kirk Hall	khall@spp.org	Webex
Kurt Stradley (LES)	kstradley@les.com	Webex
Leon Howell	howelllc@oge.com	Webex
Liz Coffield (SPP)	lcoffield@spp.org	Webex
Michael Watt (OMPA)	mwatt@ompa.com	Webex
Mike Proctor	mproctor910@sbcglobal.net	Webex
Nathan McNeil (MIDW)	nmcneil@mwenergy.com	Webex
Noumvi Ghomsi	nghomsi@gmail.com	Webex
Pat Hayes (Ameren)	phayes@ameren.com	Webex
Pat McCool	patrick.mccool@kcpl.com	Webex
Paul Dietz	paul.dietz@westarenergy.com	Webex
Randy Collier (CUS)	randy.collier@cityutilities.net	Webex
Sanjoy (AEP)	sksarawgi@aep.com	Webex
Sharma	asharma@aep.com	Webex
Steve Gaw	rsgaw1@gmail.com	Webex
Thanh Tran (BMcD)	tntran@burnsmcd.com	Webex
Tim Owens (NPPD)	tjowens@nppd.com	Webex
Tim Soles (Occidental)	tim_soles@oxy.com	Webex
Wayman Smith (AEP)	wlsmith1@aep.com	Webex

ECONOMIC STUDIES WORKING GROUP

April 24th, 2014

Conference Call

• A G E N D A •

8:30 am – 11:30 am

1. Administrative items
   a. Call to Order, Introductions.. Alan Myers (5 minutes)
   b. Receipt of Proxies .... Juliano Freitas (1 minute)
   c. Review of Agenda .... Alan Myers (1 minute)
2. Metrics Review .... SPP Staff (2 hours)
3. DPP Project Selection Methodology.. Juliano Freitas (1 hour)
4. Closing Items .... All

Metrics Review

April 10th, 2014

SPP Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future

Overview

- ESWG has been tasked with reviewing the calculation of metrics going forward
  - ITP10
  - RCAR 2
- Today – continue discussion of metrics that have been developed previously
  - Focus will be on the calculation of metrics that have received more attention from stakeholders during ITP and the previous RCAR

Approved Metrics for the RCAR

- Adjusted Production Cost (APC) Savings
- Reduction of Emission Rates and Values
- Savings due to Lower Ancillary Service Needs and Production Costs
- Avoided or Delayed Reliability Projects
- Capacity Cost Savings due to Reduced On-Peak Transmission Losses
- Mitigation of Transmission Outage Costs
- Assumed Benefit of Mandated Reliability Projects
- Public Policy Benefits

ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

Reliability Benefit Allocation Methodologies

- **Highway/Byway – utilized in RCAR**
- **DFAX**
- **LODF**
- **System Reconfiguration**

*These allocation methodologies do not impact the total reliability benefit of projects. They only impact the allocation of benefit to zones.

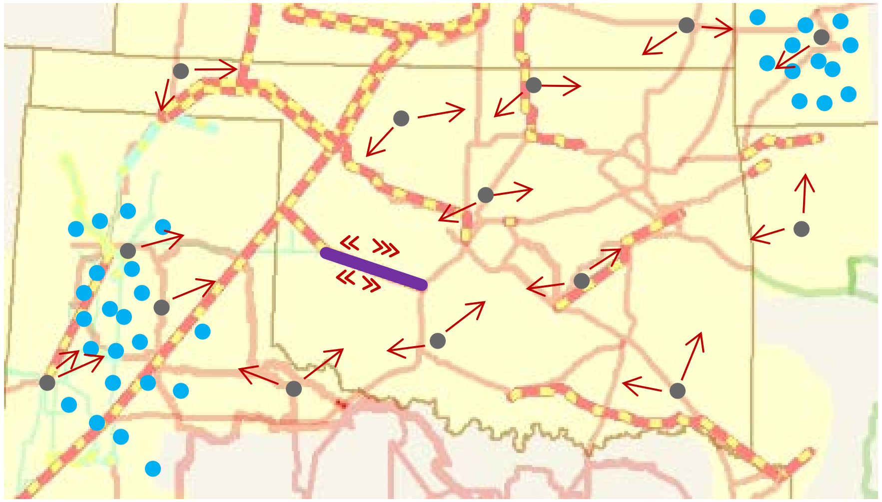
Highway/Byway Approach

- Benefits would be allocated in the same manner costs are allocated
- For upgrades > 300 kV:
  - 100% of benefit allocated to the region, based on Load Ratio Share (LRS)
- For upgrades between 100 kV and 300 kV:
  - 1/3 of benefit allocated to the region, based on LRS
  - 2/3 of benefit allocated to the zone
- For upgrades < 100 kV:
  - 100% of benefit allocated to the zone

DFAX Approach

- Distribution factors (DFAX) used to calculate the portion of a transfer of energy from a defined source to a defined sink that will flow across a specific transmission facility
- A DFAX is calculated for each transmission zone by modeling a transfer from all generation in the SPP region individually to the loads in each transmission zone
- The change in flow for the reliability upgrade was calculated for each of the zonal transfers
- DFAX represent a measure of the use by the load of each transmission zone of the required Reliability Project as determined by power flow analysis

DFAX Approach



Large DFAX -> large benefit

Small DFAX -> small benefit

DFAXs for each of the 16 transfers are normalized to develop allocation factors. These allocation factors are then normalized based on peak load by zone to obtain final allocation factors.

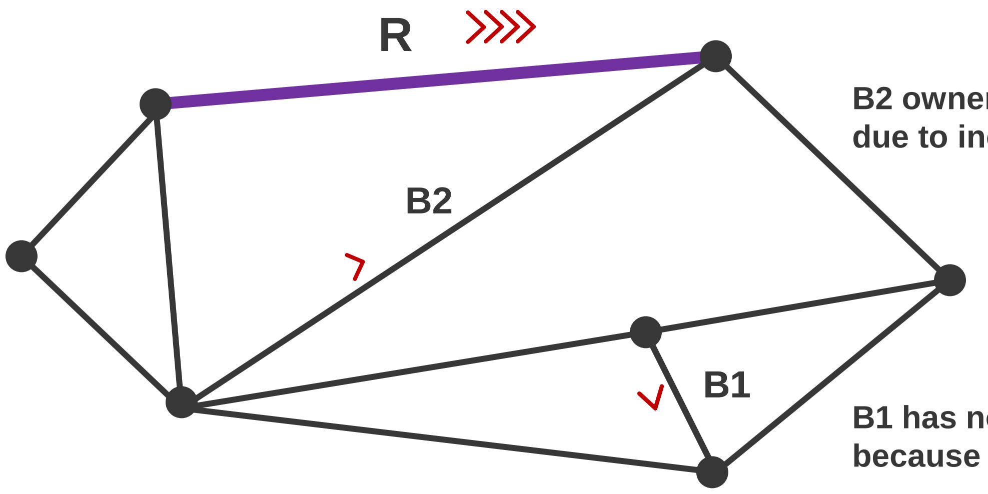
Zones with transfers that impact the reliability upgrade flow the most will have the most benefit.

