BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

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|---|---|
| IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S REQUEST FOR PERMANENT APPROVAL TO PARTICIPATE IN THE SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION, | Case No. 13-00031-UT |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | |
| APPLICANT. | |

SUPPLEMENTAL DIRECT TESTIMONY

*of*

WILLIAM A. GRANT

*on behalf of*

SOUTHWESTERN PUBLIC SERVICE COMPANY

August 30, 2013

## TABLE OF CONTENTS

## GLOSSARY OF ACRONYMS AND DEFINED TERMS

| Acronym/Defined Term | Meaning |
|---|---|
| ATP | Authorization to Plan |
| ATRR | Annual Transmission Revenue Requirement |
| B/C | Benefit-to-Cost Ratio |
| BOD | Board of Directors |
| CAT | Curtailment Adjustment Tool |
| ESWG | Economic Studies Working Group |
| FERC | Federal Energy Regulatory Commission |
| Interim Period | February 3, 2010 – February 2, 2015 |
| MOPC | Market and Operations Policy Committee |
| MTF | Metrics Task Force |
| NERC | North American Electric Reliability Corporation (successor to the North American Electric Reliability Council) |
| NMPRC | New Mexico Public Regulation Commission |
| NPV | Net Present Value |
| NTC | Notice to Construct |
| RCAR | Regional Cost Allocation Review |
| RSC | Regional State Committee |
| RTO | Regional Transmission Organization |
| SPP | Southwest Power Pool, Inc. |

| Acronym/Defined Term | Meaning |
|---|---|
| SPS | Southwestern Public Service Company, a New Mexico corporation |
| TLR | NERC Transmission Loading Relief |
| Xcel Energy | Xcel Energy Inc. |
| XES | Xcel Energy Services Inc. |

## LIST OF ATTACHMENTS

| **Attachment** | **Description** |
|---|---|
| WAG-S1 | Monthly production cost savings for the period of December 2012 through February 2013. |
| WAG-S2 | SPP Regional Cost Allocation Review |

## I. WITNESS IDENTIFICATION AND QUALIFICATIONS

**Q. Please state your name and business address.**

A. My name is William A. Grant. My business address is 600 South Tyler, Suite 2900, Amarillo, Texas 79101.

**Q. Are you the same William A. Grant who submitted direct testimony in this proceeding?**

A. Yes. I submitted Direct Testimony as part of Southwestern Public Service Company's[1] ("SPS") Interim Report on its participation in the Southwest Power Pool ("SPP"). The New Mexico Public Regulation Commission ("NMPRC") directed SPS to file the Interim Report in its February 2, 2012 Order in Case No. 07-00390 ("February 2nd Order").[2]

**Q. What is the purpose of your supplemental testimony?**

A. My Supplemental Direct Testimony addresses the items in paragraph R of the Hearing Examiner's Procedural Order issued August 22, 2013 ("Order") in this

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[1] *SPS, a New Mexico corporation and electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is the parent company of the following four wholly owned electric and gas utility operating companies: Northern States Power Company, a Minnesota corporation; Northern States Power Company, a Wisconsin corporation; Public Service Company of Colorado, a Colorado corporation ("PSCo"); and SPS (collectively, "Operating Companies"). Xcel Energy's natural gas pipeline subsidiary is WestGas Interstate, Inc.*

[2] *In the Matter of an Investigation into the Prudence of Southwestern Public Service Company's participation in the Southwest Power Pool Regional Transmission Organization*, Case No. 07-00390-UT, Final Order Approving Certification of Stipulation (February 2, 2010).

case. Specifically, the Order requested that, to the extent not included in SPS's Interim Report, SPS shall file supplemental information regarding:

(a) the SPS projected savings and benefits (on an annual basis) as required in the Certification of Stipulation in Case 07-00390-UT; and

(b) whether there have been any service reliability changes as a result of SPS's participation in the SPP Regional Transmission Organization ("RTO").

In my direct testimony filed February 4, 2013, both of these topics were addressed. However, I am providing the following additional information in this supplemental direct testimony:

(1) Production cost savings resulting from SPS's membership in the SPP Energy Imbalance Service ("EIS") Market, on an annual basis;

(2) Description of the SPP Regional Cost Allocation Review Benefit Metrics and a Summary of Benefit/Cost Ratios as detailed in the Brattle Group's July 29, 2013 report prepared for the SPP's Regional Allocation Review Task Force ("Brattle Group Report"); and

(3) Reliability benefits to the SPS transmission system from participation in the SPP RTO.

**Q. Is any other witness from SPS providing supplemental direct testimony?**

A. No.

## II. SPS PROJECTED SAVINGS AND BENEFITS

**Q. Did you provide an assessment of the annual benefits of SPS's participation in the SPP RTO in your direct testimony?**

A. Yes. I presented the following information in terms of savings in my direct testimony:

| Description | Savings | Source |
|---|---|---|
| Production cost savings Resulting from SPS membership in the EIS Market | $43.7 million from December of 2012 to February of 2015 | Grant Direct Testimony, pp. 56-57 |
| Cost savings resulting from the contingency reserve sharing agreement | Annual savings of $80.9 million due to lower fuel and start up costs associated with maintaining sufficient contingency reserves | Grant Direct Testimony, pp. 59-60 |
| Cost savings resulting from reduced capacity from SPS's participation in the SPP reserve-sharing group | Annual savings of $32.96 million as a result of procuring a reduced amount of contingency reserves | Grant Direct Testimony, pp. 60-61 |
| Labor cost savings | $100,000 annually saved from SPP performing transmission planning; $250,000 annually saved from SPP processing wholesale generation interconnection requests; and $295,000 annually from SPP providing tariff administration and scheduling services | Grant Direct Testimony, pp. 61-65 |

**Q. Were the production cost savings provided on an annual basis in your direct testimony?**

A. No. The production cost savings resulting from SPS's membership in the current EIS Market were presented as a total projected savings amount for the period of December 2012 through February 2015 in my direct testimony. The assessment for this time frame is consistent with Section 4 of the Stipulation, which required the Interim Report to, "contain a comparison of estimated production costs for participation in the SPP EIS market to an estimate of SPS energy costs absent SPS's participation in the EIS market during the period between the date of the Interim Report and the end of the Interim Period."

**Q. What are SPS's projected production costs savings on an annual basis through the end of the Interim Period?**

A. As noted above, the estimated production cost savings is $43.7 million from December of 2012 to February of 2015. On an annual basis, the estimate of production cost savings is:

| **Month** | **Estimate of Production Cost Savings (SPS total company)** |
|---|---|
| Calendar Year 2013 | $17.3 million |
| Calendar Year 2014 | $22.1 million |

Please see Attachment WAG-S1, for the monthly estimated production cost savings for the period of December 2012 through February 2015.

**Q. In addition to the benefits presented in your direct testimony, have there been any assessments of benefits resulting from SPS's membership in the SPP that SPS has received since the filing your direct testimony?**

A. Yes. In January 2012, the SPP's Market and Operations Policy Committee ("MOPC"), Regional State Committee ("RSC") and Board of Directors ("BOD") endorsed a report that recommended transmission benefits be evaluated by the Economic Studies Working Group ("ESWG") for the purpose of the regional cost allocation review ("RCAR"). In February 2012, the ESWG initiated a Metrics Task Force ("MTF") with the purpose of developing tangible, monetized transmission benefit metrics for economic evaluations. In September 2012, the MTF completed its report, which contained a list of recommended transmission benefit metrics. These metrics were approved by the MOPC, RSC and BOD in October of 2012. The Brattle Group was selected to perform the RCAR, using the metrics established by the MTF, as well as SPP Integrated Transmission Planning metrics. The RCAR results were released on July 29, 2013.

**Q. Please describe the methodology used in the RCAR.**

A. Two studies were undertaken as a part of the RCAR to show the benefits and costs by each pricing zone within SPP of: (1) transmission projects that have received notices to construct ("NTC") since June 2010; and (2) projects that have received a NTC since June 2010 and projects with an Authorization to Plan ("ATP") and have an in-service year of 2023 or earlier. The studies use a 40-year assessment to evaluate transmission project costs and benefits. The RCAR treated projects with NTCs with greater weight than those with ATPs. The benefits of the projects considered under the RCAR consist of:

1. Adjusted Production Cost ("APC")
    i. Emission Rates and Values.
    ii. Ancillary Service Needs and Production Costs.
2. Avoided or Delayed Reliability Projects.
3. Capacity Cost Savings due to Reduced On-Peak Transmission Losses.
4. Mitigation of Transmission Outage Costs.
5. Benefits of Public Policy Goals.

The most up to date annual transmission revenue requirement ("ATRR") for each zone was used to calculate the costs of transmission projects. The RCAR then developed benefit-to-cost ratios ("B/C") ratios for each SPP pricing zone based upon the transmission project costs and benefits.

**Q. What were the results of the metrics for the RCAR?**

A. The RCAR cost and benefit metric results are:

1. On an SPP-wide basis, the 40-year net present value ("NPV") of the ATRRs are estimated to be $4.8 billion for the NTC projects, $338 million for suspended NTCs and $210 for ATP projects.
   - For the SPS pricing zone, the 40-year present value of the ATTRs was a little under $1 billion.
2. On an SPP-wide basis, the 40-year NPV APC savings is $2.5 billion for NTCs, $560 million for suspended NTCs, and $225 million for ATPs.
   - For the SPS pricing zone, the estimated 40-year present value of APC savings was $1.354 billion for NTC projects, $780 million for suspended NTCs and $184 million for ATP projects.
3. On an SPP-wide basis, the benefits of avoided or delayed reliability projects for NTC projects was $97 million in 2013 dollars.
   - For the SPS pricing zone, the estimated benefits relating to the NTC projects was between $5 and $10 million, and with the addition of 75% of the ATP projects, $15 million.

4. On an SPP-wide basis, the 40-year NPV Capacity savings due to Reduced On-Peak Transmission Losses was $153 million for NTC projects, $1.4 million for suspended NTC projects, and $15.3 million for ATP projects.
    - For the SPS pricing zone, the 40-year estimated benefits are $70.8 million for NTC projects, $1.1 million for suspended NTCs, and $900,000 for ATP projects.
5. On an SPP-wide basis, the 40-year NPV of benefits related to mitigation of transmission outage costs is $277 million for NTC projects, $84 million for suspended NTCs and $25 million for ATP projects.
    - Each SPP pricing zone receives these benefits based on its load ratio share.
6. On an SPP-wide basis, the benefits in 2013 dollars related to mandated reliability projects is $2.4 billion for NTC projects, $122 million for suspended NTC projects, and $210 million for ATP projects
    - For the SPS pricing zone, nearly $600 million in 2013 dollars is estimated to result from NTC, suspended NTC and ATP projects.
7. On an SPP-wide basis, the 40-year NPV of benefits related to facilitation of public policy goals is estimated to be $296 million for the SPP region.

- Because SPS's existing wind generation meets its renewable energy mandates, the SPP pricing zone is not viewed as being allocated these benefits, as this value reflects benefits to those zones who have not yet met the renewable mandate requirements.

**Q. What was the B/C ratio for the SPS pricing zone under the RCAR?**

A. The B/C ratio for the SPS pricing zone has a range of 3.20 to 3.76 under various sensitivities, meaning that at a minimum for every dollar spent on projects, the RCAR estimates that SPS is receiving $3.20 of benefits. The RCAR is provided as Attachment WAG-S2. Please see pages 22 through 25 for the B/C ratios under the sensitivity scenarios.

**Q. What is the status of the RCAR?**

A. The RCAR report is currently in draft form. The stakeholders are reviewing the report and submitting comments to the SPP. The SPP expects the RCAR report to be finalized in October 2013. While the report is in draft form and SPS is working through the stakeholder process, the report shows that the SPS pricing zone will receive more benefits than costs incurred for the SPP transmission expansion by improving the access to the market footprint.

