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Via Electronic Filing

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First St, NE
Washington, DC 20426

Re: Oklahoma Gas and Electric Company,
Docket No. ER10-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the Federal Energy Regulatory Commission's ("Commission") regulations,[2] Oklahoma Gas and Electric Company ("OG&E") submits (a) revised tariff sheets to its Open Access Transmission Tariff ("OATT") and (b) revised *pro forma* tariff sheets to the Southwest Power Pool, Inc. ("SPP") OATT, to implement transmission rate incentives in accordance with FPA Section 219[3] and Order No. 679.[4] OG&E is seeking two limited transmission rate incentives and is not seeking an enhanced return on equity. The revised tariff sheets will authorize recovery of 100 percent of all prudently-incurred Construction Work in Progress ("CWIP") in rate base for specific transmission projects to be constructed by OG&E within SPP. In addition, the revised tariff sheets will authorize OG&E to recover 100 percent of all prudently-incurred development and construction costs if the transmission projects identified and described herein are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. OG&E respectfully requests that the Commission accept the revised tariff sheets for filing effective January 1, 2011, without suspension or hearing.

I. INTRODUCTION.

A. Oklahoma Gas and Electric Company.

OG&E is an electric public utility with plant, property, and other assets dedicated to the production, transmission, distribution, and sale of electric energy to wholesale and retail

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[1] 16 U.S.C. § 824d (2006).

[2] 18 C.F.R. pt. 35 (2010).

[3] 16 U.S.C. § 824s (2006).

[4] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

customers in Oklahoma and western Arkansas. OG&E serves more than 750,000 retail customers and sells electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. OG&E owns and operates approximately 6,641 MWs of generation capacity comprising natural gas, low-sulfur coal, and wind generation facilities and also purchases power from third parties for resale. OG&E's transmission system includes approximately 4,064 miles of transmission lines plus 48 substations. OG&E is an Oklahoma corporation and a wholly-owned subsidiary of OGE Energy Corp.

OG&E is a member of SPP and SPP serves as the transmission provider for all new transmission transactions on the OG&E system. SPP administers a regional OATT, which governs transmission service over the facilities of SPP's member transmission owners within the SPP region.[5] Each SPP member retains the unilateral right to make an FPA Section 205 filing to change that member's rates or rate structure.[6] Although all new transmission service requests on OG&E's transmission facilities must be obtained through the SPP OATT, OG&E continues to serve two customers under existing long-term service agreements entered into under OG&E's OATT.

B. Transmission Projects for Which Incentives are Requested.

As explained in the Direct Testimony of Philip L. Crissup at Exhibit No. OGE-1, the transmission investments for which OG&E seeks incentives are the product of SPP's regional planning efforts, which were implemented to develop new transmission to meet applicable North American Reliability Corporation ("NERC") reliability standards, to relieve congestion, and to access a broader generation resource portfolio.[7] Through its planning processes, SPP has identified the need for new large-scale transmission projects to facilitate expansive renewable resource developments in the western portion of its system and for diverse resource options in load centers in the eastern portion of SPP and in neighboring balancing authority areas.[8] To this end, projects vetted and selected through SPP's planning processes, including the projects for which OG&E seeks FPA Section 219 incentives, as described below, are intended to strengthen the reliability of SPP's system and provide regional benefits by relieving congestion that already exists or that will exist due to requests for new transmission service.[9]

As described in detail below, OG&E seeks to revise the OG&E OATT and the SPP OATT to provide for recovery of certain transmission incentives authorized by FPA Section 219 and Order No. 679 in connection with a group of major transmission projects to be constructed

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5 *See Southwest Power Pool, Inc.*, 82 FERC ¶ 61,267, at 62,049 (1998).

6 *See Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 95 (2004).

7 Crissup Testimony, Exhibit No. OGE-1 at 6, *citing* SPP OATT at Attachment O, Section VII.

8 SPP OATT, Attachment O, Section IV; *see also*, Southwest Power Pool, May 17, 2010 Filing, Docket No. ER10-1269 at 4-7.

9 *See* SPP OATT at Attachments O, J, and Z1.

by OG&E in the SPP region (collectively, the "Projects"). These Projects are identified and described herein and in Mr. Crissup's testimony.

1. The Hitchland-Woodward Project ("Hitchland-Woodward") is a double-circuit 345-kV, 120-mile transmission line that will extend from OG&E's Woodward District extra high voltage ("EHV") substation to Southwestern Public Service Company's Hitchland substation, together with associated upgrades to the Woodward District EHV substation. The OG&E portion of the Hitchland-Woodward 345-kV line is estimated to be 82 miles in length, will cost approximately $178.6 million, and has an estimated in-service date of June 30, 2014;

2. The Woodward-Kansas Project ("Woodward-Kansas") is a double-circuit 345-kV, 80-mile transmission line to be built from OG&E's Woodward District EHV substation to the Prairie Wind LLC interception point at the Oklahoma-Kansas state line, together with associated upgrades to the Woodward District EHV substation. Woodward-Kansas is estimated to cost $134.4 million and has an estimated in-service date of December 31, 2014;

3. The Sooner-Cleveland Project ("Sooner-Cleveland") is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's Cleveland substation, plus associated upgrades to the Sooner substation. OG&E will construct the entire Sooner-Cleveland line. This project is estimated to cost $64 million, and has an expected in-service date of March 31, 2013;

4. The Seminole-Muskogee Project ("Seminole-Muskogee") is a single-circuit, 345-kV, 120-mile transmission line to be built from OG&E's Seminole substation to OG&E's Muskogee substation, as well as associated upgrades to both the Seminole and the Muskogee substations. Seminole-Muskogee has an estimated cost of $179.1 million and an estimated in-service date of December 31, 2013;

5. The Tuco-Woodward Project ("Tuco-Woodward") is a 345-kV, 250-mile transmission line from OG&E's Woodward District EHV to the SPS Tuco substation. The OG&E portion of the Tuco-Woodward project is 72 miles in length and will terminate at a reactor station to be constructed at approximately the Oklahoma-Texas state border south of Interstate 40. The project has an estimated cost of $120 million with an estimated in-service date of May 19, 2014;

6. The Anadarko Project ("Anadarko") is a 345/138-kV substation to be constructed on the OG&E line from Cimarron towards the AEP Lawton East Side 345-kV line near the town of Gracemont, Oklahoma. Anadarko, also known as the Gracemont substation project, is expected to cost $14.6 million and has an estimated in-service date of December 31, 2011;

7. The Sunnyside-Hugo Project ("Sunnyside-Hugo") is a 345-kV, 120-mile transmission line to be built from OG&E's Sunnyside substation to the Western Farmers Electric Cooperative's Hugo Generation Plant, as well as associated upgrades to the Sunnyside substation. Sunnyside-Hugo is estimated to cost $187 million and has an estimated in-service date of April 1, 2012; and

8. The Sooner-Rose Hill Project ("Sooner-Rose Hill") is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation to an interface with a Westar Energy line segment at the Oklahoma-Kansas state line. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length, is estimated to cost $57.8 million and has an estimated in-service date of June 1, 2012.

Each of the Projects was included in the 2009 SPP Transmission Expansion Plan ("2009 STEP"),[10] and SPP has issued a "Notification To Construct" for each Project.[11] As of September 28, 2010, OG&E has accepted the SPP Notification to Construct for all eight Projects. OG&E estimates that construction of the Projects will require between one and four years, and that the annual construction costs will be as follows:

[10] The STEP is an annual report issued by SPP that identifies planned transmission upgrades in the SPP region for a 20-year planning horizon. *See* SPP OATT, Attachment O. Exhibit No. OGE-2 includes excerpts of the relevant sections of the 2009 STEP Report. The report can be found in its entirety at: http://www.spp.org/publications/2009%20SPP%20Transmission%20Expansion%20Plan%20(Redacted%20Version).pdf.

[11] Pursuant to the SPP OATT, after a new transmission project has been approved under the STEP, SPP, in writing, directs "the appropriate Transmission Owner(s) to begin implementation of the project." SPP OATT, Attachment O, Section VI.4. This written notification, called a "Notification to Construct," includes: "(1) the specifications of the project required by [SPP] and (2) a reasonable project schedule, including a project completion date." SPP OATT, Attachment O, Section VI.4.

Projected Budget for OG&E Transmission Projects
(Dollars in Millions)

Project	2010	2011	2012	2013	2014	Total
Hitchland-Woodward	$0	$5.5	$33	$95	$45.1	$178.6
Woodward-Kansas	$0	$5.5	$24	$60	$44.9	$134.4
Sooner-Cleveland	$2.385	$19.074	$41.069	$1.536	$0	$64.064
Seminole-Muskogee	$0	$11.1	$101	$67	$0	$179.1
Tuco-Woodward	$0	$4.7	$23	$62.7	$29.6	$120
Anadarko	$1	$13.668	$0	$0	$0	$14.668
Sunnyside-Hugo	$25.105	$140.28	$21.904	$0	$0	$187.289
Sooner-Rose Hill	$10.858	$33.931	$13.045	$0	$0	$57.834
Total	$39.348	$233.753	$257.018	$286.236	$119.6	$935.955

The Projects represent an unprecedented level of new investment by OG&E in transmission infrastructure.[12] For example, the Projects will add approximately 555 miles of new transmission facilities to the OG&E transmission system within the SPP region, a significant expansion of the 4,450 miles of high voltage transmission lines that currently compose OG&E's transmission system. The cost projections for the combined Projects is approximately $936 million, which is equal to about 175 percent of OG&E's current net transmission plant of $534 million.[13] Such expenditures far exceed OG&E's normal capital investment. The average annual capital investment in the Projects over the next four years will equal approximately $187 million, representing more than nine times OG&E's previous average annual capital investment of $20 million.

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12 *See* Crissup Testimony, Exhibit No. OGE-1 at 7.

13 *Id.* The actual cost will depend on multiple factors such as the final routes for the proposed lines, and the costs of equipment, commodities and other construction elements.

C. The Transmission Projects are the Product of SPP's Regional Planning Process.

The Projects are components of a larger group of transmission facility investments to be constructed by a number of SPP member utilities as part of a regional program to enhance system reliability and reduce constraints and system congestion. As Mr. Crissup explains in his testimony, pursuant to SPP's Commission-approved regional transmission planning process set forth at Attachment O of the SPP OATT, each of the Projects was evaluated as part of a group of related projects under one of three SPP planning categories:

Priority Projects. Priority Projects are part of SPP's plans to "proactively build a robust 'transmission superhighway' that will benefit customers of not just one utility, but across the entire region."[14] The Priority Projects are specifically intended to "reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's east and west regions."[15]

Transmission Service Upgrades. Transmission service upgrades, identified pursuant to the Aggregate Transmission Service Study Procedures set forth at Attachment Z1 of the SPP OATT, are determined by SPP to be necessary to alleviate constraints on the transmission system and facilitate requests for transmission service.[16] This practice is intended to allow SPP and participating stakeholders to "develop a more efficient expansion of the transmission system" that will provide the necessary capacity to resolve congestion and reliability problems and do so at the minimum total cost to beneficiaries.[17]

Balanced Portfolio Projects. Balanced Portfolio projects are a cohesive group of economic transmission upgrades intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs" across the SPP region.[18]

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[14] *See* SPP News Release, "SPP Approves Construction of New Electric Transmission Infrastructure To Bring $3.7 Billion in Regional Benefits," (April 27, 2010), Exhibit No. OGE-8 ("SPP News Release").

[15] *See* SPP Priority Projects Phase II Final Report, Exhibit No. OGE-7 at 3 (April 27, 2010) ("Priority Projects Report"). Exhibit No. OGE-7 includes excerpts from the relevant sections of the Priority Projects Report. The report, in its entirety, can be found at http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf. The Priority Projects are part of SPP's Synergistic Planning Project which is intended "to address gaps and conflicts between SPP's transmission planning processes and help position the organization to respond to the Obama Administration's focus on improving our nation's electric infrastructure." *See* 2009 STEP at 10.

[16] SPP OATT, Attachment Z1.

[17] *See* SPP OATT, Attachment Z1, Sections I.

[18] SPP Balanced Portfolio Report (last revised June 23, 2009), Exhibit No. OGE-14 at 3.

II. DESCRIPTION OF FILING.

In addition to this transmittal letter, this filing contains the following materials:

- Attachment 1: proposed SPP Open Access Transmission Tariff sheets (clean);
- Attachment 2: proposed SPP Open Access Transmission Tariff sheets (red-line);
- Attachment 3: proposed OG&E Open Access Transmission Tariff sheets (clean);
- Attachment 4: proposed OG&E Open Access Transmission Tariff sheets (red-line);
- Attachment 5: Direct Testimony and Exhibits of Philip L. Crissup;
- Attachment 6: Direct Testimony and Exhibits of David L. Kays;
- Attachment 7: Direct Testimony and Exhibits of Donald R. Rowlett; and
- Attachment 8: Attestation as required by 18 C.F.R. § 35.13(d)(6).

III. REQUEST FOR INCENTIVES.

The Projects that OG&E intends to construct are large-scale transmission investments with region-wide benefits and associated risks. As a result, OG&E seeks to implement a narrowly-focused set of transmission incentives to reduce the risks and challenges inherent in such investments. Specifically, OG&E respectfully requests that the Commission accept for filing proposed tariff sheets that will authorize OG&E (a) to include 100 percent of prudently-incurred CWIP in rate base, and (b) to recover 100 percent of prudently-incurred costs of transmission facilities that are cancelled or abandoned, in whole or in part, for reasons beyond OG&E's control. These incentive rate treatments will apply only to the Projects identified and described herein.

The specific tariff changes designed to implement these incentives are described below and in the Direct Testimony of David L. Kays, Exhibit No. OGE-17. With regard to CWIP, OG&E will populate its formula rate template with the costs of CWIP for the Projects. A populated version of OG&E's Formula Rate template illustrating the CWIP incentive is included for informational purposes at Exhibit No. OGE-18. With regard to the recovery of abandoned plant costs, OG&E does not seek to recover any costs associated with abandoned plant at this time. In the event that some or all of the Projects are abandoned, in whole or in part, OG&E will make an FPA Section 205 filing to recover such costs at that time.

OG&E's request for incentives is consistent with FPA Section 219 and the Commission's regulations and should be approved. Section 219 of the FPA provides for the Commission to establish incentive-based rate treatment for qualifying transmission investments.[19] Under Order No. 679, the incentives a utility may request can include a return on equity ("ROE") sufficient to attract capital, recovery of CWIP and pre-commercial expenses, the use of a hypothetical capital structure, accelerated depreciation, and Abandoned Plant,[20] but this list is not exhaustive.[21] To qualify for any of these incentives, an entity must show that: (1) the facilities for which incentives are sought ensure reliability or reduce the costs of delivered power by reducing congestion; (2) the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project (*i.e.*, the "nexus" test); and (3) the resulting rates are just and reasonable.[22]

OG&E's limited request for the CWIP and Abandoned Plant incentives satisfies fully these requirements and the Commission should authorize OG&E's requested transmission incentives.

A. The Projects Meet the Standard for the Rebuttable Presumption Under FPA Section 219.

Where transmission projects are the product of a fair and open regional planning process, or have received construction approval from a state authority, the Commission has adopted a rebuttable presumption that such projects will ensure reliability or reduce the costs of delivered power by reducing congestion, so long as the regional planning process "considered whether the project ensures reliability or reduce congestion."[23] The Projects for which OG&E seeks incentives meet this requirement for application of the rebuttable presumption. As detailed herein and in Mr. Crissup's testimony, the SPP planning processes through which the Projects were approved evaluate whether identified transmission projects will enhance reliability and/or reduce congestion.

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19 *See* 16 U.S.C. § 824s(a) ("the Commission shall establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting [*sic*] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion").

20 Order No. 679 at PP 85-193.

21 *See id.* P 55.

22 *Id.* P 76.

23 Order No. 679-A at PP 5, 49-50.

1. Priority Projects.

In 2009, SPP began a series of studies and analyses to identify a group of "Priority Projects," which are specifically intended to "reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's east and west regions."[24] Engineering and economic analyses of potential projects were conducted by SPP staff, Quanta Technologies, Brattle Group, and Brown Engineers[25] using various metrics including "Adjusted Production Cost [*i.e.*, a measure of the impact on production cost savings by Locational Marginal Price], loss impacts, reliability assessment, local and environmental impacts, and deliverability of capacity and energy to load,"[26] as well as gas price impact.[27] Based on the results of these analyses, a final report ("Priority Projects Report") was prepared, and approved, identifying a group of projects that would satisfy SPP's goals for the Priority Projects.[28]

The Priority Projects Report recommended a group of six transmission projects to be constructed in the SPP region. This group includes Woodward-Kansas and Woodward-Hitchland. The Priority Projects Report concludes that the selected projects yield a greater benefit-to-cost ratio than an alternative group that was studied. More specifically, the report finds that the selected Priority Projects "will reduce [grid] congestion, as demonstrated in the APC [*i.e.*, adjusted production cost] analysis and by the levelization of Locational Marginal Prices (LMPs) across the SPP footprint."[29] Moreover, the Priority Projects "will improve the Aggregate Study process by creating additional transfer capability and allowing additional transmission service requests to be enabled."[30] All in all, SPP estimates that the Priority Projects will benefit the SPP region by at least $3.7 billion over the next 40 years.[31] The SPP Board of Directors approved the Priority Projects, and SPP has issued a Notification to Construct for Woodward-Kansas and Woodward-Hitchland, which OG&E has accepted.[32]

The Priority Projects also will facilitate the interconnection of new renewable generation (as well as other generation) to the grid.[33] Currently, a backlog of generation interconnection

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[24] *See* Priority Projects Report, Exhibit No. OGE-7 at 3.

[25] *See* 2009 STEP, Exhibit No. OGE-2 at 13.

[26] *See id.*; Priority Projects Report, Exhibit No. OGE-7 at 4 & 15-19.

[27] Priority Projects Report, Exhibit No. OGE-7 at 26.

[28] Crissup Testimony, Exhibit No. OGE-1 at 12-13.

[29] In the Priority Projects Report, SPP found that the Priority Projects meet the goals of SPP's Synergistic Planning Project, which included relieving congestion. *See* Priority Projects Report, Exhibit No. OGE-7 at 6.

[30] Priority Projects Report, Exhibit No. OGE-7 at 6 & 23.

[31] *See* SPP News Release, Exhibit No. OGE-8.

[32] Crissup Testimony, Exhibit No. OGE-1 at 17; SPP Notification to Construct, SPP-NTC-20100 (June 31, 2010), Exhibit No. OGE-3.

[33] *See* SPP News Release, Exhibit No. OGE-8.

requests exists in SPP, with many of the pending requests involving new wind facilities.[34] Woodward-Kansas and Woodward-Hitchland will help clear this backlog of pending requests and enable substantial amounts of new wind generation to interconnect to the grid. In granting transmission incentives in other cases, the Commission has recognized the benefit of cost savings achieved by low-cost renewable resources displacing higher-priced fossil fuel resources.[35]

2. Upgrades to Fulfill Requests for Transmission Service.

Pursuant to SPP's Attachment Z1 procedures, SPP conducts an open season during which customers may make requests for long-term transmission service.[36] SPP then conducts an Aggregate Facilities Study ("AFS") of the eligible requests for transmission service received during the open season. The AFSs relevant to the Projects are attached to this filing as Exhibit Nos. OGE-12 and OGE-13.[37] Determining which upgrades will relieve congestion on the system is a key objective of the AFS process: "[s]ystem constraints will be identified and appropriate upgrades determined."[38] SPP also is charged with determining "the upgrades required to reliably provide all of the requested service" and determining which "alternative solutions would reduce overall cost to customers."[39] This approach results in "a more efficient expansion of the transmission system."[40] Upgrades evaluated for transmission requests pursuant to Attachment Z1 are folded into the Attachment O integrated transmission planning study and analysis,[41] which incorporates NERC Reliability Standards, load and capacity forecasts, and congestion within SPP and between SPP and other regions.[42]

In the most recent STEP Report, SPP identified Sunnyside-Hugo and Sooner-Rose Hill as two of the "[m]ajor 345 kV projects" currently proposed in SPP.[43] SPP has determined that

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34 SPP Generation Interconnection Active Requests, *available at* https://studies.spp.org/SPPGeneration/GI_ActiveRequests.cfm.

35 *See, e.g.*, *Green Power Express LP*, 127 FERC ¶ 61,031, at P 41 (2009), *reh'g pending*; *Pioneer Transmission LLC*, 126 FERC ¶ 61,281, at P 38 (2009), *order granting clarification and denying reh'g*, 130 FERC ¶ 61,044 (2010); *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, at P 41 (2008), *reh'g pending* ("*Tallgrass*").

36 SPP OATT, Attachment Z1; *see also*, Crissup Testimony, Exhibit No. OGE-1 at 18-20.

37 Aggregate Facility Study SPP-2006-AG3-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers at 10-13 (September 16, 2008), Exhibit No. OGE-12 ("SPP September 2008 Study"); Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers at 11-13 (Revised March 19, 2009), Exhibit No. OGE-13 ("SPP March 2009 Study").

38 SPP OATT, Attachment Z1.

39 *Id*. The AFS methodology also is designed to ensure that NERC Reliability Standards are met. *See* SPP September 2008 Study, Exhibit No. OGE-12 at 10; SPP March 2009 Study, Exhibit No. OGE-13 at 10.

40 SPP OATT, Attachment Z1.

41 *See* Crissup Testimony, Exhibit No. OGE-1 at 18-19; SPP OATT, Attachment O, Figure 1 and Sections III.3-III.5.

42 *See* SPP OATT, Attachment O, Section III.6.

43 Crissup Testimony, Exhibit No. OGE-1 at 20-21; 2009 STEP, Exhibit No. OGE-2 at 6-7. These projects are transmission service upgrades and are considered "part of the future expansion of the [SPP] Transmission System." *See also* SPP OATT, Second Revised Sheet No. 300.

Sunnyside-Hugo and Sooner-Rose Hill are necessary upgrades to alleviate congestion and thereby facilitate requests for transmission service in the region.[44] The Aggregate Facilities Studies relevant to the Sunnyside-Hugo line and the Sooner-Rose Hill line state "that limiting constraints exist in many areas of the regional transmission system"[45] and SPP found that Sunnyside-Hugo and Sooner-Rose Hill are among the upgrades needed to alleviate these constraints.[46] Subsequently, these Projects were included in the 2009 STEP Report, which was approved by the SPP Board of Directors. SPP has issued Notifications to Construct for Sunnyside-Hugo and Sooner-Rose Hill.[47]

3. Balanced Portfolio Network Upgrades.

SPP's Balanced Portfolio projects are intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs."[48] To select which projects would be included in the Balanced Portfolio, SPP's Cost Allocation Working Group ("CAWG"), with stakeholder input, identified "upgrades that would provide a balanced benefit to SPP members over a specified ten-year payback period."[49] Pursuant to Attachment O of the SPP OATT, the Balanced Portfolio must be (1) cost beneficial, meaning that "[t]he sum of the benefits [measured using an adjusted production cost metric] . . . must equal or exceed the sum of the costs [measured as the net present value of the revenue requirements];"[50] and (2) balanced, meaning that the benefits must also equal or exceed the costs for each SPP zone.[51] From an initial list compiled by the CAWG, SPP conducted an analysis of the adjusted production cost of each potential project.[52] The annual benefits of the potential projects were compared to the estimated engineering and construction costs, which were provided by transmission owners.[53] A potential project's benefit-to-cost ratio was used to determine potential groupings of projects.[54]

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44 SPP September 2008 Study, Exhibit No. OGE-12 at 18 and Table 3; SPP March 2009 Study, Exhibit No. OGE-13 at 18 and Table 3.

45 SPP September 2008 Study, Exhibit No. OGE-12 at 18; SPP March 2009 Study, Exhibit No. OGE-13 at 18.

46 In the 2009 STEP, SPP found that Sooner-Rose Hill may mitigate a constraint at one of SPP's top ten congested flowgates. The top ten congested flowgates are those with the highest "value of relieving the constraint measured in dollars." *See* 2009 STEP, Exhibit No. OGE-2 at 59-60.

47 Crissup Testimony, Exhibit No. OGE-1 at 20; SPP Notification to Construct, SPP-NTC-20017 (January 16, 2009), Exhibit No. OGE-4; SPP Notification to Construct, SPP-NTC-20055 (September 18, 2009), Exhibit No. OGE-5.

48 Crissup Testimony, Exhibit No. OGE-1 at 21; SPP Balanced Portfolio Report, Exhibit No. OGE-14 at 3.

49 *See* SPP's description of the Balanced Portfolio at http://www.spp.org/section.asp?pageID=120.

50 SPP OATT, Attachment O, Section IV.3.

51 *Id.*

52 SPP Balanced Portfolio Report, Exhibit No. OGE-14 at 6.

53 *Id.* at 8.

54 *Id.*

In the 2009 STEP Report, SPP identified Sooner-Cleveland, Seminole-Muskogee, and Tuco-Woodward as three of the "[m]ajor 345 kV projects" currently proposed in SPP.[55] These three projects, along with Anadarko, are SPP Balanced Portfolio Network Upgrades and are included in the Portfolio 3E "Adjusted."[56] This final selection of projects was based on a grouping of projects that ensured that a project was included for each SPP zone "with the most beneficial project chosen in each zone."[57] Studies have demonstrated that the benefits of these projects outweigh their costs[58] and these projects will relieve congestion by addressing "many of the top constraints in the SPP."[59] This reduction in congestion will result in demonstrable cost savings to customers.[60] Sooner-Cleveland, Seminole-Muskogee, Tuco-Woodward, and Anadarko have been approved by the SPP Board of Directors. A Notification to Construct has been issued for all four projects, and OG&E has accepted these Notifications to Construct.[61]

B. The Projects Satisfy FPA Section 219's Nexus Requirement.

In order to meet the requirements for incentives under FPA Section 219 and Order No. 679, a party requesting incentives must show a nexus between the incentives being sought and the investments in transmission projects.[62] The Commission has stated that this standard is not a "but for" test and that a party seeking incentives meets FPA Section 219's requirements by showing a rational relationship between the proposed incentives and the specific transmission projects.[63] The Commission also has explained that an applicant may seek incentives and satisfy the nexus requirement for a group of projects.[64]

The nexus test is fact-specific and the Commission evaluates applications for incentives on a case-by-case basis.[65] In evaluating requests for incentives, the Commission has explained that it "will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the

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55 *See* 2009 STEP, Exhibit No. OGE-2 at 6-7.

56 Crissup Testimony, Exhibit No. OGE-1 at 22.

57 SPP Balanced Portfolio Report, Exhibit No. OGE-14 at 9.

58 *See* SPP's description of the Balanced Portfolio at http://www.spp.org/section.asp?pageID=120.

59 2009 SPP Balanced Portfolio Report, Exhibit No. OGE-14 at 35. Moreover, in the 2009 STEP, SPP found that Seminole-Muskogee will mitigate in part constraints at two of SPP's top ten congested flowgates. The top ten congested flowgates are those with the highest "value of relieving the constraint measured in dollars." *See* 2009 STEP, Exhibit No. OGE-2 at 59-60.

60 *See* Crissup Testimony, Exhibit No. OGE-1 at 23. The net benefit to a typical residential customer is estimated to be $0.78/month. Balanced Portfolio Report, Exhibit No. OGE-14 at 3.

61 SPP Notification to Construct, SPP-NTC-20041 (June 19, 2009), Exhibit No. OGE-6.

62 Order No. 679 at P 48.

63 *Id.*

64 Order No. 679-A at PP 123-24; *PacifiCorp*, 125 FERC ¶ 61,076 at P 46 (2008). *See generally Otter Tail Power Co.*, 129 FERC ¶ 61,287 (2009) ("*Otter Tail*"); *Virginia Elec. and Power Co.*, 124 FERC ¶ 61,207 (2008) ("*VEPCo*").

65 *See, e.g.*, *Otter Tail*, 129 FERC ¶ 61,287 at P 28; *VEPCo*, 124 FERC ¶ 61,207 at P 47.

project."[66] The Commission has found particularly relevant whether a project is "routine,"[67] as compared to "other transmission projects or upgrades that are constructed in the ordinary course of maintaining a utility's transmission system to provide safe and reliable service."[68] In determining whether a project is routine, the Commission will consider "all relevant factors," for example, "(i) the scope of the project (*e.g.*, dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (ii) the effect of the project (*e.g.*, improving reliability or reducing congestion costs); and (iii) the challenges or risks faced by the project (*e.g.*, siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments)."[69]

The following discussion addresses these factors and demonstrates that the Projects meet the nexus requirement under FPA Section 219 and Order No. 679.

1. The Projects are Substantial in Scope and Effect and are not Routine.

The Projects are undeniably significant in cost, both in terms of miles of new transmission lines added, and in their likely impact on the SPP region. When completed, the Projects will add approximately 555 miles of 345-kV transmission lines to the SPP region, compared to 4,450 miles of high voltage transmission lines currently comprising OG&E's transmission system. Further, the expected cost of the Projects is approximately $936 million, which exceeds by a wide margin OG&E's current net transmission plant of $534 million. The annual capital investment associated with Projects will equal approximately $187 million, more than nine times OG&E's recent level of capital investment. Projects of this scale are not routine.[70]

The scale of the Projects is illustrated further by their regional design and by the fact that several of them are multi-state. For example, with respect to Sooner-Rose Hill, Westar, an electric utility headquartered in Topeka, Kansas, and OG&E both must complete their respective construction prior to the line being energized. In cases such as this one, OG&E is dependent on these other parties to construct their portion of the joint facilities and to otherwise meet their obligations. Should these parties fail to construct their facilities, or fail to do so on a timely basis, the project could be delayed or abandoned.[71] The Commission has acknowledged that

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66 Order No. 679 at P 27.

67 *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084 at P 48 (2007) ("*BG&E*").

68 Order No. 679-A at P 60; *BG&E* 120 FERC ¶ 61,084 at P 53. To show a project is not routine, a utility may also compare its investment in the project "to some other aggregate measure of investment, such as total rate base or recent annual investment levels." *Pepco Holdings, Inc.*, 125 FERC ¶ 61,130 at P 54 (2008).

69 *BG&E*, 120 FERC ¶ 61,084 at P 52.

70 *See Pub. Serv. Elec. & Gas Co.*, 129 FERC ¶ 61,300 at P 44 (2009) ("*PSE&G*") (noting that the proposed investment would "more than double [PSE&G's] net transmission plant in service"); *PacifiCorp*, 125 FERC ¶ 61,076 at P 44 (noting that the proposed project represented a large increase in PacifiCorp's existing transmission rate base); *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 at P 32 & n. 21, *reh'g denied*, 124 FERC ¶ 61,229 (2008) ("*PPL*").

71 *See* Crissup Testimony, Exhibit No. OGE-1 at 28.

such projects present particular challenges and risks beyond those associated with ordinary transmission investments.[72]

This major addition of transmission infrastructure to the region will modernize and integrate the SPP system and provide numerous significant benefits to users of the SPP system.[73] In addition to substantially reducing congestion in the SPP region -- and thereby reducing costs to consumers -- SPP has found that the Priority Projects will provide for better integration of SPP's east and west regions, improved ability by SPP members to deliver power to customers, "enabling future SPP energy markets, dispatch savings, reduction in carbon emissions and required operating reserves, storm hardening, meeting future reliability needs, improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, and additional societal economic benefits,"[74] as well as enabling SPP "to better manage many uncertain future scenarios such as carbon policy, varying fuel prices, growth in electricity demand, and state or federal renewable energy standards."[75] Moreover, the Projects will facilitate the interconnection of new renewable resources, principally wind resources located in Texas and Western Oklahoma, as well as other generation, to the grid.[76]

An analysis of the Priority Projects conducted by The Brattle Group showed an overall economic impact of $962 million, overall job impacts of 7,475 full-time equivalent years, additional earnings related to job impact of $368 million, and state and local government tax impacts of $34.4 million.[77] Moreover, SPP has found that the Portfolio 3E "Adjusted" projects may provide benefits such as "increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources."[78] The Commission has recognized that a project's ability to facilitate the interconnection of new generation, and renewable generation in particular, is a factor supporting transmission incentives.[79]

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72 Order No. 679 at P 94.

73 *See* Crissup Testimony, Exhibit No. OGE-1 at 12, 14-17, 23.

74 Priority Projects Report, Exhibit No. OGE-7 at 6.

75 *See* SPP News Release, Exhibit No. OGE-8.

76 *See, e.g.*, Crissup Testimony, Exhibit No. OGE-1 at 16-17, 23.

77 Priority Projects Report, Exhibit No. OGE-7 at 39; Priority Projects Report Attachment 4, Exhibit No. OGE-9.

78 Balanced Portfolio Report, Exhibit No. OGE-14 at 3.

79 *See, e.g.*, *Pioneer*, 126 FERC ¶ 61,281, *order granting clarification and denying reh'g*, 130 FERC ¶ 61,044 at P 50; *So. Cal. Edison Co.*, 129 FERC ¶ 61,246 at P 40 (2009); *Citizens Energy Corp.*, 129 FERC ¶ 61,242 at P 18 (2009); *Tallgrass*, 125 FERC ¶ 61,248 at P 54. *See also* Order No. 679 at P 25 and Order No. 679-A at P 22 (recognizing the need for new transmission to integrate new generation and load).

2. The Projects Face Substantial Risks and Challenges.

The Projects also face substantial risks and challenges. These factors are addressed in detail in Mr. Crissup's testimony and in Mr. Rowlett's testimony.[80] The risks and challenges generally arise from the magnitude and scope of the Projects and warrant the adoption of the requested incentives.

a. Risks associated with the Projects' substantial size and scope.

As noted above, the Projects represent an unprecedented expansion of OG&E's transmission system and are regional projects with system-wide benefits and risks. Because of their large size and scope, the Projects will require long lead times to accommodate construction, in some instances as long as four years. The longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and the required regulatory approvals, could change for reasons beyond the control of OG&E and make the project more expensive or potentially unfeasible. Moreover, large projects to be developed and constructed over longer time periods present complex logistical and management issues that also increase the risk of delay or cost increases.[81]

b. Risks attributable to required permits and other approvals.

The Projects are subject to required approvals to be obtained from multiple federal and state agencies. These requirements are detailed in Mr. Crissup's testimony, and include approvals from the U.S. Army Corps of Engineers, permits from the Federal Aviation Administration, and studies for the Oklahoma Archeological Survey. Moreover, OG&E will be required to comply with the requirements of the National Environmental Policy Act, the Endangered Species Act, and the National Historic Preservation Act, as well as these statutes' implementing regulations and the associated approvals.[82]

In addition, OG&E must secure the necessary rights of way, as well as address any relevant environmental or tribal land right concerns. As noted above, the Projects call for OG&E to construct approximately 555 miles of new transmission lines, for which OG&E will need to acquire significant new rights of way. Affected landowners do not always yield the necessary rights-of-way voluntarily, raising the potential for condemnation proceedings which can be lengthy and, if unsuccessful, could lead to lengthy delays or re-routing of a Project, if not a new round of planning.[83] In an extreme case such factors could result in the abandonment of the Project.

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80 *See* Crissup Testimony, Exhibit No. OGE-1 at 26-29; Rowlett Testimony, Exhibit No. OGE-19 at 4-7.

81 *See* Crissup Testimony, Exhibit No. OGE-1 at 26-27; Rowlett Testimony, Exhibit No. OGE-19 at 7.

82 Crissup Testimony, Exhibit No. OGE-1 at 27.

83 *Id.* at 28.

Further, while some of the Projects are undertaken solely by OG&E, other Projects are undertaken jointly by OG&E and another utility, sometimes in a neighboring state.[84] In such cases, OG&E is dependent on these other parties to construct their portion of the joint facilities and to otherwise meet their obligations. Six of the Projects will connect with another Transmission Owner.[85] Timely completion of these projects therefore will depend on obtaining rights of way and other siting and regulatory approvals in more than one state. This added layer of approvals raises an additional risk of delay. Should these parties fail to obtain necessary rights of way or other authorizations in other jurisdictions, or fail to do so on a timely basis, the project could be delayed or abandoned.[86] The Commission has recognized that the need to coordinate with other utilities when planning transmission projects poses special challenges.[87]

Finally, the same regional planning process that evaluated and approved the Projects could make subsequent changes that would lead to the Projects' delay or abandonment. In *PPL*, the Commission acknowledged that RTO planning processes could result in transmission projects being cancelled and found that an abandoned plant incentive would help to ameliorate that risk.[88]

c. Financial risks and challenges.

The size of the investment required for the Projects – over $900 million – will present a number of financial challenges for OG&E. By comparison, OG&E's annual expenditures for capital additions over the past several years has averaged approximately $20 million.[89] The risks and challenges are highlighted herein and addressed in Mr. Rowlett's testimony at Exhibit No. OGE-19, as well as the exhibits appended to Mr. Rowlett's testimony (*i.e.*, Exhibit Nos. OGE-20-23).

First, funding projects of this size and scope will require significant outlays of cash, decreasing OG&E's cash flow.[90] The large investment required by the Projects will depress OG&E's cash flow during the construction phase of the Projects. Over the next five years, OG&E will face a negative cash flow position as a result of meeting the extensive level of capital expenditures required by the Projects. This is due to the fact that cash flows generated from operations will not be sufficient to cover these transmission projects over the next five years. The decreased cash flow will put stress on OG&E's credit metrics, and a decreased cash flow also increases the risk that utility may not be able to satisfy its financial obligations and can harm credit ratings. For example, Standard and Poor's ("S&P") has noted that cash flow support is

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84 *Id.* at 28.

85 *Id.* at 26.

86 *Id.* at 28.

87 *See, e.g.*, *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 65 (2008) ("*Pepco*").

88 *PPL*, 123 FERC ¶ 61,068 at P 47.

89 *See* Rowlett Testimony, Exhibit No. OGE-19 at 3.

90 *Id.* at 4-5.

crucial in maintaining credit quality during upswings in the capital expenditures.[91] The Commission also has recognized that long lead times can impact cash flow.[92]

Second, these expenditures will increase OG&E's debt and will burden OG&E's financial metrics, raising the risk of a credit downgrade.[93] As Mr. Rowlett explains, credit ratings agencies rely largely on two financial ratios to determine if the company has a sufficient level of cash flow to satisfy its obligations: Funds From Operations to Interest Expense ("FFO/Interest") and the ratio of Funds From Operations to Total Debt ("FFO/Total Debt"). Funds From Operations is largely composed of net income and depreciation expense. The more debt and other fixed contractual obligations a company has, the higher the adjusted interest expense and total adjusted debt and the lower the cash flow coverage ratios. This problem is most acute during the construction cycle of large projects, at which time the denominator of both formulas increases while the denominator decreases.

OG&E has very recent experience in this regard.[94] On June 29, 2010, Fitch Ratings downgraded the Issuers Default Rating ("IDR") of OG&E to A from A+. Fitch stated:

> The one-notch downgrade of OG&E is driven by downward-trending credit metrics at the utility as it continues with a capital expenditure program that is significantly higher than the historical norm. The cap-ex, which is being primarily channeled into wind, transmission and smart grid investments, is expected to remain elevated over the next several years based on known and committed projects. While OG&E enjoys constructive regulatory treatment for these investments and has minimal regulatory lag once these projects become operational, there is expected to be pressure on credit metrics during the construction period.[95]

Strong credit ratings are important to OG&E's ability to borrow money at a lower cost.[96] Credit ratings also affect a company's access to capital markets and define its over-all risk profile.

Third, internal competition for capital with other OG&E expenditures raises additional financing challenges.[97] OG&E has a number of additional capital expenditures that will compete with the Projects for financing. OG&E is facing aging utility infrastructure that will require investments higher than historical levels several years into the future. Additionally, OG&E is

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91 Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor's Global Crdit Portal: RatingsDirect* (March 11, 2010), Exhibit No. OGE-24 at 6.

92 Order No. 679 at P 103.

93 *See* Rowlett Testimony, Exhibit No. OGE-19 at 4-5.

94 *See id*. at 6.

95 Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" (June 28, 2010) (Exhibit No. OGE-23).

96 *See* Rowlett Testimony, Exhibit No. OGE-19 at 6.

97 *See id*. at 6-7.

also investing in new Smart Grid technology over the next three years as well as additional obligations in renewable energy and environmental initiatives. OG&E's total projected base transmission, distribution, generation and other capital expenditures through year 2014, as well as the expenditures for the Projects, will be over $3.2 billion. The sheer volume of these capital expenditures means that numerous capital projects will be competing with the Projects in question for funding priority within OG&E.

Fourth, the long lead times associated with the Projects will compound each of these risks.[98] Several of the Projects will not be placed into service until 2014, even though OG&E will incur significant costs in connection with those projects starting right away. These Projects face long lead times with regard to acquisition of rights of way and materials and securing labor resources. This creates risk in terms of cost increases, construction delays and continually building carrying costs. The Commission has found that projects with in-service dates three to four years in the future have long lead times.[99]

Finally, the Projects face commercial risks that could result in the postponement or abandonment of one or more of the Projects. Aspects of the Projects are intended to facilitate development of wind resources. If, however, the generation resources are not constructed some or all of these Projects may no longer be required or may be substantially re-designed.

d. Environmental and other regulatory risks.

In addition to the issues that may arise from the acquisition of rights of way, other unanticipated site-specific concerns may arise that will require additional time for analysis and potential mitigation, and which may lead to delays and/or modification of the Projects.[100] For example, the Woodward-Hitchland and Woodward-Kansas lines cross through the natural habitat of the Lesser Prairie Chicken, a species of bird that is classified as a candidate for future listing as a Threatened Species by the U.S. Fish and Wildlife Service ("USFWS"). Relevant excerpts from the USFWS's Species Report including the Lesser Prairie Chicken are included at Exhibit No. OGE-15.[101] Once the Projects clear the necessary hurdles, there will be challenges associated with building the proposed Projects while minimizing harm to the protected Lesser

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98 *See id*. at 7.

99 *See, e.g.*, *ITC Great Plains, LLC*, 126 FERC ¶ 61,223 at P 82 (2009) (three years); *Green Energy Express LLC*, 129 FERC ¶ 61,165 at P 35 (2009) (three to four years); *PSE&G*, 129 FERC ¶ 61,300 (four years).

100 *See* Crissup Testimony, Exhibit No. OGE-1 at 28-29.

101 The entire USFWS assessment can be found at http://www.fws.gov/ecos/ajax/docs/candforms_pdf/r2/B0AZ_V01.pdf. The Lesser Prairie Chicken is a Candidate Species under the USFWS Endangered Species Act and, for the State of Oklahoma, is currently under the jurisdiction of the Oklahoma Department of Wildlife Conservation ("ODWC"). While there are no defined regulatory approvals that are required when interacting with Lesser Prairie Chicken Habitat in Oklahoma, ODWC and USFWS are providing active guidance to agricultural, wind farm development and transmission construction interests in order to limit the possibility of the Lesser Prairie Chicken moving from a Candidate Species to an Endangered Species.

Prairie Chicken habitat. The Commission has recognized that siting of transmission facilities within endangered species habitats presents the type of risk relevant to the nexus analysis.[102]

Other environmental concerns also may pose risks to the Projects. For example, a recent lawsuit was filed by two environmental groups challenging the construction of the John W. Turk, Jr. Power Plant, which the Sunnyside-Hugo project transmission line is designed to support. The outcome of this litigation is uncertain and its impact (if any) on the construction and operation of the Turk plant or on the Sunnyside-Hugo Project is far from clear. At the very least, however, this lawsuit adds new uncertainties to the Project.

3. The Total Package of Requested Incentives is Tailored to the Specific Risks and Challenges of the Projects.

The requested incentives are necessary to mitigate these risks, will provide OG&E with up-front certainty, and will reduce the financial pressure on OG&E that would otherwise occur from the financing and construction of the Projects. The CWIP and Abandoned Plant incentives are tailored to the specific risks and challenges of the Projects. Notably, OG&E has not sought to implement certain of the potential transmission incentives identified in Order No. 679, most significantly an increased ROE, but has instead submitted revised tariff sheets to adopt a narrowly-focused set of incentives that are designed around the Projects for which the incentives will apply. The Commission has previously relied on similar considerations to approve requested CWIP and Abandoned Plant incentives.[103]

With regard to CWIP, the Commission has recognized that inclusion of 100 percent of CWIP in rate base can promote transmission investment, provide up-front regulatory certainty to investors, stabilize rates, and improve cash flow.[104] The Commission has indicated that it will grant the CWIP incentive where the transmission investment is large or "where denying such an incentive would adversely affect the utility's ratings."[105] As discussed above and in the testimony of Donald R. Rowlett, the substantial level of investment OG&E will make in the Projects – approximately $936 million over the next 4 years – as well as the long lead times associated with some of the Projects will place a major strain on OG&E's cash flow. The CWIP incentive will ease this strain by ensuring adequate cash flow during the construction phase of the Projects.[106] Exhibit No. OGE-20 demonstrates the difference in cash flow OG&E would experience between receiving the 100 percent CWIP incentive as compared to AFUDC treatment. Also included as Exhibit No. OGE-21 is a summary of the cash flow to debt impact of CWIP in rate base. These exhibits demonstrate that without CWIP in rate base, OG&E's ability to pay the interest on its debt decreases.

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[102] *See, e.g.*, *Pepco*, 124 FERC ¶ 61,176 at P 72.

[103] *See Xcel Energy Services, Inc.*, 121 FERC ¶ 61,284 at PP 59, 63 (2007) ("*Xcel*"); *Otter Tail*, 129 FERC ¶ 61,287 at PP 31, 33; *Great River Energy*, 130 FERC ¶ 61,001 at PP 33, 35 (2010) ("*Great River*").

[104] Order No. 679 at P 115. *See, e.g.*, *Otter Tail*, 129 FERC ¶ 61,287 at P 32.

[105] Order No. 679 at P 117.

[106] *See* Rowlett Testimony, Exhibit No. OGE-19 at 8-10.

The improved cash flow provided by the CWIP incentive also will help OG&E maintain its credit ratings, which could be harmed by a negative cash flow.[107] The Fitch Report that addressed the potential challenges facing OG&E and which downgraded OG&E's IDR from A+ to A noted the positive effect of the requested CWIP incentive: "[o]ther favorable regulatory mechanisms if implemented, such as cash recovery of capital costs during construction work in progress, would be viewed as credit enhancing by Fitch."[108] As noted by Fitch, the CWIP incentive can prevent a possible credit downgrade by providing more stable cash flow and decreasing financial risk. Avoiding a credit rating downgrade is important because a downgrade would increase borrowing costs and thereby increase rates for customers.[109]

Because 100 percent CWIP recovery reduces downward pressure on OG&E's credit ratings, OG&E would be able to borrow money at a lower cost. Not having to finance AFUDC costs would also help OG&E to minimize the final amount of capital expenditures incurred to complete the Projects.[110] Exhibit No. OGE-20 shows that, over four years, OG&E would avoid the need to finance approximately $66.6 million of costs through the inclusion of CWIP in rate base and interest costs would be approximately $8.9 million less when CWIP is included in rate base. The certainty of cost recovery provided by the CWIP incentive also will allow the Projects to compete effectively with other transmission projects for financing.

Allowing OG&E to recover CWIP in its rate base will also benefit customers through greater rate stability.[111] Absent including CWIP in rate base, transmission customers may experience rate shock when large-scale transmission projects are placed into service.[112] The CWIP incentive allows for a project's costs to be more gradually incorporated into rates over the course of the construction period.

Similarly, with regard to recovery of the future costs of Abandoned Plant, the Commission has recognized that allowing a utility to recover 100 percent of prudently incurred costs if a transmission project is abandoned for reasons outside the control of the utility's management is an "effective means to encourage transmission development by reducing the risk of non-recovery of costs."[113] The Projects face substantial risks that warrant approval of the

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[107] *See id.* at 8. *See also, e.g., PSE&G*, 129 FERC ¶ 61,300 at P 44; *Am. Elec. Power Serv. Corp.*, 116 FERC ¶ 61,059 at P 59 (2006), *order on reh'g*, 118 FERC ¶ 61,041 at P 27 (2007); *PPL*, 123 FERC ¶ 61,068 at P 43.

[108] Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" (June 28, 2010) (Exhibit No. OGE-23).

[109] *See* Rowlett Testimony, Exhibit No. OGE-19 at 10.

[110] *See id.* at 8-9.

[111] *Id.* at 11.

[112] *See, e.g., Duquesne Light Co.*, 125 FERC ¶ 61,028, at P 37 (2008); *Southern Indiana Gas & Elec. Co.*, 125 FERC ¶ 61,124, at P 42 (2008).

[113] Order No. 679 at P 163. The OG&E OATT contains an abandoned plant provision, which is similar to the FERC Order No. 679 incentive. Section VIII of Attachment J of the SPP OATT states: "The costs of Network Upgrades that are not completed through no fault of the Transmission Owner charged with construction of the upgrades shall be handled as follows: If a proposed Network Upgrade was accepted and approved by the Transmission Provider, the Transmission Provider shall develop a mechanism to recover such costs and distribute

Abandoned Plant incentive. There a number of environmental and regulatory factors that may lead to the eventual abandonment of some or all of the Projects. For example, OG&E must secure rights of way for the length of the Projects, as well as numerous regulatory approvals, and there is the potential that OG&E may not be able to secure all the necessary lands and approvals. In addition, the Projects cross environmentally sensitive lands, including the habitat of the protected Lesser Prairie Chicken, a factor that creates material risk that portions of the Projects may be forced to be abandoned.[114]

In sum, the combination of CWIP recovery and the potential for future recovery of abandoned plant costs are closely tied to the risks and challenges associated with the Projects and adoption of the requested incentives will reduce these risks and challenges and remove potential obstacles to the construction of the Projects. This "package" of incentives is focused on responding to the risks faced by the Projects and reducing disincentives to their construction. The Commission itself has noted the linkage of these two incentives.[115]

C. The Resulting Rates are Just and Reasonable.

In Order No. 679, the Commission endorsed single-issue incentives filings.[116] The Commission stated that "applicants for single-issue ratemaking are only required to address cost and rate issues associated with the new investment and therefore are not obligated to justify the reasonableness of unchanged rates."[117]

In this case, the proposed incentive rates are just and reasonable. As the Commission has found, CWIP recovery "merely affects the timing of cost recovery, and not the level of cost recovery."[118] Further, as Mr. Rowlett explains, the CWIP incentive may serve to lower costs paid by OG&E's customers by preventing increases in OG&E's borrowing costs and by reducing financing expenses associated with AFUDC.[119] For example, as discussed above, Exhibit No. OGE-20 shows that, over four years, OG&E would avoid the need to finance approximately

(continued…)

such revenue on a case by case basis. Such recovery and distribution mechanism shall be filed with the Commission. The Transmission Owner(s) that incurred the costs shall be reimbursed for those costs by the Transmission Provider. These costs shall include, but are not limited to: the costs associated with attempting to obtain all necessary approvals for the project, study costs, and any construction costs." Because this provision has not been applied in practice, and therefore the scope of its application is unclear, OG&E is requesting the Order No. 679 abandoned plant incentive to ensure recovery of its prudently incurred costs if the Projects are abandoned for reasons outside of OG&E's control.

114 *See* Crissup Testimony, Exhibit No. OGE-1 at 28-29.

115 Order No. 679 at P 117.

116 *Id.* P 191.

117 Order No. 679-A at P 98.

118 *See, e.g., id.* P 38; *Great River*, 130 FERC ¶ 61,001 at P 40.

119 *See* Rowlett Testimony, Exhibit No. OGE-19 at 10-11.

$66.6 million of costs through the inclusion of CWIP in rate base, and interest costs would be approximately $8.9 million less. These reduced financing expenses would benefit customers.

Moreover, approval of the requested Abandoned Plant incentive will not affect OG&E's existing transmission rates because OG&E is not seeking to recover these costs currently.[120] In the event that OG&E seeks to recover abandoned plant costs, it will make an FPA Section 205 filing in which it will show that the costs to be recovered were prudently incurred and that the Projects were abandoned for reasons beyond OG&E's control.

IV. REQUESTED TARIFF CHANGES.

OG&E's transmission rates are calculated pursuant to a FERC-approved formula, which is on file with FERC as an appendix to the OG&E OATT and the SPP OATT. The current rate formula does not have a placeholder to allow the automatic inclusion of the requested CWIP incentive. Accordingly, OG&E proposes certain revisions to the rate formula in order to implement the CWIP incentive requested herein.[121] OG&E then will populate its formula rate template with the costs of CWIP for the Projects.[122] OG&E also proposes two changes to the Formula Rate Implementation Protocols to ensure that the Protocols apply to the CWIP associated with the Projects;[123] CWIP balances and any future costs associated with Abandoned Plant will be included in OG&E's annual True-Up calculation of its Formula Rate in the same manner as all other aspects of the Formula Rate.[124] Further, although OG&E's rate formula template does contain a placeholder for the Abandoned Plant incentive, OG&E proposes tariff changes to supplement and clarify the specific mechanism for recovery of abandoned plant costs.[125] Finally, OG&E proposes to implement two additional changes to its OATT and to the SPP OATT to correct an error and an omission in its formula rate template.[126] These tariff revisions are each described in the testimony of David L. Kays at Exhibit No. OGE-17, and the revised tariff pages are included at Attachments 1 through 4.

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[120] *See, e.g.*, *Great River*, 130 FERC ¶ 61,001 at P 40 ("Great River's request for Abandoned Plant Recovery will not affect Great River's transmission rates because Great River is not currently seeking to recover any such abandoned plant cost associated with the projects").

[121] *See* Kays Testimony, Exhibit No. OGE-17 at 5-7.

[122] A populated version of OG&E's Formula Rate template illustrating the CWIP incentive is included for informational purposes at Exhibit No. OGE-18.

[123] *See* Kays Testimony, Exhibit No. OGE-17 at 5-7.

[124] *Id.* at 9-10.

[125] *Id.* at 8-9. OG&E does not seek herein to recover abandoned plant costs through its formula rate currently. In the event that OG&E seeks to recover these costs, OG&E will make a future Section 205 filing to do so.

[126] *Id.* at 10.

V. COMMUNICATIONS.

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VI. ADDITIONAL FILING REQUIREMENTS AND REQUEST FOR WAIVERS.

A. Advanced Technology Statement.

The Commission requires applicants seeking transmission rate incentives to provide a technology statement describing "what advanced technologies have been considered and, if those technologies are not to be employed or have not been employed, an explanation of why they were not deployed."[127] Advanced technologies are defined as technologies "that increase[] the capacity, efficiency, or reliability of an existing or new transmission facility."[128]

As discussed in Mr. Crissup's testimony, OG&E intends to employ certain advanced technologies in the Projects for which incentives are requested. Specifically:

- OG&E is installing SEL-421 relays for standard line protection on EHV transmission. These relays are capable of transmitting synchro-phasor data, which are the line currents and voltages (magnitude and angle) synchronized to a GPS time standard. The purpose of this advanced technology is to expand OG&E's ability to collect data from strategic locations across the transmission system. This information is processed for analysis, display and archival purposes in order to improve system efficiency and reliability.

- OG&E is planning synchro-phasor implementation for 14 substations and 25 relays within the OG&E Projects. The benefits to synchro-phasor implementation are check phasing of Current Transformers and Potential Transformers, advanced fault analysis,

127 Order No. 679 at P 302.

128 Energy Policy Act of 2005, Pub. L. No. 109-58, § 1223(a), 119 Stat. 594, 953 (2005).

wide area disturbance recording, monitoring of transmission system stability, the ability to import actual data for state estimation, measure line constraints and wide area protection schemes.

- OG&E is installing fiber optic cable and related systems with these Projects to allow for faster, more reliable communication among the substations. Fiber optic cable is replacing existing carrier system technology involving signals sent through transmission wires themselves. In addition to being more reliable, fiber optic cable also allows for future potential applications to be developed through OG&E's Smart Grid program.

B. Additional Requirements Applicable to Requested CWIP Recovery.

1. Statement BM.

Section 35.13(h)(38) of the Commission's regulations requires an applicant seeking to include CWIP in rate base to submit a Statement BM in support of the CWIP request. OG&E witness Donald R. Rowlett has prepared a Statement BM in support of OG&E's CWIP request, and he describes the contents of the statement in his testimony.[129] The statement is included as Exhibit No. OGE-22, an attachment to Mr. Rowlett's testimony. This exhibit explains how the proposed Projects are prudent and consistent with a least-cost energy supply program, and describes how the SPP planning processes relevant to the Projects identify reliability and economic upgrades and how alternatives were considered to reduce costs to customers.

2. Accounting to Protect Against Double Recovery.

The Commission's regulations require that any utility that includes CWIP in rate base "must discontinue the capitalization of any AFUDC related to those amounts of CWIP in rate base."[130] Additionally, the utility must propose accounting procedures to "[e]nsure that wholesale customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP proposed to be included in rate base . . . [or] for any corresponding AFUDC capitalized as a result of different accounting or ratemaking treatments accorded CWIP by state or local regulatory authorities."[131] To satisfy these requirements, OG&E will not accrue AFUDC in Account 107, Construction Work in Progress.[132] Moreover, OG&E will use the SAP plant accounting system to maintain its accounting records for CWIP electric plant assets during construction and after the Projects are placed into service. The SAP system includes the capability to identify specific work orders that should not be included in the calculation and capitalization of AFUDC. The work orders related to the Projects will be identified in SAP, and no AFUDC will be calculated on their balances. This will prevent a double-recovery of CWIP

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129 *See* Rowlett Testimony, Exhibit No. OGE-19 at 14.

130 18 C.F.R. § 35.25(e) (2010).

131 18 C.F.R. § 35.25(f) (2010).

132 *See* Rowlett Testimony, Exhibit No. OGE-19 at 12-13.

and capitalized AFUDC on the same rate base items. If OG&E is accorded different ratemaking treatment of CWIP by the OCC or APSC, any accrued AFUDC would be recorded in FERC Account 182.3 Other Regulatory Assets. The AFUDC regulatory asset would be amortized over the depreciable life of the Projects. The amortization amount would be debited to FERC Account 407.3 Regulatory Debits. The AFUDC regulatory asset and associated amortization would not be included in the rate charged to OG&E's wholesale transmission customers.

3. Specific Accounting Treatment.

The Commission has noted that, where a utility proposes to recover a current return on CWIP, this cost is recovered in a different period than ordinarily would occur under the Uniform System of Accounts. Accordingly, to maintain the comparability of financial information among entities, the Commission has required utilities recovering a current return on CWIP to "debit through FERC Account 407.3, Regulatory Debits, and credit through FERC Account 254, Other Regulatory Liabilities, in accordance with the objectives of those accounts. Amounts recorded in FERC Account 254 related to return on the proposed Project[s] must be deducted from the rate base."[133] However, the Commission has granted waiver of that accounting treatment and permitted utilities, in lieu, to use footnote disclosures.[134] Consistent with this precedent, OG&E requests waiver of the specific accounting treatment and proposes instead to use footnote disclosures.[135]

4. Request for Waiver of 18 C.F.R. §§ 35.25(c)(4) and (g).

Section 35.25(c)(4) of the Commission's regulations requires that, to address the potential for anti-competitive effects resulting from CWIP recovery including the potential for prices squeeze and double whammy, an applicant seeking to include CWIP in rate base develop "forward looking allocation ratios reflecting the anticipated average annual use the wholesale customers will make of the system over the estimated service life of the project." The Commission has determined that this Section should be waived as to the double whammy concern.[136] Section 35.25(g) of the Commission's regulations requires additional information on the potential anti-competitive impacts of CWIP recovery. The required information includes:

> (i) The percentage of the proposed increase in the jurisdictional rate level attributable to non-pollution control/fuel conversion CWIP and the percentage of non-pollution control/fuel conversion CWIP supporting the proposed rate level; (ii) The percentage of non-pollution control/fuel conversion CWIP permitted by the state or local commission supporting the current retail rates of the public utility against which the relevant wholesale customers compete; and (iii)

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[133] *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058 at P 106 (2006), *order on reh'g*, 118 FERC ¶ 61,042 (2007).

[134] *See, e.g.*, *Tallgrass*, 125 FERC ¶ 61,248 at P 80 (referencing *Am. Transmission Co. LLC*, 105 FERC ¶ 61,388 (2003), *order on reh'g*, 107 FERC ¶ 61,117 at PP 16-17 (2004); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, *order on reh'g*, 121 FERC ¶ 61,009 (2007); and *So. Cal. Edison Co.*, 122 FERC ¶ 61,187 (2008)).

[135] *See* Rowlett Testimony, Exhibit No. OGE-19 at 13-14.

[136] *See* Order No. 679 at P 119.

> Individual earned rate of return analyses of each of the competing retail rates developed on a basis fully consistent with the wholesale cost of service for the same test period if the requested percentage of wholesale non-pollution control/fuel conversion CWIP exceeds that permitted by the relevant state or local authority to support the currently competing retail rates.[137]

OG&E respectfully requests waiver of Sections 35.25(c)(4) and (g). These regulations mainly address concerns about the potential for anti-competitive effects resulting from the inclusion of generation-related CWIP in rates. These concerns are less significant with respect to transmission-related CWIP, which is at issue in this filing. OG&E has included in this filing evidence showing the projected CWIP balances for the year 2011,[138] the estimated amount of CWIP to be included in rate base for years 2011 to 2014,[139] as well as a comparison of the rate impact on customers of the CWIP recovery versus the AFUDC approach.[140] OG&E believes this information, as well as the additional information included in this application, is sufficient to satisfy Sections 35.25(c)(4) and (g). To the extent it has not fulfilled these requirements, OG&E requests waiver of Sections 35.25(c)(4) and (g).

5. Annual Filing Requirement.

In Order No. 679, the Commission "determined that recovery of CWIP on a formulary basis is not permitted without prior Commission review. The Commission will allow public utilities to propose a method to limit their filing requirement related to CWIP to an annual filing."[141] Consistent with this policy, OG&E requests permission to satisfy the CWIP filing requirement through an annual submission of the FERC Form 730.[142]

C. Request for Waiver of Cost of Service Statements.

The testimony of David L. Kays describes the proposed tariff changes to the formula rate in lieu of full Statements AA through BL. Consistent with this approach, OG&E respectfully requests waiver of Section 35.13 of the Commission's regulations, including the requirements to submit Period I and II data. The Commission has recognized that these cost of service statements are not necessary with respect to formula rates, which are based on a utility's actual costs.[143] Moreover, the attached testimony provides the necessary support for the proposed tariff revisions.

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137 18 C.F.R. § 35.25(g) (2010).

138 *See* Kays Tesitmony, Exhibit No. OGE-17 at 7-8.

139 *See* "Summary of Cash Flow and Interest Impact," Exhibit No. OGE-20.

140 *See* Rowlett Testimony, Exhibit No. OGE-19 at 10.

141 Order No. 679 at P 121.

142 The Commission has permitted this approach in past cases. *See, e.g., Otter Tail*, 129 FERC ¶ 61,287 at P 34; *Xcel*, 121 FERC ¶ 61,284 at P 68.

143 *See, e.g., Oklahoma Gas and Electric Co.*, 122 FERC ¶ 61,071 at P 41 (2008).

D. Request for Waiver of Electronic Filing Requirements of 18 C.F.R. §35.7.

Section 35.7 of the Commission's regulations requires parties to submit tariff filings through the Commission's electronic filing system. On October 7, 2010, OG&E filed a "Request for Waiver of Baseline Electronic Filing Requirements" explaining that it had not yet been able to submit its baseline tariff filing and requesting waiver of the Commission's regulation to allow OG&E to submit its baseline filing on or before November 15, 2010. For the reasons stated therein, OG&E respectfully requests that the Commission waive its regulations to the extent necessary to accept this filing.

E. Posting and Service.

Pursuant to Sections 35.1(a) and 35.2(e) of the Commission's regulations, a copy of this filing is being served on SPP, the Oklahoma Corporation Commission, the Arkansas Public Service Commission, and all of SPP's and OG&E's OATT customers. In addition, a complete copy of this filing is available on the OG&E OASIS.

VII. EFFECTIVE DATE.

OG&E respectfully requests that the proposed tariff changes included herein be made effective January 1, 2011.

VIII. CONCLUSION

For the foregoing reasons, OG&E respectfully requests that the Commission grant OG&E the CWIP and Abandoned Plant incentives with respect to the Projects discussed herein and accept the enclosed tariff sheets for filing. OG&E requests that the proposed tariff revisions be made effective on January 1, 2011.

Respectfully submitted,

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ATTACHMENT 1

PROPOSED SPP OPEN ACCESS TRANSMISSION TARIFF SHEETS (CLEAN)

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

Oklahoma Gas and Electric Company

Index of Worksheets

	Worksheet	Description
1	Worksheet	Description
2	Attachment H - Addendum 2-A	Rate Formula Template Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy and " Data"
3	Worksheet A	Account 454, Rent from Electric Property
4		Account 456, Other Electric Revenues
4		Account 456.1, Revenues from Transmission of Electricity of Others, Current Year Less Credits
5		Revenue from Grandfathered Interzonal Transactions and amounts received from SPP for PTP service
6	Worksheet B	Transmission Network Load (MW)
7	Worksheet C	Account 281, Accumulated Deferred Income Taxes - Accelerated Amortization Property
8		Account 282, Accumulated Deferred Income Taxes - Other Property
9		Account 283, Accumulated Deferred Income Taxes - Other
10		Account 190, Accumulated Deferred Income Taxes
11		Account 255, Accumulated Deferred Investment Tax Credits
12	Worksheet D	Account 928, Regulatory Commission Expense Allocations
13		Account 930.1, General Advertising Allocations (safety related only to trans.)
14		Account 930.2, Miscellaneous General Expenses
15		Transmission Lease Payments
16	Worksheet E	Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility
17	Worksheet F	Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase
18		Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase
19		Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives
20	Worksheet G	Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities
21	Worksheet H	Transmission Plant Adjustments
22	Worksheet I	Plant Held for Future Use
23	Worksheet J	Development of Composite State Income Tax Rates
24	Worksheet K	13 Month Balances for Plant & Accumulated Depreciation, Material & Stores and Debt & Equity
25		Account 165, Prepayments Calculation
26		Long Term Debt Cost Calculation
27	Worksheet L	True-Up Adjustment with Interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation
28	Worksheet M	Depreciation Rates
29	Worksheet N	Unfunded Reserves Calculation
30	Worksheet O	Amortizations for Extraordinary O&M and Storm Costs
31	Worksheet P	Construction Work in Progress and Abandoned Plant Balances

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

For rates effective mmm dd, yyyy

Line No.					Transmission Amount
1	NET SPP OATT RELATED UPGRADE REV. REQ.	(Addendum 2-A, ln 17 - ln 18)			$ -
2	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(Addendum 2-A, ln 21)			-
3	DIVISOR				
4	TO's Transmission Network Load	(Worksheet B, ln 14)			-
5	RATES				
6	Annual Cost ($/kW/Yr)	(ln 2 / ln 4)	-		
7	P-to-P Rate ($/kW/Mo)	(ln 6 / 12)	-		
			Peak		Off-Peak
8	Weekly P-To-P Rate ($/kW/Wk)	(ln 6 / 52; ln 6 / 52)	-		-
9	Daily P-To-P Rate ($/kW/Day)	(ln 8 / 5; ln 8 / 7)	-	Capped at weekly rate	-
10	Hourly P-To-P Rate ($/MWh)	(ln 9 / 16; ln 9 / 24 both x 1,000)	-	Capped at weekly & daily rate	-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.			Total	Allocator		Transmission Amount
11	REVENUE REQUIREMENT (w/o incentives)	(ln 117)				$ -
12	REVENUE CREDITS	(Note A)				
13						$ -
14	Other Transmission Revenue	(Worksheet A)	-	DA	1.00000	$ -
15	Total Revenue Credits		-			$ -
16	NET REVENUE REQUIREMENT (w/o incentives)	(ln 11 less ln 15)				$ -
17	SPP OATT RELATED UPGRADES REVENUE REQUIREMENT	(Worksheet G & P) (Note X)				$ -
18	SPP OATT RELATED UPGRADES REV. REQ. TRUE-UP	(Worksheet L)				$ -
19	PRIOR YEAR TRUE-UP ADJUSTMENT w/INTEREST	(Worksheet L)				$ -
20	ADDITIONAL REVENUE REQUIREMENT (w/ incentives)	(Note C) & (Worksheet F, ln 61)				$ -
21	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(ln 16 - ln 17 - ln 18 - ln 19 + ln 20)				$ -
22	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)				
23	Annual Rate	((ln 16 / ln 46) x 100)				0.00%
24	Monthly Rate	(ln 23 / 12)				0.00%
25	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)				
26	Annual Rate	(((ln 16 - ln 92) / ln 46) x 100)				0.00%
27	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)				
28	Annual Rate	(((ln 16 - lns 92 - ln 115 - ln 116) / lns 46) x 100)				0.00%

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
29	GROSS PLANT IN SERVICE					
30	Production	(Worksheet K)	-	NA		
31	Transmission	(Worksheet K)	-	TP	0.00000	-
32	Distribution	(Worksheet K)	-	NA		
33	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
34	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
35	TOTAL GROSS PLANT	(sum lns 30 to 34)	-			-
36	GROSS PLANT ALLOCATOR	(ln 35 - Col. 5 / Col. 3)		**GP=**	**0.000000**	
37	ACCUMULATED DEPRECIATION					
38	Production	(Worksheet K)	-	NA		
39	Transmission	(Worksheet K)	-	TP	0.00000	-
40	Distribution	(Worksheet K)	-	NA		
41	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
42	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
43	TOTAL ACCUMULATED DEPRECIATION	(sum lns 38 to 42)	-			-
44	NET PLANT IN SERVICE					
45	Production	(ln 30 - ln 38)	-	NA		
46	Transmission	(ln 31 - ln 39)	-			-
47	Distribution	(ln 32 - ln 40)	-	NA		
48	General Plant	(ln 33 - ln 41)	-			-
49	Intangible Plant	(ln 34 - ln 42)	-			-
50	TOTAL NET PLANT IN SERVICE	(sum lns 45 to 49)	-			-
51	NET PLANT ALLOCATOR	(ln 50 - Col. 5 / Col. 3)		**NP=**	**0.000000**	
52	ADJUSTMENTS TO RATE BASE	(Note D)				
53	Account No. 281	(Worksheet C)	-			-
54	Account No. 282	(Worksheet C)	-			-
55	Account No. 283	(Worksheet C)	-			-
56	Account No. 190	(Worksheet C)	-			-
57	Account No. 255	(Worksheet C)	-			-
58	Unfunded Reserves	(Worksheet N)	-	DA	1.00000	-
59	TOTAL ADJUSTMENTS	(sum lns 53 to 57)	-			-
60	UNAMORTIZED ABANDONED PLANT	(Worksheet P) (Note R)	0	DA	1.00000	0
60a	Construction Work in Progress (CWIP)	(Worksheet P) (Note Z)	0	DA	1.00000	0
61	LAND HELD FOR FUTURE USE	(Worksheet I) (Note F)	-	TP	0.00000	-
62	WORKING CAPITAL	(Note G)				
63	CWC	(1/8 * ln 90)	-			-
64	Materials & Supplies -- Transmission Related	(Worksheet K) (Note S)	-	TP	0.00000	-
65	Prepayments (Account 165)	(Worksheet K)	-	GP	0.00000	-
66	TOTAL WORKING CAPITAL	(sum lns 63 to 65)	-			-
67	RATE BASE (sum lns 50, 59, 60, 61, 66)		-			-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) **EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total**	(4) **Allocator**		(5) **Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
68	Transmission	321.112.b				
68a	Less Extraordinary & Storm Cost Amortization	(Worksheet O) (Note Y)	-			
69	Less expenses for LSE cost responsibility	(Worksheet E, ln 14)				
70	Less Account 561 (Load Dispatching)	321.84-92.b (Note P & U)				
71	Less Account 565	321.96.b (Note I)				
72	Plus Acct 565 native load, zonal or pool	(Note I)				
73	Transmission Subtotal	(ln 68 - ln 69 - ln 70 - ln 71 + ln 72)	-	TP	0.00000	-
74	Administrative and General	323.197.b (Note J)		NA		
75	Less: Acct. 924, Property Insurance	323.185.b		NA		
76	Less: Acct. 928, Reg. Com. Exp.	323.189.b		NA		
77	Less: Acct. 930.1, Gen. Advert. Exp.	323.191.b		NA		
78	Less: Acct. 930.2, Misc. General Exp.	323.192.b				
79	Less: PBOP amount included in Line 73	(Note T)				
80	Balance of A & G	(ln 74 - sum ln 75 to ln 79)	-	W/S	0.00000	-
81	Plus: Acct. 924	(ln 75)	-	GP	0.00000	-
82	Plus: Acct. 928 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
83	Plus: Acct. 928 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
84	Plus: Acct. 930.1 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
85	Plus: Acct. 930.1 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
86	Plus: Acct. 930.2 - Adj. Misc. General Expenses	(Worksheet D)	-	W/S	0.00000	-
87	Plus: PBOP Amount	(Note T)	-	W/S	0.00000	-
88	A & G Subtotal	(sum lns 80 to 87)	-			-
89	Transmission Lease Payments	(Worksheet D)	-	DA	1.00000	-
90	TOTAL O & M EXPENSE	(ln 73 + ln 88 + ln 89)	-			-
91	DEPRECIATION AND AMORTIZATION EXPENSE					
92	Transmission	336.7.b		TP	0.00000	-
93	Plus: Extraordinary & Storm Cost O&M Amortization	(Worksheet O) (Note W)	-	TP	0.00000	-
94	Plus: Recovery of Abandoned Incentive Plant	(Worksheet P) (Note R)	0	DA	1.00000	0
95	General	336.10.b		W/S	0.00000	-
96	Intangible	336.1.f		W/S	0.00000	-
97	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 92 to 96)	-			-
98	TAXES OTHER THAN INCOME	(Note L)				
99	Labor Related					
100	Payroll	263.i		W/S	0.00000	-
101	Plant Related					
102	Property	263.i		GP	0.00000	-
103	Gross Receipts	263.i				
104	Other	263.i		GP	0.00000	-
105	TOTAL OTHER TAXES	ln 100 + (sum lns 102 to 104)	-			-
106	INCOME TAXES	(Note M)				
107	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
108	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
109	where WCLTD=(ln 137) and R= (ln 140)					
110	and FIT, SIT & p are as given in Note M.					
111	1 / (1 - T) = (from ln 107)		-			
112	Amortized Investment Tax Credit	266.8.f (enter negative)				
113	Income Tax Calculation	(ln 108 * ln 116)	-	NA		-
114	ITC adjustment	(ln 111 * ln 112)	-	NP	-	-
115	TOTAL INCOME TAXES	(sum lns 113 to 114)	-			-
116	RETURN (Rate Base * Rate of Return)	(ln 67 * ln 140)	-	NA		-
117	REVENUE REQUIREMENT (sum lns 90, 97, 105, 115, 116)		-			-

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes - continued

V Accumulated Amortization for Intangible Plant shall be reflected as a Rate Base Adjustment under "Accumulated Depreciation".
W OG&E may only include the amortization of transmission-related extraordinary property losses if; (1) OG&E makes a filing with the Oklahoma Corporation Commission requesting approval for the new amount to be recovered and the amortization period and (2) OG&E makes a single issue FPA Section 205 filing that requests the same recovery treatment from the FERC. OG&E shall be obligated to make such a single issue FPA Section 205 filing whenever it requests amortized extraordinary property loss costs recovery from the Oklahoma Corporation Commission.
X SPP OATT Related Upgrades include Base Plan Upgrades, Sponsored, Economic Portfolio Upgrades, Transmission Service Upgrades and Generator Interconnection Facilities, etc. whose individual Revenue Requirements are calculated and summarized in Worksheet G. Also included are the individual Revenue Requirements of facilities receiving Construction Work in Progress and Abandoned Plant incentives, as calculated and summarized in Worksheet P. The sum of the individual Revenue Requirements is credited to zonal network customers on line 17 above.
Y Exclude annualized amortization amounts booked back into O&M accounts that costs would have been booked had not a Regulatory Asset and amortization period been approved by the Oklahoma Corporation Commission and the FERC. This amount should equal amount reflected on line 93.
Z OG&E may only recover CWIP on projects that the FERC has specifically authorized the incentive.

List of Allocators:		
Direct Assigned	DA	1.000000
Gross Plant	GP	0.000000
Net Plant	NP	0.000000
Trans. Plant in SPP	TP	0.000000
Wages & Salaries	W/S	0.000000
No Allocator	NA	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

III. Base Plan Upgrade True-Up Calculations

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year on Base Plan Upgrade Projects.

18 Average Interest Rate on Amount of Refunds or Surcharges calculated per Section V below.

	Proj. No.		Projected ATRR - Prior Year (1)	Baseline ATRR - Prior Year (2)	True-Up Adjustment Without Interest	Refund / (Surcharge) 0	Refund / (Surcharge) 1	Refund / (Surcharge) 2
19	1	Reno-Sunny Lane 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
20	2	Richards Tap-Richards 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
21	3	Van Buren AVEC-Van Buren Interconnect 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
22	4	Brown Explorer Tap 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
23	5	NE Enid-Glenwood 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
24	6	Razorback-Short Mountain 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
25	7	Richards-Piedmont 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
26	8	OG&E Windfarm-WFEC Mooreland 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
27	9	Ft. Smith-Colony 161kV Line	$ -	$ -	$ -	$ -	$ -	$ -
28	10	Cedar Lane-Canadian 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -

29 **TOTAL PRIOR YEAR BASE PLAN UPGRADE PROJECTS TRUE-UP ADJUSTMENT** (sum ln 19 thru ln 28) **$ -**

NOTE: (1) Projected ATRR for individual Base Plan Projects comes from the Prior Year's Projected ATRR calculation, Worksheet G and Worksheet P - Summary page
(2) Baseline ATRR for individual Base Plan Projects comes from the Prior Year Baseline ATRR calculation, Worksheet G and Worksheet P - Summary page

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

I. Project Summary

Proj. No.	A. CWIP Annual Transmission Revenue Requirements — Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	CWIP Totals	

Proj. No.	B. Abandoned Plant Annual Transmission Revenue Requirements — Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	Abandoned Plant Totals	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant Balances

II. Construction Work in Progress (CWIP) Balances

Line No.	Month	Year	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
1	December	2010											
2	January	2011											
3	February	2011											
4	March	2011											
5	April	2011											
6	May	2011											
7	June	2011											
8	July	2011											
9	August	2011											
10	September	2011											
11	October	2011											
12	November	2011											
13	December	2011											
14	Average Balances												
15	Return	(Data Ln 140 * Ln 14)	0										
16	Taxes	(Data Ln 108 * Ln 15)	0										
17	ATRR	(Ln 15 + Ln 16)	0										

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

III. Abandoned Plant

Line No.			Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
18	**Abandoned Plant Balance**												
19	**Amortization Period (months)**												
20	**Monthly Amortization Amount**												
	Month	Year											
21	**December**	2010											
22	**January**	2011											
23	**February**	2011											
24	**March**	2011											
25	**April**	2011											
26	**May**	2011											
27	**June**	2011											
28	**July**	2011											
29	**August**	2011											
30	**September**	2011											
31	**October**	2011											
32	**November**	2011											
33	**December**	2011											
34	**Average Balances**												
35	**Return**	(Data Ln 140 * Ln 34)	0										
36	**Taxes**	(Data Ln 108 * Ln 35)	0										
37	**Amortization Abandoned Plant** (Beg. Bal. less End. Bal.)		0										
38	**ATRR**	(Ln 35 + Ln 36 + Ln 37)	0										

ADDENDUM 2-B to ATTACHMENT H
OG&E FORMULA RATE IMPLEMENTATION PROTOCOLS

I. Annual Update and True-Up Adjustments

1.1 The formula rate template contained in Attachment H – Addendum 2-A and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Oklahoma Gas and Electric Company ("OG&E") for transmission service under the Open Access Transmission Tariff ("OATT") of the Southwest Power Pool, Inc. ("SPP"). OG&E shall follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR"), rates for its Point-to-Point transmission service, and the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades.

1.2 The Formula Rate shall initially be effective for service on and after July 1, 2008, through December 31, 2008, and shall be applicable thereafter for services in subsequent years on and after January 1 of each calendar year through December 31 of that calendar year ("Rate Year"). The purpose of these protocols is to establish a set of procedures that may be used by Interested Parties (as defined in Section 1.3(a)(4) herein) to review and challenge Annual Updates and True-Up Adjustments, as defined herein. Provided, however, (i) nothing herein shall limit the rights of OG&E or any Interested Party to initiate a proceeding at the Federal Energy Regulatory Commission ("Commission") at any time with respect to the Formula Rate consistent with the Party's rights under the Federal Power Act ("FPA") and the Commission's regulations and (ii) the provisions of these Protocols applicable to review and challenge of Annual Updates and True-Up Adjustments shall not apply to proceedings other than (a) Formal Challenges initiated in accordance with the procedures set forth herein and/or (b) proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment, and shall not be relied upon to alter any Party's rights or obligations under the FPA and the Commission's regulations in proceedings other than such Formal Challenges and/or proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment. The term "Party" or "Parties" is defined to include OG&E and/or one or more Interested Parties.

1.3 Posting of Annual Update and Related Procedures

(a) On or before September 1 of each calendar year (unless September 1 falls on a weekend or a holiday recognized by the Commission, in which case the date shall be the next business day), OG&E:

(1) shall recalculate the ATRR by removing the 13-month average net plant balances and the 13-month average Construction Work in Progress ("CWIP") balances from the most recent Baseline ATRR and replacing them with projected 13-month average net plant balances for the following Rate Year (the "Projected ATRR"). (The "OG&E ZONAL REVENUE REQUIREMENT for SPP OATT

Attachment H, Sec. 1, Col. 3" is the Projected ATRR, adjusted to take account of any related True-Up Adjustment(s).) OG&E shall also calculate the rates for its Point-to-Point transmission service, and shall calculate the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades, for the new Rate Year in accordance with the Formula Rate. (The calculations described in this Section 1.3(a)(1) are collectively referred to as the "Annual Update.");

(2) shall provide such Annual Update and supporting information to SPP, for posting on the publicly accessible portion of the SPP website (the date of such posting to be the "Posting Date"). For purposes of these Protocols, "supporting information" shall include, at minimum, a data-populated Formula Rate template in a fully-functioning Excel file (and/or as applicable, other native format) showing all calculations, any supporting calculations and workpapers that demonstrate or explain information not otherwise set out in OG&E's FERC Form No. 1 or the Formula Rate template, a Portable Document Format version of the data-populated Formula Rate template described above, and a side-by-side comparison of the Formula Rate template components (by line) as compared to the most recent Baseline ATRR (as defined in Section 1.4(a));

(3) shall provide SPP with the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR;

(4) shall provide the Annual Update and supporting information identified in Section 1.3(a)(2) above, and detailed information concerning the projected 13-month average net plant and CWIP balances (including project-specific information for planned additions), upon written request, including a standing request for all future Annual Updates and supporting information, to (i) any entity that is or may become a customer taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP; (ii) any entity served under the SPP OATT; (iii) any affected state and federal regulatory authorities; and (iv) FERC staff (collectively, "Interested Parties");

(5) shall notify SPP transmission customers taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP, affected regulatory commissions and other parties that have made a request in accordance with Section 1.3(a)(4), of the Annual Update posting via email and / or United States mail to the most recent address provided to OG&E;

(b) After the Posting Date and before October 1 of each calendar year, OG&E shall convene a meeting ("Customer Meeting") to afford Interested Parties an opportunity to discuss and become better informed regarding the Annual Update. OG&E will provide at least fifteen days' notice of the Customer Meeting via a notice included with the Annual Update and posted on the SPP website; and

(c) After the Customer Meeting and before November 1 for each calendar year, OG&E shall provide timely notice of any errors found in the review process, any updates to the projections of 13-month average net plant and CWIP balances, resolutions of Preliminary Challenges and/or proceedings provided for in Section 3.6, and/or any corrections to that year's True-Up Adjustment that are agreed to by OG&E and an Interested Party, and Interested Parties may object in writing by November 8 to any such proposed corrections or updates. Notice shall be accomplished by providing such information to SPP for posting on the publicly accessible portion of the SPP website and by providing e-mail notice of such posting to any Interested Party that has submitted a request for information pursuant to Section 2.1. No later than November 15 of each calendar year, OG&E shall modify the Annual Update to reflect uncontested corrections and updates, and shall cause a revised Annual Update to be posted on the SPP website no later than December 1. At that time, OG&E shall also provide SPP with any updated ATRR associated with each of OG&E's Base Plan Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR.