Line Outage Distribution Factor (LODF) Approach

- N-1 Contingency Analysis
- Change in flow for Reliability Upgrade computed for each outage (LODF)
- Increase in flow for Reliability Upgrade due to Zone A Outage is credited as benefit to Zone A
- Sum of LODFs by zone are normalized to compute allocation factors by zone

LODF Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



B2 owner is assigned benefit, due to increased flow on R

B1 has no impact on benefit, because flow on R stays same

Outage taken for every branch, 1 by 1, and increase in flow on R is measured

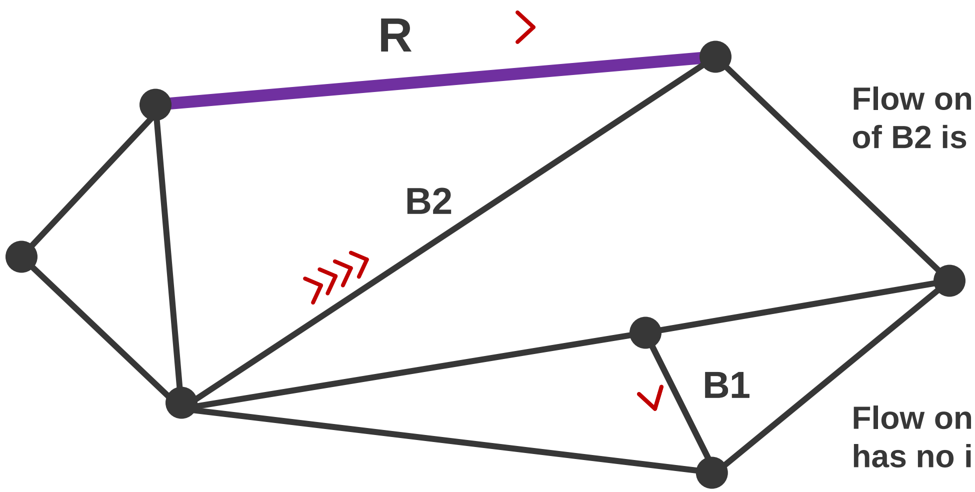
Benefits assigned to zones based on who owns the outaged facilities that cause increases in flow on R

System Reconfiguration Approach

- This approach is modified form of the MW-mile cost allocation utilized prior to Highway/Byway
  - This approach does not utilize line lengths
- Analyze all flows both with and without the reliability upgrade
  - Lines with increased flows after reliability upgrade is outaged are identified as beneficiaries of the reliability upgrade
  - Zones that own these lines are credited with reliability benefit
  - Approach and results are very similar to LODF

System Reconfiguration Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



Flow on B2 increases, owner of B2 is assigned benefit

Flow on B1 stays the same. B1 has no impact on benefit.

Flow on every branch is analyzed, 1 by 1, to determine if flow increased as a result of R being outaged

Benefit assigned to zones based on who owns the branches with increased flow after R is outaged

PJM Allocation Method

Cost Allocation Example

- 5 LDAs
- 1 upgrade (U1) resolves one or more criteria violations
- DFAX cutoff = 1%
- Usage: 80%/20% of U1 MWh is projected to be in the positive/negative direction

LDA	Peak Load (MW)	DFAX on U1 (%)
1	10,000	5.0
2	6,000	-10.0
3	4,000	0.9
4	3,000	-3.0
5	2,000	10.0

Cost Allocation Example

Step	Reference	LDA 1	LDA 2	LDA 3	LDA 4	LDA 5	Total
1. Peak Load (MW)	From PJM Load Report	10,000	6,000	4,000	3,000	2,000	25,000
2. DFAX	From DFAX Analysis	5.0%	-10.0%	0.9%	-3.0%	10.0%	
3. Positive Impact (MW)	Line 1 * Line 2 if DFAX is >= 1% Else 0	500	0	0	0	200	700
4. Negative Impact (MW)	Line 1 * Line 2 if DFAX is =< -1% Else 0	0	-600	0	-90	0	-690
5. Positive Usage	Line 5 Total * Line 3 / Line 3 Total (Line 5 Total From Production Cost Simulation)	57.14%	0	0	0	22.86%	80%
6. Negative Usage	Line 6 Total * Line 4 / Line 4 Total (Line 6 Total From Production Cost Simulation)	0	17.39%	0	2.61%	0	20%
7. DFAX Allocation	Line 5 + Line 6	57.14%	17.39%	0%	2.61%	22.86%	100%

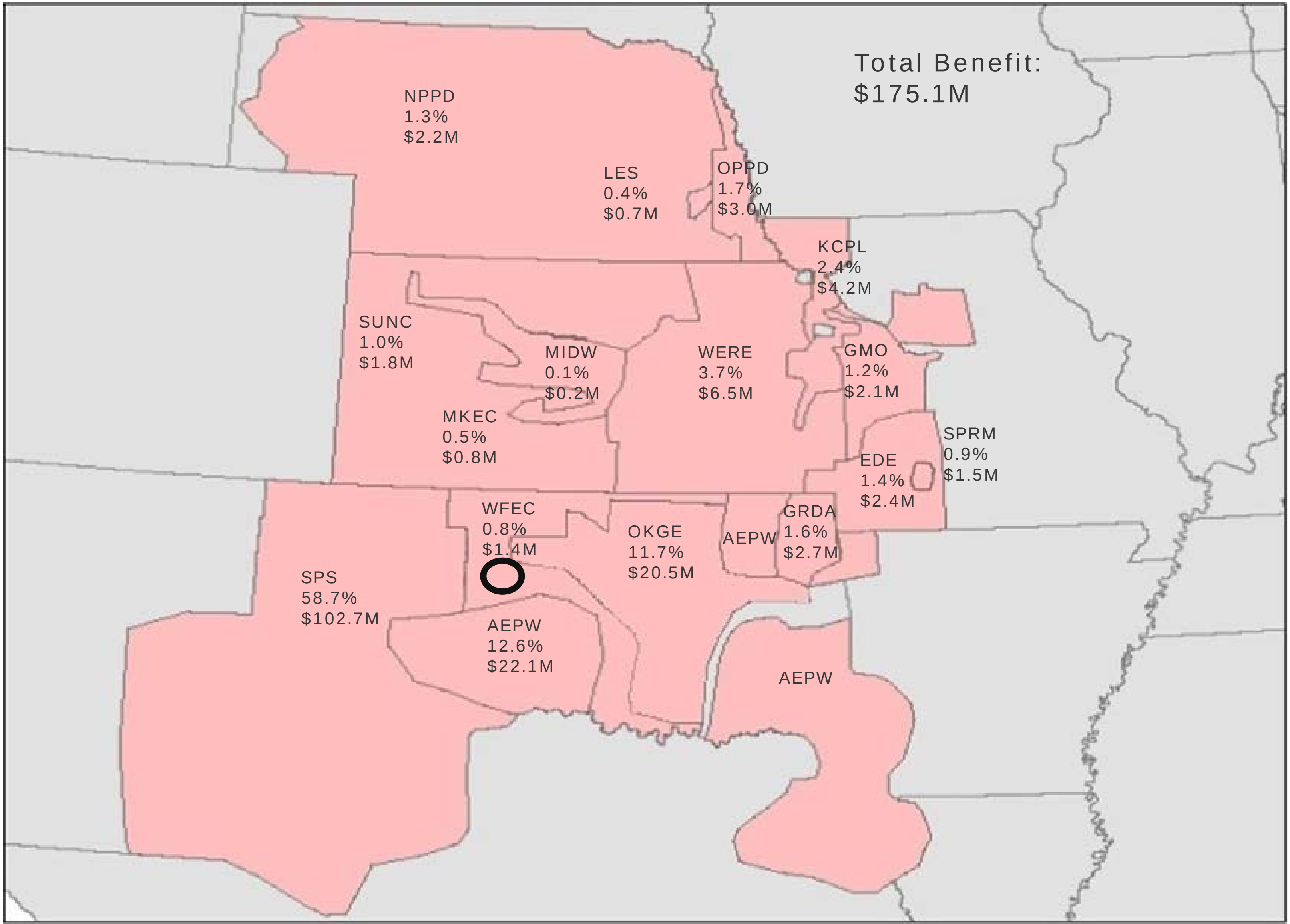
* For Regional and Necessary Lower Voltage Facilities greater than or equal to $5 Million, the allocation for each LDA will be the average of the DFAX allocation and the LDA load ratio share based on the appropriate Network Service Peak Loads.