**Q. Is SPS participating in the review of the draft RCAR report and has SPS recommended any changes to SPP for consideration?**

A. Yes, SPS has met with the SPP and continues to review the draft RCAR report. While SPS has provided items to be considered to be modified in the modeling and report, I do not believe that even if all of the modifications were adopted that the report would reflect that SPS is no longer a beneficiary of the transmission build out in the SPP.

**Q. Based on the RCAR and other benefits you discussed earlier and in your direct testimony, do you continue to conclude that SPS's participation in the SPP is beneficial to the New Mexico customers?**

A. Yes. When compared to the cost presented in Attachment RMS-1 to SPS witness Ruth M. Sakya's testimony, the benefits I have identified more than offset the costs of participating in SPP especially since some of the fees assessed in the attachment would be assessed without SPS's participation in SPP.

Q. **Which fees would be assessed without participation in SPP?**

A. One example relates to charges paid for the SPP Regional Entity ("RE"). All loads are required to be under the authority of a RE for the purpose of measuring compliance to the North American Electric Reliability Corporation ("NERC") standards. There are eight REs, including the SPP RE. If SPS were not a member of the SPP RE, the Federal Energy Regulatory Commission ("FERC") would require SPS to become a member of another RE. Thus, the costs SPS incurs related to the SPP RE would be incurred regardless of whether they were for SPP RE purposes or another RE.

Another example involves costs incurred for base plan transmission upgrades. Most of the base plan transmission projects in the SPS region were needed to relieve a reliability issue identified through SPP's planning process. If SPS were not a member of the SPP, then it is highly likely SPS's own transmission planning would have identified the need for similar base plan upgrade transmission projects.

## III. SERVICE RELIABILITY CHANGES AS A RESULT OF SPS'S MEMBERSHIP IN THE SPP

**Q. In addition to cost-saving benefits described here and in your direct testimony, has SPS experienced service reliability changes as a result of its participation in the SPP?**

A. Yes. These service reliability changes have been positive and have benefitted SPS's customers. For example, as discussed on pages 23 and 24 of my direct testimony, as the reliability coordinator the SPP is responsible for the bulk transmission reliability and power supply reliability within its Reliability Coordination Area. Bulk transmission reliability functions include assessment of real-time, current day and next-day operating conditions, loading relief procedures, re-dispatch of generation, coordination of transmission and generation outages, and ordering curtailment of transactions and load. Thus, the SPP monitors power flow throughout its regional footprint. The SPP anticipates problems and takes preemptive action to mitigate operating limit violations. The SPP also coordinates regional response in emergency situations or blackouts.

In addition, the SPP also undertakes congestion management to relieve transmission congestion on the bulk electric power system. As discussed on page 24 of my direct testimony, SPP manages congestion through Transmission Load Relief ("TLR") or redispatch of generation. Prior to the SPP Energy Imbalance

Service Market, use of TLRs was the primary way that relief was provided. Now, the SPP uses it's Curtailment Adjustment Tool ("CAT") to redispatch generation (and utilizes TLR when necessary) when it is participating in the EIS Market to provide congestion relief. This allows flows that in the past would have been curtailed.

Finally, as discussed on page 25 of my direct testimony, the SPP is required to coordinate line outages as a part of its reliability coordination function. For planned outages, the SPP performs reliability studies with the expected generation pattern and the forecasted load. SPP criteria requires for one week notice for 230 kV line outages and before noon day ahead for 115 kV outages. These timing requirements are there so that the Reliability Coordinator can study the bulk electric system and identify operational issues before approval is given for line outages. The SPP models all of the TOs' systems and is able to tell if an outage in another system is causing issues on the SPS transmission system and if an outage on SPS will cause issues on a neighboring system as well. The ability to see all of the SPP footprint and more improves the reliability of the SPS system since outages on neighboring systems will impact flows on the SPS system and if unexpected, could cause overloads.

## X. CONCLUSION

**Q. Are Attachments WAG-S1 and WAG-S2 true copies of the documents you have represented them to be?**

A. Yes.

**Q. Does this conclude your pre-filed supplemental direct testimony?**

A. Yes.

# VERIFICATION

STATE OF TEXAS )<br>
) ss.<br>
COUNTY OF POTTER )

**William A. Grant**, first being sworn on his oath, states:

I am the witness identified in the preceding testimony. I have read the testimony and the accompanying attachments and am familiar with their contents. Based upon my personal knowledge, the facts stated in the supplemental direct testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

William A. Grant

**WILLIAM A. GRANT**

SUBSCRIBED AND SWORN TO before me this 23 day of August, 2013.

Notary Public of the State of Texas<br>
My Commission Expires: 7-22-2017

NOTARY PUBLIC STATE OF TEXAS<br>
Emily Bustos<br>
Commission Expires<br>
07-22-2017

**Southwestern Public Service Company**

**Forecasted Savings for remainder of Stipulation**

| Date | | Value ($000) |
|---|---|---|
| Dec-12 | $ | 1,294.04 |
| **Yr Total** | **$** | **1,294.04** |
| Jan-13 | $ | 1,012.81 |
| Feb-13 | $ | 690.62 |
| Mar-13 | $ | 1,410.05 |
| Apr-13 | $ | 2,143.77 |
| May-13 | $ | 998.37 |
| Jun-13 | $ | 1,513.15 |
| Jul-13 | $ | 2,073.73 |
| Aug-13 | $ | 1,197.99 |
| Sep-13 | $ | 1,246.62 |
| Oct-13 | $ | 2,308.24 |
| Nov-13 | $ | 1,476.50 |
| Dec-13 | $ | 1,242.43 |
| **Yr Total** | **$** | **17,314.28** |
| Jan-14 | $ | 2,596.09 |
| Feb-14 | $ | 1,346.60 |
| Mar-14 | $ | 1,636.35 |
| Apr-14 | $ | 2,346.97 |
| May-14 | $ | 1,253.56 |
| Jun-14 | $ | 1,344.31 |
| Jul-14 | $ | 2,341.47 |
| Aug-14 | $ | 1,498.80 |
| Sep-14 | $ | 1,228.71 |
| Oct-14 | $ | 1,986.19 |
| Nov-14 | $ | 2,229.84 |
| Dec-14 | $ | 2,326.79 |
| **Yr Total** | **$** | **22,135.68** |
| Jan-15 | $ | 1,361.96 |
| Feb-15 | $ | 1,623.70 |
| **Yr Total** | **$** | **2,985.66** |
| **Total** | **$** | **84,473.66** |

The Brattle Group

DRAFT

# SPP Regional Cost Allocation Review Benefit Metrics and Summary of B/C Ratios

Prepared for:
**Regional Allocation Review Task Force Meeting**

Presented by:
**Johannes Pfeifenberger**
**Onur Aydin**
**Kent Diep**

**July 29, 2013**



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# Content

# 1. Introduction

- RCAR Methodology
- Transmission Projects Evaluated
- Project Costs and ATRR Estimates
- Benefit Metrics Considered in this RCAR Report

# 2. Benefits Analysis

# 3. Summary of Results and B/C Ratios

# 4. Appendix

# RCAR Methodology

**RCAR analyses uses a methodology consistent with RARTF and MTF recommendations**

- Apply a reduced weighting of 75% to value costs and benefits of the projects without NTCs
- Use a baseline that includes all projects that are in-service or received an NTC prior to June 2010
- Use aggregate value of dollars for project costs and benefits when calculating Benefit-to-Cost (B/C) ratios for each SPP pricing zone
- Use a 40-year assessment to evaluate transmission project costs and benefits
- Use the most up-to-date ATTR estimates for each zone to calculate costs of transmission projects (and also certain benefit metrics tied to these cost estimates)
- Calculate standard ITP metrics (with some modifications) and a <u>subset</u> (to reduce cost of effort) of MTF-recommended new metrics (see next slide).
  - Feasibility of additional benefit metrics identified by MTF for future consideration (e.g., reduced cycling of base load plants; mitigation of weather uncertainty) not evaluated at this point

# Transmission Projects Evaluated

**This RCAR effort evaluates three sets of transmission projects**

- NTC: All SPP projects that have been issued a Notice to Construct (NTC) since June 2010 and have not been suspended;
- Suspended NTC: All NTC projects that are suspended pending further review; and
- ATP: All projects that have received an Authorization to Plan (ATP) and have an in-service year of 2023 or earlier (ten years or less from issuance of RCAR report)

**RCAR follows the direction of the RARTF on the following issues that were not initially anticipated:**

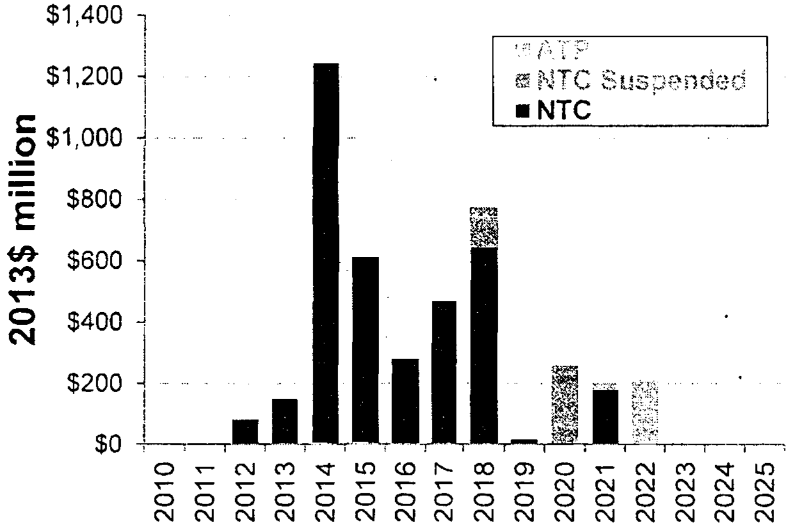
- New NTC projects approved in 2013 are included in the RCAR analysis (SPP staff has updated the models accordingly)
- The existing NTC projects suspended by SPP Board of Directors for further study are also included in the RCAR analysis (but at a reduced weighting of 75%)

# Project Costs and ATRR Estimates

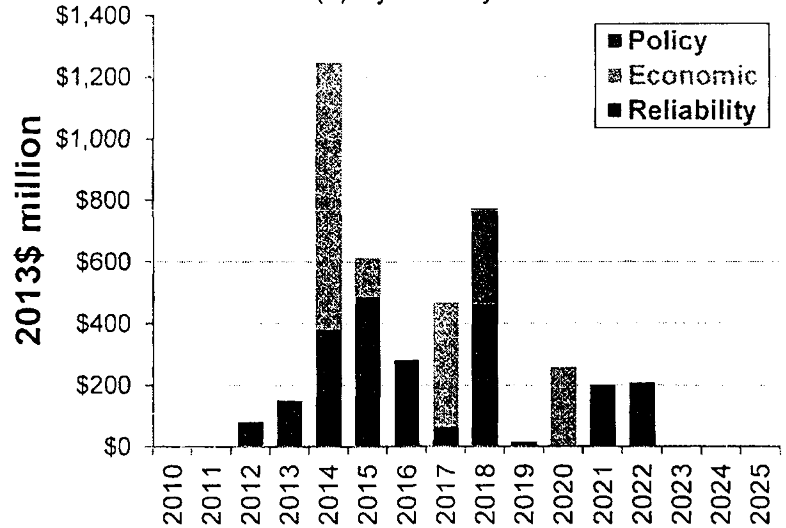
- To conduct the RCAR analysis, the projects were classified by:
  - Project type (NTCs, suspended NTCs, and ATPs within 10 years); and
  - Primary driver (Reliability, Economic, and Public Policy)