ATTACHMENT 2

PROPOSED SPP OPEN ACCESS TRANSMISSION TARIFF SHEETS (RED-LINE)

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy

(Enter whether "Projected Data" or "Actual Data")

Oklahoma Gas and Electric Company

Index of Worksheets

1	Worksheet	Description
2	Attachment H - Addendum 2-A	Rate Formula Template Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy and " Data"
3	Worksheet A	Account 454, Rent from Electric Property
4		Account 456, Other Electric Revenues
4		Account 456.1, Revenues from Transmission of Electricity of Others, Current Year Less Credits
5		Revenue from Grandfathered Interzonal Transactions and amounts received from SPP for PTP service
6	Worksheet B	Transmission Network Load (MW)
7	Worksheet C	Account 281, Accumulated Deferred Income Taxes - Accelerated Amortization Property
8		Account 282, Accumulated Deferred Income Taxes - Other Property
9		Account 283, Accumulated Deferred Income Taxes - Other
10		Account 190, Accumulated Deferred Income Taxes
11		Account 255, Accumulated Deferred Investment Tax Credits
12	Worksheet D	Account 928, Regulatory Commission Expense Allocations
13		Account 930.1, General Advertising Allocations (safety related only to trans.)
14		Account 930.2, Miscellaneous General Expenses
15		Transmission Lease Payments
16	Worksheet E	Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility
17	Worksheet F	Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase
18		Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase
19		Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives
20	Worksheet G	Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities
21	Worksheet H	Transmission Plant Adjustments
22	Worksheet I	Plant Held for Future Use
23	Worksheet J	Development of Composite State Income Tax Rates
24	Worksheet K	13 Month Balances for Plant & Accumulated Depreciation, Material & Stores and Debt & Equity
25		Account 165, Prepayments Calculation
26		Long Term Debt Cost Calculation
27	Worksheet L	True-Up Adjustment with Interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation
28	Worksheet M	Depreciation Rates
29	Worksheet N	Unfunded Reserves Calculation
30	Worksheet O	Amortizations for Extraordinary O&M and Storm Costs
31	Worksheet P	Construction Work in Progress and Abandoned Plant Balances

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

For rates effective mmm dd, yyyy

Line No.					Transmission Amount
1	NET SPP OATT RELATED UPGRADE REV. REQ.	(Addendum 2-A, ln 17 - ln 18)			$ -
2	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(Addendum 2-A, ln 21)			-
3	DIVISOR				
4	TO's Transmission Network Load	(Worksheet B, ln 14)			-
5	RATES				
6	Annual Cost ($/kW/Yr)	(ln 2 / ln 4)	-		
7	P-to-P Rate ($/kW/Mo)	(ln 6 / 12)	-		
			Peak		Off-Peak
8	Weekly P-To-P Rate ($/kW/Wk)	(ln 6 / 52; ln 6 / 52)	-		-
9	Daily P-To-P Rate ($/kW/Day)	(ln 8 / 5; ln 8 / 7)	-	Capped at weekly rate	-
10	Hourly P-To-P Rate ($/MWh)	(ln 9 / 16; ln 9 / 24 both x 1,000)	-	Capped at weekly & daily rate	-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.			Total	Allocator		Transmission Amount
11	REVENUE REQUIREMENT (w/o incentives)	(ln 117)				$ -
12	REVENUE CREDITS	(Note A)	Total	Allocator		
13						$ -
14	Other Transmission Revenue	(Worksheet A)	-	DA	1.00000	$ -
15	Total Revenue Credits		-			$ -
16	NET REVENUE REQUIREMENT (w/o incentives)	(ln 11 less ln 15)				$ -
17	SPP OATT RELATED UPGRADES REVENUE REQUIREMENT	(Worksheet G & P) (Note X)				$ -
18	SPP OATT RELATED UPGRADES REV. REQ. TRUE-UP	(Worksheet L)				$ -
19	PRIOR YEAR TRUE-UP ADJUSTMENT w/INTEREST	(Worksheet L)				$ -
20	ADDITIONAL REVENUE REQUIREMENT (w/ incentives)	(Note C) & (Worksheet F, ln 61)				$ -
21	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(ln 16 - ln 17 - ln 18 - ln 19 + ln 20)				$ -
22	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)				
23	Annual Rate	((ln 16 / ln 46) x 100)				0.00%
24	Monthly Rate	(ln 23 / 12)				0.00%
25	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)				
26	Annual Rate	(((ln 16 - ln 92) / ln 46) x 100)				0.00%
27	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)				
28	Annual Rate	(((ln 16 - lns 92 - ln 115 - ln 116) / lns 46) x 100)				0.00%

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
29	GROSS PLANT IN SERVICE					
30	Production	(Worksheet K)	-	NA		
31	Transmission	(Worksheet K)	-	TP	0.00000	-
32	Distribution	(Worksheet K)	-	NA		
33	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
34	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
35	TOTAL GROSS PLANT	(sum lns 30 to 34)	-			-
36	GROSS PLANT ALLOCATOR	(ln 35 - Col. 5 / Col. 3)		**GP=**	**0.000000**	
37	ACCUMULATED DEPRECIATION					
38	Production	(Worksheet K)	-	NA		
39	Transmission	(Worksheet K)	-	TP	0.00000	-
40	Distribution	(Worksheet K)	-	NA		
41	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
42	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
43	TOTAL ACCUMULATED DEPRECIATION	(sum lns 38 to 42)	-			-
44	NET PLANT IN SERVICE					
45	Production	(ln 30 - ln 38)	-	NA		
46	Transmission	(ln 31 - ln 39)	-			-
47	Distribution	(ln 32 - ln 40)	-	NA		
48	General Plant	(ln 33 - ln 41)	-			-
49	Intangible Plant	(ln 34 - ln 42)	-			-
50	TOTAL NET PLANT IN SERVICE	(sum lns 45 to 49)	-			-
51	NET PLANT ALLOCATOR	(ln 50 - Col. 5 / Col. 3)		**NP=**	**0.000000**	
52	ADJUSTMENTS TO RATE BASE	(Note D)				
53	Account No. 281	(Worksheet C)	-			-
54	Account No. 282	(Worksheet C)	-			-
55	Account No. 283	(Worksheet C)	-			-
56	Account No. 190	(Worksheet C)	-			-
57	Account No. 255	(Worksheet C)	-			-
58	Unfunded Reserves	(Worksheet N)	-	DA	1.00000	-
59	TOTAL ADJUSTMENTS	(sum lns 53 to 57)	-			-
60	UNAMORTIZED ABANDONED PLANT	(Worksheet P) (Note R)	0	DA	1.00000	0
60a	Construction Work in Progress (CWIP)	(Worksheet P) (Note Z)	0	DA	1.00000	0
61	LAND HELD FOR FUTURE USE	(Worksheet I) (Note F)	-	TP	0.00000	-
62	WORKING CAPITAL	(Note G)				
63	CWC	(1/8 * ln 90)	-			-
64	Materials & Supplies -- Transmission Related	(Worksheet K) (Note S)	-	TP	0.00000	-
65	Prepayments (Account 165)	(Worksheet K)	-	GP	0.00000	-
66	TOTAL WORKING CAPITAL	(sum lns 63 to 65)	-			-
67	RATE BASE (sum lns 50, 59, 60, 61, 66)		-			-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) **EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total**	(4) **Allocator**		(5) **Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
68	Transmission	321.112.b				
68a	Less Extraordinary & Storm Cost Amortization	(Worksheet O) (Note Y)	-			
69	Less expenses for LSE cost responsibility	(Worksheet E, ln 14)				
70	Less Account 561 (Load Dispatching)	321.84-92.b (Note P & U)				
71	Less Account 565	321.96.b (Note I)				
72	Plus Acct 565 native load, zonal or pool	(Note I)				
73	Transmission Subtotal	(ln 68 - ln 69 - ln 70 - ln 71 + ln 72)	-	TP	0.00000	-
74	Administrative and General	323.197.b (Note J)		NA		
75	Less: Acct. 924, Property Insurance	323.185.b		NA		
76	Less: Acct. 928, Reg. Com. Exp.	323.189.b		NA		
77	Less: Acct. 930.1, Gen. Advert. Exp.	323.191.b		NA		
78	Less: Acct. 930.2, Misc. General Exp.	323.192.b				
79	Less: PBOP amount included in Line 73	(Note T)				
80	Balance of A & G	(ln 74 - sum ln 75 to ln 79)	-	W/S	0.00000	-
81	Plus: Acct. 924	(ln 75)	-	GP	0.00000	-
82	Plus: Acct. 928 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
83	Plus: Acct. 928 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
84	Plus: Acct. 930.1 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
85	Plus: Acct. 930.1 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
86	Plus: Acct. 930.2 - Adj. Misc. General Expenses	(Worksheet D)	-	W/S	0.00000	-
87	Plus: PBOP Amount	(Note T)	-	W/S	0.00000	-
88	A & G Subtotal	(sum lns 80 to 87)	-			-
89	Transmission Lease Payments	(Worksheet D)	-	DA	1.00000	-
90	TOTAL O & M EXPENSE	(ln 73 + ln 88 + ln 89)	-			-
91	DEPRECIATION AND AMORTIZATION EXPENSE					
92	Transmission	336.7.b		TP	0.00000	-
93	Plus: Extraordinary & Storm Cost O&M Amortization	(Worksheet O) (Note W)	-	TP	0.00000	-
94	Plus: Recovery of Abandoned Incentive Plant	(Worksheet P) (Note R)	0	DA	1.00000	0
95	General	336.10.b		W/S	0.00000	-
96	Intangible	336.1.f		W/S	0.00000	-
97	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 92 to 96)	-			-
98	TAXES OTHER THAN INCOME	(Note L)				
99	Labor Related					
100	Payroll	263.i		W/S	0.00000	-
101	Plant Related					
102	Property	263.i		GP	0.00000	-
103	Gross Receipts	263.i				
104	Other	263.i		GP	0.00000	-
105	TOTAL OTHER TAXES	ln 100 + (sum lns 102 to 104)	-			-
106	INCOME TAXES	(Note M)				
107	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
108	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
109	where WCLTD=(ln 137) and R= (ln 140)					
110	and FIT, SIT & p are as given in Note M.					
111	1 / (1 - T) = (from ln 107)		-			
112	Amortized Investment Tax Credit	266.8.f (enter negative)				
113	Income Tax Calculation	(ln 108 * ln 116)	-	NA		-
114	ITC adjustment	(ln 111 * ln 112)	-	NP	-	-
115	TOTAL INCOME TAXES	(sum lns 113 to 114)	-			-
116	RETURN (Rate Base * Rate of Return)	(ln 67 * ln 140)	-	NA		-
117	REVENUE REQUIREMENT	(sum lns 90, 97, 105, 115, 116)	-			-

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes - continued

V Accumulated Amortization for Intangible Plant shall be reflected as a Rate Base Adjustment under "Accumulated Depreciation".
W OG&E may only include the amortization of transmission-related extraordinary property losses if; (1) OG&E makes a filing with the Oklahoma Corporation Commission requesting approval for the new amount to be recovered and the amortization period and (2) OG&E makes a single issue FPA Section 205 filing that requests the same recovery treatment from the FERC. OG&E shall be obligated to make such a single issue FPA Section 205 filing whenever it requests amortized extraordinary property loss costs recovery from the Oklahoma Corporation Commission.
X SPP OATT Related Upgrades include Base Plan Upgrades, Sponsored, Economic Portfolio Upgrades, Transmission Service Upgrades and Generator Interconnection Facilities, etc. whose individual Revenue Requirements are calculated and summarized in Worksheet G. Also included are the individual Revenue Requirements of facilities receiving Construction Work in Progress and Abandoned Plant incentives, as calculated and summarized in Worksheet P. The sum of the individual Revenue Requirements is credited to zonal network customers on line 17 above.
Y Exclude annualized amortization amounts booked back into O&M accounts that costs would have been booked had not a Regulatory Asset and amortization period been approved by the Oklahoma Corporation Commission and the FERC. This amount should equal amount reflected on line 93.
Z OG&E may only recover CWIP on projects that the FERC has specifically authorized the incentive.

List of Allocators:

Direct Assigned	DA	1.000000
Gross Plant	GP	0.000000
Net Plant	NP	0.000000
Trans. Plant in SPP	TP	0.000000
Wages & Salaries	W/S	0.000000
No Allocator	NA	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

III. Base Plan Upgrade True-Up Calculations

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year on Base Plan Upgrade Projects.

18 Average Interest Rate on Amount of Refunds or Surcharges calculated per Section V below.

	Proj. No.		Projected ATRR - Prior Year (1)	Baseline ATRR - Prior Year (2)	True-Up Adjustment Without Interest	Refund / (Surcharge) 0	Refund / (Surcharge) 1	Refund / (Surcharge) 2
19	1	Reno-Sunny Lane 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
20	2	Richards Tap-Richards 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
21	3	Van Buren AVEC-Van Buren Interconnect 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
22	4	Brown Explorer Tap 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
23	5	NE Enid-Glenwood 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
24	6	Razorback-Short Mountain 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
25	7	Richards-Piedmont 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
26	8	OG&E Windfarm-WFEC Mooreland 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
27	9	Ft. Smith-Colony 161kV Line	$ -	$ -	$ -	$ -	$ -	$ -
28	10	Cedar Lane-Canadian 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -

29 **TOTAL PRIOR YEAR BASE PLAN UPGRADE PROJECTS TRUE-UP ADJUSTMENT** (sum ln 19 thru ln 28) **$ -**

NOTE: (1) Projected ATRR for individual Base Plan Projects comes from the Prior Year's Projected ATRR calculation, Worksheet G and Worksheet P - Summary page

(2) Baseline ATRR for individual Base Plan Projects comes from the Prior Year Baseline ATRR calculation, Worksheet G and Worksheet P - Summary page

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

I. Project Summary

Proj. No.	A. CWIP Annual Transmission Revenue Requirements	
	Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	CWIP Totals	

Proj. No.	B. Abandoned Plant Annual Transmission Revenue Requirements	
	Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	Abandoned Plant Totals	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant Balances

II. Construction Work in Progress (CWIP) Balances

Line No.	Month	Year	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
1	December	2010											
2	January	2011											
3	February	2011											
4	March	2011											
5	April	2011											
6	May	2011											
7	June	2011											
8	July	2011											
9	August	2011											
10	September	2011											
11	October	2011											
12	November	2011											
13	December	2011											
14	Average Balances												
15	Return	(Data Ln 140 * Ln 14)	0										
16	Taxes	(Data Ln 108 * Ln 15)	0										
17	ATRR	(Ln 15 + Ln 16)	0										

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

III. Abandoned Plant

Line No.			Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
18	Abandoned Plant Balance												
19	Amortization Period (months)												
20	Monthly Amortization Amount												
	Month	Year											
21	December	2010											
22	January	2011											
23	February	2011											
24	March	2011											
25	April	2011											
26	May	2011											
27	June	2011											
28	July	2011											
29	August	2011											
30	September	2011											
31	October	2011											
32	November	2011											
33	December	2011											
34	Average Balances												
35	Return	(Data Ln 140 * Ln 34)	0										
36	Taxes	(Data Ln 108 * Ln 35)	0										
37	Amortization Abandoned Plant (Beg. Bal. less End. Bal.)		0										
38	ATRR	(Ln 35 + Ln 36 + Ln 37)	0										

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I. Annual Update and True-Up Adjustments

1.1 The formula rate template contained in Attachment H – Addendum 2-A and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Oklahoma Gas and Electric Company ("OG&E") for transmission service under the Open Access Transmission Tariff ("OATT") of the Southwest Power Pool, Inc. ("SPP"). OG&E shall follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR"), rates for its Point-to-Point transmission service, and the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades.

1.2 The Formula Rate shall initially be effective for service on and after July 1, 2008, through December 31, 2008, and shall be applicable thereafter for services in subsequent years on and after January 1 of each calendar year through December 31 of that calendar year ("Rate Year"). The purpose of these protocols is to establish a set of procedures that may be used by Interested Parties (as defined in Section 1.3(a)(4) herein) to review and challenge Annual Updates and True-Up Adjustments, as defined herein. Provided, however, (i) nothing herein shall limit the rights of OG&E or any Interested Party to initiate a proceeding at the Federal Energy Regulatory Commission ("Commission") at any time with respect to the Formula Rate consistent with the Party's rights under the Federal Power Act ("FPA") and the Commission's regulations and (ii) the provisions of these Protocols applicable to review and challenge of Annual Updates and True-Up Adjustments shall not apply to proceedings other than (a) Formal Challenges initiated in accordance with the procedures set forth herein and/or (b) proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment, and shall not be relied upon to alter any Party's rights or obligations under the FPA and the Commission's regulations in proceedings other than such Formal Challenges and/or proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment. The term "Party" or "Parties" is defined to include OG&E and/or one or more Interested Parties.

1.3 Posting of Annual Update and Related Procedures

(a) On or before September 1 of each calendar year (unless September 1 falls on a weekend or a holiday recognized by the Commission, in which case the date shall be the next business day), OG&E:

(1) shall recalculate the ATRR by removing the 13-month average net plant balances and the 13-month average Construction Work in Progress ("CWIP") balances from the most recent Baseline ATRR and replacing them with projected 13-month average net plant balances for the following Rate Year (the "Projected ATRR"). (The "OG&E ZONAL REVENUE REQUIREMENT for SPP OATT

Attachment H, Sec. 1, Col. 3" is the Projected ATRR, adjusted to take account of any related True-Up Adjustment(s).) OG&E shall also calculate the rates for its Point-to-Point transmission service, and shall calculate the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades, for the new Rate Year in accordance with the Formula Rate. (The calculations described in this Section 1.3(a)(1) are collectively referred to as the "Annual Update.");

(2) shall provide such Annual Update and supporting information to SPP, for posting on the publicly accessible portion of the SPP website (the date of such posting to be the "Posting Date"). For purposes of these Protocols, "supporting information" shall include, at minimum, a data-populated Formula Rate template in a fully-functioning Excel file (and/or as applicable, other native format) showing all calculations, any supporting calculations and workpapers that demonstrate or explain information not otherwise set out in OG&E's FERC Form No. 1 or the Formula Rate template, a Portable Document Format version of the data-populated Formula Rate template described above, and a side-by-side comparison of the Formula Rate template components (by line) as compared to the most recent Baseline ATRR (as defined in Section 1.4(a));

(3) shall provide SPP with the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR;

(4) shall provide the Annual Update and supporting information identified in Section 1.3(a)(2) above, and detailed information concerning the projected 13-month average net plant and CWIP balances (including project-specific information for planned additions), upon written request, including a standing request for all future Annual Updates and supporting information, to (i) any entity that is or may become a customer taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP; (ii) any entity served under the SPP OATT; (iii) any affected state and federal regulatory authorities; and (iv) FERC staff (collectively, "Interested Parties");

(5) shall notify SPP transmission customers taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP, affected regulatory commissions and other parties that have made a request in accordance with Section 1.3(a)(4), of the Annual Update posting via email and / or United States mail to the most recent address provided to OG&E;

(b) After the Posting Date and before October 1 of each calendar year, OG&E shall convene a meeting ("Customer Meeting") to afford Interested Parties an opportunity to discuss and become better informed regarding the Annual Update. OG&E will provide at least fifteen days' notice of the Customer Meeting via a notice included with the Annual Update and posted on the SPP website; and

(c) After the Customer Meeting and before November 1 for each calendar year, OG&E shall provide timely notice of any errors found in the review process, any updates to the projections of 13-month average net plant and CWIP balances, resolutions of Preliminary Challenges and/or proceedings provided for in Section 3.6, and/or any corrections to that year's True-Up Adjustment that are agreed to by OG&E and an Interested Party, and Interested Parties may object in writing by November 8 to any such proposed corrections or updates. Notice shall be accomplished by providing such information to SPP for posting on the publicly accessible portion of the SPP website and by providing e-mail notice of such posting to any Interested Party that has submitted a request for information pursuant to Section 2.1. No later than November 15 of each calendar year, OG&E shall modify the Annual Update to reflect uncontested corrections and updates, and shall cause a revised Annual Update to be posted on the SPP website no later than December 1. At that time, OG&E shall also provide SPP with any updated ATRR associated with each of OG&E's Base Plan Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR.

ATTACHMENT 3

PROPOSED OG&E OPEN ACCESS TRANSMISSION TARIFF SHEETS (CLEAN)

Attachment H
Addendum 2-A

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

Oklahoma Gas and Electric Company

Index of Worksheets

1	Worksheet	Description
2	Attachment H - Addendum 2-A	Rate Formula Template Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy and " Data"
3	Worksheet A	Account 454, Rent from Electric Property
4		Account 456, Other Electric Revenues
4		Account 456.1, Revenues from Transmission of Electricity of Others, Current Year Less Credits
5		Revenue from Grandfathered Interzonal Transactions and amounts received from SPP for PTP service
6	Worksheet B	Transmission Network Load (MW)
7	Worksheet C	Account 281, Accumulated Deferred Income Taxes - Accelerated Amortization Property
8		Account 282, Accumulated Deferred Income Taxes - Other Property
9		Account 283, Accumulated Deferred Income Taxes - Other
10		Account 190, Accumulated Deferred Income Taxes
11		Account 255, Accumulated Deferred Investment Tax Credits
12	Worksheet D	Account 928, Regulatory Commission Expense Allocations
13		Account 930.1, General Advertising Allocations (safety related only to trans.)
14		Account 930.2, Miscellaneous General Expenses
15		Transmission Lease Payments
16	Worksheet E	Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility
17	Worksheet F	Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase
18		Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase
19		Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives
20	Worksheet G	Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities
21	Worksheet H	Transmission Plant Adjustments
22	Worksheet I	Plant Held for Future Use
23	Worksheet J	Development of Composite State Income Tax Rates
24	Worksheet K	13 Month Balances for Plant & Accumulated Depreciation, Material & Stores and Debt & Equity
25		Account 165, Prepayments Calculation
26		Long Term Debt Cost Calculation
27	Worksheet L	True-Up Adjustment with Interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation
28	Worksheet M	Depreciation Rates
29	Worksheet N	Unfunded Reserves Calculation
30	Worksheet O	Amortizations for Extraordinary O&M and Storm Costs
31	Worksheet P	Construction Work in Progress and Abandoned Plant Balances

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

For rates effective mmm dd, yyyy

Line No.					Transmission Amount
1	NET SPP OATT RELATED UPGRADE REV. REQ.	(Addendum 2-A, ln 17 - ln 18)			$ -
2	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(Addendum 2-A, ln 21)			-
3	DIVISOR				
4	TO's Transmission Network Load	(Worksheet B, ln 14)			-
5	RATES				
6	Annual Cost ($/kW/Yr)	(ln 2 / ln 4)	-		
7	P-to-P Rate ($/kW/Mo)	(ln 6 / 12)	-		
			Peak		Off-Peak
8	Weekly P-To-P Rate ($/kW/Wk)	(ln 6 / 52; ln 6 / 52)	-		-
9	Daily P-To-P Rate ($/kW/Day)	(ln 8 / 5; ln 8 / 7)	-	Capped at weekly rate	-
10	Hourly P-To-P Rate ($/MWh)	(ln 9 / 16; ln 9 / 24 both x 1,000)	-	Capped at weekly & daily rate	-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.			Total	Allocator		Transmission Amount
11	REVENUE REQUIREMENT (w/o incentives)	(ln 117)				$ -
12	REVENUE CREDITS	(Note A)	Total	Allocator		
13						$ -
14	Other Transmission Revenue	(Worksheet A)	-	DA	1.00000	$ -
15	Total Revenue Credits		-			$ -
16	NET REVENUE REQUIREMENT (w/o incentives)	(ln 11 less ln 15)				$ -
17	SPP OATT RELATED UPGRADES REVENUE REQUIREMENT	(Worksheets G & P) (Note X)				$ -
18	SPP OATT RELATED UPGRADES REV. REQ. TRUE-UP	(Worksheet L)				$ -
19	PRIOR YEAR TRUE-UP ADJUSTMENT w/INTEREST	(Worksheet L)				$ -
20	ADDITIONAL REVENUE REQUIREMENT (w/ incentives)	(Note C) & (Worksheet F, ln 61)				$ -
21	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(ln 16 - ln 17 - ln 18 - ln 19 + ln 20)				$ -
22	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)				
23	Annual Rate	((ln 16 / ln 46) x 100)				0.00%
24	Monthly Rate	(ln 23 / 12)				0.00%
25	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)				
26	Annual Rate	(((ln 16 - ln 92) / ln 46) x 100)				0.00%
27	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)				
28	Annual Rate	(((ln 16 - lns 92 - ln 115 - ln 116) / lns 46) x 100)				0.00%

Attachment H
Addendum 2-A

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
29	GROSS PLANT IN SERVICE					
30	Production	(Worksheet K)	-	NA		
31	Transmission	(Worksheet K)	-	TP	0.00000	-
32	Distribution	(Worksheet K)	-	NA		
33	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
34	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
35	TOTAL GROSS PLANT	(sum lns 30 to 34)	-			-
36	GROSS PLANT ALLOCATOR	(ln 35 - Col. 5 / Col. 3)		**GP=**	**0.000000**	
37	ACCUMULATED DEPRECIATION					
38	Production	(Worksheet K)	-	NA		
39	Transmission	(Worksheet K)	-	TP	0.00000	-
40	Distribution	(Worksheet K)	-	NA		
41	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
42	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
43	TOTAL ACCUMULATED DEPRECIATION	(sum lns 38 to 42)	-			-
44	NET PLANT IN SERVICE					
45	Production	(ln 30 - ln 38)	-	NA		
46	Transmission	(ln 31 - ln 39)	-			-
47	Distribution	(ln 32 - ln 40)	-	NA		
48	General Plant	(ln 33 - ln 41)	-			-
49	Intangible Plant	(ln 34 - ln 42)	-			-
50	TOTAL NET PLANT IN SERVICE	(sum lns 45 to 49)	-			-
51	NET PLANT ALLOCATOR	(ln 50 - Col. 5 / Col. 3)		**NP=**	**0.000000**	
52	ADJUSTMENTS TO RATE BASE	(Note D)				
53	Account No. 281	(Worksheet C)	-			-
54	Account No. 282	(Worksheet C)	-			-
55	Account No. 283	(Worksheet C)	-			-
56	Account No. 190	(Worksheet C)	-			-
57	Account No. 255	(Worksheet C)	-			-
58	Unfunded Reserves	(Worksheet N)	-	DA	1.00000	-
59	TOTAL ADJUSTMENTS	(sum lns 53 to 57)	-			-
60	UNAMORTIZED ABANDONED PLANT	(Worksheet P) (Note R)	0	DA	1.00000	0
60a	Construction Work in Progress (CWIP)	(Worksheet P) (Note Z)	0	DA	1.00000	0
61	LAND HELD FOR FUTURE USE	(Worksheet I) (Note F)	-	TP	0.00000	-
62	WORKING CAPITAL	(Note G)				
63	CWC	(1/8 * ln 90)	-			-
64	Materials & Supplies -- Transmission Related	(Worksheet K) (Note S)	-	TP	0.00000	-
65	Prepayments (Account 165)	(Worksheet K)	-	GP	0.00000	-
66	TOTAL WORKING CAPITAL	(sum lns 63 to 65)	-			-
67	RATE BASE (sum lns 50, 59, 60, 61, 66)		-			-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) **EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total**	(4) **Allocator**		(5) **Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
68	Transmission	321.112.b				
68a	Less Extraordinary & Storm Cost Amortization	(Worksheet O) (Note Y)	-			
69	Less expenses for LSE cost responsibility	(Worksheet E, ln 14)				
70	Less Account 561 (Load Dispatching)	321.84-92.b (Note P & U)				
71	Less Account 565	321.96.b (Note I)				
72	Plus Acct 565 native load, zonal or pool	(Note I)				
73	Transmission Subtotal	(ln 68-ln 68a-ln 69-ln 70-ln 71+ln 72)	-	TP	0.00000	-
74	Administrative and General	323.197.b (Note J)		NA		
75	Less: Acct. 924, Property Insurance	323.185.b		NA		
76	Less: Acct. 928, Reg. Com. Exp.	323.189.b		NA		
77	Less: Acct. 930.1, Gen. Advert. Exp.	323.191.b		NA		
78	Less: Acct. 930.2, Misc. General Exp.	323.192.b				
79	Less: PBOP amount included in Line 73	(Note T)				
80	Balance of A & G	(ln 74 - sum ln 75 to ln 79)	-	W/S	0.00000	-
81	Plus: Acct. 924	(ln 75)	-	GP	0.00000	-
82	Plus: Acct. 928 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
83	Plus: Acct. 928 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
84	Plus: Acct. 930.1 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
85	Plus: Acct. 930.1 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
86	Plus: Acct. 930.2 - Adj. Misc. General Expenses	(Worksheet D)	-	W/S	0.00000	-
87	Plus: PBOP Amount	(Note T)	-	W/S	0.00000	-
88	A & G Subtotal	(sum lns 80 to 87)	-			-
89	Transmission Lease Payments	(Worksheet D)	-	DA	1.00000	-
90	TOTAL O & M EXPENSE	(ln 73 + ln 88 + ln 89)	-			-
91	DEPRECIATION AND AMORTIZATION EXPENSE					
92	Transmission	336.7.b		TP	0.00000	-
93	Plus: Extraordinary & Storm Cost O&M Amortization	(Worksheet O) (Note W)	-	TP	0.00000	-
94	Plus: Recovery of Abandoned Incentive Plant	(Worksheet P) (Note R)	0	DA	1.00000	0
95	General	336.10.b		W/S	0.00000	-
96	Intangible	336.1.f		W/S	0.00000	-
97	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 92 to 96)	-			-
98	TAXES OTHER THAN INCOME	(Note L)				
99	Labor Related					
100	Payroll	263.i		W/S	0.00000	-
101	Plant Related					
102	Property	263.i		GP	0.00000	-
103	Gross Receipts	263.i				
104	Other	263.i		GP	0.00000	-
105	TOTAL OTHER TAXES	ln 100 + (sum lns 102 to 104)	-			-
106	INCOME TAXES	(Note M)				
107	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
108	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
109	where WCLTD=(ln 137) and R= (ln 140)					
110	and FIT, SIT & p are as given in Note M.					
111	1 / (1 - T) = (from ln 107)		-			
112	Amortized Investment Tax Credit	266.8.f (enter negative)				
113	Income Tax Calculation	(ln 108 * ln 116)	-	NA		-
114	ITC adjustment	(ln 111 * ln 112)	-	NP	-	-
115	TOTAL INCOME TAXES	(sum lns 113 to 114)	-			-
116	RETURN (Rate Base * Rate of Return)	(ln 67 * ln 140)	-	NA		-
117	REVENUE REQUIREMENT (sum lns 90, 97, 105, 115, 116)		-			-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes - continued

V Accumulated Amortization for Intangible Plant shall be reflected as a Rate Base Adjustment under "Accumulated Depreciation".

W OG&E may only include the amortization of transmission-related extraordinary property losses if; (1) OG&E makes a filing with the Oklahoma Corporation Commission requesting approval for the new amount to be recovered and the amortization period and (2) OG&E makes a single issue FPA Section 205 filing that requests the same recovery treatment from the FERC. OG&E shall be obligated to make such a single issue FPA Section 205 filing whenever it requests amortized extraordinary property loss costs recovery from the Oklahoma Corporation Commission.

X SPP OATT Related Upgrades include Base Plan Upgrades, Sponsored, Economic Portfolio Upgrades, Transmission Service Upgrades and Generator Interconnection Facilities, etc. whose individual Revenue Requirements are calculated and summarized in Worksheet G. Also included are the individual Revenue Requirements of facilities receiving Construction Work in Progress and Abandoned Plant incentive, as calculated and summarized in Worksheet P. The sum of the individual Revenue Requirements is credited to zonal network customers on line 17 above.

Y Exclude annualized amortization amounts booked back into O&M accounts that costs would have been booked had not a Regulatory Asset and amortization period been approved by the Oklahoma Corporation Commission and the FERC. This amount should equal amount reflected on line 93.

Z OG&E may only recover CWIP on projects that the FERC has specifically authorized the incentive.

List of Allocators:

Direct Assigned	DA	1.000000
Gross Plant	GP	0.000000
Net Plant	NP	0.000000
Trans. Plant in SPP	TP	0.000000
Wages & Salaries	W/S	0.000000
No Allocator	NA	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

III. Base Plan Upgrade True-Up Calculations

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year on Base Plan Upgrade Projects.

18 Average Interest Rate on Amount of Refunds or Surcharges calculated per Section V below.

	Proj. No.		Projected ATRR - Prior Year (1)	Baseline ATRR - Prior Year (2)	True-Up Adjustment Without Interest	Refund / (Surcharge) 0	Refund / (Surcharge) 1	Refund / (Surcharge) 2
19	1	Reno-Sunny Lane 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
20	2	Richards Tap-Richards 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
21	3	Van Buren AVEC-Van Buren Interconnect 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
22	4	Brown Explorer Tap 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
23	5	NE Enid-Glenwood 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
24	6	Razorback-Short Mountain 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
25	7	Richards-Piedmont 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
26	8	OG&E Windfarm-WFEC Mooreland 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
27	9	Ft. Smith-Colony 161kV Line	$ -	$ -	$ -	$ -	$ -	$ -
28	10	Cedar Lane-Canadian 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -

29 **TOTAL PRIOR YEAR BASE PLAN UPGRADE PROJECTS TRUE-UP ADJUSTMENT** (sum ln 19 thru ln 28) **$ -**

NOTE: (1) Projected ATRR for individual Base Plan Projects comes from the Prior Year's Projected ATRR calculation, Worksheet G and Worksheet P - Summary page
(2) Baseline ATRR for individual Base Plan Projects comes from the Prior Year Baseline ATRR calculation, Worksheet G and Worksheet P - Summary page

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

I. Project Summary

Proj. No.	A. CWIP Annual Transmission Revenue Requirements Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	CWIP Totals	

Proj. No.	B. Abandoned Plant Annual Transmission Revenue Requirements Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	Abandoned Plant Totals	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant Balances

II. Construction Work in Progress (CWIP) Balances

Line No.	Month	Year	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
1	**December**	2010											
2	**January**	2011											
3	**February**	2011											
4	**March**	2011											
5	**April**	2011											
6	**May**	2011											
7	**June**	2011											
8	**July**	2011											
9	**August**	2011											
10	**September**	2011											
11	**October**	2011											
12	**November**	2011											
13	**December**	2011											
14	**Average Balances**												
15	**Return**	(Data Ln 140 * Ln 14)	0										
16	**Taxes**	(Data Ln 108 * Ln 15)	0										
17	**ATRR**	(Ln 15 + Ln 16)	0										

Issued by: Melvin H. Perkins, Jr.
Vice President of Power Delivery

Issued on: October 12, 2010

Effective: January 1, 2011

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

III. Abandoned Plant

Line No.			Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
18	**Abandoned Plant Balance**												
19	**Amortization Period (months)**												
20	**Monthly Amortization Amount**												
	Month	Year											
21	**December**	2010											
22	**January**	2011											
23	**February**	2011											
24	**March**	2011											
25	**April**	2011											
26	**May**	2011											
27	**June**	2011											
28	**July**	2011											
29	**August**	2011											
30	**September**	2011											
31	**October**	2011											
32	**November**	2011											
33	**December**	2011											
34	**Average Balances**		-										
35	**Return**	(Data Ln 140 * Ln 34)	0										
36	**Taxes**	(Data Ln 108 * Ln 35)	0										
37	**Amortization Abandoned Plant** (Beg. Bal. less End. Bal.)		0										
38	**ATRR**	(Ln 35 + Ln 36 + Ln 37)	0	-	-	-	-	-					

ATTACHMENT H - ADDENDUM 2-B
OG&E FORMULA RATE IMPLEMENTATION PROTOCOLS

I. Annual Update and True-Up Adjustments

1.1 The formula rate template contained in Attachment H - Addendum 2-A and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Oklahoma Gas and Electric Company ("OG&E") for transmission service under the Open Access Transmission Tariff ("OATT") of the Southwest Power Pool, Inc. ("SPP"). OG&E shall follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR"), rates for its Point-to-Point transmission service, and the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades.

1.2 The Formula Rate shall initially be effective for service on and after July 1, 2008, through December 31, 2008, and shall be applicable thereafter for services in subsequent years on and after January 1 of each calendar year through December 31 of that calendar year ("Rate Year"). The purpose of these protocols is to establish a set of procedures that may be used by Interested Parties (as defined in Section 1.3(a)(4) herein) to review and challenge Annual Updates and True-Up Adjustments, as defined herein. Provided, however, (i) nothing herein shall limit the rights of OG&E or any Interested Party to initiate a proceeding at the Federal Energy Regulatory Commission ("Commission") at any time with respect to the Formula Rate consistent with the Party's rights under the Federal Power Act ("FPA") and the Commission's regulations and (ii) the provisions of these Protocols applicable to review and challenge of Annual Updates and True-Up Adjustments shall not apply to proceedings other than (a) Formal Challenges initiated in accordance with the procedures set forth herein and/or (b) proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment, and shall not be relied upon to alter any Party's rights or obligations under the FPA and the Commission's regulations in proceedings other than such Formal Challenges and/or proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment. The term "Party" or "Parties" is defined to include OG&E and/or one or more Interested Parties.

1.3 Posting of Annual Update and Related Procedures

(a) On or before September 1 of each calendar year (unless September 1 falls on a weekend or a holiday recognized by the Commission, in which case the date shall be the next business day), OG&E:

(1) shall recalculate the ATRR by removing the 13-month average net plant balances and the 13-month average Construction Work in Progress ("CWIP") balances from the most recent Baseline ATRR and replacing them with projected 13-month average net plant and CWIP balances for the following Rate Year (the "Projected ATRR"). (The "OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3" is the Projected ATRR, adjusted to take account of any related True-Up Adjustment(s).) OG&E shall also calculate the

rates for its Point-to-Point transmission service, and shall calculate the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades, for the new Rate Year in accordance with the Formula Rate. (The calculations described in this Section 1.3(a)(1) are collectively referred to as the "Annual Update.")

(2) shall provide such Annual Update and supporting information to SPP, for posting on the publicly accessible portion of the SPP website (the date of such posting to be the "Posting Date"). For purposes of these Protocols, "supporting information" shall include, at minimum, a data-populated Formula Rate template in a fully-functioning Excel file (and/or as applicable, other native format) showing all calculations, any supporting calculations and workpapers that demonstrate or explain information not otherwise set out in OG&E's FERC Form No. 1 or the Formula Rate template, a Portable Document Format version of the data-populated Formula Rate template described above, and a side-by-side comparison of the Formula Rate template components (by line) as compared to the most recent Baseline ATRR (as defined in Section 1.4(a));

(3) shall provide SPP with the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR;

(4) shall provide the Annual Update and supporting information identified in Section 1.3(a)(2) above, and detailed information concerning the projected 13-month average net plant and CWIP balances (including project-specific information for planned additions), upon written request, including a standing request for all future Annual Updates and supporting information, to (i) any entity that is or may become a customer taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP; (ii) any entity served under the SPP OATT; (iii) any affected state and federal regulatory authorities; and (iv) FERC staff (collectively, "Interested Parties");

(5) shall notify SPP transmission customers taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP, affected regulatory commissions, and other parties that have made a request in accordance with Section 1.3(a)(4), of the Annual Update posting via email and/or United States mail to the most recent address provided to OG&E;

(b) After the Posting Date and before October 1 of each calendar year, OG&E shall convene a meeting ("Customer Meeting") to afford Interested Parties an opportunity to discuss and become better informed regarding the Annual Update. OG&E will provide at least fifteen days' notice of the Customer Meeting via a notice included with the Annual Update and posted on the SPP website; and

(c) After the Customer Meeting and before November 1 for each calendar year, OG&E shall provide timely notice of any errors found in the review process, any updates to the projections of 13-month average net plant and CWIP balances, resolutions of Preliminary Challenges and/or proceedings provided for in section 3.6, and/or any corrections to that year's True-Up Adjustment that are agreed to by OG&E and an Interested Party, and Interested Parties may object in writing by November 8 to any such proposed corrections or updates. Notice shall be accomplished by providing such information to SPP for posting on the publicly accessible portion of the SPP website and by providing e-mail notice of such posting to any Interested Party that has submitted a request for information pursuant to Section 2.1. No later than November 15 of each calendar year, OG&E shall modify the Annual Update to reflect uncontested corrections and updates, and shall cause a revised Annual Update to be posted on the SPP website no later than December 1. At that time, OG&E shall also provide SPP with any updated ATRR associated with each of OG&E's Base Plan Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR.

1.4 On June 1 of each calendar year (unless June 1 falls on a weekend or a holiday recognized by the FERC, in which case the date shall be the next business day) (the "Publication Date"), OG&E shall, in accordance with the Formula Rate, calculate the Baseline ATRR for the Rate Year that has most recently concluded, reconcile the Projected ATRR with the Baseline ATRR for the corresponding Rate Year and calculate the amount of any over- or under-recovery (all of which, plus any corrections pursuant to Section 1.10 or any changes to account for the resolution of any Preliminary Challenge, Formal Challenge, or a proceeding initiated *sua sponte* by FERC challenging a True-Up Adjustment, to the extent such changes have not been reflected in a prior Annual Update, shall be considered the "True-Up Adjustment"). On the Publication Date, OG&E shall submit the True-Up Adjustment to FERC for informational purposes only. The informational filing shall not require any action by the Commission.[1] On or before the Publication Date, OG&E shall follow the procedures set forth in Sections 1.3(a)(2)-(5) for disseminating the True-Up Adjustment and supporting information (as defined in Section 1.3(a)(2)). The True-Up Adjustment:

(a) shall, to the extent specified in the Formula Rate, be based upon data properly recorded in the appropriate accounts, consistent with FERC accounting policies and accounting practices, in (i) OG&E's FERC Form No. 1 for the most recent calendar year (*i.e.*, the most recently completed Rate Year), and (ii) the books and records of OG&E.[2] (The ATRR determined using these data shall be termed the "Baseline ATRR".);

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[1] The transmittal letter accompanying the informational filing shall inform the Commission that the True-Up Adjustment is not intended to be subject to the Commission's notice requirements and it is not intended for the Commission to take action accepting the informational filing, and shall inform the Commission regarding the procedures contained in these Protocols for review and challenge of the True-Up Adjustment. If the Commission issues a notice of or an order accepting the informational filing, OG&E shall advise the Commission of the challenge process in these Protocols and shall work with the Settling Parties to seek rescission of such actions. No Commission action on the informational filing shall affect any rights under the Formula Rate or these Protocols.

[2] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

ATTACHMENT 4

PROPOSED OG&E OPEN ACCESS TRANSMISSION TARIFF SHEETS (RED-LINE)

Attachment H
Addendum 2-A

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

Oklahoma Gas and Electric Company

Index of Worksheets

1	Worksheet	Description
2	Attachment H - Addendum 2-A	Rate Formula Template Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy and " Data"
3	Worksheet A	Account 454, Rent from Electric Property
4		Account 456, Other Electric Revenues
4		Account 456.1, Revenues from Transmission of Electricity of Others, Current Year Less Credits
5		Revenue from Grandfathered Interzonal Transactions and amounts received from SPP for PTP service
6	Worksheet B	Transmission Network Load (MW)
7	Worksheet C	Account 281, Accumulated Deferred Income Taxes - Accelerated Amortization Property
8		Account 282, Accumulated Deferred Income Taxes - Other Property
9		Account 283, Accumulated Deferred Income Taxes - Other
10		Account 190, Accumulated Deferred Income Taxes
11		Account 255, Accumulated Deferred Investment Tax Credits
12	Worksheet D	Account 928, Regulatory Commission Expense Allocations
13		Account 930.1, General Advertising Allocations (safety related only to trans.)
14		Account 930.2, Miscellaneous General Expenses
15		Transmission Lease Payments
16	Worksheet E	Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility
17	Worksheet F	Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase
18		Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase
19		Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives
20	Worksheet G	Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities
21	Worksheet H	Transmission Plant Adjustments
22	Worksheet I	Plant Held for Future Use
23	Worksheet J	Development of Composite State Income Tax Rates
24	Worksheet K	13 Month Balances for Plant & Accumulated Depreciation, Material & Stores and Debt & Equity
25		Account 165, Prepayments Calculation
26		Long Term Debt Cost Calculation
27	Worksheet L	True-Up Adjustment with Interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation
28	Worksheet M	Depreciation Rates
29	Worksheet N	Unfunded Reserves Calculation
30	Worksheet O	Amortizations for Extraordinary O&M and Storm Costs
31	Worksheet P	Construction Work in Progress and Abandoned Plant Balances

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

For rates effective mmm dd, yyyy

Line No.					Transmission Amount
1	NET SPP OATT RELATED UPGRADE REV. REQ.	(Addendum 2-A, ln 17 - ln 18)			$ -
2	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(Addendum 2-A, ln 21)			-
3	DIVISOR				
4	TO's Transmission Network Load	(Worksheet B, ln 14)			-
5	RATES				
6	Annual Cost ($/kW/Yr)	(ln 2 / ln 4)	-		
7	P-to-P Rate ($/kW/Mo)	(ln 6 / 12)	-		
			Peak		Off-Peak
8	Weekly P-To-P Rate ($/kW/Wk)	(ln 6 / 52; ln 6 / 52)	-		-
9	Daily P-To-P Rate ($/kW/Day)	(ln 8 / 5; ln 8 / 7)	-	Capped at weekly rate	-
10	Hourly P-To-P Rate ($/MWh)	(ln 9 / 16; ln 9 / 24 both x 1,000)	-	Capped at weekly & daily rate	-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.			Total	Allocator		Transmission Amount
11	REVENUE REQUIREMENT (w/o incentives)	(ln 117)				$ -
12	REVENUE CREDITS	(Note A)	Total	Allocator		
13						$ -
14	Other Transmission Revenue	(Worksheet A)	-	DA	1.00000	$ -
15	Total Revenue Credits		-			$ -
16	NET REVENUE REQUIREMENT (w/o incentives)	(ln 11 less ln 15)				$ -
17	SPP OATT RELATED UPGRADES REVENUE REQUIREMENT	(Worksheets G & P) (Note X)				$ -
18	SPP OATT RELATED UPGRADES REV. REQ. TRUE-UP	(Worksheet L)				$ -
19	PRIOR YEAR TRUE-UP ADJUSTMENT w/INTEREST	(Worksheet L)				$ -
20	ADDITIONAL REVENUE REQUIREMENT (w/ incentives)	(Note C) & (Worksheet F, ln 61)				$ -
21	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(ln 16 - ln 17 - ln 18 - ln 19 + ln 20)				$ -
22	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)				
23	Annual Rate	((ln 16 / ln 46) x 100)				0.00%
24	Monthly Rate	(ln 23 / 12)				0.00%
25	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)				
26	Annual Rate	(((ln 16 - ln 92) / ln 46) x 100)				0.00%
27	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)				
28	Annual Rate	(((ln 16 - lns 92 - ln 115 - ln 116) / lns 46) x 100)				0.00%

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
29	GROSS PLANT IN SERVICE					
30	Production	(Worksheet K)	-	NA		
31	Transmission	(Worksheet K)	-	TP	0.00000	-
32	Distribution	(Worksheet K)	-	NA		
33	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
34	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
35	TOTAL GROSS PLANT	(sum lns 30 to 34)	-			-
36	GROSS PLANT ALLOCATOR	(ln 35 - Col. 5 / Col. 3)		**GP=**	**0.000000**	
37	ACCUMULATED DEPRECIATION					
38	Production	(Worksheet K)	-	NA		
39	Transmission	(Worksheet K)	-	TP	0.00000	-
40	Distribution	(Worksheet K)	-	NA		
41	General Plant	(Worksheet K) (Note J)	-	W/S	0.00000	-
42	Intangible Plant	(Worksheet K) (Note V)	-	W/S	0.00000	-
43	TOTAL ACCUMULATED DEPRECIATION	(sum lns 38 to 42)	-			-
44	NET PLANT IN SERVICE					
45	Production	(ln 30 - ln 38)	-	NA		
46	Transmission	(ln 31 - ln 39)	-			-
47	Distribution	(ln 32 - ln 40)	-	NA		
48	General Plant	(ln 33 - ln 41)	-			-
49	Intangible Plant	(ln 34 - ln 42)	-			-
50	TOTAL NET PLANT IN SERVICE	(sum lns 45 to 49)	-			-
51	NET PLANT ALLOCATOR	(ln 50 - Col. 5 / Col. 3)		**NP=**	**0.000000**	
52	ADJUSTMENTS TO RATE BASE	(Note D)				
53	Account No. 281	(Worksheet C)	-			-
54	Account No. 282	(Worksheet C)	-			-
55	Account No. 283	(Worksheet C)	-			-
56	Account No. 190	(Worksheet C)	-			-
57	Account No. 255	(Worksheet C)	-			-
58	Unfunded Reserves	(Worksheet N)	-	DA	1.00000	-
59	TOTAL ADJUSTMENTS	(sum lns 53 to 57)	-			-
60	UNAMORTIZED ABANDONED PLANT	(Worksheet P) (Note R)	0	DA	1.00000	0
60a	Construction Work in Progress (CWIP)	(Worksheet P) (Note Z)	0	DA	1.00000	0
61	LAND HELD FOR FUTURE USE	(Worksheet I) (Note F)	-	TP	0.00000	-
62	WORKING CAPITAL	(Note G)				
63	CWC	(1/8 * ln 90)	-			-
64	Materials & Supplies -- Transmission Related	(Worksheet K) (Note S)	-	TP	0.00000	-
65	Prepayments (Account 165)	(Worksheet K)	-	GP	0.00000	-
66	TOTAL WORKING CAPITAL	(sum lns 63 to 65)	-			-
67	RATE BASE (sum lns 50, 59, 60, 61, 66)		-			-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
68	Transmission	321.112.b				
68a	Less Extraordinary & Storm Cost Amortization	(Worksheet O) (Note Y)	-			
69	Less expenses for LSE cost responsibility	(Worksheet E, ln 14)				
70	Less Account 561 (Load Dispatching)	321.84-92.b (Note P & U)				
71	Less Account 565	321.96.b (Note I)				
72	Plus Acct 565 native load, zonal or pool	(Note I)				
73	Transmission Subtotal	(ln 68-ln 68a-ln 69-ln 70-ln 71+ln 72)	-	TP	0.00000	-
74	Administrative and General	323.197.b (Note J)		NA		
75	Less: Acct. 924, Property Insurance	323.185.b		NA		
76	Less: Acct. 928, Reg. Com. Exp.	323.189.b		NA		
77	Less: Acct. 930.1, Gen. Advert. Exp.	323.191.b		NA		
78	Less: Acct. 930.2, Misc. General Exp.	323.192.b				
79	Less: PBOP amount included in Line 73	(Note T)				
80	Balance of A & G	(ln 74 - sum ln 75 to ln 79)	-	W/S	0.00000	-
81	Plus: Acct. 924	(ln 75)	-	GP	0.00000	-
82	Plus: Acct. 928 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
83	Plus: Acct. 928 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
84	Plus: Acct. 930.1 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
85	Plus: Acct. 930.1 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
86	Plus: Acct. 930.2 - Adj. Misc. General Expenses	(Worksheet D)	-	W/S	0.00000	-
87	Plus: PBOP Amount	(Note T)	-	W/S	0.00000	-
88	A & G Subtotal	(sum lns 80 to 87)	-			-
89	Transmission Lease Payments	(Worksheet D)	-	DA	1.00000	-
90	TOTAL O & M EXPENSE	(ln 73 + ln 88 + ln 89)	-			-
91	DEPRECIATION AND AMORTIZATION EXPENSE					
92	Transmission	336.7.b		TP	0.00000	-
93	Plus: Extraordinary & Storm Cost O&M Amortization	(Worksheet O) (Note W)	-	TP	0.00000	-
94	Plus: Recovery of Abandoned Incentive Plant	(Worksheet P) (Note R)	0	DA	1.00000	0
95	General	336.10.b		W/S	0.00000	-
96	Intangible	336.1.f		W/S	0.00000	-
97	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 92 to 96)	-			-
98	TAXES OTHER THAN INCOME	(Note L)				
99	Labor Related					
100	Payroll	263.i		W/S	0.00000	-
101	Plant Related					
102	Property	263.i		GP	0.00000	-
103	Gross Receipts	263.i				
104	Other	263.i		GP	0.00000	-
105	TOTAL OTHER TAXES	ln 100 + (sum lns 102 to 104)	-			-
106	INCOME TAXES	(Note M)				
107	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
108	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
109	where WCLTD=(ln 137) and R= (ln 140)					
110	and FIT, SIT & p are as given in Note M.					
111	1 / (1 - T) = (from ln 107)		-			
112	Amortized Investment Tax Credit	266.8.f (enter negative)				
113	Income Tax Calculation	(ln 108 * ln 116)	-	NA		-
114	ITC adjustment	(ln 111 * ln 112)	-	NP	-	-
115	TOTAL INCOME TAXES	(sum lns 113 to 114)	-			-
116	RETURN (Rate Base * Rate of Return)	(ln 67 * ln 140)	-	NA		-
117	REVENUE REQUIREMENT (sum lns 90, 97, 105, 115, 116)		-			-

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data") 0

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes - continued

V Accumulated Amortization for Intangible Plant shall be reflected as a Rate Base Adjustment under "Accumulated Depreciation".

W OG&E may only include the amortization of transmission-related extraordinary property losses if; (1) OG&E makes a filing with the Oklahoma Corporation Commission requesting approval for the new amount to be recovered and the amortization period and (2) OG&E makes a single issue FPA Section 205 filing that requests the same recovery treatment from the FERC. OG&E shall be obligated to make such a single issue FPA Section 205 filing whenever it requests amortized extraordinary property loss costs recovery from the Oklahoma Corporation Commission.

X SPP OATT Related Upgrades include Base Plan Upgrades, Sponsored, Economic Portfolio Upgrades, Transmission Service Upgrades and Generator Interconnection Facilities, etc. whose individual Revenue Requirements are calculated and summarized in Worksheet G. Also included are the individual Revenue Requirements of facilities receiving Construction Work in Progress and Abandoned Plant incentive, as calculated and summarized in Worksheet P. The sum of the individual Revenue Requirements is credited to zonal network customers on line 17 above.

Y Exclude annualized amortization amounts booked back into O&M accounts that costs would have been booked had not a Regulatory Asset and amortization period been approved by the Oklahoma Corporation Commission and the FERC. This amount should equal amount reflected on line 93.

Z OG&E may only recover CWIP on projects that the FERC has specifically authorized the incentive.

List of Allocators:

Direct Assigned	DA	1.000000
Gross Plant	GP	0.000000
Net Plant	NP	0.000000
Trans. Plant in SPP	TP	0.000000
Wages & Salaries	W/S	0.000000
No Allocator	NA	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

III. Base Plan Upgrade True-Up Calculations

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year on Base Plan Upgrade Projects.

18 Average Interest Rate on Amount of Refunds or Surcharges calculated per Section V below.

	Proj. No.		Projected ATRR - Prior Year (1)	Baseline ATRR - Prior Year (2)	True-Up Adjustment Without Interest	Refund / (Surcharge) 0	Refund / (Surcharge) 1	Refund / (Surcharge) 2
19	1	Reno-Sunny Lane 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
20	2	Richards Tap-Richards 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
21	3	Van Buren AVEC-Van Buren Interconnect 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
22	4	Brown Explorer Tap 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
23	5	NE Enid-Glenwood 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
24	6	Razorback-Short Mountain 69kV Line	$ -	$ -	$ -	$ -	$ -	$ -
25	7	Richards-Piedmont 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
26	8	OG&E Windfarm-WFEC Mooreland 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -
27	9	Ft. Smith-Colony 161kV Line	$ -	$ -	$ -	$ -	$ -	$ -
28	10	Cedar Lane-Canadian 138kV Line	$ -	$ -	$ -	$ -	$ -	$ -

29 **TOTAL PRIOR YEAR BASE PLAN UPGRADE PROJECTS TRUE-UP ADJUSTMENT** (sum ln 19 thru ln 28) **$ -**

NOTE: (1) Projected ATRR for individual Base Plan Projects comes from the Prior Year's Projected ATRR calculation, Worksheet G and Worksheet P - Summary page
(2) Baseline ATRR for individual Base Plan Projects comes from the Prior Year Baseline ATRR calculation, Worksheet G and Worksheet P - Summary page

Issued by: Melvin H. Perkins, Jr.
Vice President of Power Delivery

Issued on: October 12, 2010

Effective: January 1, 2011

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

I. Project Summary

Proj. No.	A. CWIP Annual Transmission Revenue Requirements	
	Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	CWIP Totals	

Proj. No.	B. Abandoned Plant Annual Transmission Revenue Requirements	
	Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	Abandoned Plant Totals	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant Balances

II. Construction Work in Progress (CWIP) Balances

Line No.	Month	Year	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
1	December	2010											
2	January	2011											
3	February	2011											
4	March	2011											
5	April	2011											
6	May	2011											
7	June	2011											
8	July	2011											
9	August	2011											
10	September	2011											
11	October	2011											
12	November	2011											
13	December	2011											
14	Average Balances												
15	Return	(Data Ln 140 * Ln 14)	0										
16	Taxes	(Data Ln 108 * Ln 15)	0										
17	ATRR	(Ln 15 + Ln 16)	0										

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

III. Abandoned Plant

Line No.			Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
18	Abandoned Plant Balance												
19	Amortization Period (months)												
20	Monthly Amortization Amount												
	Month	Year											
21	December	2010											
22	January	2011											
23	February	2011											
24	March	2011											
25	April	2011											
26	May	2011											
27	June	2011											
28	July	2011											
29	August	2011											
30	September	2011											
31	October	2011											
32	November	2011											
33	December	2011											
34	Average Balances		-										
35	Return	(Data Ln 140 * Ln 34)	0										
36	Taxes	(Data Ln 108 * Ln 35)	0										
37	Amortization Abandoned Plant (Beg. Bal. less End. Bal.)		0										
38	ATRR	(Ln 35 + Ln 36 + Ln 37)	0	-	-	-	-	-					

ATTACHMENT H - ADDENDUM 2-B
OG&E FORMULA RATE IMPLEMENTATION PROTOCOLS

I. Annual Update and True-Up Adjustments

1.1 The formula rate template contained in Attachment H - Addendum 2-A and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Oklahoma Gas and Electric Company ("OG&E") for transmission service under the Open Access Transmission Tariff ("OATT") of the Southwest Power Pool, Inc. ("SPP"). OG&E shall follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR"), rates for its Point-to-Point transmission service, and the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades.

1.2 The Formula Rate shall initially be effective for service on and after July 1, 2008, through December 31, 2008, and shall be applicable thereafter for services in subsequent years on and after January 1 of each calendar year through December 31 of that calendar year ("Rate Year"). The purpose of these protocols is to establish a set of procedures that may be used by Interested Parties (as defined in Section 1.3(a)(4) herein) to review and challenge Annual Updates and True-Up Adjustments, as defined herein. Provided, however, (i) nothing herein shall limit the rights of OG&E or any Interested Party to initiate a proceeding at the Federal Energy Regulatory Commission ("Commission") at any time with respect to the Formula Rate consistent with the Party's rights under the Federal Power Act ("FPA") and the Commission's regulations and (ii) the provisions of these Protocols applicable to review and challenge of Annual Updates and True-Up Adjustments shall not apply to proceedings other than (a) Formal Challenges initiated in accordance with the procedures set forth herein and/or (b) proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment, and shall not be relied upon to alter any Party's rights or obligations under the FPA and the Commission's regulations in proceedings other than such Formal Challenges and/or proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment. The term "Party" or "Parties" is defined to include OG&E and/or one or more Interested Parties.

1.3 Posting of Annual Update and Related Procedures

(a) On or before September 1 of each calendar year (unless September 1 falls on a weekend or a holiday recognized by the Commission, in which case the date shall be the next business day), OG&E:

(1) shall recalculate the ATRR by removing the 13-month average net plant balances and the 13-month average Construction Work in Progress ("CWIP") balances from the most recent Baseline ATRR and replacing them with projected 13-month average net plant and CWIP balances for the following Rate Year (the "Projected ATRR"). (The "OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3" is the Projected ATRR, adjusted to take account of any related True-Up Adjustment(s).) OG&E shall also calculate the

rates for its Point-to-Point transmission service, and shall calculate the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades, for the new Rate Year in accordance with the Formula Rate. (The calculations described in this Section 1.3(a)(1) are collectively referred to as the "Annual Update.")

(2) shall provide such Annual Update and supporting information to SPP, for posting on the publicly accessible portion of the SPP website (the date of such posting to be the "Posting Date"). For purposes of these Protocols, "supporting information" shall include, at minimum, a data-populated Formula Rate template in a fully-functioning Excel file (and/or as applicable, other native format) showing all calculations, any supporting calculations and workpapers that demonstrate or explain information not otherwise set out in OG&E's FERC Form No. 1 or the Formula Rate template, a Portable Document Format version of the data-populated Formula Rate template described above, and a side-by-side comparison of the Formula Rate template components (by line) as compared to the most recent Baseline ATRR (as defined in Section 1.4(a));

(3) shall provide SPP with the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR;

(4) shall provide the Annual Update and supporting information identified in Section 1.3(a)(2) above, and detailed information concerning the projected 13-month average net plant and CWIP balances (including project-specific information for planned additions), upon written request, including a standing request for all future Annual Updates and supporting information, to (i) any entity that is or may become a customer taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP; (ii) any entity served under the SPP OATT; (iii) any affected state and federal regulatory authorities; and (iv) FERC staff (collectively, "Interested Parties");

(5) shall notify SPP transmission customers taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP, affected regulatory commissions, and other parties that have made a request in accordance with Section 1.3(a)(4), of the Annual Update posting via email and/or United States mail to the most recent address provided to OG&E;

(b) After the Posting Date and before October 1 of each calendar year, OG&E shall convene a meeting ("Customer Meeting") to afford Interested Parties an opportunity to discuss and become better informed regarding the Annual Update. OG&E will provide at least fifteen days' notice of the Customer Meeting via a notice included with the Annual Update and posted on the SPP website; and

(c) After the Customer Meeting and before November 1 for each calendar year, OG&E shall provide timely notice of any errors found in the review process, any updates to the

-projections of 13-month average net plant and CWIP balances, resolutions of Preliminary Challenges and/or proceedings provided for in section 3.6, and/or any corrections to that year's True-Up Adjustment that are agreed to by OG&E and an Interested Party, and Interested Parties may object in writing by November 8 to any such proposed corrections or updates. Notice shall be accomplished by providing such information to SPP for posting on the publicly accessible portion of the SPP website and by providing e-mail notice of such posting to any Interested Party that has submitted a request for information pursuant to Section 2.1. No later than November 15 of each calendar year, OG&E shall modify the Annual Update to reflect uncontested corrections and updates, and shall cause a revised Annual Update to be posted on the SPP website no later than December 1. At that time, OG&E shall also provide SPP with any updated ATRR associated with each of OG&E's Base Plan Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR.

1.4 On June 1 of each calendar year (unless June 1 falls on a weekend or a holiday recognized by the FERC, in which case the date shall be the next business day) (the "Publication Date"), OG&E shall, in accordance with the Formula Rate, calculate the Baseline ATRR for the Rate Year that has most recently concluded, reconcile the Projected ATRR with the Baseline ATRR for the corresponding Rate Year and calculate the amount of any over- or under-recovery (all of which, plus any corrections pursuant to Section 1.10 or any changes to account for the resolution of any Preliminary Challenge, Formal Challenge, or a proceeding initiated *sua sponte* by FERC challenging a True-Up Adjustment, to the extent such changes have not been reflected in a prior Annual Update, shall be considered the "True-Up Adjustment"). On the Publication Date, OG&E shall submit the True-Up Adjustment to FERC for informational purposes only. The informational filing shall not require any action by the Commission.[1] On or before the Publication Date, OG&E shall follow the procedures set forth in Sections 1.3(a)(2)-(5) for disseminating the True-Up Adjustment and supporting information (as defined in Section 1.3(a)(2)). The True-Up Adjustment:

(a) shall, to the extent specified in the Formula Rate, be based upon data properly recorded in the appropriate accounts, consistent with FERC accounting policies and accounting practices, in (i) OG&E's FERC Form No. 1 for the most recent calendar year (*i.e.*, the most recently completed Rate Year), and (ii) the books and records of OG&E.[2] (The ATRR determined using these data shall be termed the "Baseline ATRR".);

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[1] The transmittal letter accompanying the informational filing shall inform the Commission that the True-Up Adjustment is not intended to be subject to the Commission's notice requirements and it is not intended for the Commission to take action accepting the informational filing, and shall inform the Commission regarding the procedures contained in these Protocols for review and challenge of the True-Up Adjustment. If the Commission issues a notice of or an order accepting the informational filing, OG&E shall advise the Commission of the challenge process in these Protocols and shall work with the Settling Parties to seek rescission of such actions. No Commission action on the informational filing shall affect any rights under the Formula Rate or these Protocols.

[2] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

ATTACHMENT 5

DIRECT TESTIMONY AND EXHIBITS OF PHILIP L. CRISSUP

Exhibit No. OGE-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER10-___-000

DIRECT TESTIMONY AND EXHIBITS OF
PHILIP L. CRISSUP

October 12, 2010

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company) Docket No. ER10-___-000

DIRECT TESTIMONY AND EXHIBITS OF PHILIP L. CRISSUP

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Philip L. Crissup. My business address is 321 N. Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101. I am Director of Regional Transmission Affairs of Oklahoma Gas and Electric Company ("OG&E").

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. As Director of Regional Transmission Affairs, my areas of responsibility include the coordination of Transmission Planning and Transmission Policy activities at OG&E and in coordination with the Southwest Power Pool, Inc. ("SPP").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Oklahoma in 1983. Upon graduation, I began my career at OG&E at the Northern Region Engineering office in Enid, Oklahoma as a Distribution Engineer. I was promoted to Design Engineer in the Transmission Design section of Corporate Engineering in 1987, and then to Senior Engineer in the same department in 1994. I moved to the Engineering Planning section in 1997, and became Manager of the Transmission Planning group in 2002. In 2006, I became

Director of Regional Transmission Affairs. I am a Licensed Professional Engineer in the State of Oklahoma.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION OR BEFORE A STATE REGULATORY AGENCY?

A. Yes. At the Federal Energy Regulatory Commission ("Commission" or "FERC"), I submitted testimony in 2008 in support of a Federal Power Act Section 205 filing by Tallgrass Transmission LLC in Docket No. ER09-35-000. Further, I submitted testimony in 2008 in connection with a Federal Power Act Section 203 filing by OG&E and Redbud Energy LP in Docket No. EC08-58-000.

I also have filed testimony in proceedings before the Oklahoma Corporation Commission ("OCC") in a 2008 proceeding concerning International Transmission Corporation's application to be classified and regulated by the OCC as a transmission-only utility, as well as in an OCC filing for recovery of OG&E's costs associated with the WindSpeed 345kV transmission line.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS TESTIMONY.

A. My testimony identifies and describes the eight transmission projects that are the subject of OG&E's request for transmission rate incentives (collectively, "the Projects"). I also will address the relevant SPP planning processes and the status of the Projects with respect to those processes; the benefits and costs of the Projects; and the non-financial risks and challenges that OG&E faces in completing the Projects.

OG&E is presenting two other witnesses in support of its filing. David L. Kays, the Lead Transmission Activities Engineer at OG&E, describes the changes to OG&E's FERC-filed transmission formula rate that are required to accommodate the two incentive rates that OG&E requests: (1) the recovery of 100 percent of construction work in progress, or "CWIP," in rate base, and (2) recovery of 100 percent of prudently incurred expenses should the Projects be abandoned for reasons outside OG&E's control, or "Abandoned Plant."[1] Donald R. Rowlett, OG&E's Director of Regulatory Policy and Compliance, describes the Projects' financial risks and challenges and the benefits of the requested incentives.[2] Mr. Rowlett further describes the CWIP-related accounting procedures that OG&E plans to implement in accordance with the Commission's regulations.

II. THE PROJECTS

Q. PLEASE DESCRIBE OG&E.

A. OG&E is an electric public utility with plant, property, and other assets dedicated to the production, transmission, distribution, and sale of electric energy to wholesale and retail customers in Oklahoma and western Arkansas. OG&E serves more than 750,000 retail customers and sells electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives, and other market participants. OG&E owns and operates approximately 6,641 MWs of generation capacity composed of natural gas, low-sulfur coal, and wind generation facilities, and also purchases power from third parties for resale.

[1] *See* Direct Testimony of David L. Kays, Exhibit No. OGE-17.

[2] *See* Direct Testimony of Donald R. Rowlett, Exhibit No. OGE-19.

OG&E's transmission system includes approximately 4,450 miles of transmission lines plus 48 substations. OG&E is an Oklahoma corporation and a wholly-owned subsidiary of OGE Energy Corp. OG&E is a member of SPP.

Q. PLEASE DESCRIBE THE PROJECTS.

A. The Projects are a set of additions to the SPP transmission system that will help meet the region's growing transmission needs and provide significant benefits, as I will detail later in my testimony. The Projects consist of eight specific transmission facility additions:

1. The Hitchland-Woodward Project ("Hitchland-Woodward") is a double-circuit 345-kV, 120-mile transmission line that will extend from OG&E's Woodward District extra high voltage ("EHV") substation to Southwestern Public Service Company's Hitchland substation, together with associated upgrades to the Woodward District EHV substation. The OG&E portion of the Hitchland-Woodward 345-kV line is estimated to be 82 miles in length, will cost approximately $178.6 million, and has an estimated in-service date of June 30, 2014;

2. The Woodward-Kansas Project ("Woodward-Kansas") is a double-circuit 345-kV, 80-mile transmission line to be built from OG&E's Woodward District EHV substation to the Prairie Wind LLC interception point at the Oklahoma-Kansas state line, together with associated upgrades to the Woodward District EHV substation. Woodward-Kansas is estimated to cost $134.4 million and has an estimated in-service date of December 31, 2014;

3. The Sooner-Cleveland Project ("Sooner-Cleveland") is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's Cleveland substation, plus associated upgrades to the Sooner substation. OG&E will construct the entire Sooner-Cleveland line. This project is estimated to cost $64 million, and has an expected in-service date of March 31, 2013;

4. The Seminole-Muskogee Project ("Seminole-Muskogee") is a single-circuit, 345-kV, 120-mile transmission line to be built from OG&E's Seminole substation to OG&E's Muskogee substation, as well as associated upgrades to both the Seminole and the Muskogee substations. Seminole-Muskogee has an estimated cost of $179.1 million and an estimated in-service date of December 31, 2013;

5. The Tuco-Woodward Project ("Tuco-Woodward") is a 345-kV, 250-mile transmission line from OG&E's Woodward District EHV to the SPS Tuco substation. The OG&E portion of the Tuco-Woodward project is 72 miles in length and will terminate at a reactor station to be constructed at approximately the Oklahoma-Texas state border south of Interstate 40. The project has an estimated cost of $120 million with an estimated in-service date of May 19, 2014;

6. The Anadarko Project ("Anadarko") is a 345/138-kV substation to be constructed on the OG&E line from Cimarron towards the AEP Lawton East Side 345kV line near the town of Gracemont, Oklahoma. Anadarko, also known as the Gracemont substation project, is expected to cost $14.6 million and has an estimated in-service date of December 31, 2011;

7. The Sunnyside-Hugo Project ("Sunnyside-Hugo") is a 345-kV, 120-mile transmission line to be built from OG&E's Sunnyside substation to the Western Farmers Electric Cooperative's Hugo Generation Plant, as well as associated upgrades to the Sunnyside substation. Sunnyside-Hugo is estimated to cost $187 million and has an estimated in-service date of April 1, 2012; and

8. The Sooner-Rose Hill Project ("Sooner-Rose Hill") is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation to an interface with a Westar Energy line segment at the Oklahoma-Kansas state line. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length, is estimated to cost $57.8 million, and has an estimated in-service date of June 1, 2012.

Q. WHAT ARE THE KEY DRIVERS OF THESE INVESTMENTS?

A. The key drivers of these investments are derived from SPP's regional planning efforts, which were implemented to develop new transmission to meet applicable North American Reliability Corporation ("NERC") reliability standards, to relieve congestion, and to access remote renewable resources.[3] In tailoring its planning processes, SPP has reiterated the need for new large-scale transmission projects to facilitate expansive renewable resource developments in the western portion its system and for diverse resource options in load centers in the eastern portion and in neighboring systems.[4] To this end, projects vetted and selected through SPP's planning processes generally strengthen the reliability of SPP's system and

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[3] SPP Open Access Transmission Tariff ("OATT") at Attachment O, Section VII.

[4] SPP OATT at Attachment O, Section IV; *see also*, SPP May 17, 2010 Filing, Docket No. ER10-1269-000 at 4-7.

provide regional benefits by relieving congestion that already exists or that will exist due to requests for new transmission service.[5]

Q. DO THE PROJECTS REPRESENT A SIGNIFICANT EXPANSION OF THE OG&E TRANSMISSION SYSTEM?

A. Yes. The Projects will add approximately 555 miles of new transmission facilities to the OG&E system within the SPP region, compared to 4,450 miles of high voltage transmission lines, and 910 miles specifically of 345-kV lines, currently comprising OG&E's transmission system. The current cost projection for the combined Projects is approximately $936 million. The actual cost will depend on multiple factors such as the final routes for the proposed lines, and the costs of equipment, commodities, and other construction elements. The projected investment is equal to about 175 percent of OG&E's current net transmission plant of $534 million. The average annual capital investment in the Projects over the next 5 years will equal approximately $192 million, representing more than eight times OG&E's previous average annual capital investment of $20 million.

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[5] *See* SPP OATT at Attachments O, J, and Z1; SPP May 17, 2010 Filing, Docket No. ER10-1269-000 at 4-7.

OG&E estimates that the annual construction costs will be as follows:

<u>Projected Budget for OG&E Transmission Projects</u>
(Dollars in Millions)

Project	2010	2011	2012	2013	2014	Total
Hitchland-Woodward	$0	$5.5	$33	$95	$45.1	$178.6
Woodward-Kansas	$0	$5.5	$24	$60	$44.9	$134.4
Sooner-Cleveland	$2.385	$19.074	$41.069	$1.536	$0	$64.064
Seminole-Muskogee	$0	$11.1	$101	$67	$0	$179.1
Tuco-Woodward	$0	$4.7	$23	$62.7	$29.6	$120
Anadarko	$1	$13.668	$0	$0	$0	$14.668
Sunnyside-Hugo	$25.105	$140.28	$21.904	$0	$0	$187.289
Sooner-Rose Hill	$10.858	$33.931	$13.045	$0	$0	$57.834
Total	$39.348	$233.753	$257.018	$286.236	$119.6	$935.955

III. SPP REGIONAL PLANNING PROCESSES

Q. HAVE THE PROJECTS BEEN INCLUDED IN ANY REGIONAL PLANNING PROCESSES?

A. Yes. SPP recently completed its 2009 SPP Transmission Expansion Plan ("STEP")[6] pursuant to the planning processes set forth at Attachment O of the SPP OATT. Each of the Projects was evaluated and approved by SPP through regional planning processes and subsequently included in the 2009 STEP. The

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[6] *See* 2009 STEP, Exhibit No. OGE-2. Exhibit No. OGE-2 includes excerpts of the relevant sections of the 2009 STEP Report. The report, in its entirety, can be found at http://www.spp.org/publications/2009%20SPP%20Transmission%20Expansion%20Plan%20(Redacted%20Version).pdf.

SPP Board of Directors has approved each of the Projects, and SPP has issued a Notification to Construct for each project.[7]

Q. WHAT IS A NOTIFICATION TO CONSTRUCT?

A. Pursuant to the SPP OATT, "[a]fter a new transmission project is (i) approved under the SPP Transmission Expansion Plan or (ii) required pursuant to a Service Agreement or (iii) required by a generation interconnection agreement to be constructed by a Transmission Owner(s) other than the Transmission Owner that is a party to the generation interconnection agreement, [SPP] shall [in writing] direct the appropriate Transmission Owner(s) to begin implementation of the project[.]"[8] The Transmission Owner(s) designated to construct the project are referred to as the "Designated Transmission Owner(s)." The written notification includes: "(1) the specifications of the project required by the Transmission Provider and (2) a reasonable project schedule, including a project completion date ("Notification to Construct")."[9] As of September 28, 2010, OG&E has accepted the SPP Notification to Construct for all eight Projects.

Q. WHAT IS THE 2009 SPP TRANSMISSION EXPANSION PLAN?

A. SPP's planning processes are outlined in Attachment O of SPP's Tariff, and include the requirement for SPP to produce an annual STEP that addresses SPP's transmission expansion needs over a 20 year planning horizon.[10] The 2009 STEP

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7 *See* SPP Notification to Construct, SPP-NTC-20100 (June 30, 2010), Exhibit No. OGE-3; SPP Notification to Construct, SPP-NTC-20017 (January 16, 2009), Exhibit No. OGE-4; SPP Notification to Construct, SPP-NTC-20055 (September 18, 2009), Exhibit No. OGE-5; SPP Notification to Construct, SPP-NTC-20041 (June 19, 2009), Exhibit No. OGE-6.

8 SPP OATT, Attachment O, Section VI.4.

9 *Id.*

10 SPP OATT, Attachment O, Sections I & V.

includes a regional reliability assessment for the period of 2010 to 2019 and identifies needed transmission upgrades and possible problems in both normal and contingency conditions.[11] The 2009 STEP also highlights the region's top congested flowgates and identifies priority projects that will lower production costs and relieve congestion.[12]

Q. WERE THE PROJECTS EVALUATED IN THE 2009 STEP?

A. Yes. Within its overall transmission planning process, SPP uses several distinct evaluation and approval processes to determine the need for new transmission infrastructure. Each of the relevant processes is described in the STEP Report. Each Project was vetted through processes that considered reliability needs and congestion relief before being approved and included in the STEP.[13]

There are three evaluation and approval processes relevant to the Projects. First, SPP's Synergistic Planning Project has a goal to establish "innovative and forward-thinking solutions to gaps and conflicts between SPP's transmission planning processes."[14] The Priority Projects, which include Woodward-Hitchland and Woodward-Kansas, are part of the Synergistic Planning Project.[15]

Second, SPP conducts tariff studies to identify, among other things, transmission expansion projects needed to address the reliability and/or congestion concerns created by new requests for transmission service.

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11 2009 STEP, Exhibit No. OGE-2 at 3.

12 *Id*. at 3-4.

13 *See, e.g.*, SPP OATT, Attachment O, Sections III.3-6.

14 *See* 2009 STEP, Exhibit No. OGE-2 at 3.

15 *See id*. at 14-15.

Accordingly, SPP combines all requests for transmission service that it has received during an open season, identifies all system constraints, and then determines "the upgrades required to reliably provide all of the requested service."[16] This practice is intended to allow SPP and participating stakeholders to "develop a more efficient expansion of the transmission system" that will provide the necessary capacity to resolve congestion and reliability problems and do so at the minimum total cost to beneficiaries.[17] As an additional component to this process, SPP conducts a regional review to determine if alternative solutions would reduce overall cost to customers (*i.e.*, through congestion reduction, greater efficiencies, *etc*.).[18] Through this process, SPP identified the need for Sunnyside-Hugo and Sooner-Rose Hill.

Third, SPP's Balanced Portfolio process identifies projects "intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs." [19] Sooner-Cleveland, Seminole-Muskogee, Anadarko, and Tuco-Woodward are each Balanced Portfolio upgrades.

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16 *See* SPP OATT, Attachment Z1, Sections I & III.a.

17 *See* SPP OATT, Attachment Z1, Sections I.

18 *See* SPP OATT, Attachment Z1, Sections III.a.

19 *See* 2009 STEP, Exhibit No. OGE-2 at 23.

Q. PLEASE DESCRIBE FURTHER THE SYNERGISTIC PLANNING PROJECT.

A. In 2009, the SPP Board of Directors created a Synergistic Planning Project Team ("SPPT") to make recommendations "to address gaps and conflicts between SPP's transmission planning processes and help position the organization to respond to the Obama administration's focus on improving our nation's electric infrastructure."[20] The SPPT recommended a new Integrated Transmission Plan ("ITP"),[21] a highway-byway cost allocation methodology, and the identification and development of Priority Projects.

Q. WHAT IS THE PURPOSE OF THE PRIORITY PROJECTS?

A. The Priority Projects are intended to provide system-wide benefits across the SPP region by "reduc[ing] grid congestion, improv[ing] the Generation Interconnection and Aggregate Study processes, and better integrat[ing] SPP's east and west regions."[22]

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[20] *See id*. at 11.

[21] The objectives of the ITP are to integrate and improve several of SPP's existing planning processes and to develop a "transmission backbone to connect load centers to known or expected large generation resources [and to] more strongly connect SPP's eastern and western regions, strengthen ties to the Eastern Interconnection, and . . . possibly connect to the Western Interconnection." *See* 2009 STEP, Exhibit No. OGE-2 at 12.

[22] SPP Priority Projects Phase II Final Report, Rev. 1 (April 27, 2010), Exhibit No. OGE-7 at 3 ("Priority Projects Report"). Exhibit No. OGE-7 includes excerpts from the relevant sections of the Priority Projects Report. The report, in its entirety, can be found at http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf.

Q. PLEASE DESCRIBE HOW THE PRIORITY PROJECTS ARE IDENTIFIED.

A. A pool of potential projects was identified with input from stakeholders and several SPP working groups and narrowed down to ten projects.[23] These ten projects were assessed using various metrics including "Adjusted Production Cost [*i.e.*, a measure of the impact on production cost savings by Locational Marginal Price], loss impacts, reliability assessment, local and environmental impacts, and deliverability of capacity and energy to load,"[24] as well as gas price impact.[25] Analyses of the potential projects were conducted by SPP staff, Quanta Technologies, Brattle Group, and Brown Engineers.[26] Based on the results of these analyses, SPP published several drafts of a Priority Projects report recommending approval of several of the screened projects. The analyses were updated before the issuance of a final report. The final Priority Projects report was approved by the SPP Board of Directors and issued on April 27, 2010. The relevant portions of this report are included as Exhibit No. OGE-7.

Q. PLEASE DESCRIBE THE FINDINGS IN SPP'S PRIORITY PROJECTS REPORT.

A. The Priority Projects Report analyzed two alternative groupings of six projects. The first grouping ("Group 1") included two projects – including Woodward-Kansas – constructed at 765 kV and operated at 345 kV. The second grouping

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23 *See* 2009 STEP, Exhibit No. OGE-2 at 14.

24 *See id*. at 14; Priority Projects Report, Exhibit No. OGE-7 at 4 & 15-19.

25 Priority Projects Report, Exhibit No. OGE-7 at 26.

26 *See* 2009 STEP, Exhibit No. OGE-2 at 13.

("Group 2") included these same two projects constructed and operated as a 345 kV double-circuit line. The report concluded that the Group 2, *i.e.*, where Woodward-Kansas is constructed and operated as a 345 kV double-circuit line, yields a greater benefit-to-cost ratio than the alternative.[27] More specifically, the report finds that the selected Priority Projects "will reduce [grid] congestion, as demonstrated in the APC [*i.e.*, adjusted production cost] analysis and by the levelization of Locational Marginal Prices (LMPs) across the SPP footprint."[28] Moreover, the Priority Projects "will improve the Aggregate Study process by creating additional transfer capability and allowing additional transmission service requests to be enabled."[29]

Q. WILL THE PRIORITY PROJECTS FACILITATE THE INTERCONNECTION OF NEW GENERATION TO THE GRID?

A. Yes. The Priority Projects will facilitate the interconnection of 3,000-5,000 MW of wind power and the addition of other new non-renewable generation.[30] Currently, a backlog of generation interconnection requests exists in SPP, with many of the pending requests involving new wind facilities.[31] Woodward-Kansas and Woodward-Hitchland will help clear this backlog of pending requests. Analyses also showed that the Priority Projects will "increase the ability to

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27 Priority Projects Report, Exhibit No. OGE-7 at 5.

28 *Id.* at 6 & 22.

29 *Id.* at 6 & 23.

30 *Id.*

31 *See* SPP Generation Interconnection Active Requests, https://studies.spp.org/SPPGeneration/GI_ActiveRequests.cfm.

transfer power in an eastward direction for two-thirds of the eastward paths by connecting SPP's western and eastern areas."[32]

Q. WHAT OTHER BENEFITS WILL THE PRIORITY PROJECTS PROVIDE?

A. Additional benefits of the Priority Projects include "enabling future SPP energy markets, dispatch savings, reduction in carbon emissions and required operating reserves, storm hardening, meeting future reliability needs, improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, and additional societal economic benefits,"[33] as well as enabling SPP "to better manage many uncertain future scenarios such as carbon policy, varying fuel prices, growth in electricity demand, and state or federal renewable energy standards."[34] Moreover, an analysis conducted by The Brattle Group showed an overall economic impact of the Group 2 projects of $962 million, overall job impacts of 7,475 full-time equivalent years, additional earnings related to job impact of $368 million, and state and local government tax impacts of $34.4 million.[35] All in all, SPP

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[32] Priority Projects Report, Exhibit No. OGE-7 at 6 & 25.

[33] *Id*. at 6.

[34] *See* SPP News Release, "SPP Approves Construction of New Electric Transmission Infrastructure To Bring $3.7 Billion in Regional Benefits," (April 27, 2010), Exhibit No. OGE-8, at 1 ("SPP News Release").

[35] Priority Projects Report, Exhibit No. OGE-7 at 39; Priority Projects Report Attachment 4, Exhibit No. OGE-9 (The Brattle Group, "Job and Economic Benefits of Transmission and Wind Generation Investments in the SPP Region" (March 2010)).

estimates that the Priority Projects will benefit the SPP region by at least $3.7 billion over the next 40 years.[36]

Q. HOW DO THE PRIORITY PROJECTS RELATE TO THE PROJECTS THAT WERE THE SUBJECT OF THE COMMISSION'S ORDER APPROVING TRANSMISSION INCENTIVES FOR TALLGRASS TRANSMISSION, LLC?

A. In *Tallgrass Transmission, LLC*, the Commission granted incentives for a major transmission line following the same path as is proposed for Woodward-Kansas and Woodward-Hitchland and providing essentially the same benefits as these two lines.[37] As discussed in the Priority Projects Report and prior drafts of that report, the transmission line concerned in the *Tallgrass* case was proposed to be built either at 765 kV or at 345 kV.[38] Tallgrass Transmission, LLC ("Tallgrass") originally proposed to build the line at 765 kV. However, SPP has determined that the 345-kV option will better meet the needs of the SPP system.[39] The analyses supporting the Priority Projects Report showed that the group of projects that includes Woodward-Kansas as a 345-kV double-circuit line will yield greater loss savings,[40] greater increases in revenues from wind generation,[41] and greater

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36 *See* SPP News Release, Exhibit No. OGE-8 at 1.

37 *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 (2008) ("*Tallgrass*").

38 *See* Priority Projects Report, Exhibit No. OGE-7 at 4-5. *See also* 2nd Draft SPP Priority Projects Report (last revised October 7, 2009), Exhibit No. OGE-10 at 6. Exhibit No. OGE-10 includes excerpts from the relevant sections of the second draft of the report. The draft in its entirety can be found at http://www.spp.org/publications/Priority%20Projects%20Report%20-%202nd%20DRAFT%2020091007%20(clean).pdf.

39 *See* Priority Projects Report, Exhibit No. OGE-7 at 4-6.

40 *Id*. at 28-29.

41 *Id*. at 30-34.

savings from reduced natural gas prices,[42] and will provide greater reliability benefits.[43]

SPP has issued a Notification to Construct to OG&E for the Woodward-Kansas and Woodward-Hitchland projects,[44] and OG&E plans to build these transmission facilities at 345 kV as called for in the Priority Projects Report. Woodward-Hitchland and Woodward-Kansas will provide most of the same benefits that the Tallgrass project would have provided. These benefits include "cost savings due in substantial part to increased transfer capability that would reduce congestion and allow transportation of low-cost wind energy to displace higher cost energy from fossil fuel sources."[45]

Q. PLEASE DESCRIBE HOW SPP EVALUATES TRANSMISSION PROJECTS REQUIRED TO MEET TRANSMISSION SERVICE REQUESTS.

A. Pursuant to the Aggregate Transmission Service Study Procedures set forth at Attachment Z1 of the SPP OATT, SPP conducts an open season during which customers may make requests for long-term transmission service. SPP then conducts an Aggregate Facilities Study ("AFS") of the eligible requests for transmission service received during the open season. During the AFS, "[s]ystem constraints will be identified and appropriate upgrades determined."[46] SPP is

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42 *Id*. at 38; Priority Projects Report Attachment 6, Exhibit No. OGE-11 (KEMA Report, "SPP Priority Projects – Natural Gas Price Reduction" (March 26, 2010)).

43 Priority Projects Report, Exhibit No. OGE-7 at 29-30.

44 SPP Notification to Construct, SPP-NTC-20100, Exhibit No. OGE-3.

45 *Tallgrass*, 125 FERC ¶ 61,248 at PP 41, 54.

46 SPP OATT, Attachment Z1, Section III.a.

charged with determining "the upgrades required to reliably provide all of the requested service" and with performing "a regional review of the required upgrades to determine if alternative solutions would reduce overall cost to customers."[47] SPP conducts a system impact analysis to determine the steady-state impact of the aggregate transmission service requests on the SPP system, as well as on first tier non-SPP control areas. This analysis ensures that SPP's criteria and the NERC Reliability Standards are met.[48] To determine the impact of transmission service requests on the transmission system, SPP uses several seasonal models to study the aggregate transfer of the total requested service over a variety of requested service periods.[49] A transfer analysis is completed using the Power System Simulator for Engineering ("PSS/E") AC Contingency Calculation ("ACCC").[50] This analysis screens for potential loading violations under contingency conditions. Curtailment and redispatch are considered as alternatives to assigning new network upgrades.[51]

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47 *Id*.

48 *See, e.g.*, Aggregate Facility Study SPP-2006-AG3-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers (September 16, 2008), Exhibit No. OGE-12 at 10-13 ("SPP September 2008 Study"); Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers (Revised March 19, 2009), Exhibit No. OGE-13 at 11-13 ("SPP March 2009 Study").

49 SPP September 2008 Study, Exhibit No. OGE-12 at 10; SPP March 2009 Study, Exhibit No. OGE-13 at 10.

50 *See, e.g.*, SPP September 2008 Study, Exhibit No. OGE-12 at 13; SPP March 2009 Study, Exhibit No. OGE-13 at 13.

51 *See, e.g.*, SPP September 2008 Study, Exhibit No. OGE-12 at 13-14; SPP March 2009 Study, Exhibit No. OGE-13 at 13-14.

Q. WHAT IS THE PURPOSE OF EVALUATING TRANSMISSION SERVICE REQUESTS ON AN AGGREGATE BASIS?

A. SPP studies transmission service requests on an aggregate basis in order "to develop a more efficient expansion of the transmission system that provides the necessary ATC [*i.e.*, available transfer capability] to accommodate all such requests at the minimum total cost."[52] As stated above, this practice is intended to allow SPP and participating stakeholders to "develop a more efficient expansion of the transmission system" that will provide the necessary capacity to resolve congestion and reliability problems and do so at the minimum total cost to beneficiaries.[53] Upgrades evaluated for transmission requests pursuant to Attachment Z1 are folded into the Attachment O integrated transmission planning study and analysis,[54] which incorporates NERC Reliability Standards, load and capacity forecasts, and congestion within SPP and between SPP and other regions.[55] Projects vetted by this process are then reviewed together with projects from other studies such as high priority studies and the "Balanced Portfolio." In short, SPP's evaluation of upgrades pursuant to Attachments Z1 and O are reviewed against system-wide constraints and needs in order to ensure that the projects selected enhance reliability and/or reduce congestion.

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52 SPP OATT, Attachment Z1, Section I.

53 *See id*.

54 See SPP OATT, Attachment O, Figure 1; *see also*, Attachment O, Sections III.3-III.5.

55 *See* SPP OATT, Attachment O, Section III.6.

Q. WERE THE OG&E PROJECTS EVALUATED BY SPP IN THIS PROCESS?

A. Yes. Sunnyside-Hugo was evaluated in Aggregate Facility Study SPP-2006-AG3-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers, issued on September 16, 2008. Sooner-Rose Hill was evaluated in Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers, issued on December 10, 2008 and revised on March 19, 2009. These studies are included in this filing at Exhibit Nos. OGE-12 and OGE-13. Through the Aggregate Transmission Service Study Procedures, SPP determined that the Sunnyside-Hugo and Sooner-Rose Hill Projects were among the projects needed to accommodate the aggregate transmission service requests.[56] Subsequently, these Projects were included in the 2009 STEP Report, which was approved by the SPP Board of Directors. Notifications to Construct also have been issued for these two Projects.[57]

Q. WHAT FINDINGS DID SPP MAKE IN CONNECTION WITH ITS EVALUATION OF THESE PROJECTS?

A. SPP found that limiting constraints exist on SPP's system that would prevent the requests for transmission service from being granted unless upgrades are made to

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[56] SPP September 2008 Study, Exhibit No. OGE-12 at 14-15; SPP March 2009 Study, Exhibit No. OGE-13 at 15 and Table 3.