This methodology was used for final allocations in the DFAX, LODF, and System Reconfiguration Approaches

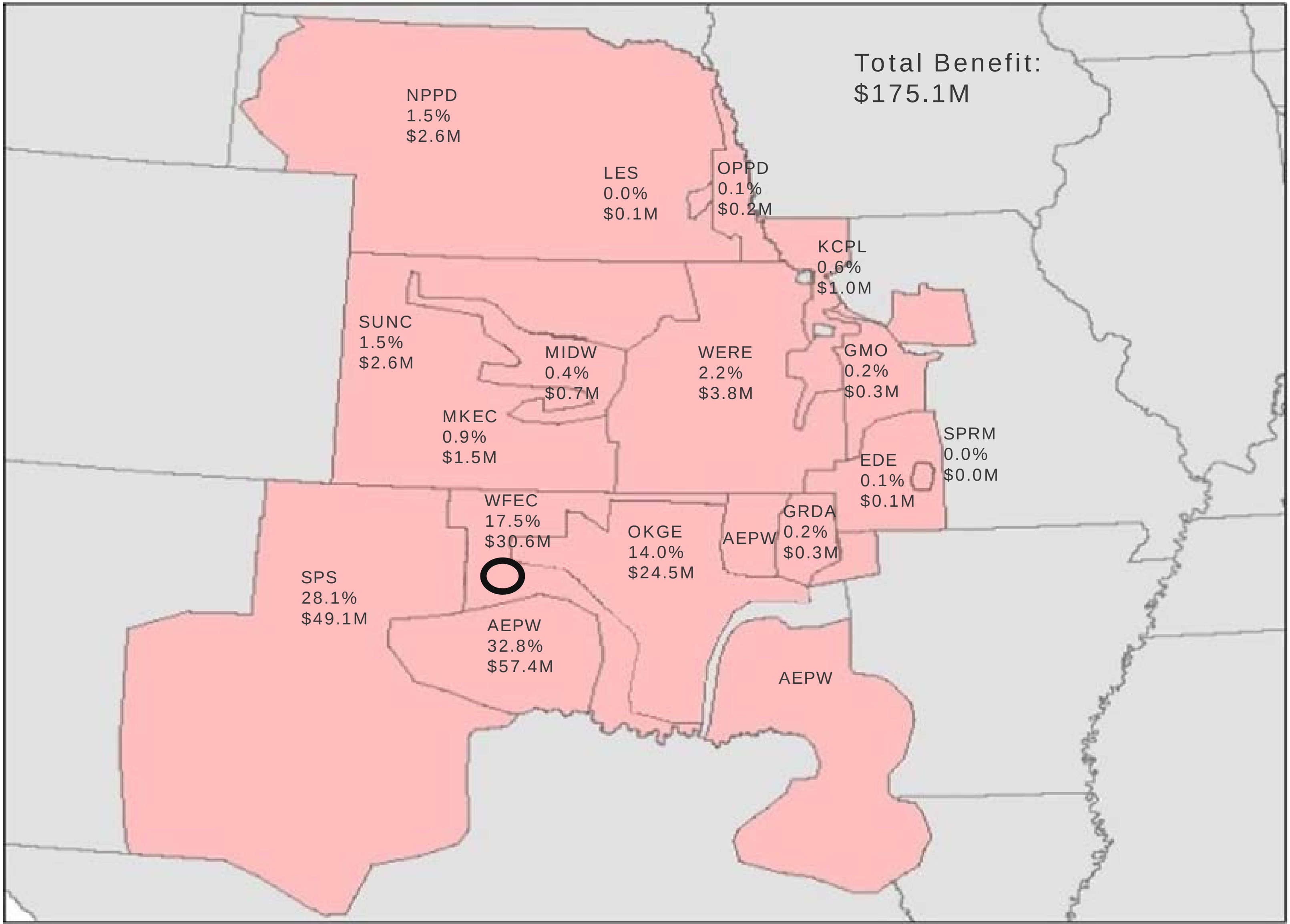
Examples

- Considered three existing reliability projects
  - Summit – Elm Creek 345 (central KS)
  - Elk City – Gracemont 345 (west OK)
  - Oronogo Jct – Riverton 161 (southwest MO)
- For each, compared the benefit allocation results using the different approaches
  - Highway/Byway – used in RCAR
  - DFAX
  - LODF
  - System Reconfiguration