**Summary of Capital Cost by In-Service Year**

(a) By Project Type




(b) By Primary Driver



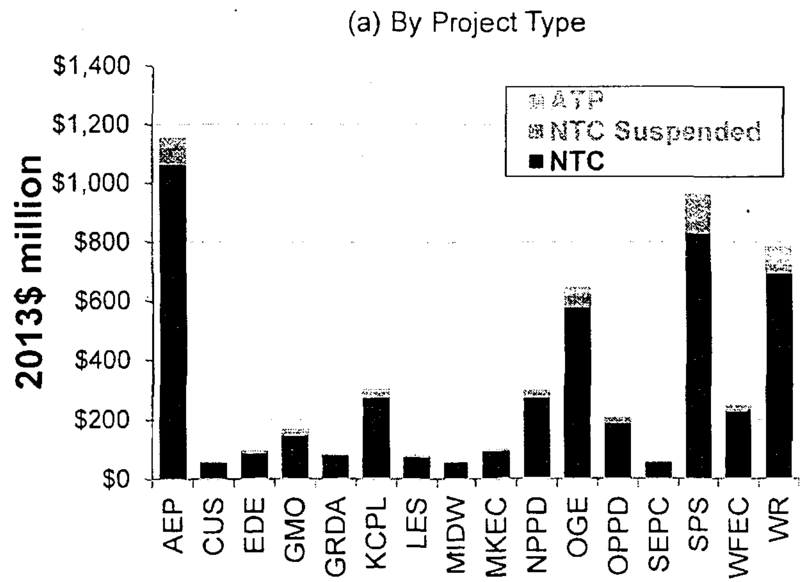
# Project Costs and ATRR Estimates (cont'd)

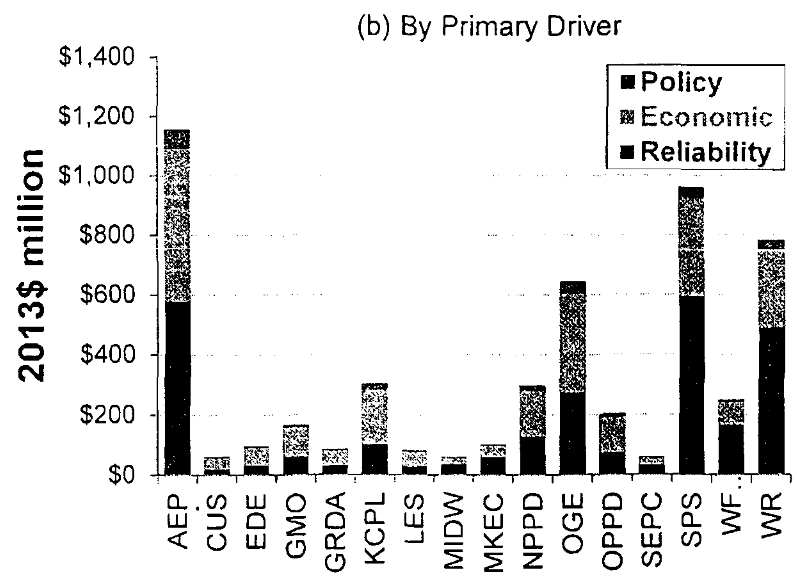
- Per SPP's tariff, SPP calculated the ATRRs for each zone at the project level, as summarized below:
  - Cost allocated to zones based on SPP's **Highway/Byway methodology**:
    - 100% regional if 300 kV or above,
    - 33% regional, 67% zonal if between 100 kV and 299 kV, and
    - 100% zonal if below 100 kV.
  - **Load ratio share (LRS)** used for the portion of costs allocated on a regional basis
    - Used actual 12-coincident peak loads for 2012, as provided by SPP
  - **Net plant carrying charge (NPCC)** applied at the zonal level to calculate first year ATRRs in 2013 dollars
  - **2.5%/yr inflation** applied to estimate first year ATRRs in nominal dollars
  - **2.5%/yr straight-line depreciation** applied in calculating declining ATRR profile over time in nominal dollars
  - Present values calculated for 40-year depreciated ATRRs for 2013-2052 at a **nominal discount rate of 8.0%**

# Project Costs and ATRR Estimates (cont'd)

- At the regional level, the 40-year present value of ATRRs are estimated to be **$4.8 billion** for the NTC projects, **$338 million** for the suspended NTCs and **$210 million** for the ATP projects (in 2013 dollars, before PtP revenue offset)

**40-Year Present Value of ATRRs by Zone**



# Benefit Metrics Considered in this RCAR Report

| Metric Name | ITP Metric | MTF Recommended New metrics | Considered in this effort? |
|---|---|---|---|
| Adjusted Production Cost (APC) Savings | ✓ | | Yes |
| Reduction of Emission Rates and Values | ✓ | | Yes |
| Savings due to Lower Ancillary Service Needs and Production Costs | ✓ | | Yes |
| Avoided or Delayed Reliability Projects | ✓ | | Yes |
| Capacity Cost Savings due to Reduced On-Peak Transmission Losses | ✓ | | Yes |
| Mitigation of Transmission Outage Costs | | ✓ | Yes |
| Assumed Benefit of Mandated Reliability Projects | | ✓ | Yes |
| Benefits from Meeting Public Policy Goals | | ✓ | Yes |
| Increased Wheeling Through and Out Revenues | | ✓ | No |
| Capital Savings due to Reduction of Members' Minimum Required Margin | | ✓ | No |
| Reducing the Cost of Extreme Events | | ✓ | No |
| Reduced Loss of Load Probability | | ✓ | No |
| Marginal Energy Losses Benefits | | ✓ | No |

1. Introduction

## 2. Benefits Analysis

A. Adjusted Production Cost Savings (incl. Savings for Reduced Emissions & Lower Ancillary Service Costs)
B. Avoided or Delayed Reliability Projects
C. Capacity Savings from Reduced On-Peak Transmission Losses
D. Mitigation of Transmission Outage Costs
E. Benefits of Mandated Reliability Projects
F. Benefits from Facilitating Public Policy Goals

3. Summary of Results and B/C Ratios

4. Appendix

# Summary of the Approaches Used

| Benefit Metric Name | Summary of the Approaches |
|---|---|
| **Adjusted Production Cost (APC) Savings** | Based on PROMOD simulations for three study years (2018, 2023, and 2033) and five cases (Base, CC1, CC1A, CC2, and CC2A) |
| Reduction of Emission Rates and Values | Based on PROMOD simulations used to calculate APC savings; the value of any $SO_2$ and $NO_X$ emission reductions **already captured** under "APC savings" metric |
| Savings due to Lower Ancillary Service Needs and Production Costs | Quantities of spinning reserves and regulation (1% of average monthly peak load) set aside in PROMOD simulations; the benefits **already captured** under "APC savings" metric |
| **Avoided or Delayed Reliability Projects** | Economic and public policy projects removed from the powerflow models; Resulting thermal overloads are addressed by non-NTC projects, *representing avoided reliability projects* |
| **Capacity Cost Savings due to Reduced On-Peak Losses** | Powerflow models used to calculate reductions in on-peak losses by SPP zone for study years 2018 and 2023; the annual savings estimated based on assumed net CONE |
| **Mitigation of Transmission Outage Costs** | Simulated 2023 with a subset historical transmission outage events for the 2011-2012 period (selected based on voltage, duration, and the likely impact on system congestion) and compared to standard APC savings to determine incremental benefits |
| **Assumed Benefit of Mandated Reliability Projects** | Set to the 40-year present value of ATRRs for all of the reliability projects, and allocated to zones in the same way as the projects' costs are allocated |
| **Benefits from Meeting Public Policy Goals** | Set to the 40-year present value of ATRRs for all of the public policy projects, and allocated to zones based on their unmet demand for renewable energy relative to June 2010 renewable supplies |

# A. Adjusted Production Cost Savings

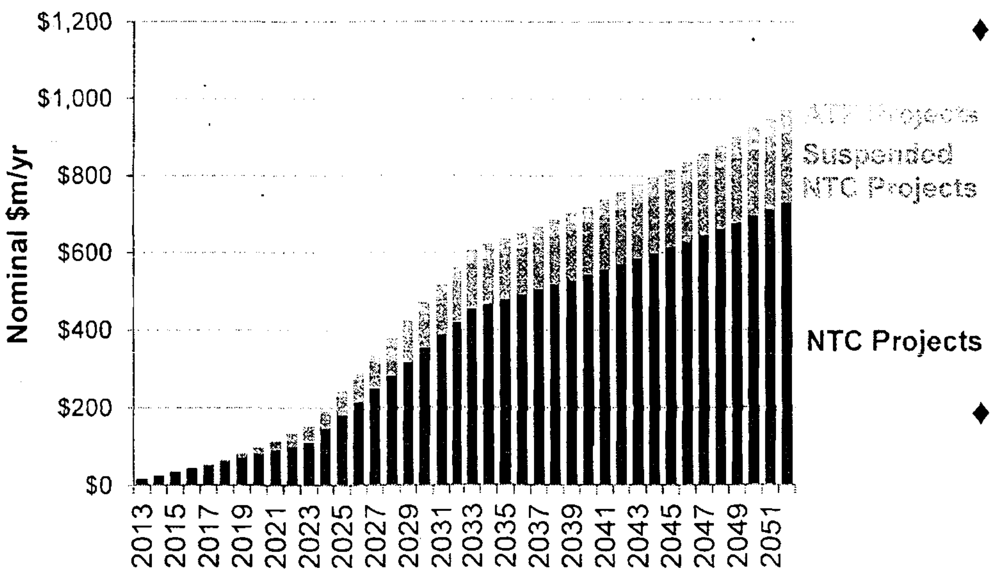
- PROMOD simulations of the SPP system plus most of the Eastern Interconnect were undertaken for 2018, 2023 and 2033
- Simulated 5 cases with different transmission topology for each of the three years (but holding all other inputs and assumptions constant)
  - APC savings of the projects are estimated based on the differences between these cases

| | | NTC | Susp. NTC | ATP |
|---|---|---|---|---|
| **Base Case** | | No | No | No |
| **Change Case 1** | $CC_1$ | **Yes** | No | No |
| **Change Case 1A** | $CC_{1A}$ | **Yes** | **Yes** | No |
| **Change Case 2** | $CC_2$ | **Yes** | **Yes** | **Yes** |
| **Change Case 2A** | $CC_{2A}$ | **Yes** | No | **Yes** |

- SPP provided powerflow and PROMOD system database for the analysis to be used as a starting point
  - Additional changes implemented to create more realistic cases for the purpose of the RCAR study (see Appendix)

# A. Adjusted Production Cost Savings (cont'd)

**APC Savings for the 2013-2052 Period**
(Applies 75% Weight for Suspended NTCs and ATP Projects)




## Annual APC savings estimated to increase over time

- Driven by load growth and fuel price increase
- Savings projected to be $65 million in 2018, growing to $165 million in 2023, and more than $600 million in 2033 (in nominal dollars)
  - Post-2033 savings assumed to increase at inflation (conservative)
- NPV of 40-yr savings adds up to approximately $2.5 billion for NTCs, $560 million for suspended NTCs, and $225 million for ATPs (in 2013 dollars, before weights applied)