[57] SPP Notification to Construct, SPP-NTC-20017, Exhibit No. OGE-4; SPP Notification to Construct, SPP-NTC-20055, Exhibit No. OGE-5.

the transmission system. These necessary upgrades include Sunnyside-Hugo and Sooner-Rose Hill.[58]

Q. PLEASE DESCRIBE FURTHER HOW SPP EVALUATES TRANSMISSION PROJECTS THAT ARE PART OF A BALANCED PORTFOLIO.

A. The Balanced Portfolio is an SPP initiative to select a cohesive group of economic transmission upgrades to benefit the SPP region as a whole.[59] The Balanced Portfolio projects are intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs," and the sum of the benefits must exceed the sum of the costs.[60]

Q. HOW WERE THE OG&E PROJECTS EVALUATED BY SPP IN THIS PROCESS?

A. SPP's Cost Allocation Working Group ("CAWG"), with stakeholder input, identified "upgrades that will provide a balanced benefit to customers over the specified ten-year payback period."[61] Pursuant to Attachment O of the SPP OATT, the Balanced Portfolio must be (1) cost beneficial, meaning that "[t]he sum of the benefits [measured using an adjusted production cost metric] . . . must equal or exceed the sum of the costs [measured as the net present value of the revenue requirements];" and (2) balanced, meaning that the benefits must also

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58 SPP September 2008 Study, Exhibit No. OGE-12 at 18 and Table 3; SPP March 2009 Study, Exhibit No. OGE-13 at 18 and Table 3.

59 SPP Balanced Portfolio Report (last revised June 23, 2009) at 3, Exhibit No. OGE-14.

60 *Id.* at 3.

61 *Id.*

equal or exceed the costs for each SPP zone.[62] From an initial list compiled by the CAWG, SPP conducted an analysis of the adjusted production cost of each potential project.[63] The annual benefits of the potential projects were compared to the estimated engineering and construction costs, which were provided by transmission owners.[64] A potential project's benefit-to-cost ratio was used to determine potential groupings of projects.[65] The final selection of projects was based on a grouping of projects that ensured that a project was included for each SPP zone "with the most beneficial project chosen in each zone."[66] This group of transmission projects was referred to by SPP as Portfolio 3E "Adjusted."

Q. WHAT IS PORTFOLIO 3E "ADJUSTED"?

A. Portfolio 3E "Adjusted" is the group of 345-kV transmission projects selected to fulfill the Balanced Portfolio objectives. It has an estimated total cost of $692 million[67] This group of projects includes the Sooner-Cleveland, Seminole-Muskogee, Anadarko, and Tuco-Woodward Projects. Portfolio 3E "Adjusted" has been approved by the SPP Board of Directors, and a Notification to Construct has been issued for Sooner-Cleveland, Seminole-Muskogee, Anadarko, and Tuco-Woodward.[68]

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62 SPP OATT, Attachment O, Section IV.3.e.

63 SPP Balanced Portfolio Report, Exhibit No. OGE-14 at 6.

64 *Id*. at 8.

65 *Id*.

66 *Id*. at 9.

67 *Id*. at 3.

68 SPP Notification to Construct, SPP-NTC-20041, Exhibit No. OGE-6.

Q. WHAT IS THE PRIMARY BENEFIT OF THE PROJECTS INCLUDED IN PORTFOLIO 3E "ADJUSTED"?

A. Portfolio 3E "Adjusted" will alleviate several of the most congested flowgates in SPP, benefiting the entire region through reduced congestion and cost savings.[69] SPP estimates that Portfolio 3E "Adjusted" will provide a net benefit of $0.78 per month to the typical monthly residential customer whose current bill is $7.58 monthly.[70]

Q. WHAT OTHER BENEFITS WILL PORTFOLIO 3E "ADJUSTED" PROVIDE?

A. The Balanced Portfolio projects can provide increased reliability and lower required reserve margins, thus deferring reliability upgrades, and "environmental benefits due to more efficient operation of assets and greater utilization of renewable resources."[71] For example, SPP estimates that the Portfolio 3E "Adjusted" projects will save SPP Transmission Owners over $25 million in deferred reliability project costs, providing a net reliability benefit of over $9 million in the region, and over $2 million overall.[72]

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69 SPP Balanced Portfolio Report, Exhibit No. OGE-14 at 3.

70 *Id.*

71 *Id.* at 3.

72 *Id.* at 42.

IV. USE OF ADVANCED TECHNOLOGIES

Q. DID OG&E CONSIDER THE USE OF ANY ADVANCED TECHNOLOGIES FOR THE PROJECTS?

A. Yes. OG&E has begun to install advanced technologies in the OG&E Projects to maximize the capability and functionality of these transmission assets.

Q. PLEASE DESCRIBE THESE ADVANCED TECHNOLOGIES.

A. Order No. 679 requires parties seeking transmission rate incentives to provide a technology statement describing the advanced technologies used and considered.[73] The Projects will take advantage of technologies that are considered "advanced transmission technologies" under Section 1223 of the Energy Policy Act of 2005[74] which defines advanced transmission technology as "technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility."

OG&E is installing SEL-421 relays for standard line protection on EHV transmission. These relays are capable of transmitting synchro-phasor data, which are the line currents and voltages (magnitude and angle) synchronized to a GPS time standard. The purpose of this advanced technology is to expand OG&E's ability to collect data from strategic locations across the transmission system. This information is processed for analysis, display and archival purposes in order to improve system efficiency and reliability.

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[73] *Promoting Transmission Investment Through Pricing* Reform, Order No. 679, FERC Stats. & Regs., Regs. ¶ 31,222, at P 302, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

[74] 42 U.S.C § 16422(a) (2006).

In addition to relays, OG&E is planning synchro-phasor implementation for 14 substations and 25 relays within the OG&E Projects. The benefits to synchro-phasor implementation are check phasing of Current Transformers and Potential Transformers, advanced fault analysis, wide area disturbance recording, monitoring of transmission system stability, the ability to import actual data for state estimation, measure line constraints and wide area protection schemes.

OG&E also is installing fiber optic cable and related systems with these Projects to allow for faster, more reliable communication among the substations. Fiber optic cable is replacing existing carrier system technology involving signals sent through transmission wires themselves. In addition to being more reliable, fiber optic cable also allows for future potential applications to be developed through OG&E's Smart Grid program. In addition to these technologies, and where appropriate in the design and construction process, OG&E will incorporate tubular steel structures rather than lattice-type structures.

V. RISKS AND CHALLENGES ASSOCIATED WITH THE PROJECTS

Q. PLEASE DESCRIBE THE RISKS AND CHALLENGES FACED BY THE PROJECTS.

A. The Projects face a number of financial risks and challenges that are addressed in Mr. Rowlett's testimony at Exhibit No. OGE-19. In addition, the Projects face non-financial risks and challenges that can be broken into four general categories. First, the Projects face risks associated with their substantial size and scope, such as long lead times. Second, each Project requires various state and federal authorizations and approvals, any of which could delay siting or construction and increase costs. Third, the Projects must coordinate with parties in adjacent states and with non-jurisdictional public power agencies. For example, six of the projects will connect with another Transmission Owner, requiring close construction coordination and the potential for delays that are beyond OG&E's control. Finally, the Projects have environmental risks such as additional costs and delays that could result from species that may be found to be endangered.

Q. PLEASE EXPLAIN THE RISKS RAISED BY THE SIZE AND SCOPE OF THE PROJECTS.

A. Because of their large size and scope, the Projects will require long lead times to accommodate construction, ranging from about one years to as long as about 4.5 years. The longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and the required regulatory approvals, could change for reasons beyond the control of OG&E and make the project unfeasible. The costs of materials can increase significantly in a short time period, and OG&E may encounter shortages or delays in the availability of certain materials. This risk is compounded by the fact that a large project requires a large amount of material. Moreover, a large project generates complex logistical and management issues that also increase the risk of delay or cost overruns.

Q. PLEASE DESCRIBE THE RISKS ASSOCIATED WITH SECURING THE NECESSARY PERMITS AND APPROVALS.

A. The Projects are subject to the approval of multiple federal and state agencies. A list of these agencies is set out at Exhibit No. OGE-16, which is appended to my testimony. They include approvals from the U.S. Army Corps of Engineers, permits from the Federal Aviation Administration, and studies for the Oklahoma Archeological Survey. Moreover, OG&E will be required to comply with the requirements of the National Environmental Policy Act, the Endangered Species Act, and the National Historic Preservation Act, as well as these statutes' implementing regulations and the associated approvals.

A qualified utility in Oklahoma also must secure the necessary rights of ways, as well as address any relevant environmental or tribal land right concerns. As noted above, the Projects call for OG&E to construct approximately 555 miles of new transmission lines, for which OG&E will need to acquire significant new rights of way. Affected landowners do not always yield the necessary rights-of-way voluntarily, raising the potential for condemnation proceedings which can be lengthy and, if unsuccessful, could lead to lengthy delays or re-routing of a

Project, if not a new round of planning. In an extreme case such factors could result in the abandonment of the Project.

Q. PLEASE EXPLAIN THE EXTENT TO WHICH OG&E MUST COORDINATE WITH OTHER PARTIES TO CONSTRUCT THE PROJECTS.

A. While some of the Projects are undertaken solely by OG&E, other Projects are undertaken by OG&E and another utility, sometimes in a neighboring state. The Sooner-Rose Hill project is one such example. Westar, an electric utility headquartered in Topeka, Kansas, and OG&E both must complete their respective construction prior to the line being energized. In such cases, OG&E is dependent on these other parties to construct their portion of the joint facilities and to otherwise meet their obligations. Should these parties fail to construct their facilities, or fail to do soon a timely basis, the project could be delayed or abandoned.

Q. WHAT ENVIRONMENTAL RISKS DO THE PROJECTS FACE?

A. Unanticipated site-specific concerns may arise that will require additional time for analysis and potential mitigation, which may lead to delays and/or modification of the Projects.

For example, the Woodward-Hitchland and Woodward-Kansas lines cross through the natural habitat of the Lesser Prairie Chicken, a species of bird that is classified as a candidate for future listing as a Threatened Species by the U.S. Fish and Wildlife Service ("USFWS").[75]

The Lesser Prairie Chicken is a Candidate Species under the USFWS Endangered Species Act and, for the State of Oklahoma, is currently under the jurisdiction of the Oklahoma Department of Wildlife Conservation ("ODWC"). While there are no defined regulatory approvals that are required when interacting with Lesser Prairie Chicken Habitat in Oklahoma, ODWC and USFWS are providing active guidance to agricultural, wind farm development and transmission construction interests in order to limit the possibility of the Lesser Prairie Chicken moving from a Candidate Species to an Endangered Species.

Q. ARE THERE OTHER ENVIRONMENTAL ISSUES THAT MAY IMPACT THE CONSTRUCTION OF THE PROJECTS?

A. Yes. With respect to the Sunnyside-Hugo project, a recent lawsuit was filed by two environmental groups challenging the construction of the John W. Turk, Jr. Power Plant, which the transmission line is designed to support. At this time I cannot predict the outcome of this litigation, and cannot speculate as to what impact (if any) it may have on the construction and operation of the Turk plant or on the Sunnyside-Hugo Project.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

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[75] Selected pages of the USFWS Species Assessment and Listing Priority Assignment Form for the Lesser Prairie Chicken are included as Exhibit No. OGE-15. The entire assessment can be found at http://www.fws.gov/ecos/ajax/docs/candforms_pdf/r2/B0AZ_V01.pdf.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company) Docket No. ER10-___-000

AFFIDAVIT

State of Oklahoma

County of Oklahoma

I, PHILIP L. CRISSUP, being first duly sworn, depose and state that I am the witness identified in the foregoing Direct Testimony and Exhibits, that I prepared the testimony and exhibits and am familiar with their content, and that the facts set forth therein are true and correct to the best of my knowledge, information and belief.

Philip L. Crissup

Philip L. Crissup

Subscribed and sworn before me this 6th day of October 2010

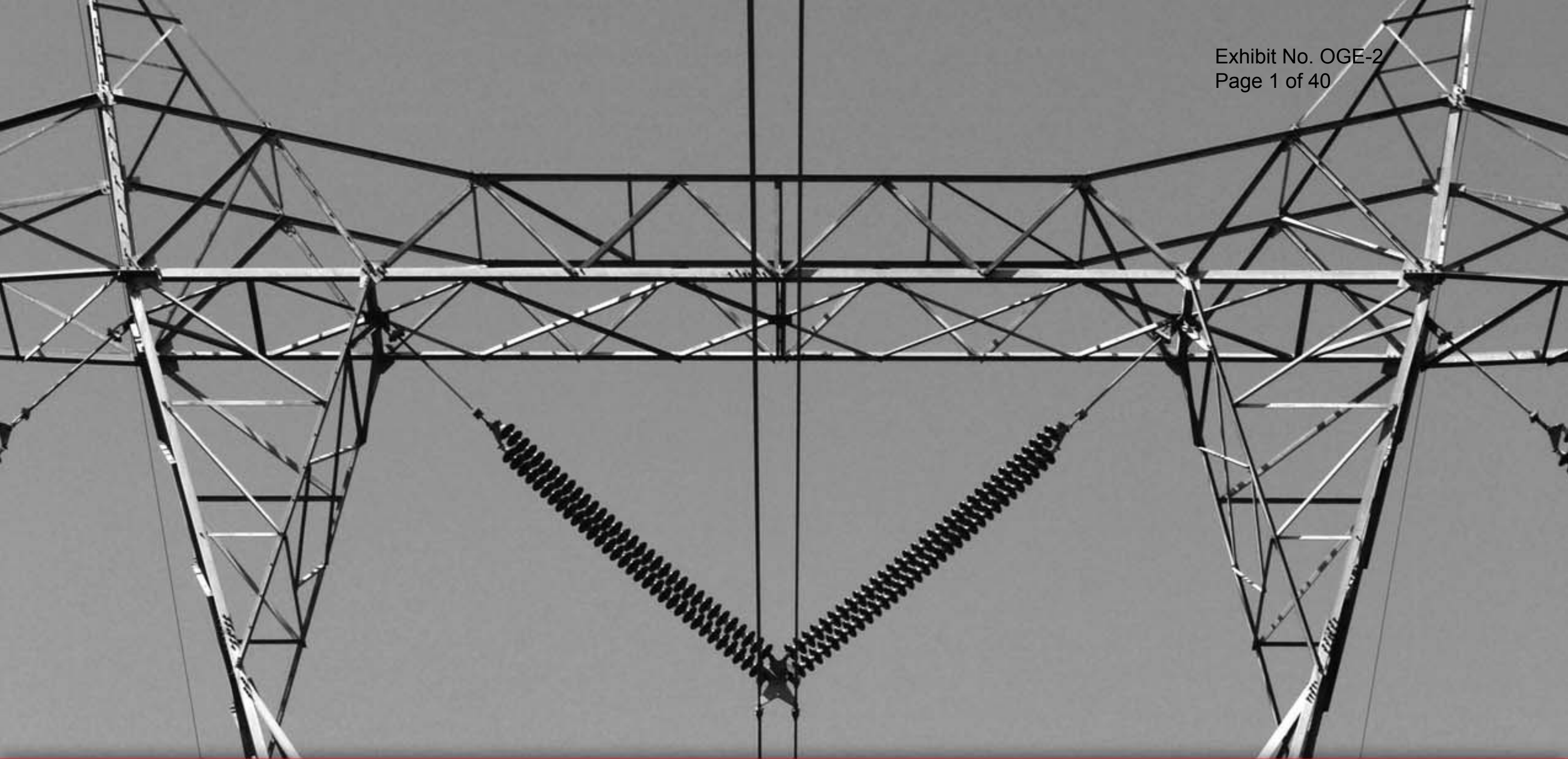
Amanda Reyes

Notary Public

My commission expires: 4/3/11

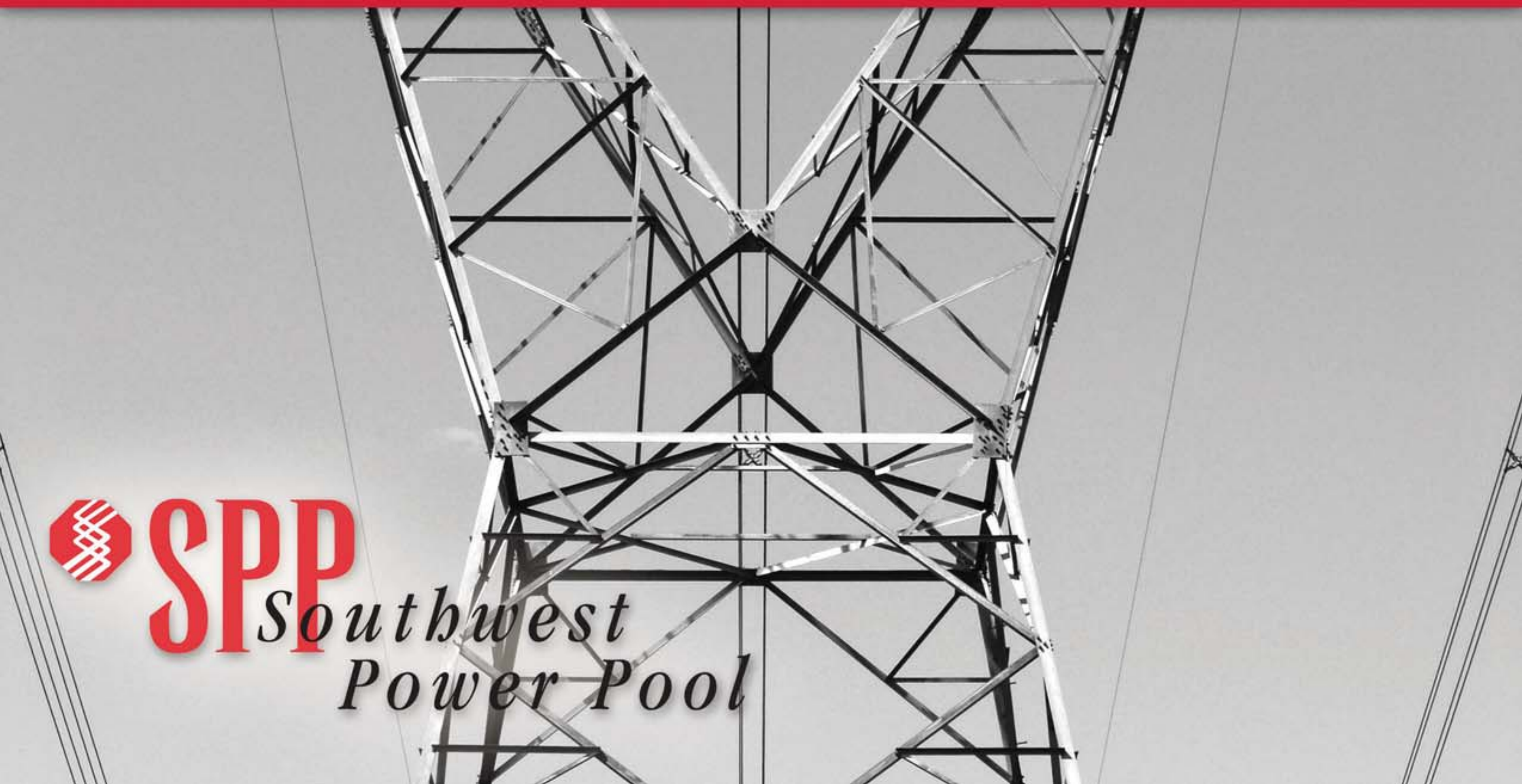
AMANDA REYES
NOTARY
07003269
EXP. 04/03/11
PUBLIC
STATE OF OKLAHOMA

EXHIBIT NO. OGE-2



2009 SPP Transmission Expansion Plan

A Report of the SPP Regional Transmission Organization



SPP Southwest Power Pool

Table of Contents

1. Executive Summary

1.1 What is the 2009 SPP Transmission Expansion Plan?

The 2009 Southwest Power Pool, Inc. (SPP) Transmission Expansion Plan (STEP) summarizes 2009 activities that impact future development of the SPP transmission grid. Seven key topics are included that are critical to meeting mandates of either the SPP strategic plan or the nine planning principles in FERC Order 890. As a Regional Transmission Organization (RTO) of the Federal Energy Regulatory Commission (FERC), SPP must meet requirements of FERC and the SPP Open Access Transmission Tariff (OATT or Tariff).

1. **Synergistic Planning Project**: In January 2009 a Synergistic Planning Project Team (SPPT) was created to look for innovative and forward-thinking solutions to gaps and conflicts between SPP's transmission planning processes. The SPPT report, released in April, recommended that SPP adopt a new set of planning principles and transition the EHV Overlay, Balanced Portfolio, and reliability assessment processes to a new Integrated Transmission Plan (ITP). The ITP was approved by the SPP Board of Directors (BOD) in October; it is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term assessments. The SPPT also recommended that SPP identify and evaluate a set of priority transmission projects to keep the momentum of transmission construction while transitioning to the ITP. In October the BOD approved six Priority Projects for further analysis.

2. **Regional reliability assessment 2010-2019**: This assessment, which was developed with extensive stakeholder review and input, creates a long-range transmission expansion plan for the SPP region, identifying needed transmission upgrades and possible problems in both normal and contingency conditions. The assessment identified approximately $2.8 billion in needed reliability projects and $4.45 billion for all upgrades, including economic and sponsored projects. Several issues impacted this year's assessment, including the addition of three Nebraska organizations to the footprint, major load increases in the Southwestern Public Service Company region, and some load decreases due to the economic downturn.

3. **Tariff studies**: In 2009 transmission expansion projects identified as needed to meet Transmission Service Requests totaled $455 million, and projects needed to meet Generation Interconnection requests totaled $81 million. During 2009, changes were made to the Tariff to improve the Aggregate Study and Generation Interconnection processes, and to create a new cost allocation methodology for wind projects. A Wind Integration Study will be issued in January 2010 to assess the operational and reliability impacts of integrating large amounts of wind into the SPP system.

4. **Sub-regional and local area planning**: Each year SPP holds a series of local planning meetings to address local needs in five sub-regions. In 2009 SPP studied the impact of additional load from 29 planned TransCanada oil pipelines across the footprint; 12 new reliability projects were identified and incorporated into the STEP.

5. **High priority economic studies**: In April 2009 the BOD approved a group of economic transmission expansion projects totaling almost $700 million, to be funded by a "postage stamp" rate to Transmission Owners across the SPP footprint. The project group is called the Balanced Portfolio because both costs and benefits are balanced across the region. The projects are

intended to lower production costs and reduce congestion. SPP monitors congestion on the transmission grid and in the STEP identifies the region's top 10 congested flowgates.

6. **Interregional coordination**: In addition to regional planning, SPP conducts interregional planning with neighboring systems. In 2009 the Entergy/SPP Regional Planning Process was created to share system plans and identify solutions to congestion between Entergy and SPP. SPP also participated in the Eastern Interconnection Wind Integration Transmission Study, which evaluates the power system impacts and needed transmission associated with increasing wind penetration to 20-30% for most of the Eastern Interconnection.

7. **Project tracking**: After the BOD approves expansion projects, SPP issues Notification To Construct (NTC) letters to relevant Transmission Owners. In 2009, 43 NTCs were issued with estimated construction costs of $1.85 billion. SPP actively monitors the progress of expansion projects by soliciting feedback from Transmission Owners. By the end of 2009, 124 projects were scheduled to be completed.

The SPP RTO acts independently of any single member, customer, market participant, or class of participants. It has sufficient scope and configuration to maintain electric reliability; effectively perform its functions, including Tariff administration and transmission planning; and support efficient and non-discriminatory power markets.

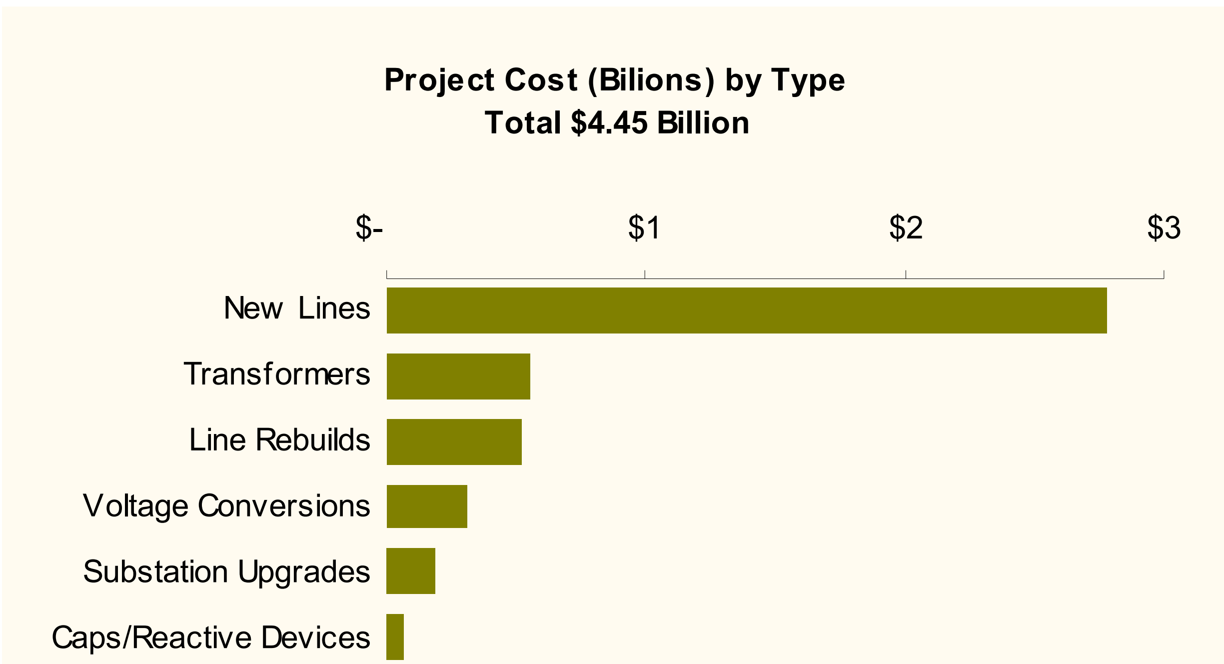
SPP's transmission planning process incorporates all of the organization's value propositions:

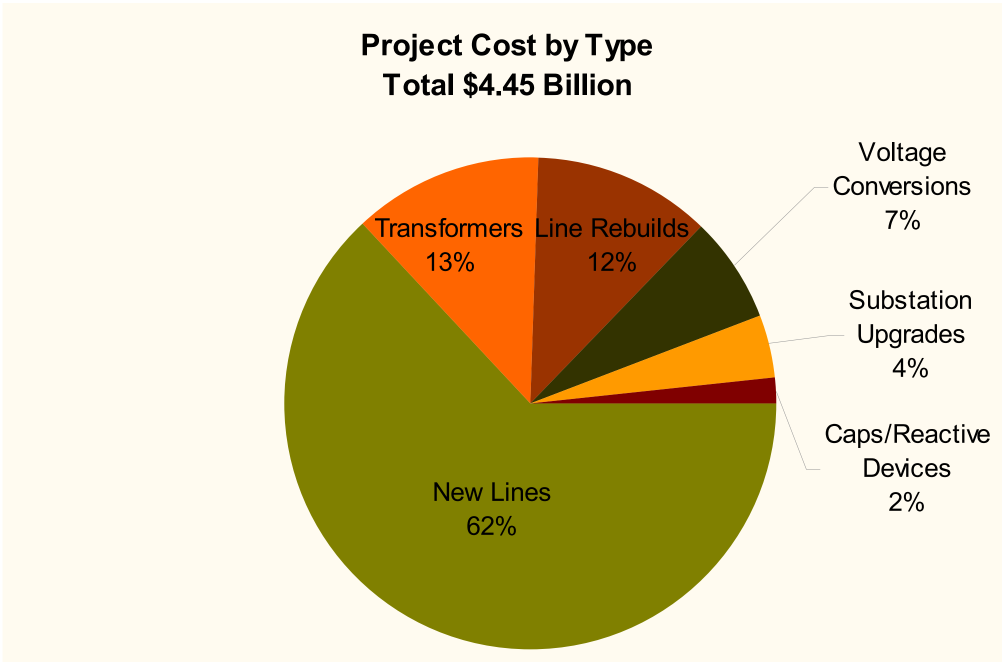
- Relationship-based
- Member-driven
- Independence through diversity
- Evolutionary vs. revolutionary
- Reliability and economics are inseparable

While SPP also serves as a Regional Entity (RE) under the North American Electric Reliability Corporation, the STEP functions are separate from the SPP RE.

1.2 Summary of 2010-2019 Network Upgrades

The 2009 STEP identifies approximately $4.45 billion of transmission Network Upgrades. This summary includes Network Upgrades required for NERC Reliability Standards or SPP criteria; Zonal Reliability Upgrades (compliance to Transmission Owner company-specific planning criteria); requests for Transmission Service under the Tariff with a FERC-filed Service Agreement; Generation Interconnections with a FERC-filed interconnection agreement; and Balanced Portfolio upgrades.




Project Cost by Type
Total $4.45 Billion
Voltage Conversions 7%
Transformers 13%
Line Rebuilds 12%
Substation Upgrades 4%
Caps/Reactive Devices 2%
New Lines 62%

The following table of project categories for the 2009 STEP is a cost summary and comparison with the 2007 and 2008 STEP:

2009 STEP (Nearest 10 Million)	2008 STEP (Nearest 10 Million)	2007 STEP (Nearest 10 Million)	Upgrade Type
$540	$320	$290	Transmission Service Request and Generation Interconnection Service Agreements
$1,690	$880	$720	Reliability - Base Plan
$1,070	$800	$640	Reliability - Other
$320	$620	$460	Sponsored Upgrades
$770			Balanced Portfolio
$60	$60	$90	Interregional Coordinated Upgrades
$4.45B	$2.7B	$2.2B	Appendix A - TOTAL

Has filed Service Agreement or is BOD-approved

(APPENDIX A includes a breakdown of projects in the 10-year horizon)

Major 345 kV projects in various stages of approval or sponsorship that were studied during the 2009 STEP process:

- American Electric Power to construct 33 miles of 345 kV transmission line from Turk in southwest Arkansas to Northwest Texarkana in northeast Texas
- American Electric Power to construct 18 miles of 345 kV transmission line from Flint Creek to Shipe Road in northwest Arkansas
- American Electric Power to construct 55 miles of 345 kV transmission line from Shipe Road to Osage Creek (passing near East Rogers) in northwest Arkansas
- Associated Electric Cooperative to construct 113 miles of 345 kV transmission line from Blackberry in southwestern Missouri to Sportsman to GRDA 1 in northeastern Oklahoma
- ITC Great Plains to construct 19 miles of 345 kV transmission line from Hugo Power Station to Valliant in southeastern Oklahoma
- Kansas City Power and Light to construct 30 miles of 345 kV transmission line from Iatan to Nashua in northwest Missouri
- Nebraska Public Power District to construct 79 miles of 345 kV transmission line from Shell Creek to Columbus East to NW 68 and Holdrege in east central Nebraska
- Oklahoma Gas and Electric to construct 120 miles of 345 kV transmission line from Northwest to Woodward District EHV in western Oklahoma

- Oklahoma Gas and Electric to construct 53 miles and Westar Energy to construct 53 miles of 345 kV transmission line from Rose Hill in central Kansas to Sooner in central Oklahoma
- Oklahoma Gas and Electric to construct 36 miles of 345 kV transmission line from Sooner to Cleveland in central Oklahoma
- Oklahoma Gas and Electric to construct 120 miles of 345 kV transmission line from Hugo to Sunnyside in southern Oklahoma
- Oklahoma Gas and Electric to construct 100 miles of 345 kV transmission line from Seminole to Muskogee in central Oklahoma
- Oklahoma Gas and Electric and Southwestern Public Service Company to construct 250 miles of 345 kV transmission line from Woodward District EHV in western Oklahoma to Oklahoma/Texas Stateline to Tuco in northwestern Texas
- Westar Energy to construct 51 miles of 345 kV transmission line from Reno County to Summit in central Kansas
- Construct 90 miles of 345 kV transmission line from Spearville to Wolf (Knoll) in western Kansas
- Construct 125 miles of 345 kV transmission line from Wolf in western Kansas to Axtell in southern Nebraska
- Convert from 230 kV to 345 kV transmission line from Hobbs Interchange to Midland in western Texas
- Construct 130 miles of 345 kV transmission line from Potter County Interchange to Frio-Draw in western Texas
- Construct 100 miles of 345 kV transmission line from Oklahoma/Texas Stateline to Gracemont in western Oklahoma
- Construct 215 miles of 345 kV transmission line from Potter County Interchange to Oklahoma/Texas Stateline in northwestern Texas
- Construct 30 miles of 345 kV transmission line from Tuco to Jones in western Texas

1.2.1 Appendices A and B

Appendix A includes a comprehensive listing of transmission projects identified by the SPP RTO. Not all projects in Appendix A have been approved by the SPP Board of Directors (BOD), but all BOD-approved projects are included in the list. Appendix A also includes Tariff study projects, economic projects, zonal projects and associated interregional projects.

Appendix B lists proposed transmission projects for which sponsors or RTO staff requested 1st quarter 2010 action by the BOD and were approved for construction. The original Appendix B list presented to the BOD by RTO staff was shortened from a 4-year to a 2-year financial window by the BOD. The Appendix B list includes projects specifically needed for regional reliability that have a financial commitment lead-time inside the 2010-2011 two-year commitment window. Appendix B includes more than regional reliability upgrades and Zonal Reliability Upgrades in which BOD approval is being requested. It also includes projects for which withdrawals are being sought.

Projects in appendices A and B are categorized in the column labeled “Project Type Exp” by the following designations:

Generation Interconnect – Projects associated with a FERC-filed Generation Interconnection Agreement

Interregional – Projects developed with neighboring Transmission Providers (Appendix A only)

Regional reliability – Projects needed to meet the reliability of the region

Regional reliability – non-OATT – Projects to maintain reliability for SPP members not participating under the SPP OATT (Appendix A only)

Transmission service – Projects associated with a FERC-filed Service Agreement

Zonal Reliability – Projects identified to meet more stringent local Transmission Owner criteria

Zonal – sponsored – Projects sponsored by facility owner with no Project Sponsor Agreement

Balanced Portfolio – Projects identified through the Balanced Portfolio process

Sponsored – Projects with an executed Project Sponsor Agreement or that have previously been identified as an economic projects to receive transmission revenue credits under the OATT attachment Z2.

As transmission usage changes, proposed and approved projects are subject to evaluation. Appendix A projects can be reevaluated by the SPP RTO for “best” regional and/or local area solutions. Even though many are approved, Network Upgrades listed in Appendix A are not considered beyond the scope of reevaluation. Transmission Network Upgrades approved for construction have the opportunity for additional review on a case-by-case basis. The goal of reevaluation is to investigate viable alternatives considering new information and then determine if a more regionally-beneficial solution exists. This also takes into account long-term strategy and regional reliability needs.

Appendix B includes only new proposed transmission projects that have SPP RTO support and for which sponsors or RTO staff are requesting action by the BOD. This appendix does not include Network Upgrades identified by the SPP OATT Attachment Z Transmission Service Procedure or Attachment V Generation Interconnections. If approved, these Network Upgrades will be included in the SPP OATT Transmission Service study models. Transmission Network Upgrades authorized for construction have the opportunity for additional review on a case-by-case basis. The goal of such reevaluation is to evaluate and compare viable alternatives and then determine a cost-effective transmission solution while taking into consideration long-term strategy and regional reliability needs.

SPP is committed to performing necessary analysis to determine needs, costs, and benefits, while supporting its members' state regulatory requirements necessary to substantiate funding of identified Network Upgrade costs.

Included in Appendix B are withdrawal requests for projects that have been previously issued a Notification to Construct (NTC). These projects are identified in the "BOD Action" column as "NTC – withdraw". The reasons listed below explain why these projects are no longer required:

- Network Upgrade no longer required due alternate solution
- Network Upgrade no longer required due to new load forecast
- Network Upgrade no longer required due to model correction
- Network Upgrade no longer required due to new generation

2. Synergistic Planning Project

2.1 SPPT Report

At the SPP Board of Directors (BOD) meeting on January 27, 2009, a Synergistic Planning Project was endorsed to address gaps and conflicts between SPP's transmission planning processes and help position the organization to respond to the Obama administration's focus on improving our nation's electric infrastructure. The BOD created the Synergistic Planning Project Team (SPPT) which includes the following members:

- Paul Suskie – Chairman, Arkansas Public Service Commission
- Barry Smitherman – Chairman, Public Utility Commission of Texas
- Kelly Harrison – Vice President of Transmission Operations and Environmental, Westar Energy
- Ricky Bittle - Vice President of Planning, Rates and Dispatching, Arkansas Electric Cooperative Corporation
- Rob Janssen - Senior Vice President, Kelson Energy
- Ric Abel - Managing Director, Prudential Capital Group
- Carl Monroe - Executive Vice President and Chief Operating Officer, SPP

At its April 29, 2009 meeting the BOD approved a report by the SPPT that recommended restructuring the organization's regional planning processes. The SPPT recommended SPP adopt a new set of planning principles that focus on the construction of a robust transmission system, large enough in both scale and geography to provide flexibility to meet SPP's future needs. These planning principles established a new Integrated Transmission Plan (ITP) that improves and integrates SPP's existing planning processes: the reliability assessment, Aggregate Transmission Service Study process, Generation Interconnection process, Balanced Portfolio, and Extra High Voltage (EHV) Overlay Study. The ITP will be discussed further in section 2.2.

In its April 29 report to the BOD, the SPPT also recommended moving to a "highway-byway" approach for funding transmission. The higher voltage "highway" would be funded with a regional rate, and lower-voltage "byways" would be funded with local rates. This method supports uniformity of customer costs, eases the administrative burden associated with current differing cost allocation methods, provides a basis for cost allocation across seams, and is more consistent with the "national transmission highway" being discussed at the federal level.

On October 26, 2009, the Regional State Committee (RSC) approved a recommendation from the Cost Allocation Working Group (CAWG) for a "highway-byway" cost allocation methodology for the ITP. The highway portion, which is funded regionally, will include transmission lines and facilities operated at voltages higher than 300 kV. Facilities with voltage levels operated below 300 kV will be included in the byway component. These lower-voltage facilities will follow the current Base Plan funding methodology.

2.2 Integrated Transmission Plan

At its October 28, 2009 meeting, the SPP BOD approved the Integrated Transmission Plan (ITP) which will be used to determine what transmission is needed to maintain electric reliability and provide near- and long-term economic benefits to the SPP region. Implementing the ITP will enable SPP and its stakeholders to better facilitate the development of a robust transmission grid that will give regional customers improved access to the SPP region's diverse resources. Development of the ITP was driven by the Synergistic Planning Project Team (SPPT) and its planning recommendations. The ITP will create synergies by integrating three existing processes: the Extra High Voltage Overlay, the Balanced Portfolio, and the reliability assessment. By integrating these processes, additional efficiencies are expected to be realized in the Generation Interconnection and Aggregate Transmission Service Request study processes. The ITP will work in concert with SPP's existing sub-regional planning stakeholder process, and will continue in parallel with the NERC TPL Reliability Standards compliance process.

The ITP will focus on regional needs and position SPP to prepare for and quickly respond to national energy priorities. A major objective is the design and construction of a transmission backbone to connect load centers to known or expected large generation resources. The backbone should more strongly connect SPP's eastern and western regions, strengthen ties to the Eastern Interconnection, and be strong enough to possibly connect to the Western Interconnection.

The ITP is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments. The process seeks to target a reasonable balance between long-term transmission investment and congestion costs to customers. Study assumptions will include, among others, fuel and emissions costs, load and generation forecasts, types and locations of new generation, generation retirements, market structures, and wind profiles. Analysis must also encompass a plausible collection of assumptions for each specific model run, including varying levels of renewable electricity standards, demand response, fuel prices, and governmental regulations. The Economic Studies Working Group will develop the metrics and process for qualifying and quantifying the projects for the ITP, including Adjusted Production Cost, impact on losses, reliability and environmental impacts, capacity margins, and operating reserves.

Once ITP plans have been reviewed by the MOPC and approved by the BOD, staff will issue Notification to Construct (NTC) letters for approved projects needed within the four-year financial commitment horizon. An Authorization to Plan (ATP) will be issued for projects needed beyond the four-year financial horizon. Once an NTC or ATP is issued, the project will be reviewed annually to evaluate the continued need for the project and the required in-service date.

Beginning in January 2010, SPP will perform its planning duties in accordance with the ITP process. Evaluation of future scenarios that may affect the ITP will occur during the first half of 2012 for the 20-Year Assessment and during the second half of 2013 for the 10-Year Assessment. The 20-Year Assessment will begin in year one and be completed in year two. The 10-Year Assessment will begin during year two and be completed in year three. The Near-Term Assessment will be performed each year to ensure reliability and to incorporate local planning requirements. The regional reliability assessment will be performed in 2010 as it has in recent years, but will be replaced by the ITP Near-Term Assessment beginning in 2011.

Successful implementation of the ITP will result in a list of transmission expansion projects and completion dates that facilitate the creation of a robust, flexible, and cost-effective transmission network in the SPP footprint.

2.3 Priority Projects

In addition to the new cost allocation methodology and ITP process, at its April 2009 meeting the SPP BOD identified a third major component to restructuring SPP's regional transmission expansion planning process: an effort to identify, evaluate, and recommend Priority Projects to improve the transmission system and capture near-term opportunities that should not be lost in the transition to the ITP.

Stakeholders submitted Priority Projects for consideration and had input into scope development via numerous conference calls and meetings. The Transmission, Economic Studies, and Cost Allocation Working Groups provided significant support to this effort, and the Markets and Operations Policy Committee (MOPC) approved a list of 10 projects chosen for further screening and detailed evaluation. Five of these projects were evaluated and studied at 765 kV, 765 kV construction operated at 345 kV, and double circuit 345 kV. Four other projects were recommended for construction and operation at 345 kV; the remaining project was recommended for 138 kV operation.

Analysis of these ten Priority Projects included multiple value metrics including Adjusted Production Cost, loss impacts, reliability assessment, local and environmental impacts, and deliverability of capacity and energy to load. SPP used internal staff and outside consultants, including Quanta Technologies, Brattle Group, and Brown Engineers, to perform engineering and economic analysis. The study included two different wind levels. Level one was a 10-year growth level in which 20% of the energy in SPP is supplied by renewable wind. Level two was a slower growth projection with the same 10-year growth, but to only a 10% level of wind.

On September 22, SPP published a draft Priority Projects report. In the report SPP staff recommended the approval of five of the screened Priority Projects:

- Spearville – Comanche – Medicine Lodge – Wichita, constructed and operated at 765 kV
- Comanche – Woodward District EHV, constructed and operated at 765 kV
- Valliant – NW Texarkana, constructed and operated at 345 kV
- Cooper – Maryville – Sibley, constructed and operated at 345 kV
- Riverside Station – Tulsa Power Station 138 kV reactor addition

This draft report was the subject of stakeholder debate at a September 29 Priority Projects workshop. A subsequent updated draft was considered at the October 14 MOPC meeting. In response to input from these forums, staff discussed modifications to its draft recommendations with the Strategic Planning Committee (SPC) at its October 15 meeting. With the SPC's concurrence, at the October 27 Members Committee and BOD meeting staff recommended that the following Priority Projects be considered for immediate construction following approval by the BOD in January 2010 to continue the momentum of transmission construction in the SPP footprint:

- 345 kV double circuit line linking the Hitchland substation south of Guyman, Oklahoma to the planned Woodward District EHV substation near Woodward, Oklahoma at an estimated cost of $237 million

- 345 kV line from Cooper in the southeast corner of Nebraska through Maryville, Missouri to Sibley (just east of Kansas City, Missouri) at an estimated cost of $278 million
- 345 kV line from Valliant in southeast Oklahoma to Texarkana on the Texas-Arkansas state line at an estimated cost of $131 million
- 138 kV reactor at a Tulsa, Oklahoma power station at an estimated cost of $842,000

The BOD approved this package of transmission expansion projects for further analysis and review by regional stakeholders with oversight from the SPC and in coordination with the MOPC. In addition to the four staff recommended projects, the BOD approved two other projects to be included in the package for further analysis:

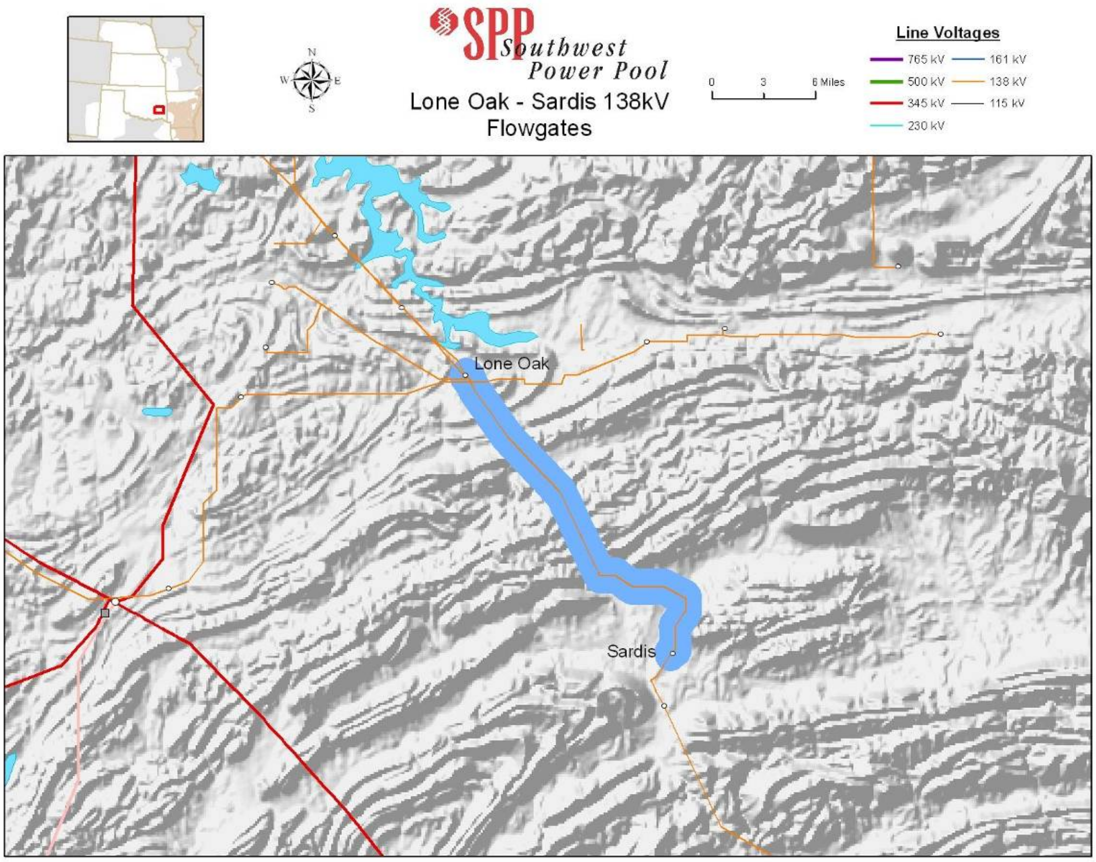
- Line in Kansas linking Spearville, a planned substation in Comanche County, Medicine Lodge, and Wichita. If built at 765 kV and operated at 345 kV, the estimated cost is $478 million. (If built at 345 kV double circuit, the estimated cost is $356 million.*)
- Line linking a planned substation in Comanche County, Kansas to the planned Woodward District EHV substation near Woodward, Oklahoma. If built at 765 kV and operated at 345 kV, the estimated cost is $132 million. (If built at 345 kV double circuit, the estimated cost is $108 million.*)

Total engineering and construction costs for all six proposed projects are approximately $1.26 billion (*1.12 billion).

These Priority Projects are to be studied with a scenario assuming seven gigawatts of wind in the SPP footprint, incorporating approved Balanced Portfolio and reliability transmission projects. Results will be presented to the MOPC, Regional State Committee, and BOD in February 2010.

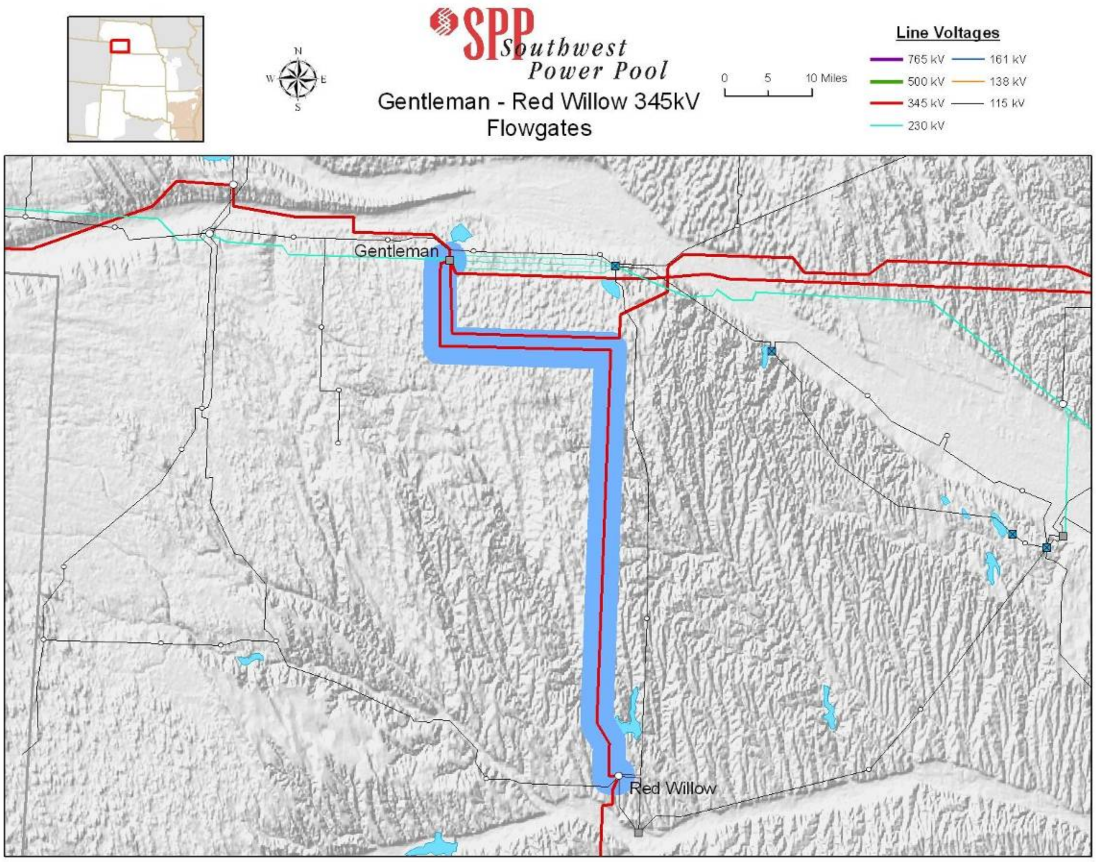
LONSARPITVAL – Located in Southeastern Oklahoma

The LONSARPITVAL flowgate monitors the 138 kV line from Lone Oak to Sardis for the loss of the 345 kV line from Pittsburg to Valliant. The percentage of total intervals breached or binding over the last twelve months is 2.3% with an average shadow price of $12.87. As with the flowgate above, the new nineteen mile Hugo to Valliant 345 kV line with a 138 kV/345 kV transformer at Hugo Power Plant 4 will potentially help mitigate this constraint. The in-service date of these projects is April of 2012.



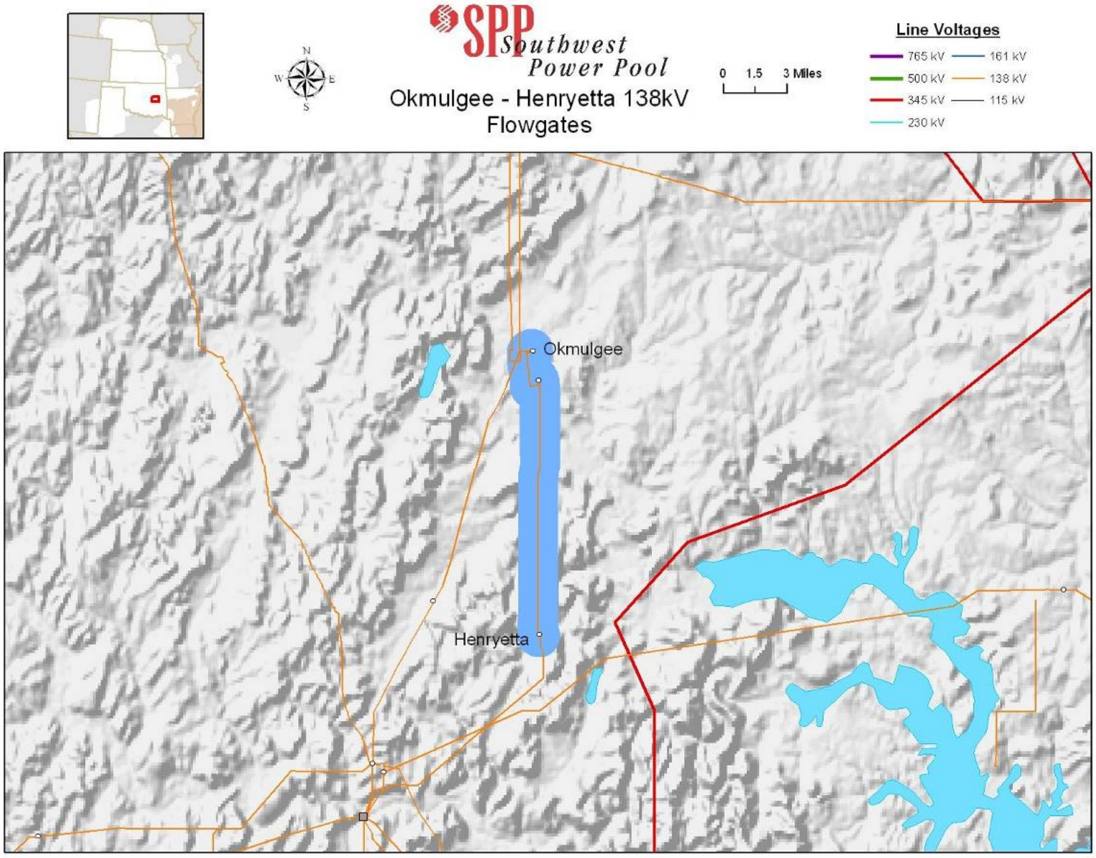
GENTLMREDWIL – Located in Southern Nebraska

The GENTLMREDWIL flowgate monitors the 345 kV line from Gentleman to Red Willow. The percentage of total intervals breached or binding over the last twelve months is 4.1% with an average shadow price of $6.03. The Balanced Portfolio-approved 345 kV line from Spearville to Axtell to Knoll will potentially help address the north–south flow from Nebraska. This project has an expected in-service date of June 2013.



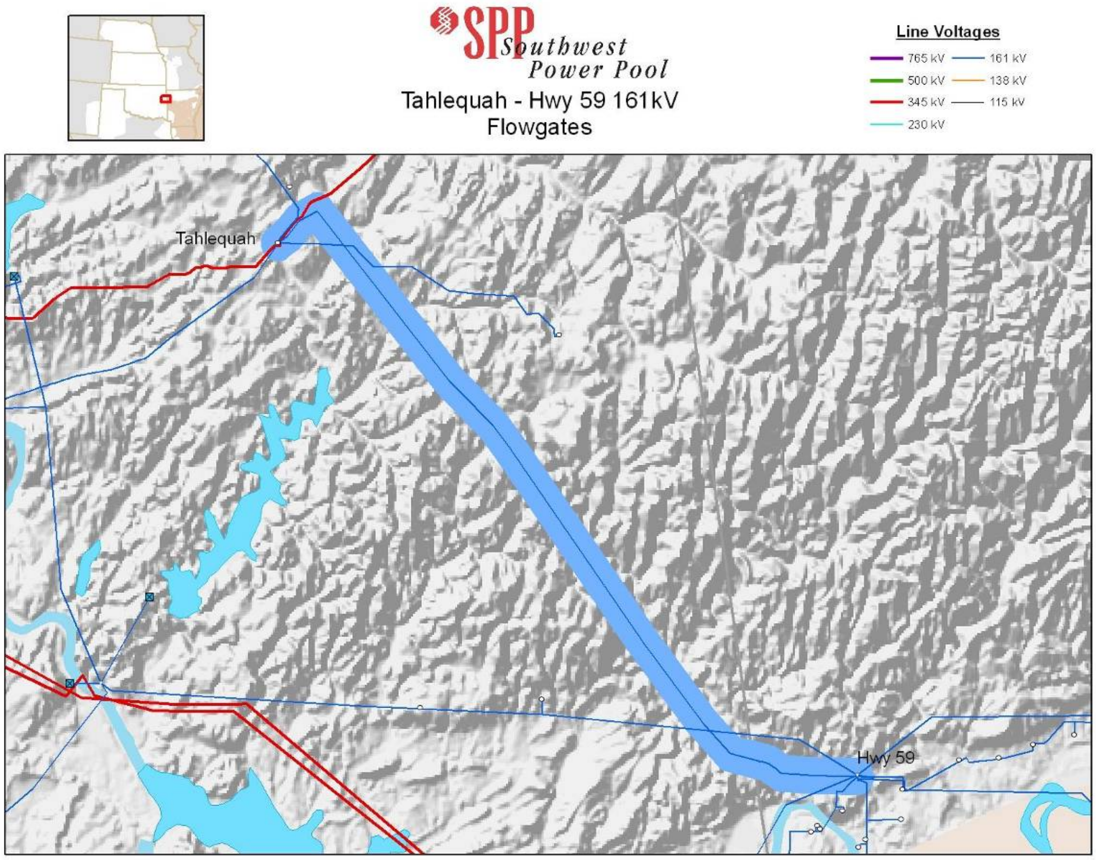
OKMHENOKMKEL – Located in Eastern Oklahoma

The OKMHENOKMKEL flowgate monitors the 138 kV line from Okmulgee to Henryetta for the loss of Okmulgee to Kelco 138 kV line. The percentage of total intervals breached or binding over the last twelve months is 1.9% with an average shadow price of $5.01. The Balanced Portfolio-approved 345 kV line from Seminole to Muskogee 345 kV will potentially help mitigate the congestion on this flowgate. This project has an expected in-service date of April 2012.



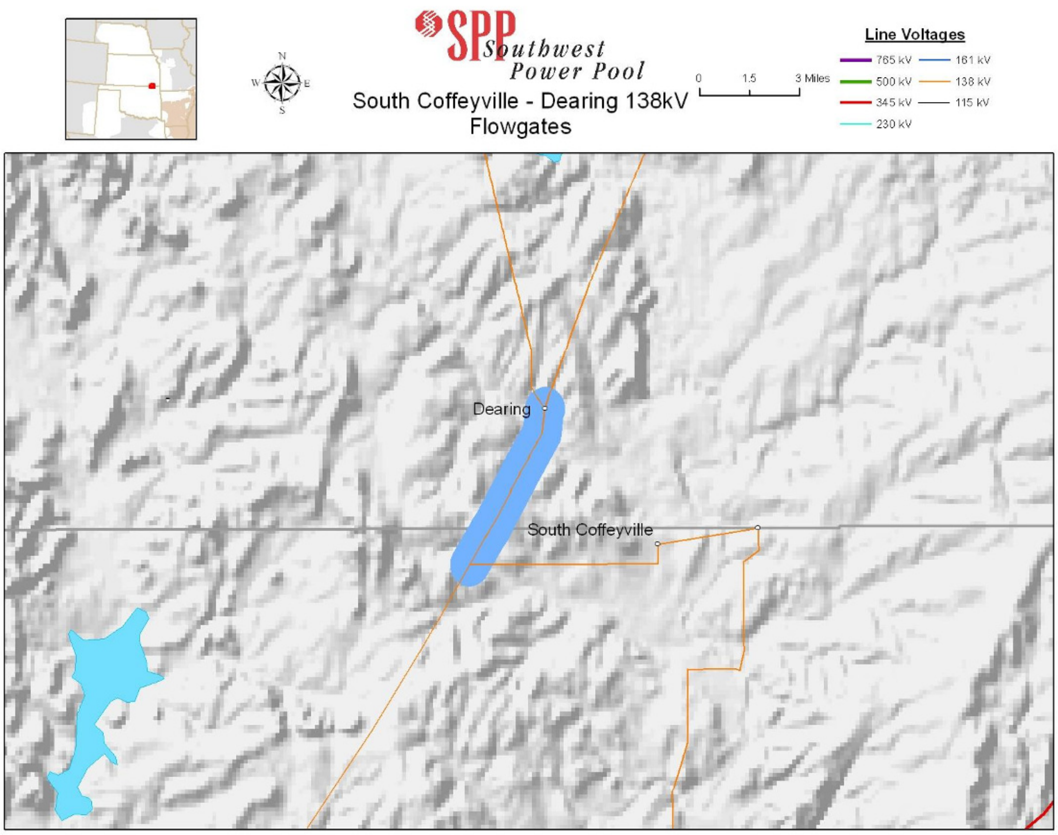
TAHH59MUSFTS – Located in Eastern Oklahoma

The TAHH59MUSFTS flowgate monitors the 161 kV line from Tahlequah to Highway 59 for the loss of the 345 kv line from Muskogee to Fort Smith. The percentage of total intervals breached or binding over the last twelve months is 0.5% with an average shadow price of $3.98. Significant mitigation on the TAHH59MUSFTS flowgate will probably not take place until a project from Ft. Smith to a location in Oklahoma, such as Chamber Springs or Pittsburgh, is developed.



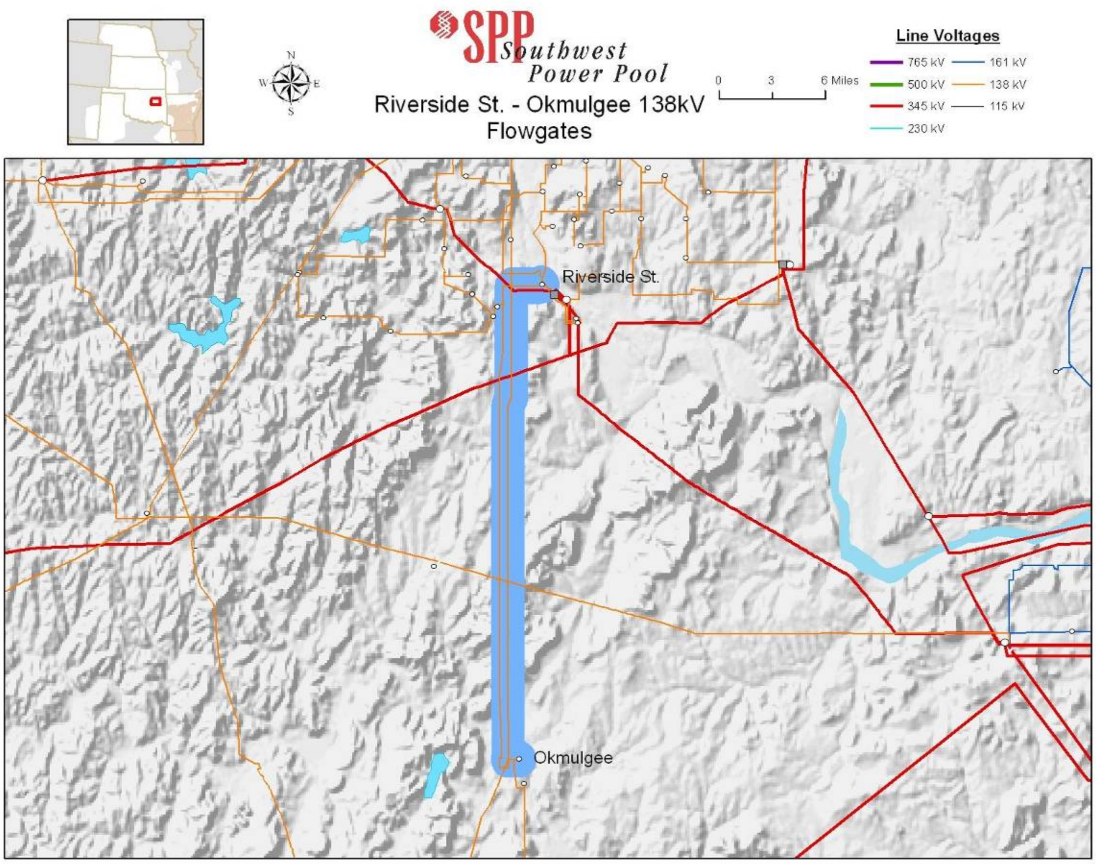
SCODEADELNEO – Located in Southeastern Kansas and Northeastern Oklahoma

The SCODEADELNEO flowgate monitors the 138 kV line from South Coffeyville to Dearing for the loss of the 345 kV line from Delaware to Neosho. The percentage of total intervals breached or binding over the last twelve months is 1.1% with an average shadow price of $2.50. The project to rebuild the 138 kV line from Coffeyville Tap to Dearing will potentially help mitigate the congestion on this flowgate. The in-service date for this project is June of 2010.



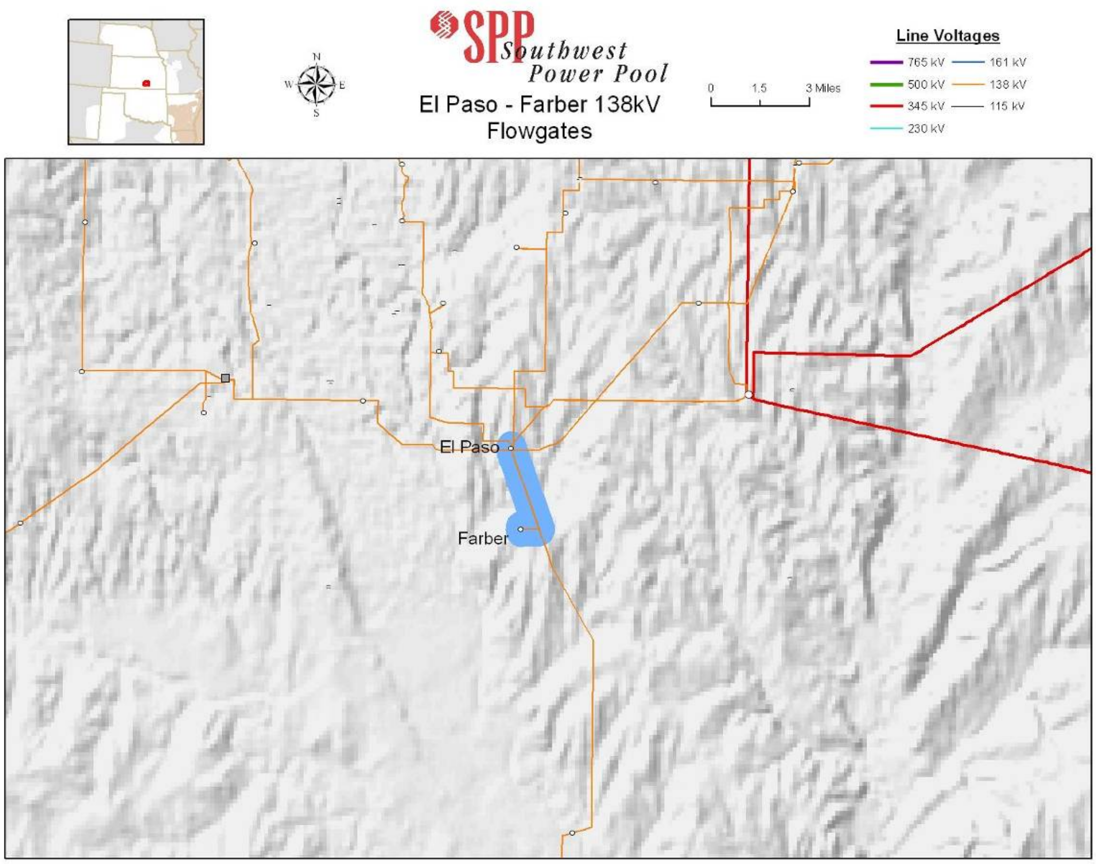
RSSOKMRSSEXP – Located in Eastern Oklahoma

The RSSOKMRSSEXP flowgate monitors the 138 kV line from Riverside Station to Okmulgee City for the loss of the 138 kV line from Riverside Station to Explorer Okmulgee. The percentage of total intervals breached or binding over the last twelve months is 0.9% with an average shadow price of $2.30. The Balanced Portfolio-approved 345 kV line from Seminole to Muskogee 345 kV will potentially help mitigate the congestion on this flowgate. This project has an expected in-service date of April 2012.



ELPFARWICWDR – Located in Southern Kansas

The ELPFARWICWDR flowgate monitors the 138 kV line from El Paso to Farber for the loss of the 345 kV line from Wichita to Woodring. The percentage of total intervals breached or binding over the last twelve months is 2.0% with an average shadow price of $2.29. The new Rose Hill to Sooner 345 kV line is a regional reliability upgrade that will potentially provide mitigation when it is completed by 12/1/2012.



6.3 Balanced Portfolio

The Balanced Portfolio is a cohesive group of economic transmission upgrades that were approved by the SPP Board of Directors (BOD) in April 2009. The benefits of these upgrades were demonstrated by model analysis to outweigh the costs, which will be allocated regionally. These upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. The projects may provide other benefits, such as increasing reliability, lowering end-use consumer costs, and allowing greater utilization of renewable resources. To provide regional "balance", portions of revenue requirement were transferred between regions.

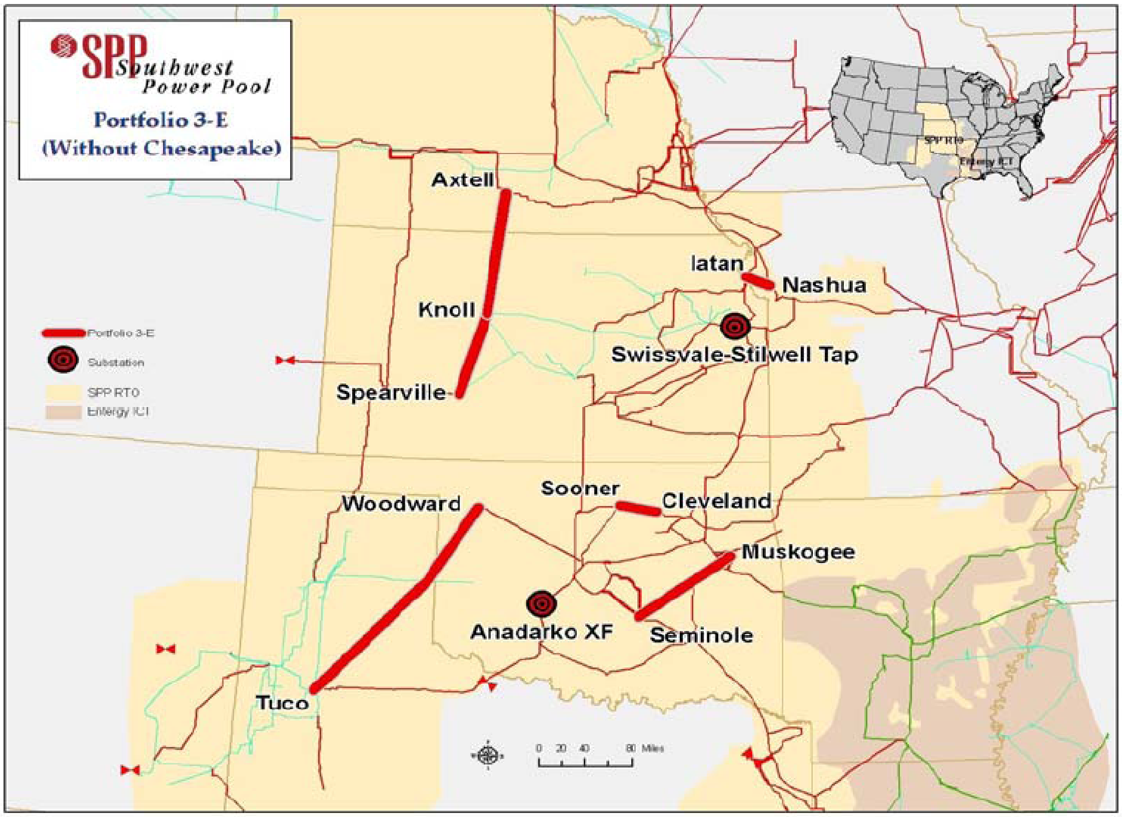
After developing and reviewing numerous iterations of the Balanced Portfolio, the Cost Allocation Working Group (CAWG) endorsed "Portfolio 3E 'Adjusted' (without Chesapeake, without Reno Co – Summit)". Portfolio 3E "Adjusted" will provide significant benefit versus cost to the SPP region, and will require lower transfers of revenue requirements necessary to achieve balance. The CAWG and the Economics Modeling and Methods Task Force (now the Economic Studies Working Group) reviewed and approved the study assumptions used in Balanced Portfolio analysis, which are listed in the appendix.

Portfolio 3E "Adjusted" contains a diverse group of 345 kV transmission projects addressing many of the top SPP flowgates. Projects in Portfolio 3E "Adjusted":

- The 250 mile "Woodward -Tuco" line between Hale County, Texas (north of Abernathy) and Woodward, Oklahoma
- The 215 mile "Spearville-Knoll-Axtell" line between Spearville, Kansas (east of Dodge City); Hays County, Kansas; and Axtell, Nebraska
- The 100 mile "Seminole-Muskogee" line between Seminole County and Muskogee, Oklahoma
- The 36 mile "Sooner-Cleveland" line between Sooner Lake in Noble County, Oklahoma and Cleveland, Oklahoma
- The 30 mile "Iatan-Nashua" line between Iatan and Nashua, Missouri (north of Kansas City)
- The Anadarko Transformer in Anadarko, Oklahoma
- The Swissvale-Stilwell Tap near Gardner, Kansas

Total engineering and construction costs: $692 million

Portfolio 3-E "Adjusted"



The CAWG-endorsed Balanced Portfolio was presented to the Markets and Operations Policy Committee (MOPC) on April 15, 2009. The MOPC reviewed and discussed the portfolio options and the impact on the SPP footprint. After discussion, the MOPC endorsed the Balanced Portfolio 3E "Adjusted" pending issuance of the final Balanced Portfolio report, according to the SPP Tariff. On April 28 the BOD approved the Balanced Portfolio 3-E "Adjusted" for inclusion in the SPP Transmission Expansion Plan. The BOD directed staff to finalize the Balanced Portfolio report, then issue Notification to Construct (NTC) letters for Balanced Portfolio projects.

In June 2009, SPP staff issued NTC letters to the incumbent transmission owner for the projects in Balanced Portfolio 3-E "Adjusted".

7. Interregional Coordination

7.1 SPP RTO and Entergy ICT Coordination

As the Independent Coordinator of Transmission (ICT) for Entergy Services, Inc. (Entergy), SPP facilitates transmission planning for Entergy. The SPP RTO and ICT coordinate planning study conclusions and look for opportunities to collaborate on seams-related transmission improvements. These investigations include third-party impacts identified from transmission service requests on both systems. The RTO and ICT continue to work closely on the Joint Coordinated System Plan study, and both groups are involved in the SERC Reliability Corporation's planning processes.

7.1.1 Entergy/SPP Regional Planning Process

7.1.1.1 Introduction

In accordance with FERC Order 890, SPP OATT Attachment O, and Entergy OATT Attachment K, the Entergy/SPP Regional Planning Process (ESRPP) was created to identify system enhancements that could relieve interregional congestion between Entergy and SPP, and to share system plans to ensure they are simultaneously feasible and otherwise use consistent assumptions and data.

7.1.1.2 Joint Planning Committee

The Joint Planning Committee (JPC) was established for the ESRPP to perform studies and coordinate stakeholder communication. Each party assesses the simultaneous feasibility of expansion plans, assesses the consistency of data and assumptions, and reports any inconsistencies or incompatibilities to the JPC. The JPC will conduct stakeholder-requested studies intended to identify system enhancements that could relieve interregional congestion or integrate new resources on an aggregate basis.

Up to five high-level studies will be requested annually to provide screening to identify constraints and needed upgrades, and to approximate costs and timelines. Based on the results of these high-level studies, stakeholders may request a more detailed study to be undertaken in the following planning cycle which will provide detailed cost estimates and timelines.

7.1.1.3 2009 Activity

At the first ESRPP meeting in May 2009, it was reported that stakeholders narrowed their list of regional economic studies for consideration to the following five projects:

- Turk – McNeil 345 kV Line
- Spadra – Russellville 161 kV Line

- Turk – Fulton – El Dorado 345 kV Line
- Messick 500/230 kV Auto
- Flint Creek – Chamber Springs – Fort Smith – ANO 345 kV Line

The second meeting of the ESRPP was held August 12, 2009. At the meeting, the JPC presented an overview of the initial results of the stakeholders' regional economic studies.

7.1.1.4 Next Steps

In the first quarter of 2010, it is expected that the ESRPP 2009 Step 1 High-Level Analysis Report will be completed. The study results will then be presented at the third ESRPP meeting.

7.1.2 Operational Efficiency Task Force

The Operational Efficiency Task Force (OETF) was formed to develop a proposal for a "one-stop shop" approach to address issues regarding the separate Tariff processes and study parameters for provision of transmission service across the SPP RTO and Entergy transmission systems. On a July 2, 2009 conference call and a July 14, 2009 meeting, the OETF discussed this concept and developed a two-phase approach.

Phase one will define initiatives for implementation in 2010 without making changes to existing OATTs or OASIS, and develops a customer-focused process for a one-stop shop. These efforts will include:

- Concentrating only on the impact to monthly and yearly transmission service.
- Creating a new Transmission Request Advocacy Assistance and Coordination (TRAAC) function. TRAAC's role is still to be determined, but any proposal from the OETF will define the oversight responsibilities, reporting structure, funding structure, requirements for enhanced customer service, and coordination of TSRs between the Entergy and SPP RTO regions.

Phase two will focus on long-term operational and planning issues with expanded initiatives through Seams Agreements that could include changes to OATT and OASIS software. These efforts will include:

- Reviewing current seams agreements for areas of increased synergy of operational efficiency.
- Reviewing several processes shared by Entergy and SPP RTO, including coordination of study processes, AFC/ATC data, cost allocation, congestion management, long-term re-dispatch, shared database of confirmed service, and creation of one-stop shop software solutions.

OETF will develop and finalize a proposal for phase one as a recommendation to the Strategic Planning Committee. The OETF continues to seek input from both SPP members and Entergy stakeholders on the proposal.

7.2 Eastern Interconnection Wind Integration Transmission Study

7.2.1 History

The Eastern Interconnection Wind Integration Transmission Study (EWITS) was commissioned by the U.S. Department of Energy (DOE) through its National Renewable Energy Laboratory (NREL) to address a range of technical questions related to a 20%-30% wind scenario for the large portion of electric load that resides in the Eastern Interconnection, which includes SPP.

EWITS is one of three current studies designed to model and analyze wind penetrations on a large scale. The Western Wind and Solar Integration Study, also sponsored by DOE/NREL, is examining the planning and operational implications of adding up to 30% wind and solar energy penetration to the WestConnect footprint in the Western Electricity Coordinating Council. The European Wind Integration Study (EWIS) is an initiative established by European associations of transmission system operators in collaboration with the European Commission. EWIS is aimed at developing, where possible and appropriate, common solutions to wind integration challenges in Europe.

To help guide this study, NREL convened a Technical Review Committee (TRC) of regional electric reliability council representatives, expert reviewers, the study subcontractor, transmission planners, utility administrators, and wind industry representatives. The TRC held six full-day meetings, along with numerous net conferences and conference calls over the 14-month project duration to review study progress. SPP was represented on the TRC.

7.2.2 Scenario Development

With input from a wide range of stakeholders including the TRC, the EWITS project team constructed four high-penetration scenarios to represent different wind generation development possibilities in the Eastern Interconnection.

A brief description of each scenario:

- **Scenario 1, 20% penetration** – High Capacity Factor, Onshore: Utilizes high-quality wind resources in the Great Plains, with other development in the eastern United States where good wind resources exist.
- **Scenario 2, 20% penetration** – Hybrid with Offshore: Some wind generation in the Great Plains is moved east. Some East Coast offshore development is included.
- **Scenario 3, 20% penetration** – Local with Aggressive Offshore: More wind generation is moved east toward load centers, necessitating broader use of offshore resources. The offshore wind assumptions represent an uppermost limit of what could be developed by 2024 under an aggressive technology push scenario.
- **Scenario 4, 30% penetration** – Aggressive On- and Offshore: Meeting the 30% energy penetration level uses a substantial amount of the higher quality wind resource in the NREL database. A large amount of offshore generation is needed to reach the target energy level.

The study team developed a Reference Scenario to approximate the current state of wind development plus some expected level of near-term development, guided by interconnection queues and state renewable portfolio standards (RPS). This scenario totaled about 6% of the total 2024 projected load requirements for the U.S. portion of the Eastern Interconnection.

Supplying 20% of the electric energy requirements of the U.S. portion of the Eastern Interconnection would call for approximately 225,000 MW of wind generation capacity, which is about a tenfold increase above today's levels. To reach 30% energy from wind, the installed capacity would have to rise to 330,000 MW.

7.2.3 Study Results

The specific numeric results of the analysis are sensitive to the many assumptions that were required to define the 2024 study year, most of which are detailed in the full report. Changes in any of these assumptions would almost certainly affect the numeric results for the different scenarios. In general, though, the study showed the following results:

- High penetrations of wind generation - providing 20-30% of the electric energy requirements of Eastern Interconnection - are technically feasible with significant expansion of the transmission infrastructure.
- New transmission will be required for all the future wind scenarios in the Eastern Interconnection, including the reference case. Planning for this transmission, then, is imperative because it takes longer to build new transmission capacity than it does to build new wind plants.
- Without transmission enhancements, substantial curtailment of wind generation would be required for all of the 20% scenarios.
- Interconnection-wide costs for integrating large amounts of wind generation are manageable with large regional operating pools, where benefits of load and wind diversity can be exploited and large numbers of supply resources are efficiently committed and dispatched.
- Transmission helps reduce the impacts of the variability of the wind, which reduces wind integration costs, increases reliability of the electrical grid, and helps make more efficient use of the available generation resources.
- Although costs for aggressive expansions of the existing grid are significant, they do make up a relatively small piece of the total annualized costs in any of the scenarios studied.
- Wind generation displaces carbon-based fuels, directly reducing carbon dioxide (CO_2) emissions. Emissions continue to decline as more wind is added to the supply picture. Increasing the cost of carbon in the analysis results in higher total production costs.

7.2.4 Summary

EWITS was the first study of its kind in terms of scope, scale, and process. The scenarios developed for this study do not constitute a plan; instead, they should be seen as an initial perspective on a top-down, high-level view of four different 2024 futures. The full report is currently going through the final stages of the stakeholder review process. The public release of the EWITS report is scheduled for January 20, 2010.

8. Project Tracking

After the SPP Board of Directors (BOD) approves a transmission project and a Notification to Construct (NTC) is issued, SPP tracks and monitors the projects to ensure they continue to provide the best regional transmission solutions and, where applicable, are following cost recovery requirements under the SPP Open Access Transmission Tariff (OATT). SPP provides quarterly project status updates to the BOD on approved transmission projects and conducts an annual unintended consequences review of Base Plan cost allocation impacts per Attachment J of the OATT.

8.1 NTC Letters Issued in 2009

The NTC, previously called a Letter of Authorization, informs transmission project owners of their responsibility for constructing BOD-approved Network Upgrades. Additionally, NTCs were requested by project owners to assist them in the regulatory and cost recovery process. Through the end of 2009, 43 NTCs were issued with total estimated construction costs of $1.85 billion. Of this $1.85 billion, $435 million is for regional reliability, $14 million is for Zonal Reliability, $415 million is for Transmission Service, $218 million is for Sponsored Upgrades, and $770 million is for Balanced Portfolio projects.

8.2 Projects Completed in 2009

SPP actively monitors and supports the progress of transmission expansion projects. Each quarter, SPP staff solicits feedback from Transmission Owners to determine the progress of each transmission project. The quarterly reports chart the progress of all STEP projects, including projects approved by the BOD and those from an executed Service Agreement under the OATT. As of the third quarter of 2009, 80 upgrades had been completed, and another 44 are scheduled to be completed by the end of the year. Of the upgrades to be completed in 2009, 74 are for regional reliability, two are for zonal reliability, 14 are for Transmission Service, and 31 are for Sponsored Upgrades. The total estimated cost for upgrades completed in 2009 was $317 million, with $227 million for regional reliability, $2 million for Zonal Reliability, $28 million for Transmission Service, $56 million for Zonal-sponsored upgrades, and $4 million for Sponsored Upgrades. Projects completed in the fourth quarter of 2009 will be reported in the 2010 1st Quarter Project Tracking Report.

Appendix A - Complete List of Network Upgrades

Appendix A is a complete list of planned 2010 - 2019 SPP transmission Network Upgrades identified by the following seven sources:

Generation Interconnect – Projects associated with a FERC-filed Generation Interconnection Agreement

Interregional- Projects developed with neighboring Transmission Providers (Appendix A, only)

Regional reliability – Projects needed to meet the reliability of the region.

Regional reliability – non-OATT - Projects to maintain reliability for SPP members not participating under the SPP OATT (Appendix A, only)

Transmission service – Projects associated with a FERC-filed Service Agreement

Zonal Reliability - Projects identified to meet more stringent local Transmission Owner criteria

Zonal-sponsored – Projects sponsored by facility owner with now Project Sponsor Agreement

Balanced Portfolio – Projects identified by the Balanced Portfolio process

Sponsored – Projects with an executed Project Sponsor Agreement or that have previously been identified as an economic project to receive transmission revenue credits under the OATT attachment Z2.

The complete Network Upgrade list includes three dates.

1. In-service: Date Transmission Owner has identified as the date the upgrade is planned to be in-service.

2. 2009 STEP: Date upgrade was identified as needed for reliability, based on the 2009STEP analysis.

    M: Upgrade was in the base load flow model,

    R: Upgrade was replaced by an alternate project

    D: Project was deferred beyond 2019

3. Letter of notification to construct date, which is the date SPP sent the notification to construct (previously known as the letter of authorization) letter. Many close-in reliability network upgrades were identified by the previous STEP or by Transmission Owner studies reviewed by SPP.

The column titled “BOD Action” lists the action for which sponsors or RTO staff are requesting of the SPP Board of Directors (BOD) and have SPP RTO support. The cost estimates highlighted in yellow were estimated by SPP.