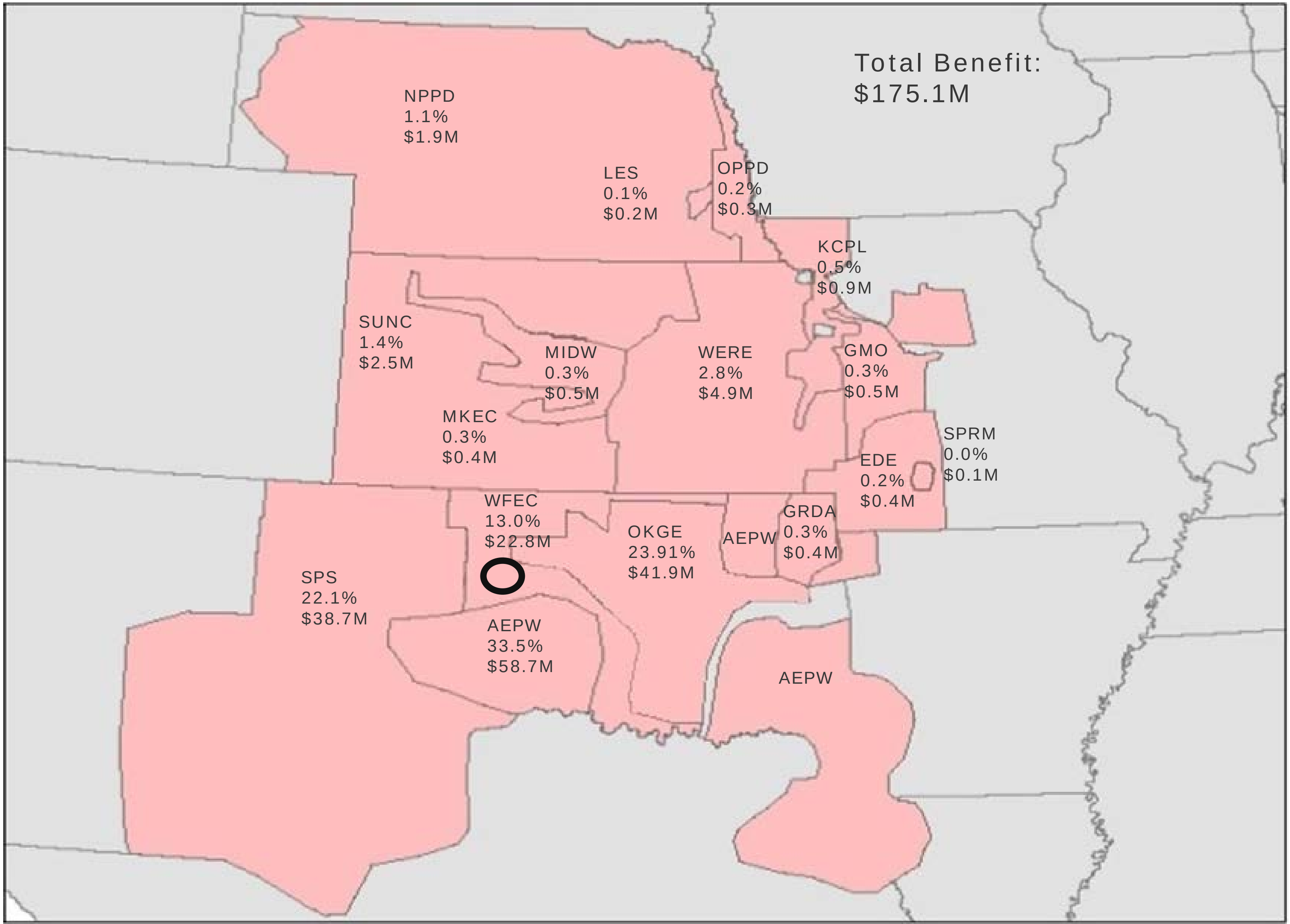
DFAX – Elk City to Gracemont 345 kV



LODF – Elk City to Gracemont 345 kV

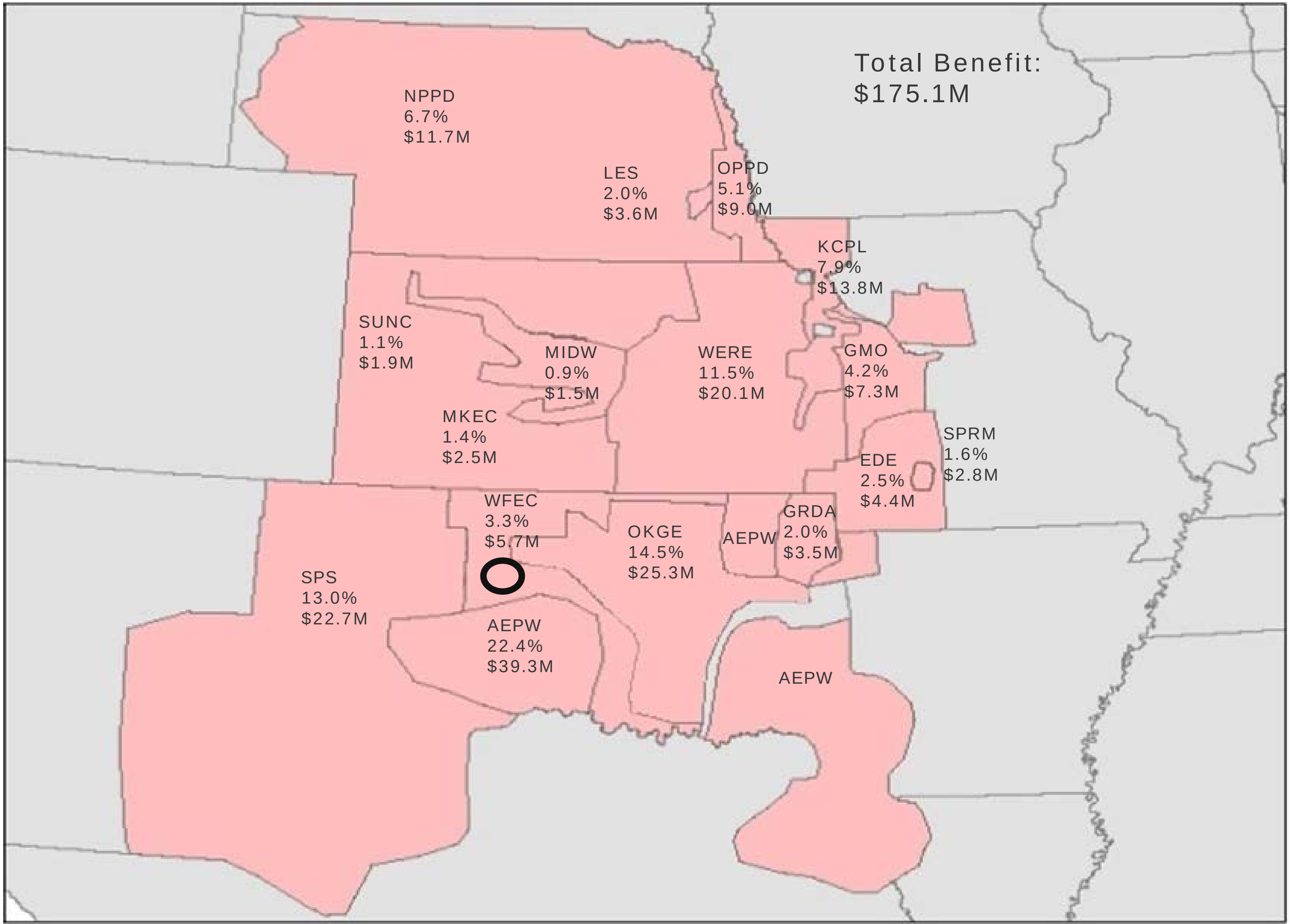