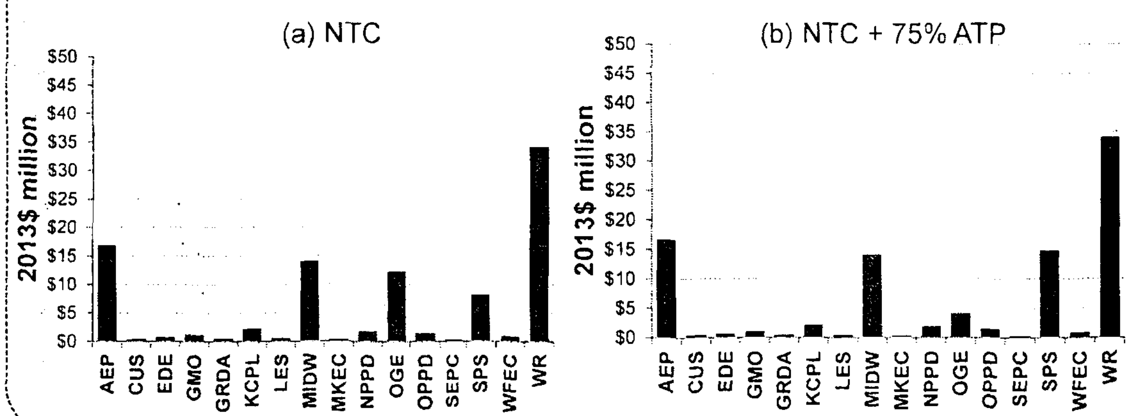
# A. Adjusted Production Cost Savings (cont'd)

| Zone | NTC Projects | | | | Suspended NTC Projects | | | | ATP Projects | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2018 (nominal $m/yr) | 2023 (nominal $m/yr) | 2033 (nominal $m/yr) | 40-yr NPV (2013 $m) | 2018 (nominal $m/yr) | 2023 (nominal $m/yr) | 2033 (nominal $m/yr) | 40-yr NPV (2013 $m) | 2018 (nominal $m/yr) | 2023 (nominal $m/yr) | 2033 (nominal $m/yr) | 40-yr NPV (2013 $m) |
| AEPW | $1.6 | $3.6 | $56.3 | **$245.1** | -$0.1 | $0.4 | -$2.1 | **-$7.5** | -$0.2 | -$1.2 | $9.1 | **$33.5** |
| CUS | $0.4 | $0.8 | $0.9 | **$7.9** | $0.0 | -$0.2 | -$0.3 | **-$1.7** | $0.0 | $0.2 | $0.3 | **$1.8** |
| EDE | -$0.1 | $0.4 | $1.5 | **$6.7** | $0.0 | $0.1 | $0.1 | **$0.6** | -$0.1 | $0.2 | $0.3 | **$1.4** |
| GMO | -$0.4 | $1.4 | $5.0 | **$23.1** | $0.0 | $0.0 | $0.0 | **-$0.1** | $0.0 | -$0.1 | -$1.1 | **-$4.5** |
| GRDA | $0.5 | $1.1 | $1.8 | **$12.9** | $0.0 | -$0.7 | -$0.4 | **-$3.8** | -$0.2 | $0.0 | $0.5 | **$1.7** |
| KCPL | $4.0 | $3.1 | -$2.0 | **$18.6** | $0.0 | $0.7 | $1.1 | **$6.6** | $0.4 | $2.5 | $4.6 | **$25.3** |
| LES | $0.3 | $1.8 | -$0.4 | **$5.6** | $0.0 | $0.0 | -$0.1 | **-$0.6** | $0.0 | $0.0 | $0.2 | **$1.0** |
| MIDW | -$0.1 | $0.9 | $14.7 | **$62.0** | $0.0 | -$0.4 | -$0.5 | **-$3.0** | $0.0 | $0.3 | $0.9 | **$4.1** |
| MKEC | $0.1 | $2.3 | $9.1 | **$44.4** | $0.0 | -$0.4 | -$0.5 | **-$3.3** | $0.0 | $0.5 | $1.5 | **$7.2** |
| NPPD | $6.8 | $22.4 | $30.8 | **$223.3** | -$0.1 | $0.4 | $0.5 | **$3.1** | $0.5 | -$1.7 | -$2.6 | **-$13.0** |
| OKGE | $2.9 | $15.6 | $28.8 | **$177.3** | $0.1 | -$0.9 | -$0.1 | **-$3.1** | -$0.6 | -$0.1 | -$0.6 | **-$4.3** |
| OPPD | $0.9 | $2.3 | $5.6 | **$33.3** | $0.1 | $0.0 | $0.3 | **$1.4** | $0.0 | $0.2 | -$0.4 | **-$1.2** |
| SUNC | -$2.5 | -$1.5 | $2.4 | **-$5.9** | $0.0 | -$0.5 | -$0.9 | **-$5.5** | $0.0 | $0.8 | $2.8 | **$13.1** |
| SWPS | $40.3 | $45.0 | $258.6 | **$1,354.1** | $3.2 | $49.0 | $153.9 | **$780.2** | $0.5 | $7.8 | $41.0 | **$184.2** |
| WEFA | $0.8 | $1.8 | $6.3 | **$34.5** | $0.1 | -$1.5 | -$2.2 | **-$13.3** | $0.1 | $1.0 | $2.1 | **$11.2** |
| WRI | $6.7 | $11.3 | $37.8 | **$215.7** | $0.0 | -$0.6 | $0.2 | **-$1.2** | $0.0 | -$1.5 | -$8.3 | **-$36.9** |
| **Total** | **$62.2** | **$112.5** | **$457.1** | **$2,458.5** | **$3.1** | **$45.3** | **$149.0** | **$748.8** | **$0.3** | **$8.8** | **$50.5** | **$224.5** |

# B. Avoided or Delayed Reliability Projects

- The powerflow models represent transmission utilization based on selected snapshots of generation dispatch and system loads
- A subset of projects excluded in "modified" base cases to identify: (a) the reliability violations, and (b) the reliability projects avoided by these selected projects
  - Selected projects are designated as either economic or public policy projects (see Appendix)
- The benefits are assumed to be equal to the 40-year present value of ATRRs of the avoided reliability projects (cost data provided by SPP)

**Benefits of Avoided or Delayed Reliability Projects**




- NPV benefits for NTC projects adds up to **$97 million** in 2013 dollars (zero from suspended NTCs)
- The region-wide benefits do not change when ATP projects are included, but the allocation across zones shift slightly

# C. Reduced On-Peak Transmission Losses

- On-peak losses quantified for two study years (2018, 2023) and five cases (Base, $CC_1$, $CC_{1A}$, $CC_2$, and $CC_{2A}$)
  - NTCs estimated reduce losses by 72 MW in 2018 and 122 MW in 2023 (suspended NTCs have very little impact)
  - Including ATPs further reduce the losses by 0.5 MW in 2018 and about 17 MW in 2023
  - Loss reductions assumed to remain constant after 2023 (conservative).
- Reductions in on-peak transmission losses grossed up by the 12% reserve margin, and then valued at a Net CONE of $84/kW-yr in 2013 dollars
  - 40-year present value of estimated capacity savings are about **$154 million** for NTCs, **$1 million** for suspended NTCs, and **$15 million** for ATPs

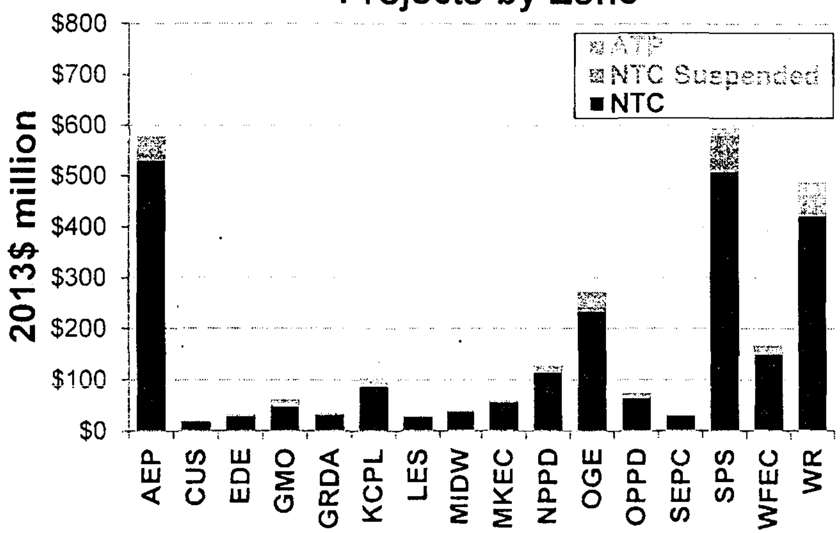
**Capacity Savings due to Reduced On-Peak Transmission Losses**

| | Savings Related to NTCs | | | Savings Related to Suspended NTCs | | | Savings Related to ATPs | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2018 (nominal $m/yr) | 2023 (nominal $m/yr) | **40-yr NPV (2013 $million)** | 2018 (nominal $m/yr) | 2023 (nominal $m/yr) | **40-yr NPV (2013 $million)** | 2018 (nominal $m/yr) | 2023 (nominal $m/yr) | **40-yr NPV (2013 $million)** |
| AEPW | $1.6 | $2.9 | **$30.7** | $0.0 | $0.0 | **$0.1** | $0.0 | $1.7 | **$12.7** |
| CUS | $0.0 | $0.0 | **$0.1** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.0** |
| EDE | $0.0 | -$0.1 | **-$0.9** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.0** |
| GMO | $0.1 | $0.1 | **$1.0** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.2** |
| GRDA | $0.0 | $0.1 | **$0.8** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.0** |
| KCPL | $0.4 | $0.5 | **$5.6** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.3** |
| LES | $0.1 | $0.1 | **$1.1** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.0** |
| MIDW | $0.2 | $0.3 | **$2.8** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.0** |
| MKEC | $0.4 | $0.8 | **$8.6** | $0.0 | -$0.1 | **-$1.2** | -$0.1 | $0.0 | **-$0.3** |
| NPPD | $0.2 | $1.5 | **$13.0** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **-$0.2** |
| OKGE | $0.1 | $0.5 | **$4.5** | $0.0 | $0.0 | **-$0.1** | $0.0 | $0.0 | **$0.3** |
| OPPD | $0.1 | $0.2 | **$2.0** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.0 | **$0.0** |
| SUNC | $0.1 | $0.0 | **$0.6** | $0.0 | $0.2 | **$1.3** | $0.1 | $0.0 | **$0.3** |
| SWPS | $3.7 | $6.6 | **$70.8** | $0.1 | $0.1 | **$1.1** | $0.1 | $0.1 | **$0.9** |
| WEFA | -$0.1 | $0.3 | **$2.3** | $0.0 | $0.0 | **$0.1** | $0.0 | $0.0 | **$0.4** |
| WRI | $0.7 | $0.9 | **$10.5** | $0.0 | $0.0 | **$0.0** | $0.0 | $0.1 | **$0.7** |
| **TOTAL** | **$7.6** | **$14.7** | **$153.6** | **$0.1** | **$0.1** | **$1.4** | **$0.1** | **$2.0** | **$15.3** |

# D. Mitigation of Transmission Outage Costs

- "Transmission Outage" cases analyzed in PROMOD for 2023
  - Developed based on historical outage data for 2011-2012
- A <u>subset</u> of outage events modeled due to large volume of data (selected based on likely impact on system congestion in SPP)
  - Facilities ≥ 230 kV and duration ≥ 5 days
  - Facilities ≥ 100 kV, duration ≥ 4 days, and significant impact on a defined contingency or a binding constraint in base case PROMOD runs
  - 732 outage events included capturing 11% of events and 22% of outage hours
- Comparing the results between Base Case and $CC_2$ translated to annual savings 11.3% higher when the transmission outages are considered
  - This difference is applied to the 40-year present value of APC savings in order to monetize the SPP-wide benefits of mitigating transmission outage costs (**$277 million** for NTCs, **$84 million** for suspended NTCs, and **$25 million** for ATPs)
  - As recommended in the September 2012 MTF report, the SPP-wide benefits are allocated to SPP pricing zones based on a load ratio share

# E. Mandated Reliability Projects




- September 2012 MTF report recommended this metric to be calculated conservatively only for "regional" reliability projects
  - For the purpose of this RCAR effort, all of the projects marked as reliability projects considered to be mandated and regional
- Benefits set equal to the 40-year present value of ATRRs for the reliability projects, and allocated to zones in the same way as the projects' costs are allocated
- SPP-wide benefits add up to **$2.4 billion** for NTCs, **$122 million** for suspended NTCs, and **$210 million** for ATPs (in 2013 dollars)