Facility owner abbreviations used in Appendices A and B:

Abbreviation and Identification	
AECC	Arkansas Electric Cooperatives
AECI	Associated Electric Cooperative, Incorporated
AEP	American Electric Power
CRE	Cap Rock Energy
CUS	City Utilities, Springfield Missouri
DETEC	Deep East Texas Electric Cooperative
EDE	Empire District Electric Company
EES	Entergy, Incorporated
GMO	KCP&L Greater Missouri Operations Company
GRDA	Grand River Dam Authority
GRIS	Grand Island Electric Department (GRIS)
INDN	City Power & Light, Independence, Missouri
HU	Hastings Utilities
ITCGP	ITC Great Plains
KACY	Board of Public Utilities, Kansas City, KS
KCPL	Kansas City Power and Light Company
LEA	Lea County Cooperative
LES	Lincoln Electric System
MIDW	Midwest Energy, Incorporated
MKEC	Mid-Kansas Electric Company
NPPD	Nebraska Public Power District
OGE	Oklahoma Gas and Electric Company
OMPA	Oklahoma Municipal Power Authority
OPPD	Omaha Public Power District
RCEC	Rayburn Electric Cooperative
SEPC	Sunflower Electric Power Corporation
SPS	Southwestern Public Service Company
SWPA	Southwestern Power Administration
TSGT	Tri-State G & T Association
WAPA	Western Area Power Pool
WFEC	Western Farmers Electric Cooperative
WR	Westar Energy

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
			Year 2010																			
20000	229	10294	AEP	06/01/10		M	02/13/08	$5,017,000	AEP	24 months	regional reliability	506960	Bentonville 279th Street 161 kV	506929	East Centerton 161 kV	1	161	5.14			429/597	Reconductor 5.14 mile Bentonville 279th St. - East Centerton 161 kV with 1590 conductor.
20016	343	10440	AEP	06/01/10		M	01/16/09	$90,000	AEP	15 months	regional reliability	508316	Winnsboro 69 kV	508299	Magnolia Tap 69 kV	1	69				73/85	Replace 69 kV switches at Winnsboro and reset CT ratios and relay settings.
20016	346	10443	AEP	06/01/10		M	01/16/09	$185,000	AEP	15 months	regional reliability	508340	Forest Hills 69 kV	508353	Quitman 69 kV	1	69				73/85	Replace Quitman 69 kV bus, switches and jumpers. Change CT and relay settings.
	893	11185	AEP	07/01/10				$1,456,000	AEP	10 months	zonal - sponsored	510897	Lone Oak 138 kV		EnoGex Wilberton 138 kV	1	138					Restore existing 9.2 mile radial de-energized 138 kV line to service. Build 138-4.16 kV station at Enogex Wilberton.
	894	11186	AEP	12/01/10				$3,550,000	AEP	15 months	zonal - sponsored	508369	Exxon-Mobil Hawkins 138 kV	508351	Perdue 138 kV	1	138		0.6		215/237	Build new 0.6 mile double circuit tap from the existing Perdue - Lake Hawkins 138 kV line to a new 138 kV Exxon - Mobil Hawkins switching station.
	894	11187	AEP	12/01/10				$3,550,000	AEP	15 months	zonal - sponsored	508369	Exxon-Mobil Hawkins 138 kV	508358	Lake Hawkins 138 kV	1	138		0.6		261/287	Build new 0.6 mile double circuit tap from the existing Perdue - Lake Hawkins 138 kV line to a new 138 kV Exxon - Mobil Hawkins switching station.
20016	507	10652	AEP	06/01/10		M	01/16/09	$5,428,300	AEP	18 months	transmission service	507711	Arsenal Hill 138 kV	507731	Fort Humbug 138 kV	1	138	3.24			438/478	Rebuild 3.24 miles of 1272 AAC with 2156 ACSR. Replace 3 138 kV switches, breaker jumpers, and reset CTs at Arsenal Hill. Replace 2 138 kV switches and jumpers at Fort Humbug.
20016	30147	50155	AEP	06/01/10		M	01/16/09	$3,005,700	AEP	18 months	transmission service	507711	Arsenal Hill 138 kV	507710	Arsenal Hill 69 kV	2	138/69				224/246	Replace auto and 69 kV breaker and switches.
20016	30146	50154	AEP	06/01/10		M	01/16/09	$3,005,700	AEP	18 months	transmission service	507711	Arsenal Hill 138 kV	507710	Arsenal Hill 69 kV	1	138/69				224/246	Replace auto and 69 kV breaker and switches.
20016	30153	50161	AEP	06/01/10		M	01/16/09	$200,000	AEP	12 months	transmission service	508809	Longwood 345 kV	508808	Longwood 138 kV	1	345/138				451/503	Replace four (4) switches and upgrading bus work.
	657	10862	AEP		NTC	06/01/10		$150,000	AEP	12 months	regional reliability	510407	Pryor Junction 115 kV	510400	Pryor Junction 69 kV	1	115/69				76/100	Replace (3) 600 A switches with 1200 A switches.
19959	289	10375	AEP	06/01/10		M	10/17/06	$135,400	AEP	9 months	transmission service	511447	Clinton City 69 kV	511522	Foss Tap 69 kV	1	69				72/79	Replace wave trap at Clinton City Substation.
20000	294	10380	AEP	06/01/10		M	02/13/08	$339,000	AEP	15 months	regional reliability	508348	North Mineola 69 kV	508347	Mineola 69 kV	1	69				72/85	Replace Mineola 2 Switches & Breaker
	231	10296	AEP	12/31/10		M		$25,590,000	AEP	48 months	Generation Interconnect	507454	Turk 138 kV	508078	SE Texarkana 138 kV	1	138		34		368/512	Build new 34 mile Turk - SE Texarkana 138 kV line and add SE Texarkana 138 kV terminal.
	232	10297	AEP	12/31/10		M		$18,427,000	AEP	48 months	Generation Interconnect	507454	Turk 138 kV	508080	Sugar Hill 138 kV	1	138		24		368/512	Build new 24 mile Turk - Sugar Hill 138 kV line and add Sugar Hill 138 kV terminal.
19953	295	10381	AEP	06/01/10		M	06/26/07	$1,008,000	AEP	24 months	transmission service	510422	Coffeyville T 138 kV	533002	Dearing 138 kV	1	138	1.09			368/512	AEPW to reconductor 1.09 miles of 795 ACSR with 1590 ACSR. (Also, Westar to rebuild 3.93 miles of 795 ACSR with 1590 ACSR.) These ratings are just for the AEP facilities.
20000	297	10383	AEP	06/01/10		M	02/13/08	$3,827,000	AEP	24 months	regional reliability	508353	Quitman 69 kV	508354	Westwood 69 kV	1	69	3.91			52/68	Reconductor Quitman - Westwood 69 kV 3.91 miles of 2/0 with 795 ACSR
20016	296	10382	AEP	06/01/10		M	01/16/09	$6,252,000	AEP	24 months	transmission service	506927	Dyess 161 kV	504010	Elm Springs 161 kV	1	161	5.17			502/552	Rebuild/reconductor 5.17 mile Dyess - Elm Springs 161 kV with 2156 ACSR.
20016	348	10445	AEP	06/01/10		M	01/16/09	$224,000	AEP	12 months	regional reliability	506927	Dyess 161 kV	506957	Tontitown 161 kV	1	161				502/552	Replace 161 kV breaker, switches and CTs at Dyess.
20027	613	10784	AEP	12/01/10		M	01/27/09	$100,000	AEP	12 months	regional reliability	508831	Diana 138 kV	508297	Lone Star South 138 kV	1	138				246/287	Replace switch at Diana for higher winter rating of 287/316 MVA. Summer rating unchanged.
20027	292	10378	AEP	06/01/10		M	01/27/09	$4,047,000	AEP	24 months	regional reliability	508542	Greggton 69 kV	508551	Lake Lamond 69 kV	1	69	2.66			133/143	Reconductor 2.66 mile Greggton - Lake Lamond 69 kV with 1272 ACSR.
20027	480	10617	AEP	12/31/10		M	01/27/09	$800,000	AEP	24 months	regional reliability	511435	AEP Snyder 138 kV	521052	WFEC Snyder 138 kV	1	138		4		183/228	Build new 4 mile AEP Snyder - WFEC Snyder 138 kV. WFEC to connect AEP Snyder to WFEC Snyder. AEP to provide 138 kV terminal at AEP Snyder.
	767	11011	AEP		NTC	06/01/10		$17,000,000	AEP	36 months	regional reliability	510946	Canadian River 138 kV	510908	McAlester City 138 kV	1	138			17	319/471	Convert 17 mile Canadian River - McAlester City line from 69 kV to 138 kV.
	767	11012	AEP		NTC	06/01/10		$8,500,000	AEP	36 months	regional reliability	515422	Canadian River 345 kV	510946	Canadian River 138 kV	1	345/138				450/495	Tap Pittsburg - Muskogee 345 kV about 33 miles north of the Pittsburg station and step down to 138 kV with a 450 MVA auto.
	767	11183	AEP		NTC	06/01/10		$2,900,000	AEP	36 months	regional reliability	510908	McAlester City 138 kV	510921	Dustin 138 kV	1	138		5.73		88/107	Rebuild McAlester City Tap, double circuiting existing line, eliminate the "T" at McAlester City North Tap.
	767	11184	AEP		NTC	06/01/10		$2,900,000	AEP	36 months	regional reliability	510908	McAlester City 138 kV	510909	McAlester City North Tap 138 kV	1	138	5.73			96/105	Rebuild McAlester City Tap, double circuiting existing line, eliminate the "T" at McAlester City North Tap.
20011	212	10271	CUS	06/01/10		M	02/13/08	$1,485,000	CUS	24 months	regional reliability	549928	Norton 69 kV	549930	Neergard 69 kV	1	69	3			111/115	Reconductor 3 mile 69 kV line from 336.4 kcmil ACSR to 477 kcmil ACSS/TW
	339	10436	CUS	10/01/10		M		$3,200,000	CUS	24 months	zonal - sponsored	549954	Southwest 161 kV	549893	Southwest 2 20 kV	1	161/20				334/400	Step-Up Transformer for new SWPS #2 (DNR)
	216	10275	DETEC	12/31/10		M				18 months	regional reliability - non OATT	508593	Ben Wheeler (Wood County EC) 138 kV	509246	Barton's Chapel (Rayburn County) 138 kV	1	138		10		215/215	Rayburn Project -- Build new 10 mile Ben Wheeler - Barton Chapel 138 kV.
20049	382	10495	EDE	06/01/10		M	09/18/09	$50,000	EDE	6 months	regional reliability	547601	SUB 404 - Hockerville 69 kV	547554	SUB 271 - Baxter Springs West 69 kV	1	69				51/61	Change CT setting on Breaker #6973 at Baxter #271 to 800/5 ratio.
20036	421	10547	EDE	06/01/10		M	01/27/09	$5,000	EDE	6 months	regional reliability	547537	SUB 124 - Aurora H. T. 69 kV	547540	SUB 152 - Monett H.T. 69 kV	1	69				54/65	Change CT ratio on breaker #6936 at Aurora Substation 124.
19969	338	10435	EDE	06/01/10		M	09/22/06	$1,215,000	EDE	12 months	transmission service	547471	SUB 184 -Neosho South Junction 161 kV	505486	Neosho (SWPA) 161 kV	1	161	1.7			167/167	Rebuild 1.7 mile Neosho South Jct. - Neosho SPA 161 kV from 336 ACSR to 795 ACSR and replace terminal equipment
20049	496	10641	EDE	06/01/10		06/01/15	09/18/09	$55,000	EDE	12 months	regional reliability	547539	SUB 145 - Joplin West 7TH 69 kV	547526	SUB 64 - Joplin 10TH ST. 69 kV	1	69				86/104	Replace 600 amp disconnect switches with a minimum 1,200 amp units and replace leads on Breaker #6965 at Sub #64 and #6932 at Sub #145.
20034	601	10768	GMO	06/01/10		M	01/27/09	$50,000	GMO	6 months	regional reliability	541223	Grandview East 161 kV	541224	Longview 161 kV	1	161				233/265	Replace wavetraps at Longview and Grandview East on the Grandview - Longview 161kV line.
20034	628	10816	GMO	12/01/10		M	01/27/09	$50,000	GMO	6 months	regional reliability	541221	Platte City 161 kV	541204	Smithville 161 kV	1	161				233/265	Replace wavetrap at Platte City.
20034	635	10832	GMO	07/01/10		M	01/27/09	$5,405,930	GMO	24-30 months	regional reliability	541257	Cook 161 kV	541255	Lake Road 161 kV	1	161				293/335	Build a new Edmond 161/69/34.5 kV substation between the Cook and Lake Road 161 kV substations that will pick up the loads supplied by the Lake Road 161/34.5 kV sources.
20053	30222	50226	GMO	06/01/10			09/18/09	$20,000	GMO	6 months	regional reliability											Reset the overcurrent relay at South Harper 69 kV substation to open South Harper - Freeman 69 kV line upon reaching thermal limit of Freeman – Anaconda – Harrisonville West 69 kV line
	302	10389	GRDA	06/01/10		M		$3,210,200	GRDA	24 months	zonal - sponsored	512751	Siloam Springs Tap 161 kV	512643	Siloam City 161 kV	1	161		7		347/403	Tap the GRDA 1-Flint Creek 345 kV line and build a 345/161 transformer. Then build a 161 kV line down to Siloam Springs.
20001	301	10388	GRDA	06/01/10		M	02/13/08	$3,000,000	GRDA	24 months	regional reliability	512652	Sallisaw 69 kV	505550	Sallisaw 161 kV	2	161/69				75/84	Add second 161/69 kV 75 MVA autotransformer at Sallisaw
	279	10363	KCPL	06/01/10		M		$192,000	KCPL	6 months	zonal - sponsored	542978	Craig 161 kV	543038	Lenexa 161 kV	1	161				513/513	Replace Lenexa Circuit Switcher R1-4 with 2000 Amp Breaker
	200	10256	KCPL	09/30/10		M		$4,352,600	KCPL	10 months	zonal - sponsored	542991	Terrace 161 kV	543003	Boulevard 161 kV	1	161		1		259/259	New Boulevard sub and new 161kV line
	201	10257	KCPL	03/30/10		M		$4,750,000	KCPL		zonal - sponsored	542990	Crosstown 161 kV	543003	Boulevard 161 kV	1	161		1.3		259/259	New 161kV line
	714	10951	KCPL		NTC	06/01/10		$5,000	KCPL	12 months	regional reliability	543100	Amoco Pipeline 69 kV	543096	Mayview Tap 69 kv	1	69				65/73	Replace 200 A CT and 400 A wavetrap at Mayview to increase line rating.
	866	11144	LES	05/31/10		M		$621,875	SPP		zonal - sponsored	640278	Sheldon 115 kV	650238	20th & PIO 115 kV	1	115		1		240/240	Rebuild Sheldon to 20th & PIO. Upgrade based on condition of facility.
	867	11145	LES	05/31/10		M		$790,625	SPP		zonal - sponsored	650218	3rd & Vandn 115 kV	650238	20th & PIO 115 kV	1	115		1.4		139/155	Rebuild 3rd & Vandn to 20th & PIO. Upgrade based on condition of facility.
20052	30219	50223	MIDW	06/01/10			09/18/09	$1,812,500	MIDW		transmission service						34.5	14				Rebuild approximately 14.5 miles of 34.5 kV line between Rice County and Ellinwood to achieve a minimum 600 amp emergency rating
	744	10981	NPPD	11/01/10		M		$5,000,000	NPPD	24 months	transmission service	640103	Canaday 115 kV	640102	Canaday 230 kV	1	230/115				336/336	Replace Canaday transformer.
	603	10772	NPPD	10/01/10	NTC	06/01/10		$3,000,000	NPPD	48 months	regional reliability	533332	Knob Hill 115 kV	640030	Steele City 115 kV	1	115		2.4		223/245	Build 2.4 miles of new 115 kV line from Kansas/Nebraska state line to Steele City.
	605	10775	NPPD	06/01/10	NTC	M		$5,000,000	NPPD	24 months	regional reliability	640286	N. Platte 115 kV	640287	N. Platte 115 kV	2	230/115				336/336	
	606	11160	NPPD	04/01/10	NTC	M				48 months	regional reliability	640125	Columbus East 345 kV	650114	NW 68th and Holdrege 345 kV	1	345		67		1195/1195	Build new 67 mile Columbus East - NW 68th & Holdrege 345 kV line.
	606	11161	NPPD	10/13/09	NTC	M				48 months	regional reliability	640342	Shell Creek 345 kV	640125	Columbus East 345 kV	1	345		12		1195/1195	Build new 12 mile Columbus East - Shell Creek 345 kV line.
	606	10970	NPPD	04/01/10	NTC	M					regional reliability	640127	Columbus East 115 kV	640136	Columbus 115 kV	1	115				238/238	Upgrade Columbus East - Columbus line to 238 MVA.
	606	10971	NPPD	04/01/10	NTC	M		$150,000,000	NPPD	48 months	regional reliability	640316	Pawnee Lk 115 kV	640340	Seward 115 kV	1	115	6			120/120	Upgrade Pawnee Lake - Seward line to 120 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.
	606	10972	NPPD	04/01/10	NTC	M				48 months	regional reliability	640316	Pawnee Lk 115 kV	650214	NW 68th & Holdrege 115 kV	1	115	5			137/137	Upgrade Pawnee Lake - NW 68th & Holdrege line to 137 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.
	606	10973	NPPD	04/01/10	NTC	M				48 months	regional reliability	640328	Rising City 115 kV	640340	Seward 115 kV	1	115	13			120/120	Upgrade Rising City - Seward line to 120 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.
	606	11162	NPPD	10/13/09	NTC	M				48 months	regional reliability	640127	Columbus East 115 kV	640125	Columbus East 345 kV	1	345/115				336/336	Add Columbus East 345/115/13.8 kV transformer.
	720	10957	NPPD	06/01/10		M		$6,750,000	NPPD	48 months	transmission service	640178	Geneva 115 kV	640372	Sutton 115 kV	1	115	16			240/240	Upgrade line to 240 MVA for WEC2.
	721	10958	NPPD	06/01/10		M		$200,000	NPPD	48 months	transmission service	640215	Hastings 115 kV	641088	Hastings City 115 kV	1	115				240/240	Upgrade line to 240 MVA for WEC2.
	723	10960	NPPD	06/01/10		M		$8,437,500	NPPD	48 months	transmission service	640372	Sutton 115 kV	641087	Whelan Energy Center 115 kV	1	115	20			240/240	Upgrade line to 240 MVA for WEC2.
	614	10787	OGE	03/30/10		M			OGE		Sponsored	514880	Northwest 345 kV	515375	Woodward Distric EHV 345 kV	1	345		120		2013/2013	Build 120 mile 345 kV, 3000 amp capacity line from new OG&E Woodward District EHV substation to Northwest substation
	614	10915	OGE	03/30/10		M			OGE		Sponsored	514880	Northwest 345 kV			1	345				2013/2013	At Northwest substation, install a 3000 amp 345 kV breaker and new line terminal. Relocate Spring Creek Line to new bay. Terminate line from Tatonga. Install line relays and coordinate all relays at Northwest Substation.
	614	10788	OGE	03/30/10		M		$218,000,000	OGE		Sponsored	515375	Woodward Distric EHV 345 kV	515376	Woodward EHV 138 kV		345/138				537/616	Install 345/138 kV transformer.
	614	10789	OGE	03/30/10		M			OGE		Sponsored	515376	Woodward EHV 138 kV	514785	Woodward 138 kV	1	138		0.5		537/616	Build .5 miles of 138 kV and install terminal equipment .
	614	10790	OGE	03/30/10		M			OGE		Sponsored	515376	Woodward EHV 138 kV	514785	Woodward 138 kV	2	138		0.5		537/616	Build .5 miles of 138 kV and install terminal equipment .
	614	10791	OGE	03/30/10		M			OGE		Sponsored	515376	Woodward EHV 138 kV	514796	Iodine 138 kV	1	138				268/308	Tap Iodine - Woodward 138 kV.
	892	11182	OGE		NTC	06/01/10		$5,500,000	OGE	30 months	regional reliability	515422	Canadian River 345 kV				345				1195/1195	Install Canadian River 345 kV terminal equipment at new Canadian River substation tapping the Pittsburg-Muskogee line.
	310	10391	OGE	06/01/10		M		$1,416,000	OGE		zonal - sponsored	503902	Fitzhugh 161 kV	515327	Helberg 161 kV	1	161			5	313/359	Conversion from 69kV to 161kV.
	310	10393	OGE	12/31/10		M		$660,000	OGE		zonal - sponsored	515352	Altus 161 kV	503902	Fitzhugh 161 kV	1	161			2	134/143	Conversion from 69kV to 161kV.
	310	10395	OGE	06/01/10		M		$2,112,000	OGE		zonal - sponsored	515319	Little Spadra 161 kV	515355	Igo 161 kV	1	161			7	226/259	Conversion from 69kV to 161kV.
	309	10397	OGE	06/01/10		M		$50,000	OGE		zonal - sponsored	515177	Park Lane 69 kV	515187	Ahloso Tap 69 kV	1	69				97/111	Relay upgrade.
	310	10398	OGE	10/01/10		M		$2,973,000	OGE		zonal - sponsored	515355	Igo 161 kV	515357	Razorback 161 kV	1	161			10	134/143	Conversion from 69kV to 161kV.
	310	10399	OGE	06/01/10		M		$500,000	OGE		zonal - sponsored	515357	Razorback 161 kV	515358	Short Mountain 161 kV	1	161			14	134/143	Conversion from 69kV to 161kV.
	310	10400	OGE	10/01/10		M		$3,231,000	OGE		zonal - sponsored	515358	Short Mountain 161 kV	515316	Branch 161 kV	1	161			11	134/143	Conversion from 69kV to 161kV.
20029	354	10463	OGE	06/01/10	NTC-Modify Scope	06/01/10	01/27/09	$100,000	OGE	12 months	regional reliability	515256	Muldrow 69 kV	515307	3rd St 69 kV	1	69				77/86	Upgrade wavetrap and switches to 800 A at 3rd St. substation.
20002	395	10513	OGE	06/01/10		M	02/13/08	$347,073	OGE	12 months	regional reliability	515120	Russett 138 kV	521044	Russett 138 kV	1	138				191/191	Replace a wave trap, breaker, and increase CT ratio.
	758	11001	OPPD	02/26/10		M		$2,500,000	OPPD		zonal - sponsored	647902	SUB 902 69 kV	647983	SUB 983 69 kV	1	69	6.48			57/57	Rebuild Sub 902 - Sub 983 69 kV. The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.
	256	10336	SEPC	06/01/10	NTC	06/01/10		$10,650,000	SPP	36 months	regional reliability	531424	Johnson 115 kV	531391	Pioneer 115 kV	1	115		.	38	165/198	Convert Johnson Corner - Pioneer line from 69 kV to 115 kV.
	315	10407	SPS	06/01/10		M		$200,000	SPS	6 months	regional reliability	524908	Roosevelt County Interchange 115 kV	524822	Curry County Interchange 115 kV		115				185/185	Upgrade terminal equipment, Rate A & B 185 MVA
20004	248	10317	SPS	06/01/10		M	02/13/08		SPS	30 months	regional reliability	523797	Grave County Tap 115 kV	523796	Graves Sub 69 kV		115/69				40/40	Install 115/69 kV Graves transformer.
20004	248	10318	SPS	06/01/10		M	02/13/08	$10,585,000	SPS	30 months	regional reliability	523777	Wheeler Interchange 230 kV	523776	Wheeler Interchange 115 kV		230/115				150/150	Install new 230/115 kV transformer at Wheeler Co (near State Line of Oklahoma and Texas)
20004	248	10319	SPS	06/01/10		M	02/13/08		SPS	30 months	regional reliability	523776	Wheeler Interchange 115 kV	523797	Graves Sub 115 kV		115		17		186/205	Build new 17 mile Wheeler Co to Graves 115 kV and modify 69 kV bus.
20004	248	10800	SPS	06/01/10		M	02/13/08	$2,000,000	SPS	12 months	regional reliability	511490	Elk City 230KV	523777	Wheeler Interchange 230 kV	1	230				319/351	Wheeler County tap
20004	248	10801	SPS	06/01/10		M	02/13/08		SPS	12 months	regional reliability	523771	Grapevine Interchange 230 kV	523777	Wheeler Interchange 230 kV	1	230				319/351	Wheeler County tap
20031	156	10326	SPS	12/31/10		M	01/27/09	$16,094,371	SPS	48 months	regional reliability	523309	Moore Co 230 kV	523095	Hitchland 230 kV	1	230		50		492/541	Build new 50 mile Moore County - Hitchland 230 kV rated at 541 MVA.
20004	156	10327	SPS	06/01/10		M	02/13/08	$12,577,500	SPP	24 months	regional reliability	523097	Hitchland 345 kV	523095	Hitchland 230 kV	1	345/230				559/559	Add 3-Winding 345/230 kV transformer at Hitchland - 560 MVA.
20004	156	10328	SPS	06/01/10		M	02/13/08	$15,848,000	SPP	36 months	regional reliability	523175	Sherman Tap 115 kV	523093	Hitchland 115 kV	1	115		28.2		146/161	Build new 28 mile Hitchland - Sherman Tap 115 kV rated at 161 MVA.
20004	156	10329	SPS	06/01/10	NTC-Modify Scope	M	02/13/08	$10,771,825	SPS	48 months	regional reliability	523168	Sherman Sub 115 kV	523228	Dallam County Interchange 115 kV	1	115		35		146/1161	Add 115 kV line from Sherman to Dallam - 161 MVA.
20004	156	10200	SPS	06/01/10		M	02/13/08	$5,132,829	SPS	24 months	regional reliability	523090	Texas County Interchange 115 kV	523093	Hitchland 115 kV	2	115		9.00		146/161	Build new 9 mile Hitchland - Texas Co. 115 kV rated at 161 MVA.
20004	156	10201	SPS	06/01/10		M	02/13/08	$31,915,701	SPS	24 months	regional reliability	523093	Hitchland 115 kV	523095	Hitchland 230 kV	1	230/115				252/252	Add 2-winding 230/115 kV transformer at Hitchland - 252 MVA.
20004	156	10802	SPS	06/01/10		M	02/13/08			24 months	regional reliability	523093	Hitchland 115 kV	523195	Hansford 3 115 kV	1	115				164/180	Tap the Texas County to Hansford line.
20004	156	10805	SPS	06/01/10		M	02/13/08			12 months	regional reliability	523090	Texas County Interchange 115 kV	523093	Hitchland 115 kV	1	115				164/180	Tap the Texas County to Hansford line.
20031	554	10704	SPS	12/31/10		M	01/27/09		SPS	30 months	regional reliability	523228	Dallam County Interchange 115 kV	523868	Channing 115 kV	1	115		35		246/271	Build new 35 mile Dallam - Channing 115 kV using 795 ACSR.
20031	554	10705	SPS	12/31/10		M	01/27/09	$27,452,677	SPS	30 months	regional reliability	523868	Channing 115 kV	523875	Tascosa 115 kV	1	115			15	246/271	Convert 15 mile Channing - Tascosa line from 69 kV to 115 kV with 795 ACSR.
20031	554	10706	SPS	12/31/10		M	01/27/09		SPS	30 months	regional reliability	523875	Tascosa 115 kV	524106	Northwest Interchange 115 kV	1	115			30	246/271	Convert 30 mile Tascosa - Northwest Interchange line from 69 kV to 115 kV with 795 ACSR.
	773	11018	SPS		NTC	06/01/10		$5,670,000	SPP	24 months	regional reliability	524908	Roosevelt County Interchange 115 kV	524909	Roosevelt County Interchange 230 kV	2	230/115				252/289.8	Add 2nd 230/115 kV transformer at Roosevelt.
	776	11026	SPS	06/30/10	NTC	06/01/10		$600,000	SPP	6 months	regional reliability	524622	Deaf Smith County Interchange 115 kV	524597	Panda Energy Substation, Hereford 115 kV	1	115		1		120/154	Build new 1 mile Deaf Smith to Panda 115 kV line.
	777	11027	SPS		NTC	06/01/10		$1,100,000	SPP	12 months	regional reliability	524162	East Plant Interchange 115 kV	524224	Manhattan Sub 115 kV	1	115	2.24			226/249	Reconductor 2.24 mile East Plant - Manhattan 115 kV line.
	782	11032	SPS		NTC	06/01/10		$1,687,500	SPP	18 months	regional reliability	524322	South Georgia Interchange 115 kV	524345	Osage Switching Station 115 kV	1	115	4			227/249	Rebuild 4 mile Osage Switching Station - South Georgia Interchange 115 kV with 795 ACSR.
	821	11084	SPS		NTC	06/01/10		$1,125,000	SPP	12 months	regional reliability	524345	Osage Switching Station 115 kV	524364	Randall County Interchange 115 kV	1	115	2			139/160	Reconductor 2 mile Osage Switching Station - Randall County Interchange 115 kV line with 795 ACSR.
	830	11097	SPS		NTC	06/01/10		$900,000	SPP	12 months	regional reliability	524354	Manhatten Tap 115 kV	524364	Randall County Interchange 115 kV	1	115	1.6			246/271	Reconductor 1.6 mile Manhattan - Randall County Interchange 115 kV line with 795 ACSR.
	851	11121	SPS	06/16/10	NTC	06/01/10		$225,000	SPP	12 months	regional reliability	523978	Harrington Mid 230 kV	524365	Randall Co 230 kV	1	230				436/502	Replace existing wavetrap with 1200 A unit.
	342	10439	SWPA	01/01/10		06/01/10		$2,200,000	SWPA	12 months	regional reliability - non OATT	505460	Bull Shoals 161 kV	338123	Bullshoals 161 kV	1	161				335/335	Upgrade the bus to 1200 amp and reconnect CT ratios to 1200/5.
	101	10125	SWPA	10/01/10		M		$3,000,000	SWPA	24 months	regional reliability - non OATT	505570	Eufaula 161 kV	505574	Eufaula 138 kV	1	161/138				200/200	Replace Eufaula161/138 kV transformer with 200 MVA unit.
20003	138	10176	WFEC	06/01/10		M	02/13/08	$1,050,000	SPP	10 months	regional reliability	514782	OGE Woodward 69 kV	521096	WFEC Woodward 69kV	1	69	3.5			91/114	Upgrade WFEC Woodward sub to 1200 A and reconductor from 336.4 ACSR to 795 ACSR; new rating 91/110 MVA.
20030	239	10305	WFEC	12/31/10		M	01/27/09	$3,373,000	SPP	16 months	regional reliability	511435	AEP Snyder 138 kV	521052	WFEC Snyder 138 kV	1	138		4		118/154	Build new 4 mile AEP Snyder - WFEC Snyder 138 kV.
20003	241	10307	WFEC	06/01/10		M	02/13/08	$1,124,000	SPP	12 months	regional reliability	520814	Anadarko 138 kV	520923	Georgia 138 kV	1	138	2			212/264	Rebuild 2 mile Anadarko - Georgia 138 kV line from 556 to 1113 ACSR.
20003	242	10308	WFEC	06/01/10		M	02/13/08	$3,240,000	SPP	12 months	regional reliability	520898	Elmore 69 kV	521022	Paola 69 kV	1	69	10.8			47/61	Elmore - Paoli Rebuild 3/0 to 336 ACSR - 10.8 miles.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
20003	243	10309	WFEC	06/01/10		M	02/13/08	$2,753,800	SPP	16 months	regional reliability	521104	OU Switchyard 138 kV	520924	Goldsby 138 kV	1	138			4.9	183/228	Convert 5 mile Oklahoma University (OU) Switch - Goldsby from 69 kV to 138 kV.
20003	243	10310	WFEC	06/01/10		M	02/13/08	$2,250,000	SPP	16 months	regional reliability	520924	Goldsby 138 kV	520842	Canadian SW 138 kV	1	138			6	183/228	Convert 6 mile Goldsby - Canadian Switch from 69 kV to 138 kV.
20003	243	10311	WFEC	06/01/10		M	02/13/08	$5,000,000	SPP	16 months	regional reliability	521104	OU Switchyard 138 kV	521018	OU Switchyard 69 kV	1	138/69				112/112	Install 138/69 kV transformer at Oklahoma University.
20003	136	10174	WFEC	06/01/10		M	02/13/08	$6,674,000	SPP	10 months	regional reliability	520994	Meeker 138 kV	520951	Hammett 138 kV	1	138		10		219/235	Build new 10 mile Meeker - Hammett 138 kV and install terminal equipment.
20003	137	10175	WFEC	06/01/10		M	02/13/08	$5,378,750	SPP	10 months	regional reliability	521085	Wakita 69 kV	520938	Hazelton 69 kV	1	69	18.9			53/65	Reconductor 18.9 mile Wakita - Hazelton Junction 69 kV from 1/0 ACSR to 336.4 ACSR for new rating of 53/65 MVA.
20003	311	10401	WFEC	06/01/10		M	02/13/08	$2,065,000	SPP	12 months	regional reliability	520917	Franklin SW 138 kV	520802	ACME 138 kV	1	138			4.9	131.7/162.54	Convert 5 mile Acme - Franklin from 69 kV to 138 kV.
20003	311	10402	WFEC	06/01/10		M	02/13/08	$1,601,000	SPP	12 months	regional reliability	520802	ACME 138 kV	521095	West Norman 138 kV	1	138			3.8	183/228	Convert 4 mile West Norman - Acme from 69 kV to 138 kV.
20003	311	10403	WFEC	06/01/10		M	02/13/08	$1,577,000	SPP	12 months	regional reliability	521095	West Norman 138 kV	521104	OU SW 138 kV	1	138			8.3	182/228	Convert 8 mile OU - West Norman from 69 kV to 138 kV.
20030	616	10794	WFEC	06/01/10		M	01/27/09	$5,765,600	SPP	24 months	regional reliability	520882	Dover SW 138 kV	520879	Dover 138 kV	1	138			11	144/179	Convert 11 mile Dover Southwest - Dover from 69 kV to 138 kV and install terminal equipment at Dover Southwest.
20030	616	10795	WFEC	06/01/10		M	01/27/09	$5,315,700	SPP	24 months	regional reliability	520879	Dover 138 kV	521073	Twin Lakes 138 kV	1	138			12.6	144/179	Convert 12.6 mile Dover - Twin Lakes from 69 kV to 138 kV
20030	616	10796	WFEC	06/01/10		M	01/27/09	$3,164,000	SPP	24 months	regional reliability	521073	Twin Lakes 138 kV	520847	Cashion 138 kV	1	138			7.5	144/179	Convert 7.5 mile Twin Lakes - Cashion from 69 kV to 138 kV.
20030	616	10797	WFEC	06/01/10		M	01/27/09	$3,937,500	SPP	24 months	regional reliability	521073	Twin Lakes 138 kV	515377	Crescent 138 kV	1	138		7		144/179	Build new 7 mile WFEC Twin Lakes - OG&E Crescent 138 kV.
20030	617	10798	WFEC	06/01/10		M	01/27/09	$150,000	WFEC	8 months	regional reliability	520846	Carter JCT 69 kV	520978	Lake Creek 69 kV	1	69				53/65	Upgrade CTs at Lake Creek (Carter Branch) to 600A.
20030	135	10799	WFEC	06/01/10		M	01/27/09	$1,248,750	SPP	12 months	regional reliability	520977	Lindsay 69 kV	520979	Lindsay SW 69 kV	1	69	3.7			72/89	Reconductor 3.7 miles of 1/0 ACSR to 556.5 ACSR from Lindsay to Lindsay Southwest 69 kV.
20030	135	10173	WFEC	06/01/10		M	01/27/09	$2,328,750	SPP	18 months	regional reliability	520829	Bradley 69 kV	521041	Rush Springs 69 kV	1	69	6.9			53/65	Reconductor 6.9 miles of 1/0 ACSR to 336.4 ACSR from Bradley to Rush Springs 69 kV.
19985	140	10179	WFEC	06/01/10		M	02/02/07	$912,000	WFEC	8 months	regional reliability	520802	ACME 69 kV	521095	W Norman 69 kV	1	69	3.8			81/106	Reconductor 3.8 miles from 3/0 ACSR to 795 ACSR. Rate A=81MVA, Rate B=106MV/
20006	171	10220	WR	12/01/10		M	02/13/08	$2,242,907	WR	6 months	regional reliability	533604	Weaver 69 kV	533837	Rose Hill 69 kV	1	69	5.76			116/128	Rebuild Weaver-Rose Hill 69 kV
20059	182	10231	WR	06/01/10		M	09/18/09	$5,184,701	WR	8 months	regional reliability	533588	Chase 69 kV	533605	White Junction 69 kV	1	69	7.3			72/72	Rebuild approximately 7.5 miles Chase - White Junction 69 kV line. Replace existing 2/0 copper conductor to achieve a minimum 600 amp emergency rating.
19964	318	10412	WR	06/01/10		M	06/27/07	$2,819,000	WR	18 months	transmission service	510422	Coffeyville Tap 138 kV	533002	Dearing 138 kV	1	138	3.93			287/287	AEP - Tie Line, Reconductor 1.09 miles of 795 ACSR with 1590 ACSR. WERE - Tie Line, Rebuild 3.93 miles of 795 ACSR with 1590 ACSR. AEP: The limiting factor is the AEP portion of 795 ACSR conductor The estimated cost of doing a sag analysis on this line to see if it can rated for a higher limit is 6000 New ratings are for AEP only. The new limit is the 1590 ACSR conductor Per MW-Mile files, 78% WR, 22% AEP of 5.02 miles
	262	10345	WR	06/01/10		M		$100,618,016	WR	24 months	Sponsored	532771	Reno County 7 345 kV	532773	Summit 345 kV	1	345		50.55		956 / 956	Install new 50.55-mile 345 kV line from Reno county to Summit; 31 miles of 115 kV line between Circle and S Philips would be rebuilt as double circuit with the 345 kV line to minimize ROW impacts; Substation work required at Summit for new 345 kV terminal and completion of ring bus.
20006	330	10426	WR			M	02/13/08	$5,000,000	WR	18 months	regional reliability	532929	Southwest Bourbon 161 kV	532930	Fort Scott 161 kV	1	161		22		312/342	Tap Litchfield-Marmaton 161 kV with new SWBourb5 bus to Ft Scott
20006	328	10424	WR	06/01/10		M	02/13/08	$5,800,000	WR	12 months	regional reliability	533413	Circle 115 kV	533429	Moundridge 115 kV	1	115	17.12			223/245	Rebuild Circle - Moundridge 115 kV
	328	10425	WR	06/01/10				$1,700,000	WR		zonal - sponsored	533013	Moundridge 138 kV	533429	Moundridge 115 kV	2	138/115				100/110	Install New (2nd) 138/115 kV transformer at Moundridge (57429/57013). Operate both 138/115 kV transformers normally closed.
20006	170	10219	WR	06/01/10		M	02/13/08	$3,639,327	WR	6 months	regional reliability	533321	Anzio 115 kV	533328	Fort Junction	1	115	3.53			141/141	3.53 miles Anzio - Fort Junction Switching Station 115 kV
20033	621	10809	WR			M	01/27/09	$17,085,938	SPP	12 months	regional reliability	532861	E. Manhattan 230 kV	532852	JEC 230 kV	1	230				446/490	Uprate JEC- E. Manhattan 230 kV line to 100 deg C operation by raising structures.
20033	625	10813	WR	06/01/10		M	01/27/09	$2,255,250	WR	18 months	regional reliability	533786	Chisholm 69 kV	533832	Ripley 69 kV	1	69			2.37	134/147	Rebuild the 2.37 mile Chisholm - Ripley 69 kV line using single 1192.5 ACSR.
20019	578	10739	WR	06/01/10		M	11/17/08	$25,751,000	WR	36 months	regional reliability	533332	Knob Hill 115 kV	640426	Steele City 115 kV	1	115		28		223/245	New 115 kV Line from Knob Hill to Kansas/Nebraska state line.
20019	577	10738	WR	12/01/10		M	11/17/08	$5,825,000	WR	24 months	regional reliability	533217	Kelly 115 kV	533337	South Seneca 115 kV	1	115	10.3			223/245	Rebuild 10.3 mile line between Kelly and South Seneca.
20033	599	10766	WR	12/31/10		M	01/27/09	$3,890,000	WR	12 months	regional reliability	533182	Tecumseh Hill 115 kV	533187	27th & Croco 115 kV	1	115	2.72			223/240	Tear down and rebuild the 2.72 mile Tecumseh Hill - 27th & Croco 115 kV line as a single circuit.
20059	30228	50235	WR	06/01/10			09/18/09	$115,000	WR	12 months	transmission service	533646	Tioga 69 kV	533666	Chanute TAP 69 kV	1	69	4.82			72/72	Replace Jumpers to achieve a minimum 600 amp emergency rating.
20059	30229	50237	WR	06/01/10			09/18/09	$600,000	WR		transmission service	510422	Coffeyville Tap 138 kV	533002	Dearing 138 kV	1	138				382/382	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers with a minimum 2000 amp emergency rating equipment
20059	30224	50238	WR	07/01/10			09/18/09	$3,335,500	WR	18 months	transmission service	533636	Green 69 kV	533631	Coffey County No. 4 Vernon 69 kV	1	69	7.19			116/128	Rebuild approximately 7 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
20059	561	10711	WR	06/01/10		M	09/18/09	$5,513,000	WR	12 months	transmission service	533041	Evans Energy Center South 138 KV	533053	Lakeridge 138 KV	1	138				382/413	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers a minimum 2000 amp emergency rating
		Year 2011																				
	283	10367	AECI	06/01/12					SPP		inter-regional	96272	Blackberry 345 kV	300740	Sportsman Acres 345	1	345		108		1369/1369	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Chouteau 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Chouteau 345kV bus a 345/161 transformer connects to Chouteau 161kV sub.
	283	10368	AECI	02/01/11					SPP		inter-regional	300740	Sportsman Acres 345	512650	GRDA 1 345 kV	1	345		5		977/977	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	283	10369	AECI	02/01/11				$57,000,000	SPP		inter-regional	300740	Sportsman Acres 345 kV	300741	Sportsman Acres 161 kV	1	345/161				505/505	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	283	10916	AECI	02/01/11					SPP		inter-regional	300740	Sportsman Acres 345 kV	300741	Sportsman Acres 161 kV	2	345/161				505/505	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	283	10781	AECI	02/01/11					SPP		inter-regional		Sportsman Acres 161kV	300069	Chouteau 161 kV		161				1067/1067	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	350	10459	AEP	12/31/11				$277,000	AEP	60 months	Generation Interconnect	508054	Bann 138 kV	508075	Red Springs REC 138 kV	1	138				224/261	Replace breaker 3310.
	349	10446	AEP	06/01/11		M		$7,810,000	AEP	60 months	Generation Interconnect	507402	Ashdown REC (Millwood) 138 kV	507428	Okay 138 kV	1	138			14.3	368/512	Reconductor and convert line to 138 kV and replace switches at Ashdown REC
	349	10447	AEP	12/31/11		M		$11,431,000	AEP	60 months	Generation Interconnect	507402	Ashdown REC (Millwood) 138 kV	507431	Patterson 138 kV	1	138			5	368/512	Reconductor line and convert line to 138 kV. Convert Patterson station to breaker-and-a half configuration.
	349	10448	AEP	12/31/11		M		$1,773,000	AEP	60 months	Generation Interconnect	507409	McNab REC 115 kV	507456	Turk 115 kV	1	115		1.5		150/174	Build new McNab-Turk 115 kV line
	349	10451	AEP	12/31/11		M		$3,266,000	AEP	60 months	Generation Interconnect	507427	Okay 69 kV	507428	Okay 138 kV	1	138/69				83/92	Convert 115-69 kV station to 138-69 kV.
	349	10452	AEP	12/31/11		M		$8,170,000	AEP	60 months	Generation Interconnect	507428	Okay 138 kV	507454	Turk 138 kV	1	138	12	2		368/512	Build two mile, 138 kV, 1590ACSR line section from Turk Sub to existing Okay-Hope 115 kV line and rebuild twelve miles of 115 kV line to Okay Sub to 138 kV, 1590 ACSR , to form a Turk-Okay 138 kV line
	349	10457	AEP	12/31/11		M		$7,806,000	AEP	48 months	Generation Interconnect	507456	Turk 115 kV	507454	Turk 138 kV	1	138/115				175/234	Build Turk 138-115 kV station and relocate autotransformer (and spare) from Patterson to this new Turk station.
20027	452	10586	AEP	06/01/11		M	01/27/09	$350,000	AEP	18 months	regional reliability	508575	Whitney 138 kV	508574	Whitney 69 kV	1 & 2	138/69				140/170	Replace one breaker and four switches.
20016	349	10449	AEP	12/31/11		M	01/16/09	$540,000	AEP	60 months	transmission service	504122	McNab REC 115 kV	507456	Turk 115 kV	1	115	0.5			307/398	Reconductor about 0.5 miles of 666 ACSR with 1590 ACSR
20016	349	10450	AEP	12/31/11		M	01/16/09	$2,170,000	AEP	60 months	transmission service	504122	McNab REC 115 kV	507453	Hope 115 kV	1	115	3.55			307/398	Reconductor 3.55 miles of 666 ACSR with 1590 ACSR
20048	446	10578	AEP	06/01/11			09/18/09	$13,100,000	AEP	24 months	transmission service	510386	North Bartlesville 138 kV	510422	Coffeyville Tap 138 kV	1	138	13.11			287/287	Rebuild approximately 13 miles of line with 1590 ACSR to achieve a minimum 2000 Amp emergency rating
20048	454	10588	AEP	06/01/11			09/18/09	$8,400,000	AEP	24 months	transmission service	510391	Bartlesville Southeast 138 kV	510386	North Bartlesville 138 kV	1	138	8.37			280/287	Rebuild approximately 8.5 miles of line with 1590 ACS to achieve a minimum 2000 Amp emergency rating & reset relays at Bartlesville Southeast accordingly
	287	10373	DETEC	06/01/11				$11,299,000			zonal - sponsored	97813	Etoile 138 kV		Chireno 138 kV	1	138		12.5		215/225	Build 12 miles of 138 kV from Etoile - Chireno
19970	499	10644	EDE	06/01/11		M	01/10/08	$4,000,000	EDE	36 months	transmission service	547467	ORO110 5 161 IV	547534	ORO110 2 69 kV	1	161/69				150/150	Replace Auto transformer at ORONOGO 110 with 150 MVA rated Auto transformer due to increased generation available
19970	352	10730	EDE	06/01/11		M	01/10/08	$5,750,000	EDE	36 months	transmission service	547467	Sub 110 - Oronogo Jct.	547469	Sub 167 - Riverton	1	161	11.9			299/335	Reconductor 11.9 miles of Oronogo Jct. to Riverton 161kV Ckt. 1 from 556 ACSR to 795 ACSR, change CT settings @ Oronogo, and replace wavetrap.
	284	10370	EES	06/01/11		06/01/10		$6,000,000		36 months	inter-regional	338099	Grandview 161 kV	338682	Osage 161 kV	1	161		5.34		247/247	Entergy Planning has identified this proposed project as installing a new switching station, Grandview, on the existing 161 kV line between Table Rock Dam and Eureka Springs substation and constructing a new 161 kV line between Grandview and the existing Osage Creek substation.
20034	634	10830	GMO	11/01/11		M	01/27/09	$2,369,625	GMO	24-30 months	regional reliability	542998	Loma Vista 161 kV	541245	KC South 161 kV	1	161		4		293/335	Tap the Montrose - LomaVista 161 kV Line into KC South 161 kV substation. This project is an alternative to replace the reconductor project of the Duncan Rd - Blue Spring East and Martin City - Grandview East 161 kV lines.
	334	10431	GMO	06/01/11		M		$7,096,402	GMO	24-36 months	zonal - sponsored	541316	Lone Jack 161 kV	541218	Greenwood 161 kV	1	161		4		223/245	Radial Line From Greenwood to a new distribution sub at Lone Jack
	331	10428	GMO	06/01/11				$2,418,750	SPP	6-12 months	zonal - sponsored	541352	Clinton 161 kV				161					Tap Clinton AECI (300071) to Clinton MIPU (541242) with new Clinton bus and tie in existing Clinton transformer into new bus.
20034	650	10854	GMO	06/01/11		M	01/27/09	$2,259,673	GMO	18 months	regional reliability	542969	Stillwell 161 kV	541207	Archie 161 kV	1	161		3.6		293/335	Tap Stilwell - Archie Junction 161 kV line into South Harper 161 kV sub and make it two new 161 kV sections: Stilwell - South Harper and Archie Junction - South Harper.
	278	10361	GMO	06/01/11		M		$893,868	GMO	12~18 months	zonal - sponsored	541224	Longview 161 kV	541345	Sampson 161 kV	1	161				223/245	161kV Tap of Longview to Grandview East
	278	10362	GMO	06/01/11		M		$0	GMO	12~18 months	zonal - sponsored	541345	Sampson 161 kV	541223	Grandview East 161 kV	1	161				223/245	161kV Tap of Longview to Grandview East
	273	10356	GMO	06/01/11		M		$1,350,000	GMO	12~18 months	zonal - sponsored	541353	Cookingham 161 kV	541247	Liberty West 161 kV	1	161				223/245	161kV Tap of Nashua to Liberty West
	273	10357	GMO	06/01/11		M			GMO	12~18 months	zonal - sponsored	541203	Nashua 161 kV	541353	Cookingham 161 kV	1	161				223/245	161kV Tap of Nashua to Liberty West
20056	30223	50227	GMO	06/01/11			09/18/09	$4,400,000	SJLP	18 months	transmission service	541253	ST Joe 161 KV	541257	Cook 161 KV	1	161	4.6			446/446	Reconductor the line from 1192 ACSR to 1192 ACSS and rebuild the line terminals to 2000 amp capability
20001	393	10511	GRDA	06/01/11	NTC-Modify Timing	06/01/10	02/13/08	$2,500,000	GRDA	24 months	regional reliability	512632	Afton161 kV	512633	Afton 69 kV	1	161/69				50/50	Add 50MVA 161/69 kV transformer #2 at Afton.
	302	10390	GRDA	12/01/11		M		$8,019,000	GRDA	24 months	zonal - sponsored	512750	Siloam Springs Tap 345 kV	512751	Siloam Springs Tap 161 kV	1	345/161				75/140	Tap the GRDA 1-Flint Creek 345 kV line and build a 345/161 transformer. Then build a 161 kV line down to Siloam Springs.
20050	394	10512	GRDA	06/01/11			09/18/09	$10,450,000	GRDA	24 months	regional reliability	512634	Kerr 161 kV	512629	Pensacola 115 kV	1	161			22	162/186	Rebuild approximately 22 miles of line with 795 ACSR
20051	30218	50222	KCPL	06/01/11			09/18/09	$2,200,000	KCPL	24 months	transmission service	542969	Stilwell 161 kV	543053	Redel 161 kV	1	161	4.4			557/557	Reconductor line and upgrade terminal equipment for 2000 amps
	609	10924	OPPD	12/31/11	NTC	M			OPPD		regional reliability	646341	SUB 1341 161 kV				161					Build new 161-kV substation Sub 1341. Remove 0.06 mile of 161 kV line from Sub 1251- Sub 1305.
	609	10925	OPPD	12/31/11	NTC	M		$16,300,000	OPPD		regional reliability	646341	SUB 1341 161 kV	646251	SUB 1251 161 kV	1	161		1	0.41		Tap 161-kV line from Sub 1251 to Sub 1305 and route it into and out of new 161-kV substation Sub 1341.
	609	10926	OPPD	12/31/11	NTC	M			OPPD		regional reliability	646341	SUB 1341 161 kV	646305	SUB 1305 161 kV	1	161		1	0.34		Tap 161-kV line from Sub 1251 to Sub 1305 and route it into and out of new 161-kV substation Sub 1341.
	310	10392	OGE	03/31/11		M		$543,000	OGE		zonal - sponsored	515353	Great Lakes Carbon 161 kV	515352	Altus 161 kV	1	161			2	134/143	Conversion from 69kV to 161kV
	310	10394	OGE	03/31/11		M		$2,994,000	OGE		zonal - sponsored	515355	Igo 161 kV	515354	Noark 161 kV	1	161			10	134/143	Conversion from 69kV to 161kV
	310	10396	OGE	03/31/11		M		$522,000	OGE		zonal - sponsored	515354	Noark 161 kV	515353	Great Lakes Carbon 161 kV	1	161			2	134/143	Conversion from 69kV to 161kV
	895	11190	OGE	04/01/11		M		$1,300,000	OGE	12 months	zonal - sponsored	514870	Stonewall138 kV	514872	Remington Park 138 kV	1	138				268/308	Three terminal line will be upgraded to 2000A with breakers. Limiting equipment will be 795AS33 conductor.
20017	30158	50166	OGE	06/01/11		M	01/16/09	$1,400,000	OGE	24 months	transmission service	515163	Rocky Point 69 kV	515166	Ardmore 69 kV	1	69	4.65			72/72	Replace 4.65 miles of line with 477AS33
20017	30162	50170	OGE	06/01/11		M	01/16/09	$50,000	OGE	12 months	transmission service	515135	Sunnyside 138 kV	515137	Uniroyal 138 kV	1	138				194/222	Replace wavetrap 800A at Uniroyal
20017	30159	50167	OGE	06/01/11		M	01/16/09	$300,000	OGE	12 months	transmission service	515142	Dillard 138 kV	515141	Healdton Tap 138 kV	1	138				191/191	Replace Differential Relaying
20029	615	10792 & 10793	OGE	06/01/11		M	01/27/09	$5,404,250	OGE	18 months	regional reliability	515377	Crescent 138 kV	514827	Cottonwood Creek 138 kV	1	138			13.64	84/104	Convert 13.64 miles of 69 kV to 138 kV from Crescent to Cottonwood Creek and install terminal equipment at Cottonwood Creek, completing loop from Crescent to Twin Lakes (WFEC).
	896	11188	OGE	05/30/11		M					zonal - sponsored	515048	Keystone West 138 kV	515369	Bell Cow 138 kV	1	138				268/287	Bell Cow Sub is delayed until 2011. Install Bell Cow sub and associated lines, remove chandler sub.
	896	11189	OGE	05/30/11		M					zonal - sponsored	515047	Warwick 138 kV	515369	Bell Cow 138 kV	1	138				268/287	Bell Cow Sub is delayed until 2011. Install Bell Cow sub and associated lines, remove chandler sub.
	304	10731	OGE	06/01/11		M			OGE		zonal - sponsored	515150	Caney Creek 138 kV			1	138					At Caney Creek remove 2 existing line terminals to the north and expand the 138 kV bus north into a ring bus
	304	10732	OGE	06/01/11		M			OGE		zonal - sponsored	514808	Johnson County 138 kV	515150	Caney Creek 138 kV	1	138		25			Construct 25 miles of 138 kV of 795AS33 line from the new Johnson County sub to Caney Creek.
	304	10733	OGE	06/01/11		M			OGE		zonal - sponsored	515809	Johnson County 345 kV	514808	Johnson County 138 kV	1	345/138				400/400	Build a new 345 EHV substation in the Sunnyside to Pittsburg line. Install a 400 MVA transformer with 3-345kv breakers in a ring bus and 4-138kv breakers in a ring bus at new Johnson County sub.
	304	10734	OGE	06/01/11		M		$32,975,000	OGE		zonal - sponsored	515136	Sunnyside 345 kV	514809	Johnson County 345 kV	1	345					Replace relays at Sunnyside 345 kV
	304	10735	OGE	06/01/11		M			OGE		zonal - sponsored	515809	Johnson County 345 kV	510907	Pittsburg 345 kV	1	345					Replace relays at Pittsburg 345 kV
	304	10820	OGE	06/01/13		M			OGE		zonal - sponsored	514808	Johnson County 138 kV	515121	Millcreek	1	138				191/191	Tap the MillCreek to Russett 138 kV into the New Johnson County substation
	304	10821	OGE	06/01/13		M			OGE		zonal - sponsored	514808	Johnson County 138 kV	515120	Russett 138 kV 138 kV	1	138	2.99			287/287	Tap the MillCreek to Russett 138 kV into the New Johnson County substation and reconductor Jonson County to Russett Sub with 795 AS33