System Reconfiguration – Elk City to Gracemont 345 kV

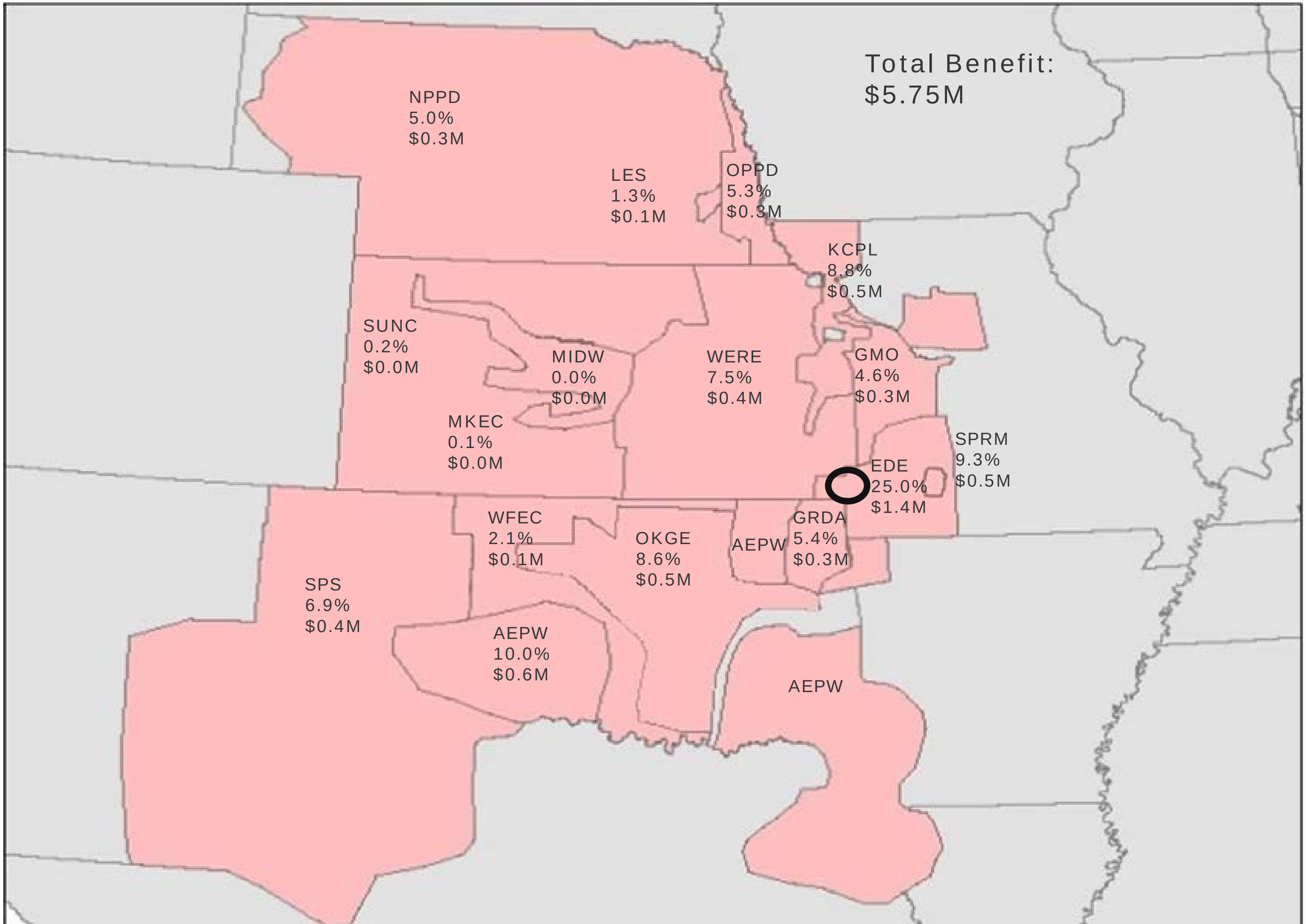


SPP

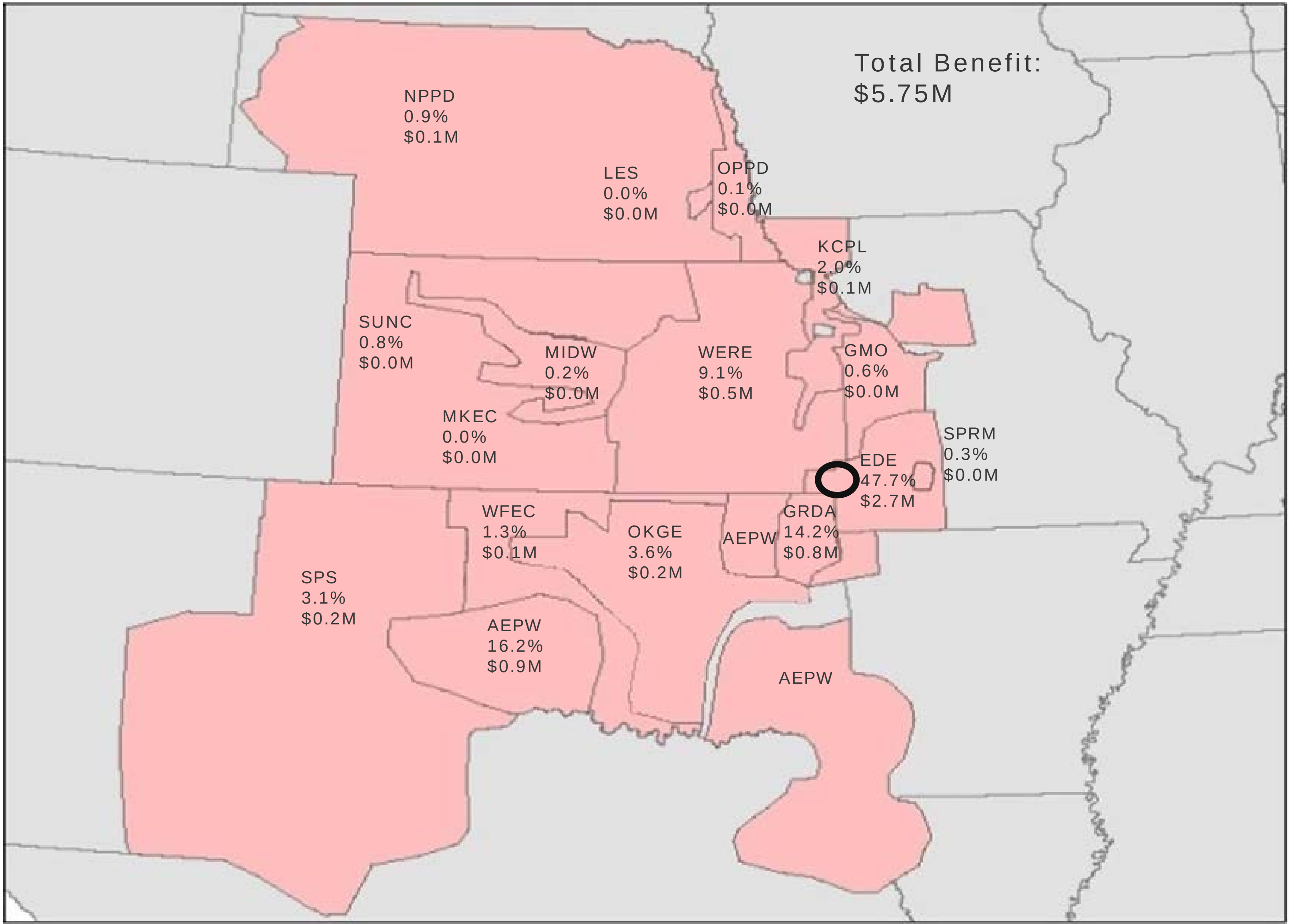
Highway/Byway – Elk City to Gracemont 345 kV