# F. Facilitating Public Policy Goals

- The September 2012 MTF report recommended that the benefits of meeting public policy goals be set equal to the cost of the cost-effective projects needed to meet the public policy goals
  - For the purpose of this RCAR effort, this metric is limited to the benefits of meeting public policy goals related to renewable energy
  - NTC projects marked as "public policy" projects used as a very conservative designation of cost-effective projects needed to meet public policy goals (none of the suspended NTC or ATPs are identified as "public policy" projects so their public policy benefits assumed to be zero)
- Using this conservative approach, the SPP-wide benefits are estimated to be **$296 million**, which is equal to the 40-year present value of the ATRRs of the public policy projects
  - Benefits are allocated to the SPP pricing zones in proportion to each zone's share of unmet renewable energy goals (determined based on the latest available data SPP provided for existing wind generation and renewable energy goals)

# F. Facilitating Public Policy Goals (cont'd)

| SPP Zone | Existing Wind as of Jun'10 (MWh) | Renewable Goals 2033 Mandate (MWh) | Target (MWh) | Total (MWh) | Unmet Goal (MWh) | (%) | 40-yr NPV of Public Policy Projects ($m) | Allocated Benefits of Public Policy Projects ($m) |
|---|---|---|---|---|---|---|---|---|
| AEPW | 3,083,978 | 1,241,236 | 3,629,868 | **4,871,104** | 1,787,126 | 10.1% | $66.4 | **$30.0** |
| CUS | 196,318 | 0 | 0 | **0** | 0 | 0.0% | $4.7 | **$0.0** |
| EDE | 426,127 | 1,314,000 | 0 | **1,314,000** | 887,873 | 5.0% | $7.5 | **$14.9** |
| GMO | 0 | 1,737,706 | 0 | **1,737,706** | 1,737,706 | 9.8% | $12.4 | **$29.1** |
| GRDA | 0 | 0 | 0 | **0** | 0 | 0.0% | $6.0 | **$0.0** |
| KCPL | 606,426 | 3,512,963 | 0 | **3,512,963** | 2,906,537 | 16.4% | $23.3 | **$48.7** |
| LES | 27,135 | 0 | 0 | **0** | 0 | 0.0% | $6.0 | **$0.0** |
| MIDW | 193,177 | 0 | 0 | **0** | 0 | 0.0% | $2.5 | **$0.0** |
| MKEC | 94,233 | 322,355 | 0 | **322,355** | 228,122 | 1.3% | $4.2 | **$3.8** |
| NPPD | 393,018 | 0 | 1,767,552 | **1,767,552** | 1,374,534 | 7.8% | $19.8 | **$23.0** |
| OKGE | 1,514,043 | 0 | 5,000,000 | **5,000,000** | 3,485,957 | 19.7% | $42.8 | **$58.4** |
| OPPD | 132,626 | 0 | 1,602,696 | **1,602,696** | 1,470,070 | 8.3% | $15.1 | **$24.6** |
| SUNC | 196,318 | 322,355 | 0 | **322,355** | 126,037 | 0.7% | $3.2 | **$2.1** |
| SWPS | 2,378,980 | 1,558,029 | 0 | **1,558,029** | 0 | 0.0% | $38.7 | **$0.0** |
| WEFA | 775,606 | 0 | 1,580,000 | **1,580,000** | 804,394 | 4.6% | $9.7 | **$13.5** |
| WRI | 986,042 | 3,854,400 | 0 | **3,854,400** | 2,868,358 | 16.2% | $34.0 | **$48.1** |
| **Total** | **11,004,027** | **13,863,043** | **13,580,116** | **27,443,160** | **17,676,714** | **100.0%** | **$296.4** | **$296.4** |

It is important to note the public policy benefits shown here are <u>very conservative</u>. The unmet renewable energy goal of 17.6 million MWh translates to approximately 5,000 MW of wind capacity. If valued at $450/kW-wind based on lowest "local" transmission cost reported in MISO's Regional Generation Outlet Study (RGOS) study, this would translate to more than $2.2 billion of public policy benefits, instead of the much lower $296 million shown here.

## 3. Summary of Results and B/C Ratios

- NTC Projects including Suspended NTCs at 75%
- NTC Projects including Suspended NTCs at 75% Plus ATP Projects (also at 75%)
- High Gas Price Sensitivity

# NTC Projects + Suspended NTCs at 75%

| | Present Value of 40-yr Benefits for 2013-2052 | | | | | | | | | | | | Present Value of 40-yr ATRRs | | | | Gap to Reach 0.8 B/C Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Adjusted Production Cost Savings | Cost Savings from Reduced On-peak Trans-mission Losses | Avoided or Delayed Reliability Projects | Mitigation of Trans-mission Outage Costs | Assumed Benefit of Mandated Reliability Projects | Benefit from Meeting Public Policy Goals | Increased Wheeling Through and Out Revenues | Reduced Cost of Extreme Events | Capital Savings from Reduced Minimum Required Margin | Reduced Loss of Load Probability | Marginal Energy Losses Benefits | Total Benefits | Before PtP Revenue Offset | PtP Revenue Offset | After PtP Revenue Offset | Est. Benefit-to-Cost Ratio | TOTAL | Levelized Real |
| | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | | (2013 $million) | (2013 $m/yr) |
| AEPW | $240 | $31 | $17 | $76 | $539 | $30 | | | | | | $933 | $1,106 | $115 | $991 | 0.94 | | |
| CUS | $7 | $0 | $0 | $5 | $19 | $0 | | | | | | $31 | $59 | $6 | $53 | 0.59 | $11 | $0.7 |
| EDE | $7 | -$1 | $1 | $9 | $30 | $15 | | | | | | $60 | $94 | $10 | $84 | 0.72 | $7 | $0.4 |
| GMO | $23 | $1 | $1 | $14 | $50 | $29 | | | | | | $118 | $155 | $16 | $139 | 0.85 | | |
| GRDA | $10 | $1 | $1 | $7 | $33 | $0 | | | | | | $51 | $83 | $9 | $75 | 0.68 | $9 | $0.6 |
| KCPL | $24 | $6 | $2 | $27 | $93 | $49 | | | | | | $200 | $291 | $30 | $261 | 0.77 | $9 | $0.6 |
| LES | $5 | $1 | $1 | $7 | $28 | $0 | | | | | | $42 | $79 | $8 | $71 | 0.59 | $15 | $0.9 |
| MIDW | $60 | $3 | $14 | $3 | $38 | $0 | | | | | | $118 | $59 | $6 | $53 | 2.21 | | |
| MKEC | $42 | $8 | $0 | $5 | $56 | $4 | | | Not Monetized | | | $115 | $98 | $10 | $88 | 1.30 | | |
| NPPD | $226 | $13 | $2 | $23 | $118 | $23 | | | | | | $404 | $286 | $30 | $257 | 1.58 | | |
| OKGE | $175 | $4 | $12 | $49 | $239 | $58 | | | | | | $539 | $604 | $63 | $541 | 0.99 | | |
| OPPD | $34 | $2 | $2 | $17 | $67 | $25 | | | | | | $147 | $196 | $20 | $176 | 0.84 | | |
| SUNC | -$10 | $2 | $0 | $4 | $31 | $2 | | | | | | $29 | $58 | $6 | $52 | 0.55 | $13 | $0.8 |
| SWPS | $1,939 | $72 | $8 | $44 | $562 | $0 | | | | | | $2,626 | $915 | $95 | $820 | 3.20 | | |
| WEFA | $24 | $2 | $1 | $11 | $151 | $13 | | | | | | $204 | $234 | $24 | $210 | 0.97 | | |
| WRI | $215 | $11 | $34 | $39 | $427 | $48 | | | | | | $773 | $716 | $74 | $642 | 1.20 | | |
| TOTAL | $3,020 | $155 | $97 | $340 | $2,481 | $296 | | | | | | $6,389 | $5,036 | $523 | $4,513 | 1.42 | $64 | $4.0 |

# NTC Projects + Suspended NTCs at 75% + ATP Projects at 75%

| | Present Value of 40-yr Benefits for 2013-2052 | | | | | | | | | | | | Present Value of 40-yr ATRRs | | | Est. Benefit-to-Cost Ratio | Gap to Reach 0.8 B/C Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Adjusted Production Cost Savings | Cost Savings from Reduced On-peak Transmission Losses | Avoided or Delayed Reliability Projects | Mitigation of Transmission Outage Costs | Assumed Benefit of Mandated Reliability Projects | Benefit from Meeting Public Policy Goals | Increased Wheeling Through and Out Revenues | Reduced Cost of Extreme Events | Capital Savings from Reduced Minimum Required Margin | Reduced Loss of Load Probability | Marginal Energy Losses Benefits | Total Benefits | Before PtP Revenue Offset | PtP Revenue Offset | After PtP Revenue Offset | | TOTAL | Levelized Real |
| | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | | (2013 $million) | (2013 $m/yr) |
| AEPW | $265 | $40 | $17 | $80 | $567 | $30 | | | | | | $999 | $1,133 | $117 | $1,016 | 0.98 | | |
| CUS | $8 | $0 | $0 | $6 | $20 | $0 | | | | | | $34 | $60 | $6 | $54 | 0.64 | $9 | $0.5 |
| EDE | $8 | $1 | $1 | $9 | $32 | $15 | | | | | | $64 | $96 | $10 | $86 | 0.75 | $5 | $0.3 |
| GMO | $20 | $1 | $1 | $15 | $58 | $29 | | | | | | $124 | $163 | $17 | $146 | 0.85 | | |
| GRDA | $11 | $1 | $1 | $7 | $34 | $0 | | | | | | $54 | $85 | $9 | $76 | 0.71 | $7 | $0.4 |
| KCPL | $43 | $6 | $2 | $28 | $100 | $49 | | | | | | $228 | $298 | $31 | $268 | 0.85 | | |
| LES | $6 | $1 | $1 | $7 | $30 | $0 | | | | | | $45 | $81 | $8 | $73 | 0.62 | $13 | $0.8 |
| MIDW | $63 | $3 | $14 | $3 | $39 | $0 | | | | | | $122 | $60 | $6 | $54 | 2.26 | | |
| MKEC | $47 | $7 | $0 | $5 | $59 | $4 | | | **Not Monetized** | | | $123 | $101 | $10 | $91 | 1.36 | | |
| NPPD | $216 | $13 | $2 | $24 | $124 | $23 | | | | | | $402 | $292 | $30 | $262 | 1.53 | | |
| OKGE | $172 | $5 | $6 | $52 | $263 | $58 | | | | | | $556 | $628 | $65 | $563 | 0.99 | | |
| OPPD | $33 | $2 | $1 | $18 | $72 | $25 | | | | | | $152 | $201 | $21 | $180 | 0.84 | | |
| SUNC | $0 | $2 | $0 | $4 | $32 | $2 | | | | | | $40 | $59 | $6 | $53 | 0.76 | $3 | $0.2 |
| SWPS | $2,077 | $72 | $13 | $47 | $574 | $0 | | | | | | $2,784 | $928 | $96 | $831 | 3.35 | | |
| WEFA | $33 | $3 | $1 | $12 | $163 | $13 | | | | | | $225 | $245 | $25 | $220 | 1.02 | | |
| WRI | $187 | $11 | $34 | $41 | $472 | $48 | | | | | | $794 | $762 | $79 | $683 | 1.16 | | |
| TOTAL | $3,188 | $166 | $96 | $359 | $2,639 | $296 | | | | | | $6,744 | $6,194 | $538 | $4,656 | 1.45 | $36 | $2.3 |