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	582	10747	OGE	06/01/11		M		$1,900,000	OGE		zonal - sponsored	514827	Cottonwood Creek 138 kV	514907	Arcadia 138 kV	1	138				268/287	Install Terminal equipment to remove Three terminal line
	582	10748	OGE	06/01/11		M			OGE		zonal - sponsored	514907	Arcadia 138 kV	529272	Garber 138 kV	1	138				268/287	Install Terminal equipment to remove Three terminal line
20041	709	10946	OGE	12/31/11		M	06/19/09	$15,000,000		24 months	Balanced Portfolio	515800	Anadarko (Gracemont) 345 kV	515802	Gracemont 138 kV	1	345/138				448/493	Tap Lawton East Side to Cimarron 345 kV line at Anadarko and build substation. Install a 345/138 kV transformer in substation.
20002	396	10514	OGE	10/01/11		M	02/13/08	$1,000,000	OGE	12 months	regional reliability	515156	Bodle 138 kV	515155	Bodle 138 kV	1	138					Install a 138 kV breaker at Bodle to close the normally open switch. Breaker connects 515155 Bodle 138 kV to 515156 Bodle138 kV.
	165	10214	SEPC	09/01/11		M		$10,500,000	SEPC	24 months	zonal - sponsored	539685	Phillipsburg 115 kV	531373	Rhoades 115 kV	1	115		35		165/198	Build new 35 mile Phillipsburg - Rhoades 115 kV.
20007	166	10215	SEPC	09/01/11		M	02/13/08	$3,650,000	SEPC	18 months	regional reliability	531448	Holcomb 115 kV	531393	Plymell 115 kV	1	115	11.96			230/276	Rebuild 12 mile Holcomb - Plymell 115 kV.
20014	367	10480	SEPC	09/01/11		M	09/18/08	$3,200,000	SEPC	24 months	regional reliability	531393	Plymell 115 kV	531392	Pioneer Tap 115 kV	1	115	14.87			230/276	Rebuild 15 mile Holcomb - Pioneer Tap 115kV.
	791	11040	SPS	12/22/11	NTC	06/01/10		$11,250,000	SPP	24 months	regional reliability	525461	Newhart 230 kV	525460	Newhart 115 kV	1	230/115				150/173	Tap the Potter Interchange - Plant X Station 230 kV line for new Newhart Substation install 230/115 kV 150/173 MVA transformer.
	824	11090	SPS	12/22/11	NTC	06/01/10		$11,250,000	SPP	24 months	regional reliability	527894	Hobbs Interchange 230 kV	527895	Hobbs Interchange 345 kV	1	345/230/13.2				515/560	New 345/230 kV transformer rated 515/560 MVA at Hobbs Interchange.
	824	11091	SPS	12/22/11	NTC	06/01/10		$11,250,000	SPP	24 months	regional reliability	527915	Midland 345 kV	522992	Midland 138 kV	1	345138/13.2				400/440	New 345/138 kV transformer rated 400/440 MVA at Midland.
	779	11029	SPS	06/25/11	NTC	06/01/10		$3,000,000	SPP	18 months	regional reliability	528355	Maddox Station 115 kV	528463	Sanger Switching Station 115 kV	1	115	6.15			226/249	Reconductor 6.15 mile Maddox - Sanger Switching Station 115kV line for 226/239 MVA rating.
	774	11019	SPS	08/24/11	NTC	06/01/10		$112,500	SPP	20 months	regional reliability	524010	Cherry Sub 230 kV	523959	Potter County Interchange 230 kV	1	230		0.1		218/239	New Tap to new Cherry 230/115 kV Transformer.
	774	11020	SPS	08/24/11	NTC	06/01/10		$4,905,000	SPP	20 months	regional reliability	524010	Cherry Sub 230 kV	524009	Cherry Sub 115 kV	1	230/115				218/239	New 230/115 kV Autotransformer at Cherry Substation.
20031	590	10757	SPS	06/01/11		06/01/10	01/27/09	$1,222,843	SPS	24 months	regional reliability	528160	Carlsbad Interchange 115 kV	528131	Ocotillo Sub 115 kV	1	115			8	54/54	Convert 8 miles of 69 kV to 115 kV from Carlsbad Interchange - Ocotillo. Convert Ocotillo substation to 115 kV.
20004	156	10325	SPS	06/01/11		M	02/13/08	$11,922,643	SPS		zonal - sponsored	523267	Pringle Interchange 230 kV	523095	Hitchland 230 kV	1	230		34		492/541	Add 230 kV line from Pringle to Hitchland - 541 MVA.
20004	156	10330	SPS	06/01/11		M	02/13/08	$10,766,250	SPS	48 months	regional reliability	523095	Hitchland 230 kV	523155	Ochiltree 230 kV	1	230		35		492/541	Add 230 kV line from Hitchland to Ochilltree - 541 MVA.
20004	156	10331	SPS	06/01/11		M	02/13/08	$5,846,295	SPS	24 months	regional reliability	523158	Perryton Interchange 115 kV	523155	Ochiltree 230 kV	1	230/115				150/172.5	Add 2-Winding 230/115 kV transformer at Ochiltree – 172.5 MVA
	783	11033	SPS	08/24/11	NTC	06/01/10		$11,250,000	SPP	20 months	regional reliability	524365	Randall County Interchange 230 kV	524364	Randall County Interchange 115 kV	2	230/115				224/239	Install second 230/115 kV transformer in Randall substation.
20031	632	10822	SPS	06/01/11		M	01/27/09	$3,937,500	SPS	24 months	regional reliability	527346	Legacy Interchange 115 kV (new interchange	527349	Boardman Tap 69 kV	1	115/69				40/46	Tap line from Tenneco - Boardman Tap 69 kV and add new 75/75 MVA 115/69 kV transformer at new Legacy Interchange substation.
20031	632	10823	SPS	06/01/11		M	01/27/09	$3,375,000	SPS	24 months	regional reliability	527340	Doss Interchange 115 kV	527346	Legacy Interchange 115 kV (new interchange and sub)	1	115		6		90/99	Build new 6 mile 115 kV line from Doss Interchange - Legacy Interchange.
20031	632	10824	SPS	06/01/11		M	01/27/09	$3,093,750	SPS	24 months	regional reliability	527322	Gaines County Interchange 115 kV	527346	Legacy Interchange 115 kV (new interchange and sub)	1	115		5.5		90/99	Build new 5.5 mile 115 kV line from Gaines County Interchange - Legacy Interchange.
20031	633	10825	SPS	04/15/11		M	01/27/09	$3,285,000	SPS	36 months	regional reliability	527710	Eagle Creek 69 kV (new sub)	527711	Eagle Creek 115 kV (new sub)	1	115/69				40/46	Tap line 69 kV from Navajo No. 2 - Navajo No. 4, tap line 115 kV from Navajo No. 3 - Navajo No. 4, and install Eagle Creek Substation and 115/69 kV transformer.
20031	633	10826	SPS	04/15/11		M	01/27/09	$281,250	SPS	36 months	regional reliability	527743	Navajo No.5 Sub 115 kV (new sub)	527739	Navajo No.4 Sub 115 kV	1	115		0.5		179/197	Build new 0.5 mile 115 kV line from new Navajo No. 5 substation - Navajo No. 4 substation 115 kV.
20031	633	10827	SPS	04/15/11		M	01/27/09	$281,250	SPS	36 months	regional reliability	527742	Navajo No.5 Sub 115 kV (new sub)	527720	Navajo No.3 Sub 115 kV	1	115		0.5		179/197	Build new 0.5 mile 115 kV line from new Navajo No. 5 substation - Navajo No. 3 substation 115 kV.
20031	633	10828	SPS	04/15/11		M	01/27/09	$1,350,000	SPS	36 months	regional reliability	527747	Artesia Town Sub 69 kV	527775	Artesia South Rural Sub 69 kV	1	69		3		179/197	Build new 3 mile 69 kV line from Artesia Town - Artesia South Rural 69 kV.
20031	696	10829	SPS	06/01/11		06/01/11	01/27/09	$4,716,600	SPP		regional reliability	527482	Chaves County Interchange 115 kV	527564	Roswell Interchange 115 kV	1	115			11.18	54/54	Convert 11.8 miles of 69 kV line to 115 kV from Chaves County - Price - Central Valley REC-Pine Lodge - Capitan - Roswell. SPS-provided mitigation was verified by SPP staff until 12/2012 when the conversion will be completed.
	786	11036	SPS	06/25/11	NTC	06/01/11		$1,417,500	SPP	18 months	regional reliability	528355	Maddox Station 115 kV	528491	Monument Sub 115 kV	1	115	3.36			226/249	Reconductor 3.36 mile Maddox - Monument CKT 1 115 kV with 795 ACSR.
	829	11096	SPS	12/22/11	NTC	06/01/11		$1,935,000	SPP	24 months	regional reliability	523711	Kingsmill 69 kV	523712	Kingsmill 115 kV	2	115/69				75/86	Install second 115/69 kV transformer rated 75/86 MVA at Kingsmill.
19987	150	10194	SPS	-		06/01/11	02/02/07	$1,250,000	SPS	18 months	regional reliability	525191	Kress 69 kV	525192	Kress 115 kV	2	115/69				84/84	Upgrade #2 Transformer
	857	11196	SPS		NTC	06/01/11		$596,250	SPP	24 months	regional reliability	524162	East Plant 115 kV	524185	Pierce 115 kV	1	115	1.06			246/271	Reconductor EAST PLANT-PIERCE 1.06 miles 115 kV to 795 ACSR line
	580	10741	SWPA			12/01/11		$3,150,000	SPP		regional reliability - non OATT	505412	Paragould 161 kV	505414	Paragould 69 kV	1 & 2	161/69				70/70	Replace Paragould auto transformers 1 and 2 with 70 MVA units.
	612	10944	SWPA	06/01/11		06/01/10		$165,000	SPP	12 months	regional reliability - non OATT		Dardanelle 161 kV		Russellville South 161 kV	1	161				374/374	Replace wave trap, disconnect switches, current transformers, and breaker at Dardanelle
20044	705	10938	WFEC	12/31/11		M	06/19/09	$200,000			Balanced Portfolio		Anadarko (Gracemont) Tap 138 kV			1	138					Tap the existing WFEC Anadarko - Washita 138 kV line into the new Gracemont 345 kV substation.
19951	357	10467	WFEC	06/01/11		M	01/02/07	$2,000,000	WFEC	16 months	transmission service	520814	Anadarko 138 kV	520810	Anadarko 69 kV	2	138/69				224/224	'Install 2nd 112 MVA auto in parallel with existing Unit
20003	361	10471	WFEC	06/01/11		M	02/13/08	$2,000,000	WFEC	16 months	regional reliability	520911	Fletcher 69 kV	520990	Marlow Jct 69 kV	1	69	7			91/114	Upgrade 7 miles to 795 ACSR from Fletcher SW to Marlow Junction 69 kV.
	845	11114	WFEC		NTC	06/01/11		$225,000	SPP	12 months	regional reliability	521051	Snyder 69 kV	521070	Tipton 69 kV	1	69				53/65	Upgrade Snyder CTs from 400A to 600A.
20003	238	10303	WFEC	01/01/11		M	02/13/08	$8,265,000	WFEC	12 months	regional reliability	521188	Atoka West 138 kV	505600	Tupelo (WFEC) 138 kV	1	138		6.5		262/329	WFEC will build a double circuit 138 kV line, approximately 6.5 miles long, from AEP's Atoka substation to the south and looping into the WFEC Tupelo-Lane 138 kV line - Atoka to Tupelo line.
20003	238	10304	WFEC	01/01/11		M	02/13/08		WFEC	12 months	regional reliability	521187	Atoka East 138 kV	520968	Lane (WFEC) 138 kV	1	138		6.5		262/329	WFEC will build a double circuit 138 kV line, approximately 6.5 miles long, from AEP's Atoka substation to the south and looping into the WFEC Tupelo-Lane 138 kV line - Atoka to Lane line.
20033	266	10349	WR	06/01/11		M	01/27/09	$710,000	WR	18 months	regional reliability	533421	Hutchinson Gas Turbine Station 115 kV	533413	Circle 115 kV	1	115	0.23			223/245	Rebuild 0.23 mile Circle - HEC GT 115 kV line.
20033	491	10636	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$2,085,000	WR	18 months	regional reliability	533234	Bismark 115 kV	533236	Farmer's Consumer Co-op 115 kV	1	115	2.9			181/181	Rebuild 2.9 mile Bismark - Farmer's Consumer Co-op 115 kV.
20006	369	10482	WR	06/01/11		M	02/13/08	$2,000,000	WR	18 months	regional reliability	533271	SW Lawrence 115 kV	533277	Wakarusa 115 kV	1	115	4.09			223/240	Rebuild SW Lawrence - Wakarusa 115 kV line.
20006	370	10483	WR	06/01/11		M	02/13/08	$760,000	WR	18 months	regional reliability	533236	Farmer's Consumer Co-op 115 kV	533277	Wakarusa 115 kV	1	115	1.53			223/240	Rebuild 1.53 miles Co-op-Wakarusa 115 kV line
	660	10866	WR		NTC	06/01/11		$3,324,375	SPP	18 months	regional reliability	533045	Gill W4 138 kV	533036	Clearwater 138 kV	1	138	7.88			534/586	Tear down and rebuild 7.88 mile Gill - Clearwater 138 kV.
20033	493	10638	WR	06/01/11		M	01/27/09	$8,050,000	WR	15 months	regional reliability	533244	Jarbalo 115 kV	533268	Stranger Creek 115	2	115	7.1			223/240	Rebuild Jarbalo - Stranger Ckt 2 7.1 miles of 115 kV and tap the existing Jarbalo - Northwest Leavenworth line into Stranger.
20033	493	10639	WR	06/01/11		M	01/27/09		WR	15 months	regional reliability	533268	Stranger Creek 115	533259	NW Leavenworth	1	115	6.5			223/240	Rebuild Stranger - Northwest Leavenworth 6.5 miles of 115 kV and tap existing Jarbalo - Northwest Leavenworth line into Stranger.
20033	618	10806	WR	12/01/11		M	01/27/09	$17,437,500	SPP	24 months	regional reliability	533333	KSU Campus 115 KV	533345	Wildcat 115 kV	1	115				223/223	Tap KSU - Wildcat 115 kV into Northwest Manhattan.
20033	618	10808	WR			M	01/27/09	$11,250,000	SPP	18 months	regional reliability	539658	Concordia 230 kV	532861	East Manhattan 230 kV	1	230				280/308	Tap the Concordia - East Manhattan 230 kV line and build new Northwest Manhattan 230/115 kV substation.
20059	30224	50239	WR	12/01/11		06/01/11	09/18/09	$3,811,500	WR	18 months	transmission service	533638	Lehigh Tap 69 kV	533651	Owl Creek 69 kV	1	69	8.47			72/72	Rebuild approximately 8.5 miles of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating.
20059	30224	50232	WR	04/01/11			09/18/09	$1,418,500	WR	18 months	transmission service	533623	Athens Switching Station 69 kV	533642	Owl Creek 69 kV	1	69	2.93			72/72	Rebuild approximately 3 miles of line with 954 kcmil ACSR to achieve a minimum 600 amp emergency rating.
20059	30230	50241	WR	06/01/11			09/18/09	$250,000	WR	6 months	transmission service	533021	Neosho 138 kV	533005	Northeast Parsons 138 kV	1	138				203/203	Replace bus and Jumpers at NE Parsons 138 kV substation
20059	30231	50242	WR	06/01/11			09/18/09	$9,360,000	WR		Zonal Reliability	532992	Timber Junction 138 kV	532984	Summer County Tap 138 KV	1	138	12				Tap Belle Plaine-Oxford 138 kV line, build a 3-breaker ring bus switching station, build approximately 12 miles 138 kV line from Sumner County 138 kV to Timber Junction 138 kV, and Install Timber Junction. 138-69 kV 100 MVA transformer with LTC.
20059	30224	50245	WR	01/01/11			09/18/09	$2,426,500	WR	18 months	transmission service	533631	Coffey County No. 4 Vernon 69 kV	533623	Athens Switching Station 69 kV	1	69	5.17			116/128	Rebuild approximately 5 miles of line with 954-KCM ACSR to achieve a minimum 1200 amp emergency rating.
20059	622	10810	WR	06/01/11			09/18/09	$2,815,000	WR	12 months	Zonal Reliability	533837	Roshe Hill Junction 69 kV	533550	Richland 69 kV	1	69	5.43			72/72	Rebuild approximately 5.5 mile Rose Hill Junction-Richland
20033	600	10767	WR	12/31/11		M	01/27/09	$3,227,500	WR	12 months	regional reliability	533188	27TH & Croco Junction 115 KV	533160	41ST & California 115 KV	1	115	3.43			223/240	Tear down and rebuild the 3.43 mile 27th & Croco - 41st & California 115 kV line as a single circuit.
20006	321	10417	WR	06/01/11		M	02/13/08	$1,292,500	WR	12 months	regional reliability	533824	Oaklawn 69 kV	533826	Oliver 69 kV	1	69	2.11			116/128	Tear down/rebuild 1.91-miles of Oaklawn - Oliver 69 kV line replacing 477 kcmil ACSR conductor with 954 kcmil ACSR conductor. Limit would be 0.2-mile 750 kcmil CU underground cable.
20033	267	10350	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$2,500,000	WR	12 months	regional reliability	533736	Halstead 69 kV	533744	Mud Creek Junction 69 kV	1	69	7.3			116/128	Tear down and rebuild 7.3-mile Halstead - Mud Creek 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil ACSR conductor and replace terminal equipment at substations.
20033	267	10351	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$360,000	WR	12 months	regional reliability	533744	Mud Creek Junction 69 kV	533741	Mid-American Junction 69 kV	1	69	1.0			116/128	Rebuild 1.0 mile Mud Creek Junction - Mid-American Junction 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil
20033	267	10352	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$1,300,000	WR	12 months	regional reliability	533741	Mid-American Junction 69 kV	533745	Newton 69 kV	1	69	3.9			116/128	Rebuild 3.9 mile Mid-American Junction - Newton 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil ACSR conductor and replace terminal equipment at substations.
	Year 2012																					
20015	30143	50151	AECC	04/01/12			01/16/09	$165,000	AECC		transmission service	507456	Turk 115	504122	McNab REC 115 kV	1	115					Upgrades to McNab Substation
20015	351	10460	AECC	04/01/12		M	01/16/09	$1,512,000			transmission service	503912	Fulton 115 kV	507453	Hope 115 kV	1	115	3.61			245/301	Reconductor line to 1590 ACSR the Hope-Fulton line. Build at 138 and operate at 115 kV
20015	351	10461	AECC	04/01/12		M	01/16/09	$440,000			transmission service	503912	Fulton 115 kV				115					Upgrade Fulton Switching Station
20016	30157	50165	AEP	04/01/12		M	01/16/09	$8,193,000	AEP	24 months	transmission service	508086	Texarkana Plant 69 kV	504117	South Texarkana REC 69 kV	1	69	5.92			90/121	Rebuild 5.92 miles of 266 ACSR with 795 ACSR. Replace 69 kV switches, jumpers, and reset CTs and relays at Texarkana
20016	30156	50164	AEP	04/01/12		M	01/16/09	$128,000	AEP		transmission service	508077	SE Texarkana 69 kV	508086	Texarkana Plant 69 kV	1	69				114/143	Change out the 500 Cu jumpers at Texarkana Plant.
20016	30155	50163	AEP	04/01/12		M	01/16/09	$80,000	AEP		transmission service	507427	Okay 69 kV	507415	Tollette 69 kV	1	69				71/96	Replace 69 kV switches.
20048	30148	50156	AEP	06/01/12		M	09/18/09	$273,400	AEP	24 months	transmission service	508053	Bann 69 kV	508063	Lone Star Ordinance Tap 69 kV	1	69				73/85	Replace 69 kV switch at Lone Star Ordinance Tap with a minimum 800 amp emergency rating
20016	30152	50160	AEP	06/01/12		M	01/16/09	$456,000	AEP	15 months	transmission service	507748	Powell Street 138 kV	507738	Linwood 138 kV	1	138				260/304	Replace 138 kV breaker, switches, and jumpers at Linwood. Replace circuit switcher at Powell Street.
20016	30142	50148	AEP	04/01/12		M	01/16/09	$48,580,000	AEP	33 months	transmission service	507455	Turk 345 kV	508072	NW Texarkana 345 kV	1	345		33		1336/1915	Build approximately 33 miles of of 2-954 ACSR from Turk to NW Texarkana.
20016	30142	50149	AEP	04/01/12		M	01/16/09		AEP	33 months	transmission service	507455	Turk 345 kV	508072	NW Texarkana 345 kV	1	345				1336/1915	Add 345 kV terminal at NW Texarkana
20016	30142	50150	AEP	04/01/12		M	01/16/09		AEP	33 months	transmission service	507455	Turk 345 kV	508072	NW Texarkana 345 kV	1	345				1336/1915	Add 345 kV terminal at Turk (Hempstead)
20016-1	349	10456	AEP	04/01/12		M	09/18/09	$7,310,000	AEP	60 months	transmission service	507454	Turk 138 kV	507455	Turk 345 kV	1	345/138				675/675	Add Turk 345/138 kV transformer
20016	288	10374	AEP	04/01/12		M	01/16/09	$3,840,000	AEP	24 months	transmission service	520929	Hugo Power Plant 345 kV	510911	Valliant 345 kV	1	345				913/1140	Install 345 kV terminal equipment at Valliant Substation
	875	11155	AEP		NTC	04/01/12		$100,000	AEP	12 months	regional reliability	508080	Sugar Hill 138 kV	508079	Sugar Hill 69 kV	1	138/69				138/180	Replace 69 kV switch 11985 and 1033 AAC jumpers at Sugar Hill.
20027	392	10510	AEP	06/01/12		M	01/27/09	$3,986,000	AEP	18 months	regional reliability	508545	Howell 69 kV	508546	Kilgore 69 kV	1	69	3.49			52/69	Rebuild 3.49 miles of Howell - Kilgore 69 kV 4/0 ACSR with 795 ACSR.
20000	387	10505	AEP	06/01/12		M	02/13/08	$125,000	AEP	15 months	regional reliability	509783	Riverside Station 138 kV	510898	Okmulgee 138 kV	1	138				202/235	Replace wave trap at Okmulgee.
20000	388	10506	AEP	06/01/12		M	02/13/08	$100,000	AEP	15 months	regional reliability	508068	North New Boston 69KV	508067	New Boston 69 kV	1	69				71/96	Replace 2 sets of New Boston switches on terminal to North New Boston.
20000	391	10509	AEP	06/01/12		M	02/13/08	$300,000	AEP	15 months	regional reliability	508297	Lone Star South 138 kV	508313	Pittsburg 138 kV	1	138				280/331	Replace 138 kV wavetraps at both ends. Reset CTs at Lone Star South. Replace138 kV switches & reset relays at Pittsburg.
20000	113	10140	AEP	06/01/12		M	02/13/08	$9,480,000	AEP	24 months	regional reliability	507736	Haughton 138 kV	507751	Red Point 138 kV	1	138			3.2	368/512	Convert Red Point-Haughton to 138 kV, 1590 ACSR (includes Red Point terminal & Haughton station conversion).
20000	113	10141	AEP	06/01/12		M	02/13/08	$19,482,000	AEP	24 months	regional reliability	507741	Mcdade 138 kV	507736	Haughton 138 kV	1	138			11.3	368/512	Convert Haughton-McDade to 138 kV, 1590 ACSR (includes McDade station conversion).
20000	113	10786	AEP	06/01/12		M	02/13/08	$11,988,400	AEP	24 months	regional reliability	507741	Mcdade 138 kV	507791	Caplis 138 kV	1	138		10		368/512	Build new Caplis-McDade 138 kV, 1590 ACSR line
	636	10834	DETEC	06/01/12				$7,617,000			zonal - sponsored		Chireno 138 kV		Martinsville 138 kV	1	138		9.5		215/225	Install new 138 kV line from Chireno to Martinsville
20036	638	10839	EDE	06/01/12	NTC-Modify Timing	06/01/10	01/27/09	$3,520,000	EDE	18 months	regional reliability	547542	SUB 170 - Nichols ST. 69 kV	547529	Sedalia 69 kV	1	69	8.92			54/65	Reconductor 8.92 mile Nichols - Sedalia 69 kV with 556 ACSR and upgrade CTs.
20036	420	10546	EDE	06/01/12		M	01/27/09	$50,000	EDE	6 months	regional reliability	300673	Jamesville 69 kV	547604	SUB 415 - Blackhawk Junction 69 kV	1	69				73/89	Replace jumpers on breaker #6950 at Blackhawk Junction with 556 ACSR for rates 73/89 MVA.
20040	698	10927	GRDA	12/31/12		M	06/19/09	$1,806,000			Balanced Portfolio	514803	Sooner 345 kV	512694	Cleveland 345 kV	1	345				1195/1195	Install terminal equipment at Cleveland Substation
20021	299	10385	GRDA	06/01/12		M	01/16/09	$4,212,500	GRDA	24 months	regional reliability	512714	Kansas Tap 161 kV	512642	W Siloam Springs 161 kV	1	161	8.8			347/403	Reconductor line to 1590 ACSR, A = 347, B = 403. $255K/mile @ 8.8 mi.
20021	299	10386	GRDA	06/01/12		M	01/16/09	$1,700,000	GRDA	24 months	regional reliability	512642	W Siloam Springs 161 kV	512643	Siloam City 161 kV	1	161	4.2			347/403	Reconductor line to 1590 ACSR, A = 347, B = 403. $255K/mile @ 4.2 mi.
	718	10955	GRIS	12/01/12		M		$3,937,500	SPP		regional reliability - non OATT	642073	SUB-F 7 115 kV	640353	ST.LIB 7 115 kV	1	115		7		160/160	Adding 115 kV line from Sub F - Libory. City of Grand Island Owned Transmission Facility that is NOT under SPP OATT
	719	10956	GRIS	04/01/12		M		$200,000	SPP		regional reliability - non OATT	642066	SUB H 115 kV	642072	SUB E 115 kV	1	115				179/179	Upgrade line to 179 MVA. City of Grand Island Owned Transmission Facility that is NOT under SPP OATT.
20018	313	10405	ITCGP	04/01/12		M	01/16/09	$18,000,000	WFEC	24 months	transmission service	521157	Hugo Power Plant 345	510911	Valliant 345 kV	1	345		19		913/1140	Install new line from Valliant 345 kV to Hugo Power Plant with 19 miles of bundled 795 ACSR conductor
20018	314	10406	ITCGP	04/01/12		M	01/16/09	$12,000,000	WFEC	24 months	transmission service	521157	Hugo Power Plant 345 kV	521158	HugoPower Plant 138 kV	1	345/138				500/500	Install new 345/138 kV transformer
20042	702	10934	KCPL	06/01/12		M	06/19/09	$2,000,000			Balanced Portfolio	542965	West Gardner 345 kV									West Gardner 345kV bus cut-in to Swissvale-Stillwell 345 kV line
	377	10490	KCPL	06/01/12		M		$2,622,850	KCPL	18 months	zonal - sponsored	543069	Paola 161 kV	543129	Middle Creek 161 kV	1	161		15		293/335	New Middle Creek sub and Paola-Middle Creek 161kV line
	378	10491	KCPL	06/01/12		M		$12,179,000	KCPL	24 months	zonal - sponsored	543058	North Louisburg 161 kV	543129	Middle Creek 161 kV	1	161		12		293/335	New North Louisburg-Middle Creek 161kV line
	414	10540	KCPL			M		$3,756,500	KCPL	24 months	zonal - sponsored	543054	Cedar Niles	543131	Clare 161 kV	1	161		4.5		293/335	New Cedar Niles-Clare 161 kV Line & Clare substation
20009	417	10543	KCPL	06/01/12		M	02/13/08	$13,000	KCPL	6 months	regional reliability	543015	Avondale 161 kV	543016	Gladstone 161 kV	1	161				293/335	Upgrade wavetrap at Gladstone from 800 A to 1200 A
	823	11086	LEA			06/01/12		$1,000,000	SPP	24 months	regional reliability - non OATT	527362	LE_ERF 115 kV	527361	LE_ERF 69 kV	1	115/69				44/44	New substation and transformer 115/69 kV 44 MVA
	823	11087	LEA			06/01/12		$1,000,000	SPP		regional reliability - non OATT	527361	LE_ERF 69 kV	528768	Lea- Ancell 69 kV	1	69				41/54	New Line 69 kV
	823	11088	LEA			06/01/12		$1,000,000	SPP		regional reliability - non OATT	527361	LE_ERF 69 kV	528776	Lea- Gaines 69 kV	1	69				41/54	New Line 69 kV
20046	707	10941	MIDW	06/01/12		M	06/19/09	$3,000,000			Balanced Portfolio	530583	Wolf 345 kV	530584	Wolf 230	1	345/230				373/373	Install new 345/230 kV transformer at Wolf
	717	10954	NPPD	11/01/12		M		$5,625,000	NPPD	48 months	zonal - sponsored	640436	Clarks 115 kV	640434	CEN.C.N7 115 kV	1	115		10		174/174	Tap CENCITY7 - Silver Creek 115 kV at CLARKS7. Build new 115 kV line from CLARKS7 - CEN.C.N7. Radial 115 kV line for TransCanada Keystone XL project.
	732	10969	NPPD	11/01/12		M		$16,031,250	NPPD	48 months	zonal - sponsored	640305	Oneill 115 kV	640441	Stuarts 115 kV	1	115		28.5		174/174	Build new line from Oneill to new STUARTS7. Radial 115 kV line for TransCanada Keystone XL project.
	738	10975	NPPD	11/01/12		M		$19,687,500	NPPD	48 months	zonal - sponsored	640318	Petersburg 115 kV	640437	Ericson 115 kV	1	115		35		174/174	Build new line from Petersburg to new ERICSON7. Radial 115 kV line for TransCanada Keystone XL project.
	749	10986	NPPD	06/01/12	NTC	06/01/12		$2,000,000	NPPD	24 months	regional reliability	640265	Maloney 115 kV	640287	North Platte 115 kV	1	115				155/155	Uprate conductor and terminal equipment to 100 Deg Rating by 2012. 155 MVA normal continuous rating. 155 MVA 4-hour emergency rating.
	818	11080	NPPD	06/01/12	NTC	06/01/12		$1,000,000	NPPD	24 months	regional reliability	640259	Loup City 115 kV	640284	North Loup 115 kV	1	115				137/137	Uprate conductor and terminal equipment to 100 Deg Rating by 2012. 137 MVA normal continuous rating. 137 MVA 4-hour emergency rating.
	629	11151	NPPD	06/01/12	NTC	M			NPPD	48 months	regional reliability	640387	Twin Church 115 kV	640424	South Sioux City 115 kV	1	115		5.5		266/266	Build new 5.5 miles double circuit line from Twin CH- new South Sioux City sub. Includes rebuild of Twin Church sub and new South Sioux City sub.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	629	11206	NPPD	12/31/08		M		$33,000,000	NPPD		zonal - sponsored	640387	Twin Church 115 kV	640080	Belden 115 kV	1	115				99/99	Rate B was increased from 88 MVA to 99 MVA by replacing substation terminal equipment.
	629	11152	NPPD	06/01/12	NTC	M			NPPD	48 months	regional reliability	640387	Twin Church 115 kV	640424	South Sioux City 115 kV	2	115		5.5		266/266	Build new 5.5 miles double circuit line from Twin CH- new South Sioux City sub. Includes rebuild of Twin Church sub and new South Sioux City sub.
20029	583	10749	OGE	03/31/12		M	01/27/09	$4,972,000	OGE	12 months	regional reliability	515339	VBI 161 kV	515406	Adabell 161 kV	1	161				223/223	Install new tap for Adabell substation.
20029	583	10749	OGE	03/31/12		M	01/27/09	$4,972,000	OGE	12 months	regional reliability	515348	Aloca Tap 161 kV	515406	Adabell 161 kV	1	161				223/223	Install new tap for Adabell substation.
20055	523	10668	OGE	06/01/12		M	09/18/09	$45,000,000	OGE	42 months	regional reliability	514803	Sooner 345 kV	532794	Rose Hill 345 kV	1	345		53		956/1052	New 345 kV line from Sooner to Oklahoma/Kansas Stateline or the interface with the Westar Energy line segment to achieve
20041	699	10929	OGE	12/31/12		M	06/19/09	$47,200,000		32 months	Balanced Portfolio	514803	Sooner 345 kV	512694	Cleveland 345 kV	1	345		36		1195/1195	Build new 345 kV line from Sooner to Cleveland. Install terminal equipment at Sooner
20017	30161	50169	OGE	04/01/12		M	01/16/09	$200,000,000	OGE	42 months	transmission service	521157	Hugo 345 kV	515136	Sunnyside 345 kV	1	345		120		1195/1195	Add 345 kV line from Sunnyside to WFEC interception of 345 kV line from Hugo, Install 345 kV breaker, switches, and relays at Sunnyside.
20017	30163	50171	OGE	04/01/12		M	01/16/09	$10,000,000	OGE	24 months	transmission service	515136	Sunnyside 345 kV	515135	Sunnyside138 kV	2	345/138				240/240	Add 2nd 345/138 kV Auto Transformer
	551	10837	OGE	06/01/12	NTC	06/01/12		$3,200,000	OGE	24 months	regional reliability	515315	Oak Park 161 kV	515293	Johnson 161 kV	1	161		2		313/335	Install 2 miles of 161 kV from Johnson to Oak Park and install terminal equipment at Oak Park.
	551	10701	OGE	06/01/12	NTC	06/01/12		$5,500,000	OGE	24 months	regional reliability	515293	Johnson 161 kV	515343	Massard 161 kV	1	161			5.6	313/335	Convert 5.6 miles of 69 kV to 161 kV.
	759	11002	OPPD	11/10/12		11/10/12		$565,000	OPPD		zonal - sponsored	646221	SUB 1221 161 kV	646255	S1255 161 kV	1	161				352/352	Replace terminal equipment so that the overall facility rating is 352 MVA.
20045	706	10939	SEPC	06/01/12		M	06/19/09	$54,000,000	ITC GP		Balanced Portfolio	531469	Spearville 345 kV	530583	Wolf 345 kV	1	345		45		1792/1792	Build new 345 kV line from Spearville to interception point of Spearville to Knoll line.
	835	11102	SPS	11/17/12		06/01/14		$16,245,000	SPP	18 months	regional reliability	524772	EST Clovis 69 kV	524835	E Clovis 115 kV	1	115					Move load from 69 to 115 kV bus
	835	11103	SPS	12/17/12		06/01/14		$2,257,031	SPP	1 months	regional reliability	524838	FE-Clovis 115 kV	524831	FE-Holland 115 kV	1	115	5.35				Reconductor 5.35 mile FE-Clovis to Curry CKT 1 with 397.5 ACSR.
	797	11056	SPS	03/21/12	NTC	06/01/10		$11,250,000	SPP	3 months	regional reliability	522896	Caprock REC-Vealmoor 138 kV	526830	Borden County Interchange 230 kV	2	230/138				168/168	Add second 230/138kV transformer at Borden County by moving old from Midland when retired.
	791	11045	SPS	12/16/12	NTC	06/01/10		$8,438	SPP	36 months	regional reliability	525414	Lamton Interchange 115 kV	525124	Hart Industrial 115 kV	1	115		15		157/173	New 15 mile Lampton Interchange - Hart Industrial Substation 115 kV line.
	791	11041	SPS	12/16/12	NTC	06/01/10		$16,031,250	SPP	36 months	regional reliability	525461	Newhart 230 kV	525213	Swisher County Interchange 230 kV	1	230		19		492/541	New 19 mile Swisher County Interchange - Newhart 230 kV line.
	791	11042	SPS	12/16/12	NTC	06/01/10		$10,125,000	SPP	36 months	regional reliability	525192	Kress Interchange 115 kV	525460	Newhart 115 kV	1	115		18		157/173	New 18 mile Kress - Newhart 115 kV line.
	791	11043	SPS	12/16/12	NTC	06/01/10		$13,500,000	SPP	36 months	regional reliability	524746	Castro County Interchange 115 kV	525460	Newhart 115 kV	1	115		24		157/173	New 24 mile Castro County Interchange - Newhart 115 kV line.
	824	11089	SPS	01/21/12	NTC	06/01/10		$4,725,000	SPP	1 months	regional reliability	527895	Hobbs 345 kV	527915	Midland 345 kV	1	345			89.22	1475/1623	Convert existing 89.22 mile Hobbs - Midland 230 kV line to operate at 345 kV.
	774	11021	SPS	08/18/12	NTC	06/01/10		$5,062,500	SPP	30 months	regional reliability	524135	Hastings 115 kV	524135	Hastings 115 kV		115					Convert Hastings Sub from 69kV to 115 kV
	774	11022	SPS	09/01/12	NTC	06/01/10		$2,200,000	SPP	18 months	regional reliability	524135	Hastings 115 kV	524124	Bush Sub 115 kV	1	115		5		157/173	New 5 mile Hastings - Bush 115 kV line.
	789	11038	SPS	05/26/12	NTC	06/01/12		$114,000	SPP	12 months	regional reliability	527564	Roswell Interchange 115 kV	527534	Brasher Tap	1	115	0.27			146/161	Reconductor .27 mile Roswell interchange - Brasher Tap 115 kV with 397 kcmil conductor.
	704	11085	SPS		NTC-Modify Timing	06/01/12	06/19/09	$11,250,000	SPP	24 months	Balanced Portfolio	525832	Tuco Interchange 345 kV	525830	Tuco Interchange 230 kV	2	345/230/13.2				515/560	Add second 345/230/13.2 kV Tuco Interchange 515/560 MVA transformer.
	795	11052	SPS	05/21/12	NTC	06/01/11		$11,250,000	SPP	24 months	regional reliability	524897	Frio-Draw 230kV	524898	Frio-Draw 115 kV	1	230/115				252/252	New 230/115kV transformer at Frio-Draw substation.
	795	11053	SPS	05/21/12	NTC	06/01/11		$13,500,000	SPP	24 months	regional reliability	524897	Frio-Draw 230kV	524875	Oasis Interchange 230 kV	1	230		16		492/546	Build new 16 mile Frio-Draw - Oasis 230kV line.
	795	11054	SPS	11/17/12	NTC	06/01/11		$21,937,500	SPP	30 months	regional reliability	524897	Frio-Draw 230kV	524909	Roosevelt County Interchange 230 kV	1	230		26		492/546	Build new 26 mile Frio-Draw - Roosevelt County 230kV line.
	887	11176	SPS	12/16/12	NTC	6/1/2010		$7,762,500	SPP	36 months	regional reliability	524516	Canyon West 115 kV	524544	Spring Draw 115 kV	1	115		9		157/173	Build new 9 mile Canyon West - Spring Draw 115 kV line.
	888	11177	SPS	12/16/12	NTC	6/1/2010		$27,450,000	SPP	36 months	regional reliability		Randall Co 230 kV	524415	Amarillo South 230 kV	1	230		20		492/541	Build new 20 mile Randall Co - Amarillo South 230 kV line.
	102	10835	SWPA			06/01/18		$1,575,000	SPP		regional reliability - non OATT	505496	Nixa 161 kV	505501	Nixa 69 kV	2	161/69				70/70	Upgrade Nixa #2 transformer to 70 MVA
20018	30165	50173	WFEC	04/01/12		M	01/16/09	$2,000,000	WFEC	36 months	transmission service	521157	Hugo 345 kV	515136	Sunnyside 345 kV	1	345				1195/1195	Install 345 kV breaker at Hugo
20003	402	10522	WFEC	06/01/12		M	02/13/08	$1,125,000	SPP	12 months	regional reliability	521194	Grandfield 138 kV	520954	Indiahoma 138 kV	1	138			3	183/228	Convert 3 miles of 69 kV to 138 kV from Indiahoma to Grandfield.
20003	402	10523	WFEC	06/01/12		M	02/13/08	$7,306,000	SPP	24 months	regional reliability	520954	Indiahoma 138 kV	521193	Cache SW 138 kV	1	138		13.7		183/228	Tap Cache to Paradise 138 kV and install 13.7 miles of 138 kV from Cache to Indiahoma.
20003	402	10524	WFEC	06/01/12		M	02/13/08	$5,000,000	SPP	24 months	regional reliability	521194	Grandfield 138 kV	520926	Grandfield 69 kV	1	138/69				70/70	Install new 138/69 kV transformer at Grandfield
20003	399	10519	WFEC	06/01/12		M	02/13/08	$1,347,000	SPP	12 months	regional reliability	520979	Lindsay 69 kV	521087	Wallville 69 kV	1	69	4.85			53/65	Upgrade line from 1/0 to 336.4, 4.85 miles
20003	400	10520	WFEC	06/01/12		M	02/13/08	$225,000	SPP	6 months	regional reliability	505592	Pharoah 138 kV	521026	Weleetka 138 kV	1	138				223/228	WFEC will upgrade 800 A CTs, new CT limit will be 1200 A at Pharaoh.
20003	401	10521	WFEC	06/01/12		M	02/13/08	$50,000	WFEC	6 months	regional reliability	521043	WFEC Russell 138 kV	511448	AEP Altus Jct Tap 138 kV	1	138				143/143	Replace CT at WFEC Russell
	672	10878	WFEC		NTC	06/01/12		$1,950,000	WFEC	18 months	regional reliability	520892	El Reno 69 kV	520899	El Reno SW 69 kV	1	69	6.5			36/36	Reconductor 6.5 miles of 1/0 conductor with 336.4 ACSR.
20033	463	10602	WR	06/01/12		M	01/27/09	$4,100,000	WR	12 months	regional reliability	532862	East Manhattan 230kV	532861	McDowell 230kV	1	230			15.65	358/358	The East Manhattan-McDowell 115 kV is built as a 230 kV line but is operated at 115 kV. Substation work will have to be performed in order to convert this line to 230 kV operation..
	754	10995	WR	06/01/12		M		$5,625,000	SPP		zonal - sponsored	533036	Clearwater 138 kV	533073	Goddard 138 kV	1	138		10		534/586	Build a new 138kV line from Clearwater and a new 138kV line from Evans to serve the new Goddard substation
	754	10996	WR	06/01/12		M		$5,625,000	SPP		zonal - sponsored	533041	Evans Energy Center South 138 kV	533073	Goddard 138 kV	1	138		10		534/586	Build a new 138kV line from Clearwater and a new 138kV line from Evans to serve the new Goddard substation
20059	30224	50228	WR	06/01/12			09/18/09	$2,560,500	WR	12 months	transmission service	533621	Allen 69 kV	533638	Lehigh Tap 69 kV	1	69	5.69			72/72	Rebuild approximately 6 miles of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating
20006	172	10221	WR	06/01/12		M	02/13/08	$2,100,000	WR	6 months	regional reliability	533180	Tecumseh Energy Center 115 kV	533252	Midland 115 kV	1	115			19.33	117/117	Convert TEC-Midland from 161 kV to 115 kV
19964	375	10488	WR	06/01/12		M	06/27/07	$8,100,000	WR	24 months	transmission service	532794	Rose Hill 345 kV	533062	Rose Hill 138 kV	3	345/138				400/440	Install 3rd Rose Hill 345/138 kV TRANSFORMER.
20063	664	10870	WR	06/01/12		06/01/13	11/02/09	$1,000,000	SPP	12 months	regional reliability	533045	Gill Energy Center West 138 kV	533072	Waco 138 kV	1	138	1.8			534/586	Tear down and rebuild 1.8 mile Gill Energy Center West - Waco 138 kV with bundled 1192.5 ACSR conductor.
			Year 2013																			
20027	443	10575	AEP	06/01/13		M	01/27/09	$2,000,000	AEP	24 months	regional reliability	506979	Osbourne 161 kV	506980	Osbourne Tap 161 kV	1	161		1.5		428/636	Tap the South Springdale-East Fayetteville 161 kV line and build 1.5 miles of 161 kV to new Osbourne station.
	546	10695	AEP		NTC	06/01/13		$26,150,000	AEP	36 months	regional reliability	511463	Hobart Junction 138 kV	511445	Carnegie 138 kV	1	138	26.15			287/287	Rebuild the 26.2 mi Carnegie - Hobart Jct. 138 kV line from 397 ACSR to 1272 ACSR. Replace 3 switches, wave traps and jumpers. Reset CTs and relays.
	546	10696 & 10697	AEP		NTC	06/01/13		$11,030,000	AEP	36 months	regional reliability	511445	Carnegie 138 kV	511477	Southwest Station 138 kV	1	138	14.37			220/235	Reconductor the 14.37 mile Southwest Station - Carnegie 138 kV line from 795 ACSR to 1272 ACSR. Replace wave traps and jumpers.
20064	770	11015	AEP	06/01/13			11/02/09	$2,500,000	AEP	18 months	regional reliability	504124	Ashdown 138 kV	510890	Craig Junction 138 kV	1	138	2.45			265/287	Rebuild 2.45 miles of 795 ACSR with 1590 ACSR and reset relays.
20057	539	10687	CUS	06/01/13		06/01/19	09/18/09	$120,000	CUS	12 months	transmission service	549969	Brookline 161 kV	549955	Junction 161 kV	1	161				340/358	Brookline: Replace 1,200 amp switches with 2,000 amp units and replace metering CTs. Junction: Replace 1,200 amp switches
20034	646	10847	GMO	06/01/13		M	01/27/09	$2,000,000	SPP	12-18 months	regional reliability	541303	Clinton 69 kV	541352	Clinton 161 kV	1	69/161				100/125	Replace Clinton 161/69 kV transformer #1 with new 100/125 MVA to match transformer #2.
	333	10430	GMO	06/01/13		M		$302,795	GMO	12~18 months	zonal - sponsored	541346	Ritchfield 161	541202	Sibley 161	1	161				223/245	161kV Tap of Hallmark to Sibley
	335	10432	GMO	06/01/13		M		$0	GMO	12~18 months	zonal - sponsored	541215	Hallmark 161	541346	Ritchfield 161	1	161				223/245	161kV Tap of Hallmark to Sibley
	414	10541	KCPL	06/01/13		M		$1,385,000	KCPL	18 months	zonal - sponsored	543037	Quarry 161 kV	#N/A	Clare 161 kV	1	161		4.5		293/335	New Quarry-Clare 161 kV Line
	418	10544	KCPL	06/01/13		M		$1,632,300	KCPL	18 months	zonal - sponsored	543030	Waldron 161 kV	546656	Maywood 161 kV	1	161				293/335	New Waldron sub cut-in
	418	10545	KCPL	06/01/13		M			KCPL		zonal - sponsored	543030	Waldron 161 kV	543017	Weatherby 161 kV	1	161				293/335	New Waldron sub cut-in
	715	10952	KCPL		NTC	06/01/13		$200,000	KCPL	24 months	regional reliability	543081	Glenare 69 kV	541262	Liberty 69 kV	1	69				70/79	Reconductor GMO portion of Glenare - Liberty 69 kV for 70/79 MVA rating.
	711	10948	LES	05/31/13		M		$11,250,000	SPP		zonal - sponsored	650214	NW68 & HOLDRIDGE 115 kV	650114	Nw68 & Holdridge 345 Kv	1	345/115/13.8				336/420	Add NW68th Holdrege 345/115kV Transformer #2. Driven by NERC Category C (TPL-003) - prior outage of one 345/115kV transformer, followed by an outage of a second 345/115kV transformer.
20046	707	10940	MIDW	06/01/13		M	06/19/09	$42,000,000			Balanced Portfolio	531469	SPEARVILLE 345 kV	530583	Wolf 345 kV	1	345		45		1792/1792	Build new 345 kV line from Knoll to interception point of Spearville to Knoll line.
20046	707	10943	MIDW	06/01/13		M	06/19/09	$66,000,000			Balanced Portfolio	640065	Axtell 345 kV	530583	Wolf 345 kV	1	345		80		1792/1792	Build new 345 kV line from Knoll to interception point of Axtell to Knoll line.
20032	697	10914	MIDW			06/01/13	01/27/09	$6,250,000	MIDW	9 months	regional reliability	533419	Hutchinson Energy Center 115 KV	530618	Huntsville 115 kV	1	115	21.1			164/194	Rebuild 21.1 mile HEC - Huntsville 115 kV line and replace CT, wave trap and relays.
	653	10858	MKEC		NTC	06/01/13		$9,239,000	SPP	24 months	regional reliability	539696	St. John 115 kV	539687	Pratt 115 kV	1	115	21.9			165/198	Rebuild 21.9 mile St. John - Pratt 115 kV line with 795 ACSR conductor.
20047	708	10942	NPPD	06/01/13		M	06/19/09	$76,000,000	NPPD	48 months	Balanced Portfolio	640065	Axtell 345 kV	530583	Wolf 345 kV	1	345		45		1792/1792	Build new 345 kV line from Axtell to interception point of Axtell to Wolf line (Kansas Border). Includes substation expansion at Axtell and line reactor.
	817	11079	NPPD	06/01/13	NTC	06/01/13		$1,000,000	NPPD	24 months	regional reliability	640054	Albion 115 kV	640347	Spalding 115 kV	1	115				174/174	Uprate line and substation equipment to 100 Deg C Rating by 2013. 174 MVA Normal Continuous Rating. 174 MVA 4-Hour Emergency Rating.
20029	642	10843	OGE	06/01/13			01/27/09	$10,000	OGE	9 months	regional reliability	515335	Kilgore 69 kV	515336	VBI 69 kV	1	69				72/72	Remove wavetrap at VBI.
	235	10300	OGE	06/01/13	NTC	06/01/13		$2,500,000	OGE	24 months	regional reliability	515300	Fort Smith 161 kV	515345	Colony 161 kV	1	161	2.2			446/446	Reconductor 2.2 miles to 1590 kmcm ACSR and change terminal equipment at Ft. Smith and Colony substations to 2000A.
20041	700	10930	OGE	12/31/13		M	06/19/09	$131,000,000		40 months	Balanced Portfolio	515045	Seminole 345 kV	515224	Muskogee 345 kV	1	345		100		1200/1200	Build new 345 kV line from Seminole to Muskogee
20041	700	10931	OGE	12/31/13		M	06/19/09	$4,000,000		22 months	Balanced Portfolio	515044	Seminole 138 kV	515045	Seminole 345 kV	3	345/138				493/493	Install 3rd 345/138 kV transformer at Seminole
	862	11139	OPPD		NTC	06/01/13		$4,638,000	OPPD	24 months	regional reliability	647906	SUB 906 North 69 kV	647928	SUB 928 69 kV	1	69	2			111/0110	Rebuild 2 mile Sub 906 North - Sub 928 line. Change CT tap settings, and replace line jumpers for 110 MVA rating.
	864	11141	OPPD			06/01/13		$272,000	OPPD	12 months	regional reliability	647907	SUB 907 69 kV	647919	Sub 919 69 kV	1	69				76/76	Increase line clearances to allow the use of a higher conductor rating.
	791	11044	SPS	03/16/13	NTC	06/01/10		$2,250,000	SPP	15 months	regional reliability	525124	Hart Industrial 115 kV	525460	Newhart 115 kV	1	115		4		157/173	Build new 4 mile Hart Industrial Substation - Newhart Substation 115 kV line.
	774	11023	SPS	03/16/13	NTC	06/01/10		$1,700,000	SPP	4 months	regional reliability	524135	Hastings Sub 69 kV	524162	East Plant Interchange 115 kV	1	115		3.7		157/173	Build new 3.7 mile Hastings - East Plant 115kV line.
	793	11047	SPS		NTC	06/01/13		$2,320,300	SPP	18 months	regional reliability	527322	Gaines County Interchange 115 kV	527346	Legacy 115 kV	1	115	5.5			120/154	Reconductor 5.5 mile Gains County Interchange - Legacy 115 kV line.
	795	11050	SPS	12/31/13	NTC	06/01/13		$146,250,000	SPP	48 months	regional reliability	524896	Frio-Draw 345kV	523961	Potter County Interchange 345 kV	1	345		130		1643/1793	Build new 130 mile 345 kV line from Potter to new Frio-Draw substation at Roosevelt.
	795	11051	SPS	12/31/13	NTC	06/01/13		$11,250,000	SPP	24 months	regional reliability	524896	Frio-Draw 345 kV	524897	Frio-Draw 230kV	1	345/230				560/560	Build new Frio-Draw substation with 345/230 kV transformer.
	794	11049	SPS	06/01/13	NTC	06/01/13		$900,000	SPP	24 months	regional reliability	523797	GRAVE 3 115 kv	523796	Grave 2 69 kV	2	115/69				40/40	Add a second Grave 115/69 kV transformer.
	834	11101	SPS	05/21/13	NTC	06/01/13		$3,487,500	SPP	18 months	regional reliability	524924	Portales Interchange 115 kV	524936	Zodiac 115 kV	1	115			3	157/173	Convert existing 3 mile Portales Interchange - Zodiac 69 kV line to operate at 115 kV.
	640	10841	SWPA			M		$50,000	SPP		regional reliability - non OATT	505404	Malden 69 kV	505402	New Madrid 69 kV	1	69				71/71	Resag conductor and replace some structures.
	769	11014	SWPA			06/01/13		$112,500	SPP	12 months	regional reliability - non OATT	505448	Norfolk 161 kV	338814	Southland 161 kV	1	161				223/223	Replace bus and CTs at Norfolk.
	846	11115	WFEC		NTC	06/01/13		$14,737,500	SPP	36 months	regional reliability	520814	Anadarko 138 kV	520828	Blanchard 138 kV	1	138			25.2	212/264	Rebuild 25.2 mile Anadarko - Blanchard 69 kV as 138 kV.
	846	11116	WFEC			06/01/13		$1,125,000	SPP	12 months	regional reliability	520828	Blanchard 138 kV	521104	OU Switchyard 138 kV	1	138			2	212/264	Rebuild 2 mile Blanchard - OU Switchyard 69 kV as 138 kV.
	467	10603	WR		NTC	06/01/13		$50,000	WR	18 months	regional reliability	533044	Gill Energy Center East 138 kV	533051	Interstate 138 kV	1	138				232/232	Replace wave traps on Gill - Interstate 138 kV line for a new rating of 232/256 MVA.
20033	643	10844	WR	06/01/13		M	01/27/09	$4,000,000	SPP	18 months	regional reliability	533008	TWIN VALLEY NO. 1 MOUND VALLEY 138 k	533021	Neosho 138 kV	1	138				191/210	Tap the Neosho - Twin Valley line into Altamont.
20063	645	10846	WR	06/01/13		M	11/02/09	$2,400,000	WR	18 months	regional reliability	533064	17TH Street 4 138 kV	5330840	17TH Street 2 69 kV	1	138/69				150/165	Add second transformer in 17th Street substation.
20033	533	10678	WR	06/01/13	NTC-Modify Timing	06/01/15	01/27/09	$12,622,500	WR	24 months	regional reliability	532851	Auburn 230 kV	533151	Auburn 115 kV	2	230/115				280/308	Install second Auburn Road 230/115 kV transformer.
	819	11082	WR		NTC	06/01/13		$3,127,500	SPP	18 months	regional reliability	533795	Gill Energy Center East 69 kV	533813	Macarthur 69 kV	1	69	5.56			107/116	Rebuild 5.56 mile Gill Energy Center East - MacArthur 60 kV line. Replace substation bus and jumpers at MacArthur 69 kV.
20059	30224	50233	WR	07/01/13			09/18/09	$3,340,000	WR	24 months	transmission service	533626	Burlington Junction 69 kV	533630	Coffey County No. 3 Westphalia 69 Kv	1	69	7.2			116/128	Rebuild approximately 7 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
20059	30224	50234	WR	01/01/13			09/18/09	$1,945,000	WR	24 months	transmission service	533626	Burlington Junction 69 kV	533653	Wolf Creek 69 kV	1	69	4.1			116/128	Rebuild approximately 4 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
20059	30224	50240	WR	11/01/13			09/18/09	$593,775	WR	12 months	transmission service	533638	LEHIGH TAP 69 KV	533651	United No. 9 Conger 69 kV	1	69	0.91			72/72	Rebuild approximately 1 mile of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating.
20059	529	10674	WR	01/01/13		M	09/18/09	$84,669,696	WR	24 months	regional reliability	514803	Sooner 345 kV	532794	Rose Hill 345 kV	1	345		53		956/1052	New 345 kV line from Oklahoma/Kansas Stateline or the interface with the OG&E line segment to Rose Hill to achieve 3000 amp
			Year 2014																			
20000	450	10584	AEP	06/01/14		M	02/13/08	$13,104,000	AEP	48 months	regional reliability	507001	Shipe Road 345 kV	507002	Shipe Road 161 kV	1	345/161				675/743	Install 345/161 kV transformer at Shipe Road.
20000	450	10585	AEP	06/01/14		M	02/13/08	$34,085,000	AEP	60 months	regional reliability	506935	Flint Creek 345 kV	507001	Shipe Road 345 kV	1	345		18		1336/1915	Install 22 miles of new 345 kV, 2-954 ACSR line.
20000	450	10582	AEP	06/01/14		M	02/13/08	$11,962,000	AEP	60 months	regional reliability	507002	Shipe 161 kV	506929	East Centerton 161 kV	1	161		9		520/729	Install 2 miles of 161 kV from new Shipe Road Substation to East Centerton Substation.
20027	649	10853	AEP	06/01/14		M	01/27/09	$2,150,000	AEP	24 months	regional reliability	510399	Lone Star 115 kV	510423	Locust Grove 115 kV	1	115	2.15			120/129	Reconductor 2.15 mile section of 115 kV line with 795 ACSR.
	445	10577	AEP	06/01/14		06/01/15		$5,400,000	AEP	24 months	regional reliability	508335	Big Sandy 69 kV	508350	Perdue 69 kV	1	69	5.4			123/143	Rebuild 5.4 mile Big Sandy - Perdue 69 kV line from 477 ACSR to 1272 ACSR.
	873	11153	AEP			06/01/14		$250,000	AEP	12 months	regional reliability	508077	SE Texarkana 69 kV	508086	Texarkana 69 kV	1	69				114/155	Upgrade 600 A breaker and two switches at Texarkana Plant.
	880	11169	AEP			06/01/14		$200,000	AEP	12 months	regional reliability	509054	Beckville 69 kV	509082	Rock Hill 69 kV	1	69				90/105	Upgrade 2 sets of switches at Rock Hill and 1 set of switches at Beckville bus.
	648	10849	DETEC	06/01/14				$8,837,000			zonal - sponsored		Martinsville 138 kV		Shady Grove 138 kV	1	138			9.58	215/225	Covert from 59 kV to 138 kV
	648	10850	DETEC	06/01/14							zonal - sponsored		Shady Grove 138 kV		Central Hieghts 138 kV	1	138			8.82	215/225	Covert from 59 kV to 138 kV
	648	10851	DETEC	06/01/14							zonal - sponsored		Central Hieghts 138 kV		Fitze 138 kV	1	138			10.52	215/225	Covert from 59 kV to 138 kV
	648	10852	DETEC	06/01/14							zonal - sponsored		Fitze 138 kV		Tempson 138 kV	1	138			3.7	215/225	Covert from 59 kV to 138 kV
	812	11074	EDE			06/01/14		$100,000	SPP	12 months	regional reliability	547600	SUB 403 - Jasper West Tap 69 kV	547548	SUB 249 - Boston East 69 kV	1	69				33/39	Replace jumpers.
	811	11073	EDE			06/01/14		$50,000	SPP	12 months	regional reliability	547538	SUB 131 - Diamond Junction 69 kV	547582	SUB 362 - Sarcoxie Southwest 69 kV	1	69				32/44	Raise structures on Diamond Jct. - Sarcoxie Southwest 69 kV line to achieve a new rating B of 44 MVA.
	437	10567	EDE	06/01/14		06/01/15		$75,000	EDE	12 months	regional reliability	547541	Sub 167 - Riverton 69 kV	547555	SUB 278 - Galena Northeast 69 kV	1	69				76/91	Replace switch on transfer bus at Sub# 167 for Rate B = 91 MVA.
20036	202	10258	EDE			06/01/14	01/27/09	$400,000	EDE	12 months	regional reliability	547527	SUB 436 - Webb City Cardinal 69 kV	547534	SUB 110 - Oronogo Junction 69 kV	1	69	1			54/65	Reconductor 1.0 Mile of 4/0 ACSR with 336 ACSR for 65 MVA Rate E
	489	10633	MIDW			06/01/14		$5,250,000	MIDW	9 months	regional reliability	530618	Huntsville 115 kV	530624	St. John 115 kV	1	115	26.55			164/199	Rebuild 26.55 mile Huntsville - St. John 115 kV line and replace CT, wavetrap, breakers, and relays.
	816	11078	NPPD	06/01/14		06/01/14		$1,000,000	NPPD	24 months	regional reliability	640054	Albion 115 kV	640181	Genoa 115 kV	1	115				137/137	Uprate line and substation equipment to effect 100 Deg C Rating by 2014. 137 MVA Normal Continuous Rating. 137 MVA 4-Hour Emergency Rating.
	889	11143	OPPD			06/01/14		$251,000	OPPD	12 months	regional reliability	647921	Sub 921 69 kV	647942	Sub 942 69 kV	1	69				103/103	Increase line clearances to allow the use of a higher conductor rating. Change CT tap settings.
	860	11137	OPPD			06/01/14		$105,000	OPPD	12 months	regional reliability	647901	SUB 901 69 kV	647105	Junction 205 69 kV	1	69				85/85	increase line clearances to allow the use of a higher conductor rating.
	861	11138	OPPD			06/01/14		$251,000	OPPD	12 months	regional reliability	647910	SUB 910 69 kV	647105	Junction 205 69 kV	1	69				85/85	increase line clearances to allow the use of a higher conductor rating.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	865	11142	OPPD			06/01/14		$253,000	OPPD	12 months	regional reliability	647917	Sub 917 69 kV	647918	Sub 918 69 kV	1	69				70/70	Increase line clearances to allow the use of a higher conductor rating.
	897	11191	OGE	06/01/14		M					zonal - sponsored	514888	36 & Meridian 138 kV	514889	WRAirport 138 kV	1	138				233/267	New Distribution Sub - WR Airport
	897	11192	OGE	06/01/14		M					zonal - sponsored	514889	WRAirport 138 kV	514925	Pennsylvania 138 kV	1	138				233/267	New Distribution Sub - WR Airport
20041	701	10932	OGE	05/19/14		M	06/19/09	$105,000,000		40 months	Balanced Portfolio	525835	Stateline 345 kV	515375	Woodward EHV 345kv	1	345		125		1475/1623	Build new 345 kV line from Woodward EHV to Border
20041	701	10933	OGE	05/19/14		M	06/19/09	$15,000,000		24 months	Balanced Portfolio	515376	Woodward EHV 138 kV	515375	Woodward EHV 345 kV	2	345/138				448/493	Install 2nd 345/138 kV transformer at Woodward EHV
	796	11055	SPS			06/01/14		$11,250,000	SPP	24 months	regional reliability	526676	Grassland Interchange 115 kV	526677	Grassland Interchange 230 kV	2	230/115				100/115	Add second 230/115 kV transformer at Grassland Interchange.
20043	704	10936	SPS	05/19/14		M	06/19/09	$122,597,500			Balanced Portfolio	525832	Tuco Interchange 345 kV	525835	Stateline 345 kV	1	345		125		1792/1792	Build new 345 kV line from Tuco to Border
20043	704	10937	SPS	05/19/14		M	06/19/09	$14,880,000	SPP		Balanced Portfolio	525835	Stateline 345 kV				345					Build Border at interception point of Woodward to Tuco line.
	764	11007	SPS	06/01/14		06/01/14		$1,890,000	SPP	28 months	regional reliability	525154	Happy Interchange 115 kV	525153	Happy Interchange 69 kV	1	115/69				84/96	Upgrade both Happy County 115/69 kV transformers to 84 MVA.
	764	11009	SPS	06/01/14		06/01/14		$1,890,000	SPP	28 months	regional reliability	525154	Happy Interchange 115 kV	525153	Happy Interchange 69 kV	2	115/69				84/96	Upgrade both Happy County 115/69 kV transformers to 84 MVA.
	826	11093	SPS	06/01/14		06/01/14		$11,250,000	SPP	28 months	regional reliability	527482	Chaves 115 kV	527483	Chaves 230 kV	2	230/115				225/258.5	Replace existing 149/171 MVA Chaves 230/115 kV transformer with 225 MVA transformer.
	836	11104	SPS	06/01/14		06/01/14		$3,318,750	SPP	20 months	regional reliability	525017	Muleshoe 69 kV	524030	Muleshoe E 115 kV	1	115				120/120	Move load from Muleshoe 69 kV to Muleshoe 115 kV.
	839	11107	SPS	06/01/14	NTC	06/01/14		$14,737,500	SPP	36 months	regional reliability	525192	Kress Int 115 kV	525271	Plainview CTY 115 kV	1	115		22.2		157/173	Build new 22.2 mile Kress Interchange - Plainview County 115 kV.
	839	11108	SPS	06/01/14	NTC	06/01/14		$990,000	SPP	30 months	regional reliability	525270	Planiview Co 69 kV	525271	Plainview CTY 115 kV	1	115/69				44/50.6	Add new Plainview County 115/69 kV transformer with 44/50.6 MVA ratings.
	840	11109	SPS	06/01/15	NTC	06/01/14		$7,762,500	SPP	36 months	regional reliability	525326	Cox 115 kV	525271	Plainview CTY 115 kV	1	115		9.8		157/173	Build new 9.8 mile Cox - Plainview 115 kV line unit.
	852	11122	SPS	06/01/14		06/01/14		$225,000	SPP	12 months	regional reliability	526338	Jones 230 kV	526677	Grassland 230 kV	1	230				478/617	Replace wave trap with 1200 A minimum.
	883	11172	SPS	05/16/14	NTC	06/01/11		$30,395,000	SPP	36 months	regional reliability	526338	Jones 230 kV	526677	Grassland 230 kV	2	230		26.72		492/541	Build new second Jones - Grassland 230 kV line.
	900	11197	SPS			06/01/14		$315,000	SPP	24 months	regional reliability	524898	Frio Draw 115 kV	524838	Farmers Electric REC-Clovis 115 kV	1	115	0.56			246/271	Reconductor FRIO-DRAW 0.56 miles 115 kV to 795 ACSR line
	631	10819	SWPA			06/01/14		$10,095,750	SPP	18 months	regional reliability - non OATT	300056	Asherville 161 kV	505434	Idalia 161 kV	1	161	19.23			335/335	Reconductor line to 335/335 MVA.
	651	10856	SWPA			06/01/14		$5,625,000	SPP		regional reliability - non OATT		Carthage 161 kV		Carthage 69 kV	1 & 2	161/69				125/125	Replace both Carthage auto transformers with larger units.
	524	10669	WFEC			06/01/14		$900,000	SPP	18 months	regional reliability	520929	Gypsum 69 kV	521042	Russell 69 kV	1	69	3			53/65	Reconductor 3 mile Gypsum - Russell 69 kV line from 1/0 to 336.4 ACSR.
20063	563	10713	WR	06/01/13		M	11/02/09	$75,000	WR	12 months	regional reliability	533765	Litchfield 69 kV	533756	Aquarius 69 kV	1	69				80/80	Replace 69 kV disconnect switches at Aquarius with a minimum 600 amp emergency rating
20033	534	10679	WR	06/01/14	NTC-Modify Timing	06/01/11	01/27/09	$1,400,000	WR	24 months	regional reliability	533012	Halstead South 138 kV	533736	Halstead 69 kV	1	138/69				100/110	Replace Halstead 138/69/13.2 kV transformer with 100/110 MVA unit.
	469	10605	WR			M		$20,000	WR	18 months	zonal - sponsored	533733	Gatz 69 kV	533745	Newton 69 kV	1	69				116/128	Reset CTs on Moundridge - Newton 69 kV line (multiple rating changes).
	755	10997	WR			06/01/14		$3,712,500	SPP	18 months	regional reliability	533153	County Line 115 kV	533162	Goodyear Junction 115 kV	1	115	6.6			446/490	Tear down and rebuild 6.6 mile County Line - Goodyear Junction 115 kV line.
20059	30224	50236	WR	04/01/14			09/18/09	$4,249,000	WR	24 months	transmission service	533636	Green 69 kV	533630	Coffye County No. 3 Westphalia 69 kV	1	69	9.22			116/128	Rebuild approximately 9 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
		Year 2015																				
	876	11156	AEP			06/01/15		$1,000,000	AEP	18 months	regional reliability	511481	Weatherford 69 kV	511517	Thomas Tap 69 kV	1	69	0.9			72/72	Rebuild 0.9 mile Weatherford - Thomas Tap 69 kV line from 4/0 ACSR with 795 ACSR. Replace Weatherford wavetrap.
20036	537	10685	EDE	06/01/15	NTC-Modify Timing	06/01/19	01/27/09	$7,369,319	EDE	48 months	regional reliability	547480	SUB 383 - Monett 161kV	547510	South Monett 161 kV	1	161		9.2		218/268	Build new 9.2 mile Substation 383 - Monett 5 161 kV line.
20036	537	10686	EDE	06/01/15	NTC-Modify Timing	06/01/19	01/27/09	$8,000,000	EDE	36 months	regional reliability	547510	South Monett 161 kV	547401	SUB 376 - Monett City South 69 kV	1	161/69				100/100	Install 3-winding transformer connecting new 161 kV bus to Monett City South 69 kV.
	536	10681	EDE	06/01/15		06/01/18		$275,000	EDE	12 months	regional reliability	547400	Monett City South Jct. 69 kV	547402	Monett City East 69 kV	1	69	1.2			54/65	Reconductor 1.2 mi with 336 ACSR.
20042	703	10935	KCPL	06/01/15		M	06/19/09	$54,444,000			Balanced Portfolio	542982	Iatan 345 kV	542980	Nashua 345 kV	1	345		30		2546/2546	Tap Nashua 345kV bus in Hawthorn - St. Joseph 345 kV line. Build new 345 kV line from Iatan to Nashua.
20042	703	10945	KCPL	06/01/15		M	06/19/09	$4,620,000			Balanced Portfolio	542980	Nashua 345 kV	543028	Nashua 161 kV	1	345/161				400/440	Install new 345/161 kV transformer at Nashua
	757	11000	OGE			06/01/15		$4,200,000	OGE	24 months	regional reliability	515785	Windfarm 138 kV	514785	Woodward District 138 kV	1	138	12.08			404/465	Reconductor 12.08 mile FPL Switch to Woodward District line to 1590 AS52.
	670	10876	OGE			06/01/15		$12,000,000	OGE	30 months	regional reliability	514908	Arcadia 345 kV	514907	Arcadia 138 kV	3	345/138				493/493	Install third Arcadia 345/138 kV autotransformer.
	858	11129	OGE			06/01/15		$16,000,000	OGE	36 months	regional reliability	515513	Mehan 138 kV	515033	Cushing 138 kV	1	138			14	194/222	Convert 14 mile Mehan - Cushing 69 kV line to 138 kV.
	858	11130	OGE			06/01/15			OGE		regional reliability	515011	Stillwater 138 kV	515512	Spring Valley 138 kV	1	138			5.98	194/222	Convert 6 mile Stillwater - Spring Valley 69 kV line to 138 kV.
	858	11131	OGE			06/01/15			OGE		regional reliability	515512	Spring Valley 138 kV	515513	Mehan 138 kV	1	138			3	194/222	Convert 3 mile Spring Valley - Mehan 69 kV line to 138 kV.
	858	11132	OGE			06/01/15			OGE		regional reliability	515512	Spring Valley 138 kV	515514	Knipe 138 kV	1	138			8.69	268/286	Convert 8.7 mile Spring Valley - Knipe 69 kV line to 138 kV.
	858	11133	OGE			06/01/15			OGE		regional reliability	515033	Cushing 138 kV	515417	Bristow 138 kV	1	138				120/120	Tap existing Cushing - Bristow 138 kV line into new Greenwood Sub 138 kV transformer bus and add new Greenwood 138/69/13.8 transformer.
	858	11134	OGE			06/01/15			OGE		regional reliability	515021	OakGrove 69 kV	515019	Hwy 99 Tap 69 kV	1	69				52/66	Tap existing Oak Grove - Hwy 99 Tap 69 kV circuit into new Greenwood Sub 69 kV transformer bus.
	899	11195	SEPC			06/01/15		$4,000,000	SEPC	24 months	regional reliability	531448	Holcomb 115 kV	531420	Fletcher 115 kV	1	115	11.1				Rebuild 11.1 miles with 954 ACSR Cardinal
	766	11010	SPS			06/01/15		$3,892,500	SPP	24 months	regional reliability	525460	Newhart 3 115 kV	525461	Newhart 6 230 kV	2	115/230				150/173	Add second Newhart 230/115 kV transformer.
	798	11057	SPS	06/01/15		06/01/15		$992,000	SPP	18 months	regional reliability	524414	Amarillo South Interchange 115 kV	524377	Farmers Sub 115 kV	1	115	2.35			246/271	Reconductor Amarillo - Farmers 115 kV Circuit 2.35 miles with 795 kcmil conductor
	801	11060	SPS			06/01/15		$3,825,000	SPP	24 months	regional reliability	528768	Lea County REC-Ancell 69 kV	528776	Lea County REC-Gaines 69 kV	1	69		8.5		41/54	Build new 8.5 mile Lea County Ancell - Gaines 69kV line.
	801	11061	SPS			06/01/15		$4,050,000	SPP	24 months	regional reliability	528763	Lea County REC-TP91 69 kV	528784	Lea County REC-Darby 69 kV	1	69		9		41/54	Build new 9 mile Lea County TP-91 - Darby 69kV line.
	801	11062	SPS			06/01/15		$11,250,000	SPP	24 months	regional reliability	527362	New ERF3 115 kV	527361	Lea County ERF 69 kV	1	115/69				44/44	Build new ERF3 substation with new 44MVA 115/69kV transformer.
	886	11175	SPS	06/01/15		6/1/2015		$6,350,000	SPP	24 months	regional reliability	525213	Swisher 230 kV	525212	Swisher 115 kV	2	230/115				150/150	Add second Swisher 230/115 kV transformer.
20004	146	10186	SPS	06/01/15		M	02/13/08	$8,920,699	SPS	48 months	regional reliability	527894	Hobbs 230 kV	527276	Seminole 230 kV	1	230		45		492/541	Add 230 kV line from Hobbs to Seminole - 541 MVA.
	694	10836	SWPA			06/01/15		$167,500	SPP	12 months	regional reliability - non OATT	300056	Asherville 161 kV	505438	Poplar Bluff 161 kV	1	161				206/206	Replace disconnect switches, replace some structures and resag line.
	444	10576	SWPA			06/01/15		$660,000	SPP	12 months	regional reliability - non OATT	505501	Nixa 69 kV	505541	Nixa DT 69 kV	1	69	2.2			72/72	Reconductor the 2.2 mi line with 795 ACSR.
	490	10635	WR	06/01/15		06/01/16		$1,950,000	WR	12 months	regional reliability	533234	Bismark 115 kV	533252	Midland 115 kV	1	115	5.2			181/181	Rebuild 5.2 miles of the Bismark to Midland 115 kV line.
20033	652	10857	WR	06/01/15	NTC-Modify Timing	06/01/13	01/27/09	$12,487,500	SPP	36 months	regional reliability	533419	Hutchinson Energy Center 115 KV	530618	Huntsville 115 kV	1	115	7.7			164/194	Rebuild the Westar portion of the 28.8 mile HEC - Huntsville 115 kV line and reset CTs at HEC.
	492	10637	WR			M		$920,000	WR	18 months	regional reliability	533798	Gill Energy Center 69 kV	533825	Oatville 69 kV	1	69	3.55			96/96	Tear down / Rebuild 3.55-mile Gill Energy Center - Gill junction portion of the Gill - Oatville 69 kV line. Replace 477 kcmil ACSR conductor with 954 kcmil ACSR and replace terminal equipment. The new rating is the CT limit.
		Year 2016																				
	882	11171	AEP			06/01/16		$11,400,000	AEP	24 months	regional reliability	509082	Rock Hill 69 kV	509056	Carthage 69 kV	1	69	11.4			123/143	Rebuild/reconductor 11.4 miles of 336 ACSR with 1272 ACSR on the Rock Hill - Carthage 69 kV line. Upgrade Carthage breaker & relay settings & Rock Hill jumpers. Upgrade switches, CT ratios, and relay settings at Rock Hill and Carthage. Remove switches in middle of line.
20000	511	10656	AEP	06/01/16		M	02/13/08	$11,000,000	AEP	60 months	regional reliability	90002	Osage 345 kV	99832	Osage 161 kV	1	345/161				400/440	Install new 345/161 kV transformer at Osage Creek
20000	511	10659	AEP	06/01/16		M	02/13/08	$24,500,000	AEP	60 months	regional reliability	507001	Shipe Road 345 kV	90001	E Rogers 345 kV	1	345		15		1336/1915	Install 9 miles of 345 kV line from Shipe Road to East Rogers
20000	511	10660	AEP	06/01/16		M	02/13/08	$65,500,000	AEP	60 months	regional reliability	90001	E Rogers 345 kV	90002	Osage 345 kV	1	345		40		1336/1915	Install 32 miles of 345 kV line from East Rogers to Osage Creek
	681	10898	AEP			06/01/16		$2,000,000	AEP	24 months	regional reliability	507716	Broadmoor 69 kV	507724	Fern Street 69 kV	1	69	2			90/105	Rebuild 2 miles of 266 ACSR with 795 ACSR and replace Fern Street Switches
	647	10848	EDE	06/01/16				$12,375,000	SPP	18 months	zonal - sponsored						69			27		Convert 27 mi of 34.5 kV to 69 kV in the Baxter Springs area
	716	10953	GMO			06/01/16		$150,000	SPP	12 months	regional reliability	541211	Blue Spring South 161 kV	541206	Prairie Lee kV	1	161				229/260	Replace Wavetrap
	549	10698	GRDA			06/01/16		$370,530	GRDA	12 months	regional reliability	512626	Maid 69 kV	512681	Pryor Foundry South 69 kV	1	69	1.4			130/143	Reconductor 69 kV Line to 1272 ACSR and replace 600A switch with 1200A switch.
	550	10699	GRDA			06/01/16		$370,530	GRDA	12 months	regional reliability	512626	Maid 69 kV	512696	Redden 69 kV	1	69	1.3			130/143	Reconductor 69 kV Line to 1272 ACSR and replace 600A switch with 1200A switch.
20002	518	10663	OGE	06/01/16			02/13/08	$250,000	OGE	12 months	regional reliability	514927	HSLEast 69 kV	514937	HSLWest 69 kV	1	69				134/143	Increase rating of HSL East kV to HSL West 69 kV line to 143 MVA. Planned by OGE in 2008.
	682	10899	OGE			06/01/16		$5,300,000	OGE	24 months	regional reliability	515088	Little River 69 kV	515054	Maud 69 kV	1	69	10.67			111/125	Rebuild 10.67 miles of line to 477AS33
	842	11111	SPS	06/01/16		06/01/11		$5,166,960	SPP	18 months	regional reliability	524209	Lawrence pk 69 kV	524321	Georgia S 69 kV	2	69		1.91		60/60	add new 69 kV Ckt Georgia-Lawrence pk pipe type cable CKT 2
	843	11112	SPS	06/01/16		06/01/16		$6,571,440	SPP	18 months	regional reliability	524216	Lawrence Pk 2 69 kV	524200	Soncy 69 kV	2	69		3.24		60/60	add new 69 kV Ckt SONCY-Lawrence pk 2 pipe type cable CKT 2
	844	11113	WFEC			06/01/16		$3,341,000	SPP	24 months	regional reliability	521005	Mustang 69kV	521058	Sunshine Canyon 69kV	1	69	9.9			91/114	Upgrade 9.9 miles of 69 kV between Mustang to Sunshine Canyon from 4/0 to 795; new rating 91/114
	847	11117	WFEC			06/01/16		$6,705,000	SPP	18 months	regional reliability	521008	Nash 69 kV	521085	Wakita 69 kV	1	69	14.9			53/65	Upgrade Wakita to Nash, 1/0 to 336.4 ACSR
	659	10865	WFEC	06/01/16		06/01/14		$3,712,500	SPP	12 months	regional reliability	521037	Reeding 138 kV	520847	Cashion 138 kV	1	138			11	144/179	Convert 11 mile Reeding - Cashion 69 kV line to 138 kV.
	663	10869	WR			06/01/16		$641,250	SPP	12 months	regional reliability	533180	Tecumseh Energy Center 115 kV	533192	Hook Jct 115 kV	1	115	1.52			223/240	Tear down and rebuild TEC - Hook Jct. - County Line 115 kV.
		Year 2017																				
	877	11157	AEP			06/01/17		$13,900,000	AEP	24 months	regional reliability	511447	Clinton City 69 kV	511517	Thomas Tap 69 kV	1	69	13.9			69/72	Rebuild 13.9 miles of 4/0 ACSR with 795 ACSR and reset Clinton City relay.
	878	11158	AEP			06/01/17		$2,700,000	AEP	24 months	regional reliability	508348	North Mineola 69 kV	508347	Mineola 69 kV	1	69	2.68			123/143	Reconductor 2.68 miles of 477 ACSR 69 kV line with 1272 ACSR and raise CT ratio and relay settings.
	504	10649	AEP			06/01/17		$4,700,000	AEP	24 months	regional reliability	507718	Brown Lee 69 kV	507745	North Market 69 kV	1	69	4.7			133/143	Rebuild 4.7 mile Brown Lee- North Market 69 kV line of 2-203 ACSR & 666 ACSR with 1272 ACSR & raise CT ratio & relay
	502	10647	AEP			06/01/17		$3,220,000	AEP	24 months	regional reliability	509075	Northwest Henderson 69 kV	509081	Poynter 69 kV	1	69	3.22			143/143	Reconductor 3.25 miles Northwest Henderson-Poynter 69 kV line with 1272 ACSR.
20036	440	10571	EDE		NTC-Modify Timing	06/01/17	01/27/09	$2,274,000	SPP	18 months	regional reliability	547538	SUB 131 - Diamond Junction 69 kV	547582	SUB 362 - Sarcoxie Southwest 69 kV	1	69	7.55			54/65	Reconductor 7.55 mile Diamond Jct. - Sarcoxie Southwest 69 kV line from 1/0 Cu to 336 ACSR.
	677	10891	EDE	06/01/17		06/01/18		$25,000,000	EDE	48 months	regional reliability	547498	SUB 439 - Stateline 161 kV	547900	Joplin 59 161 kV	1	161		5.32			Tear down the Riverton to Joplin 59 69 kV line, rebuilding the line to 161 kV from Stateline to outside Joplin 59 sub. Tear down and rebuild Joplin 59 to Gateway to Pillsbury to Reinmiller, converting those 69 kV lines to 161 kV. Tap the 161 kV line between Joplin 59 and Gateway at Joplin 422.
	677	10892	EDE	06/01/17		06/01/18					regional reliability	547900	Joplin 59 161 kV	547551	Gateway 161 kV	1	161		2.94			
	677	10893	EDE	06/01/17		06/01/18					regional reliability	547551	Gateway 161 kV	547685	Pillsbury 161 kV	1	161		1			
	677	10894	EDE	06/01/17		06/01/18					regional reliability	547685	Pillsbury 161 kV	547500	Reinmiller 161 kV	1	161		3.25			
20036	203	10259	EDE		NTC-Modify Timing	06/01/17	01/27/09	$1,277,935	EDE	18 months	regional reliability	547533	SUB 109 - Atlas Junction 69 kV	547532	SUB 108 - Carthage Northwest 69 kV	1	69	3.5			54/65	Reconductor 3.5 mile Atlas Jct. - Carthage Northwest 69 kV line from 4/0 ACSR to 336 ACSR for 65 MVA Rate B.
	565	10716	GMO	06/01/17		06/01/19		$450,000	GMO	12 months	regional reliability	541303	Clinton 69 kV	541301	Clinton Plant 69 kV	1	69	2			100/107	Reconductor with 795ACSR.
	687	10904	GMO			06/01/17		$50,000	GMO	12 months	regional reliability	541224	Longview 161 kV	541222	Western Electric 161 kV	1	161				229/260	Replace wavetraps at Longview and Western Electric
20017	30160	50168	OGE	06/01/17		M	01/16/09	$11,000,000	OGE	18 months	transmission service	515305	Fort Smith 500 kV	515300	Fort Smith 161 kV	5	500/161					Convert Ft. Smith 161 kV to 1-1/2 breaker design and install 3rd 500-161 kV transformer bank.
20017	30164	50172	OGE	06/01/17		M	01/16/09	$100,000	OGE	9 months	transmission service	515336	VBI 161 kV	504032	VBI North 161 kV	1	161				72/72	Upgrade CT
	810	11071	OGE			06/01/17		$120,000,000	OGE	48 months	regional reliability	525835	Stateline 345 kV	521126	Anadarko (Gracemont) 345 kV	1	345		100		1793/1793	Build new 100 mile 345 kV line from OGE Anadarko to Oklahoma/Texas border towards SPS's Reactor station on Woodward-Tuco 345 kV line.
	863	11140	OPPD			06/01/17		$146,000	OPPD	12 months	regional reliability	647907	SUB 907 69 kV	647911	SUB 911 69 kV	1	69				102/102	Increase line clearances to allow the use of a higher conductor rating.
	761	11004	SPS	06/01/17		06/01/17		$3,375,000	SPP	20 months	regional reliability	527482	Chaves County Interchange 115 kV	527546	Samson Sub 115 kV	1	115	7.78			226/249	Reconductor 7.78 miles with 795 kcmil conductor.
	762	11005	SPS	06/01/17		06/01/17		$3,375,000	SPP	20 months	regional reliability	527482	Chaves County Interchange 115 kV	527501	Urton Sub 115 kV	1	115	3.7			226/249	Reconductor 3.70 miles with 795 kcmil conductor.
	807	11069	SPS	06/01/17		06/01/17		$16,425,000	SPP	48 months	regional reliability	525835	Stateline 345 kV	521126	Anadarko (Gracemont) 345 kV	1	345		10		1643/1793	Build new 10 mile 345 kV line from SPS's Reactor station on Woodward-Tuco 345 kV line to Oklahoma/Texas border towards OGE Anadarko.
	808	11070	SPS	06/01/17		06/01/17		$134,325,000	SPP	48 months	regional reliability	523961	Potter County Interchange 345 kV	525835	Stateline 345 kV	1	345		115		1643/1793	Build new 115 mile 345 kV line from Potter to Stateline.
	763	11006	SPS	06/01/17		06/01/17		$1,890,000	SPP	24 months	regional reliability	523636	Gray County Interchange 115 kV	523635	Gray County Interchange 69 kV	2	115/69				84/96.6	Add second 115/69 kV transformer at Gray County substation.
	856	11127	SPS			06/01/17		2812500	SPP	18 months	regional reliability	524567	NE Hereford 115 kV	524555	Centre 115 Kv	1	115		5		157/173	Convert 69 kava load to 115 kV and build 5 mile line
	833	11100	SPS	06/01/17		06/01/17		$1,890,000	SPP	30 months	regional reliability	524567	NE Hereford 115 kV	524573	NE Hereford 69 kV	2	115/69				84/96	Add 2nd transformer 115/69 kV 84/96 MVA CKT 2
	909	11205	WFEC			06/01/17		$2,250,000	SPP	12 months	regional reliability	521018	Oklahoma University SW 69 kV	520861	Cole 69 kV	1	69	4			72/89	Reconductor 4.0 miles with 556 kcmil conductor.
	661	10867	WR			06/01/17		$1,063,125	SPP	18 months	regional reliability	533192	Hook JCT 115 KV	533153	County Line 3 115 kV	1	115	2.52			223/223	Tear down and rebuild 2.52-mile County Line-Hook Jct 115 kV line, 1192 ACSR.
	756	10998	WR			06/01/17		$6,930,000	SPP		regional reliability	532858	Baldwin Creek 230 kV	533232	Baldwin Creek 115 kV	1	230/115				280/308	Tap Lawrence Hill-Swissvale 230 kV line near Baldwin Creek substation and Install Baldwin Creek 230/115 kV transformer
		Year 2018																				
	479	10616	AEP			06/01/18		$12,630,000	AEP	24 months	regional reliability	509064	Georgia-Pacific 138 kV	509050	Keatchie REC 138 kV	1	138	12.63			287/287	Rebuild 12.63 mi of the Georgia Pacific-Keatchie 138 kV 795 ACSR line with 1272 ACSR.
	478	10615	AEP			06/01/18		$350,000	AEP	18 months	regional reliability	507728	Forbing Tap 69 kV	507754	South Shreveport 69 kV	1	69	0.27			90/121	Rebuild 0.27 miles Forbing Road to South Shreveport 69 kV to 1272 ACSR (next limit is 500 Cu bus & jumpers).
	509	10654	AEP			06/01/18		$2,904,000	AEP	24 months	regional reliability	506980	Centerton 161 kV			1	161					Convert the 506952 Centerton 69-12.5 kV station to 161-12.5 kV. Disconnect Centerton station from the 69 kV line and connect to the 506929 East Centerton to 506960 Bentonville Hwy 279 161 kV line 2.0 miles west of 506929 East Centerton station.
	814	11076	CUS	06/01/18		M		$1,282,500	SPP		zonal - sponsored	549904	James River 69 kV	549908	South Highway 65 69 kV	1	69	3.8			153/159	Rebuild James River to South Highway 69 kV
	815	11077	CUS	06/01/18		M		$641,250	SPP		zonal - sponsored	549907	Sunset 69 kV	549908	South Highway 65 69 kV	1	69	1.9			153/159	Rebuild South Highway to Sunset 69 kV
	688	10905	GMO			06/01/18		$2,000,000	SPP	18 months	regional reliability	541229	Odessa 161kV	541267	Odessa 69kV	1	161/69				100/110	Replace Odessa 161/69kV transformer with new 100/110MVA
	667	10873	GRDA			06/01/18		$112,500	SPP	6 months	regional reliability	512681	Pryor Foundry South 69 kV	512661	CPP Transformer #2 69 kV	1	69				85/97	Replace 600A switch with 1200A switch
	850	11120	OGE			06/01/18		$25,000	OGE	12 months	regional reliability	514977	Kentucky Tap 69 kV	514924	Pennsylvania 69 kV	1	69				134/143	Upgrade the 800 amp CT in Penn Sub to 1200 amp
	804	11066	SPS			06/01/18		$13,500,000	SPP	24 months	regional reliability	525830	Tuco Interchange 230 kV	525828	Tuco Interchange 115 kV	3	230/115				250/250	Add 3rd transformer at TUCO 230/115 250 MVA CKT 3
	805	11067	SPS			06/01/18		$1,890,000	SPP	24 months	regional reliability	523748	Bowers Interchange 115 kV	523747	Bowers Interchange 69 kV	2	115/69				84/96	Add 2nd transformer at Bowers 115/69 kV CKT 2
	854	11124	SPS	06/01/18		06/01/18		$33,367,500	SPP	48 months	regional reliability	525832	Tuco 345 kV	526340	Jones 345 kV	1	345		29.66		1643/1793	Add new 345 kV line Tuco - Jones Ckt 1 29.66 miles
	854	11125	SPS			06/01/18		$22,150,000	SPP	30 months	regional reliability	526340	Jones 345 kV	526338	Jones 230 kV	1	345/230				559/559	Add new 345-230 kV 559 MVA CKT 1
	837	11105	SPS			06/01/18		$2,925,000	SPP	28 months	regional reliability	525636	Lamb Co 115 kV	525651	LC-Little 115 kV	1	115		5.2		157/173	Add new 115 kV Ckt Lamb Co to Lea County Littlefield
	884	11173	SPS	06/01/18		6/1/2018		$8,352,500	SPP	30 months	regional reliability	527800	Eddy 230 kV	527798	Eddy 115 KV	2	230/115				168/168	Add 2nd transformer Eddy Co 230-115 kV CKT 2
	885	11174	SPS	06/01/18		6/1/2018		$8,352,500	SPP	30 months	regional reliability	526161	Carlise 230 kV	526160	Carlise 115 kV	2	230/115				168/168	Add 2nd transformer Carlise 230-115 kV CKT 2

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	679	10896	SWPA			06/01/18		$2,250,000	SPP		regional reliability - non OATT	505436	Poplar Bluff 69 kV	505438	Poplar Bluff 161 kV	2	161/69				70/70	Replace Poplar Bluff 2nd transformer with larger transformer, 70/70 MVA unit.
	433	10563	WR			M		$150,000	SPP	18 months	regional reliability	533747	Yost 69 kV	533742	Moundridge 69 kV	1	69				108/108	Reset ct's. New Rate A:108 B:108
	820	11083	WR			06/01/18		$1,687,500	SPP	12 months	regional reliability	533175	17th & Fairlawn 115 kV	533166	Indian Hills 115 kV	1	115	3			240/240	Tear down and rebuild 17th & Fairlawn - Indian Hills 115kV Ckt 1
			Year 2019																			
	481	10619	AEP			06/01/19		$6,000,000	AEP	36 months	regional reliability	507189	North Huntington 161 kV	507196	Midland REC 161 kV	1	161			4	429/597	Rebuild and reconductor 4.0 miles of 4/0 ACSR 69 kV to 1590 ACSR 161 kV from converting North Huntington to Midland REC to 161 kV. Add 161 kV terminal at North Huntington.
	481	10620	AEP			06/01/19		$1,500,000	AEP	36 months	regional reliability	507196	Midland REC 161 kV	507202	Midland 161 kV	1	161			1.25	429/597	Rebuild and reconductor Midland REC-Midland from 69 kV 4/0 ACSR to 161 kV 1590 ACSR.
	481	10621	AEP			06/01/19		$2,500,000	AEP	36 months	regional reliability	507202	Midland 161 kV	507187	Midland 69 kV	1	161/69				90/102	Add 161/69 kV autotransformer at Midland.
	481	10624	AEP			06/01/19		$17,000,000	AEP	36 months	regional reliability	515261	Bonanza Tap 161 kV	507202	Midland 161 kV	1	161		6	8.9	429/597	Build Bonanza-Midland 1590 ACSR 161 kV line. Old Midland-Excelsior section to be converted from 69 kV to 161 kV. Add 4-161 kV breakers at Bonanza.
	879	11158	AEP			06/01/19		$9,000,000	AEP	24 months	regional reliability	515242	Bluebell 138 kV	509758	Prattville 138 kV	1	138	9			287/287	Rebuild 9.0 mile Prattville-Bluebell 138 kV line from 795 ACSR to 1590 ACSR. New summer ratings 287/287 limited by breaker, switches, CTs, wave trap.
	501	10646	AEP			06/01/19		$200,000	AEP	12 months	regional reliability	509061	Evenside 69 kV	509075	NW Henderson 69 kV	1	69				65/76	Replace 600 A breaker with 1200A at Evenside 69 kV.
	473	10609	CUS	06/01/19		06/01/19		$979,000	CUS	24 months	regional reliability	549904	James River 69 kV	549933	Twin Oaks 69 kV	1	69	3			153/159	Reconductor 69kV line from 636 ACSR to 762.8 ACSS/TW
	671	10877	OGE			06/01/19		$450,000	OGE	12 months	regional reliability	515166	Ardmore 69 kV	515170	Chickasaw 69 kV	1	69				97/111	Increase CT ratio at both Chickasaw and Ardmore. Also possibly change out relay
	30212	10999	OGE			06/01/19		$250,000	OGE	12 months	regional reliability	514840	Jones Tap 138 kV	514839	Bryant 138 kV	1	138				478/478	Replace Jones Tap bus 1200A switch with 2000A switch.
	849	11119	OGE			06/01/19		$60,000	OGE	12 months	regional reliability	514976	Kentucky 69 kV	514977	Kentucky Tap 69 kV	1	69				134/143	Upgrade the existing 600 amp 69 kV switches in Kentucky Sub to 1200 amp
	910	11207	OGE			06/01/19		$225,000	SPP	12 months	regional reliability	514839	Bryant 138 kV	514835	Memorial 138 kV	1	138					Replace wavetrap
	689	10906	KCPL			06/01/19		$2,000,000	KCPL	24 months	regional reliability	543063	South Waverly 161kV	543094	South Waverly 69kV	1	161/69				30/33	Replace South Waverly 161/69kV transformer with larger 30/33MVA model; interim mitigation is to move 20% of load off S Waverly 161kV bus starting in 2010
	859	11136	KCPL			06/01/19		$1,670,625	SPP	24 months	regional reliability	543020	Birmingham 161kV	542973	Hawthorn 161kV	1	161	3.3				Reconductor Hawthorn - Birmingham 161kV
	30211	10994	MKEC			06/01/19		$3,825,000	SPP	24 months	regional reliability	539674	Medicine Lodge 138 kV	539673	Medicine Lodge 115 kV	1	138/115				147/170	Replace Medicine Lodge 138/115 kV transformer with a larger 147/170 MVA transformer
	30208	10991	MKEC			06/01/19		$3,150,000	SPP	18 months	regional reliability	533036	Clearwater 138 kV	539675	Milan Tap 138 kV	1	138	5.6			534/534	Rebuild MKEC portion of the Clearwater-Milan tap 115 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)
	30210	10993	MKEC			06/01/19		$225,000	SPP	12 months	regional reliability	539668	Harper 138 kV	539675	Milan Tap 138 kV		138				120/120	Replace Wave Trap at Harper Substation.
	753	10990	NPPD	06/01/19		06/01/19		$6,000,000	NPPD	24 months	regional reliability	640076	Beatrice 115 kV	640208	Harbine 115 kV	1	115	10			240/240	Reconductor and upgrade terminal equipment to effect higher rating by 2019. 240 MVA Normal Continuous Rating. 240 MVA 4-Hour Emergency Rating.
20031	151	10195	SPS			06/01/19	01/27/09	$1,260,000	SPP	24 months	regional reliability	525826	Tuco 69 kV	525828	Tuco 115 kV	1	115/69				84/84	Add third Tuco 115/69 kV autotransformer with 84/84 MVA rating.
20031	153	10197	SPS			06/01/19	01/27/09	$600,000	SPP	24 months	regional reliability	527961	Potash Junc 69 kV	527962	Potash Junc 115 kV	1	115/69				40/40	Add third Potash Junction Interchange 115/69 kV transformer.
	825	11092	SPS			06/01/19		$225,000	SPP	18 months	regional reliability	527701	Artesia 69 kV	527754	CV-Artesia 69 kV	1	69	0.45			120/154	Reconductor 0.45 miles 69 kV from 4/0 to 397.5 ACSR
	827	11094	SPS			06/01/19		$3,518,438	SPP	18 months	regional reliability	524009	Cherry 115 kV	524106	Northwest 115 kV	1	115	8.34			226/249	Reconductor 8.34 miles 115 kV from 397.5 to 750 ACSR
	832	11099	SPS			06/01/19		$1,890,000	SPP	28 months	regional reliability	524105	Northwest 69 kV	524106	Northwest 115 kV	2	115/69				84/96	Add 2nd transformer 115/69 kV 84/96 MVA CKT 2
	838	11106	SPS			06/01/19		$3,037,500	SPP	18 months	regional reliability	526020	Hockley Co 115 kV	526058	E Levelland 115 Kv	1	115		5.4		157/173	Add new 115 kV Ckt Hockley Co-E Levelland Co
	855	11126	SPS			06/01/19		85375	SPP	18 months	regional reliability	526075	Stanton 69 kV	526076	Stanton 69 kV	1	69			0.2		convert 69 kV load onto 115 kV
	901	11198	SPS			06/01/19		$450,000	SPP	6 months	regional reliability	524044	Nichols Station 230 kV	524415	Amarillo South Interchange 230 kV	1	230				436/502	Replace NICHOLS Line Trap with 1200 Amp B unit 230 kV
	655	10860	SWPA			06/01/19		$825,000	SPP		regional reliability - non OATT	505492	Springfield 161 kV	505494	Springfield 69 kV	1	161/69				70/70	Replace Springfield transformer #1 three winding transformer with 70 MVA auto transformer.
	898	11193	WR	06/01/19		M		$8,521,875	SPP		zonal - sponsored	533153	County Line 115 kV	533482	Valley Falls 115 kV	1	115			20.2	223/245	convert County Line - Arnold to 115 kV. Valley Falls sub converted to 115
	898	11194	WR	06/01/19		M		$9,534,375	SPP		zonal - sponsored	533211	Arnold 115 kV	533482	Valley Falls 115 kV	1	115			22.6	223/245	convert County Line - Arnold to 115 kV. Valley Falls sub converted to 115
	30209	10992	WR			06/01/19		$3,431,250	SPP	18 months	regional reliability	533036	Clearwater 138 kV	539675	Milan Tap 138 kV	1	138	6.1			534/534	Rebuild Westar portion of the Clearwater-Milan tap 115 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)
			Withdraw																			
20000	347	10444	AEP	06/01/11	NTC-Withdraw	D	02/13/08	$2,000,000	AEP	18 months		508830	Baldwin 69 kV	508842	Woodlawn 69 kV	1	69	2.7			72/83	Reconductor with 2.7 miles 477 ACSR 69 kV Woodlawn-Baldwin. Reset relays.
20027	477	10614	AEP	06/01/13	NTC-Withdraw	D	01/27/09	$6,900,000	AEP	24 months		508830	Baldwin 69 kV	508836	Karnack Tap 69 kV	1	69	6.9			72/83	Reconductor 6.9 miles with 477 ACSR 69 kV from Baldwin - Karnack Tap.
20016	345	10442	AEP	06/01/10	NTC-Withdraw	D	01/16/09	$125,000	AEP	15 months		508299	Quitman-Magnolia 69 kV	508340	Forest Hills REC 69 kV	1	69				143/143	Replace 69 kV switch at Magnola tap for new emergency limit 85 MVA.
20011	441	10572	CUS	06/01/12	NTC-Withdraw	D	02/13/08	$805,000	CUS	24 months		549906	Kickapoo 69 kV	549907	Sunset 69 kV	1	69	1			153/159	Reconductor 69kV line from 636 ACSR to 762.8 ACSS/TW
20009	379	10492	KCPL	06/01/15	NTC-Withdraw	D	02/13/08	$5,418,700	KCPL	24 months		543121	Hillsdale 161 kV	543054	Cedar Niles 161 kV	1	161		8		293/335	New Hillsdale-Cedar Niles 161 kV Line and Cedar Niles ring bus
20002	397	10515	OGE	06/01/12	NTC-Withdraw	D	02/13/08	$6,850,000	OGE	24 months		514861	Mustang 138 kV	514886	Yukon 138 kV	1	138			7	268/308	Convert 7 mile Mustang -Yukon 69 kV line to 138 kV.
20002	397	10516	OGE	06/01/12	NTC-Withdraw	D	02/13/08	$3,500,000	OGE	24 months		514886	Yukon 138 kV	514898	Cimarron 138 kV	1	138			3	268/308	Convert 3 mile Yukon - Cimarron 69 kV line to 138 kV.
20033	623	10811	WR	12/31/10	NTC-Withdraw	D	01/27/09	$7,415,000	WR	24 months		533558	Timber Junction 69 kV	533561	City Of Winfield 69 Kv	1	69	14.63			132/145	Rebuild the 14.63 miles of 69 kV line from Timber Junction - Winfield.
20033	624	10812	WR	06/01/11	NTC-Withdraw	D	01/27/09	$4,927,500	SPP	24 months		533328	Fort Junction Switching Station 115 kV	533342	West Junction City 115 kV	1	115		8.76		240/240	Build new 8.76 mile Fort Junction - West Junction City 115 kV line that follows the path of the JEC - Summit 345 kV line. Remove old double circuit and West Junction City Junction (East) - West Junction City 115 kV line.
20006	410	10536	WR		NTC-Withdraw	D	02/13/08	$2,306,250	SPP	12 months		533412	Ark Valley 115 kV	533455	Tower 33 115 kV	1	115	4.1			223/245	Rebuild Ark Valley-Tower 33 115 kV
20033	495	10640	WR		NTC-Withdraw	D	01/27/09	$2,377,448	WR	18 months		533250	Lawrence Hill 115kV	533253	Mockingbird Hill 115 kV	1	115	5.49			223/240	Rebuild the 5.49 mile Lawrence Hill to Mockingbird Hill 115 kV line.
20033	169	10218	WR	06/01/17	NTC-Withdraw	D	01/27/09	$10,000	WR	12 months		533362	Chapman 115 kV	533323	Clay Center Junction 115 KV	1	115				72/72	Uprate CT ratio on Chapman - Clay Center 115 kV line.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	Device Type	SPP MDWG Bus Number 2007 series	Location	Voltage	Total Rating	Project Description
			Year 2010														
	30248	50286	CRE			06/01/10		$1,166,400	SPP	12 months	regional reliability - non OATT	Cap Bank	522973	CR-S. Midland 138 kV	138	28.8 Mvar	Install 2 Blocks of 14.4 Mvar
	30249	50287	CRE			06/01/10		$583,200	SPP	12 months	regional reliability - non OATT	Cap Bank	522914	CR-Salem	138	14.4 Mvar	Install 2 Blocks of 7.2 Mvar
20010	30078	50084	EDE	12/01/10		M	02/13/08	$2,600,000	EDE	24 months	Zonal Reliability	Cap Bank	547497	SUB 438 - Riverside 161 kV	161	66 Mvar	Install (3) 22 Mvar capacitor banks for a total of 66 Mvar at Riverside Sub #43
20053	30221	50225	GMO	06/01/10			09/18/09	$486,000	GMO	12 months	regional reliability	Cap Bank	541279	Ralph Green 69 kV	69	12 Mvar	Add 12 Mvar cap bank at Ralph Greer
20028	30072	50078	GRDA	06/01/10		M	01/27/09	$800,000	GRDA	18 months	regional reliability	Cap Bank	512633	Afton 69 kV	69	21.6 Mvar	Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Afton 69 kV bus
20009	30077	50083	KCPL	06/01/10		M	02/13/08	$1,057,630	KCPL	12 months	Zonal Reliability	Cap Bank	542978	Craig 161 kV	161	50 Mvar	New Craig 50 Mvar capacitor bank
20054	30062	50068	MKEC	05/01/10		M	09/18/09	$1,400,000	MKEC	3 months	regional reliability	Cap Bank	539668	Harper 138 kV	138	20 Mvar	Add 138 kV 20 Mvar cap bank at Harpe
20007	30061	50067	MKEC	03/01/10		M	02/13/08	$2,300,000	MKEC	7 months	regional reliability	Cap Bank	539687	Pratt 115 kV	115	24 Mvar	Install (2) 12 Mvar capacitor banks at Pratt 115kV
	30195	50202	NPPD	06/01/10		M		$375,000	NPPD	24 months	zonal - sponsored	Cap Bank	640408	Westminster 34.5 kV	34.5	7.2 Mvar	Add one 7.2 Mvar cap at Westminster
	30240	50252	OGE		NTC	06/01/10		$360,000	SPP	12 months	regional reliability	Cap Bank	515413	Cushing Oil2 69kV	69	9 Mvar	Install 9 Mvar capacitor bank at Cushing Oil 69kV bus
	30240	50253	OGE		NTC	06/01/10		$240,000	SPP	12 months	regional reliability	Cap Bank	515027	Tiger Creek2 69kV	69	6 Mvar	Install 6 Mvar capacitor bank at Tiger Creek 69kV bus
	30234	50246	SEPC		NTC	06/01/10		$1,000,000	SEPC	18 months	regional reliability	Cap Bank	531424	Johnson Corner 115 kV	115	12 Mvar	Install 12 Mvar capacitor bank at Johnson Corner 115 kV substation.
	30213	50217	SPS		NTC	06/01/10		$2,025,000	SPP	12 months	regional reliability	Cap Bank	524162	East Plant 115 kV	115	50 Mvar	Install 50 Mvar capacitor bank at East Plant 115 kV bus configured as two blocks of 25 Mvar.
	30250	50288	SPS	06/01/10		M		$288,000	SPP		zonal - sponsorec		523157	Perryton Interchange 69 kV	69	7.2 Mvar	Install 1 stage of 7.2 Mvar
	30251	50289	SPS	06/01/10		M		$288,000	SPP		zonal - sponsorec		524745	Castro County Interchange 69 kV	69	7.2 Mvar	Install a 7.2 Mvar cap at Castro County 69 kV
	30244	50257	SPS		NTC	06/01/10		$225,000	SPP	12 months	regional reliability	Line Trap	523978	Harrington Station Mid Bus 230 kV	230	1200 Amp	Replace 800A wave trap with 1200A.
20003	30079	50085	WFEC	06/01/10		M	02/13/08	$324,000	SPP	12 months	regional reliability	Cap Bank	520846	Carter 69 kV	69	12 Mvar	Install 12 Mvar capacitor at Carter Jct which makes at total of 24 Mvar
20030	30172	50180	WFEC	06/01/10		M	01/27/09	$300,000	SPP	12 months	regional reliability	Cap Bank	520890	Eagle Chief 69 kV	69	12 Mvar	Install 12 Mvar capacitor at Eagle Chief Southwest 69 kV bus
20006	30056	50062	WR	06/01/10	NTC-Modify Timing & Scope	06/01/17	02/13/08	$588,600	WR	18 months	regional reliability	Cap Bank	533348	Trans Canada / Seneca 115 kV	115	10.9 Mvar	Add 10.9 Mvar capacitor bank at Trans Canada 115 kV instead of Seneca
	30252	50290	WR	12/01/10		M		$3,072,000	SPP		zonal - sponsorec	Cap Bank	532986	Benton 138 kV	138		Add 76.8 Mvar bank at Benton
19986	30082	50088	WR	6/1/2010		M	02/02/07	$500,000	WR	18 months	Zonal Reliability	Cap Bank	533435	3rd & VanBuren 115 kV	115	17 Mvar	Install switched capacitor bank.
19986	30057	50063	WR	6/1/2010		M	02/02/07	$715,000	WR	18 months	Zonal Reliability	Cap Bank	533481	Nortonville 69 kV	69	15 Mvar	Install 15 Mvar capacitor at Nortonville 69 kV (bus #533481)
			Year 2011														
	30187	50194	GMO		NTC	06/01/11		$810,000	SPP	12 months	regional reliability	Cap Bank	541240	Adrian 161kV	161	20 Mvar	Add 20 Mvar capacitor bank at Adrian 161 kV
20053	30220	50224	GMO	06/01/11			09/18/09	$1,400,000	GMO	18 months	regional reliability	Cap Bank	541205	Blue Springs East 161 kV	161	50 Mvar	Add 50 Mvar cap bank at Blue Springs Eas
20001	30086	50092	GRDA	06/01/11		M	02/13/08	$800,000	GRDA	18 months	regional reliability	Cap Bank	512720	Jay Gr2 69 kV	69	21.8 Mvar	Install 21.8 Mvar capacitor at Jay 69 kV substation
20051	30217	50221	KCPL	06/01/11			09/18/09	$50,000	KCPL	18 months	transmission service	Cap Bank		Craig 161 kV	161	20 Mvar	Add 20 Mvar cap bank to make a total of 70 Mvar at Craig 161kV
20032	30176	50184	MIDW	06/01/11	NTC-Modify Scope	06/01/11	01/27/09	$300,000	MIDW	12 months	regional reliability	Cap Bank	530619	Kinsley 115 kV	115	5 Mvar	Install 5 Mvar Cap at Kinsley 115 kV
	30190	50197	MIDW		NTC	06/01/11		$300,000	MIDW	12 months	regional reliability	Cap Bank	530621	Pawnee 115 kV	115	5 MVar	Install 5 Mvar capacitor bank at Pawnee 115 kV.
20007	30090	50096	MKEC	06/01/11		M	02/13/08	$1,300,000	MKEC	18 months	regional reliability	Cap Bank	539701	Russell 115 kV	115	9.6 Mvar	Add 9.6 Mvar capacitor at Russell 115 kV
	30204	50211	NPPD	06/01/11	NTC	06/01/11		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640392	Valentine 115 kV	115	10.8 Mvar	Install 10.8 Mvar capacitor bank at Valentine 115 kV.
	304	50148	OGE	03/01/11				$264,000	OGE	12 months	zonal - sponsorec	Cap Bank	515158	Madill Industries 138 kV	138	9 Mvar	Add 9 Mvar of emergency capacitors
	30235	50247	SEPC		NTC	06/01/11		$650,000	SEPC	12 months	regional reliability	Cap Bank	531424	Johnson Corner 115 kV	115	12 Mvar	Install 2nd 115 kV 12 Mvar cap bank at Johnson Corner substation.
	30246	50259	SPS		NTC	06/01/11		$583,200	SPP	12 months	regional reliability	Cap Bank	525224	Kress Rural 69 kV	69	14.4 Mvar	Install 2 Blocks of 7.2 Mvar capacitor bank at Kress 69 kV.
20059	30232	50243	WR	06/01/11			09/18/09	$1,215,000	WR		transmission service	Cap Bank		Timber 138 kV	138	30 Mvar	Add 138 kV 30 Mvar Cap bank at Timber
20059	30233	50244	WR	06/01/11			09/18/09	$607,500	WR	12 months	transmission service	Cap Bank	533646	Tioga 69 kV	69	15 Mvar	Add 69 kV 15 Mvar Cap bank at Tioga
	30253	50291	WR	06/01/11		M		$384,000	SPP		zonal - sponsorec	Cap Bank	533319	Riley 115 kV	115	9.6 Mvar	one stage of 9.6 Mvar
	30254	50292	WR	12/01/11		M		$3,072,000	SPP		zonal - sponsorec	Cap Bank	533062	Rose Hill 138 kV	138	76.8 Mvar	Install 2nd block of 76.8 Mvar
	30255	50293	WR	06/01/11		M		$432,000	SPP		zonal - sponsorec	Cap Bank	533861	Butler County No. 5-Furley 69 kV	69	10.8 Mvar	one stage of 10.8 Mvar
			Year 2012														
	30070	50076	AEP	12/1/2012				$500,000	AEP		zonal - sponsorec	Station	504186	Sugar Loaf 69 kV	69		Add tap and switches for new delivery point along 69 kV line from 507187 Midland to old 507185 Excelsior station sit
20028	30074	50080	GRDA	07/01/12		M	01/27/09	$779,000	GRDA	12 months	regional reliability	Cap Bank	300971	Tahlequah West 69 kV	69	21.6 Mvar	Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Tahlequah West 69 kV.
20007	30098	50104	MKEC	06/01/12		M	02/13/08	$1,600,000	MKEC	18 months	regional reliability	Cap Bank	539686	Plainville 115 kV	115	20 Mvar	Install 20 Mvar capacitor bank at Plainville 115 kV
	30236	50248	NPPD	06/01/12	NTC	06/01/12		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640250	Kearney 115 kV	115	36 Mvar	Install 36 Mvar capacitor bank at Kearney 115 kV.
	30200	50207	NPPD	11/01/12	NTC	11/01/12		$607,500	SPP	24 months	regional reliability	Cap Bank	640318	Petersburg 115 kV	115	15 Mvar	Add one 15 Mvar cap at Petersburg.
	30201	50208	NPPD	11/01/12	NTC	11/01/12		$729,000	SPP	24 months	regional reliability	Cap Bank	640436	Clarks 115 kV	115	18 Mvar	Add one 18 Mvar cap at Clarks 7.
	30202	50209	NPPD	11/01/12	NTC	11/01/12		$50,000	NPPD	24 months	regional reliability	Cap Bank	640051	Ainsworth 115 kV	115	18 Mvar	Expand existing 9 Mvar cap to 18 Mvar cap at Ainsworth
	30199	50206	NPPD	11/01/12		11/01/12		$364,500	SPP	24 months	zonal - sponsored	Cap Bank	640306	Oneill 69 kV	69	9 Mvar	Add one 9 Mvar cap at Oneill 69 kV
	30203	50210	NPPD	11/01/12	NTC	11/01/12		$729,000	SPP	24 months	regional reliability	Cap Bank	640305	Oneill 115 kV	115	36 Mvar	Add one 18 Mvar cap at Oneill 115
20058	30104	50110	SEPC	06/01/12			09/18/09	$2,500,000	SEPC	18 months	regional reliability	Cap Bank	531455	North Cimarron 115 kV	115	24 Mvar	Add 24 Mvar Cap bank at North Cimarron
	30257	50294	WAPA	06/01/12				$405,000	SPP	12 months	regional reliability - non OATT	Cap Bank	652478	Gregory 115 kV	115	10 Mvar	10 Mvar cap at Gregory WAPA
	30258	50296	WAPA	06/01/12				$874,800	SPP	12 months	regional reliability - non OATT	Cap Bank	652479	Martin 115 kV	115	21.6 Mvar	21.6 Mvar cap at Martin WAPA
	30259	50297	WAPA	06/01/12				$1,215,000	SPP	12 months	regional reliability - non OATT	Cap Bank	652487	Phillips 115 kV	115	30 Mvar	30 Mvar cap bank at PHILLIPS WAPA
19985	30041	50047	WFEC	06/01/12		M	02/02/07	$350,000	WFEC	12 months	regional reliability	Cap Bank	520864	Comanche 138 kV	138	12 Mvar	Install 12 Mvar capacitor at Comanche 138 kV bus
20003	30093	50099	WFEC	06/01/12		M	02/13/08	$324,000	SPP	12 months	regional reliability	Cap Bank	520971	Latta Junction 138 kV	138	12 Mvar	Install 12 Mvar capacitor at Latta Junction 138 kV
20006	30096	50102	WR	06/01/12		M	02/13/08	$580,000	WR	18 months	Zonal Reliability	Cap Bank	533240	Eudora 115 kV	115	20 Mvar	Install 20 Mvar capacitor bank at Eudora 115 kV
20059	30225	50229	WR	06/01/12			09/18/09	$607,500	WR	12 months	transmission service	Cap Bank	533621	Allen 69 kV	69	15 Mvar	Add 15 Mvar Cap bank at Allen
	30256	50295	WR	06/01/12		M		$1,120,000	SPP		zonal - sponsorec	Cap Bank	533036	Clearwater 138 kV	138	28.8 Mvar	Install 2nd block of 14.4 Mvar
			Year 2013														
	30206	50213	NPPD	06/01/12	NTC	06/01/13		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640192	Gordon 138 kV	115	9 Mvar	Install 9 Mvar capacitor bank at Gordon 115 kV.
20030	30178	50186	WFEC	06/01/13	NTC-Modify Timing	06/01/11	01/27/09	$240,000	SPP	12 months	regional reliability	Cap Bank	520894	Electra 69 kV	69	6 Mvar	Install 6 Mvar capacitor bank at Electra 69 kV bus for a total of 18 Mvar at this locatior
20006	30105	50111	WR	06/01/13		M	02/13/08	$1,000,000	WR	18 months	Zonal Reliability	Cap Bank	533267	Springhill 115 kV	115	30 Mvar	Install 30 Mvar capacitor at Springhill 115 kV
20059	30227	50231	WR	06/01/13			09/18/09	$607,500	WR	12 months	transmission service	Cap Bank	533623	Athens 69 kV	69	15 Mvar	Add 15 Mvar Cap bank at Athens
	30260	50298	WR	06/01/13		M		$432,000	SPP		zonal - sponsorec	Cap Bank	533173	Scranton 115 kV	115	10.8 Mvar	1 stage of 10.8 Mvar
	30261	50299	WR	06/01/13		M		$432,000	SPP		zonal - sponsorec	Cap Bank	533176	Shawnee Heights 115 kV	115	10.8 Mvar	1 stage of 10.8 Mvar
			Year 2014														
	30247	50260	GRDA			06/01/14		$291,600	SPP	12 months	regional reliability	Cap Bank	512697	Wagoner 69 kV	69	7.2 Mvar	Install 7.2 Mvar capacitor bank at Wagner 69 kV
	30237	50249	NPPD	06/01/14		06/01/14		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640224	Holdrege 115 kV	115	18 Mvar	Install 18 Mvar capacitor bank at Holdrege 115 kV
	30262	50275	SPS			06/01/14		$291,600	SPP	12 months	regional reliability	Cap Bank	523579	Canadian 115 kV	115	7.2 Mvar	Install 7.2 Mvar at Canadian Sub
	30113	50119	SWPA	06/01/14		06/01/14		$1,215,000	SPP	12 months	regional reliability - non OATT	Cap Bank	504080	Glencoe 161 kV	161	30 Mvar	Install 30 Mvar capacitor at Glencoe 161 kV substation
20003	30039	50045	WFEC	06/01/14		M	01/27/09	$243,000	SPP	12 months	regional reliability	Cap Bank	520904	Esquandale 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Esquandale 69 kV
20059	30226	50230	WR	06/01/14			09/18/09	$607,500	WR	18 months	transmission service	Cap Bank	533673	Altoona East 69 kV	69	6 Mvar	Add 6 Mvar Cap bank at Altoona Eas
			Year 2015														
	30191	50198	MIDW			06/01/15		$180,000	MIDW	12 months	regional reliability	Cap Bank	530619	Kinsley 115 kV	115	3 Mvar	Install 3 additional Mvar cap at Kinsley 115 kV for a total 8 Mva
	30192	50199	MIDW			06/01/15		$180,000	MIDW	12 months	regional reliability	Cap Bank	530621	Pawnee 115 kV	115	3 Mvar	Install 3 additional Mvar cap at Pawnee 115 kV for a total 8 Mva
	766	50215	SPS			06/01/15		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525192	Kress 115 kV	115	28.8 Mvar	Add 28.8 Mvar capacitor at Kress 115 kV bus.
	766	50216	SPS			06/01/15		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525212	Swisher 115 kV	115	28.8 Mvar	Add 28.8 Mvar capacitor at Swisher 115 kV bus.
	30263	50300	SPS			06/01/15		$583,200	SPP	12 months	regional reliability	Cap Bank	528547	JAL 138 kV	138	14.4 Mvar	Install 2 Blocks of 7.2 Mvar
	30264	50301	SPS			06/01/15		$1,166,400	SPP	12 months	regional reliability	Cap Bank	528505	Lea Road 138 kV	138	28.8 Mvar	Install 2 Blocks of 14.4 Mvar
	30272	50285	WFEC			06/01/15		$300,000	SPP	12 months	regional reliability	Cap Bank	520861	Cole 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Cole 69 kV bus.
	30180	50189	WFEC	06/01/15		06/01/13		$243,000	WFEC	12 months	regional reliability	Cap Bank	520804	Altus Air Force Base 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Altus Air Force Base 69 kV bus
	30188	50195	WFEC			06/01/15		$729,000	SPP	12 months	regional reliability	Cap Bank	520903	Erick 138kV	138	18 Mvar	Install 18 Mvar capacitor at Erick 138 kV bus
			Year 2016														
	30238	50250	NPPD	06/01/16		06/01/16		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640331	Riverdale 115 kV	115	36 Mvar	Add one 36 Mvar cap at Riverdale
	30239	50251	NPPD	06/01/16		06/01/16		$500,000	NPPD	24 months	zonal - sponsorec	Cap Bank	640073	Battle Creek 69 kV	69	9 Mvar	Add one 9 Mvar cap at Battle Creel
	30265	50302	SPS			06/01/16		$583,200	SPP	12 months	regional reliability - non OATT	Cap Bank	527361	LE_ERF sub 69 kV	69	14.4 Mvar	Install min. 2 blocks 7.2 Mvar

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	Device Type	SPP MDWG Bus Number 2007 series	Location	Voltage	Total Rating	Project Description
			Year 2017														
	30243	50256	AEP			06/01/17		$500,000	AEP	18 months	regional reliability	Cap Bank	508055	Bloomburg 69 kV	69	12 Mvar	Install 12 Mvar cap bank at Bloomburg 69 kV
	30207	50214	NPPD	06/01/17		06/01/17		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640144	Cozad 115 kV	115	18 Mvar	18 Mvar 115 KV CAP BANK AT COZAD
	30216	50220	SPS			06/01/17		$4,050,000	SPP	12 months	regional reliability	Cap Bank	522914	Wheeler 230 kV	230	50 Mvar	Install 50 Mvar capacitor bank at Wheeler min. 2 Blocks 25Mvar
	30266	50303	SPS			06/01/17		$583,200	SPP	12 months	regional reliability	Cap Bank	525027	Bailey Co 69 kV	69	14.4 Mvar	Install additional BLOCK 14.4 Mvar
	30140	50146	SWPA			06/01/17		$145,800	SPP	12 months	regional reliability - non OATT	Cap Bank	505458	China 69 kV	69	3.6 Mvar	Install 3.6 Mvar capacitor at China
			Year 2018														
	30184	50193	AEP			06/01/18		$600,000	AEP	18 months	regional reliability	Cap Bank	507434	South Nashville 138 kV	138	6 Mvar	Install 6 Mvar capacitor for a total of 12 Mvar at South Nashville
	30130	50136	CUS	06/01/18		06/01/18		$750,000	CUS	24 months	regional reliability	Cap Bank	549933	Twin Oaks 69 kV	69	30 Mvar	Install 30 MVAR capacitor at Twin Oaks Substation
	30267	50304	WR	06/01/18		M		$432,000	SPP		zonal - sponsored		533621	Allen 69 kV	69	20 Mvar	add one stage of 10 Mvar to existing 10 Mvar
	30268	50305	WR	06/01/18		M		$432,000	SPP		zonal - sponsored		533623	Athens 69 kV	69	20 Mvar	add one stage of 10 Mvar to existing 10 Mvar
			Year 2019														
	30241	50254	OPPD			06/01/19		$2,213,000	OPPD	12 Months	regional reliability	Cap Bank	647401	Neb City U Sub 903 69 kV	69	21.6 Mvar	Install 21.6 Mvar capacitor bank
	30269	50306	SPS			06/01/19		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525636	Lamb Co 115 kV	115	28.8 Mvar	Install 2 Blocks of 14.4 Mvar
	30270	50307	SPS			06/01/19		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525622	Deaf Smith 115 kV	115	28.8 Mvar	Install min. 2 blocks 14.4 Mvar
			Withdraw														
20034	30174	50182	GMO		NTC-Withdraw	D	01/27/09	$350,000	SPP	12 months		Cap Bank	541365	Craig 69 kV	69	5 Mvar	Install 5 Mvar capacitor at Craig 69 kV bus
20034	30076	50082	GMO		NTC-Withdraw	D	01/27/09	$409,900	GMO	12 months		Cap Bank	541277	Warsaw 69 kV	69	12 Mvar	Install 12 Mvar capacitor at Warsaw 69 kV bus
20028	30177	50185	GRDA		NTC-Withdraw	D	1/27/2009	$291,600	GRDA	12 months		Cap Bank	300971	Tahlequah West 69 kV	69	7.2 Mvar	Add additional 7.2 Mvar capacitor at Tahlequah West, for a 28.8 Mvar total.
20003	30094	50100	WFEC		NTC-Withdraw	D	02/13/08	$162,000	SPP	12 months		Cap Bank	521005	Mustang 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Mustang 69 kV

EXHIBIT NO. OGE-3

Southwest Power Pool

HELPING OUR MEMBERS WORK TOGETHER TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

SPP
Notification to Construct

June 30, 2010 SPP-NTC-20100

Mr. Mel Perkins
Oklahoma Gas and Electric Co.
M/C 1103, PO Box 321
Oklahoma City, OK 73101

RE: Notification to Construct Approved Priority Projects

Dear Mr. Perkins,

Pursuant to Section 3.3 of the Southwest Power Pool, Inc. ("SPP") Membership Agreement and Attachment O, Section VIII, of the SPP Open Access Transmission Tariff ("OATT"), SPP provides this Notification to Construct ("NTC") directing Oklahoma Gas and Electric Co. ("OGE"), as the Designated Transmission Owner, to construct the Network Upgrades.