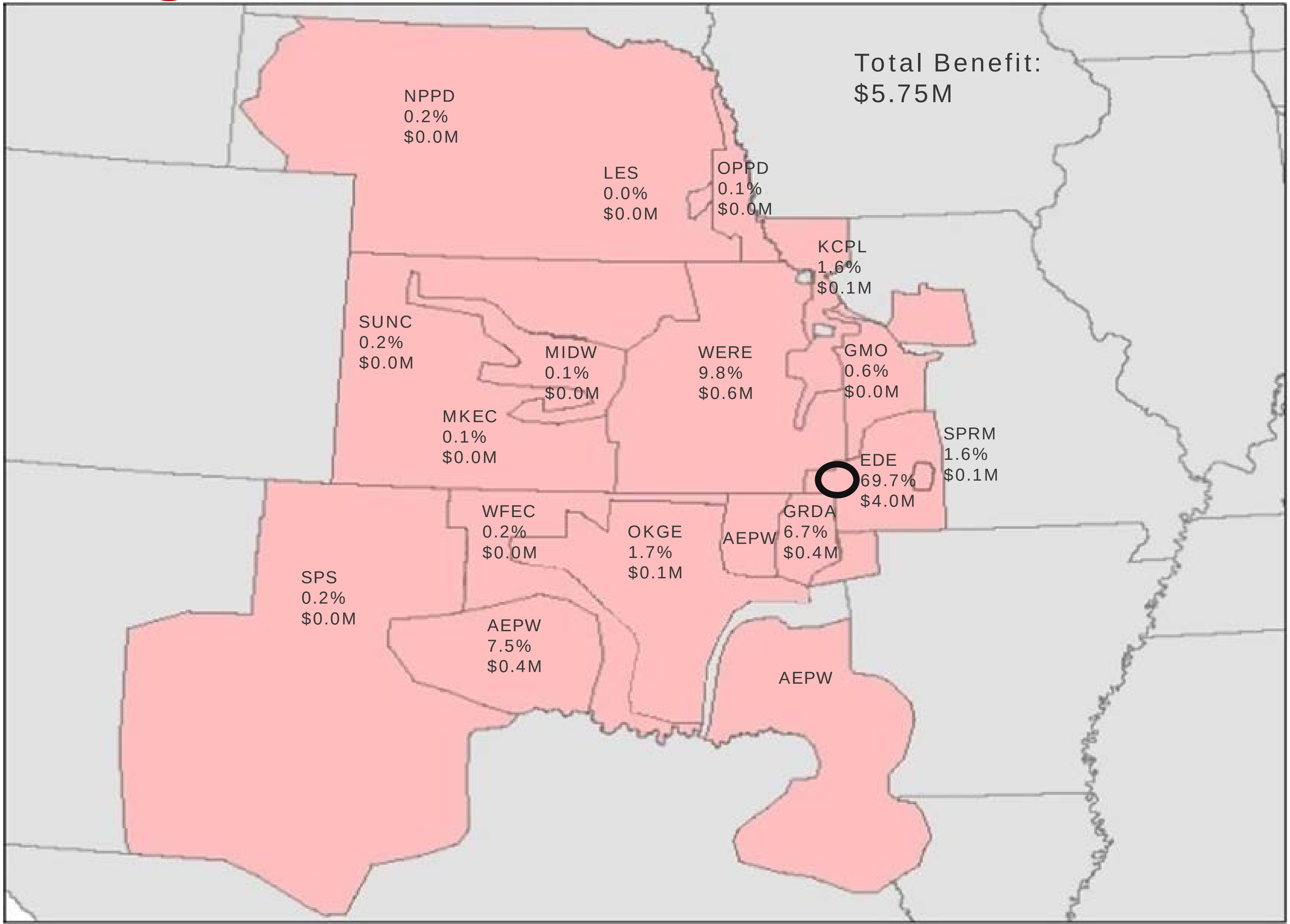
DFAX – Riverton to Oronogo 161 kV



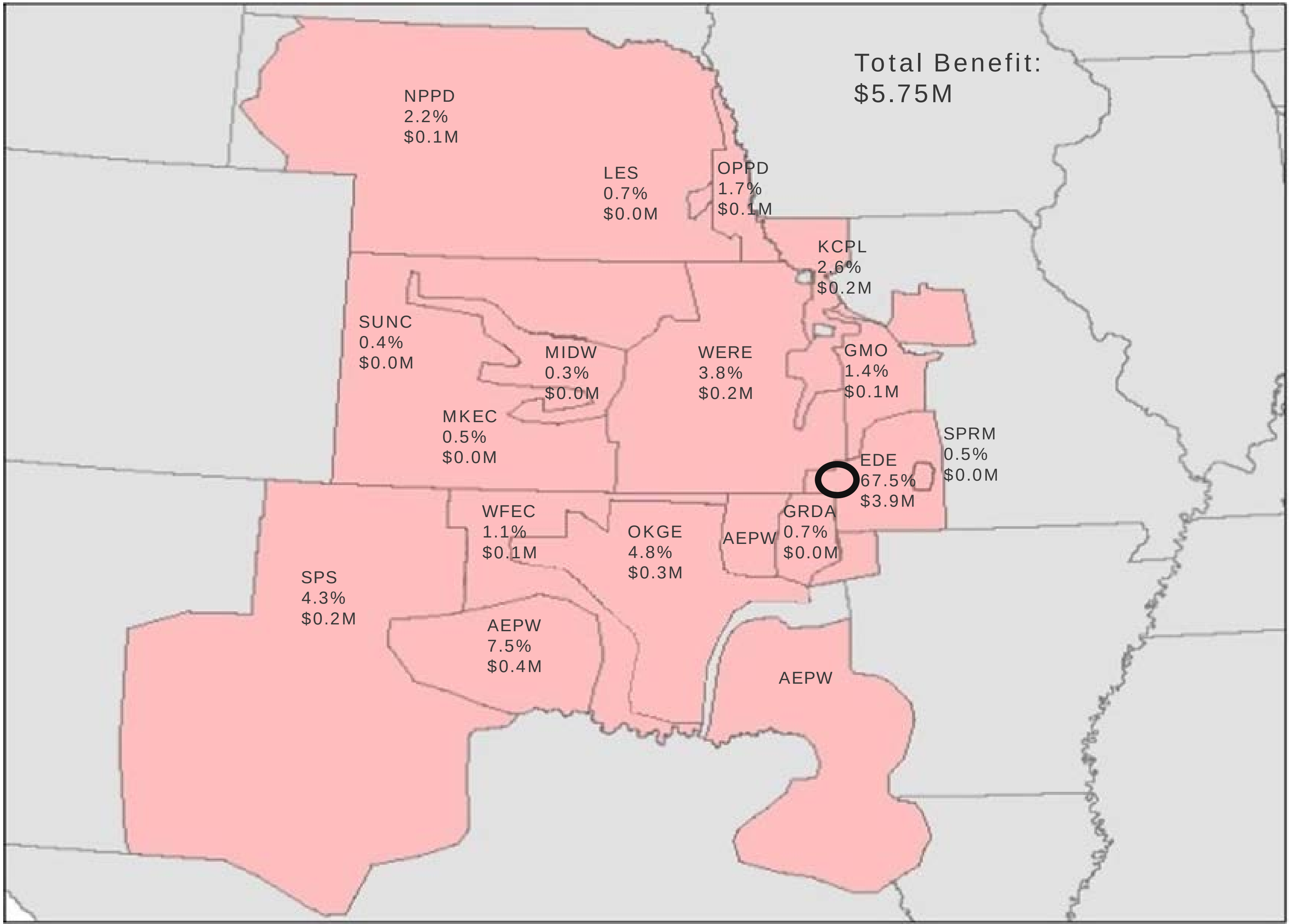
LODF – Riverton to Oronogo 161 kV



System Reconfiguration – Riverton to Oronogo 161 kV



Highway/Byway – Riverton to Oronogo 161 kV



Results Comparison – Elk City to Gracemont 345

Elk City - Gracemont 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$39,292,246	12.61%	$22,070,635	32.80%	$57,426,760	33.50%	$58,652,851
523	GRDA	2.01%	$3,523,360	1.56%	$2,732,454	0.18%	$308,351	0.25%	$441,514
524	OKGE	14.47%	$25,325,133	11.73%	$20,542,390	14.01%	$24,519,535	23.91%	$41,851,230
525	WFEC	3.27%	$5,723,806	0.82%	$1,442,962	17.49%	$30,623,101	13.00%	$22,763,222
526	SPS	12.98%	$22,725,093	58.67%	$102,707,267	28.07%	$49,143,574	22.11%	$38,711,584
531	MIDW	0.85%	$1,485,501	0.13%	$228,919	0.40%	$706,122	0.28%	$483,359
534	SUNC	1.08%	$1,893,089	1.00%	$1,757,112	1.48%	$2,587,438	1.44%	$2,513,189
536	WERE	11.48%	$20,100,127	3.73%	$6,527,446	2.19%	$3,836,896	2.81%	$4,919,923
540	GMO	4.18%	$7,318,366	1.21%	$2,123,400	0.19%	$329,406	0.27%	$471,908
541	KCPL	7.86%	$13,761,449	2.39%	$4,179,816	0.57%	$999,096	0.51%	$899,100
544	EMDE	2.53%	$4,430,995	1.38%	$2,422,150	0.08%	$146,083	0.20%	$357,008
546	SPRM	1.59%	$2,782,656	0.88%	$1,536,618	0.03%	$44,045	0.04%	$66,146
640	NPPD	6.69%	$11,706,991	1.29%	$2,249,917	1.49%	$2,613,735	1.10%	$1,925,600
645	OPPD	5.11%	$8,953,392	1.73%	$3,031,455	0.09%	$158,632	0.20%	$349,009
650	LES	2.03%	$3,555,862	0.40%	$706,349	0.04%	$78,612	0.12%	$208,336
539	MKEC	1.42%	$2,483,325	0.46%	$802,503	0.88%	$1,540,005	0.26%	$447,414
Total		100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392

Results Comparison – Summit to Elm Creek 345

Summit - Elm Creek 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$25,373,674	22.96%	$25,952,226	4.03%	$4,553,167	2.49%	$2,813,179
523	GRDA	2.01%	$2,275,273	2.93%	$3,316,056	0.52%	$586,534	0.46%	$523,117
524	OKGE	14.47%	$16,354,160	23.50%	$26,570,727	1.46%	$1,644,876	3.06%	$3,463,442
525	WFEC	3.27%	$3,696,250	6.75%	$7,627,840	0.44%	$496,188	0.46%	$522,626
526	SPS	12.98%	$14,675,137	32.20%	$36,401,169	3.82%	$4,317,980	0.29%	$324,247
531	MIDW	0.85%	$959,289	0.00%	$401	13.38%	$15,123,684	3.22%	$3,636,323
534	SUNC	1.08%	$1,222,496	0.00%	$479	14.63%	$16,536,242	18.64%	$21,067,896
536	WERE	11.48%	$12,980,018	9.44%	$10,677,305	33.07%	$37,386,161	52.24%	$59,057,673
540	GMO	4.18%	$4,725,966	0.00%	$2,998	0.76%	$854,705	0.75%	$848,003
541	KCPL	7.86%	$8,886,703	0.01%	$5,860	3.64%	$4,112,908	3.06%	$3,461,328
544	EMDE	2.53%	$2,861,394	1.57%	$1,773,728	0.17%	$192,165	0.29%	$323,853
546	SPRM	1.59%	$1,796,950	0.60%	$674,452	0.04%	$40,154	0.24%	$273,791
640	NPPD	6.69%	$7,560,000	0.01%	$12,617	6.38%	$7,211,929	4.41%	$4,981,700
645	OPPD	5.11%	$5,781,814	0.01%	$10,032	1.51%	$1,703,673	1.30%	$1,469,425
650	LES	2.03%	$2,296,261	0.00%	$3,177	0.27%	$299,720	0.66%	$746,945
539	MKEC	1.42%	$1,603,652	0.02%	$19,973	15.91%	$17,988,953	8.43%	$9,535,489
Total		100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038