# High Gas Price Sensitivity

## NTC Projects + Suspended NTCs at 75%

| | Present Value of 40-yr Benefits for 2013-2052 | | | | | | | | | | | | Present Value of 40-yr ATRRs | | | Est. Benefit-to-Cost Ratio | Gap to Reach 0.8 B/C Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Adjusted Production Cost Savings | Cost Savings from Reduced On-peak Transmission Losses | Avoided or Delayed Reliability Projects | Mitigation of Transmission Outage Costs | Assumed Benefit of Mandated Reliability Projects | Benefit from Meeting Public Policy Goals | Increased Wheeling Through and Out Revenues | Reduced Cost of Extreme Events | Capital Savings from Reduced Minimum Required Margin | Reduced Loss of Load Probability | Marginal Energy Losses Benefits | Total Benefits | Before PtP Revenue Offset | PtP Revenue Offset | After PtP Revenue Offset | | TOTAL | Levelized Real |
| | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | | (2013 $million) | (2013 $m/yr) |
| AEPW | $263 | $31 | $17 | $90 | $539 | $30 | | | | | | $970 | $1,106 | $115 | $991 | 0.98 | | |
| CUS | $21 | $0 | $0 | $6 | $19 | $0 | | | | | | $47 | $59 | $6 | $53 | 0.88 | | |
| EDE | $7 | -$1 | $1 | $10 | $30 | $15 | | | | | | $62 | $94 | $10 | $84 | 0.74 | $5 | $0.3 |
| GMO | $38 | $1 | $1 | $17 | $50 | $29 | | | | | | $136 | $155 | $16 | $139 | 0.98 | | |
| GRDA | $20 | $1 | $1 | $8 | $33 | $0 | | | | | | $62 | $83 | $9 | $75 | 0.83 | | |
| KCPL | $39 | $6 | $2 | $32 | $93 | $49 | | | | | | $221 | $291 | $30 | $261 | 0.85 | | |
| LES | $2 | $1 | $1 | $8 | $28 | $0 | | | | | | $40 | $79 | $8 | $71 | 0.56 | $17 | $1.1 |
| MIDW | $57 | $3 | $14 | $3 | $38 | $0 | | | | | | $116 | $59 | $6 | $53 | 2.18 | | |
| MKEC | $43 | $8 | $0 | $6 | $56 | $4 | | | **Not Monetized** | | | $117 | $98 | $10 | $88 | 1.32 | | |
| NPPD | $319 | $13 | $2 | $27 | $118 | $23 | | | | | | $502 | $286 | $30 | $257 | 1.96 | | |
| OKGE | $223 | $4 | $12 | $58 | $239 | $58 | | | | | | $596 | $604 | $63 | $541 | 1.10 | | |
| OPPD | $33 | $2 | $2 | $21 | $67 | $25 | | | | | | $149 | $196 | $20 | $176 | 0.85 | | |
| SUNC | -$20 | $2 | $0 | $4 | $31 | $2 | | | | | | $19 | $58 | $6 | $52 | 0.37 | $23 | $1.4 |
| SWPS | $2,262 | $72 | $8 | $53 | $562 | $0 | | | | | | $2,957 | $915 | $95 | $820 | 3.60 | | |
| WEFA | $29 | $2 | $1 | $13 | $151 | $13 | | | | | | $211 | $234 | $24 | $210 | 1.01 | | |
| WRI | $246 | $11 | $34 | $46 | $427 | $48 | | | | | | $811 | $716 | $74 | $642 | 1.26 | | |
| TOTAL | $3,582 | $155 | $97 | $403 | $2,481 | $296 | | | | | | $7,014 | $5,036 | $523 | $4,513 | 1.55 | $45 | $2.8 |

# High Gas Price Sensitivity

## NTCs + Suspended NTCs at 75% + ATPs at 75%

| | Present Value of 40-yr Benefits for 2013-2052 | | | | | | | | | | | | Present Value of 40-yr ATRRs | | | Est. | Gap to Reach 0.8 B/C Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Adjusted Production Cost Savings | Cost Savings from Reduced On-peak Trans-mission Losses | Avoided or Delayed Reliability Projects | Mitigation of Trans-mission Outage Costs | Assumed Benefit of Mandated Reliability Projects | Benefit from Meeting Public Policy Goals | Increased Wheeling Through and Out Revenues | Reduced Cost of Extreme Events | Capital Savings from Reduced Minimum Required Margin | Reduced Loss of Load Probability | Marginal Energy Losses Benefits | **Total Benefits** | Before PtP Revenue Offset | PtP Revenue Offset | **After PtP Revenue Offset** | **Benefit-to-Cost Ratio** | TOTAL | Levelized Real |
| | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | (2013 $million) | **(2013 $million)** | (2013 $million) | (2013 $million) | **(2013 $million)** | | **(2013 $million)** | **(2013 $m/yr)** |
| AEPW | $283 | $40 | $17 | $95 | $567 | $30 | | | | | | **$1,032** | $1,133 | $117 | **$1,016** | **1.02** | | |
| CUS | $25 | $0 | $0 | $7 | $20 | $0 | | | | | | **$52** | $60 | $6 | **$54** | **0.97** | | |
| EDE | $10 | -$1 | $1 | $11 | $32 | $15 | | | | | | **$68** | $96 | $10 | **$86** | **0.78** | **$1** | **$0.1** |
| GMO | $33 | $1 | $1 | $18 | $58 | $29 | | | | | | **$140** | $163 | $17 | **$146** | **0.96** | | |
| GRDA | $15 | $1 | $1 | $9 | $34 | $0 | | | | | | **$59** | $85 | $9 | **$76** | **0.77** | **$2** | **$0.1** |
| KCPL | $66 | $6 | $2 | $33 | $100 | $49 | | | | | | **$256** | $298 | $31 | **$268** | **0.96** | | |
| LES | $2 | $1 | $1 | $9 | $30 | $0 | | | | | | **$43** | $81 | $8 | **$73** | **0.59** | **$16** | **$1.0** |
| MIDW | $61 | $3 | $14 | $4 | $39 | $0 | | | | | | **$121** | $60 | $6 | **$54** | **2.24** | | |
| MKEC | $48 | $7 | $0 | $6 | $59 | $4 | | | **Not Monetized** | | | **$125** | $101 | $10 | **$91** | **1.38** | | |
| NPPD | $306 | $13 | $2 | $28 | $124 | $23 | | | | | | **$496** | $292 | $30 | **$262** | **1.89** | | |
| OKGE | $225 | $5 | $6 | $61 | $263 | $58 | | | | | | **$619** | $628 | $65 | **$563** | **1.10** | | |
| OPPD | $37 | $2 | $1 | $22 | $72 | $25 | | | | | | **$158** | $201 | $21 | **$180** | **0.88** | | |
| SUNC | -$9 | $2 | $0 | $5 | $32 | $2 | | | | | | **$32** | $59 | $6 | **$53** | **0.60** | **$11** | **$0.7** |
| SWPS | $2,414 | $72 | $13 | $55 | $574 | $0 | | | | | | **$3,130** | $928 | $96 | **$831** | **3.76** | | |
| WEFA | $41 | $3 | $1 | $14 | $163 | $13 | | | | | | **$235** | $245 | $25 | **$220** | **1.07** | | |
| WRI | $208 | $11 | $34 | $49 | $472 | $48 | | | | | | **$822** | $762 | $79 | **$683** | **1.20** | | |
| TOTAL | **$3,766** | **$166** | **$96** | **$424** | **$2,639** | **$296** | | | | | | **$7,386** | **$5,194** | **$538** | **$4,655** | **1.59** | **$30** | **$1.9** |

1. Introduction

2. Benefits Analysis

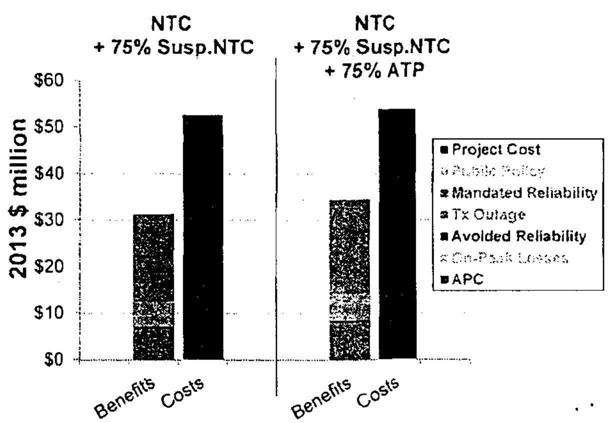
3. Summary of Results and B/C Ratios

# 4. Appendix

- Zonal Snapshots (for B/C ratio < 0.8)
- PROMOD Assumptions
- List of Selected Priority Projects
- List of Avoided Reliability Projects

## Zonal Snapshots
# City Utilities of Springfield (CUS)

| | NTC +75% Susp. NTC (2013 $million) | NTC +75% Susp. NTC +75% ATP (2013 $million) |
|---|---|---|
| **Present Value of 40-yr ATRRs** | | |
| Reliability Projects | $19 | $20 |
| Economic Projects | $35 | $35 |
| Public Policy Projects | $5 | $5 |
| Offset from PtP Revenues | -$6 | -$6 |
| **Total Costs** | $53 | $54 |
| **Present Value of 40-yr Benefits** | | |
| Adjusted Production Cost Savings | $7 | $8 |
| Capacity Cost Savings from Reduced On-Peak Losses | $0 | $0 |
| Avoided or Delayed Reliability Projects | $0 | $0 |
| Mitigation of Transmission Outage Costs | $5 | $6 |
| Assumed Benefit of Mandated Reliability Projects | $19 | $20 |
| Benefit from Meeting Public Policy Goals | $0 | $0 |
| **Total Benefits** | $31 | $34 |
| **Benefit-to-Cost Ratio** | 0.59 | 0.64 |
| **Gap to Reach a B/C Ratio of 0.8** | $11 | $9 |

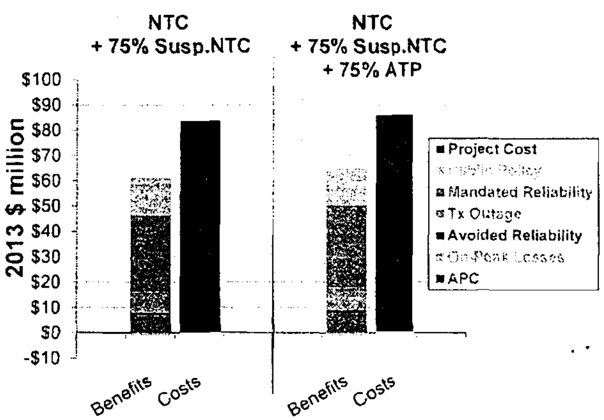



## Estimated B/C ratio in CUS is 0.59 for NTCs (including suspended NTCs) and 0.64 when ATPs are added

- Low B/C ratio in CUS is primarily driven by the limited APC savings
  - Cost of economic projects is $35 million, while present value of 40-year APC savings is $7-8 million due to relatively low congestion-relief
  - Benefit related to mitigation of transmission outage costs is approximately $5-6 million, reducing CUS' gap to reach a B/C ratio of 0.8
- CUS does not receive any public policy benefits, which contributes to a lower B/C ratio
  - CUS does not have a renewable goal, but it is responsible for about $5 million of the costs for public policy projects

## Zonal Snapshots
# Empire District Electric (EDE)

| | NTC +75% Susp. NTC (2013 $million) | NTC +75% Susp. NTC +75% ATP (2013 $million) |
|---|---|---|
| **Present Value of 40-yr ATRRs** | | |
| Reliability Projects | $30 | $32 |
| Economic Projects | $56 | $56 |
| Public Policy Projects | $7 | $7 |
| Offset from PtP Revenues | -$10 | -$10 |
| Total Costs | $84 | $86 |
| **Present Value of 40-yr Benefits** | | |
| Adjusted Production Cost Savings | $7 | $8 |
| Capacity Cost Savings from Reduced On-Peak Losses | -$1 | -$1 |
| Avoided or Delayed Reliability Projects | $1 | $1 |
| Mitigation of Transmission Outage Costs | $9 | $9 |
| Assumed Benefit of Mandated Reliability Projects | $30 | $32 |
| Benefit from Meeting Public Policy Goals | $15 | $15 |
| Total Benefits | $60 | $64 |
| **Benefit-to-Cost Ratio** | 0.72 | 0.75 |
| **Gap to Reach a B/C Ratio of 0.8** | $7 | $5 |