During the April 27, 2010 meeting, the SPP Board of Directors approved the Group 2 Priority Projects as presented in the SPP Priority Projects, Rev. 1 report with the provision that NTC letters for the projects would not be issued until the Federal Electric Reliability Corporation ("FERC") made a favorable ruling on the highway/byway cost allocation methodology. On June 17, 2010, FERC issued Order 131 FERC ¶ 61,252 approving the Highway/Byway cost allocation methodology. On June 23, 2010, the SPP Board of Directors authorized issuance of NTCs for the Priority Projects.

New Network Upgrades

Project ID: 941
Project Name: Line – Hitchland - Woodward District EHV 345 kV double circuit*
Estimated In-Service Date for Project: 06/30/2014
Estimated Cost for Project: $247,005,793 (cost for entire project including all entities)
Estimated Cost Source: OGE and Southwestern Public Service Company ("SPS")
Date of Cost Estimate: October 2009 (OGE and SPS) and March 2010 (SPS)

> **Network Upgrade ID:** 11244, 11245
> **Network Upgrade Description:** Double circuit 345 kV line from the Woodward District EHV substation to the SPS interception point from the Hitchland substation.
> **Network Upgrade Owner:** OGE
> **MOPC Representative:** Jacob Langthorn IV

415 NORTH MCKINLEY STREET, SUITE 140 | LITTLE ROCK, AR 72205 | 501-614-3200 | SPP.ORG

TWG Representative: Travis Hyde
Categorization: High priority
Network Upgrade Specification: Build 345 kV double circuit transmission; 3,000 amp or greater capacity for each circuit, from the Woodward District EHV substation to the SPS interception point from the Hitchland substation. The total mileage of this Hitchland-Woodward District EHV line is 121 miles. OGE and SPS shall decide who shall build how much of these Network Upgrades and shall provide such information, along with specific cost estimates for each Designated Transmission Owner's portion of the Network Upgrades, to SPP in its response to this NTC. Upgrade the Woodward District EHV substation with the necessary breakers and terminal equipment.
Network Upgrade Justification: Priority Projects
Estimated In-Service Date for Network Upgrade: 06/30/2014
Estimated Cost for Network Upgrade (current day dollars): To be provided by Designated Transmission Owner(s)
Cost Allocation of the Network Upgrade: Base Plan

Project ID: 942
Project Name: Line – Woodward District EHV- Comanche County 345 kV double circuit*
Estimated In-Service Date for Project: 12/31/2014
Estimated Cost for Project: $108,227,500 (cost for entire project including all entities)
Estimated Cost Source: OGE and Westar Energy, Inc
Date of Cost Estimate: October 2009

Network Upgrade ID: 11246, 11247
Network Upgrade Description: Double circuit 345 kV line from the Woodward District EHV substation to the Mid-Kansas Electric Company ("MKEC") interception point from the new Comanche County substation.
Network Upgrade Owner: OGE
MOPC Representative: Jacob Langthorn IV
TWG Representative: Travis Hyde
Categorization: High priority
Network Upgrade Specification: Build 345 kV double circuit transmission; 3,000 amp or greater capacity for each circuit, from the Woodward District EHV substation to the MKEC interception point from the Comanche County substation. The total mileage of this Woodward District EHV-Comanche County line is 55 miles. MKEC and OGE shall decide who shall build how much of these Network Upgrades and shall provide such information, along with specific cost estimates for each Designated Transmission Owner's portion of the Network Upgrades, to SPP in its response to this NTC. Upgrade the Woodward District EHV substation with the necessary breakers and terminal equipment.
Network Upgrade Justification: Priority Projects
Estimated In-Service Date for Network Upgrade: 12/31/2014

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Estimated Cost for Network Upgrade (current day dollars): To be provided by Designated Transmission Owner(s)
Cost Allocation of the Network Upgrade: Base Plan
* These projects may be revised in early 2011 to require the projects be built at a higher voltage.

Commitment to Construct

Please provide to SPP a written commitment to construct the Network Upgrade(s) within 90 days of the date of this Notification to Construct, pursuant to Attachment O, Section VIII.6 of the SPP OATT, in addition to providing a construction schedule for the Network Upgrade(s). Failure to provide a written commitment to construct as required by Attachment O could result in the Network Upgrade(s) being assigned to another entity.

Coordination with Neighbors

OGE is responsible for coordinating these jointly owned projects with other constructing Designated Transmission Owners. Coordination includes, but is not limited to, construction specifications, facility ratings, interception location, and construction timing.

Notification of Commercial Operation

Please submit a notification of commercial operation for each listed Network Upgrade to SPP as soon as the Network Upgrade is complete and in-service. Please provide SPP with the actual costs of the Network Upgrade(s) as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

Notification of Progress

On an ongoing basis, please keep SPP advised of any inability on OGE's part to complete the approved Network Upgrade(s). For project tracking purposes, SPP requires OGE to submit updates on the status of the Network Upgrade(s) on a quarterly basis in conjunction with the SPP Board of Directors meetings. However, OGE shall also advise SPP of any inability to comply with the Project Schedule as soon as the inability becomes apparent.

All terms and conditions of the SPP OATT and the SPP Membership Agreement shall apply to these Projects, and nothing in this NTC shall vary such terms and conditions.

Don't hesitate to contact me if you have questions or comments regarding these instructions. Thank you for the important ro that you play in maintaining the reliability of our electric grid.

Sincerely,

Bruce A. Rew

Bruce Rew
Vice President, Engineering
Phone (501) 614-3214 • Fax: (501) 821-3198 • BRew@spp.org

cc: Carl Monroe, Les Dillahunty, Katherine Prewitt, Phil Crissup, Jacob Langthorn IV, Travis Hyde, MKEC-Noman Williams, MKEC-Tom Hestermann, MKEC-Al Tamimi, MKEC-Clarence Stuppes, SPS-John Fulton, SPS-William Grant

EXHIBIT NO. OGE-4

SPP
Notification to Construct

January 16, 2009 SPP-NTC- 20017

Mr. Mel Perkins
Oklahoma Gas and Electric Co.
PO Box 321, M/C ME10
Oklahoma City, OK 73101

RE: Transmission System Upgrade Notification to Construct for Transmission Service request resulting from Aggregate Transmission Service Study SPP-2006-AG3-AFS-11

Dear Mr. Perkins,

Southwest Power Pool has filed Service Agreement FERC Docket ER09-439, ER09-342, ER08-1206 for Transmission Service for customers in SPP-2006-AG3-AFS-11. In the facility study conducted in the assessment of these requests, SPP concluded that system upgrades are required on the Oklahoma Gas and Electric Co. system as detailed in Aggregate Facility Study SPP-2006-AG3-AFS-11.

As a result of transmission service customers confirmation of transmission service requests requiring network upgrades, SPP is notifying Oklahoma Gas and Electric Co. as the upgrade owner to move forward with the development of the following upgrades/mitigations to alleviate associated transmission service concerns.

New Network Upgrades

Project ID: 30158
Project Name: ARDMORE - ROCKY POINT 69KV CKT 1
RTO Determined Need Date for Project: 6/1/2011
Estimated In Service Date: 6/1/2011
Estimated Cost for Project: $1,627,500

> **Upgrade ID:** 50166
> **Upgrade Description:** Replace 4.65 miles of line with 477AS33
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 10/16/2007

Project ID: 30159
Project Name: DILLARD4 - HEALDTON TAP 138KV CKT 1

RTO Determined Need Date for Project: 6/1/2011
Estimated In Service Date: 6/1/2011
Estimated Cost for Project: $300,000

Upgrade ID: 50167
Upgrade Description: Replace Differential Relaying
Categorization: Service Upgrade
Upgrade Justifications: SPP-2006-AG3-AFS-11
Source of funding for Upgrade: Full Base Plan funded
Estimated Cost Source: OKGE
Date of Estimated Cost: 10/16/2007

Project ID: 30160
Project Name: FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3
RTO Determined Need Date for Project: 6/1/2017
Estimated In Service Date: 6/1/2017
Estimated Cost for Project: $11,000,000

Upgrade ID: 50168
Upgrade Description: Convert Ft. Smith 161KV to 1-1/2 breaker design and install 3rd 500-161KV transformer bank.
Categorization: Service Upgrade
Upgrade Justifications: SPP-2006-AG3-AFS-11
Source of funding for Upgrade: Full Base Plan funded
Estimated Cost Source: OKGE
Date of Estimated Cost: 7/30/2008

Project ID: 30161
Project Name: HUGO - SUNNYSIDE 345KV OKGE
RTO Determined Need Date for Project: 4/1/2012
Estimated In Service Date: 4/1/2012
Estimated Cost for Project: $75,000,000

Upgrade ID: 50169
Upgrade Description: Add 345 KV line from SunnySide to WFEC interception of 345KV line from Hugo, Install 345KV breaker, switches, and relays at Sunnyside
Categorization: Service Upgrade
Upgrade Justifications: SPP-2006-AG3-AFS-11
Source of funding for Upgrade: Full Base Plan funded
Estimated Cost Source: OKGE
Date of Estimated Cost: 8/18/2008

Project ID: 30162
Project Name: SUNNYSIDE - UNIROYAL 138KV CKT 1

RTO Determined Need Date for Project: 6/1/2011
Estimated In Service Date: 6/1/2011
Estimated Cost for Project: $50,000

> **Upgrade ID:** 50170
> **Upgrade Description:** Replace wavetrap 800A at Uniroyal
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 8/18/2008

Project ID: 30163
Project Name: SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1
RTO Determined Need Date for Project: 4/1/2012
Estimated In Service Date: 4/1/2012
Estimated Cost for Project: $6,750,000

> **Upgrade ID:** 50171
> **Upgrade Description:** Add 2nd 345/138KV Auto Transformer
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 8/18/2008

Project ID: 30164
Project Name: VBI - VBI NORTH 69KV CKT 1
RTO Determined Need Date for Project: 6/1/2017
Estimated In Service Date: 6/1/2017
Estimated Cost for Project: $100,000

> **Upgrade ID:** 50172
> **Upgrade Description:** Upgrade CT
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 8/18/2008

Oklahoma Gas and Electric Co. shall submit a notification of commercial operation for each listed Upgrade ID# to SPP at the email address of SPPprojecttracking@spp.org as soon as the upgrade is complete and in service. Please provide SPP with the actual costs

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of these upgrades as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

Please send SPP written commitment to construct these projects within 90 days in addition to providing a construction schedule for the accepted upgrades. For project tracking, SPP will request on a quarterly basis in conjunction with the SPP Board of Directors meetings that Oklahoma Gas and Electric Co. submit updates to the upgrade schedule status. Consistent with Section 32.10 of the SPP Tariff, please keep SPP advised of any inability on Oklahoma Gas and Electric Co.'s part to complete the approved upgrades. If it is anticipated that the completion of any approved upgrade will be delayed past the estimated in service date, SPP requires a mitigation plan be filed within 60 days of the determination of expected delay in the upgrade schedule.

Don't hesitate to contact me if you have questions or comments about these requests. Thank you for the important role that you plan in maintaining the reliability of our electric grid.

Sincerely,

John E. Mills

John Mills
Manager, Tariff Studies
Phone (501) 614-3356 • Fax: (501) 666-0376 • jmills@spp.org

cc: Carl Monroe, Les Dillahunty, Pat Bourne, Jay Caspary, SPPprojecttracking@spp.org, Phil Crissup, Travis Hyde, Jacob Langthorn

EXHIBIT NO. OGE-5

SPP
Notification to Construct

September 18, 2009 SPP-NTC- 20055

Mr. Mel Perkins
Oklahoma Gas and Electric Co.
M/C 1103
Oklahoma City, OK 73101

RE: Notification to Construct for Transmission Service request resulting from Aggregate Transmission Service Study SPP-2007-AG1-AFS-12

Dear Mr. Perkins,

Pursuant to Section 3.3 of the Southwest Power Pool, Inc. ("SPP") Membership Agreement and Attachment O, Section VIII, of the SPP Open Access Transmission Tariff ("OATT"), SPP provides this Notification to Construct ("NTC") directing Oklahoma Gas and Electric Co., as the Designated Transmission Owner, to construct the Network Upgrades.

Southwest Power Pool has filed Service Agreement FERC Docket ER09-1397, ER09-1504, ER09-1506 for Transmission Service for customers in SPP-2007-AG1-AFS-12. In the facility study conducted in the assessment of these requests, SPP concluded that system upgrades are required on the Oklahoma Gas and Electric Co. system as detailed in Aggregate Facility Study SPP-2007-AG1-AFS-12.

Upgrades with Modifications

Previous NTC Number: 19961
Previous NTC Issue Date: 6/27/2007
Project ID: 523
Project Name: ROSE HILL - SOONER 345KV CKT 1 OKGE
RTO Determined Need Date for Project: 6/1/2012
Estimated In Service Date: 6/1/2012
Estimated Cost for Project: $45,000,000

> **Network Upgrade ID:** 10668
> **Network Upgrade Description:** New 345 kV line from Sooner to Oklahoma/Kansas Stateline or the interface with the Westar Energy line segment to achieve 3000 amp or greater emergency rating
> **Reason For Change:** The project is needed at an earlier in service date than previous NTC identified
> **Categorization:** Regional Reliability Upgrade

Network Upgrade Specifications: All elements and conductor must have at least an emergency rating of 1743 MVA, but is not limited to that amount.
Network Upgrade Justifications: SPP-2007-AG1-AFS-12
Source of Funding for Network Upgrade: Full Base Plan Funding
Estimated Cost Source: OKGE
Date of Estimated Cost: 1/1/2009

Commitment to Construct

Please provide to SPP a written commitment to construct the Network Upgrade(s) within 90 days of the date of this Notification to Construct, pursuant to Attachment O, Section VIII.6 of the SPP Open Access Transmission Tariff, in addition to providing a construction schedule for the Network Upgrade(s). Failure to provide a sufficient written commitment to construct as required by Attachment O could result in the Network Upgrade(s) being assigned to another entity.

Notification of Commercial Operation

Please submit a notification of commercial operation for each listed Network Upgrade to SPP at the email address of SPPprojecttracking@spp.org as soon as the Network Upgrade is complete and in-service. Please provide SPP with the actual costs of these Network Upgrades as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

Mitigation Plan

The Need Date or Estimated In-Service Date repesents the timing required for the Network Upgrade(s) to address the identified need. Your prompt attention is required to formulation and approval of any necessary mitigation plans for the Network Upgrade(s) included in the Network Upgrades(s) if the Need Date or Estimated In-Service Date is not feasible. Additionally, if it is anticipated that the complettion if any Network Upgrade will be delayed past the Need Date or Estimated In-Service Date, SPP requires a mitigation plan be filed within 60 days of determination of expected delays.

Notification of Progress

On an ongoing basis, please keep SPP advised of any ability on OKGE's part to complete the approved Network Upgrade(s). For project tracking, SPP requires OKGE to submit updates on the status of the Network Upgrade(s) on a quarterly basis in conjunction with the SPP Board of Directors meetings. However consistent with Section 20.1 and 32.10 of the SPP Tariff, OKGE shall also advise SPP of any inability to comply with the Project Scheduke as as the inability becomes apparent. All terms and conditions of the SPP OATT and the membership Agreement shall apply to this Project and nothing in this letter shall cary such terms and conditions.

Don't hesitate to contact me if you have questions or comments about these requests. Thank you for the important role that you plan in maintaining the reliability of our electric grid.

SPP Southwest Power Pool

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Sincerely,

John E. Mills

John Mills
Manager, Tariff Studies
Phone (501) 614-3356 • Fax: (501) 666-0376 • jmills@spp.org

cc: Carl Monroe, Les Dillahunty, Bruce Rew, Pat Bourne, Jay Caspary, SPPprojecttracking@spp.org, Phil Crissup, Travis Hyde, Jacob Langthorn IV, Colin Whitley, Tom Littleton, Wende Oliaro, Scott Davidson, Grant Wilkerson

EXHIBIT NO. OGE-6

Southwest Power Pool

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SPP
Notification to Construct

June 19, 2009 SPP-NTC-20041

Mr. Jacob Langthorn, IV
Oklahoma Gas and Electric Co.
301 North Harvey
Oklahoma City, OK 73102

RE: Notification to Construct Approved Balanced Portfolio Network Upgrades

Dear Mr. Langthorn:

Pursuant to Section 3.3 of the Southwest Power Pool, Inc. ("SPP") Membership Agreement and Attachment O, Section VIII, of the SPP Open Access Transmission Tariff ("OATT"), SPP provides this Notification to Construct ("NTC") directing Oklahoma Gas and Electric Company ("OKGE"), as the Designated Transmission Owner, to construct the following approved Network Upgrades.

During the April 28, 2009 meeting, the SPP Board of Directors approved Balanced Portfolio 3E "adjusted" and directed the following Network Upgrades to be constructed contingent upon the approval of the Balanced Portfolio Report by the Markets and Operations Policy Committee ("MOPC"). On June 12, 2009 the MOPC approved the 2009 Balanced Portfolio Report.

Project ID: 699
Project Name: Sooner – Cleveland 345 kV line
Estimated In-Service Date for Project: 12/31/2012
Estimated Cost for project: $17,000,000

> **Network Upgrade ID:** 10929
> **Network Upgrade Description:** 345 kV line from OKGE Sooner substation to GRDA interception of 345 kV line from Grand River Dam Authority ("GRDA") Cleveland substation.
> **Network Upgrade Owner:** OKGE
> **MOPC Representative:** Jacob Langthorn, IV
> **Categorization:** Balanced Portfolio Network Upgrade
> **Network Upgrade Specifications:** Construct 18 miles of 345 kV, 3000 amp or greater capacity transmission line from OKGE Sooner substation to GRDA interception and acquire the necessary right-of-way to accommodate the 345 kV line. Upgrade the Sooner substation with the necessary breakers, relays and ring-bus.
> **Network Upgrade Justification:** Balanced Portfolio 3E "adjusted"
> **Estimated In-Service Date for Network Upgrade:** 12/31/2012
> **Estimated Cost for Network Upgrade (current day dollars):** $17,000,000
> **Source of funding for Network Upgrade:** Region-wide charge as specified by Attachment J, SPP OATT
> **Source of Cost Estimate:** OKGE
> **Date of Cost Estimate:** April 2009

Project ID: 700
Project Name: Seminole – Muskogee 345 kV line
Estimated In-Service Date for Project: 12/31/2013
Estimated Cost for project: $131,000,000

Network Upgrade ID: 10930
Network Upgrade Description: 345 kV line from the OKGE Seminole substation to OKGE Muskogee substation.
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Construct 100 miles of 345 kV, 3000 amp or greater capacity transmission line from OKGE Seminole substation to OKGE Muskogee substation and acquire right-of-way able to accommodate the 345 kV line. Upgrade the Muskogee substation to include any necessary terminal equipment.
Network Upgrade Justification: Balanced Portfolio 3E "adjusted"
Estimated In-Service Date for Network Upgrade: 12/31/2013
Estimated Cost for Network Upgrade (current day dollars): $127,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Network Upgrade ID: 10931
Network Upgrade Description: Seminole 345/138 kV Transformer
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Upgrade the OKGE Seminole substation with a 345/138 kV 400 MVA transformer and any other necessary terminal equipment.
Network Upgrade Justification: Balanced Portfolio 3E "adjusted"
Estimated In-Service Date for Network Upgrade: 12/31/2013
Estimated Cost for Network Upgrade (current day dollars): $4,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Project ID: 701
Project Name: Tuco – Woodward District EHV 345 kV line
Estimated In-Service Date for Project: 5/19/2014
Estimated Cost for project: $79,000,000

Network Upgrade ID: 10932
Network Upgrade Description: 345 kV line from OKGE Woodward District EHV substation to Southwestern Public Service ("SPS") interception of 345 kV line at the Oklahoma/Texas state line.
Network Upgrade Owner: OKGE

MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Construct 72 miles of 345 kV, 3000 amp or greater capacity transmission line from OKGE Woodward District EHV to the SPS interception from SPS Tuco substation and acquire right-of-way able to accommodate the 345 kV line.
Network Upgrade Justification: Balanced Portfolio 3E “adjusted”
Estimated In-Service Date for Network Upgrade: 5/19/2014
Estimated Cost for Network Upgrade (current day dollars): $64,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Network Upgrade ID: 10933
Network Upgrade Description: Woodward District EHV 345/138 kV Transformer and 50 MVAR reactor bank
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Upgrade the OKGE Woodward District EHV substation with a 345/138 kV 400 MVA auto transformer with a 345 kV ring bus configuration.
Network Upgrade Justification: Balanced Portfolio 3E “adjusted”
Estimated In-Service Date for Network Upgrade: 5/19/2014
Estimated Cost for Network Upgrade (current day dollars): $15,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Project ID: 709
Project Name: Anadarko Substation
Estimated In-Service Date for Project: 12/31/2011
Estimated Cost for project: $8,000,000

Network Upgrade ID: 10946
Network Upgrade Description: Anadarko Substation
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Tap the existing Cimarron – Lawton Eastside 345 kV line at the existing Western Farmers Electric Coop. Anadarko 138 kV substation and install new 345/138 kV 450 MVA transformer at a new substation.
Network Upgrade Justification: Balanced Portfolio 3E “adjusted”
Estimated In-Service Date for Network Upgrade: 12/31/2011
Estimated Cost for Network Upgrade (current day dollars): $8,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OGKE

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Date of Cost Estimate: April 2009

OKGE is responsible for coordinating these jointly owned projects with other constructing Designated Transmission Owners. Coordination includes but is not limited to construction specifications, facility ratings, interception location, and construction timing.

Please provide to SPP a written commitment to construct the Network Upgrades within 90 days of the date of this Notification to Construct, pursuant to Attachment O, Section VIII.6 of the SPP OATT, in addition to providing a construction schedule for the Network Upgrades. Failure to provide a sufficient written commitment to construct as required by Attachment O could result in the Network Upgrades being assigned to another entity.

Please submit a notification of commercial operation for each listed Network Upgrade to SPP as soon as the Network Upgrade is complete and in-service. Please provide SPP with the actual costs of these Network Upgrades as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

On an ongoing basis, please keep SPP advised of any inability on OKGE's part to complete the approved Network Upgrades. For project tracking purposes, SPP requires OKGE to submit updates on the status of the Network Upgrades on a quarterly basis in conjunction with the SPP Board of Directors meetings. However, OKGE shall also advise SPP of any inability to comply with the Project Schedule as soon as the inability becomes apparent.

All terms and conditions of the SPP OATT and the SPP Membership Agreement shall apply to this Project, and nothing in this letter shall vary such terms and conditions.

Feel free to contact me if you have questions or comments regarding these instructions. Thank you for the important role that you play in maintaining the reliability of our electric grid.

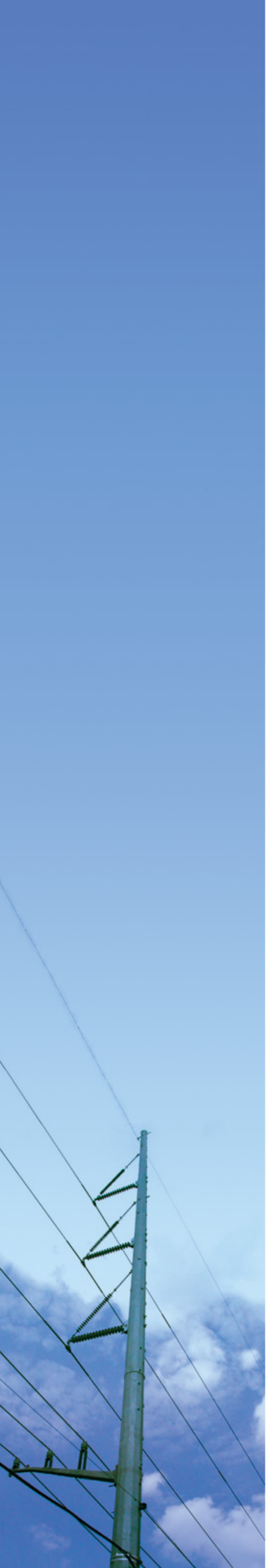
Sincerely,

Bruce A. Rew

Bruce Rew
Vice President, Engineering
Phone (501) 614-3214 • Fax: (501) 821-3198 • brew@spp.org

cc: Carl Monroe, Les Dillahunty, Pat Bourne, Jay Caspary, Keith Tynes, SPPProjecttracking@spp.org, Phil Crissup, Travis Hyde, GRDA Joe Fultz, GRDA Anthony Due, GRDA Mike Herron, SPS John Fulton, SPS William Grant, WFEC Alan Derichsweiler, WFEC Ron Cunningham, WFEC Mitchell Williams

EXHIBIT NO. OGE-7



SPP Priority Projects Phase II Final Report

MAINTAINED BY
SPP Engineering/Planning

SPP Board Approved
April 27, 2010

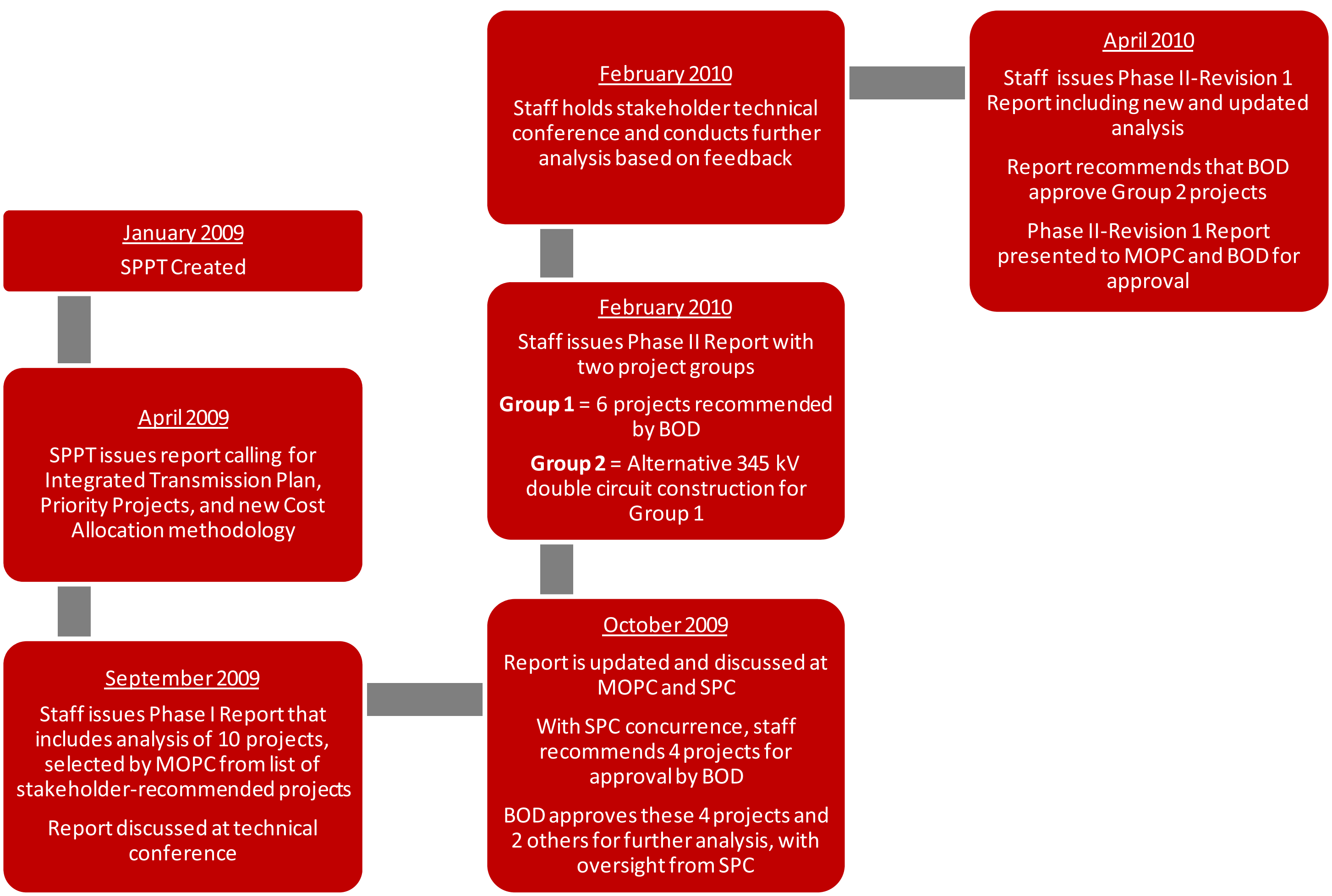
SPP Southwest Power Pool

Table of Contents

Executive Summary

In April 2009, SPP was directed by the SPP Board of Directors to implement the Synergistic Planning Project Team's (SPPT) recommendations for creating a robust, flexible, and cost-effective transmission system for the region, large enough in both scale and geography to meet SPP's future needs. Development of Priority Projects was one major recommendation; the others were to develop an Integrated Transmission Planning process that improves and integrates SPP's existing planning processes, and to implement a new cost allocation methodology.

SPP was charged with identifying, evaluating, and recommending Priority Projects that will improve the SPP transmission system and benefit the region, specifically projects that will reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's east and west regions. This report, Priority Projects Report Phase II - Revision 1, is the third in a series of Priority Projects reports that have been completed by SPP staff with input from stakeholders and the Transmission Working Group (TWG), Economic Studies Working Group (ESWG), Cost Allocation Working Group (CAWG), Markets and Operations Policy Committee (MOPC), Strategic Planning Committee (SPC), and Board of Directors (BOD). The following timeline illustrates the iterative development of the reports:



For the Phase I Report, SPP staff and outside consultants performed engineering and economic analyses to assess a number of metrics, including adjusted production costs (APC), system losses, impacts to reliability projects, local and environmental impacts, and deliverability of capacity and energy to load. The Phase I Report included two future scenarios in which either 10% (7 GW) or 20% (14 GW) of the SPP region's energy needs would be served by wind.

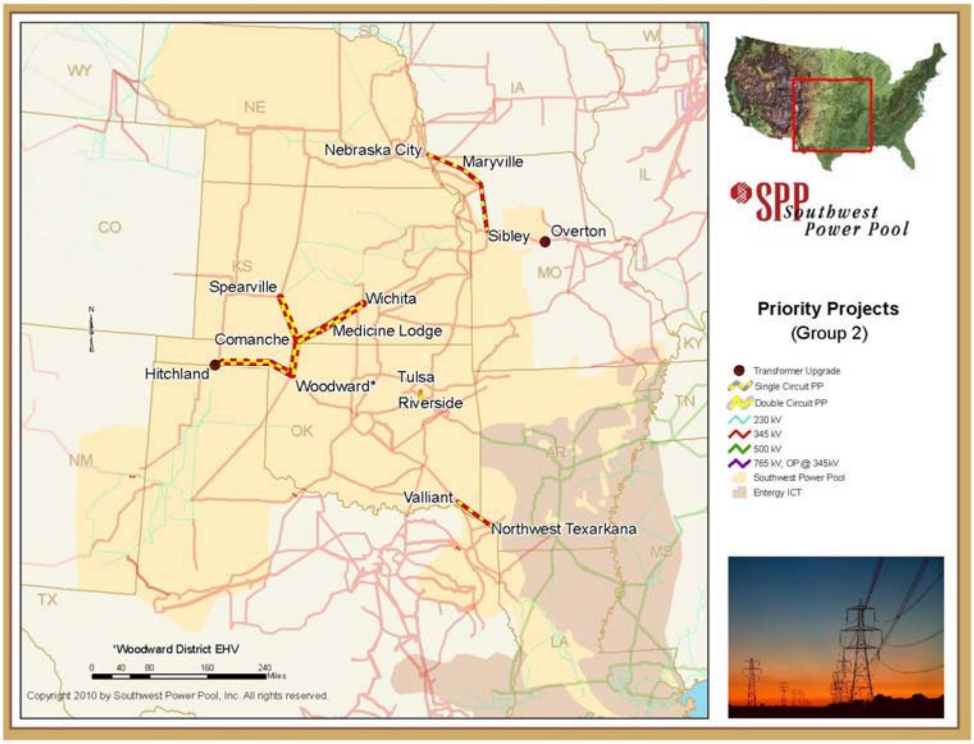
This Phase II Report-Revision 1 analysis includes two Priority Project groups with future wind levels of 7 GW and 11 GW.[1] The same projects were studied in both groups; however, in Group 1, Spearville-Comanche-Medicine Lodge-Wichita and Comanche-Woodward District EHV are constructed at 765 kV, while in Group 2 these two lines are constructed at double-circuit 345 kV.

Group 1 has estimated engineering and construction costs of $1.26 billion:

1. Spearville – Comanche – Medicine Lodge – Wichita (765 kV construction and 345 kV operation)
2. Comanche – Woodward District EHV (765 kV construction and 345 kV operation)
3. Hitchland – Woodward District EHV (345 kV double circuit construction)
4. Valiant – NW Texarkana (345 kV)
5. Nebraska City – Maryville – Sibley (345 kV)
6. Riverside – Tulsa Reactor (138 kV)

[1] The 11 GW wind level was chosen based on a CAWG survey sent to SPP members to determine what levels of renewable resources are needed to meet state mandates or voluntary targets.

Group 2 has estimated costs of $1.11 billion:



1. Spearville – Comanche – Medicine Lodge – Wichita (345 kV double circuit)
2. Comanche – Woodward District EHV (345 kV double circuit)
3. Hitchland – Woodward District EHV (345 kV double circuit)
4. Valiant – NW Texarkana (345 kV)
5. Nebraska City – Maryville – Sibley (345 kV)
6. Riverside – Tulsa Reactor (138 kV)

For Priority Projects Report Phase II - Revision 1, The Brattle Group revised its analysis based on the alternative project groups and wind levels, and KEMA updated its analysis with the most recent SPP economic model outputs. Other additions to this version: inclusion of BOD-approved projects from the 2009 SPP Transmission Expansion Plan, an additional transformer needed at Hitchland to accommodate Priority Projects, changing the Cooper-Maryville-Sibley 345 kV project to terminate at Nebraska City, an updated coal price forecast, the addition of the 11 GW wind analysis, additional constraint identification, and updated load ratio share numbers (see Revision 1 Modifications section).

Revision 1 analysis demonstrates that Group 2 has a greater Benefit to Cost (B/C) ratio: a combined 1.78 quantitative and qualitative B/C for the SPP region. Group 2 has a quantitative B/C ratio of 1.12 and a qualitative B/C of 0.66. Quantitative benefits were determined based on analysis of APC; APC adjustment due to wind revenue; transmission system losses; reduction in gas prices (Attachment 6, KEMA report); and impact on reliability project advancement, deferrals, and additions. Qualitative benefits were based on the economic output (jobs, goods/services, taxes, etc.) from the construction and operation of the projects and the operation of an additional 3.2 GW of wind (Attachment 4, The Brattle Group analysis). [2]

These Priority Projects achieve the strategic goals identified in the April 2009 SPPT report. They will reduce congestion, as demonstrated in the APC analysis and by the levelization of Locational Marginal Prices (LMPs) across the SPP footprint. The average LMP price differential reduces from +/- 35% for the base case to +/- 28% for Group 2. Priority Projects will improve the Aggregate Study process by creating additional transfer capability and allowing additional transmission service requests to be enabled. The addition of 3,000-5,000 MW of wind energy as well as new non-renewable generation will result from these projects. First Contingency Incremental Transfer Capability calculations determined that Priority Projects would increase the ability to transfer power in an eastward direction for two-thirds of the eastward paths by connecting SPP's western and eastern areas (see Attachment 5).

Staff is recommending that the Board of Directors approve Priority Projects Group 2 for construction, based on the projects' compatibility and consistency with the SPPT goals while demonstrating a calculated B/C ratio of 1.78. SPP recognizes these are only a portion of the benefits that will be attained as a result of these projects. Other benefits, which are not measured, include but are not limited to: enabling future SPP energy markets, dispatch savings, reduction in carbon emissions and required operating reserves, storm hardening, meeting future reliability needs, improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, and additional societal economic benefits.

These Priority Projects are incremental to the substantial progress SPP members have already made in expanding transmission for reliability and economic needs. The Report of the Synergistic Planning Project stated, "The SPPT believes that the region should quickly identify, review, and construct, with haste, projects that continue to show up in multiple system evaluations as needed to relieve congestion on existing flowgates and to tie the eastern and western sections of the region together". After 11 months of analysis and review, SPP staff believes the projects in Group 2 clearly meet the goals stated in the SPPT report, and requests the Board of Director's approval in taking the next step in creating regional transmission solutions to address SPP's unique challenges and opportunities.

[2] The Brattle Group studied the benefits of an additional 3.2 GW of wind (combined with SPP's existing 3.8 GW, this comprises the 7 GW scenario). The 0.66 B/C represents a conservative 25% of the $1.6 billion in benefits from the operation of 3.2 GW of wind; benefits from the construction phase were not included in the B/C.

Group 2 Benefits at a Glance

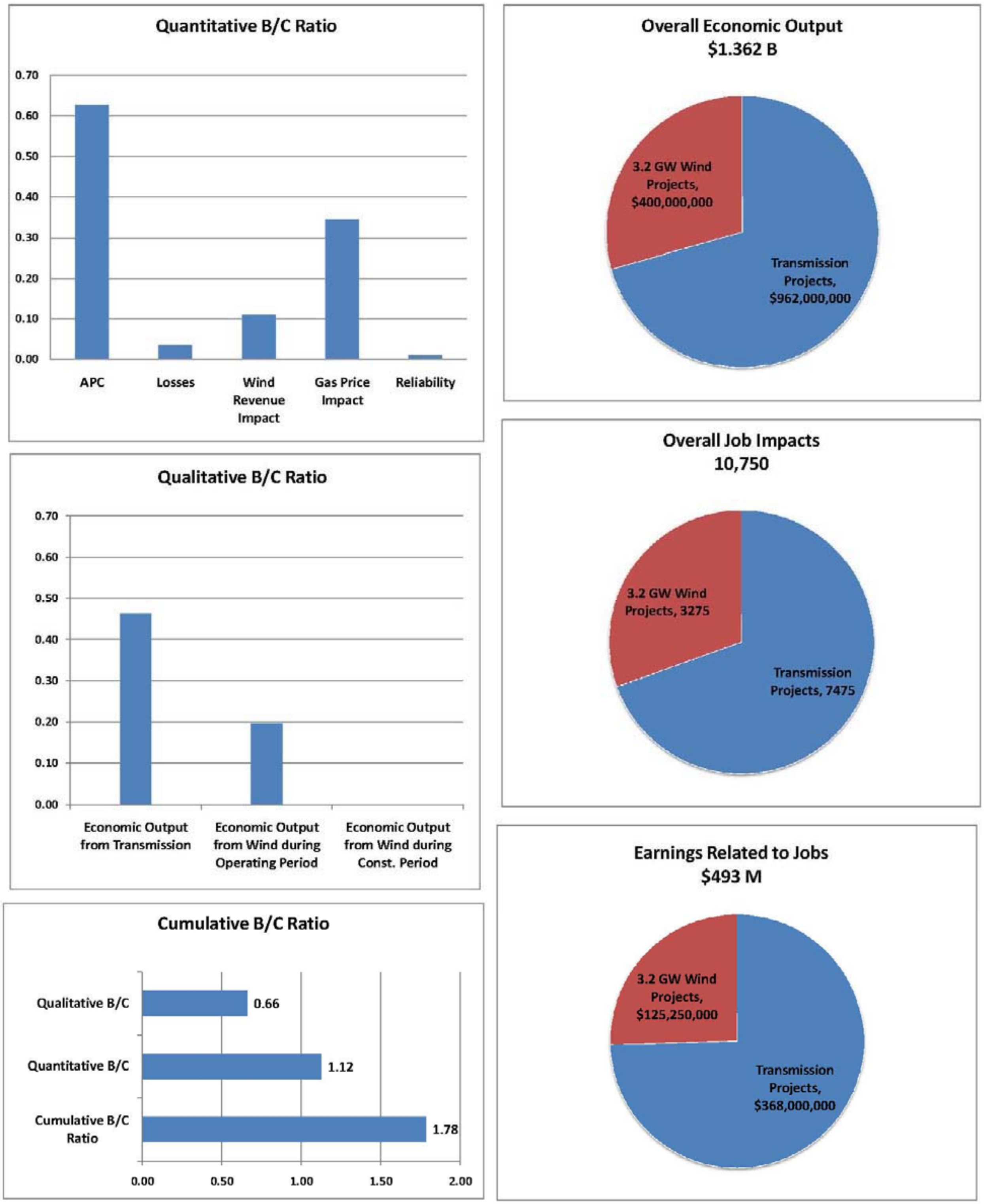


Figure 1

Revision 1 Modifications

SPP released the Priority Projects Phase II draft report on February 2, 2010, and on February 10 facilitated a stakeholder technical conference to discuss the report. Based on feedback received at the conference, SPP made several modifications to the Priority Project analysis. Many of the changes are explained in greater detail throughout this report, but a summary of the major modifications follows:

- **Inclusion of 2009 STEP Projects:** At its January 2010 meeting, the Board of Directors approved a subset of the projects included in Appendix B of the 2009 SPP Transmission Expansion Plan (STEP). SPP modified the Priority Project reliability and economic analysis to include the recently approved 2009 STEP projects; this report now includes all projects that have been issued Notifications to Construct (NTCs).

- **Previously-Identified Reliability Projects:** On January 19, 2010 the TWG endorsed with comment the TWG Reliability Report that analyzed the reliability impact of adding Priority Projects to the transmission system (see Attachments 2 and 3). The report identified an additional 345/230 kV transformer was needed at Hitchland to accommodate Priority Projects. Because this transformer is shown as needed solely due to Priority Projects, the study has been modified to consider it as part of the Priority Projects package (change case project).

- **Nebraska City-Maryville-Sibley 345 kV Project:** At the February 10 technical conference, Nebraska Public Power District (NPPD) presented its analysis of the Cooper South flowgate and potential solutions the organization considered for improving congestion. Based on discussion at the conference and NPPD's analysis and recommendation, SPP modified the termination point of the previously proposed Cooper-Maryville-Sibley 345 kV project to the Nebraska City substation rather than the Cooper substation.

- **Coal Prices:** Discussions with stakeholders identified the need for SPP to better understand the fuel price assumptions being used in the economic modeling. As explained in this report, gas prices are taken from the NYMEX exchange projections. Staff received the coal forecast from the economic modeling software vendor. The forecast used in previous Priority Project analyses indicated coal prices decreasing over time. In preparing Revision 1 analysis, staff asked several member companies what they were using for their own assumptions regarding coal prices and compared these results with the forecast previously used in the study of the Priority Projects. For this Revision 1 analysis, the software vendor provided its most recently updated coal price forecast. This updated forecast showed coal prices increasing over time which is consistent with information provided by stakeholders.

- **11GW Wind Level:** After Priority Project Phase II Report assumptions were finalized and the study began, the Cost Allocation Working Group surveyed SPP members to determine what levels of renewable resources each state was either mandated to meet or were voluntarily targeting by 2030. The results of this survey indicated approximately 11.3 GW of wind would be needed to satisfy these mandates or targets. To give stakeholders as much information as possible, SPP analyzed Priority Projects using approximately 11.3 GW as an additional analysis to the 7 GW study.

- **Additional PAT Analysis:** After performing each study, SPP attempts to improve its study methods. Based on results of previous analysis and discussions with stakeholders, staff performed additional analysis to help identify constraints that should be used in economic modeling. After this additional analysis was completed, the ESWG reviewed the constraints used in the economic modeling. Some additional modifications were made to the constraints based on this review.

- **Updated Load Ratio Share (LRS):** For this report and the calculation of benefit to cost ratios, Priority Projects costs are allocated to each zone based on LRS. LRS numbers used in the previous Priority Project reports were based on numbers used in the Balanced Portfolio analysis approved in 2009. Stakeholders had questions about LRS numbers in previous Priority Project reports since they did not correspond to the LRS numbers used in the recently approved 2009 STEP report. This report uses LRS numbers based on member data received by SPP's Settlements Department as recent as March 2010.

Scope of Priority Projects Phase II, Rev. 1 Analysis

Study Assumptions

Assumptions used in Priority Projects modeling and analysis were vetted through the SPP stakeholder process and amended by the Strategic Planning Committee (SPC) at its November 19 meeting. The majority of assumptions were developed by the Benefits Analysis Techniques Task Force (BATTF), approved by the Economic Studies Working Group (ESWG), and reviewed by the Markets and Operations Policy Committee (MOPC). For the Priority Projects analysis, PROMOD software was used to model 8,760 hours representing a full year of system-wide commitment and dispatch of resources.

- **Time Frame** – The BATTF directed use of a ten-year time frame to analyze Priority Project benefits. Three years throughout the ten-year planning horizon were modeled - 2009, 2014, and 2019 - and benefits for the years in-between were calculated using a linear progression. The total of the ten-year benefit was used to create the Net Present Value (NPV). A terminal value was used to represent the final B/C of the project from the last year of analysis (i.e. 2019). Considering the scope and lifetime of some of the projects, a 20- and 40-year financial result is extrapolated from data used in the 10-year analysis.

- **Fuel Prices** – The gas price was determined by using the Henry Hub NYMEX ten-year forecast with an additional adder for fuel distribution differences across the footprint. SPP used the 2010 forecast as the starting point since it was the first year in which an entire year's forecast was available. The starting price for the 2009 model runs was $5.20/MMBtu. The coal price forecast was provided by the economic modeling software vendor and was updated for this analysis. Other fossil fuel prices used generic assumptions and publicly-available data.

- **Wind Modeling –** SPP was directed by the SPC to study Priority Projects using 7 GW of nameplate wind generation in the SPP footprint, and to study the same wind in both the base and change cases. The Priority Projects model contained 3.8 GW of existing wind that was identified as in-service or under construction. Wind plants with a signed interconnection agreement (IA) and that have given SPP authorization to proceed with the construction of the required network upgrades were considered "under construction". To reach the 7 GW target, staff added an additional 3.2 GW of generic wind generation.

  In addition to the 7 GW study, staff assessed 11.3 GW of wind in the SPP footprint based on results of a Cost Allocation Working Group (CAWG) survey, which assessed the renewables needed to meet state mandates or targets in the SPP region. Data provided in the CAWG survey was reported in MWh. To determine what the necessary wind capacity would be to meet mandates/targets, SPP used a 40% capacity factor for Texas, Oklahoma, New Mexico, Kansas, and Nebraska. For Missouri and Arkansas, a 30% capacity factor was used. In the economic analysis, the wind profiles for wind farms in Missouri and Arkansas will represent this lower capacity factor.

Using the Generation Interconnection (GI) queue as a guide, SPP staff, with the help of the ESWG, recognized the significant amount of GI requests in the relative locations of Spearville and Hitchland. SPP staff worked in conjunction with the ESWG to modify the wind injection placement points. The results are listed below:

Wind Added to Reach 7 GW

Fairport (MO)	600 MW
Hitchland (OK)	1,077 MW
Hoskins (NE)	196 MW
Gentlemen (NE)	196 MW
Spearville (KS)	605 MW
Woodward (OK)	522 MW

Wind Added to Reach 11.3 GW

Washington County (AR)	197.5 MW
Fairport (MO)	33 MW
Spearville (KS)	1,500 MW
Knoll (KS)	200 MW
Hoskins (NE)	157 MW
Gentlemen (NE)	157 MW
Potter (TX)	600 MW
Broken Bow (NE)	80 MW
Albion (NE)	120 MW
Roosevelt (NM)	300 MW
Grapevine (TX)	50 MW
Hitchland (OK)	1,025 MW

State	Current Wind	Additional to 7GW	Additional to 11GW	Total Wind
Arkansas	0	0	198	198
Kansas	960	605	1,700	3,265
Louisiana	0	0	0	0
Missouri	0	600	33	633
Nebraska	243	392	514	1,149
New Mexico	204	0	300	504
Oklahoma	1,367	1,599	1,025	3,991
Texas	904	0	650	1,554
Total	3,677	3,196	4,420	11,292

Table 1: Wind Injection Amounts (MW)

Values in the table above do not represent any other renewable resources such as solar, hydroelectric, or biomass which may be used to meet a Renewable Portfolio Standard. Wind allocation and placement are estimates and represent reasonable approximations for the future development of wind resources within SPP as discussed by the ESWG.

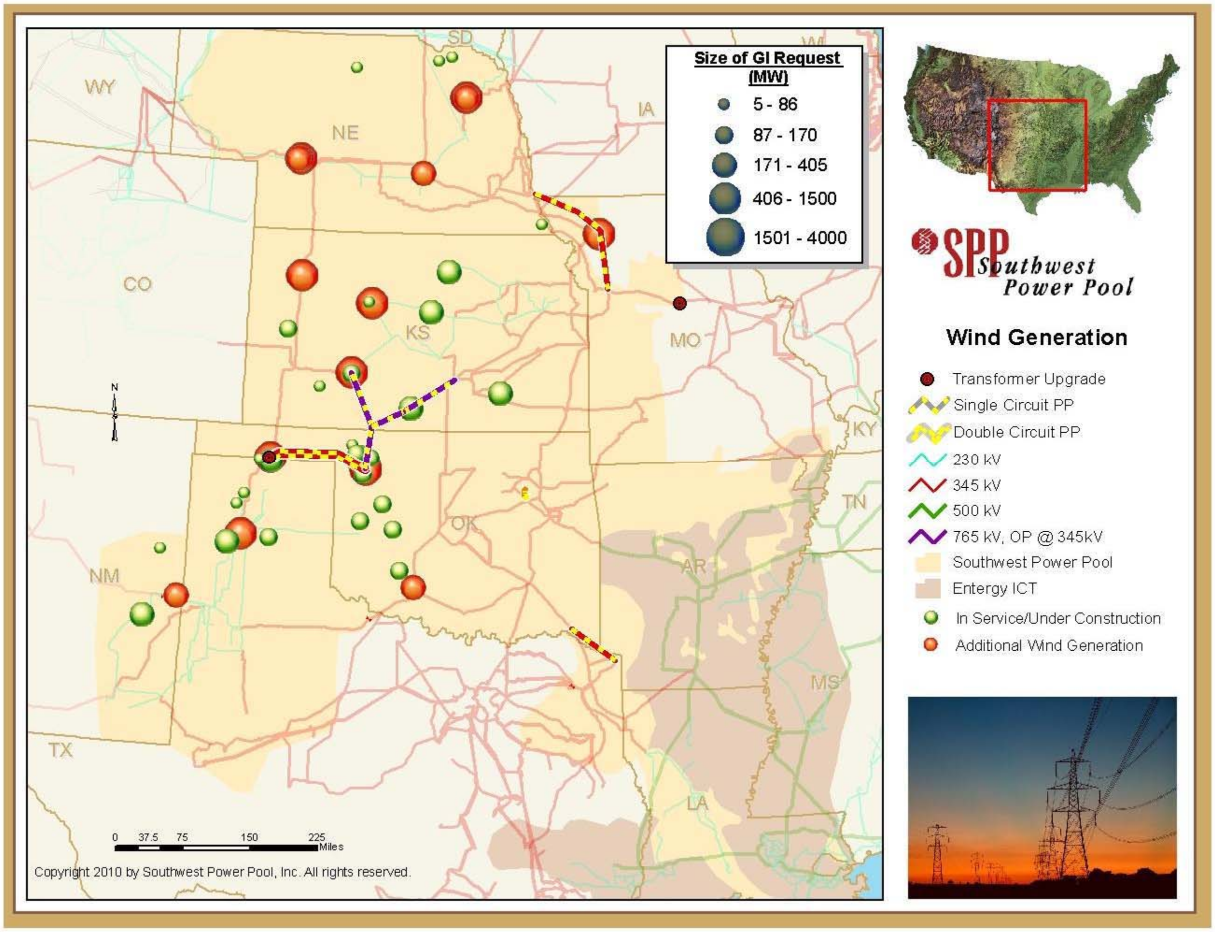


Figure 2: Wind Generation Modeled at 7 GW

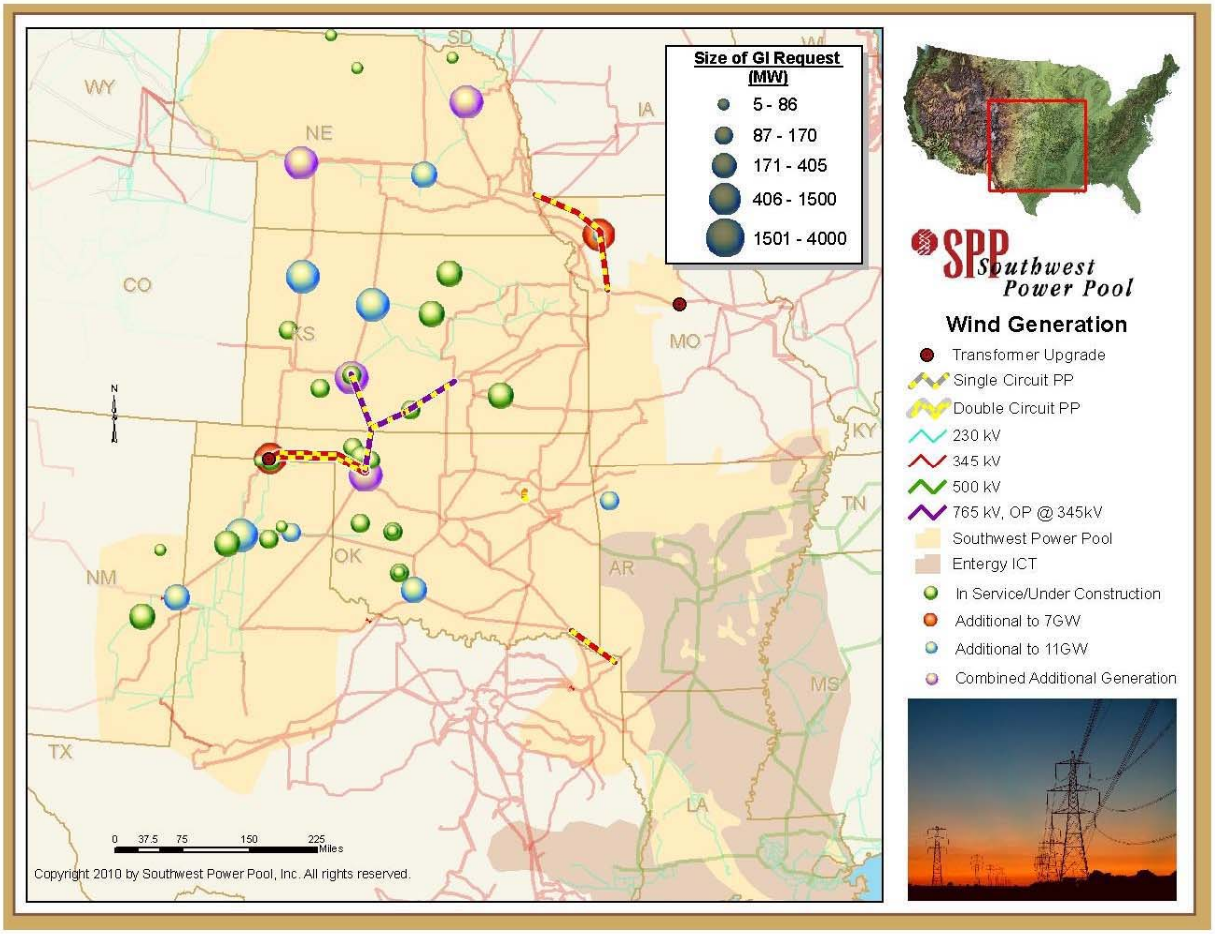


Figure 3: Wind Generation Modeled at 11 GW

- **Study Footprint** – The study footprint contains SPP, Entergy, TVA, MAPP, MISO (Ameren, MEC, et al), PJM, Southern Companies, WAPA, Basin Electric, Big Rivers Electric Company, Associated Electric Cooperative Inc. (AECI), E.ON, and East Kentucky Power Cooperative.

- **DC Ties** – Historical DC Tie profiles were used to simulate profiles for all DC Ties in the SPP region. DC ties modeled[3] for the SPP region are located at:

    - Oklaunion
    - Welsh
    - Lamar
    - Eddy County
    - Blackwater
    - Sidney

[3] The Stegall DC tie in Nebraska was not modeled in this planning assessment because Tri-State/Basin did not grant SPP permission to use the historical data.

- **Environmental Costs** – Estimates of emission costs for SO_2 and NO_x were approximated using data from the Chicago Climate Exchange. CO_2 was not explicitly priced in the economic modeling due to the uncertainty of future climate policy. Mercury was not addressed due to the lack of valid market information.

- **Non-Wind Resource Model Additions** – Only plants with a signed interconnection agreement (IA) and that have given SPP authorization to proceed with the construction of the required network upgrades were considered "under construction".

- **Plant Outages** – Data for outages and maintenance was taken from the ESWG's 2009 data collection and review process that was used for Balanced Portfolio and Priority Projects Phase I efforts. This data was originally provided by stakeholders, and stakeholders had the opportunity to provide updated outage and maintenance information in October and November 2009. Forced outage rates were taken as a single draw and locked for the change and the base cases to eliminate biased results due to different outage schedules. Similarly, maintenance outages were also locked from a single scheduled pattern. These outages were plant-specific.

- **Operating Reserves** – SPP's current reserve sharing program (as of 2009) was used in the operating reserves simulation.

- **Hurdle Rates –** Hurdle rates are rates that are applied to ensure a minimum price differential is in place before an exchange is made. Specific hurdle rates are applied in the modeling for both generating unit commitment and security-constrained economic dispatch. SPP attempts to quantify the hurdle rates within the base models to reasonably represent transactions that have occurred or will occur in the SPP market.

  A dispatch hurdle rate of $5/MW and a commit hurdle rate of $8/MW were used to commit resources across regional boundaries. These values are similar to values applied within various studies of the Eastern Interconnection and represent recommended rates as described in the Transmission Network Economic Modeling and Methods document prepared by the Economic Modeling and Methods Task Force in 2006. There were no hurdle rates for internal SPP market transactions.

- **Load Forecasts** – In early 2009, stakeholders submitted load forecasts for 2012, 2017, and 2022. To determine load for the study years of 2009, 2014, and 2019, an escalation rate of 1.29% per year was used. This escalation rate is the default used in PROMOD and represents a reasonable approximation of load growth within SPP.

- **Market Structure** – The simulation was conducted considering a consolidated balancing authority and a day-ahead market structure for the SPP region. The economic model simulates a consolidated balancing authority by economically dispatching all resources within the SPP footprint. The day-ahead market is the PROMOD default operation and means that resources in the footprint are dispatched economically based on the calculated future prices for each resource. This market structure is very different from the way SPP currently operates, so the study results should not be compared to how each individual balancing authority currently operates.

Stakeholder Data Review Process

Data used in Priority Projects analysis went through an extensive data review process. The ESWG determined that certain data fields would be reviewed and updated by stakeholders while other data fields would use only publicly available data. The publicly available data included any generation cost data as well as heat rate information. By using only publicly available data, the ESWG attempted to ensure that Tier 1 entities were treated the same as SPP members in the model and to limit the amount of proprietary information contained in the model.

The following data fields were reviewed by the SPP RTO Tariff members: Maximum Capacity, Unit Type, Commission Date, Retirement Date, Bus, Minimum Capacity, Maintenance Required Hours, Forced Outage Rate, Forced Outage Duration, Minimum Downtime, Minimum Run Time, Must Run Status, Ramp Rates, and demand data. The members also reviewed the data to ensure all units were being accounted for and were being modeled in the correct zone.

The data review process included two iterations. After the initial PROMOD run, the stakeholders were provided the model inputs as well as load and generation output data. At this time they were able to update the inputs to correct any errors which caused their units to dispatch unrealistically. Once these corrections were applied to the model, staff ran PROMOD again to produce new dispatch results and to provide members with an opportunity to review how their changes impacted unit dispatch. Members were again able to suggest changes to the model for the second iteration. Once the PROMOD run for the second iteration was complete, staff provided this data to stakeholders for approval. All Transmission Owners indicated their approval on the input and output data by Thursday, January 14, 2010.

In Revision 1 stakeholders were given the opportunity to review both the Event File and the Powerflow Branch data. If a stakeholder replied during the timeframe with additional flowgates that SPP should monitor, staff reviewed those suggestions and the flowgates were added to the event file.

Value Metrics

The BATTF developed or approved use of the following quantifiable value metrics to be used in the calculation of financial benefit from the Priority Projects analysis:

Adjusted Production Cost

Adjusted Production Cost (APC) is a measure of the impact on production cost savings by Locational Marginal Price (LMP), accounting for purchases and sales of economic energy interchange. This benefit metric is typically simulated by a production cost modeling tool accounting for 8,760 hourly profiles yearly of commitment and dispatch modeling, taken over the course of the study period.

Nodal modeling is aggregated on a zonal basis using weighted LMPs. There is concern that modeling the border points will not be accurate without additional Eastern Interconnection points. For example, the border LMPs will have significant impact on the APC within SPP. If there are lower LMP prices outside SPP, there will be no transfers from the western portion of SPP. he BATTF recommended the modeled footprint be broadened to include Southern Companies, Basin Electric, WAPA, TVA, PJM, MISO (Ameren, MEC, et al), and the DC ties (using the recent historic patterns) at a minimum when running the model to assess the impact on the borders.

The nodal analysis was aggregated on a zonal basis using the following formulation. The calculation, performed on an hourly basis:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases
Where:
Revenues from Sales = MW Export x Zonal $LMP_{\text{Gen Weighted}}$
and
Cost of Purchases = MW Import x Zonal $LMP_{\text{Load Weighted}}$

The tools used for this analysis include standard assumptions and modeling utilizing PROMOD.

The rationale for using this methodology is as follows:

- This formula was previously used by stakeholders, the MOPC, RSC, and BOD as part of the approval of the Balanced Portfolio analysis.
- The formulation represents the broad impact of new transmission projects in changing LMP costs (energy, congestion and losses cost) to rate payers within the SPP footprint. It represents much of the savings/benefits or additional cost to rate payers for specific transmission projects.

The total APC for the projects was calculated using the APC value for the projects in three different years. The years that were studied, and subsequently had an APC value, are 2009, 2014, and 2019. Benefits of the in-between years (i.e. 2010, 2011, etc.) were calculated linearly using the benefit values from the two years that were studied (i.e. 2009 and 2014). The sum of the APC benefits for each of the 10 years is the total APC. This same methodology was utilized in the recently adopted Balanced Portfolio.

Impact on Losses - Energy

Lower impedance transmission lines provide a loss savings to the transmission grid. The energy component of the loss savings is captured as part of the APC analysis. It is possible that losses will increase since generation sources could be located further from load centers.

Impact on Losses – Capacity

While the energy component of losses is captured in the APC analysis, the capacity component is not. Capacity savings associated with a loss change are determined by looking at the selected hourly loadflow models to determine the loss change associated with a transmission upgrade. The BATTF established standard capacity prices to capture capacity savings. Calculations were based on a Combustion Turbine (CT) replacement, currently priced at $750 per kW installed (based on the expected cost to install various types of machines used by BATTF members).

There is a fixed Operations and Maintenance (O&M) cost component base of $650,000 per year (average expected cost experienced by BATTF members). This is an additive benefit for capturing the capacity component of that energy typically passed on to ratepayers through Ancillary Service charges. This is the variance in quantity of energy (capacity). The capacity component of losses is captured in the formulation below:

- Capacity Savings at Coincidental Peak = ((Capacity requirement at Peak (base case) – Capacity requirement at Peak (with projects upgrades included)) x (CT replacement cost)).

  This would be a savings estimate of the capacity, since the CT installation would be a one-time cost when the upgrade was energized.

- There is a fixed O&M cost savings associated with this calculation, captured in the Ancillary Services fee.

  It is calculated as Fixed Cost Benefit = (Capacity savings (as determined from above per 150 MW) x $ 650,000/yr), escalated by the rate of inflation as reported by the Bureau of Economic Analysis.

- The price differential was calculated on an annual basis from the point the proposed upgrade is energized to the end of the defined 20-year period. There were no additional accommodations for savings after 20 years, because a CT has an estimated 20-year life span.

- This formulation is the estimated benefit or cost impact of losses.

Environmental Impacts

Initially, analysis of carbon benefits was to be conducted; however, the prescribed method of modeling the same level of wind in the base and change cases does not support the previously developed calculations needed for carbon benefit estimates. The ESWG is discussing methods to explicitly model the impacts of carbon for use in the Integrated Transmission Planning process. SPP acknowledges a great deal of additional benefit will be realized by enabling higher amounts of renewable resources to interconnect to SPP's transmission system, thereby reducing the level of carbon being emitted. Not assessing the benefits of reduced carbon emissions provides much more conservative results for the Priority Project analysis.

Reliability Impact

In the Phase I evaluation, 11 potential Priority Projects and three additional Priority Projects groups were evaluated for their impacts on the SPP Transmission Expansion Plan (STEP) Reliability Assessment. Priority Project impacts include net, new needed projects, and STEP projects that could be deferred or advanced. As part of Phase II evaluation, the list of Priority Projects was refined to two groups of projects that are electrically similar, and their impact on the STEP Reliability Assessment and on first tier parties to SPP was evaluated. This Priority Project reliability analysis was conducted in the same manner and with the same methodologies used in the STEP Reliability Assessment.

The Priority Project Reliability Report (Attachment 2) is not intended to justify any Priority Project based on deferred project cost alone; it is only intended to show the effects of Priority Projects on the STEP Reliability Assessment. At this time, in-service dates for Priority Projects are not definite. For this study the projects are included in the 2014 models. If a project identified for deferment has a STEP date before 2014 it may or may not actually be deferred. It may be possible to mitigate these issues for the short period of time before a specific Priority Project(s) is in service.

APC Adjustment Due to Wind Revenue Impact

Conventional thermal generation is modeled explicitly based on ownership or designation for each unit. This explicitly modeled generation is then factored into APC calculations through each resource's cost to produce energy as well as determining whether a zone has excess energy each hour (revenues from sales) or lacks sufficient generation to serve its load (costs from purchases).

Traditionally, SPP's APC calculations have not considered the revenues paid to wind resources because they must be modeled as a transaction rather than a conventional generating unit. The wind must be modeled as a transaction so the variability of the wind can be taken into account. Staff does this by profiling the wind based on historical output patterns for each wind resource. Wind generation's impact on *production costs* can be thought of as subtracting the dispatched wind generation from the load that is met from other generation sources. Because of the different modeling method for wind resources, the impact of wind generation on *revenues from sales* and *costs from purchases* was not included in the initial calculation of APC and must be added to obtain a corrected overall measure of these components.

To illustrate this calculation, consider the following simplified example, in which it is assumed that price differences between load and generation assigned to the same zone are zero. A zone's revenues from sales or costs from purchases can then be determined by taking the difference between what loads in a zone pay and what the generation attributed to that zone is paid. For example, if in an hour, a zone has excess generation, it will receive *revenues from sales* in the amount of the number of MWhrs in excess times the gen-weighted LMP for that hour. However, if a zone is deficient in generation for the hour, it will pay *costs from* purchases in the amount of the number of MWhrs deficient times the load-weighted LMP for that hour.

Revenues paid to wind resources were excluded from the initial calculation of *revenues from sales* and *costs of purchases*. For the above scenarios, if wind attributed to the zone is paid $1,000, then to correctly calculate APC, this $1,000 needs to be added to *revenues from sales* or subtracted from *costs for purchases* for that zone in that hour.

What is important in calculating the overall benefit from APC is the difference between APC in the change case compared to the base case. To correctly adjust APC, the Wind Revenue Impacts are calculated by subtracting the base case wind revenues from the change case wind revenues and adding the impacts back to the initial calculation of APC to correct for the initial exclusion of the revenues of these resources. The CAWG developed the methodology used to allocate the wind revenues to each zone. The allocation was calculated using the need of each zone for renewable energy to meet its renewable energy targets as determined from a CAWG survey on renewable energy targets.

SEAMS Coordination

A letter was sent to AECI, CLECO, ERCOT, ESI, MISO, TVA, and WECC on December 16, 2009 to inform them of the projects being proposed as Priority Projects. The letter also encouraged the organizations to engage in the Priority Project stakeholder process through SPP's organizational groups.

Breakeven Analysis

The ESWG met on November 3, 2009 to provide its recommendations to the Strategic Planning Committee regarding Priority Projects. One of the recommendations was for SPP to determine what level of wind would be required to produce a benefit to cost ratio (B/C) of 1 for Priority Projects. Staff agreed this analysis would be performed as time permitted, but the results of this Revision 1 analysis achieved a B/C greater than 1.0.

Economic Modeling Tools

PROMOD

PROMOD IV is a detailed nodal and zonal market simulation tool offered by Ventyx. It provides users a way to assess the economic impacts of changes to the transmission system. For the Priority Projects study, staff primarily utilized the Locational Marginal Price (LMP) forecasting and unit dispatch capabilities of PROMOD IV.

The Transmission Analysis Module (TAM) utilized by PROMOD IV performs a detailed simulation of market operations considering any inefficiencies across seams. PROMOD IV TAM is an hourly chronological simulation of electric market operations using a detailed transmission grid topology which can include up to 46,000 buses and 56,000 transmission lines. PROMOD IV TAM uses an hourly forecast of loads at each bus, along with detailed descriptions of generators to commit and dispatch under an LMP market.

LMPs are calculated for both the generation-weighted and load-weighted average hub LMPs for the footprint. Prices are provided in full hourly detail (8760 hours) and can be summarized into monthly periods. The net production cost is calculated hour-by-hour, and the formula is variable generation costs (fuel costs, variable O&M costs, emission costs, startup-costs), plus the cost of external purchases (if generation is less than demand) minus external sales revenues (if generation exceeds load) on an hourly basis. The cost of external purchases is computed as the MW purchase level times the load-weighted sub-region's LMP. The external sales' revenues are computed as the MW sale level times the generation-weighted sub-region's LMP.

The Adjusted Production Cost (APC) benefit of a project is determined by using the metrics described above. PROMOD IV also provides detailed price components of transmission congestion for market hubs while identifying areas of potential improvement.

PROMOD IV LMP utilizes a Security-Constrained Unit Commitment (SCUC) algorithm, recognizing the following bids and constraints:

- Generation:
    - Minimum capacity with no-load energy bid
    - Segmented energy bids with ramp up and ramp down limits
    - Startup cost bid
    - Minimum runtime and minimum downtime (hours)
    - Operating reserve contribution

- Transmission:
    - Individual transmission flow limits (including DC ties)
    - Flowgate limits on interfaces
    - Phase Angle Regulator (PAR) angle limits
    - Dynamically determined transmission loss penalty factors

- Market:
  - Load balance with market net interchange limits and hurdle rates
  - Regional operating reserves (both spinning and non-spinning)

LMP is calculated for individual nodes and hubs with congestion price (broken out by flowgate) and loss price components.

PROMOD Analysis Tool (PAT)

The PAT (also known as the PROMOD Analysis Tool) is an interactive program that forms and solves a transmission-constrained economic dispatch model. All of the input data for the PAT analysis for Priority Projects comes from Ventyx's PROMOD program, which is a large, complex batch program used by SPP for long-term transmission and generation planning studies. The PAT uses the same mathematical model, and provides an intuitive tool for studying and temporarily modifying the underlying details of the transmission and generation systems, and computing the resulting changes in dispatch and locational bus pricing information that result from the optimization. PAT specifically in Priority Projects analysis to research congested bottlenecks and indentify their causes. This provided staff with additional contingencies which were added for PROMOD to monitor.

Priority Projects Phase II, Rev. 1 Analysis Results

Synergistic Planning Project Team Recommendation Impacts

The Synergistic Planning Project Team (SPPT) recommended that Priority Projects should:

1. Reduce grid congestion
2. Improve the Aggregate Study and Generation Interconnection study queues
3. Integrate SPP's east and west transmission systems

Reduce Congestion

The impact of reducing congestion is primarily captured through APC modeling. Another indicator of reduced congestion is the levelization of Locational Marginal Prices (LMPs) across the footprint. As a robust transmission system is constructed and congestion reduced, the differential between the minimum and maximum LMP is reduced, resulting in lower energy costs to consumers. The difference between the average minimum and maximum LMP price for 7 GW and 11 GW wind levels is depicted in the following charts. The LMP price differential reduces from +/- 35% for the base case to +/- 28% for Group 2. Averages were calculated across the 2009, 2014, and 2019 data points.

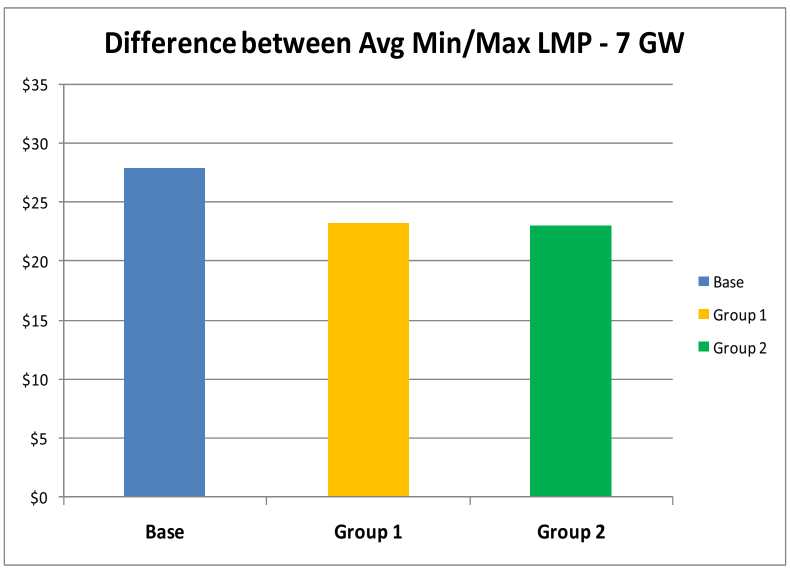


Figure 4: Spread of Avg Min/Max LMPs - 7 GW

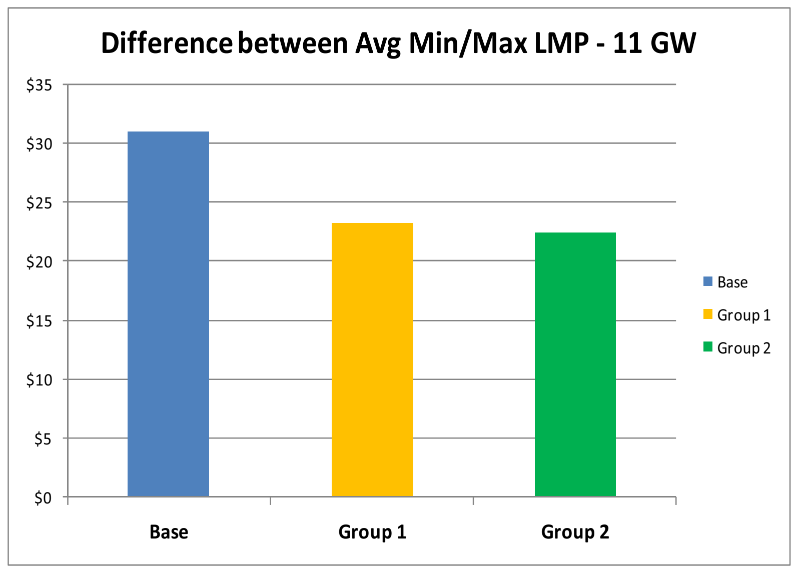


Figure 5: Spread of Avg Min/Max LMPs - 11 GW

Improve Aggregate Study and Generation Interconnection Queues

The SPPT's criteria for Priority Projects included projects that repeatedly appear in the Aggregate Study process as a known and needed upgrade to deliver transmission service for multiple parties. The Priority Projects studied in this report will create additional transfer capability across the SPP footprint. They will also relieve congestion on lower-voltage facilities for local delivery of energy, allowing additional transmission service requests to be enacted. The map below depicts Priority Projects relative to previously identified points of receipt (POR) and points of delivery (POD) taken from Aggregate Studies 2007-AG1, 2007-AG2, and 2006-AG3.

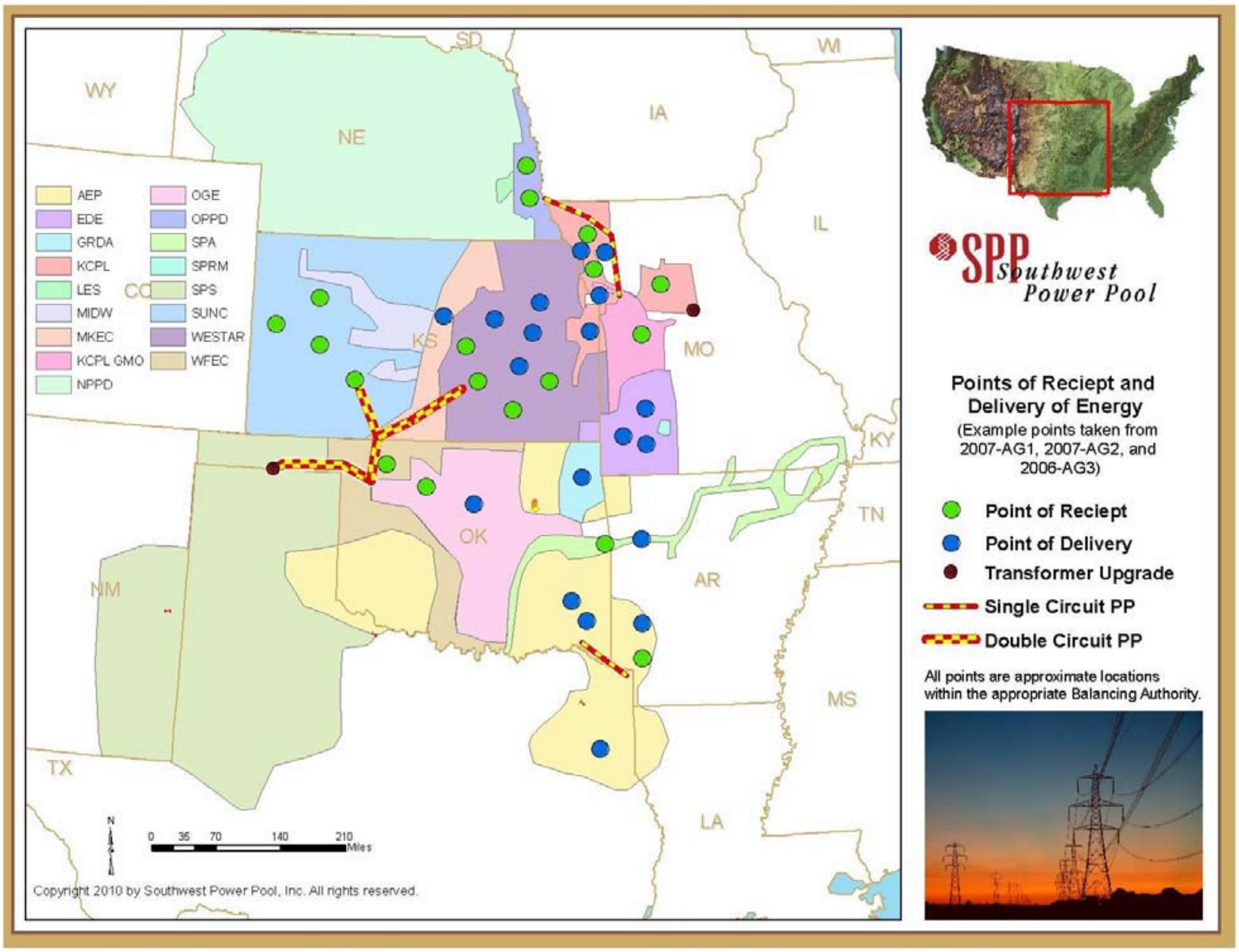


Figure 6

The SPPT stated that Priority Projects should improve the Generation Interconnection (GI) process by enabling the addition of more new generation to the grid. GI study FCS-2008-001 determined the additional transmission needed to interconnect 3,000 – 5,000 MW of additional wind. The transmission identified included a portion of the Priority Projects.

These Priority Projects will also facilitate the addition of other types of generation. Data taken from the GI queue on 2/3/2010 shows that new non-renewable generation is in close proximity to the proposed Priority Projects:

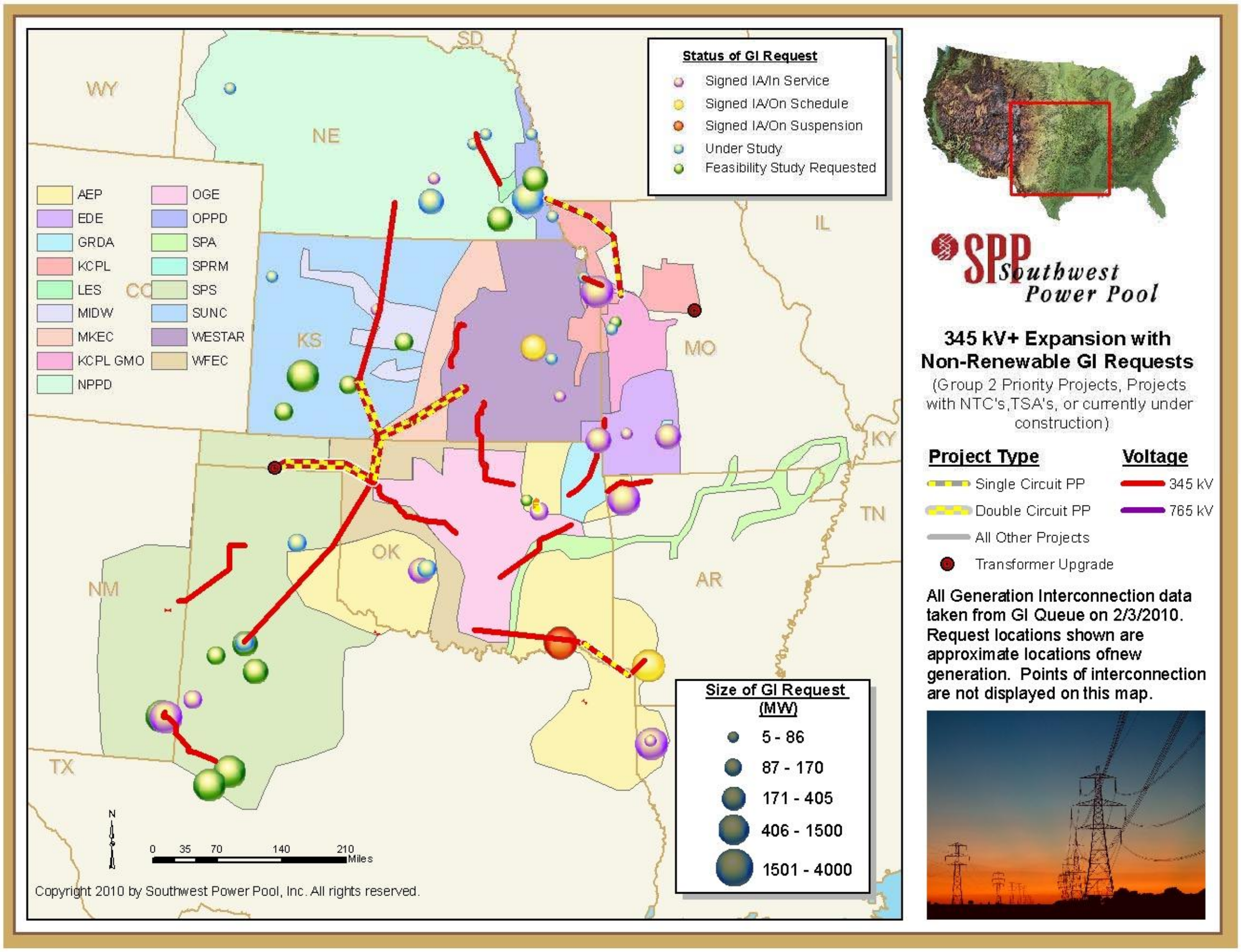


Figure 7: Non-Renewable GI Requests

Loads from multiple major cities within the SPP footprint will be positively impacted by Priority Projects. Improving the transmission system will improve congestion, allowing these cities to be served more efficiently. The figure below depicts Priority Projects and other approved extra high voltage transmission lines in relation to SPP's major load centers:

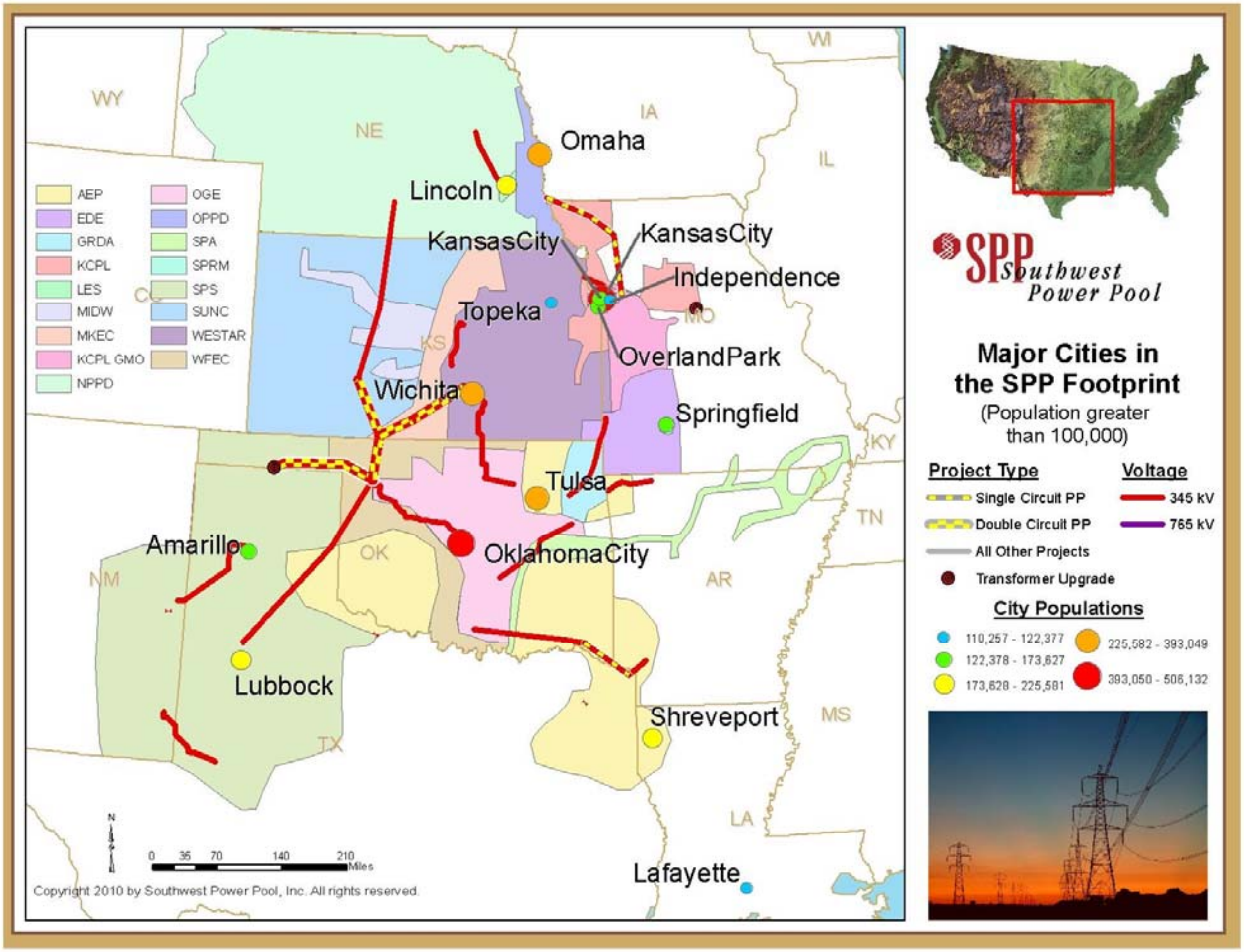


Figure 8: Major Cities in the SPP Footprint

Improve West to East Transfers

Analysis was conducted to measure enhancements to the interface between the SPP footprint's western and eastern regions as a result of Priority Projects. This analysis evaluated the support provided by the projects to power transfers originating in the western part of SPP and terminating in the eastern part. The analysis used a novel approach that geographically divided the SPP footprint into ten sections, then performed First Contingency Incremental Transfer Capability (FCITC) calculations to determine the transfer capability with and without Priority Projects.