Results Comparison – Riverton to Oronogo 161

Riverton - Oronogo Jct 161		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	7.48%	$430,193	9.97%	$573,526	16.23%	$933,380	7.48%	$430,259
523	GRDA	0.67%	$38,576	5.40%	$310,715	14.24%	$818,671	6.70%	$385,052
524	OKGE	4.82%	$277,273	8.55%	$491,670	3.58%	$205,656	1.65%	$95,045
525	WFEC	1.09%	$62,667	2.14%	$123,087	1.25%	$71,752	0.20%	$11,267
526	SPS	4.33%	$248,807	6.94%	$398,963	3.06%	$175,774	0.15%	$8,815
531	MIDW	0.28%	$16,264	0.03%	$1,926	0.21%	$11,918	0.06%	$3,168
534	SUNC	0.36%	$20,727	0.17%	$9,595	0.78%	$44,842	0.20%	$11,574
536	WERE	3.83%	$220,067	7.48%	$430,386	9.06%	$520,986	9.79%	$562,770
540	GMO	1.39%	$80,125	4.60%	$264,345	0.58%	$33,208	0.58%	$33,189
541	KCPL	2.62%	$150,668	8.75%	$502,903	1.97%	$113,406	1.60%	$92,086
544	EMDE	67.51%	$3,881,846	24.96%	$1,435,197	47.68%	$2,741,646	69.67%	$4,005,990
546	SPRM	0.53%	$30,466	9.29%	$534,013	0.33%	$18,923	1.56%	$89,502
640	NPPD	2.23%	$128,174	5.00%	$287,277	0.90%	$51,580	0.24%	$14,026
645	OPPD	1.70%	$98,027	5.28%	$303,698	0.10%	$5,563	0.05%	$3,066
650	LES	0.68%	$38,931	1.32%	$75,949	0.04%	$2,333	0.02%	$1,023
539	MKEC	0.47%	$27,189	0.12%	$6,753	0.01%	$362	0.06%	$3,168
Total		100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000

Comparison of Alternative Approaches

	DFAX	LODF	System Reconfiguration
Does it impact the total reliability benefit for a project?	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones
Does it measure how overloaded a line is or isn't?	No	No	No
Emphasizes use of the upgrade by…..	Zonal loads	Zonal branches	Zonal branches
Measures……	How much the upgrade is utilized in serving a zone's load	Additional flows that the upgrade will pick up when a zone's existing facilities are outaged	Additional flows that a zone's facilities will pick up when the upgrade is outaged
General allocation observation from examples	Allocation is slightly more levelized than the other two alternatives	Significant benefit going to a few zones closest to upgrade	Significant benefit going to a few zones closest to upgrade
Complexity in evaluating numerous projects	Moderate to difficult	Moderate	Moderate
Does it utilize PJM method of allocating based on how often flow on upgrade is positive or negative, and whether shift factor is positive or negative?	Yes	Yes	Yes
Other Notes	All SPP generators scaled. DFAX results were normalized based on peak load by zone	Similar to the System Reconfiguration approach, but a reverse variation of it.	Similar to the LODF approach, but a reverse variation of it. This is the MW-mile approach without accounting for mileage.

PUBLIC POLICY BENEFITS

Public Policy Benefits – Previous Approach

- Benefits allocated to zones in proportion to each zone's share of unmet renewable energy goals.
  - Public Policy Benefit per zone = (% share of unmet goals) x (cost of upgrade)
  - If a zone has no public policy mandate or goal, or already meets their mandate or goal, their public policy benefit is zero
- Production cost savings due to policy upgrades are additional to this benefit

Potential Alternative for Benefit Allocation

- Public Policy Benefit is allocated only to zones in the state in which the mandate/goal is driving the project
- New Gentleman – Cherry – Holt 345 kV line
  - Driven by Nebraska goal
  - Benefits allocated to Nebraska entities
  - Total 40-Year Cost = Public Policy Benefit = $296.4 M

	Unmet Renewable Goal* (MWh)	% Share of Unmet Renewable Goal	Public Policy Benefit (millions $)
NPPD	1,374,534	48%	$143
OPPD	1,470,070	52%	$153
LES	0	0%	$0
Total	**2,844,604**	**100%**	**$296**

*These numbers represent unmet goals from the RCAR; these are not up-to-date with ITP10 data

State Policy Benefit Allocation – Example

	Unmet Renewable Goal (MWh)	% Share of **SPP** Unmet Renewable Goal	Public Policy Benefit - RCAR ($M)	% Share of **Nebraska** Unmet Renewable Goal	Public Policy Benefit - State Policy Allocation ($M)
AEPW	1,787,126	10.1%	$30	0.0%	$0
CUS	0	0.0%	$0	0.0%	$0
EDE	887,873	5.0%	$15	0.0%	$0
GMO	1,737,706	9.8%	$29	0.0%	$0
GRDA	0	0.0%	$0	0.0%	$0
KCPL	2,906,537	16.4%	$49	0.0%	$0
LES	0	0.0%	$0	0.0%	$0
MIDW	0	0.0%	$0	0.0%	$0
MKEC	228,122	1.3%	$4	0.0%	$0
NPPD	1,374,534	7.8%	$23	48.3%	$143
OKGE	3,485,957	19.7%	$58	0.0%	$0
OPPD	1,470,070	8.3%	$25	51.7%	$153
SUNC	126,037	0.7%	$2	0.0%	$0
SWPS	0	0.0%	$0	0.0%	$0
WEFA	804,394	4.6%	$13	0.0%	$0
WRI	2,868,358	16.2%	$48	0.0%	$0
Total	17,676,714	100.0%	$296	100.0%	$296

*If a policy project enables members in multiple states to meet their mandates/goals, the benefit would be applied to all impacted members

MITIGATION OF TRANSMISSION OUTAGES

Mitigation of Outage Costs – Existing Approach

- Add set of historical transmission outages to production cost simulations
- Benefit = APC Benefit$_{\text{With Outages}}$ – APC Benefit$_{\text{Without Outages}}$
  - This metric is an adder to traditional APC Benefit
- Since it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone, this benefit is calculated on an SPP-wide basis and <u>allocated to zones based on a load ratio share.</u>

APC Savings Allocation Approach

- For APC Savings with no outages, calculate each zone's benefit as a percentage of the total SPP benefit
- Multiply each zone's APC benefit % by the Mitigation of Transmission Outage Costs total benefit to determine that zone's allocation of the Total Outage benefit

APC Savings Allocation Approach

	Mitigation of Transmission Outages Benefit - RCAR, based on LRS ($M)	APC Savings - 40-year NPV benefit* ($M)	Percent of Total APC Savings	Mitigation of Transmission Outages Benefit - allocated by APC Savings % ($M)
AEPW	$76	$240	7.9%	$27
CUS	$5	$7	0.2%	$1
EDE	$9	$7	0.2%	$1
GMO	$14	$23	0.8%	$3
GRDA	$7	$10	0.3%	$1
KCPL	$27	$24	0.8%	$3
LES	$7	$5	0.2%	$1
MIDW	$3	$60	2.0%	$7
MKEC	$5	$42	1.4%	$5
NPPD	$23	$226	7.5%	$25
OKGE	$49	$175	5.8%	$20
OPPD	$17	$34	1.1%	$4
SUNC	$4	-$10	-0.3%	-$1
SWPS	$44	$1,939	64.2%	$218
WEFA	$11	$24	0.8%	$3
WRI	$39	$215	7.1%	$24
Total	$340	$3,021	100.0%	$340