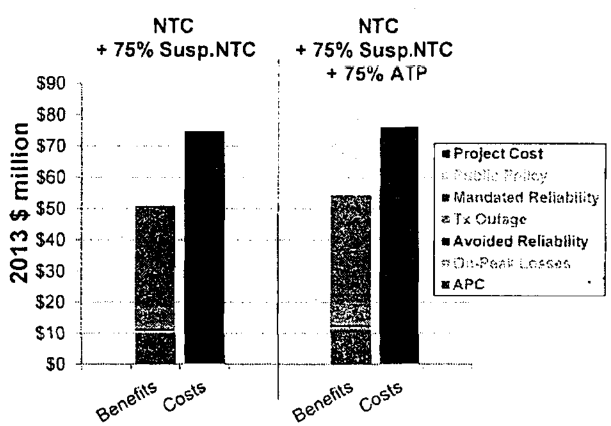

## Estimated B/C ratio in EDE is 0.72 for NTCs (including suspended NTCs) and 0.75 when ATPs are added

- Low B/C ratio in EDE is primarily driven by the limited APC savings
  - Cost of economic projects is $56 million, while present value of 40-year APC savings is $7-8 million due to relatively low congestion-relief
  - Benefit related to mitigation of transmission outage costs is approximately $9 million, reducing EDE's gap to reach a B/C ratio of 0.8
- Benefits from meeting public policy goals exceed the costs of public policy projects by approximately $8 million
  - It helps to reduce EDE's gap, but not sufficient to close it

## Zonal Snapshots

# Grand River Dam Authority (GRDA)

| | NTC +75% Susp. NTC (2013 $million) | NTC +75% Susp. NTC +75% ATP (2013 $million) |
|---|---|---|
| **Present Value of 40-yr ATRRs** | | |
| Reliability Projects | $33 | $34 |
| Economic Projects | $45 | $45 |
| Public Policy Projects | $6 | $6 |
| Offset from PtP Revenues | -$9 | -$9 |
| **Total Costs** | **$75** | **$76** |
| **Present Value of 40-yr Benefits** | | |
| Adjusted Production Cost Savings | $10 | $11 |
| Capacity Cost Savings from Reduced On-Peak Losses | $1 | $1 |
| Avoided or Delayed Reliability Projects | $1 | $1 |
| Mitigation of Transmission Outage Costs | $7 | $7 |
| Assumed Benefit of Mandated Reliability Projects | $33 | $34 |
| Benefit from Meeting Public Policy Goals | $0 | $0 |
| **Total Benefits** | **$51** | **$54** |
| **Benefit-to-Cost Ratio** | **0.68** | **0.71** |
| **Gap to Reach a B/C Ratio of 0.8** | **$9** | **$7** |



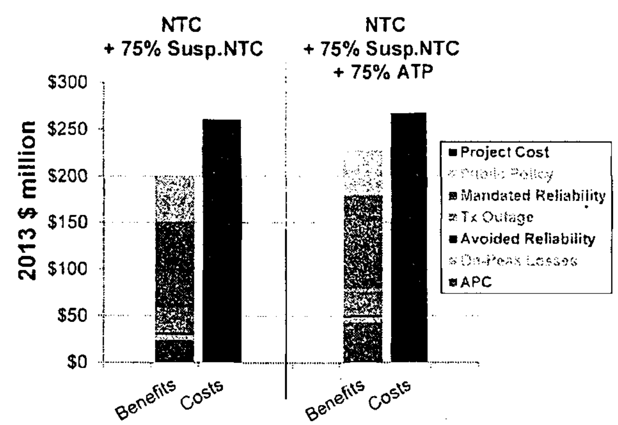

## Estimated B/C ratio in GRDA is 0.68 for NTCs (including suspended NTCs) and 0.71 when ATPs are added

- Low B/C ratio in GRDA is primarily driven by the limited APC savings
  - Cost of economic projects is $45 million, while present value of 40-year APC savings is $10-11 million due to relatively low congestion-relief
  - Benefit related to mitigation of transmission outage costs is approximately $7 million, reducing GRDA's gap to reach a B/C ratio of 0.8
- GRDA does not receive any public policy benefits, which contributes to a lower B/C ratio
  - GRDA does not have a renewable goal, but it is responsible for about $6 million of the costs for public policy projects

## Zonal Snapshots

# Kansas City Power & Light (KCPL)

| | NTC +75% Susp. NTC (2013 $million) | NTC +75% Susp. NTC +75% ATP (2013 $million) |
|---|---|---|
| **Present Value of 40-yr ATRRs** | | |
| Reliability Projects | $93 | $100 |
| Economic Projects | $175 | $175 |
| Public Policy Projects | $23 | $23 |
| Offset from PtP Revenues | -$30 | -$31 |
| **Total Costs** | $261 | $268 |
| **Present Value of 40-yr Benefits** | | |
| Adjusted Production Cost Savings | $24 | $43 |
| Capacity Cost Savings from Reduced On-Peak Losses | $6 | $6 |
| Avoided or Delayed Reliability Projects | $2 | $2 |
| Mitigation of Transmission Outage Costs | $27 | $28 |
| Assumed Benefit of Mandated Reliability Projects | $93 | $100 |
| Benefit from Meeting Public Policy Goals | $49 | $49 |
| **Total Benefits** | $200 | $228 |
| Benefit-to-Cost Ratio | 0.77 | 0.85 |
| Gap to Reach a B/C Ratio of 0.8 | $9 | $0 |

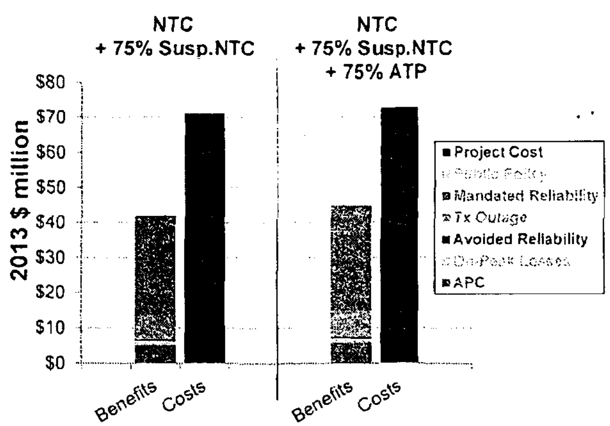



## Estimated B/C ratio in KCPL is 0.77 for NTCs (including suspended NTCs) and 0.85 when ATPs are added

- Low B/C ratio in KCPL is primarily driven by the limited APC savings
  - Cost of economic projects is $175 million, while present value of 40-year APC savings is only $24 million if ATPs are not built and $43 million if they are built
  - ATPs slightly increase KCPL's sales quantity and associated sales revenues
  - Benefit related to mitigation of transmission outage costs is approximately $27-28 million, reducing KCPL's gap to reach a B/C ratio of 0.8
- Benefits from meeting public policy goals exceed the costs of public policy projects by approximately $26 million

## Zonal Snapshots
# Lincoln Electric System (LES)

| | NTC +75% Susp. NTC (2013 $million) | NTC +75% Susp. NTC +75% ATP (2013 $million) |
|---|---|---|
| **Present Value of 40-yr ATRRs** | | |
| Reliability Projects | $28 | $30 |
| Economic Projects | $45 | $45 |
| Public Policy Projects | $6 | $6 |
| Offset from PtP Revenues | -$8 | -$8 |
| Total Costs | $71 | $73 |
| **Present Value of 40-yr Benefits** | | |
| Adjusted Production Cost Savings | $5 | $6 |
| Capacity Cost Savings from Reduced On-Peak Losses | $1 | $1 |
| Avoided or Delayed Reliability Projects | $1 | $1 |
| Mitigation of Transmission Outage Costs | $7 | $7 |
| *Assumed Benefit of Mandated Reliability Projects* | $28 | $30 |
| Benefit from Meeting Public Policy Goals | $0 | $0 |
| **Total Benefits** | $42 | $45 |
| **Benefit-to-Cost Ratio** | 0.59 | 0.62 |
| **Gap to Reach a B/C Ratio of 0.8** | $15 | $13 |



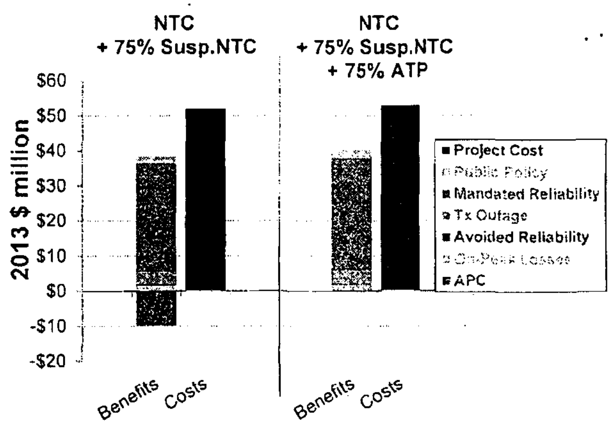

## Estimated B/C ratio in LES is 0.59 for NTCs (including suspended NTCs) and 0.62 when ATPs are added

- Low B/C ratio in LES is primarily driven by the limited APC savings
  - Cost of economic projects is $45 million, while present value of 40-year APC savings is $5-6 million due to relatively low congestion-relief in the later years
  - Benefit related to mitigation of transmission outage costs is approximately $7 million, reducing LES' gap to reach a B/C ratio of 0.8
- LES does not receive any public policy benefits, which contributes to a lower B/C ratio
  - LES does not have a renewable goal, but it is responsible for about $6 million of the costs for public policy projects

## Zonal Snapshots

# Sunflower Electric Power Corporation (SUNC)

| | NTC +75% Susp. NTC (2013 $million) | NTC +75% Susp. NTC +75% ATP (2013 $million) |
|---|---|---|
| **Present Value of 40-yr ATRRs** | | |
| Reliability Projects | $31 | $32 |
| Economic Projects | $24 | $24 |
| Public Policy Projects | $3 | $3 |
| Offset from PtP Revenues | -$6 | -$6 |
| **Total Costs** | $52 | $53 |
| **Present Value of 40-yr Benefits** | | |
| Adjusted Production Cost Savings | -$10 | $0 |
| Capacity Cost Savings from Reduced On-Peak Losses | $2 | $2 |
| Avoided or Delayed Reliability Projects | $0 | $0 |
| Mitigation of Transmission Outage Costs | $4 | $4 |
| Assumed Benefit of Mandated Reliability Projects | $31 | $32 |
| Benefit from Meeting Public Policy Goals | $2 | $2 |
| **Total Benefits** | $29 | $40 |
| *Benefit-to-Cost Ratio* | 0.55 | 0.75 |
| Gap to Reach a B/C Ratio of 0.8 | $13 | $3 |




**Estimated B/C ratio in SUNC is 0.55 for NTCs (including suspended NTCs) and 0.75 when ATPs are added**

- Low B/C ratio in SUNC is primarily driven by the zero or negative APC savings
  - Cost of economic projects is $24 million, while present value of 40-year APCs increase by $10 million
  - ATPs reduce congestion in SUNC and increase sales revenues, which result in an estimated increase of $10 million in APC savings
  - Benefit related to mitigation of transmission outage costs is approximately $4 million, reducing SUNC's gap to reach a B/C ratio of 0.8
- Benefits from meeting public policy goals are less than the costs of public policy projects by approximately $1 million