The calculations show the Priority Projects increase the ability to transfer power in an eastward direction by connecting the western and eastern areas. This detailed analysis indicates that the greatest rewards will be gained in the future, as more of the underlying limitations are mitigated. The increase in transfer capability correlates exactly with the SPPT's stated goal; that Priority Projects should enhance the interface between SPP's western and eastern transmission systems. See Attachment 5 for this analysis.

Summary of Economic Results

Multi-faceted and detailed analysis was performed using the study assumptions and definitions of the value metrics to derive APC, impact on losses (capacity), reliability (deferral and advancement of STEP projects with Notifications to Construct), gas price impact, and an APC adjustment due to revenues from wind plants.

This report describes the value metric results related to the two project study groups and wind levels. According to the CAWG member survey, the 7 GW wind level is not enough for each member to meet its existing renewable mandates/targets. For this reason, SPP performed supplemental analysis on Priority Projects considering approximately 11.3 GW wind.

The financial analysis is provided in three timeframes including the first ten years, the second ten years, and the last twenty years based on the projects' scope and lifetime.

The impact of transmission expansion on a typical residential customer electric bill is approximately 33.5 cents per kW/month of demand per $1 billion of investment. At the August 26, 2009 CAWG meeting, there was general consensus among regulators, transmission owners, marketers, and wind developers that there is a customer impact of approximately $1/month per $1 billion of transmission investment assuming a residential demand of 3 kW. Additional detail on calculating Priority Projects' impact on customer bills is in Appendix H.

7 GW									
Study Group	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Total Benefit (Years 1-40)	Total Cost (Years 1-40)	Net Benefit (B - C)	B/C
Group 1	$1,309,997,915	$13,318,645	$67,763,548	$209,902,141	$708,295,867	**$2,309,278,116**	**$2,316,856,640**	**($7,578,523)**	**1.00**
Group 2	$1,301,191,318	$20,813,781	$70,570,431	$230,924,482	$718,066,058	**$2,341,566,071**	**$2,082,298,794**	**$259,267,277**	**1.12**

Table 2: Benefits and Costs Summary – 7 GW

11 GW									
Study Group	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Total Benefit (Years 1-40)	Total Cost (Years 1-40)	Net Benefit (B - C)	B/C
Group 1	$1,979,862,546	$13,318,645	$67,763,548	$2,005,193,986	$1,006,676,089	**$5,072,814,813**	**$2,316,856,640**	**$2,755,958,174**	**2.19**
Group 2	$2,053,031,037	$20,813,781	$70,570,431	$2,202,758,931	$1,043,516,243	**$5,390,690,423**	**$2,082,298,794**	**$3,308,391,629**	**2.59**

Table 3: Benefits and Costs Summary – 11 GW

Adjusted Production Cost

The tables below indicate the results of the adjusted production cost (APC) analysis. For each group of projects studied, the APC was calculated between the base and change case for each specific study year. The results for 2009, 2014, and 2019 were then linearly interpolated between the years and extrapolated for the next ten years. After the twentieth year, benefits were held constant until the fortieth year at which time benefits were assumed to cease. Finally, a net present value (NPV) was calculated for each study group using the full forty years of benefits and an 8% discount rate. This is the value shown in the benefits summary tables above.

	2009	*2014*	*2019*
Group 1	$32,476,000	$81,119,000	$104,576,000
Group 2	$32,681,000	$80,700,000	$103,914,000

Table 4: Regional APC Results – 7 GW

	2009	*2014*	*2019*
Group 1	$69,219,000	$132,958,000	$158,293,000
Group 2	$60,892,000	$141,205,000	$160,502,000

Table 5: Regional APC Results – 11 GW

Impact on Losses – Capacity

Capacity savings and fixed cost benefits were calculated using methods suggested by the Benefit Analysis Techniques Task Force (BATTF) in the Benefit Analysis for Priority Projects Report (Attachment 1). The change in losses was calculated for each study period and interpolated between each year. Results were extrapolated to capture the last ten years of benefits. Per the BATTF recommendations, loss savings were assumed to terminate after twenty years due to the expected life of a combustion turbine. A net present value was then calculated for the losses, and the results are provided in the table below. Loss savings were calculated using the same powerflow models as used in the reliability assessment, and do not include additional wind above existing levels. These projected loss savings figures are the same for both the 7 GW and 11 GW study scenarios.

Group 1			
Zone	**2010 - 2019 NPV**	**2020 - 2029 NPV**	**Total**
AEPW	$26,179,331	$466,105	$26,645,436
EMDE	$451,662	$7,521	$459,183
GMO	$343,443	$1,905	$345,348
GRDA	($225,831)	($3,760)	($229,592)
KCPL	$2,151,017	$41,329	$2,192,347
LES	($147,456)	($1,884)	($149,340)
MIDW	$5,315,808	$95,844	$5,411,653
MKEC	$10,553,494	$195,421	$10,748,915
NPPD	$1,577,665	$24,453	$1,602,117
OKGE	($8,569,222)	($141,025)	($8,710,247)
OPPD	$1,162,154	$24,411	$1,186,565
SPRM	$148,480	$1,884	$150,363
SUNC	$301,052	$3,767	$304,820
SWPS	$17,228,076	$283,926	$17,512,002
WEFA	$9,257,033	$154,175	$9,411,209
WRI	$862,125	$20,644	$882,769
Total	**$66,588,831**	**$1,174,716**	**$67,763,548**

Table 6: Impact on Losses - Group 1

Group 2			
Zone	**2010 - 2019 NPV**	**2020 - 2029 NPV**	**Total**
AEPW	$27,993,228	$498,058	$28,491,286
EMDE	$451,662	$7,521	$459,183
GMO	$581,638	$7,535	$589,173
GRDA	($226,855)	($3,760)	($230,615)
KCPL	$2,455,224	$46,966	$2,502,190
LES	($147,456)	($1,884)	($149,340)
MIDW	$5,620,015	$101,481	$5,721,496
MKEC	$10,846,359	$199,188	$11,045,548
NPPD	$1,438,479	$24,439	$1,462,918
OKGE	($7,136,883)	($116,586)	($7,253,469)
OPPD	$1,296,223	$24,425	$1,320,648
SPRM	$148,480	$1,884	$150,363
SUNC	$222,677	$1,891	$224,568
SWPS	$17,377,579	$285,810	$17,663,389
WEFA	$9,932,480	$165,457	$10,097,937
WRI	($1,500,397)	($24,446)	($1,524,843)
Total	**$69,352,453**	**$1,217,978**	**$70,570,431**

Table 7: Impact on Losses - Group 2

Reliability Impact

SPP will work with Ameren as a potentially affected system in accordance with existing agreements to resolve the Overton impacts identified in the reliability assessment. The reliability analysis is summarized in the table below showing revenue requirements associated with advancements, deferments, and overall net impact for the Priority Project study groups. Results are categorized into:

1. Advanced: Projects that would be moved up in the reliability timeline due to the Priority Project
2. New: Projects which are now needed that were not identified in the original 10-year STEP reliability planning horizon, but may have been needed beyond that horizon
3. New third-party: Projects needed on neighboring systems due to the Priority Projects
4. Deferred: Projects which are either deferred beyond the planning horizon or mitigated entirely due to Priority Projects
5. Net Impact – Net cost or benefit of STEP reliability projects related to Priority Projects. Amounts shown for reliability impact in the overall benefits and costs summary tables are in terms of NPV of the Annual Transmission Revenue Requirements. This Net Present Value is limited to a 40-year project life.

Priority Project Group	Advanced Projects	New SPP Projects	New 3rd Party Projects	Deferred Projects	Net Impact
Group 1 Hitchland – Woodward District EHV Double 345 kV Spearville – Cmche – Med. Ldg – Wichita 765 kV @ 345 kV Comanche – Woodward District EHV 765 kV @ 345 kV Nebraska City – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$0M	$4.5M	$0M	$17.8M	$13.3M
Group 2 Hitchland – Woodward District EHV Double 345 kV Spearville – Cmche – Med. Ldg – Wichita Double 345 kV Comanche – Woodward District EHV Double 345 kV Nebraska City – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$0M	$16.8M	$0M	$37.6M	$20.8M

Table 8: Reliability Impact Results

APC Adjustment Due to Wind Revenue Impact

Traditionally, SPP's APC calculations have not considered revenues paid to wind resources because they must be modeled as a transaction rather than a conventional generating unit. The wind must be modeled as a transaction so the variability of the wind can be taken into account. SPP does this by profiling wind based on historical output patterns for each wind resource.

Wind generation's impact on *production costs* can be thought of as subtracting the dispatched wind generation from the load that is met from other generation sources. Because of the different modeling method for wind resources, the impact of wind generation on *revenues from sales* and *costs from purchases* was not included in the initial calculation of APC and must be added to obtain a corrected overall measure of these components. A more detailed explanation of this adjustment is provided in the description of value metrics in the Scope of Priority Projects Phase II, Rev. 1 Analysis section of this report.

	2009	*2014*	*2019*
Group 1	$ 15,188,839	$ 10,211,826	$ 19,712,918
Group 2	$ 15,524,748	$ 10,602,407	$ 21,706,821

Table 9: Increased Revenues from Wind – 7 GW

	2009	*2014*	*2019*
Group 1	$ 87,442,443	$ 110,493,011	$ 179,939,488
Group 2	$ 93,394,239	$ 115,558,315	$ 191,136,602

Table 10: Increased Revenues from Wind – 11 GW

The following charts depict the percentage change in MW-hour output between each group of Priority Projects and the base case. The columns displayed are aggregates of the three study years 2009, 2014, and 2019.

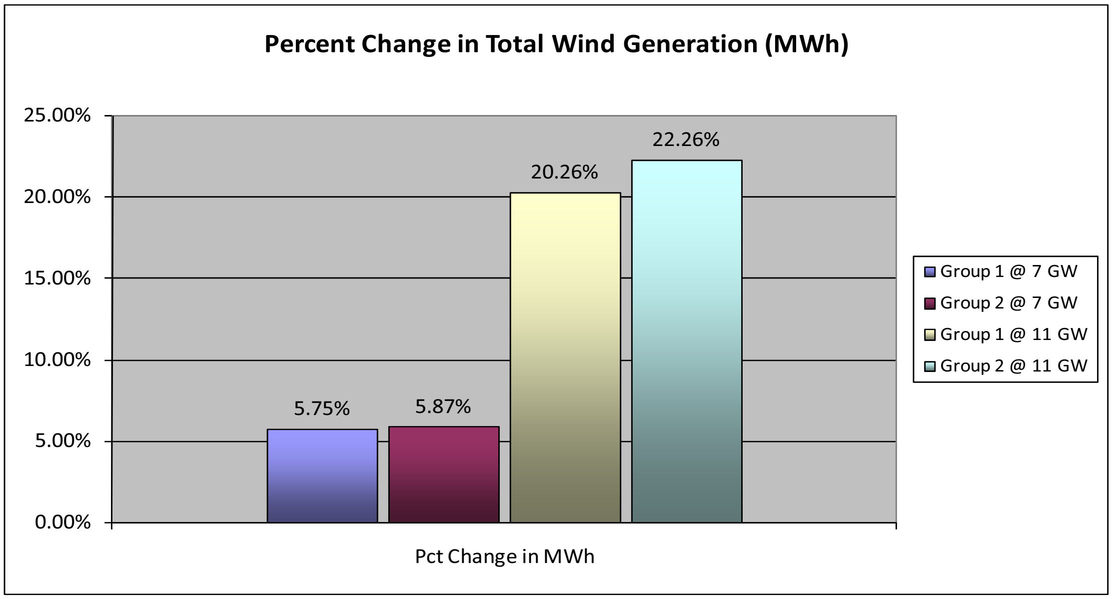


Figure 9: % Change in Total Wind Generation

Related to the above chart above, the following charts show the percentage of dispatched wind generation relative to maximum capacity of the wind generators. The potential capacity factor column indicates how much wind energy would be dispatched without any curtailment. The next three columns are the total capacity factor percentages for each of the study groups. The columns displayed are aggregates of the three study years 2009, 2014, and 2019.

As expected, the addition of the two study groups resulted in less wind curtailment in comparison to the base case model. While study Group 1 produces fewer additional wind revenues than Group 2 due to lower LMP prices, Group 1 allows more wind to be dispatched.

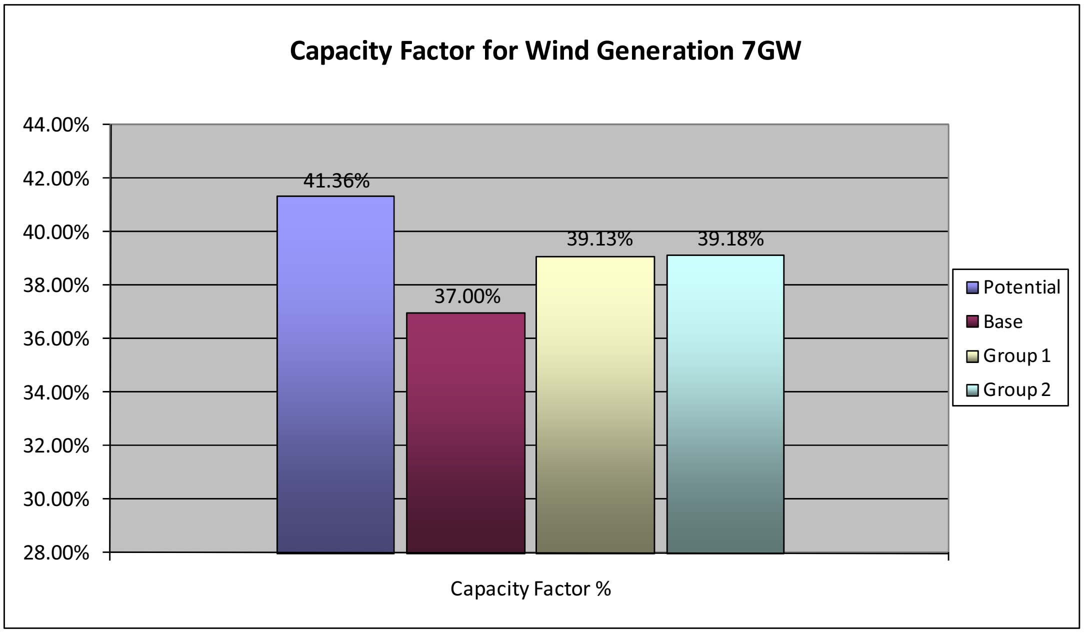


Figure 10: Wind Capacity Factor Changes – 7 GW

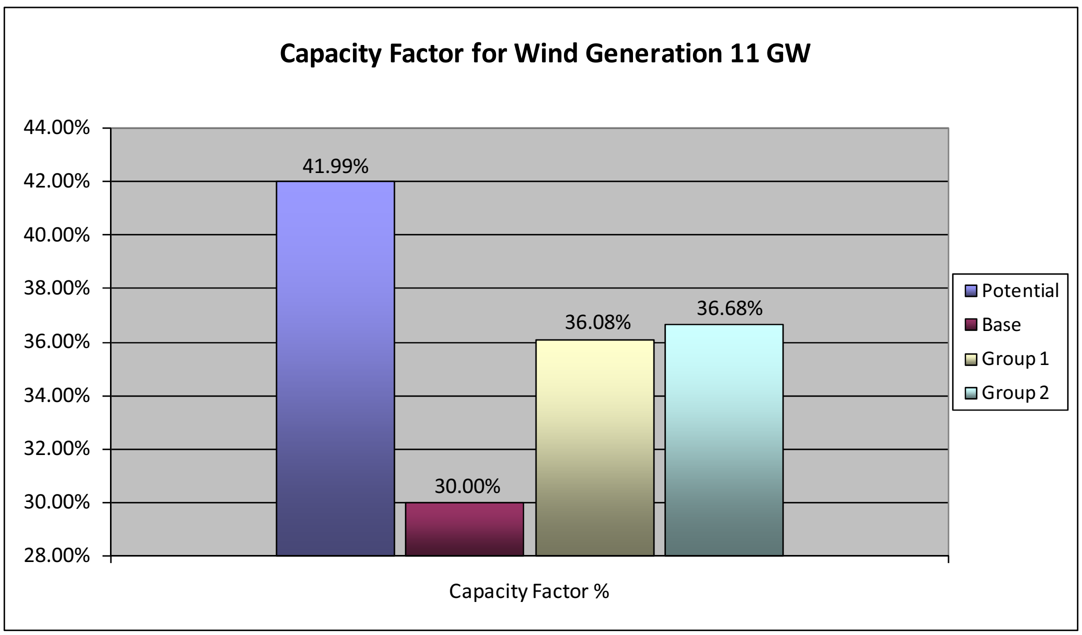


Figure 11: Wind Capacity Factor Changes – 11 GW

The above charts illustrate the change in wind output and wind capacity factor at the regional level. While it is important to see regional impact, the charts do not depict impact on the wind resources located near Priority Projects. The following charts illustrate the MW-hour and capacity factor changes of wind resources near select locations situated near Priority Projects.

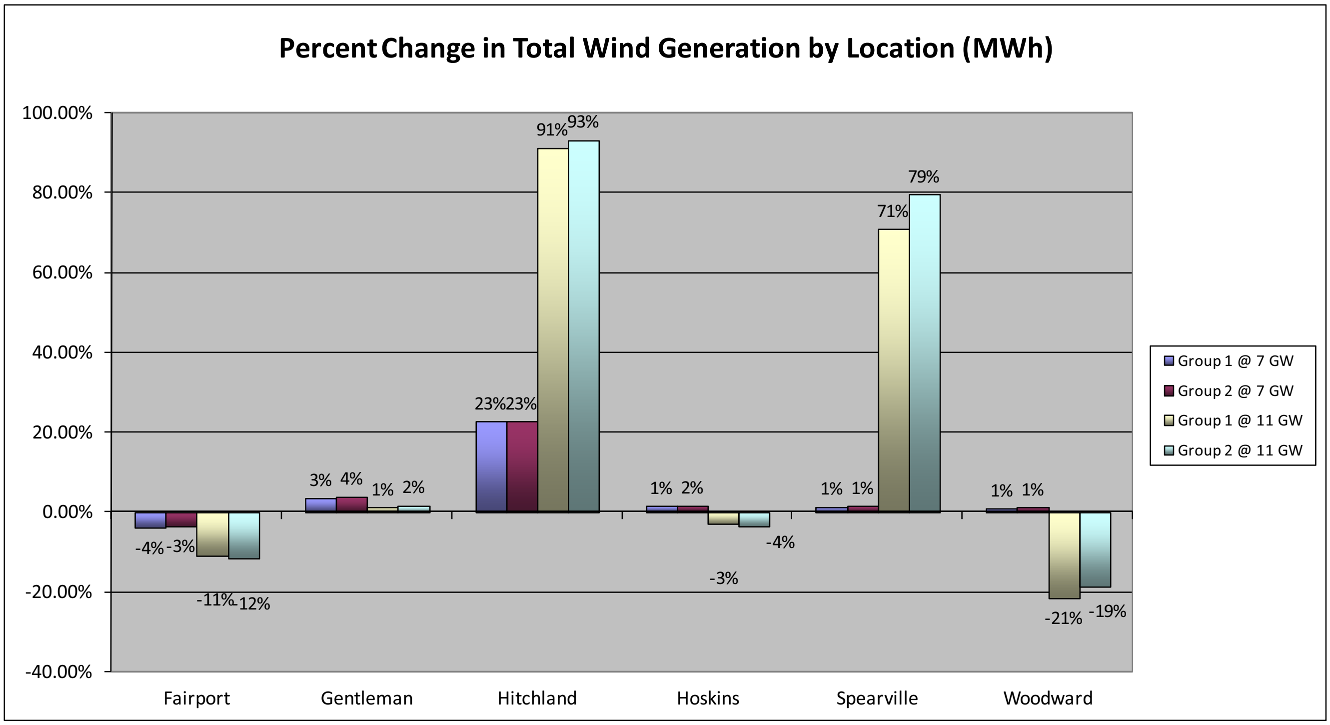


Figure 12: % Change in Wind Generation by Location

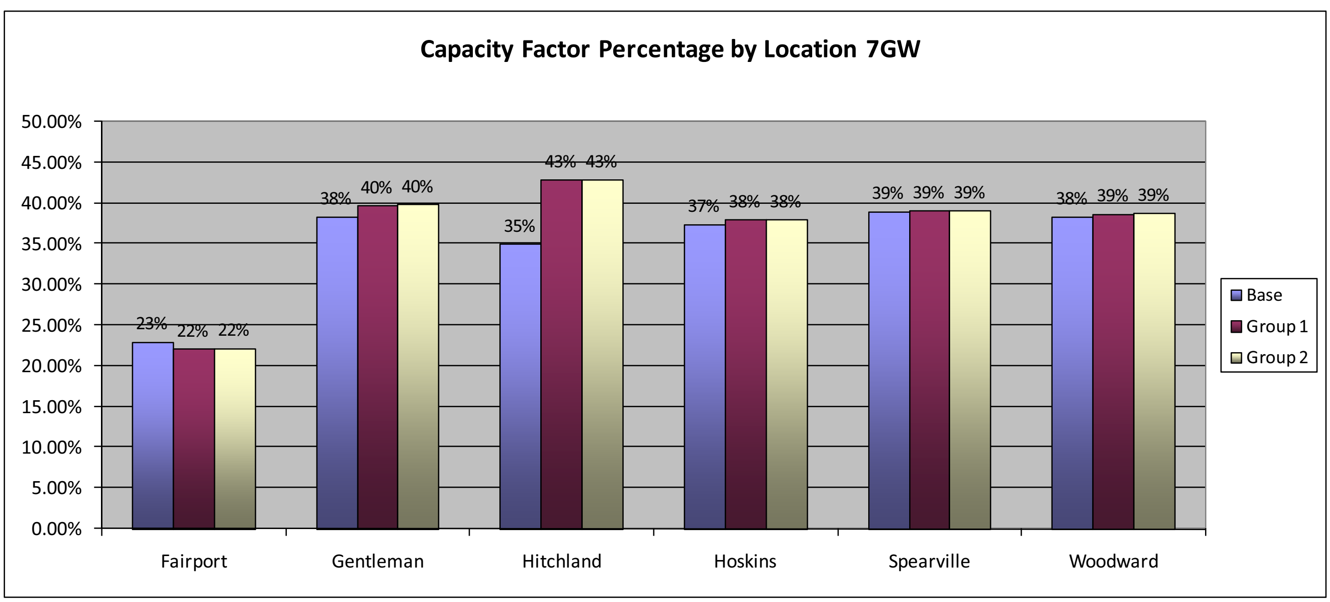


Figure 13: Capacity Factor by Location - 7 GW

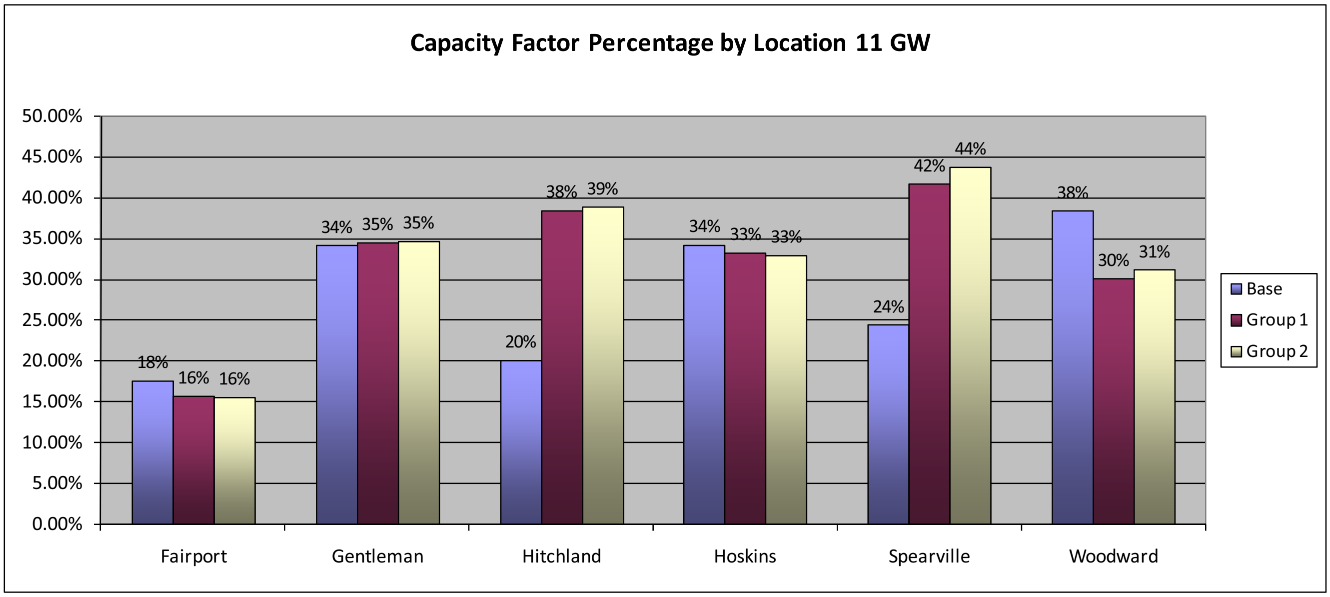


Figure 14: Capacity Factor by Location - 11 GW

Because SPP was asked to model the same level of wind in the base and change case, existing buses in the model were chosen as locations to place the wind. For Missouri, Fairport was the only 345 kV bus on the SPP system in which it was reasonable to place the Missouri wind. However, the proposed 345 kV line Nebraska City – Maryville – Sibley does not have a termination point at Fairport. This modeling nuance likely contributes to the reduced output shown at Fairport.

Priority Project Cost Calculations

The following tables show the Annual Transmission Revenue Requirement (ATRR) by project for Groups 1 and 2. The Engineering and Construction (E&C) cost estimates were provided by the Transmission Owners (TOs). The ATRR for each transmission line was calculated by multiplying the Engineering E&C cost estimates by the levelized Fixed Charged Rate (FCR) for each company. The ATRR was carried out for 40 years (the assumed life of the projects) and a net present value was determined by discounting the ATRR back using 8%. These NPV costs are represented in the summary benefit and cost tables above.

Project	Voltage	Breakout of project by TO	Owner	Levelized FCR	E & C Cost	ATRR
Spearville (ITC GP) - Comanche (ITC GP) - Medicine Lodge (ITC GP)/ (WR) - Wichita (WR)	765 @ 345 kV	Spearville-Comanche-Medicine Lodge	ITC	12.0%	$301,003,320	$36,120,398
		Wichita - Medicine Lodge	Prairie Wind	12.2%	$177,000,000	$21,552,693
Comanche (ITC GP)- Woodward District EHV (OGE)	765 @ 345 kV	Comanche - KS/OK border towards WD EHV	Westar	12.2%	$12,500,000	$1,522,083
		WD EHV- KS/OK border towards Comanche	OGE	15.1%	$119,647,059	$18,066,706
Hitchland (SPS) - Woodward District EHV (OGE)	345 kV DCT	OK Stateline - Woodward District EHV	OGE	15.1%	$233,026,000	$35,186,926
		Hitchland - OK Stateline	SPS	12.1%	$5,096,033	$ 616,620
Valliant - NW Texarkana (AEP)	345 kV	100% AEP	AEP	14.7%	$131,451,250	$19,297,044
Nebraska City (NPPD) - Maryville (KCPL) - Sibley (KCPL)	345 kV	Nebraska City-NE/MO border towards Maryville (NPPD), Maryville-NE/MO border towards Nebraska City and Maryville - Sibley (KCPL-GMO)	KCPL	15.1%	$301,029,091	$45,455,393
Riverside Station - Tulsa Power Station (Reactor) (AEP)	138 kV	100% AEP	AEP	14.7%	$842,847	$123,730
Hitchland 345/230 kV Xfmr	345/230 kV	100% SPS	SPS	12.1%	8,883,760	$1,074,935
Overton 345/161 kV Xfmr[4]	345/161 kV	100% AMMO	AMMO	13.09%[5]	6,750,000[6]	$883,446

Table 11: Project Cost Calculations – Group 1

[4] According to the reliability assessment, loading on the existing transformer increased from 99.8% to 100.6%. This project is not presented for approval as part of the Priority Projects.
[5] Estimated by averaging the levelized FCR for SPP members
[6] Staff estimate

Project	Voltage	Breakout of project by TO	Owner	Levelized FCR	E & C Cost	ATRR
Spearville (ITC GP) - Comanche (ITC GP) - Medicine Lodge (ITC GP)/ (WR) - Wichita (WR)	345 kV DCT	Spearville-Comanche-Medicine Lodge	ITC	12.0%	$205,600,000	$24,672,000
		Wichita - Medicine Lodge	Prairie Wind	12.2%	$150,700,000	$18,350,231
Comanche (ITC GP)- Woodward District EHV (OGE)	345 kV DCT	Comanche - KS/OK border towards WD EHV	Westar	12.2%	$10,800,000	$1,315,080
		WD EHV- KS/OK border towards Comanche	OGE	15.1%	$97,427,500	$14,711,553
Hitchland (SPS) - Woodward District EHV (OGE)	345 kV DCT	OK Stateline - Woodward District EHV	OGE	15.1%	$233,026,000	$35,186,926
		Hitchland - OK Stateline	SPS	12.1%	$5,096,033	$616,620
Valliant - NW Texarkana (AEP)	345 kV	100% AEP	AEP	14.7%	$131,451,250	$19,297,044
Nebraska City (NPPD) - Maryville (KCPL) - Sibley (KCPL)	345 kV	Nebraska City-NE/MO border towards Maryville (OPPD), Maryville-NE/MO border towards Nebraska City and Maryville - Sibley (KCPL-GMO)	KCPL	15.1%	$301,029,091	$45,455,393
Riverside Station - Tulsa Power Station (Reactor) (AEP)	138 kV	100% AEP	AEP	14.7%	$842,847	$123,730
Hitchland 345/230 kV Xfmr	345/230 kV	100% SPS	SPS	12.1%	8,883,760	$1,074,935
Overton 345/161 kV Xfmr[7]	345/161 kV	100% AMMO	AMMO	13.09%[8]	6,750,000[9]	$883,446

Table 12: Project Cost Calculations – Group 2

[7] According to the reliability assessment, loading on the existing transformer increased from 99.8% to 100.6%. This project is not presented for approval as part of the Priority Projects.
[8] Estimated by averaging the levelized FCR for SPP members
[9] Staff estimate

KEMA Analysis

The Priority Project economic assessment focuses on APC savings and impact on losses, reliability projects, and the impact from wind revenue. These metrics do not capture the value of transmission as enabling assets that facilitate markets and help maintain reliability. Some of the strategic and other benefits of EHV transmission which are difficult to quantify include:

- Enabling future markets
- Storm hardening
- Improving operating practices/maintenance schedules
- Lowering reliability margins
- Improving dynamic performance and grid stability during extreme events
- Societal economic benefits

The ESWG discussed many of these metrics and generally agreed that the above benefits, while at this time difficult to quantify, have the potential to provide significant value for the region. It is anticipated that further development of these metrics for the Integrated Transmission Plan will result in quantifiable benefits resulting from a robust transmission system.

KEMA Assumptions and Application to Priority Projects

KEMA was contracted to estimate the impact of Priority Projects on overall natural gas consumption and the affect this impact may have on regional gas prices. KEMA assumptions for fuel price impacts in SPP are based on PROMOD results for the Priority Projects with the two wind levels in the base and change cases. SPP was asked to study certain wind levels in the base and change case related to state renewable targets/mandates; the KEMA study assumes similar renewable targets across the country due to federal or state requirements. This assumption means that similar gas usage reductions will also be seen across the country as is measured for the SPP region.

Recent research by the Lawrence Berkeley National Laboratory and the RAND Corporation provide similar results regarding the 0.9 to 1.2 range of inverse supply price elasticity that can be expected for natural gas consumption. RAND found a value of 0.97; KEMA proposed that SPP use 1.2 in the economic analysis associated with gas price impacts of Priority Projects. Additional detail on KEMA's analysis of reduced natural gas prices can be found in Attachment 6.

The PROMOD results with 7 GW of wind in the base and change cases indicate the addition of Priority Projects will reduce natural gas consumption as a boiler fuel by 5.08 – 5.15%, which equates to a lower gas price in the range of 1.1 – 1.5%. While these price elasticity impacts are small, the resulting impact to gas costs is large in SPP. The following table shows the expected savings associated with 7 GW of wind in the base and change cases:

	2009	*2014*	*2019*
Group 1	$15.2M	$31.7M	$55.7M
Group 2	$15.4M	$32.1M	$56.4M

Table 13: Expected Savings from Reduced Natural Gas Prices – 7 GW

Results with 11 GW of wind in the base and change cases indicate the addition of Priority Projects will reduce natural gas consumption as a boiler fuel by 7.7 – 8%. The expected savings as a result of this price change are shown in the following table.

	2009	*2014*	*2019*
Group 1	$21.7M	$45.2M	$79.1M
Group 2	$22.5M	$46.7M	$81.9M

Table 14: Expected Savings from Reduced Natural Gas Prices – 11 GW

Brattle Group Analysis

In 2009, The Brattle Group estimated the potential economic benefits associated with building a set of transmission projects and expanding the build-out of wind power generation in the SPP region. For this Revision 1 report, SPP asked The Brattle Group to update its report using the most recent wind level assumptions and transmission projects under consideration. The Brattle Group uses the Minnesota IMPLAN model to estimate the potential economic impact of building a set of transmission projects. As a result of constructing the Group 2 set of projects, the Brattle Group estimated the following economic benefits:

- Overall economic output: ~ $962 million
- Overall job impacts: ~ 7,475 full-time equivalent-years
- Additional earnings related to the jobs impact: ~ $368 million
- State and local government tax impacts: ~ $34.4 million

The Brattle Group also used the Job and Economic Development Impact (JEDI) Wind model developed for the U.S. Department of Energy to estimate the potential economic impact of wind projects in the SPP footprint. The JEDI Wind model separates a wind project's life into construction and operation phases. In each phase, the model estimates direct, indirect, and induced job and economic impacts. Direct jobs construct or operate the wind facilities. Indirect jobs provide services or materials to enable construction or operation. Induced jobs provide food, housing, day care, etc. to direct and indirect employees. The Brattle Group analysis found that investment of 3.2 GW of wind projects would have the following economic benefits:

- Overall economic output during construction: ~ $1.8 billion
- Overall jobs impact during construction: ~ 17,000 full-time equivalent-years
- Additional earnings related to construction jobs impact: ~ $577 million
- Overall economic output during operation: ~ $1.6 billion
- Overall jobs impact during operation: ~ 13,100 full-time equivalent-years
- Additional earnings related to operation jobs impact: ~ $501 million

Staff recommends including all of the $962 million in transmission-related benefits identified by the IMPLAN model in evaluating Priority Projects. To the extent the transmission projects enable the interconnection of the additional wind, some of the benefits related to the continued operation of that additional wind should also be considered while evaluating Priority Projects. Staff recommends a conservative 25% of the $1.6 billion of estimated benefits from wind operation be considered. Because SPP was directed to study the same level of wind capacity in the base and change case, it is not appropriate to consider any of the benefits related to wind construction in directly evaluating Priority Projects.

In addition to the above results, The Brattle Group estimated benefits resulting from constructing 7.6 GW of additional wind above SPP's existing 3.8 GW. The results summarized above do not include any in-region manufacturing of materials needed to build transmission or wind infrastructure. The Brattle Group performed a sensitivity by considering

50% of the transmission and wind-related materials being manufactured within the SPP region. The details of the additional wind and higher in-region manufacturing sensitivity can be found in the complete Brattle Group report in Attachment 4.

EXHIBIT NO. OGE-8

FOR IMMEDIATE RELEASE

Emily Pennel, Southwest Power Pool Communications Manager
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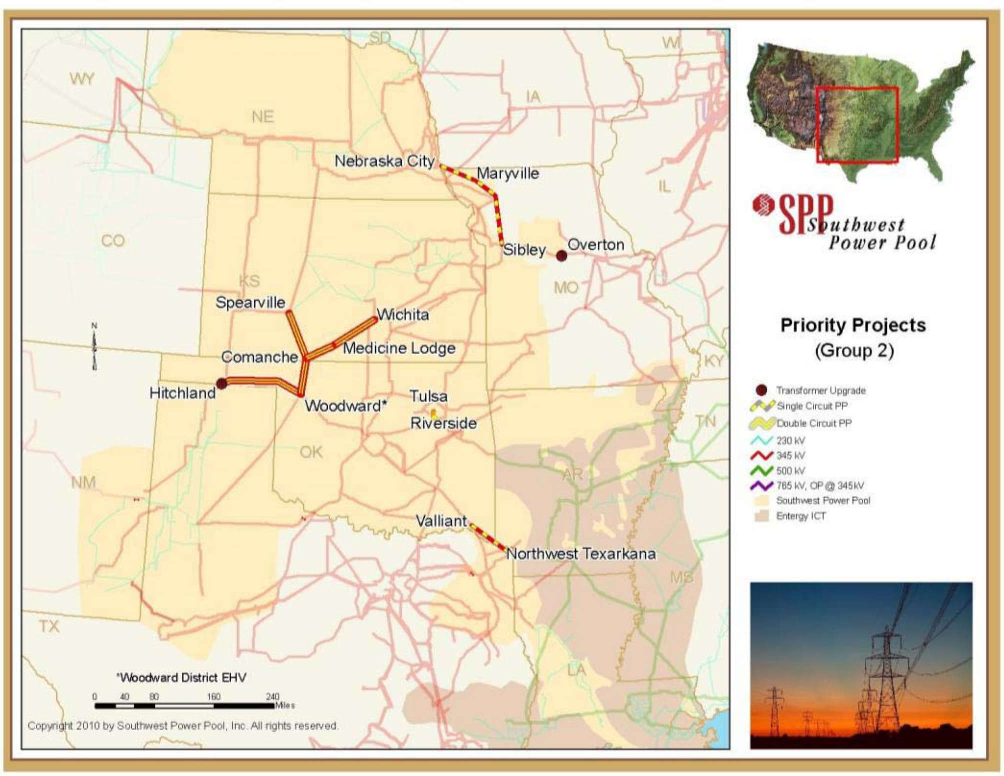
SPP Approves Construction of New Electric Transmission Infrastructure To Bring $3.7 Billion in Regional Benefits

April 27, 2010, LITTLE ROCK, ARKANSAS – Today the Southwest Power Pool, Inc. (SPP) Board of Directors and Members Committee approved for construction a group of "priority" high voltage electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects will improve the regional electric grid by reducing congestion on the power lines, better integrating SPP's east and west regions, improving SPP members' ability to deliver power to customers, and facilitating the addition of new renewable and non-renewable generation to the electric grid. SPP will issue notices to construct these projects pending successful implementation of its proposed Highway/Byway cost sharing proposal.

"Traditionally, we have built transmission infrastructure in a reactive way – incrementally 'patching' the electric grid by building just enough least-cost transmission to keep the lights on," said SPP President and CEO Nick Brown. "Our members are now shifting to a new vision of enabling transmission. We want to proactively build a robust 'transmission superhighway' that will benefit customers not just of one utility, but across the entire region. We need an electric grid that will meet near- and long-term needs, and allow us to better manage many uncertain future scenarios such as carbon policy, varying fuel prices, growth in electricity demand, and state or federal renewable energy standards."

The following map depicts the approved Priority Projects:



- The double-circuit 345-kV line from Spearville, Kansas; to Comanche County, Kansas; to Medicine Lodge, Kansas; to Wichita, Kansas is projected to cost $356 million

- The double-circuit 345-kV line from Comanche County, Kansas, to Woodward, Oklahoma is projected to cost $108 million

- The double-circuit 345-kV line from Woodward, Oklahoma to Hitchland, Texas is projected to cost $247 million

- The 345-kV line from Nebraska City, Nebraska; to Maryville, Missouri; to Sibley, Missouri is projected to cost $301 million

- The 345-kV line from Valliant, Oklahoma to Texarkana, Texas is projected to cost $131 million

- New equipment in Tulsa County, Oklahoma is projected to cost $840,000

The total cost to engineer and construct these projects is estimated to be $1.14 billion.

"There are specific times and places in the SPP region where lower-cost energy can't be delivered to customers because there's not enough transmission. These new electricity 'highways' will allow us to move more power more efficiently," said SPP Senior Vice President of Engineering and Regulatory Policy Les Dillahunty. "Thousands of temporary and permanent jobs will be created to build and operate the Priority Projects. We also expect new wind farms will be built once transmission is available to pull more wind energy from the Plains to the electric grid, providing additional jobs."

Studies indicate that these Priority Projects have a benefit to cost ratio of 1.78 for the SPP region. Quantitative benefits were determined based on Priority Projects' impact on: SPP members' costs related to grid congestion, sales, and revenues; efficient use of the transmission system; natural gas prices as related to support of renewable wind energy; and previously-identified projects needed to maintain electric reliability that may be advanced, deferred, or added. Qualitative benefits were based on the economic output (jobs, goods and services, new taxes paid by project owners, etc.) from the projects' construction and operation, and the operation of an additional 3,200,000 kilowatts of wind energy that will be facilitated by construction of Priority Projects. (For more information, see the SPP Priority Projects Phase II Report, Revision 1.)

Other benefits, which were not measured, include but are not limited to: enabling future SPP energy markets; reducing carbon emissions; lowering the amount of generating capacity that must be held in reserve for emergencies; hardening the grid to better withstand storms; and improving operating practices, maintenance schedules, and grid stability.

The transmission owners whose substations connect to the beginning or end of the lines will have the right of first obligation to build the projects. If a transmission owner chooses not to build, SPP's Open Access Transmission Tariff prescribes the selection process. Entities responsible for construction will then work with their state regulatory commissions when appropriate to obtain the necessary approvals regarding siting and rate recovery.

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EXHIBIT NO. OGE-9

The Brattle Group

Job and Economic Benefits of Transmission and Wind Generation Investments in the SPP Region

March 2010

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Prepared for

Southwest Power Pool

JOB AND ECONOMIC BENEFITS OF TRANSMISSION AND WIND GENERATION INVESTMENTS IN THE SPP REGION

EXECUTIVE SUMMARY

This study is an update to the work presented in Attachments 5 and 6 of the February 1, 2010, *SPP Priority Projects Phase II Report*, which analyzed the job and economic stimulus benefits of wind development and transmission investment in the SPP footprint. This update analyzes the impact on jobs, earnings, and economic output from two groups of transmission investments (Group 1 and Group 2, consisting of 345 kV transmission lines and 765 kV lines operated at 345 kV) in combination with the investment of an additional 3,196 MW and 7,616 MW of wind farms.

To perform our economic impact analysis, we measure the *direct* impacts on jobs, earnings, and economic activity in SPP member states stimulated by the increased spending on transmission and wind generation. We also measure the *indirect* impacts that arise as in-region suppliers to the transmission and wind generation industries, as well as other upstream producers, benefit from the increased investment. Lastly, we measure the *induced* impacts that arise as the increased income from jobs created by the transmission and wind build-out is spent on services and other industry sectors and ripples through the regional economy. To quantify these impacts, we rely on two models—the Minnesota IMPLAN Group Model and the Department of Energy's ("DOE") Job and Economic Development Impact ("JEDI") Model—that are widely used by economists and policy analysts to estimate how specified investments affect every sector of a state's or region's economy.

Our analysis only focuses on the job and economic activity stimulated by the transmission and wind generation investment. It does not address the economic impacts associated with the recovery of investment costs through utility rates, does not analyze the potential effects of additional renewable generation on other existing generating sources, and does not quantify any other economic benefits of transmission investments—such as improved reliability, reduced power prices and production costs, or increased competition and power market liquidity.

Table A below summarizes our findings regarding the overall (*i.e.*, direct, indirect, and induced) employment and economic impacts during the transmission and wind plant construction cycle (*e.g.*, over the next 5 to 10 years) as well as a 20-year wind plant operating period. The combination of the transmission build-out and 3,196 MW of wind development in SPP are estimated to support in-region jobs accounting for approximately 38,000 full-time-equivalent years ("FTE-years") of employment. This impact is associated with approximately $1.5 billion in earnings by employees, which is supported by and paid from over $4.4 billion in increased economic activity within the SPP footprint. This economic activity (*i.e.*, the stimulated "economic output") is measured as the sum of all increased sales and resale revenues within each state of the SPP region.

Table A
Employment and Economic Impacts of Transmission and Wind Investments
(Combined construction and 20-year wind-operation period impacts;
without in-region manufacturing of transmission and wind plant components)

	Employment		Overall
	Earnings (2010$ Million)	Full-Tme-Equivalent Years (FTE-years)	Economic Output (2010$ Million)
3,196 MW of New Wind			
Wind Plant Construction	$577	17,072	$1,826
Wind Plant Operation	$501	13,163	$1,633
Transmission Construction (Group 1)	$421	8,482	$1,095
Transmission Construction (Group 2)	$368	7,475	$962
Combined (Group 1)	$1,499	38,717	$4,554
Combined (Group 2)	$1,446	37,710	$4,421
7,616 MW of New Wind			
Wind Plant Construction	$1,389	40,207	$4,355
Wind Plant Operation	$1,221	31,361	$3,991
Transmission Construction (Group 1)	$421	8,482	$1,095
Transmission Construction (Group 2)	$368	7,475	$962
Combined (Group 1)	$3,031	80,050	$9,441
Combined (Group 2)	$2,978	79,043	$9,308

Similarly, the combination of the analyzed transmission build-out with 7,616 MW wind power development is estimated to support over 79,000 FTE-years of employment, approximately $3.0 billion in earnings, and over $9.3 billion in overall economic activity within the region.

These results conservatively assume that none of the components used in the construction of transmission lines and wind power plants (*e.g.*, transmission wire, towers, circuit breakers, wind turbine blades, and transformers) would be manufactured within the SPP footprint.

Additional jobs and overall economic benefits will be stimulated if some of the transmission wire, towers, circuit breakers wind turbine blades, and transformers used in the construction of these transmission and wind generation facilities are manufactured within the SPP region—which is a highly likely outcome considering the existing manufacturing capabilities within the SPP footprint. Increasing the in-region manufacturing of these components from 0% to 50% is estimated to increase the number of construction-period jobs supported through the transmission and wind investments by approximately 40%, increase earnings by approximately 50%, and magnify SPP-wide overall economic activity by up to 80% compared to the construction-period results shown in Table A. Under this higher in-region manufacturing scenario, the combined investment of the Group 1 transmission projects and 7,616 MW of new wind generation would—over the course of both the construction and operating phases of the facilities—support approximately 100,000 FTE-years of employment, $3.9 billion of earnings by SPP-region employees, and over $13 billion of total economic activity (*i.e.*, sales and resale revenues) within the SPP member states.

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I. INTRODUCTION

This report updates our prior analysis of the job and economic benefits of transmission and wind generation investments to the region served by the Southwest Power Pool ("SPP"). The previous analysis was included as Attachments 5 and 6 of the February 1, 2010, *SPP Priority Projects Phase II Report*, which was prepared by the SPP Engineering/Planning group. SPP staff has since provided us with updated investment scenarios for both transmission and wind generation investments within the SPP footprint, which is reflected in this report.

Our prior analysis and the base case of this updated analysis conservatively assumed that transmission line and wind plant components would all be imported from regions outside the SPP footprint. Because some of these components can be and, in fact, are manufactured within the SPP member states, we also estimate the additional job and economic benefits that would accrue to the region if some of these wind power and transmission line components used in the construction of these facilities are manufactured within the SPP footprint.

The approach and models employed in this update are the same as those in our prior analysis. To measure the impact on jobs, income, and overall economic activity stemming from investments in electric transmission and wind generation, we rely on a class of models known as *input-output* models. Input-output models utilize detailed production data to estimate the economic impact associated with particular investment projects, based on the nature of the local (*e.g.*, region-wide) economy. An input-output model "rebalances" the overall economy after an increase in expenditures on particular types of products (*e.g.,* electric transmission, wind generation), so that the quantity produced again equals the quantity consumed for every industry. Input-output models, therefore, use multipliers and consumption patterns that are computed from detailed national and regional economic and demographic data to represent the extent to which increases in demand lead to changes in employment, output, and earnings. This is a standard approach for assessing the economic impacts of specific investment projects, which takes into account the nature of production within the SPP footprint, including the import of goods and services sourced outside of SPP member states.

To estimate the economic impact from transmission investments, we rely on the well-known and widely-used IMPLAN® Model of the Minnesota IMPLAN Group. This model specifically considers how much of the consumed products and services are supplied from each sector of a given state or regional economy. Only activities that occur in that state or region are counted towards the measured economic impact.

The effects of increased development of wind generation are derived using the Department of Energy's ("DOE") Job and Economic Development Impact ("JEDI") Wind Energy model. Developed specifically for DOE as a tool for measuring the economic impact of generation investment, JEDI provides estimates of the increased jobs, income, and economic activity that result from developing specified wind power projects within a specific state. JEDI relies on IMPLAN® data, making the results from both models comparable and complementary.

Both IMPLAN® and JEDI quantify economic impacts in three categories: (i) number of jobs created in the region (in full-time-equivalent years of employment or "FTE-years");[1] (ii) the resulting personal income earned by employees in the region (*i.e.*, "earnings"); and, (iii) the economic activity generated in the region (*i.e.*, increased "economic output" as measured in total sales and resale revenues of businesses in SPP member states). Income (*i.e.*, earnings) refers to the compensation for workers in all of the directly or indirectly affected industry categories as supported by the stimulated increased output of goods and services. Since these models report economic activity as the sum of the values of all goods and services sold at each level of the supply chain (*i.e.*, sales and resale revenues), the reported economic output refers to the total flow of money that occurs throughout the local economy. The measured impact is the cumulative (undiscounted) amount of jobs (FTE-years), earnings by employees (in 2010 dollars), and overall economic activity (also in 2010 dollars) associated with investing in the assumed

[1] JEDI and IMPLAN® job impacts are reported as full-time-equivalents ("FTE") employment years, that is, 2,080 hour units of employment. For example, reporting 100 jobs could mean 200 workers supported for 6 months, 100 workers supported for a year, or 10 workers supported for 10 years. Operations period job impact is also reported in FTE-year terms, but since those jobs are reported as annual impacts, they can be interpreted as long-term jobs. See also: http://apps1.eere.energy.gov/wip/pdfs/tap_webcast_20090729_jedi.pdf.

investment in transmission and wind generation projects over the entire construction phase and subsequent operational period.

It is important to understand that the quantified economic stimulus benefits do not consider the economic costs of recovering this investment through utility rates or taxes, nor do these benefits reflect any potential impact that the additional wind development may have on other segments of the energy industry (*e.g.*, decreased coal and natural gas-fired generation). This analysis only quantifies the jobs, earnings, and overall economic activity related to the assumed level of wind generation and transmission investments.

Similarly, our study also does not quantify other economic benefits provided by these investments in transmission and wind generation assets, which directly offset investment-related costs. These other benefits include the following:

- increased power system reliability, reduced transmission congestion, and lower transmission losses;
- environmental benefits associated with reduced emissions (*e.g.*, SO_x, NO_x, CO_2, Mercury, particulates, reduced water use and discharge) due to increased renewable power generation;
- possible reductions in fuel prices due to a lower demand for fossil fuels;
- reductions in electric wholesale power market prices and generation costs associated with higher renewable generation and possible reduction of fuel prices;
- increased liquidity and fuel diversity of power markets due to the transmission investments' expansion of the geographic region in which different suppliers compete; and
- reduced ancillary costs of integrating mandated renewable resources (*i.e.*, the costs of providing backup generation capacity, regulation, and load-following services, as well as costs associated with resolving over-generation conditions) due to the transmission investments' expansion of the relevant geographic footprint.

The remainder of this report is organized as follows. Section II presents our estimates of job and economic benefits associated with the updated transmission investment. Section III presents our job and economic benefits estimates for the updated wind generation development assumptions. Section IV then quantifies the additional job and economic benefits of manufacturing transmission line and wind generation components within the SPP footprint.

II. ESTIMATING JOB AND ECONOMIC IMPACTS OF TRANSMISSION INVESTMENT IN SPP MEMBER STATES

A. THE IMPLAN® MODEL

The IMPLAN® (IMpact analysis for PLANing) economic impact modeling system is developed and maintained by the Minnesota IMPLAN Group ("MIG"), which has continued the original work on the system done at the University of Minnesota in close partnership with the U.S. Forest Service's Land and Management Planning Unit. IMPLAN® divides the economy into 440 sectors and allows the user to specify the expenditure allocations associated with a given expansion in demand to all relevant parts of the local economy in order to derive the economic impacts—changes in employment, earnings, and economic output. According to the U.S. Department of Agriculture, currently "over 1,500 clients across the country use the IMPLAN® model, making the results acceptable in inter-agency analysis."[2] In 2009, the U.S. Army Corps of Engineers Civil Works program utilized IMPLAN® employment multipliers "to estimate the potential number of jobs preserved or created" by the American Recovery and Reinvestment Act of 2009.[3] In addition, the U.S. Department of Commerce, the Bureau of Economic Analysis, the U.S. Department of Interior, the Bureau of Land Management, and the Federal Reserve System member banks are also among the agencies that utilize IMPLAN® for economic impact analysis.

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[2] http://www.economics.nrcs.usda.gov/technical/implan/implanmodel.html (last accessed: March 5, 2010).

[3] http://www.usace.army.mil/cecw/planningcop/documents/pa_newsletter/v12i3.pdf (last accessed: March 5, 2010).

B. Specific Assumptions And Modeling Approach

We use the IMPLAN® model to estimate the direct, indirect, and induced impacts on employment, earnings, and overall economic activity ("economic output"), and local tax impacts that will be stimulated by the investments related to transmission line construction in the SPP footprint.[4]

We evaluate the impacts of two build-out scenarios: (i) "Group 1" projects which includes a portfolio of 345 kV single- and double-circuit lines plus two 765 kV lines operated at 345 kV; and (ii) "Group 2" projects which includes the same portfolio of 345 kV single- and double-circuit projects plus an alternative build-out to the 765 kV lines mentioned above as two 345 kV double-circuit lines. The results are broken out by project into direct, indirect, and induced effects within the state in which the expenditures occur. We do not measure the spill-over effects outside of the state in which the expenditure is made.

As noted previously, the IMPLAN® model divides the economy into 440 sectors. For the base case analyses, which does not consider the benefits of manufacturing any of the materials used in the construction of transmission facilities (*e.g.*, towers, wires, and circuit breakers) within the SPP footprint, we rely on the same six sectors selected in our previous analysis to allocate costs associated with construction labor and design work. In other words, we distribute the construction labor and design costs of transmission projects across the six economics sectors shown in Table 1. In addition, when we analyze the additional benefits of manufacturing some transmission materials in the SPP footprint (Section IV), we distribute the costs of those materials across four additional sectors, as also shown in Table 1.

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[4] Note that the "direct" impact reported by IMPLAN includes the economic impacts form purchasing transmission equipment and materials. This standard convention differs from the model ("JEDI") used to estimate economic impacts from wind development, which reports the direct economic impact associated with equipment purchases only in combination with other indirect supply-chain impacts.

Table 1
IMPLAN® Cost Categories

1	Electric power generation, transmission, and distribution	Construction
2	Construction of other new nonresidential structures	Construction
3	Maintenance and repair construction of nonresidential maintenance and repair	Construction
4	Architectural, engineering, and related services	Construction/Design
5	Environmental and other technical consulting services	Design
6	Scientific research and development services	Design
7	Aluminum product manufacturing from purchased aluminum	Materials*
8	Plate work and fabricated structural product manufacturing	Materials*
9	Switchgear and switchboard apparatus manufacturing	Materials*
10	Wiring device manufacturing	Materials*

Source: www.implan.com
* Sectors identified as materials are included only for in-state manufacturing sensitivities.

Table 2 below shows the total cost of transmission lines by project and state. We apply the expenditures by category associated with the proposed investments at the state level and aggregate the impacts for all Group 1 and Group 2 projects.

Table 2
Total Cost of Transmission Lines by Project and State
(2010$, Millions)

Transmission Projects	Capacity	Arkansas	Kansas	Missouri	Nebraska	Oklahoma	Texas	Total
Both Transmission Groups:								
Hitchland-Woodward	2 - 345 kV					$238		$238
Valiant-NW Texarkana	1 - 345 kV	$13				$105	$13	$131
Nebraska City-Maryville-Sibley	1 - 345 kV			$289	$12			$301
Tulsa-Riverside 138 kV Reactor						$1		$1
Group 1:								
Comanche-Woodward District EHV	765 kV at 345 kV		$13			$119		$132
Spearville-Comanche-Medicine Lodge-Wichita	765 kV at 345 kV		$478					$478
Group 2:								
Comanche-Woodward District EHV	2 - 345 kV		$11			$97		$108
Spearville-Comanche-Medicine Lodge-Wichita	2 - 345 kV		$356					$356
Group 1 Transmission Lines Total		$13	$491	$289	$12	$463	$13	$1,282
Group 2 Transmission Lines Total		$13	$367	$289	$12	$442	$13	$1,136

C. Scope and Interpretation of Transmission Results

The economic stimulus from a given expenditure is reported by IMPLAN® as direct, indirect, and induced effects. Direct effects represent the changes in employment, earnings and overall economic activity in the industries which directly benefit from the investment (*i.e.*, construction, materials, and design services). Indirect effects measure the changes in the supply chain and inter-industry purchases generated from the new demand (*e.g.*, suppliers to transmission towers manufacturers). Induced effects reflect changes in spending resulting from increased earnings generated by the direct and indirect effects (*e.g.*, spending on restaurants and groceries by the projects' workers).[5] The impacts on employment, earnings, output, and tax are reported by state in Table 3 for Group 1 and Group 2 projects.

For Group 1 projects (under the base-case assumption that none of the transmission-related materials are manufactured in the region), the transmission investment would support approximately 8,500 FTE-years of employment (e.g., 850 full time jobs each year over a 10 year construction period) producing $421 million in earnings from these jobs. Overall, the transmission investment is estimated to stimulate $1.1 billion in economic activity (*i.e.*, "economic output" measured as the sum of stimulated sales and resale revenues) within the SPP footprint. In addition to any property and right-of-way lease payments directly paid by the transmission owners (which are not quantified in our study), this level of economic activity is estimated to generate approximately $39 million in additional local tax revenue. As Table 3 shows, the economic stimulus impacts for Group 2 projects are slightly smaller due to the lower investments associated with the Group 2 projects.

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5 We do not capture trade flows between states. For example, an expenditure made in Texas could produce trade flows that result in jobs in New Mexico (*i.e.*, in another state in our study) or elsewhere, neither of which are captured.

Table 3

GROUP 1 TRANSMISSION LINES: ECONOMIC OUTPUT AND EMPLOYMENT EFFECTS

Transmission Project	Capacity	State	Earnings (2010$ Millions)	Full-Time Equivalent Years (FTE-Years)				Economic Output (2010$ Millions)				Tax Impact (2010$ Millions)
			Total	*Direct*	*Indirect*	*Induced*	*Total*	*Direct*	*Indirect*	*Induced*	*Total*	*Total*
Hitchland - Woodward	2 - 345 kV	OK	$66	902	263	311	1,477	$102	$40	$40	$181	$6.02
Spearville - Comanche - Medicine Lodge - Wichita	765 kV at 345 kV	KS	$150	1,675	480	729	2,885	$215	$74	$94	$383	$14.07
Comanche-Woodward District EHV	765 kV at 345 kV	KS	$4	46	12	19	79	$6	$2	$3	$11	$0.39
Comanche-Woodward District EHV	765 kV at 345 kV	OK	$34	476	139	161	776	$53	$21	$21	$95	$3.16
Valliant - NW Texarkana	1 - 345 kV	OK	$36	492	143	169	806	$56	$22	$22	$99	$3.29
Valliant - NW Texarkana	1 - 345 kV	AR	$4	63	16	18	98	$7	$2	$2	$12	$0.40
Valliant - NW Texarkana	1 - 345 kV	TX	$5	63	15	19	98	$7	$3	$3	$13	$0.40
Riverside Station - Tulsa Power Station (Add Reactor)		OK	$0	4	1	1	6	$0	$0	$0	$1	$0.03
Nebraska City - Maryville-Sibley	1 - 345 kV	NE	$4	51	14	20	86	$6	$2	$3	$11	$0.39
Nebraska City - Maryville-Sibley	1 - 345 kV	MO	$116	1,176	399	595	2,172	$153	$57	$79	$290	$10.99
Total			**$421**	**4,949**	**1,480**	**2,041**	**8,482**	**$606**	**$223**	**$266**	**$1,095**	**$39.14**

Source and Notes: Results generated uisng IMPLAN Professional v3.0

GROUP 2 TRANSMISSION LINES: ECONOMIC OUTPUT AND EMPLOYMENT EFFECTS

Transmission Project	Capacity	State	Earnings (2010$ Millions)	Full-Time Equivalent Years (FTE-Years)				Economic Output (2010$ Millions)				Tax Impact (2010$ Millions)
			Total	*Direct*	*Indirect*	*Induced*	*Total*	*Direct*	*Indirect*	*Induced*	*Total*	*Total*
Hitchland - Woodward	2 - 345 kV	OK	$66	902	263	311	1,477	$102	$40	$40	$181	$6.02
Spearville - Comanche - Medicine Lodge - Wichita	2 - 345 kV	KS	$106	1,208	339	513	2,062	$153	$54	$66	$273	$10.08
Comanche-Woodward District EHV	2 - 345 kV	KS	$3	37	9	15	61	$5	$2	$2	$8	$0.31
Comanche-Woodward District EHV	2 - 345 kV	OK	$27	376	107	125	608	$42	$17	$16	$74	$2.49
Valliant - NW Texarkana	1 - 345 kV	OK	$36	492	143	169	806	$56	$22	$22	$99	$3.29
Valliant - NW Texarkana	1 - 345 kV	AR	$4	63	16	18	98	$7	$2	$2	$12	$0.40
Valliant - NW Texarkana	1 - 345 kV	TX	$5	63	15	19	98	$7	$3	$3	$13	$0.40
Riverside Station - Tulsa Power Station (Add Reactor)		OK	$0	4	1	1	6	$0	$0	$0	$1	$0.03
Nebraska City - Maryville-Sibley	1 - 345 kV	NE	$4	51	14	20	86	$6	$2	$3	$11	$0.39
Nebraska City - Maryville-Sibley	1 - 345 kV	MO	$116	1,176	399	595	2,172	$153	$57	$79	$290	$10.99
Total			**$368**	**4,373**	**1,305**	**1,785**	**7,475**	**$531**	**$198**	**$233**	**$962**	**$34.40**

Source and Notes: Results generated uisng IMPLAN Professional v3.0

The reported employment estimates represent the amount of labor (measured in full-time-equivalent years of 2,080 hours per year) that would be required to meet the demand created by the construction expenditures and is based on the output-to-worker relationship in the study area for the particular industry. Whether or not these employment estimates represent a net increase in employment depends in part on whether or not these resources (people) would be employed elsewhere in the absence of the projects analyzed. To the extent that the construction activities and indirect and induced economic activities use labor that would otherwise be idle, the employment effects reported here represent a net increase in employment. To the extent that these labor resources would be employed elsewhere absent the analyzed projects, the net effects on employment would be smaller than the gross effect reported here. Similarly, the estimates of gross economic impact and indirect tax revenues make no assumptions about how much money would be spent or how that money would be spent otherwise.

III. ESTIMATING JOB AND ECONOMIC IMPACTS OF WIND POWER DEVELOPMENT IN SPP MEMBER STATES

A. THE JEDI MODEL

To estimate the economic stimulus impact of wind generation development, we utilize the Job and Economic Development Impact ("JEDI") model, which is based on and consistent with IMPLAN®. JEDI is a computational tool specifically calibrated for the estimation of the economic impacts of developing and operating wind power projects at the state level. It was developed in 2002 for the U.S. Department of Energy's National Renewable Energy Laboratory ("NREL") to demonstrate the state and local economic development impacts associated with developing wind power plants in the United States.[6] The JEDI model is considered "the standard when analyzing the economic impacts of wind project development."[7] JEDI has been frequently

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6 U.S Department of Energy, "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply," July 2008. JEDI was originally developed and is currently maintained by Marshall Goldberg of MRG & Associates under contract from NREL.

7 Reategui, et al. "Generating Economic Development from a Wind Power Project in Spanish Fork Canyon, Utah: A Case Study and Analysis of State-Level Economic Impacts," January, 2009.

utilized by the U.S. Department of Energy, state and county policy-makers, public utility commissions, potential project developers, and others focused on examining the economic impacts from new wind project construction and operation.[8]

JEDI allows the user to enter project-specific information on capacity size, turbine size and quantity, location, and all levels and types of development costs. The model allocates those expenditures across 14 major industry types[9] to estimate the economic impacts in terms of jobs, earnings, and economic output. It is important to note that JEDI comes with pre-populated state-specific cost data for wind projects of a given size, which are continually updated by NREL. As a result, JEDI allows estimation of economic impacts even when the researcher does not have access to all aspects of a potential wind project's cost data.[10] JEDI allows users to adjust the local supply of total project construction, design and materials manufacturing activities (which ultimately drive the local economic impacts) to specify the proportion of the project cost spent locally.

The JEDI model is designed to estimate the job and economic impact of wind developments for individual states based on IMPLAN® "multipliers" used to simulate how investments affect a state's economic activities. This also means that when a wind project is sited in one state, even though some jobs and economic activities might be created in (*i.e.*, "spill over" into) a neighboring state, the model does not estimate these "spill-over" benefits. Therefore, similar to our IMPLAN® analysis of transmission investments, our wind generation economic impact estimates are conservative because they do not include the potential job and economic impact of

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[8] http://www.nrel.gov/analysis/jedi/about_jedi_wind.html (last accessed: March 5, 2010). A current list of U.S. DOE studies utilizing the JEDI model is posted at http://www.nrel.gov/analysis/jedi/publications.html.

[9] JEDI models the economic effects of expenditures related to building wind farms to flow through 14 industries: agriculture, mining, construction, manufacturing, fabricating metals, machinery, electrical equipment, transportation/communication/public utilities, wholesale trade, retail trade, finance/insurance/real estate, other miscellaneous services, professional services, and government.

[10] It is often the case that such project-specific detailed information is considered proprietary information by private developers, which makes obtaining it difficult.

each wind project on the economies of neighboring states. This omission might create the impression that each project only benefits the state in which it resides, when in fact, the region as a whole would experience additional benefits. For example, wind projects located in Oklahoma, Kansas, and Missouri may create jobs in Arkansas but this effect has not been captured directly. Economic theory and intuition, however, suggest that, given its geographical proximity to numerous potential wind projects, Arkansas also will benefit from such economic development, both in terms of jobs supported directly or indirectly by construction activities as well as, additionally, from the manufacturing activities analyzed in Section IV below.

Our results of employment effects estimated with the JEDI model are also reported in full-time-equivalent years ("FTE-years"). A FTE-year corresponds to 2,080 hours of work. As noted earlier, the employment impacts associated with the wind projects are net job gains if the labor force is not being utilized elsewhere in the economy absent the projects. If the rate of unemployment is low, these jobs would not necessarily be new and additional. Instead, employees might simply be shifting jobs from other sectors or other projects to support the wind projects under study.

Depending on how project development is implemented, there might be some economies of scale associated with larger projects. For example, if two or more projects are undertaken in close proximity or as a combined venture, some savings in labor, expertise and resources might be achieved, which would reduce the aggregate employment and economic impact compared to undertaking the two projects independently. In our analysis, we have assumed each project in the list provided in the assumption table is a stand-alone project, and have not captured any economies of scale. Thus, the estimated job and economic impact is greater than if the projects are developed in larger aggregations.

B. Specific Assumptions And Modeling Approach

The JEDI model utilizes data on project-specific characteristics and costs to estimate the direct, induced, and indirect effects on employment, earnings, and output from developing and operating the project. Consequently, the JEDI wind model requires three general groups of input data—project description, project cost, and wind farm annual operating and maintenance costs. The categories of input assumptions are summarized in Table 4 below.

Table 4
Assumption Categories for the JEDI Wind Model

Project Descriptive Data
Project Location
Total Project Size - Nameplate Capacity (MW)
Turbine Size (KW)
Project Cost Data
Construction Costs
Equipment Costs
Turbines, Blades, Towers, Transportation
Balance of Plant
Materials, Labor, Development, Engineering, Legal, and Other Costs
Labor
Wind Farm Annual Operating and Maintenance Costs
Labor
Personnel
Materials and Services
Other Parameters
Financial Parameters
Tax Parameters
Land Lease Parameters
Payroll Parameters

To estimate the job and economic activity stimulated by the wind generation development, we used project-specific data for all wind projects designated as part of two wind investment levels to be analyzed. Specifically, we have been asked to evaluate two wind development scenarios: a "Level 1" scenario of 3,196 MW of new wind projects to reach a total of 7,000 MW and a "Level 2" scenario of 7,616 MW of new wind investment to reach a total of 11,300 MW of wind in the SPP footprint. The specific projects comprising the two levels of wind development are summarized in Table 5 and Table 6 below.

Table 5
Level 1 - 3,196 MW of Wind Projects Added in SPP
(To Reach a Total of 7,000 MW)

project unique name	MAX CAPACITY (MW)	Location	STATE
Fairport_MO_1	300	Fairport	MO
Fairport_MO_2	150	Fairport	MO
Fairport_MO_3	150	Fairport	MO
Hitchland_OK_4	192	Hitchland	OK
Hitchland_OK_5	335	Hitchland	OK
Hitchland_OK_6	100	Hitchland	OK
Hitchland_OK_7	300	Hitchland	OK
Hitchland_OK_8	150	Hitchland	OK
Hoskins_NE_9	196	Hoskins	NE
Gentlemen_NE_10	100	Gentlemen	NE
Gentlemen_NE_11	96	Gentlemen	NE
Spearville_KS_12	55	Spearville	KS
Spearville_KS_13	100	Spearville	KS
Spearville_KS_14	150	Spearville	KS
Spearville_KS_15	300	Spearville	KS
Woodward_OK_16	300	Woodward	OK
Woodward_OK_17	150	Woodward	OK
Woodward_OK_18	72	Woodward	OK
Total	**3,196.00**	**MW**	

Table 6
Level 2 - 7,616 MW of Wind Projects Added in SPP
(To Reach a Total of 11,300 MW)

project unique name	MAX CAPACITY (MW)	Location	STATE
Fairport_MO_1	300	Fairport	MO
Fairport_MO_2	150	Fairport	MO
Fairport_MO_3	150	Fairport	MO
Fairport_MO_4	33	Fairport	MO
Hitchland_OK_5	192	Hitchland	OK
Hitchland_OK_6	360	Hitchland	OK
Hitchland_OK_7	300	Hitchland	OK
Hitchland_OK_8	100	Hitchland	OK
Hitchland_OK_9	300	Hitchland	OK
Hitchland_OK_10	150	Hitchland	OK
Hitchland_OK_11	300	Hitchland	OK
Hitchland_OK_12	400	Hitchland	OK
Hoskins_NE_13	200	Hoskins	NE
Hoskins_NE_14	100	Hoskins	NE
Hoskins_NE_15	53	Hoskins	NE
Gentlemen_NE_16	100	Gentlemen	NE
Gentlemen_NE_17	100	Gentlemen	NE
Gentlemen_NE_18	75	Gentlemen	NE
Gentlemen_NE_19	78	Gentlemen	NE
Spearville_KS_20	400	Spearville	KS
Spearville_KS_21	300	Spearville	KS
Spearville_KS_22	200	Spearville	KS
Spearville_KS_23	200	Spearville	KS
Spearville_KS_24	150	Spearville	KS
Spearville_KS_25	100	Spearville	KS
Spearville_KS_26	100	Spearville	KS
Spearville_KS_27	100	Spearville	KS
Spearville_KS_28	100	Spearville	KS
Spearville_KS_29	100	Spearville	KS
Spearville_KS_30	100	Spearville	KS
Spearville_KS_31	100	Spearville	KS
Spearville_KS_32	100	Spearville	KS
Spearville_KS_33	55	Spearville	KS
Woodward_OK_34	300	Woodward	OK
Woodward_OK_35	150	Woodward	OK
Woodward_OK_36	72	Woodward	OK
Washington Cty_AR_37	197.5	Washington Cty	AR
Knoll_KS_38	200	Knoll	KS
Potter_TX_39	400	Potter	TX
Potter_TX_40	200	Potter	TX
Broken Bow_NE_41	80	Broken Bow	NE
Albion_NE_42	120	Albion	NE
Roosevelt_NM_43	300	Roosevelt	NM
Grapevine_TX_44	50	Grapevine	TX
Total	**7,615.50**	**MW**	

While these projects would likely be developed over the course of the next decade and the job and economic benefits would accrue to the SPP footprint spread out over the entire construction cycle, our analysis treats these projects as if they were built in 2010, with an on-line date of 2011, and an operating life of 20 years. If, in reality, these investments are spread out evenly over a 10-year construction cycle, the *average annual impact* of the construction activity would be one-tenth of the reported total construction-related impact.

The most recent version of the JEDI model available publicly from NREL[11] incorporates recent changes in capital costs, productivity improvements, and changing industry practices. The model now contains updated construction and operating and maintenance ("O&M") labor ratios (number of workers) based on current industry averages. The multiplier data is 2006 data from the Minnesota IMPLAN Group, reflecting the most recent data available from the Bureau of Economic Analysis.[12] We have updated the equipment cost assumptions, which reflect an average overnight project cost for the portfolio of wind projects of approximately $2,011/kW for the Level 1 (3,196 MW) wind development scenario and $2,014/kW for the Level 2 (7,616 MW) scenario. Average annual O&M costs are approximately $19/kW-year.

As in our previous analysis (and consistent with JEDI default assumptions), our base case analysis assumes that none of the wind turbines, blades, towers, and transformers associated with the wind generation development would be manufactured by suppliers within the SPP footprint. This yields a conservative estimate of regional jobs and economic stimulus impacts. The additional economic benefits of such manufacturing activity within the SPP footprint are discussed in Section IV of this report.

Economic impact estimates from the JEDI model are reported separately for the construction period and the operational phase of the wind project. We have reported the employment effects during both the construction and operating period in FTE-years, recognizing that, given a 20-year operating life, 20 FTE-years during the operating phase are equivalent to one full-time job

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11 http://www.nrel.gov/analysis/jedi/

12 http://www.windpoweringamerica.gov/filter_detail.asp?itemid=707

that lasts 20 years. In addition, all jobs, earnings, and economic output estimates for the operating period are reported as the simple sum over the 20-year lifecycle of the wind assets and have not been discounted for the time value net of inflation.[13]

C. Scope and Interpretation of Wind Modeling Results

The job and economic stimulus benefits of wind generation for the Level 1 and Level 2 investment scenarios are reported in Table 7 and Table 8. These impacts represent the direct, indirect, and induced impacts associated with the wind investment, which JEDI reports as "project development and on-site labor impacts," "turbine and supply-chain impacts," and "induced" impacts.[14]

Table 7 summarizes the economic stimulus impact in the SPP region by state for the Level 1 investment scenario (3,196 MW of new wind generation). As shown, the construction phase of this wind power expansion scenario is estimated to support jobs with approximately 17,000 FTE-years of employment in the SPP region (*e.g.*, an average of 1,700 full time jobs each year over a 10-year wind construction cycle, if the entire group of projects will take 10 years to complete). This produces $0.6 billion in income by in-region employees over the course of the construction period. The associated overall SPP economic activity (*i.e.*, economic output measured as the total revenues associated with stimulated sales and resale revenues) supported by the wind generation investment is estimated to be $1.8 billion.

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13 Given the fact that both Level 1 and Level 2 scenarios are assumed to complete construction in 2010 and have an equal operating period of 20 years, discounting the earnings and economic output streams would not change the relative comparisons between the two levels.

14 Note that the "direct" impact reported in Tables 7 and 8 based on JEDI simulations include only the direct impacts associated with the on-site construction activity of the wind power plant. The economic impacts from purchasing the wind turbines and related equipment are reported as in combination with other indirect supply-chain impacts, the sum of which is reported here as "indirect" effects. In this regard JEDI deviates from the general convention used in models such as IMPLAN, which would report the economic impacts associated with purchasing wind turbines and related power plant equipment as "direct" impacts, while reporting as "indirect" only the economic effects on suppliers to the construction firms and turbine manufacturers. Due to this difference in reporting convention, the ratio of direct to indirect economic impacts differs for the transmission- and wind-related economic impacts. This difference in reporting conventions, however, neither affect estimates of induced effects nor overall (*i.e.*, the sum of direct, indirect and induced) impacts.

As Table 7 also shows, the cumulative economic benefits during the 20-year operation of an additional 3,196 MW of wind capacity are estimated at approximately 13,000 FTE-years of employment across the SPP region (*i.e.*, 650 full-time jobs lasting 20 years each), producing $0.5 billion in earnings by those employees. The associated economic activity over this 20-year operating period is approximately $1.6 billion in total sales and resale revenues.

Adding the construction and operating phase impacts shown in Table 7, the addition of 3,196 MW of wind generation (assuming no in-region manufacturing of plant components) would support 30,000 FTE-years of employment in the SPP region, $1.1 billion in additional income earned by employees across the SPP region, and $3.4 billion of economic activities.

The results in Table 8 show the economic impacts of 7,616 MW of new wind generation development in the SPP footprint (again conservatively assuming that none of the turbines, blades, towers, and transformers would be manufactured in SPP states). In this "Level 2" investment scenario, a total of 40,000 FTE-years of employment would be supported during the construction phase, producing $1.4 billion of income by employees over the course of the construction period. The corresponding economic activity (total sales and resale revenues) is estimated to be $4.4 billion.

In addition, the aggregate economic benefits during the 20-year operation of the additional 7,616 MW of wind capacity are estimated to support 31,000 FTE-years of employment across the SPP region (*i.e.*, 1,550 full-time jobs lasting 20 years), providing approximately $1.2 billion of additional income and an overall economic activity of $4.0 billion.

Combining construction and operating phase impacts, the addition of 7,616 MW of wind generation (assuming no in-region manufacturing of plant components) would support 71,000 FTE-years of employment, $2.6 billion in income earned by employees, and $8.4 billion of economic activities within the SPP footprint.

Table 7
3,196 MW of New Wind Constructed, Lifespan of 20 Years

EMPLOYMENT STIMULATED BY WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	Earnings (2010$ million)	Full-Tme Equivalent Years (FTE-yrs) Direct	Indirect	Induced	Total
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
Oklahoma	$261	894	5,706	1,986	**8,586**
Kansas	$115	366	2,049	748	**3,163**
Texas	*Positive indirect effects from neighboring projects not quantified*				
Missouri	$127	323	2,028	874	**3,225**
New Mexico	*Positive indirect effects from neighboring projects not quantified*				
Nebraska	$74	238	1,333	528	**2,099**
SPP Total	**$577**	**1,821**	**11,116**	**4,136**	**17,072**

EMPLOYMENT STIMULATED BY WIND PROJECTS DURING 20-YEAR OPERATING PERIOD

STATE	Earnings (2010$ million)	Full-Tme Equivalent Years (FTE-yrs) Direct	Indirect	Induced	Total
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
Oklahoma	$233	1,717	2,550	2,494	**6,761**
Kansas	$92	640	950	629	**2,219**
Texas	*Positive indirect effects from neighboring projects not quantified*				
Missouri	$112	648	988	953	**2,589**
New Mexico	*Positive indirect effects from neighboring projects not quantified*				
Nebraska	$64	445	665	484	**1,594**
SPP Total	**$501**	**3,451**	**5,154**	**4,559**	**13,163**

ECONOMIC OUTPUT STIMULATED BY WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	Increased Economic Output (2010$ million) Total	Direct	Indirect	Induced
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
Oklahoma	$880	$50	$631	$198
Kansas	$346	$25	$243	$78
Texas	*Positive indirect effects from neighboring projects not quantified*			
Missouri	$369	$24	$250	$96
New Mexico	*Positive indirect effects from neighboring projects not quantified*			
Nebraska	$231	$15	$161	$55
SPP Total	**$1,826**	**$115**	**$1,285**	**$426**

ECONOMIC OUTPUT STIMULATED BY WIND PROJECTS DURING 20-YEAR OPERATING PERIOD

STATE	Increased Economic Output (2010$ million) Total	Direct	Indirect	Induced
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
Oklahoma	$838	$76	$513	$249
Kansas	$260	$38	$157	$65
Texas	*Positive indirect effects from neighboring projects not quantified*			
Missouri	$345	$41	$199	$104
New Mexico	*Positive indirect effects from neighboring projects not quantified*			
Nebraska	$190	$25	$115	$50
SPP Total	**$1,633**	**$180**	**$984**	**$469**

Sources: Results generated with JEDI Model Ver. 01D_Wind_Model_rel._W1.09.03e.
Construction and operating jobs are in full-time equivalent years (1 FTE = 2,080 hours).
State-level economic impacts do not consider "spillover" benefits associated with investments in neighboring states.
Analysis assumes none of the major components (e.g. turbines, towers, blades, transformers) are purchased in-state.
Economic output and earnings during operating period represent the cumulative effect over the full operating lifespan of the facilities and have not been discounted.

Table 8
7,616 MW of New Wind Constructed, Lifespan of 20 Years

EMPLOYMENT STIMULATED
BY WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	Earnings *(2010$ million)*	*Full-Tme Equivalent Years (FTE-yrs)* Direct	*Indirect*	*Induced*	*Total*
Arkansas	$32	108	728	240	**1,076**
Oklahoma	$426	1,419	9,363	3,253	**14,034**
Kansas	$436	1,372	7,805	2,848	**12,025**
Texas	$124	363	1,948	713	**3,023**
Missouri	$136	369	2,140	928	**3,437**
New Mexico	59	155	1,053	462	**1,671**
Nebraska	$175	625	3,084	1,231	**4,940**
SPP Total	**$1,389**	**4,412**	**26,120**	**9,675**	**40,207**

EMPLOYMENT STIMULATED
BY WIND PROJECTS DURING 20-YEAR OPERATING PERIOD

STATE	Earnings *(2010$ million)*	*Full-Tme Equivalent Years (FTE-yrs)* Direct	*Indirect*	*Induced*	*Total*
Arkansas	$31	218	323	379	**920**
Oklahoma	$379	2,770	4,172	4,081	**11,022**
Kansas	$361	2,571	3,640	2,426	**8,637**
Texas	$121	681	887	1,132	**2,700**
Missouri	$120	699	1,051	1,012	**2,762**
New Mexico	$58	308	544	730	**1,582**
Nebraska	$152	1,044	1,561	1,133	**3,738**
SPP Total	**$1,221**	**8,291**	**12,177**	**10,894**	**31,361**

ECONOMIC OUTPUT STIMULATED
BY WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	Increased Economic Output (2010$ million) *Total*	*Direct*	*Indirect*	*Induced*
Arkansas	$106	$6	$77	$23
Oklahoma	$1,441	$81	$1,036	$325
Kansas	$1,315	$93	$926	$296
Texas	381	27	265	89
Missouri	$392	$27	$264	$101
New Mexico	$180	$11	$125	$45
Nebraska	$540	$40	$372	$128
SPP Total	**$4,355**	**$284**	**$3,064**	**$1,007**

ECONOMIC OUTPUT STIMULATED
BY WIND PROJECTS DURING 20-YEAR OPERATING PERIOD

STATE	Increased Economic Output (2010$ million) *Total*	*Direct*	*Indirect*	*Induced*
Arkansas	$120	$9	$74	$37
Oklahoma	$1,370	$123	$840	$407
Kansas	$1,006	$154	$600	$252
Texas	$467	$44	$282	$142
Missouri	$367	$44	$212	$111
New Mexico	$214	$18	$125	$70
Nebraska	$447	$59	$270	$118
SPP Total	**$3,991**	**$451**	**$2,403**	**$1,137**

Sources: Results generated with JEDI Model Ver. 01D_Wind_Model_rel._W1.09.03e.
Construction and operating jobs are in full-time equivalent years (1 FTE = 2,080 hours).
State-level economic impacts do not consider "spillover" benefits associated with investments in neighboring states.
Analysis assumes none of the major components (e.g. turbines, towers, blades, transformers) are purchased in-state.
Economic output and earnings during operating period represent the cumulative effect over the full operating lifespan of the facilities and have not been discounted.

IV. ADDITIONAL ECONOMIC BENEFITS FROM LOCAL MANUFACTURING

A. Low and Higher In-Region Manufacturing Scenarios

The base case results discussed above assumed that all transmission-related materials and wind components are manufactured outside the SPP footprint. We consider this base case to be a very conservative "low in-region supply" scenario. We have developed as a comparison, a "higher in-region" supply scenario assuming that 50% of all transmission-related materials and 50% of certain wind plant components (blades, towers, and transformers) would be manufactured within the SPP footprint. Significant in-region manufacturing of transmission and wind plant components is a highly likely outcome considering even preexisting manufacturing capabilities within the SPP footprint. For example, a number of wind-generation-related manufacturing facilities are already located in Arkansas, Kansas, Missouri, Nebraska and Oklahoma. They are reported to include LM Glasfiber, Mitsubishi Power Systems, Nordex, Emergya Wind Technologies, Siemens, DMI Industries, Bergey WindPower, Katana Summit, and NorthStar Wind Towers.[15] Higher levels of in-region manufacturing capability will be stimulated by additional transmission and wind generation investment, thereby magnifying the economic stimulus benefits of the investments to the region.

The following tables compare the total investment costs allocated by broad input categories and the associated in-region share for the low and higher in-region supply scenarios. Table 9 lists the broad cost categories in IMPLAN® with the breakdown for each spending category as a percentage of total transmission construction costs. The table shows that the Group 1 set of transmission projects at a total investment cost of $1.3 billion consists of the following cost components: 38% for construction labor, 53% for materials; and 10% for design work. Group 2, at a total cost of $1.1 billion, has a slightly different allocation of 39% for construction labor, 53% for materials; and 8% for design work.

[15] SPP Economic Development Presentation, February 10, 2010, slides 50-57.

As also shown on the right side of Table 9, the low in-region scenario assumes that all transmission construction and design activities are provided by in-region suppliers (*e.g.*, SPP transmission owners and local construction companies) while all materials are provided by suppliers from outside the SPP member states. For the higher in-region scenario, we assume that 50% of all transmission materials such as towers, wire, circuit breakers, and other hardware are manufactured in the region. As shown in Table 9, this means that only 47% of the total transmission project costs (including materials and construction services) are provided by in-region suppliers in the base case, whereas in the higher in-region scenario, that overall in-region cost share increases to 74%.

Table 9
IMPLAN® Construction Cost Allocation and Share of In-Region Supply for Group 1 and Group 2 Transmission Projects

	Total Cost (2010$ Millions)				Share of In-Region Supply			
					Low		High	
	Group 1	%	Group 2	%	Group 1	Group 2	Group 1	Group 2
Transmission Cost Allocations								
Construction Labor	$481	*38%*	$442	*39%*	100%	100%	100%	100%
Materials	$676	*53%*	$605	*53%*	0%	0%	50%	50%
Design	$124	*10%*	$89	*8%*	100%	100%	100%	100%
Total	**$1,282**	***100%***	**$1,136**	***100%***				
In-Region Share of Expenditures					**47%**	**47%**	**74%**	**73%**

Tables 10 and 12 list the broad construction-phase cost categories for wind generation. Tables 11 and 13 list the cost categories and percentage of total O&M costs during the operating phase of the wind projects. As shown, the overall construction-phase project spending consists of approximately: 45% for turbines; 30% for blades, towers, and related transportation; 16% for other supplies; and 9% for on-site labor, project design, and management. Accompanying these cost allocation percentages are the low and higher in-region shares where it is assumed that either zero or 50% of certain wind components (blades, towers, and transformers) are manufactured in the SPP footprint. JEDI default assumptions are used for the in-region supply share for all other wind generation cost components.