Historical Outage Data Approach

- Obtained operational data for outages from Sept 2011 to present
  - Number of outages by zone
  - Operations used different application before Sept 2011, making it more difficult to query and organize data prior to Sept 2011
  - Some tie lines are being double counted (~5% of outages)
- Number of outages by zone was divided by total outages for region to obtain allocation factor by zone
- Allocation factor multiplied by total outages benefit

Historical Outage Data Approach

Zone	# of outages	Allocation %	Benefit based on outage data ($M)	Benefit based on LRS, from RCAR ($M)	Increase in Benefit with new methodology ($M)
AEP	3,044	21.64%	$74	$76	($2)
EDE	545	3.88%	$13	$9	$4
GRDA	273	1.94%	$7	$7	($0)
KCPL	431	3.06%	$10	$27	($17)
LES	212	1.51%	$5	$7	($2)
MIDW	123	0.87%	$3	$3	($0)
GMO	393	2.79%	$10	$14	($4)
NPPD	1,492	10.61%	$36	$23	$13
OKGE	2,326	16.54%	$56	$49	$7
OPPD	434	3.09%	$10	$17	($7)
SUNC/MKEC	602	4.28%	$15	$9	$6
CUS	218	1.55%	$5	$5	$0
SPS	2,238	15.91%	$54	$44	$10
WFEC	399	2.84%	$10	$11	($1)
WR	1,334	9.49%	$32	$39	($7)
Total	14,064	100.00%	$340	$340	$0

INCREASED WHEELING THROUGH AND OUT REVENUES

Increased Wheeling Through and Out Revenues

- Increased ATC with neighbors can lead to increased through and out transactions, that can increase SPP wheeling revenues
  - Schedules 7, 8, 11
  - Metric does not capture the energy revenue from increased exports, only the wheeling revenue

Increased Wheeling – Calculation

- Increased Wheeling Benefit ($) = (Increased annual MWh exports) * (Average $/MWh Wheeling Charge)
  - Use PROMOD simulations to determine annual MWh exports in the base and change cases
  - Average $/MWh Wheeling Charge =

$$\frac{Total\ SPP{-}wide\ wheeling\ revenues\ for\ 2013}{Total\ MWh\ wheeling\ through\ and\ out\ transactions\ for\ 2013}$$

- MTF Recommendation: Allocate to zones based on Load Ratio Share

MARGINAL ENERGY LOSSES BENEFIT

Marginal Energy Losses Benefit

- Full MWh losses are not reflected in standard production cost simulations
- Energy loss savings can be calculated through post-processing of simulations
  - Based on Marginal Loss Revenues
- The calculation is performed for each zone

APPENDIX – METRICS REVIEW CALCULATIONS

DFAX Approach

For 10 MW transfer:

DFAX = (Post-transfer MW flow – Pre-transfer MW flow)/10 MW, in which:

- **Pre-transfer MW flow = MW flow over transmission upgrade before the 10 MW transfer**
- **Post-transfer MW flow = MW flow over transmission upgrade after the 10 MW transfer**

Wind units are excluded from the scaling

Units with GSF > 20% are excluded from the scaling

***In this pass, ALL other generators were scaled up equally.**

Transfers with positive DFAX are grouped together, and transfers with negative DFAX are grouped together

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Positive\ DFAX's}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) * \boldsymbol{LRS}, if\ DFAX_{Zone\ A}\ is (+)$$

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Negative\ DFAX's}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right) * \boldsymbol{LRS}, if\ DFAX_{Zone\ A}\ is\ (-)$$

(LRS = Load Ratio Share Percentage)

$$\boldsymbol{Reliability\ Project\ Benefit}\ (\$)_{\boldsymbol{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

LODF Approach

$$\sum Positive\ LODF_{Zone\ A} =$$

$$\sum_{Outages\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2} +$$

$$\sum_{Outages\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2}, \text{where}$$

$$\text{Post Contingent Flow} > \text{Pre Contingent Flow}$$

$$\sum Negative\ LODF_{Zone\ A} =$$

$$\sum_{Outages\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2} +$$

$$\sum_{Outages\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2}, \text{where}$$

$$\text{Pre Contingent Flow} > \text{Post Contingent Flow}$$

Post contingent flow (MW) = MW flow on reliability upgrade <u>after</u> contingency

Pre contingent flow (MW) = MW flow on reliability upgrade <u>prior to</u> contingency

LODF Approach

$$\boldsymbol{Allocation\ Factor_{Zone\ A}} = \left(\frac{\sum Positive\ LODF_{Zone\ A}}{\sum Positive\ LODF_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) + \left(\frac{\sum Negative\ LODF_{Zone\ A}}{\sum Negative\ LODF_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right)$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)_{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

System Reconfiguration Approach

$$\sum Positive\ Relieved\ MW's_{Zone\ A} =$$

$$\sum_{Branches\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2} + \sum_{Branches\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2}, \text{where}$$

$$\text{Post Contingent Flow} > \text{Pre Contingent Flow}$$

$$\sum Negative\ Relieved\ MW's_{Zone\ A} =$$

$$\sum_{Branches\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2} + \sum_{Branches\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2}, \text{where}$$

$$\text{Pre Contingent Flow} > \text{Post Contingent Flow}$$

Post contingent flow (MW) = MW flow on system branch <u>after</u> reliability upgrade is outaged

Pre contingent flow (MW) = MW flow on system branch <u>prior to</u> reliability upgrade being outaged

System Reconfiguration Approach

$$\boldsymbol{Allocation\ Factor_{Zone\ A}} =$$

$$\left(\frac{\sum Positive\ Relieved\ MW's_{Zone\ A}}{\sum Positive\ Relieved\ MW's_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) +$$

$$\left(\frac{\sum Negative\ Relieved\ MW's_{Zone\ A}}{\sum Negative\ Relieved\ MW's_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right)$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)_{Zone\ A}}$$
$$= Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

DPP Analysis

April 10th, 2014

SPP Southwest Power Pool

Helping our members
work together to
keep the lights on...
today and in the future

Background

- Required by FERC Order 1000
- Removes federal right of first refusal (ROFR) for the construction of transmission projects from regional tariffs
- SPP will bid out approved transmission projects to qualified participants using the Transmission Owner Selection Process (TOSP)

Pre-Project Selection

- SPP staff shall notify stakeholders of the identified transmission needs
- A transmission planning response window of thirty (30) days
- The information in the DPP must be sufficient to allow SPP staff to evaluate the project

SELECTION PROCESS

Phase 1 – Individual Project Testing

- Projects will move on to Phase 2 for further testing if they meet the following criteria
  - The project must meet the need for which it was submitted and
    - Projects to address economic needs must provide a 1-year B/C ratio greater than 0.9 by reducing the congestion. If the project is a seams project the B/C ratio requirement is .8
    - Policy Projects must allow the utilities to meet the regulatory/statutory mandates and goals. Competing projects will be tested for net APC benefit

Phase 2 – Project Grouping

- Project groupings with the greatest Net APC benefit will move on to the final portfolio per future
- Reliability, policy, and economic projects will be combined into project groupings for each future
- The grouping of projects will be evaluated for redundancies

Phase 3 – The Consolidated Portfolio

- The consolidation will be consistent with the Stakeholder approved consolidation methodology

Post Project Selection

- If the project described in a DPP is selected and approved for construction as a Competitive Upgrade, the submitting stakeholder may be eligible to receive incentive points in the bidding process

Timeline

APRIL
MAY
JUN
JUL
AUG
SEP
OCT
2014
Submittals
31
Economic Solutions
31
Policy Solutions
31
Project Grouping
21
Closing Date
Milestone Period