## PROMOD Assumptions
# Transmission

**SPP provided a powerflow and PROMOD system database (developed for 2013 ITP20 study) to be used as a starting point**

- Represents Business as Usual (BAU) future, set up to model years prior to 2033
- Transferred to PROMOD IV 10.1 (this version incorporated the needed enhancements for the metrics)
- Transmission projects in service after 2023 are not considered, as they are outside of the scope of this assessment
- The following changes were made to create more realistic cases for the purpose of RCAR study:
  - Constraints from the ITP10 event file included
  - The top 40 temporary flowgates from 2012 added to the event file
  - The top 10 constraints from the 2011 SPP State of the Market Report added to the event file
  - The PAT tool used to develop additional transmission constraints for the SPP system
  - Ratings of individual branches taken from powerflows used in the year/case combination

## PROMOD Assumptions
# External Regions

**External regions modeled consistently across all of the cases analyzed to ensure that the benefits pertain only to changes in SPP's transmission expansion**

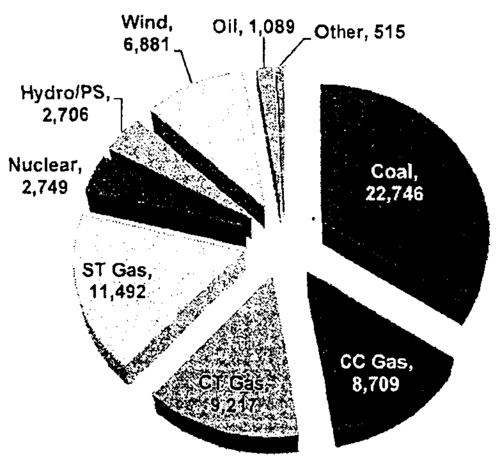
- System footprint based on what is used in the SPP ITP20 process, including the following regions:
  - SPP
  - MISO (including Entergy and CLECO)
  - MAPP Non-MISO
  - PJM
  - SERC – Central Sub-region, Southeast Sub-region, AECI

# PROMOD Assumptions
## Generation

**Generation modeled consistent with the assumptions used in the 2013 ITP20 study**

- Capacity additions through 2018 are mainly driven by RPS
- Significant amount of gas capacity is added after 2018, to maintain reserve margin at or above target
- Only limited amount of existing capacity is assumed to retire (mostly after 2023)

**Existing Capacity in SPP as of 2013**




**Capacity Additions and Retirements in SPP**

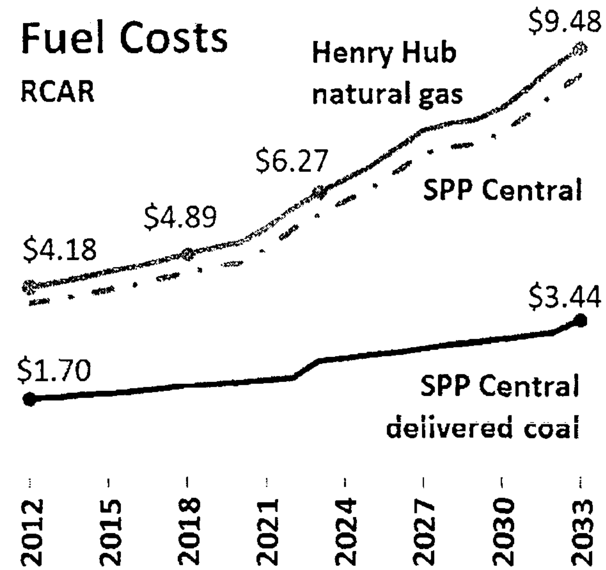
| | Additions and Retirements between 2014-2018 | Online Capacity in 2018 | Additions and Retirements between 2019-2023 | Online Capacity in 2023 | Additions and Retirements between 2024-2033 | Online Capacity in 2033 |
|---|---|---|---|---|---|---|
| Coal | 0 | **21,339** | 0 | **21,339** | -442 | **20,898** |
| CC Gas | 470 | **6,403** | 3,788 | **10,191** | 3,682 | **13,873** |
| CT Gas | 284 | **8,651** | 3,479 | **12,130** | 3,923 | **16,053** |
| ST Gas | 0 | **10,938** | -261 | **10,677** | -876 | **9,800** |
| Nuclear | 0 | **2,749** | 0 | **2,749** | 0 | **2,749** |
| Hydro/PS | 0 | **726** | 0 | **726** | 0 | **726** |
| Wind | 2,116 | **8,419** | 0 | **8,419** | 0 | **8,419** |
| Oil | 0 | **892** | 0 | **892** | 0 | **892** |
| Other | 23 | **460** | -9 | **451** | -102 | **349** |
| **TOTAL** | **2,893** | **60,578** | **6,997** | **67,575** | **6,185** | **73,760** |

* Numbers reflect total nameplate capacity in MW for SPP's 16 pricing zones

## PROMOD Assumptions
# Fuel Costs

**Fuel price projections modeled consistent with the assumptions used in the 2013 ITP20 study**

- Derived from the Ventyx Spring 2012 Reference Case and NYMEX futures
  - Natural gas prices based on NYMEX futures for Henry Hub as of April 23, 2012
- Henry Hub prices assumed to increase from current levels
  - $4.9 per MMBtu in 2018, $6.3 in 2023, and $9.5 in 2033 (in nominal dollars)
  - SPP prices slightly lower as a result of negative basis differentials
- Delivered coal prices also increase, but not as fast as gas prices
  - $2.0 per MMBtu in 2018, $2.5 in 2023, and $3.4 in 2033 (in nominal dollars)
  - Plant-specific prices vary due to differences in transportation costs



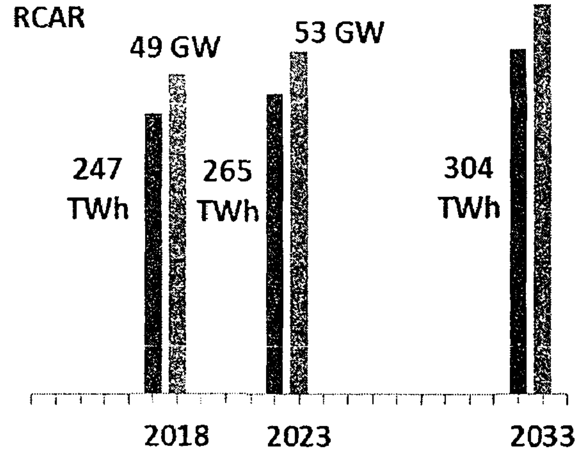
PROMOD Assumptions

# Load Forecast

## Load projections modeled consistent with the assumptions used in the 2013 ITP20 study

- The load forecast obtained through a survey of membership
  - Data based on the 2023 Summer Peak MDWG powerflow with adjustments for load growth up until 2033
  - MDWG submitted summer peak values used to determine the load in the years 2018 and 2023
- Both peak and energy in SPP increases by approximately 1.3% per year through the study horizon

Peak & Energy



PROMOD Assumptions

# Emission Prices

**Emission price projections modeled consistent with the assumptions used in the 2013 ITP20 study**

- $500/ton for annual $NO_X$, $1,000/ton for seasonal $NO_X$, $250-500/ton for $SO_2$, and zero for $CO_2$ and Hg, increasing at inflation

## Summary of Emission Price Assumptions

| | 2018 | 2023 | 2033 |
|---|---|---|---|
| CSAPR Annual .NOx | $580 | $656 | $840 |
| CSAPR Seasonal .NOx | $1,160 | $1,312 | $1,680 |
| CSAPR 1.SO2 | $580 | $656 | $840 |
| CSAPR 2.SO2 | $290 | $328 | $420 |
| National .CO2 | $0 | $0 | $0 |
| RGGI .CO2 | $0 | $0 | $0 |
| Mercury (Hg) | $0 | $0 | $0 |

* Prices in nominal $/ton

# List of Economic and Public Policy Projects

**The economic and public policy projects were removed to identify: (a) the reliability violations, and (b) the reliability projects avoided by these projects**

| PID | FACILITIES DESCRIPTION |
|---|---|
| 936 | Northwest Texarkana – Valliant 345 kV Ckt 1 |
| 937 | Tulsa Power Station 138 kV |
| 938 | Sibley 345 kV – Maryville 345 kV; Nebraska City 345 kV – Maryville 345 kV (GMO) |
| 939 | Nebraska City 345 kV – Maryville 345 kV (OPPD) |
| 940 | Hitchland Interchange 345/230kV Transformer Ckt 2; Hitchland Interchange – Woodward District EHV 345 kV Ckts 1 & 2 (SPS) |
| 941 | Hitchland Interchange – Woodward District EHV 345 kV Ckts 1 & 2 (OGE) |
| 942 | Thistle – Woodward EHV 345 kV Ckts 1 & 2 (OGE) |
| 943 | Thistle – Woodward EHV 345 kV Ckts 1 & 2 (PW) |
| 945 | Spearville 345 kV – Clark Co 345 kV Ckt 1; Clark Co 345 kV – Thistle 345 kV Ckts 1 & 2; Thistle 345/138 kV Transformer; Flat Ridge – Thistle 138 kV |
| 946 | Wichita 345 kV |
| 30375 | Cherry Co – Gentleman 345 kV Ckt 1; Gentleman 345 kV Terminal Upgrades Cherry Co – Holt Co 345 kV Ckt 1; Cherry Co 345 kV Holt Co 345 kV |
| 30376 | Amoco-Tuco-Hobbs 345 kV Circuit 1 and associated 345/230 kV transformers |

# List of Avoided Reliability Projects

**The following projects were identified as "avoided" reliability projects that would address the violations when the economic and public policy projects are excluded**

| Project Name | Area | Cost ($m) | 2018 CC1 | 2018 CC1A | 2018 CC2 | 2018 CC2A | 2023 CC1 | 2023 CC1A | 2023 CC2 | 2023 CC2A |
|---|---|---|---|---|---|---|---|---|---|---|
| Huntsville-Hutchinson Energy Center 115 kV Line | MIDW/WERE | $22.2 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Woodward-Windfarm 138 kV Line | OKGE | $12.0 | | | | | ✓ | ✓ | | |
| Gordon Evans-Lakeridge 138 kV Line | WERE | $9.6 | | | | | ✓ | ✓ | ✓ | ✓ |
| Mound-Yost 69 kV Line | WERE | $5.1 | | | | | ✓ | ✓ | ✓ | ✓ |
| Cowskin-45th St 138 kV Line | WERE | $7.6 | | | | | ✓ | ✓ | ✓ | ✓ |
| Carnegie-Southwestern 138 kV Line | AEPW | $14.7 | | | | | ✓ | ✓ | ✓ | ✓ |
| Sdierks2-Dierksr2 69 kV Line | AEPW | $2.6 | | | | | ✓ | ✓ | ✓ | ✓ |
| Lawhill-Lec 230 kV Line | WERE | $0.3 | | | | | ✓ | ✓ | ✓ | ✓ |
| Hillsboro-Spring Creek 115 kV Line | WERE | $10.9 | | | | | ✓ | ✓ | ✓ | ✓ |
| Monument-Hobbs West 115 kV Line | SPS | $8.2 | | | | | ✓ | ✓ | ✓ | |
| Texas County-Hitchland 115 kV Line | SPS | $12.6 | | | | | | | ✓ | ✓ |

**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

| | |
|---|---|
| **IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S REQUEST FOR PERMANENT APPROVAL TO PARTICIPATE IN THE SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION,** | **Case No. 13-00031-UT** |
| **SOUTHWESTERN PUBLIC SERVICE COMPANY** | |
| **Respondent.** | |

## CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the *Supplemental Direct Testimony of William A. Grant on Behalf of Southwestern Public Service Company* was electronically communicated and sent by Federal Express or hand delivered, as indicated below, to the following on this 30th day of August, 2013:

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