Table 10
JEDI Construction Cost Allocation and Share of In-Region Supply
for 3,196 MW Wind Portfolio

Project Construction Cost Inputs for JEDI	Costs	Percent of Total	Low In-Region Share	High In-Region Share
	(Millions 2010$)	(%)	(%)	(%)
Equipment Costs				
Turbines	2,925	46%	0%	0%
Blades, Towers, Transportation	1,956	30%	0%	50%
Materials				
Construction (concrete, rebar, site prep)	693	11%	90%	90%
Transformer	78	1%	0%	50%
Wire/Electrical/Other	233	4%	81%	81%
Labor				
Foundation, Erection, Electrical	100	2%	78%	78%
Management/Supervision/Other	264	4%	46%	46%
Development/Other				
Interconnection	62	1%	71%	71%
Engineering	65	1%	0%	0%
Siting	52	1%	100%	100%
Total	**6,427**	**100%**	**17%**	**33%**

Table 11
JEDI Annual O&M Cost Allocation and Share of In-Region Supply
for 3,196 MW Wind Portfolio

Project Annual Operation Cost Inputs for JEDI	Costs	Percent of Total	Low In-Region Share	High In-Region Share
	(Millions 2010$)	(%)	(%)	(%)
Labor Costs	10	16%	100%	100%
Materials				
Site Maintenance/Parts/Other	37	61%	13%	13%
Fees, Permits, Licenses, Insurance	11	19%	3%	3%
Other	3	5%	100%	100%
Total	**62**	**100%**	**29%**	**29%**

Table 12
JEDI Construction Cost Allocation and Share of In-Region Supply
for 7,616 MW Wind Portfolio

Project Construction Cost Inputs for JEDI	Costs	Percent of Total	Low In-Region Share	High In-Region Share
	(Millions 2010$)	(%)	(%)	(%)
Equipment Costs				
Turbines	6,966	45%	0%	0%
Blades, Towers, Transportation	4,662	30%	0%	50%
Materials				
Construction (concrete, rebar, site prep)	1,655	11%	90%	90%
Transformer	187	1%	0%	50%
Wire/Electrical/Other	558	4%	81%	81%
Labor				
Foundation, Erection, Electrical	251	2%	78%	78%
Management/Supervision/Other	633	4%	46%	46%
Development/Other				
Interconnection	149	1%	71%	71%
Engineering	155	1%	0%	0%
Siting	124	1%	100%	100%
Total	**15,339**	**100%**	**17%**	**33%**

Table 13
JEDI Annual O&M Cost Allocation and Share of In-Region Supply
for 7,616 MW Wind Portfolio

Project Annual Operation Cost Inputs for JEDI	Costs	Percent of Total	Low In-Region Share	High In-Region Share
	(Millions 2010$)	(%)	(%)	(%)
Labor Costs	24	16%	100%	100%
Materials				
Site Maintenance/Parts/Other	89	60%	13%	13%
Fees, Permits, Licenses, Insurance	27	18%	3%	3%
Other	8	5%	100%	100%
Total	**148**	**100%**	**30%**	**30%**

Overall, only 17% of the total construction, development and materials for the wind power portfolio are assumed to be provided by in-region suppliers in the low in-region share scenario (or base case). In the higher in-region scenario, that in-region expenditure share increases to 33% of total wind project expenditure. This differentiation of in-region manufacturing shares does not impact the operations-phase expenditures of the wind plants shown in Table 11 and Table 13.

B. Economic Benefits from Higher In-Region Manufacturing of Wind Generation and Transmission Components

Tables 14 and 15 summarize the estimated construction-period impact of increasing from 0% to 50% the in-region manufacturing share of transmission materials and certain wind generation components. The estimated additional benefits from higher in-region manufacturing are summarized in Table 14 for the Group 1 transmission projects and the two wind development scenarios (3,196 MW and 7,616 MW). Table 15 reports the additional benefits for the Group 2 transmission build-out and the two wind development scenarios.

For 3,196 MW of wind development, increasing the in-region manufacturing of selected components and materials from 0% to 50% yields construction-period economic impacts that are approximately 40% higher in terms of employment (for a total of 34,000 FTE-years), approximately 50% higher in terms of earnings by employees (for a total of $1.4 billion), and up to 80% higher in terms of overall economic output (sales and resale revenues; for a total of approximately $4.8 billion). The percentage increase in benefits from higher in-region manufacturing is similar for the 7,616 MW wind portfolio.

Table 14
Employment and Economic Output Impacts of Higher In-Region Manufacturing of Wind and Group 1 Transmission Components

3,196MW of New Wind Constructed

EMPLOYMENT AND ECONOMIC OUTPUT STIMULATED DURING CONSTRUCTION PERIOD

	Employment		
	Earnings (2010$ million)	Full-Tme Equivalent Years (FTE-yrs)	Increased Economic Output (2010$ million)
SPP Impact with 0% In-Region Manufacturing			
Wind Generation	$577	17,072	$1,826
Transmission (Group 1)	$421	8,482	$1,095
Combined	$998	25,554	$2,921
SPP Impact with 50% In-Region Manufacturing			
Wind Generation	$910	24,645	$3,360
Transmission (Group 1)	$532	10,571	$1,603
Combined	$1,442	35,216	$4,964
SPP Incremental Impact of 50% In-Region Manufacturing			
Percentage	**44%**	**38%**	**70%**

7,616MW of New Wind Constructed

EMPLOYMENT AND ECONOMIC OUTPUT STIMULATED DURING CONSTRUCTION PERIOD

	Employment		
	Earnings (2010$ million)	Full-Tme Equivalent Years (FTE-yrs)	Increased Economic Output (2010$ million)
SPP Impact with 0% In-Region Manufacturing			
Wind Generation	$1,389	40,207	$4,355
Transmission (Group 1)	$421	$8,482	$1,095
Combined	$1,810	48,689	$5,450
SPP Impact with 50% In-Region Manufacturing			
Wind Generation	$2,172	57,786	$7,993
Transmission (Group 1)	$532	$10,571	$1,603
Combined	$2,705	68,357	$9,596
SPP Incremental Impact of 50% In-Region Manufacturing			
Percentage	**49%**	**40%**	**76%**

Manufacturing Assumptions:

For wind construction impacts, the "base" case (0% in-region manufacturing) assumes no local expenditures on blades, towers, transportation, and transformers, while the "high" case (50% in-region manufacturing) assumes 50% of expenditures on the above components are directed to local sources.
For transmission construction impacts, the "base" case (0% in-region manufacturing) assumes no local expenditures on any transmission materials and components, while the "high" case (50% in-region manufacturing) assumes 50% of all transmission materials and components are purchased locally.

Table 15
Employment and Economic Output Impacts of Higher In-Region Manufacturing of Wind and Group 2 Transmission Components

3,196MW of New Wind Constructed

EMPLOYMENT AND ECONOMIC OUTPUT STIMULATED DURING CONSTRUCTION PERIOD

	Employment		
	Earnings (2010$ million)	Full-Tme Equivalent Years (FTE-yrs)	Increased Economic Output (2010$ million)
SPP Impact with 0% In-Region Manufacturing			
Wind Generation	$577	17,072	$1,826
Transmission (Group 2)	$368	7,475	$962
Combined	$945	24,547	$2,788
SPP Impact with 50% In-Region Manufacturing			
Wind Generation	$910	24,645	$3,360
Transmission (Group 2)	$468	9,345	$1,417
Combined	$1,378	33,990	$4,778
SPP Incremental Impact of 50% In-Region Manufacturing			
Percentage	**46%**	**38%**	**71%**

7,616MW of New Wind Constructed

EMPLOYMENT AND ECONOMIC OUTPUT STIMULATED DURING CONSTRUCTION PERIOD

	Employment		
	Earnings (2010$ million)	Full-Tme Equivalent Years (FTE-yrs)	Increased Economic Output (2010$ million)
SPP Impact with 0% In-Region Manufacturing			
Wind Generation	$1,389	40,207	$4,355
Transmission (Group 2)	$368	$7,475	$962
Combined	$1,757	47,682	$5,317
SPP Impact with 50% In-Region Manufacturing			
Wind Generation	$2,172	57,786	$7,993
Transmission (Group 2)	$468	$9,345	$1,417
Combined	$2,640	67,131	$9,410
SPP Incremental Impact of 50% In-Region Manufacturing			
Percentage	**50%**	**41%**	**77%**

Manufacturing Assumptions: For wind construction impacts, the "base" case (0% in-region manufacturing) assumes no local expenditures on blades, towers, transportation, and transformers, while the "high" case (50% in-region manufacturing) assumes 50% of expenditures on the above components are directed to local sources.
For transmission construction impacts, the "base" case (0% in-region manufacturing) assumes no local expenditures on any transmission materials and components, while the "high" case (50% in-region manufacturing) assumes 50% of all transmission materials and components are purchased locally.

As shown in Tables 14 and 15, the transmission investment combined with the higher level of wind development would support 67,000 FTE-years of total employment, $2.6 billion in earnings, and approximately $9.5 billion in total economic output (sales and resale revenues) over the course of the *construction period* of the transmission and wind facilities. When the wind projects' economic impact during the *operational period* is added to that, the combined investment of the Group 1 transmission projects and 7,616 MW of new wind generation would—over the course of both the construction and operating phases of the facilities—support approximately 100,000 FTE-years of employment, $3.9 billion of earnings by SPP-region employees, and over $13 billion of total economic activity (*i.e.*, sales and resale revenues) within the SPP member states.

C. Sales Increases For Local Electric and Natural Gas Utilities

This section analyzes the extent to which the increased economic activity associated with transmission and wind plant construction also increases revenues of electric and natural gas utilities in the SPP footprint. These additional utility revenues, as reported in Table 16, are a portion of the indirect and induced economic output effects reported for transmission construction activities in Sections II and IV above. As Table 16 shows, the Group 1 set of transmission projects provides between $14.0 and $22.7 million in revenues (from indirect and induced economic output) by electric and natural gas utilities in the SPP footprint, depending on the in-region manufacturing share. For the Group 2 set of transmission projects, between $12.3 and $20.0 million in additional electricity and gas sales revenues are associated with the higher economic activity within the SPP footprint. Increased natural gas sales account for approximately 20% to 22% of the combined impact on electric and natural gas utilities.

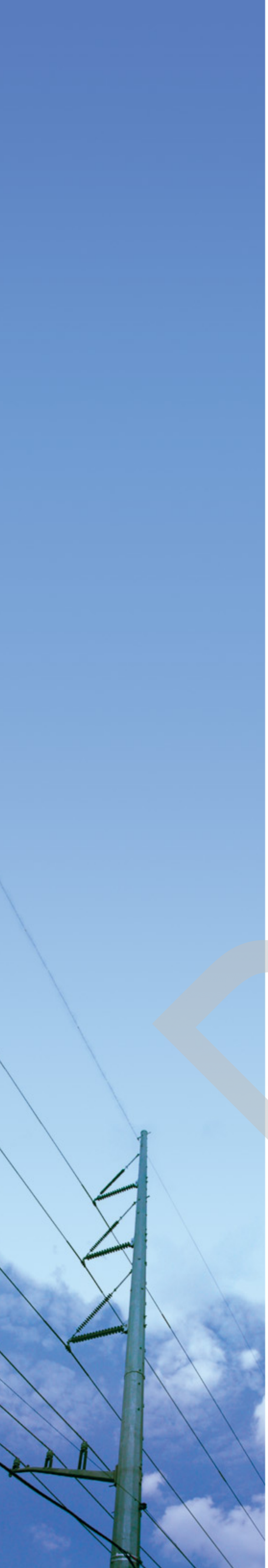
Table 16
Impact of Transmission Investments
on SPP Electric and Natural Gas Utility Revenues

Transmission Projects	Low In-Region Manufacturing			Higher In-Region Manufacturing		
	Indirect	*Induced*	*Total*	*Indirect*	*Induced*	*Total*
	(2010$ Millions)			*(2010$ Millions)*		
Group 1	$4.8	$9.2	$14.0	$10.9	$11.8	$22.7
Group 2	$4.3	$8.0	$12.3	$9.7	$10.3	$20.0

Source and Notes:
The impact on electricity and gas revenues is captured through the indirect and induced impacts from expenditures in each set of transmission line buildouts. The impacts affect the following IMPLAN sectors: electric power generation, transmission, and distribution; natural gas distribution; federal electric utilties; and state and local government electric utilities.

While the analysis above is based on our IMPLAN® modeling results and was undertaken only for transmission investments, we estimate that approximately the same ratio of utility sales increases to total in-region supply of transmission development would also apply to wind development. This implies that every $1 billion of in-region spending from wind and transmission investment activities is estimated to generate $23 million to $24 million in additional electric and natural gas utility sales within the SPP footprint. As a result, under the higher in-region manufacturing scenario, the combined in-region supply activities associated with Group 1 transmission projects and Level 2 wind generation development would stimulate approximately $140 million in additional electric and natural gas utility retail revenues during the construction phase of these projects. This estimate of utility retail sales increases captures only the impact of transmission and wind construction activities. It does not reflect the extent to which increases in supply options and reliability resulting from transmission investments or reductions in local wholesale power prices resulting from wind development may be able to attract new businesses to the SPP footprint. On the other hand, it does not account for any potential impact of changes in retail electricity prices on SPP's ability to attract businesses or residents.

EXHIBIT NO. OGE-10



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SPP Priority Projects Report

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Southwest Power Pool

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Executive Summary

At the April 28, 2009 SPP Board of Directors (BOD) meeting, Southwest Power Pool, Inc. (SPP) staff was charged with restructuring its regional transmission expansion planning process to be consistent with the Synergistic Planning Project Team (SPPT) report. This restructuring effort is comprised of three major components. First, an Integrated Transmission Planning (ITP) process will be established to improve and integrate SPP's existing planning processes. The second major effort will identify, evaluate, and recommend Priority Projects to improve the transmission system based on specifics in the SPPT report. Finally, a new cost allocation methodology will be created by the Regional State Committee (RSC) and its Cost Allocation Working Group (CAWG). This document reports on results of the Priority Project analysis and associated recommendations.

Stakeholders provided input throughout the Priority Project submittal and scope development via numerous conference calls and meetings. The Transmission, Economic Studies, and Cost Allocation Working Groups provided significant support to this effort, and the Market and Operations Policy Committee (MOPC) approved the final list of 10 projects chosen for further screening and detailed evaluation. Five of these projects that will be evaluated will be studied at 765 kV, 765 kV construction operated at 345 kV, and double circuit 345 kV. Four other projects are to be constructed and operated at 345 kV; the remaining project in the group of 10 is at 138 kV operations.

Analysis of these 10 Priority Projects included multiple value metrics including adjusted production cost, loss impacts, reliability assessment, local and environmental impacts, and deliverability of capacity and energy to load. SPP used internal staff and outside consultants, including Quanta Technologies, Brattle Group, and Brown Engineers, to perform engineering and economic analysis. The study included two different wind levels. Level one is a 10-year growth level in which 20% of the energy in SPP is supplied by renewable wind. Level two is a slower growth projection with the same 10-year growth, but to only a 10% level of wind.

SPP staff recommends the approval of five of the screened Priority Projects. These recommended projects will substantially benefit SPP's current Generation Interconnection (GI) and Aggregate Transmission Service Study (AS) processes, address known congestion, and better integrate the west and east portions of SPP's transmission system. The recommended projects are:

1. Spearville – Comanche – Medicine Lodge – Wichita, constructed and operated at 765 kV

2. Comanche – Woodward District EHV, constructed and operated at 765 kV

3. Valliant – NW Texarkana, constructed and operated at 345 kV

4. Cooper – Maryville – Sibley, constructed and operated at 345 kV

5. Riverside Station – Tulsa Power Station 138 kV reactor addition

The estimated engineering and construction cost for the two 765 kV projects is $920 million. The estimated engineering and construction cost for the three remaining projects is $410 million, for a total Priority Project cost of $1.33 billion. The projects are estimated to result in an impact of 44.5 cents per month per kW of demand on a residential customer, and will provide a known level of savings of at least two to one with a potential for much greater savings over the life of the projects. For example, with a conservative cost of $15/ton of CO_2, the benefit to cost ratio goes to three to one (See Table 2 on page 31). These five projects will provide substantial short-term benefits to relieve known congestion and improve the GI and AS queues. They will also improve long-term production cost savings opportunities by further connecting SPP's west and east transmission systems.

Construction of these projects will result in tremendous local economic benefits, including thousands of jobs created during both construction and operating phases. The local economic analysis determined that up to $2 billion could be realized if all Priority Projects are constructed.

These recommended projects are discussed in detail in the Conclusions and Recommendations section.

Addition of Hitchland–Woodward District EHV 765 kV

At the Priority Projects Workshop on September 29, 2009 stakeholders requested that SPP examine the staff recommended projects by including the Hitchland – Woodward District EHV 765kV line in the analysis. The results of the evaluation are shown in Table 27. While the benefits for APC increase by around $180,000,000, the cost of including the Hitchland to Woodward District EHV line is about $598,000,000. This has a net effect on the B/C ratio that is a reduction of about 20% overall.

Summary:

- APC benefit increases by $182,476,332
- E&C Cost increases by $336,266,974 and total revenue requirements over 40 years increases by $598,862,961
- B/C decreases by 20% to 1.63

Study Group	E&C Cost	Total Cost (Years 0-40)	APC (Years 0-40)	Reliability (Years 0-40)	Losses (Years 0-40)	Total Benefit (Years 0-40)	B/C
Staff Recommended[11]	**$1,330,377,188**	**$2,026,364,345**	($4,076,424,004)	$2,159,679	($29,102,833)	**($4,103,367,159)**	**2.02**
Staff Recommended + Hitchland - Woodward District EHV	**$1,666,644,162**	**$2,625,227,306**	($4,258,900,336)	$15,070,408[12]	($29,102,833)[13]	**($4,272,932,761)**	**1.63**

Table 14: Results of adding Hitchland-Woodward 765 kV to Staff Recommended Projects

[11] The Staff Recommended portfolio includes Spearville – Comanche – Medicine Lodge – Wichita 765kV, Comanche – Woodward District EHV 765kV, Valliant – NW Texarkana 345kV, Cooper – Maryville – Sibley 345kV, and the 138kV Riverside Station – Tulsa Power Station additional reactor.

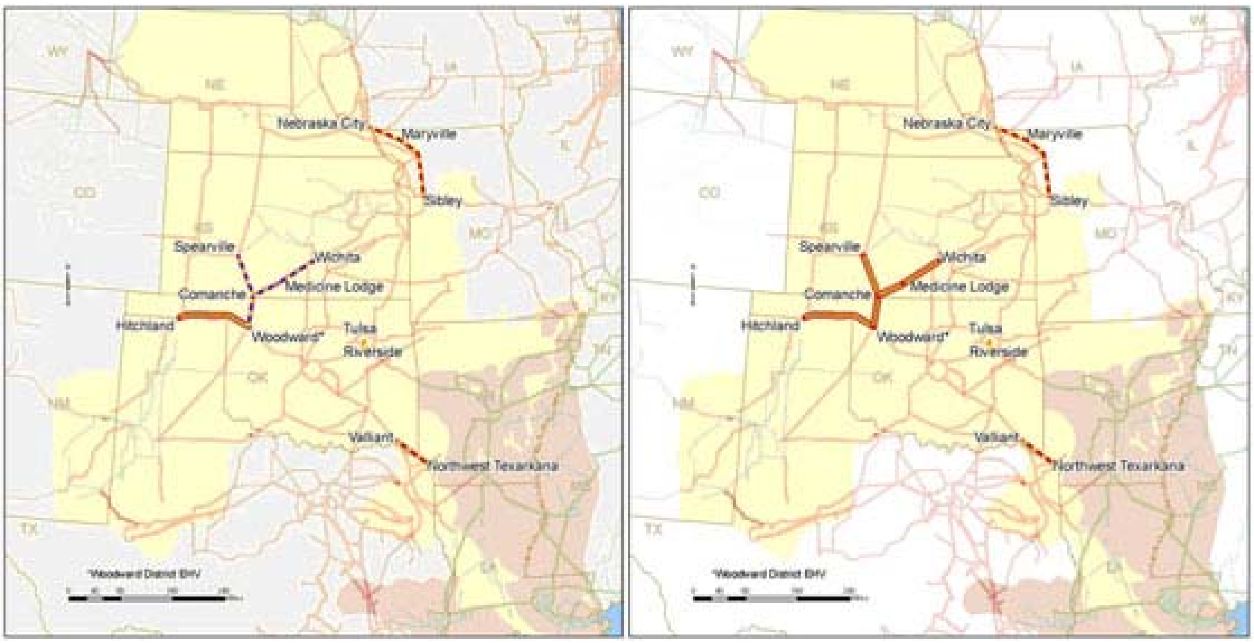
[12] The reliability number for Staff Recommendation + Hitchland – Woodward District EHV was derived from summing the reliability cost of the staff recommended portfolio and the reliability cost of Hitchland – Woodward District EHV. The number is not the result of an additional reliability analysis.

[13] The losses number for Staff Recommended + Hitchland – Woodward District EHV is the losses number from the Staff Recommended projects. New analysis on the losses has not yet been performed.

EXHIBIT NO. OGE-11

KEMA

SPP Priority Projects—Natural Gas Price Reduction



Southwest Power Pool

Benefits of EHV transmission

P. Jeffrey Palermo
26 March 2010

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1 Background

The Southwest Power Pool (SPP) staff engaged KEMA, Inc. in December 2009 to assist the evaluation of the proposed Priority Projects that were intended to capture near-term opportunities associated with the heightened focus on electric transmission expansion KEMA was asked to develop a white paper describing the strategic benefits of the Priority Projects. These benefits were to include:

1. Flexibility for future resource planning decisions affecting generation resource decisions and associated supply contracts;
2. Reliability that improves service reliability and restoration times in response to normal and extraordinary events;
3. Fuel diversity and price elasticity in supply and demand of marginal fuels;
4. Right-of-way utilization of the corridors for transmission facilities to avoid "corridor fatigue" and land use/habitat fragmentation issues; and
5. Strategic regional and national benefits including the market response to major topology/congestion changes, or EHV network headroom that enables more efficient and economic management of grid operations and maintenance schedules.

During the course of the work SPP asked KEMA to focus on the third of these—fuel diversity benefits. This report addresses KEMA's work regarding the fuel diversity benefits of the Priority Projects.

2 Transmission functions and benefits

The modern electric power system is one of mankind's greatest engineering achievements. The National Science Foundation declared it the greatest engineering achievement of the 20th century stating "it keeps our factories running—as well as the telecommunications industry, the appliances in our homes, and the lifesaving equipment in our hospitals."[1] The interconnection power system is remarkably complex as it integrates thousands of individual devices each of which has dozens to thousands of components—from large power plants to circuit breakers and circuit disconnects.

1. See www.greatachievements.org.

The electric power system is a "unitary" system—the load, generation and delivery systems must all be in balance at all times. The load and generation must obviously be in balance otherwise the generation would speed up or slow down from the 60 Hz standard frequency. There must also be enough transmission and distribution capacity available for the generation to be delivered to the load.

In this context it is interesting to compare the costs of these different parts of the utility system. On a national basis, generation typically is about 67% of the total cost of electricity, distribution is about 26%, and transmission is about 7%.[2] As will be discussed below, the transmission system is what establishes the market size and can often limit operation of the most economic generating units. In this way the transmission system—representing 7% of the cost—can have a significant impact on the cost of generation—representing 67% of the cost. This means that transmission system has a highly leveraged impact on the total cost of electricity.

In today's utility environment there are a number of generation supply markets. Regardless of the political boundaries of these markets, it is the electric system that defines the technical electrical boundaries. The lack of transmission at a market's boundaries is what limits the free exchange of power between market areas.[3] Some obvious examples include the limited interconnections between ERCOT and SPP, or between ISO-NE and NYISO. There are other famous boundaries that limit power flow into southern California from Arizona and into the Washington–New York City corridor. These were highlighted in the *National Electric Transmission Congestion Study*.[4]

Within a market area it is the transmission system that allows the free exchange of energy, limits market power by including more suppliers within the geographic area, reduces the installed generating capacity required, increases load and generation diversity, and makes possible considerable flexibility in system operation.

3 The relationship of natural gas use and supply price

Economic theory predicts that a decrease in the use of natural gas will lead to an inward shift in the natural gas demand curve, leading to a reduction in natural gas

2. US Energy Information Administration, *Annual Energy Outlook 2009*, updated reference case, Table A8—data for 2007 (tinyurl.com/2007-Electric-Price-components).
3. It also common to find transmission limitations within a market that will result in transmission congestion.
4. U.S. Department of Energy, *National Electric Transmission Congestion Study*, August 2006.

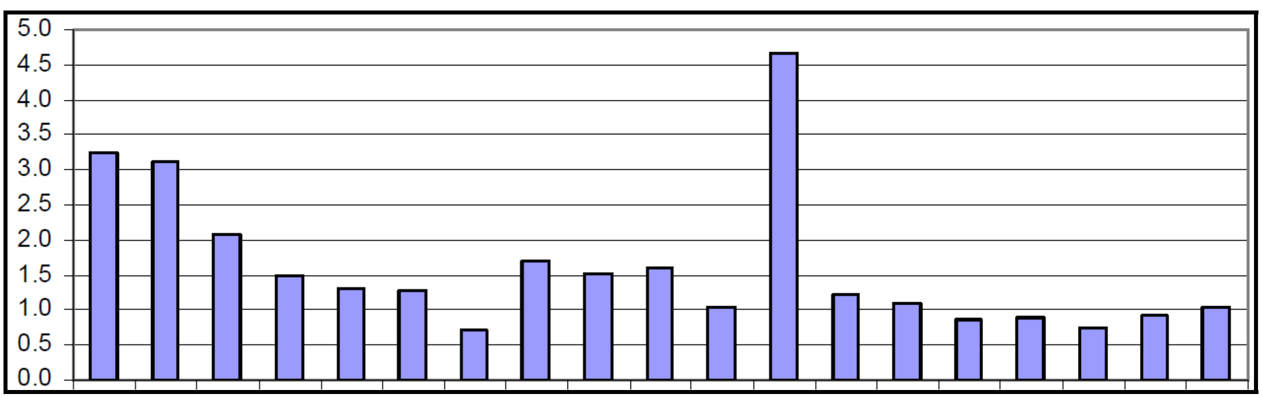
prices. Such reductions benefit consumers by reducing fuel costs to electric generators and by reducing the price of natural gas for direct use in the residential, commercial, industrial, and transportation sectors. The magnitude of the price reduction will vary based on the amount of reduced use of natural gas and the shape of the natural gas supply curve (measured by the inverse price elasticity of natural gas supply).

While there have been many studies of the price elasticity of natural gas—the response of users to changes in gas prices, there have been a smaller number of studies of the supplier's inverse price elasticity of natural gas—the response of supplier prices to changes in demand. Perhaps the most significant of these is a 2005 study by Lawrence Berkeley National Labs.[5] This report focused on the results of 19 studies:

- Seven studies by the Energy Information Administration focused on national renewable portfolio standards (RPS) policies, two of which model multiple RPS scenarios;
- Nine by the Union of Concerned Scientists that studied national RPS policies, three were multiple RPS scenarios, and one also included aggressive energy efficiency investments; and
- Three by the Tellus Institute that evaluated three different standards of a state-level RPS in Rhode Island (combined with RPS policies in Massachusetts and Connecticut).

The inverse elasticity results for these 19 studies are shown in Figure 1.

Figure 1: Range of long-term inverse elasticity results from 19 studies



5. Ryan Wiser, Mark Bolinger, Matt St. Clair, *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency*, January 2005.

The Lawrence Berkeley National Labs study found that there was reasonable consistency in the average long-term inverse elasticities. While the overall range is between 0.7 and 4.7, the study deemphasized some of the 'outliers' and focused on the elasticities from 13 of 19 analyses falling between 0.8 and 2.0.[6] The highest and lowest study results would mean price reductions from 0.7% to 4.7% for each 1% drop in demand.

We chose to exclude the highest 4 and the lowest 4 cases shown in Figure 1—so the inverse elasticity range is between 0.9 and 1.7. The average inverse elasticity for these 11 studies is 1.2.

While the 2005 Lawrence Berkeley National Labs study is focused on the impact of renewable energy and energy efficiency, the authors made it clear that "these effects are not strictly limited to renewable energy and energy efficiency investments: any non-natural-gas resource that displaces gas use is expected to provide similar consumer benefits."[7]

For this analysis we have assumed an average inverse elasticity for natural gas supply of 1.2.

4 The impact of Priority Projects on SPP gas use

4.1 The two groups of Priority Projects

Staff presented the results of the initial Priority Projects in 2009. They were directed to perform additional analysis on a group of six projects. These projects were referred to as Group 1 and are listed here and shown in Figure 2:

1. Spearville – Comanche – Medicine Lodge – Wichita (765 kV construction and 345 kV operation);
2. Comanche – Woodward District EHV (765 kV construction and 345 kV operation);
3. Hitchland – Woodward District EHV (345 kV DCT1);
4. Valiant – NW Texarkana (345 kV);

6. This would mean that each 1% reduction in national, natural gas demand is expected to lead to a 0.8% to 2% reduction in wellhead gas prices.
7. Testimony Prepared for a Hearing on Power Generation Resource Incentives & Diversity Standards California Senate Committee on Energy and Natural Resources Tuesday, March 8, 2005, 2:30 PM, Dr. Ryan Wiser, Scientist, Lawrence Berkeley National Laboratory, page 5.

5. Nebraska City – Maryville – Sibley (345kV); and
6. Riverside – Tulsa Reactor (138 kV).

The staff was also requested to study an alternative where 345 kV double-circuits are substituted for the 765 kV lines in Group 1. This is referred to as Group 2 listed here and shown in Figure 3:

1. Spearville – Comanche – Medicine Lodge – Wichita (2 x 345 kV);
2. Comanche – Woodward District EHV (2 x 345 kV);
3. Hitchland – Woodward District EHV (2 x 345 kV);
4. Valiant – NW Texarkana (345 kV);
5. Nebraska City– Maryville – Sibley (345 kV); and
6. Riverside – Tulsa Reactor (138 kV).

KEMA

Figure 2: Group 1 Priority Projects

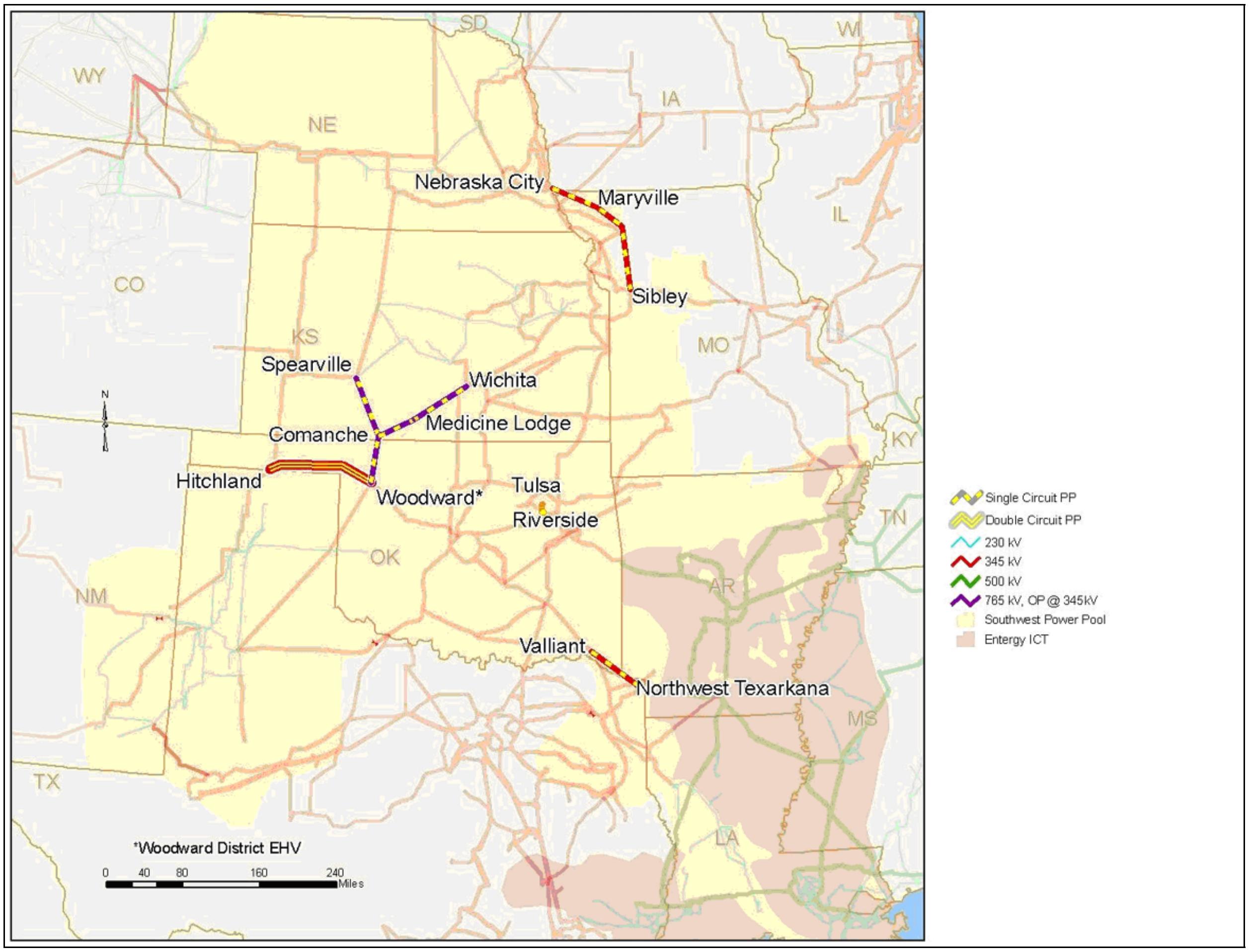
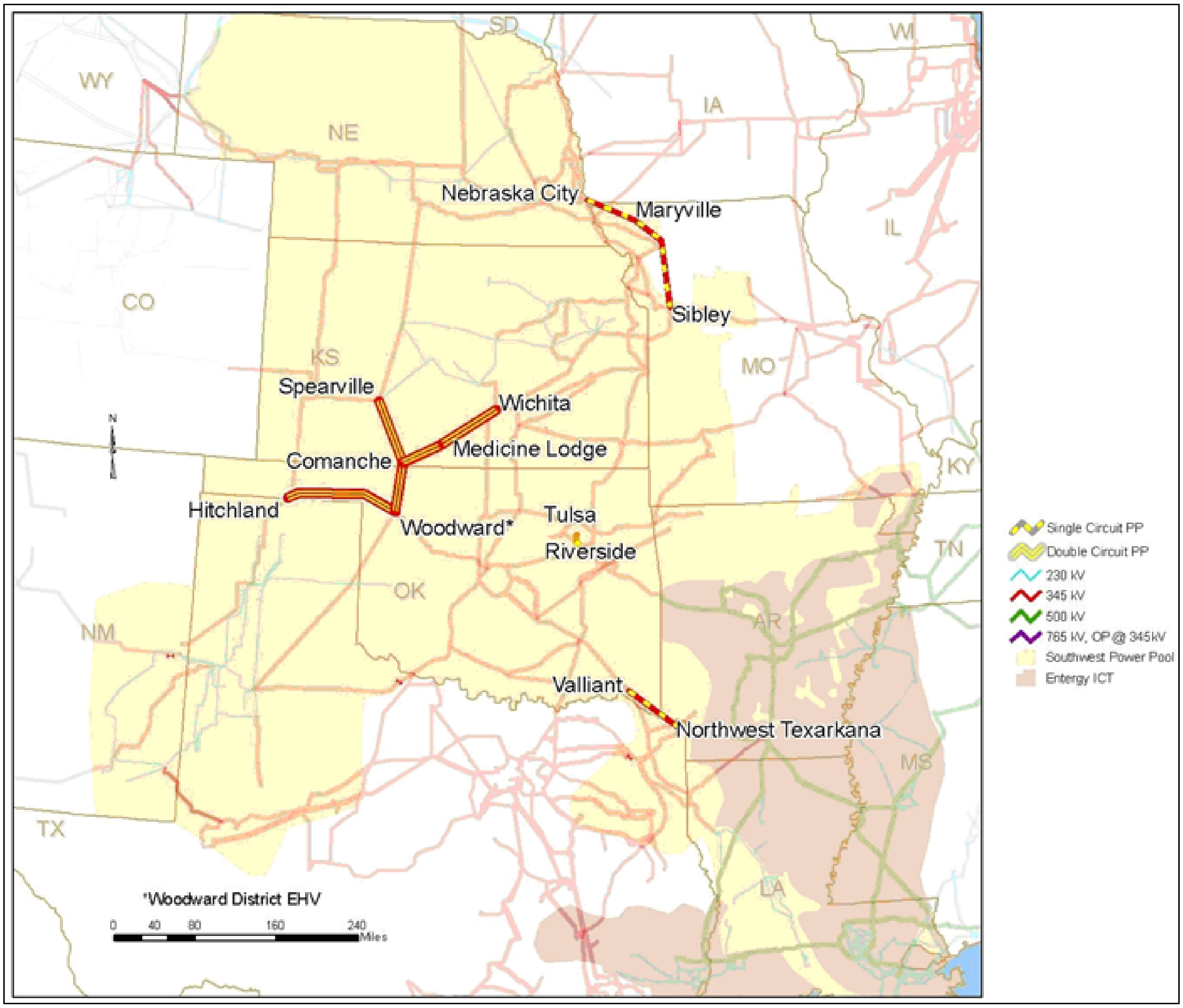


Figure 3: Group 2 Priority Projects



4.2 SPP production-cost analyses

SPP staff has made a series of computer simulations of the SPP system. These simulations estimated the operation and productions costs of the generation located within the SPP footprint. The simulation reports the performance of each generating unit in the system including the electrical output (MWh) and thermal input (MMbtu). In total 18 simulations were made—for three years (2009, 2014 and 2019), two levels of wind penetration (7 GW and 11 GW), and for three transmission topologies (existing system, adding Group 1 Priority Projects, and adding Group 2 Priority Projects).

The results for gas-fueled generators from the production-cost simulations are shown in Table 1. With 7 GW of wind generation the savings in natural gas consumption are slightly more than 5%. With 11 GW of wind the savings are nearly 8%.

Table 1: Production-cost simulation changes for Group 1 and 2 Priority Projects

	2009		2014		2019	
	Group 1	Group 2	Group 1	Group 2	Group 1	Group 2
7 GW wind						
Gas MWh	-5.03%	-5.09%	-5.63%	-5.74%	-4.64%	-4.66%
Gas MMbtu	-4.98%	-5.04%	-5.58%	-5.71%	-4.68%	-4.72%
2009-2019 average					-5.08%	-5.15%
11 GW wind						
Gas MWh	-7.77%	-7.97%	-8.01%	-8.41%	-7.12%	-7.45%
Gas MMbtu	-7.73%	-7.90%	-8.00%	-8.42%	-7.24%	-7.58%
2009-2019 average					-7.66%	-7.97%
Note: The production cost changes are with respect to the base transmission plan for each year.						

Additional detail of the production-cost simulation results are shown in Table 5 at the end of this document. This table shows the electricity production (MWh) and the fuel use (MMbtu) for each type of generation. Of particular interest to this report are the top five sections reporting the results for natural gas generation. The results from these five sections are the source for the data in Table 1, above.

5 Changes in natural gas costs due to Priority Projects

The change in natural gas prices due to the Priority Projects is calculated from three variables:

1. The inverse supply price elasticity (§3, above),
2. The change in use by SPP (see Table 1, above), and
3. The use of natural gas by SPP compared to the nation (discussed here).

The natural gas consumption by end use for 2004-2008 is shown in Table 2. The table lists the total gas use for the nation, total electric use for the nation, and the gas use for electricity by the states in the SPP area plus that of SWPS. The table shows that

27.64% of the natural gas consumed in the US is used to produce electricity and that 1.81% of the nation's use is to produce electricity in the SPP.

Table 2: Natural gas consumption by end use (Mcf)

	2004	2005	2006	2007	2008	Average
U.S. total[8]	22,388,975	22,010,596	21,684,641	23,097,140	23,226,612	22,481,593
U.S. Electricity	5,463,763	5,869,145	6,222,100	6,841,408	6,668,379	6,212,959
% electric	24.40%	26.67%	28.69%	29.62%	28.71%	27.64%
SPP use for electricity[9]						
Arkansas	40,138	48,987	71,056	63,594	64,188	
Kansas	10,474	14,105	22,477	25,560	26,640	
Louisiana	245,361	285,022	195,927	224,419	236,543	
Missouri	24,574	31,831	32,480	41,067	43,009	
10%	2,457	3,183	3,248	4,107	4,301	
Nebraska	3,340	8,066	7,787	10,908	7,230	
Oklahoma	199,907	242,178	278,602	286,686	282,942	
SWPS TX-NM	89,172	110,355	128,745	134,993	132,457	
SPP total	305,350	377,887	440,859	462,253	453,570	407,984
% electric of USA	1.36%	1.72%	2.03%	2.00%	1.95%	**1.81%**

Most of the data in Table 2 is directly from the US DOE database. Since only a small portion of the Missouri generation is in the SPP footprint, we assumed that less than 10% of the state's use would be included. While the amounts for Arkansas and Louisiana are shown they were not included in the totals since electric generation from gas units in both states is less than 1% of the SPP total. It was also necessary to estimate the use by SWPS-TX-NM. The production-cost simulations showed that SWPS used just under 30% of the SPP's total gas as shown in Table 3. This was used to estimate the SWPS gas use in Table 2.[10]

8. Source for national data: http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPG0_VC0_mmcf_a.htm
9. Source for SPP state data: http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_a_EPG0_veu_mmcf_a.htm
10. The calculation is (the sum of the other states {KS, MO, NE, OK}) x 0.2920 ÷ (1 – 0.2920)

Table 3: SWPS share of total natural gas from computer simulation

	MMbtu
SWPS CC	28,339,825
SWPS CT-gas	12,563,041
SWPS St-gas	21,130,504
SWPS gas	62,033,370
Total gas	212,420,030
SWPS share	29.20%

The impact on natural gas prices due to changes in natural gas use is shown in Table 4. The calculations shown in Table 4 mean that:

With 7 GW of wind generation

- Group 1 Priority Projects will reduce gas use by 5.08%
- Group 2 Priority Projects will reduce gas use by 5.15%

With 11 GW of wind generation

- Group 1 Priority Projects will reduce gas use by 7.66%
- Group 2 Priority Projects will reduce gas use by 7.97%

Table 4: Impact of the Priority Projects on SPP natural gas prices

		Δ by Group		
		1	2	Notes
7 GW wind				
1	Δ gas MMbtu	-5.08%	-5.15%	See Table 4
2	Inverse price elasticity of supply	1.2	1.2	See Figure 1 and the discussion at the end of §3
3	SPP share of nation gas use	1.81%	1.81%	See Table 2
4	SPP-only price impact	-0.111%	-0.112%	Product of lines 1, 2 and 3
5	Inverse price elasticity of supply	1.2	1.2	Same as line 2
6	US electric share of national gas use	27.64%	27.64%	See Table 2
7	US price impact	-1.69%	-1.71%	Product of lines 1, 5 and 6
11 GW wind				
8	Δ gas MMbtu	-7.66%	-7.97%	See Table 4
9	Inverse price elasticity of supply	1.2	1.2	See Figure 1 and the discussion at the end of §3
10	SPP share of nation gas use	1.81%	1.81%	See Table 2
11	SPP-only price impact	-0.167%	-0.173%	Product of lines 8, 9 and 10
12	Inverse price elasticity of supply	1.2	1.2	Same as line 9
13	US electric share of national gas use	27.64%	27.64%	See Table 2
14	US price	-2.54%	-2.64%	Product of lines 8, 12 and 13

The price impact is the product of: 1) The inverse supply price elasticity, 2) The change in use by SPP, and 3) The SPP natural gas share of the nation. These calculations are shown in Table 4. To demonstrate the calculations consider the case with 7 GW of wind and the Group 1 transmission additions and the US price impact:

- The inverse supply price elasticity from Figure 1 and the discussion at the end of §3 — 1.2
- The change is gas MMbtu from Table 4 — -5.08%
- The electricity from supply natural gas share of the nation Table 2 — 27.64%
- The resulting price impact is the product — 1.69%

If other regions of the nation make similar improvements to their transmission systems as the SPP the price reduction of natural gas will be about 1.7% for the 7 GW cases and 2.6% for the 11 GW cases.[11] There are a number of states that have adopted mandates for renewable energy penetration. Most have adopted a goal of 20% renewable generation by 2020. It is, thus, almost certain that most other areas of the nation will make transmission system improvements to accommodate the increased amounts of wind and other renewable generation.

11. If the SPP were the only system to make these types of transmission changes the impact on natural gas prices would be much smaller—about 0.11% for the 7 GW cases and 0.17% for the 11 GW cases. In either case, the reduced price of natural gas will affect all users of natural gas in all areas of the country.

Table 5: Annual computer simulation results summary

	7GW wind									11 GW wind								
	2009			2014			2019			2009			2014			2019		
	Base	Group 1	Group 2	Base	Group 1	Group 2	Base	Group 1	Group 2	Base	Group 1	Group 2	Base	Group 1	Group 2	Base	Group 1	Group 2
CC (gas)																		
MWh	20,248,338	19,242,451	19,264,221	25,686,605	24,165,043	24,187,352	34,064,155	32,488,204	32,514,295	19,876,947	18,319,570	18,288,124	25,118,802	23,035,957	22,982,671	33,310,968	31,005,180	30,946,136
MMbtu	148,464,262	141,089,379	141,274,033	188,975,639	177,593,565	177,806,844	251,512,708	239,677,463	239,898,966	145,803,872	134,350,961	134,152,141	184,905,690	169,312,105	168,977,942	246,138,568	228,795,038	228,428,557
CT-gas																		
MWh	2,314,055	2,290,825	2,303,428	2,851,806	2,720,201	2,713,613	3,983,788	3,825,506	3,815,815	2,252,294	2,262,941	2,280,835	2,745,547	2,612,278	2,606,417	3,822,401	3,666,242	3,648,672
MMbtu	21,172,422	21,019,828	21,192,094	27,375,479	26,165,134	26,137,083	40,230,759	38,600,440	38,531,576	20,610,024	20,797,133	21,015,499	26,295,499	25,035,349	25,020,285	38,546,891	36,918,782	36,766,113
ST-gas																		
MWh	4,206,807	3,889,243	3,839,180	6,283,108	5,976,559	5,920,701	9,286,415	8,826,353	8,797,607	4,018,700	3,532,629	3,495,864	5,914,556	5,426,466	5,348,850	8,792,288	7,984,112	7,911,479
MMbtu	42,783,346	39,728,322	39,245,604	64,137,552	61,073,905	60,534,118	95,032,806	90,386,951	90,106,636	40,905,118	36,141,725	35,778,477	60,413,896	55,547,646	54,743,279	90,032,556	81,881,679	81,118,595
Subtotal gas																		
MWh	**26,769,200**	**25,422,520**	**25,406,829**	**34,821,519**	**32,861,803**	**32,821,665**	**47,334,358**	**45,140,063**	**45,127,717**	**26,147,941**	**24,115,140**	**24,064,823**	**33,778,904**	**31,074,701**	**30,937,938**	**45,925,657**	**42,655,534**	**42,506,287**
MMbtu	**212,420,030**	**201,837,529**	**201,711,731**	**280,488,670**	**264,832,604**	**264,478,045**	**386,776,274**	**368,664,853**	**368,537,178**	**207,319,014**	**191,289,819**	**190,946,117**	**271,615,085**	**249,895,100**	**248,741,506**	**374,718,015**	**347,595,498**	**346,313,264**
Δ Gas																		
MWh	0	-1,346,680	-1,362,370	0	-1,959,716	-1,999,853	0	-2,194,295	-2,206,641	0	-2,032,801	-2,083,118	0	-2,704,203	-2,840,966	0	-3,270,123	-3,419,369
		-5.03%	-5.09%		-5.63%	-5.74%		-4.64%	-4.66%		-7.77%	-7.97%		-8.01%	-8.41%		-7.12%	-7.45%
MMbtu	0	-10,582,501	-10,708,299	0	-15,656,065	-16,010,625	0	-18,111,421	-18,239,096	0	-16,029,195	-16,372,897	0	-21,719,985	-22,873,578	0	-27,122,517	-28,404,751
		-4.98%	-5.04%		-5.58%	-5.71%		-4.68%	-4.72%		-7.73%	-7.90%		-8.00%	-8.42%		-7.24%	-7.58%
11-yr average								-5.08%	-5.15%								-7.66%	-7.97%
CT gen																		
MWh	42,900	42,783	42,389	143,628	136,668	135,265	340,339	320,937	321,448	42,554	43,277	42,696	141,888	133,099	128,667	339,257	313,762	308,872
MMbtu	443,289	441,697	437,154	1,482,550	1,409,938	1,395,900	3,510,271	3,306,484	3,312,715	439,409	446,525	440,494	1,464,562	1,374,325	1,330,719	3,498,160	3,233,912	3,186,603
CT-oil																		
MWh	8,661	8,676	8,860	177,048	160,359	158,806	396,083	355,940	353,853	8,349	8,421	8,422	175,126	159,732	157,718	387,016	349,820	344,327
MMbtu	96,911	96,978	99,510	2,384,000	2,153,129	2,131,810	5,255,002	4,712,844	4,685,651	92,678	93,569	93,599	2,358,973	2,145,740	2,117,794	5,136,520	4,637,955	4,564,375
ST-coal																		
MWh	165,398,689	167,185,470	167,305,133	163,999,019	165,569,391	165,652,027	167,721,729	169,013,079	169,044,217	161,096,123	161,493,976	161,504,722	159,050,214	158,141,942	157,939,975	163,395,387	162,605,765	162,439,586
MMbtu	1749912657	1638824125	1638567196	1734648113	1751868495	1752772410	1774916478	1788872631	1789177487	1704395406	1709286927	278,767,655	1682127043	1535889736	1533940299	1590324766	1582576424	1719381181
ST-nuclear																		
MWh	18,837,055	18,837,055	18,837,055	18,963,127	18,963,127	18,963,127	21,300,351	21,300,351	21,300,351	18,837,055	18,837,055	18,837,055	18,963,127	18,963,127	18,963,127	21,300,351	21,300,351	21,300,351
MMbtu	197,974,883	197,974,883	197,974,883	199,192,409	199,192,409	199,192,409	223,743,648	223,743,648	223,743,648	197,974,883	197,974,883	197,974,883	199,192,409	199,192,409	199,192,409	223,743,648	223,743,648	223,743,648
Total																		
MWh	**211,056,505**	**211,496,505**	**211,600,267**	**218,104,341**	**217,691,349**	**217,730,890**	**237,092,859**	**236,130,369**	**236,147,585**	**206,132,022**	**204,497,869**	**204,457,718**	**212,109,260**	**208,472,601**	**208,127,426**	**231,347,667**	**227,225,231**	**226,899,423**
MMbtu	**410,935,113**	**400,351,086**	**400,223,277**	**483,547,628**	**467,588,080**	**467,198,165**	**619,285,194**	**600,427,828**	**600,279,191**	**405,825,984**	**389,804,795**	**389,455,092**	**474,631,028**	**452,607,574**	**451,382,428**	**607,096,343**	**579,211,013**	**577,807,890**
Δ Total																		
MWh	0	440,000	543,762	0	-412,992	-373,451	0	-962,490	-945,274	0	-1,634,153	-1,674,305	0	-3,636,658	-3,981,834	0	-4,122,435	-4,448,243
		0.21%	0.26%		-0.19%	-0.17%		-0.41%	-0.40%		-0.79%	-0.81%		-1.71%	-1.88%		-1.78%	-1.92%
MMbtu	0	-10,584,027	-10,711,836	0	-15,959,548	-16,349,464	0	-18,857,366	-19,006,003	0	-16,021,188	-16,370,891	68,805,044	-22,023,455	-23,248,600	201,270,359	-27,885,329	-29,288,453
		-2.58%	-2.61%		-3.30%	-3.38%		-3.05%	-3.07%		-3.95%	-4.03%		-4.64%	-4.90%		-4.59%	-4.82%

EXHIBIT NO. OGE-12

Southwest Power Pool

Aggregate Facility Study SPP-2007-AG1-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers

SPP Engineering, SPP Tariff Studies

Table of Contents

1. Executive Summary

Pursuant to Attachment Z1 of the Southwest Power Pool Open Access Transmission Tariff (OATT), 1359 MW of long-term transmission service requests have been restudied in this Aggregate Facility Study (AFS). The first phase of the AFS consisted of a revision of the impact study to reflect the withdrawal of requests for which an Aggregate Facility Study Agreement was not executed. The principal objective of the AFS is to identify system problems and potential modifications necessary to facilitate these transfers while maintaining or improving system reliability as well as summarizing the operating limits and determination of the financial characteristics associated with facility upgrades. Facility upgrade costs are allocated on a prorated basis to all requests positively impacting any individual overloaded facility. Further, Attachment Z2 provides for facility upgrade cost recovery by stating that "Transmission Customers paying Directly Assigned Upgrade Costs for Service Upgrades or that are in excess of the Safe Harbor Cost Limit for Network Upgrades associated with new or changed Designated Resources and Project Sponsors paying Directly Assigned Upgrade Costs for Sponsored Upgrades shall receive revenue credits in accordance with Attachment Z2. Generation Interconnection Customers paying for Network Upgrades shall receive credits for new transmission service using the facility as specified in Attachment Z1."

The total assigned facility upgrade Engineering and Construction (E &C) cost determined by the AFS is $77 Million. Additionally assigned E & C cost for 3rd party facility upgrades are assignable to the customer. The total upgrade levelized revenue requirement for all transmission requests is $227 Million. This is based on full allocation of levelized revenue requirements for upgrades to customers without consideration of base plan funding. AFS data table 3 reflects the allocation of upgrade costs to each request without potential base plan funding based on either the requested reservation period or the deferred reservation period if applicable. Total upgrade levelized revenue requirements for all transmission requests after consideration of potential base plan funding is $57 Million.

Third-party facilities must be upgraded when it is determined they are constrained in order to accommodate the requested Transmission Service. These include both first-tier neighboring facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are in Table 4.

The Transmission Provider will tender a Letter of Intent on September 24th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by October 9th, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

At the conclusion of the ATSS, Service Agreements for each request for service will be tendered identifying the terms and conditions of the confirmed service.

If customers withdraw from the ATSS after posting of this AFS, the AFS will be re-performed to determine final cost allocation and Available Transmission Capability (ATC) in consideration of the remaining ATSS participants. All allocated revenue requirements for facility upgrades are assigned to the customer in the AFS data tables. Potential base plan funding allowable is contingent upon validation of designated resources meeting Attachment J, Section III B criteria.

2. Introduction

On January 21, 2005, the Federal Energy Regulatory Commission accepted Southwest Power Pool's proposed aggregate transmission study procedures in Docket ER05-109 to become effective February 1, 2005. In compliance with this Order, the first open season of 2007 commenced on October 1, 2006. All requests for long-term transmission service received prior to February 1, 2007 with a signed study agreement were then included in this first Aggregate Transmission Service Study (ATSS) of 2007.

Approximately 1359 MW of long-term transmission service has been restudied in this Aggregate Facility Study (AFS) with over $77 Million in transmission upgrades being proposed. The results of the AFS are detailed in Tables 1 through 7. A highly tangible benefit of studying transmission requests aggregately under the SPP OATT Attachment Z1 is the sharing of costs among customers using the same facility. The detailed results show individual upgrade costs by study as well as potential base plan allowances as determined by Attachments J and Z1. The following URL can be used to access the SPP OATT: (http://www.spp.org/Publications/SPP_Tariff.pdf). In order to understand the extent to which base plan upgrades may be applied to both point-to-point and network transmission services, it is necessary to highlight the definition of Designated Resource. Per Section 1.9a of the SPP OATT, a Designated Resource is "[a]ny designated generation resource owned, purchased or leased by a Transmission Customer to serve load in the SPP Region. Designated Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Transmission Customer's load on a non-interruptible basis." Therefore, not only network service, but also point-to-point service has potential for base plan funding if the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J are met.

Pursuant to Attachment J, Section III B of the SPP OATT, the Transmission Customer must provide SPP information necessary to verify that the new or changed Designated Resource meets the following conditions:

1. Transmission Customer's commitment to the requested new or changed Designated Resource must have a duration of at least five years.

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

According to Attachment Z1 Section VI.A, Point-to-Point customers pay the higher of the monthly transmission access charge (base rate) or the monthly revenue requirement associated with the assigned facility upgrades including any prepayments for redispatch required during construction.

Network Integration Service customers pay the total monthly transmission access charges and the monthly revenue requirement associated with the facility upgrades including any prepayments for redispatch during construction.

Transmission Customers paying for a directly assigned network upgrade shall receive credits for new transmission service using the facility as specified in Attachment Z2.

Facilities identified as limiting the requested Transmission Service have been reviewed to determine the required in-service date of each Network Upgrade. The year that each Network Upgrade is required to accommodate a request is determined by interpolating between the applicable model years given the respective loading data. Both previously assigned facilities and the facilities assigned to this request for Transmission Service were evaluated.

In some instances due to lead times for engineering and construction, Network Upgrades may not be available when required to accommodate a request for Transmission Service. When this occurs, the ATC with available Network Upgrades will be less than the capacity requested during either a portion of or all of the requested reservation period. As a result, the lowest seasonal allocated ATC within the requested reservation period will be offered to the Transmission Customer on an applicable annual basis as listed in Table 1. The ATC may be limited by transmission owner planned projects, expansion plan projects, or customer assigned upgrades.

Some constraints identified in the AFS were not assigned to the Customer as the Transmission Provider determined that upgrades are not required due to various reasons or the Transmission Owner has construction plans pending for these upgrades. These facilities are listed by reservation in Table 3. This table also includes constrained facilities in the current planning horizon that limit the rollover rights of the Transmission Customer. Table 6 lists possible redispatch pairs to allow start of service prior to completion of assigned network upgrades. Table 7 (if applicable) lists deferment of expansion plan projects with different upgrades with the new required in service date as a result of this AFS.

A. Financial Analysis

The AFS utilizes the allocated customer E & C cost in a present worth analysis to determine the monthly levelized revenue requirement of each facility upgrade over the term of the reservation. In some cases, network upgrades cannot be completed within the requested reservation period, thus deferred reservation periods will be utilized in the present worth analysis. If the Customer chose Option 2, Redispatch, in the Letter of Intent sent coincident with the initial AFS, the present worth analysis of revenue requirements will be based on the deferred term with redispatch in the subsequent AFS. The upgrade levelized revenue requirement includes interest, depreciation, and carrying costs.

Each request for Transmission Service is evaluated independently as the cost associated with each Network Upgrade is assigned to a request. When facilities are upgraded throughout the reservation period, the Transmission Customer shall 1) pay the total E & C costs and other annual operating costs associated with the new facilities, and 2) receive credits associated with the depreciated book value of removed usable facilities, salvage value of removed non-usable facilities, and the carrying charges, excluding depreciation, associated with all removed usable facilities based on their respective book values.

In the event that the engineering and construction of a previously assigned Network Upgrade may be expedited, with no additional upgrades, to accommodate a new request for Transmission Service, then the levelized present worth of only the incremental expenses though the reservation period of the new request, excluding depreciation, shall be assigned to the new request. These incremental expenses, excluding depreciation, include 1) the levelized difference in present worth of the engineering and construction expenses given the change in date to complete construction to account for additional interest expense and reduced engineering and construction expense due to inflation, 2) the levelized present worth of all expediting fees, and 3) the levelized present worth of the incremental annual carrying charges, excluding depreciation and interest, during the new reservation period taking into account both a) the reservation in which the project was originally assigned, and b) a reservation, if any, in which the project was previously expedited.

Achievable Base Plan Avoided Revenue Requirements in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.B methodology. A deferred Base Plan upgrade being defined as a different requested network upgrade needed at an earlier date that negates the need for the initial base plan upgrade within the planning horizon. A displaced Base Plan upgrade being defined as the same network upgrade being displaced by a requested upgrade needed at an earlier date. Assumption of a 40 year service life is utilized for Base Plan funded projects unless provided otherwise by the Transmission Owner. A present worth analysis of revenue requirements on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan revenue requirements due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The difference in present worth between the Base Plan and Requested Upgrades is assigned to the transmission requests impacting this upgrade based on the displacement or deferral.

B. Third Party Facilities

For third-party facilities listed in Table 3 and Table 5, the Transmission Customer is responsible for funding the necessary upgrades of these facilities per Section 21.1 of the Transmission Provider's OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are in Table 4. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making arrangements for necessary engineering, permitting, and construction of the third-party facilities. Third-party facility upgrade engineering and construction cost estimates are not utilized to determine the present worth value of levelized revenue requirements for SPP system network upgrades.

All modeled facilities within the Transmission Provider system were monitored during the development of this Study as well as certain facilities in first-tier neighboring systems. Third-party facilities must be upgraded when it is determined that they are overloaded while accommodating the requested Transmission Service. An agreement between the Customer and 3rd Party Owner detailing the mitigation of the 3rd party impact must be provided to the Transmission Provider prior to tendering of a Transmission Service Agreement. These facilities also include those owned by members of the Transmission Provider who have not placed their facilities under the Transmission Provider's OATT. Upgrades on the Southwest Power Administration network requires prepayment of the upgrade cost prior to construction of the upgrade.

Third-party facilities are evaluated for only those requests whose load sinks within the SPP footprint. The Customer must arrange for study of 3rd party facilities for load that sinks outside the SPP footprint with the applicable Transmission Providers.

3. Study Methodology

A. Description

The system impact analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier Non - SPP control area systems. The steady-state analysis was done to ensure current SPP Criteria and NERC Reliability Standards requirements are fulfilled. The Southwest Power Pool conforms to the NERC Reliability Standards, which provide the strictest requirements, related to voltage violations and thermal overloads during normal conditions and during a contingency. It requires that all facilities be within normal operating ratings for normal system conditions and within emergency ratings after a contingency. Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP MDWG models, respectively. The upper bound and lower bound of the normal voltage range monitored is 110% and 90%. The upper bound and lower bound of the emergency voltage range monitored is 110% and 90%. Transmission Owner voltage monitoring criteria is used if more restrictive. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations. The WERE Wolf Creek 345 kV bus voltage is monitored at 98.5% due to transmission operating procedure.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non - SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the control areas with SPP reserve share program redispatch. The monitor elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non – SPP control area branches and ties 115 kV and above. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier Non – SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN, and ENTR and a 2 % TDF cutoff was applied to MEC, NPPD, and OPPD. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer or modeling upgrades to be considered a valid limit to the transfer.

B. Model Development

SPP used eleven seasonal models to study the aggregate transfers of 1359 MW over a variety of requested service periods. The SPP MDWG 2007 Series Cases Update 2 2007/08 2008 April (08AP), 2008 Spring Peak (08G), 2008 Summer Peak (08SP), 2008 Summer Shoulder (08SH), 2008 Fall Peak (08FA), 2008/09 Winter Peak (08WP), 2009 Summer Peak (09SP), 2009/10 Winter Peak (09WP), 2012 Summer Peak (12SP), 2012/13 Winter Peak (12WP),and 2017 Summer Peak (17SP) were used to study the impact of the requested service on the transmission system. The Spring Peak models apply to April and May, the Summer Peak models apply to June through September, the Fall Peak models apply to October and November, and the Winter Peak models apply to December through March.

The chosen base case models were modified to reflect the most current modeling information. Five groups of requests were developed from the aggregate of 1359 MW in order to minimize counter flows among requested service. Each request was included in at least two of the four groups depending on the requested path. All requests were included in group five. From the twelve seasonal models, five system scenarios were developed. Scenario 1 includes SWPP OASIS transmission requests not already included in the SPP 2007 Series Cases flowing in a West to East direction with ERCOTN HVDC Tie South to North, ERCOTE HVDC Tie East to West, SPS exporting, and SPS importing from the Lamar HVDC Tie. Scenario 2 includes transmission requests not already included in the SPP 2007 Series Cases flowing in an East to West direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS exporting to the Lamar HVDC Tie. Scenario 3 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a South to North direction with ERCOTN HVDC tie South to North, ERCOTE HVDC tie East to West, SPS exporting, and SPS exporting to the Lamar HVDC Tie. Scenario 4 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a North to South direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC tie. Scenario 5 include all transmission not already included in the SPP 2007 Series Cases with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to the Lamar HVDC tie. The system scenarios were developed to minimize counter flows from previously confirmed, higher priority requests not included in the MDWG Base Case.

C. Transmission Request Modeling

Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation transfers. The Generation to Load modeling is accomplished by developing a pre-transfer case by redispatching the existing designated network resource(s) down by the new designated network resource request amount and scaling down the applicable network load by the same amount proportionally. The post-transfer case for comparison is developed by scaling the network load back to the forecasted amount and dispatching the new designated network resource being requested. Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to

Generation to Generation because the requested Network Integration Transmission Service is a request to serve network load with the new designated network resource and the impacts on transmission system are determined accordingly. If the Network Integration Transmission Service request application clearly documents that the existing designated network resource(s) is being replaced or undesignated by the new designated network resource then MW impact credits will be given to the request as is done for a redirect of existing transmission service. Point-To-Point Transmission Service requests are modeled as Generation to Generation transfers. Generation to Generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the request source and redispatching the request sink.

D. Transfer Analysis

Using the selected cases both with and without the requested transfers modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility overloads caused or impacted by the transfer. Transfer distribution factor cutoffs (SPP and 1^{st}-Tier) and voltage threshold (0.02 change) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

E. Curtailment and Redispatch Evaluation

During any period when SPP determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission System, SPP will take whatever actions that are reasonably necessary to maintain the reliability of the Transmission System. To the extent SPP determines that the reliability of the Transmission System can be maintained by redispatching resources, SPP will evaluate interim curtailment of existing confirmed service or interim redispatch of units to provide service prior to completion of any assigned network upgrades. Any redispatch may not unduly discriminate between the Transmission Owners' use of the Transmission System on behalf of their Native Load Customers and any Transmission Customer's use of the Transmission System to serve its designated load.

Redispatch was evaluated to provide only interim service during the time frame prior to completion of any assigned network upgrades. Curtailment of existing confirmed service is evaluated to provide only interim service. Curtailment of existing confirmed service is only evaluated at the request of the transmission customer.

SPP determined potential relief pairs to relieve the incremental MW impact on limiting facilities as identified in Table 6. Using the selected cases where the limiting facilities were identified, potential incremental and decremental units were identified by determining the generation amount available for increasing and decreasing from the units generation amount, maximum generation amount, and minimum generation amount. If the incremental or decremental amount was greater than 1 MW, the unit was considered as a potential incremental or decremental unit. Generation shift factors were calculated for the potential incremental and decremental units using Managing and Utilizing System Transmission (MUST). Relief pairs from the generation shift factors for the incremental and decremental units with a greater than 3% TDF on the limiting constraint were determined from the incremental units with the lowest generation shift factors and decremental units with highest generation shift factors. If the aggregate redispatch amount for the potential relief pair was determined to be three times greater than the lower of the increment or decrement then the pair was determined not to be feasible and is not included. If transmission customer would like to see additional relief pairs beyond the relief pairs determined, the transmission customer can request SPP to provide the additional pairs. The potential relief pairs were evaluated to determine impacts on limiting facilities in the SPP and 1st-Tier systems. The redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

4. Study Results

A. Study Analysis Results

Tables 1 through 6 contain the steady-state analysis results of the AFS. Table 1 identifies the participating long-term transmission service requests included in the AFS. This table lists deferred start and stop dates both with and without redispatch (based on customer selection of redispatch if available), the minimum annual allocated ATC without upgrades and season of first impact. Table 2 identifies total E & C cost allocated to each Transmission Customer, letter of credit requirements, third party E & C cost assignments, potential base plan E & C funding (lower of allocated E & C or Attachment J Section III B criteria) , total revenue requirements for assigned upgrades without consideration of potential base plan funding, point-to-point base rate charge, total revenue requirements for assigned upgrades with consideration of potential base plan funding, and final total cost allocation to the Transmission Customer. Table 3 provides additional details for each request including all assigned facility upgrades required, allocated E & C costs, allocated revenue requirements for upgrades, upgrades not assigned to customer but required for service to be confirmed, credits to be paid for previously assigned AFS or GI network upgrades, and any third party upgrades required. Table 4 lists all upgrade requirements with associated solutions needed to provide transmission service for the AFS, Minimum ATC per upgrade with season of impact, Earliest Date Upgrade is required (DUN), Estimated Date the upgrade will be completed and in service (EOC), and Estimated E & C cost. Table 5 lists identified Third-Party constrained facilities. Table 6 identifies potential redispatch pairs available to relieve the aggregate impacts on identified constraints to prevent deferral of start of service. Table 7 (if applicable) identifies deferred expansion plan projects that were replaced with requested upgrades at earlier dates.

The potential base plan funding allowable is contingent upon meeting each of the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J. If the additional capacity of the new or changed designated resource exceeds the 125% resource to load forecast for the year of start of service, the requested resource is not eligible for base plan funding of required network upgrades and the full cost of the upgrades is assignable to the customer. If the 5 year term and 125% resource to load criteria are met, the lesser of the planned maximum net dependable capacity (NDC) or the requested capacity is multiplied by $180,000 to determine the potential base plan funding allowable. When calculating Base Plan Funding amounts that include a wind farm, the amount used is 10% of the requested amount of service, or the NDC. The Maximum Potential Base Plan Funding Allowable may be less than the potential base plan funding allowable due to the E & C Cost allocated to the customer being lower than the potential amount allowable to the customer. The customer is responsible for any assigned upgrade costs in excess of Potential Base Plan Engineering and Construction Funding Allowable.

Regarding application of base plan funding for PTP requests, if PTP base rate exceeds upgrade revenue requirements without taking into effect the reduction of revenue requirements by potential base plan funding, then the base rate revenue pays back the Transmission Owner for upgrades and no base plan funding is applicable as the access charge must be paid as it is the higher of "OR" pricing.

However, if initially the upgrade revenue requirements exceed the PTP base rate, then potential base plan funding would be applicable. The test of the higher of "OR" pricing would then be made against the remaining assignable revenue requirements versus PTP base rate. Examples are as follows:

Example A:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 47 million with the difference of 27 million E & C assignable to the customer. If the revenue requirements for the assignable portion is 54 million and the PTP base rate is 101 million, the customer will pay the higher “OR” pricing of 101 million base rate of which 54 million revenue requirements will be paid back to the Transmission Owners for the upgrades and the remaining revenue requirements of (140-54) or 86 million will be paid by base plan funding.

Example B:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 10 million with the difference of 64 million E & C assignable to the customer. If the revenue requirements for this assignable portion is 128 million and the PTP base rate is 101 million the customer will pay the higher “OR” pricing of 128 million revenue requirements to be paid back to the Transmission Owners and the remaining revenue requirements of (140-128) or 12 million will be paid by base plan funding.

Example C:

E & C allocated for upgrades is 25 million with revenue requirements of 50 million and PTP base rate of 101 million. Potential base plan funding is 10 million. Base plan funding is not applicable as the higher “OR” pricing of PTP base rate of 101 million must be paid and the 50 million revenue requirements will be paid from this.

The 125% resource to load determination is performed on a per request basis and is not based on a total of designated resource requests per Customer. A footnote will provide the maximum resource designation allowable for base plan funding consideration per Customer basis per year.

Base plan funding verification requires that each Transmission Customer with potential for base plan funding provide SPP attestation statements verifying that the firm capacity of the requested designated resource is committed for a minimum five year duration.

B. Study Definitions

The Date Upgrade Needed Date (DUN) is the earliest date the upgrade is required to alleviate a constraint considering all requests. End of Construction (EOC) is the estimated date the upgrade will be completed and in service. The Total Engineering and Construction Cost (E & C) is the upgrade solution cost as determined by the transmission owner. The Transmission Customer Allocation Cost is the estimated engineering and construction cost based upon the allocation of costs to all Transmission Customers in the AFS who positively impact facilities by at least 3% subsequently overloaded by the AFS. Minimum ATC is the portion of the requested capacity that can be accommodated with out upgrading facilities. Annual ATC allocated to the Transmission Customer is determined by the least amount of allocated seasonal ATC within each year of a reservation period.

5. Conclusion

The results of the AFS show that limiting constraints exist in many areas of the regional transmission system. Due to these constraints, transmission service cannot be granted unless noted in Table 3.

The Transmission Provider will tender a Letter of Intent on September 24th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by October 9th, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

The Transmission Provider must receive an unconditional and irrevocable letter of credit in the amount of the total allocated Engineering and Construction costs assigned to the Customer. This letter of credit is not required for those facilities that are base plan funded. This amount is for all assignable Network Upgrades less pre-payment requirements. The amount of the letter of credit will be adjusted down on an annual basis to reflect amortization of these costs. The Transmission Provider will issue letters of authorization to construct facility upgrades to the constructing Transmission Owner. This date is determined by the engineering and construction lead time provided for each facility upgrade.

6. Appendix A

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASES:
Solutions - Fixed slope decoupled Newton-Raphson solution (FDNS)
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits – Apply immediately
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

ACCC CASES:
Solutions – AC contingency checking (ACCC)
MW mismatch tolerance – 0.5
Contingency case rating – Rate B
Percent of rating – 100
Output code – Summary
Min flow change in overload report – 3mw
Excld cases w/ no overloads form report – YES
Exclude interfaces from report – NO
Perform voltage limit check – YES
Elements in available capacity table – 60000
Cutoff threshold for available capacity table – 99999.0
Min. contng. case Vltg chng for report – 0.02
Sorted output – None
Newton Solution:
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits - Apply automatically
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

Table 1 - Long-Term Transmission Service Requests Included in Aggregate Facility Study

Customer	Study Number	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date without interim redispatch	Deferred Stop Date without interim redispatch	Start Date with interim redispatch	Stop Date with interim redispatch	Mimimum Allocated ATC (MW) within reservation period	Season of Minimum Allocated ATC within reservation period
EDE	AG1-2007-051	1222640	WPEK	EDE	100	11/1/2008	11/1/2028	6/1/2013	6/1/2033	11/1/2008	11/1/2028	0	09SP
INDP	AG1-2007-045	1221966	OPPD	INDN	6	6/1/2009	6/1/2034	6/1/2011	6/1/2036	6/1/2009	6/1/2034	0	12SP
KBPU	AG1-2007-043D	1221923	SPA	KACY	39	7/1/2010	7/1/2020	6/1/2013	6/1/2023	7/1/2010	7/1/2020	0	12SP
KBPU	AG1-2007-044D	1221925	WR	KACY	25	1/1/2008	1/1/2028	6/1/2013	6/1/2033	11/1/2008	11/1/2028	0	09SP
KCPS	AG1-2007-080	1223159	KCPL	EES	52	6/1/2007	6/1/2012	6/1/2013	6/1/2018	11/1/2008	11/1/2013	0	09SP
KPP	AG1-2007-052	1222644	WR	WR	333	6/1/2007	6/1/2017	6/1/2011	6/1/2021	6/1/2011	6/1/2021	0	09SP
KPP	AG1-2007-054	1222904	WPEK	WPEK	3	6/1/2007	6/1/2017	11/1/2008	11/1/2018	11/1/2008	11/1/2018	0	09SP
KPP	AG1-2007-055	1222932	WR	WR	45	6/1/2007	6/1/2027	6/1/2011	6/1/2031	6/1/2011	6/1/2031	0	09SP
KPP	AG1-2007-056	1222937	WR	WPEK	5	6/1/2007	6/1/2027	6/1/2011	6/1/2031	11/1/2008	11/1/2028	0	09SP
KPP	AG1-2007-058	1222955	WR	WR	20	6/1/2007	6/1/2017	11/1/2008	11/1/2018	11/1/2008	11/1/2018	0	09SP
KPP	AG1-2007-064	1223078	WPEK	WPEK	15	6/1/2007	6/1/2017	6/1/2011	6/1/2021	11/1/2008	11/1/2018	0	09SP
SPRM	AG1-2007-042	1220082	SPA	SPA	275	10/1/2010	10/1/2050	10/1/2010	10/1/2050	10/1/2010	10/1/2050	147	17SP
UCU	AG1-2007-023D	1214269	MPS	KCPL	2	6/1/2007	6/1/2012	6/1/2013	6/1/2018	11/1/2008	11/1/2013	0	09SP
UCU	AG1-2007-025D	1214263	MPS	WR	1	6/1/2007	6/1/2012	6/1/2013	6/1/2018	6/1/2010	6/1/2015	0	09SP
UCU	AG1-2007-060D	1223092	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	6/1/2010	6/1/2030	0	09SP
UCU	AG1-2007-060D	1223093	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	6/1/2010	6/1/2030	0	09SP
UCU	AG1-2007-060D	1223094	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	6/1/2010	6/1/2030	0	09SP
UCU	AG1-2007-060D	1223095	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	6/1/2010	6/1/2030	0	09SP
WRGS	AG1-2007-001D	1197077	EDE	WR	32	9/1/2007	9/1/2018	6/1/2013	6/1/2024	11/1/2008	11/1/2019	0	09SP
WRGS	AG1-2007-047D	1222005	WR	EES	106	10/1/2007	10/1/2010	6/1/2011	6/1/2014	11/1/2008	11/1/2011	0	09SP
					1359								

Note 1: Disregard Redispatch shown in Table 6 for limitations identified earlier than the start date with redispatch with the exception of limitations identified in the 2008 Summer Shoulder,
Note 2: Start and Stop Dates with interim redispatch are determined based on customers choosing option to pursue redispatch to start service at Requested Start and Stop Dates or earliest date possible.

Table 2 - Total Revenue Requirements Associated with Long-Term Transmission Service Requests

Customer	Study Number	Reservation	Engineering and Construction Cost of Upgrades Allocated to Customer for Revenue Requirements	[1]Letter of Credit Amount Required	[2]Potential Base Plan Engineering and Construction Funding Allowable	Notes	[4]Additional Engineering and Construction Cost for 3rd Party Upgrades	[3] Total Revenue Requirements for Assigned Upgrades Over Term of Reservation WITHOUT Potential Base Plan Funding Allocation	[3 5] Total Revenue Requirements for Assigned Upgrades Over Term of Reservation WITH Potential Base Plan Funding Allocation	Point-to-Point Base Rate Over Reservation Period	[4]Total Cost of Reservation Assignable to Customer Contingent Upon Base Plan Funding
EDE	AG1-2007-051	1222640	$ 15,713,651	$ -	$ 15,713,651		$ 6,501,000	$ 40,458,029	$ -	$ -	Schedule 9 Charges
INDP	AG1-2007-045	1221966	$ 54,523	$ 54,523	$ -		$ -	$ 316,815	$ 316,815	$ 1,584,000	$ 1,584,000
KBPU	AG1-2007-043D	1221923	$ 1,505,097	$ 1,505,097	$ -		$ -	$ 3,744,339	$ 3,744,339	$ 4,118,400	$ 4,118,400
KBPU	AG1-2007-044D	1221925	$ 175,179	$ 175,179	$ -		$ -	$ 669,281	$ 669,281	$ 5,280,000	$ 5,280,000
KCPS	AG1-2007-080	1223159	$ 45,945	$ -	$ -		$ -	$ 94,128	$ 94,128	$ 2,808,000	$ 2,808,000
KPP	AG1-2007-052	1222644	$ 32,140,877	$ -	$ 32,140,877		$ -	$ 83,822,653	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-054	1222904	$ -	$ -	$ -		$ -	$ -	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-055	1222932	$ 11,918,683	$ -	$ 11,918,683		$ -	$ 42,203,883	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-056	1222937	$ 834,166	$ -	$ 834,166		$ -	$ 2,099,290	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-058	1222955	$ -	$ -	$ -		$ -	$ -	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-064	1223078	$ 564,364	$ -	$ 564,364		$ -	$ 994,044	$ -	$ -	Schedule 9 Charges
SPRM	AG1-2007-042	1220082	$ 120,000	$ -	$ 120,000		$ -	$ 555,320	$ -	$ -	Schedule 9 Charges
UCU	AG1-2007-025D	1214263	$ 2,062	$ 2,062	$ -		$ -	$ 4,893	$ 4,893	$ 94,500	$ 94,500
UCU	AG1-2007-023D	1214269	$ 205	$ 17	$ -		$ -	$ 442	$ 442	$ 105,600	$ 105,600
UCU	AG1-2007-060D	1223092	$ 3,403,769	$ 1,919,184	$ -		$ -	$ 12,870,440	$ 12,870,440	$ 28,998,000	$ 28,998,000
UCU	AG1-2007-060D	1223093	$ 3,403,769	$ 1,919,184	$ -		$ -	$ 12,870,440	$ 12,870,440	$ 28,998,000	$ 28,998,000
UCU	AG1-2007-060D	1223094	$ 3,403,769	$ 1,919,184	$ -		$ -	$ 12,870,440	$ 12,870,440	$ 28,998,000	$ 28,998,000
UCU	AG1-2007-060D	1223095	$ 3,403,769	$ 1,919,184	$ -		$ -	$ 12,870,440	$ 12,870,440	$ 28,998,000	$ 28,998,000
WRGS	AG1-2007-001D	1197077	$ 24,124	$ -	$ 24,124		$ -	$ 79,100	$ -	$ -	Schedule 9 Charges
WRGS	AG1-2007-047D	1222005	$ 442,413	$ 121,142	$ -		$ -	$ 952,336	$ 952,336	$ 3,434,400	$ 3,434,400
Grand Total			$ 77,156,367					$ 227,476,313	$ 57,263,994		

Note 1: Letter of Credit required for financial security for transmission owner for network upgrades is determined by allocated engineering and construction costs less engineering and construction costs for upgrades when network customer is the transmission owner less the E & C allocation of expedited projects. Letter of Credit is not required for base plan funded upgrades. The Letter Of Credit Amount listed is based on meeting OATT Attachment J requirements for base plan funding.

Note 2. If potential base plan funding is applicable, this value is the lesser of the Engineering and Construction costs of assignable upgrades or the value of base plan funding calculated pursuant to Attachment J, Section III B criteria. Allocation of base plan funding is contingent upon verification of customer agreements meeting Attachment J, Section II B criteria. Not applicable if Point-to-Point base rate exceeds revenue requirements.

Note 3: Revenue Requirements (RR) are based upon deferred end dates if applicable. Deferred dates are based upon customer's choice to pursue redispatch. Achievable Base Plan Avoided RR in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.C methodology. Assumption of a 40 year service life is utilized for Base Plan funded projects. A present worth analysis of RR on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan RR due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The incremental increase in present worth of a Requested Upgrade on a common year basis as a Base Plan upgrade is assigned to the transmission requests impacting the upgrade based on the displacement or deferral. If the displacement analysis results in lower RR due to the shorter amortization period of the requested upgrade when compared to a base plan amortization period, then no direct assignment of the upgrade cost is made due to the displacement to an earlier start date.

Note 4. For Point-to-Point requests, total cost is based on the higher of the base rate or assigned upgrade revenue requirements. For Network requests, the total cost is based on the assigned upgrade revenue requirement. Allocation of base plan funding will be determined after verification of designated resource meeting Attachment J, Section II B Criteria. Additionally E & C of 3rd Party upgrades is assignable to Customer. This includes prepayments required for any SWPA upgrades. Revenue requirements for 3rd Party facilities are not calculated. Total cost to customer is based on assumption of Revenue Requirements with confirmation of base plan funding. Customer is responsible for negotiating redispatch costs if applicable. Customer is also responsible to pay credits for previously assigned upgrades that are impacted by their request. Credits can be paid from base plan funding if applicable.

Note 5: RR with base plan funding may increase or decrease even if no base plan funding is applicable to a particular request if another request that shares the upgrade is now full base plan funded resulting in a different amortization period for the upgrade and thus different RR.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
EDE	AG1-2007-051

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
EDE	1222640	WPEK	EDE	100	11/1/2008	11/1/2028	6/1/2013	6/1/2033	$ 15,713,651	$ -	$ 15,713,651	$ 40,458,030
									$ 15,713,651	$ -	$ 15,713,651	$ 40,458,030

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222640	CONCORDIA - JEWELL 3 115KV CKT 1	6/1/2013	6/1/2013			$ 5,861,848	$ 6,447,839	$ 14,692,207
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 14,620	$ 50,000	$ 54,141
	EAST MANHATTAN - NW MANHATTAN 230/115KV Displacement	6/1/2011	6/1/2011			$ 1,985,821	$ 2,001,944	$ 5,924,990
	East Manhattan to Mcdowell 230 kV Displacement	6/1/2011	6/1/2011			$ 87,338	$ 115,877	$ 268,008
	JEWELL 3 - SMITH CENTER 115KV CKT 1	6/1/2013	6/1/2013			$ 7,702,196	$ 8,472,161	$ 19,304,878
	SUB 271 - BAXTER SPRINGS WEST - SUB 404 - HOCKERVILLE 69KV CKT 1 Displacement	12/1/2008	4/1/2009		Yes	$ 1,358	$ 1,358	$ 3,933
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 60,470	$ 238,266	$ 209,873
					Total	$ 15,713,651	$ 17,327,445	$ 40,458,030

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	BULL SHOALS - BULL SHOALS 161KV CKT 1	6/1/2009	6/1/2010		Yes
	EAST 20MVAR CAPACITOR # 1	6/1/2009	6/1/2010	10/1/2009	
	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	6/1/2017	6/1/2017		
	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 EMDE	6/1/2014	6/1/2014		
	KERR - PENSACOLA 115KV CKT 1	12/1/2012	12/1/2012		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	6/1/2015	6/1/2015		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		
	SUB 73 - BOLIVAR BURNS 69KV	6/1/2015	6/1/2015		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	JOPLIN 59 - SUB 439 - STATELINE 161KV CKT 1	6/1/2012	6/1/2013		Yes
	JOPLIN 59 - SUB 59 - JOPLIN 26TH ST. 161/69kV TRANSFORMER CKT 1	6/1/2012	6/1/2013		Yes
	SUB 124 - AURORA H.T. - SUB 152 - MONETT H.T. 69KV CKT 1	6/1/2009	6/1/2009		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		
	SUB 145 - JOPLIN WEST 7TH - SUB 64 - JOPLIN 10TH ST. 69KV CKT 1	6/1/2010	6/1/2010		
	SUB 170 - NICHOLS ST. - SUB 80 - MARSHFIELD JCT. 69KV CKT 1	6/1/2012	6/1/2012		

Transmission Owner Planned Project - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	6/1/2013	6/1/2013	6/1/2009	

Third Party Limitations*

Reservation	Upgrade Name	DUN	EOC	Earliest Service Start Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1222640	HUBEN (HUBEN) 345/161/13.8KV TRANSFORMER CKT 1	6/1/2016	6/1/2016			$ 6,500,000	$ 6,500,000
	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 AECI	6/1/2014	6/1/2014			$ 1,000	$ 1,000
					Total	$ 6,501,000	$ 6,501,000

*SPP is currently cordinating with AECI to determine final costs

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
INDP	AG1-2007-045

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
INDP	1221966	OPPD	INDN	6	6/1/2009	6/1/2034	6/1/2011	6/1/2036	$ -	$ 1,584,000	$ 54,523	$ 316,816
									$ -	$ 1,584,000	$ 54,523	$ 316,816

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221966	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2010			$ 40,265	$ 4,400,000	$ 243,609
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 766	$ 50,000	$ 4,144
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011			$ 12,238	$ 2,000,000	$ 63,060
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 1,254	$ 238,266	$ 6,003
					Total	$ 54,523	$ 8,450,000	$ 316,816

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221966	MERRIAM - ROELAND PARK 161KV CKT 1	6/1/2017	6/1/2017		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221966	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		
	SUBSTATION M 161/69KV TRANSFORMER CKT 2	6/1/2010	6/1/2010		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KBPU	AG1-2007-043D

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
KBPU	1221923	SPA	KACY	39	7/1/2010	7/1/2020	6/1/2013	6/1/2023	$ -	$ 4,118,400	$ 1,505,097	$ 3,744,339
									$ -	$ 4,118,400	$ 1,505,097	$ 3,744,339

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221923	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	11/1/2008	6/1/2011		Yes	$ 498,447	$ 8,400,000	$ 1,189,483
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 777,340	$ 13,100,000	$ 1,832,332
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2010			$ 147,568	$ 4,400,000	$ 485,854
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 3,368	$ 50,000	$ 10,206
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 63,515	$ 2,000,000	$ 183,282
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 14,859	$ 238,266	$ 43,182
					Total	$ 1,505,097	$ 28,188,266	$ 3,744,339

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	BELTON SOUTH - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KBPU	AG1-2007-044D

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
KBPU	1221925	WR	KACY	25	1/1/2008	1/1/2028	6/1/2013	6/1/2033	$ -	$ 5,280,000	$ 175,179	$ 669,281
									$ -	$ 5,280,000	$ 175,179	$ 669,281

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221925	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2010			$ 98,606	$ 4,400,000	$ 399,442
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 4,486	$ 50,000	$ 16,612
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 53,853	$ 2,000,000	$ 189,941
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 18,234	$ 238,266	$ 63,286
					Total	$ 175,179	$ 6,688,266	$ 669,281

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BELTON SOUTH - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	HARPER 138KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	PHILLIPSBURG - RHOADES 115 kV	11/1/2008	6/1/2009	10/1/2008	
	PRATT 115KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	11/1/2008	12/1/2009		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KCPS

Study Number AG1-2007-080

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KCPS	1223159	KCPL	EES	52	6/1/2007	6/1/2012	6/1/2013	6/1/2018	$ -	$ 2,808,000	$ 45,945	$ 94,128
									$ -	$ 2,808,000	$ 45,945	$ 94,128

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223159	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 45,945	$ 2,000,000	$ 94,128
					Total	$ 45,945	$ 2,000,000	$ 94,128

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	11/1/2008	6/1/2010		Yes
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		Yes
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		Yes
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		Yes
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KPP
Study Number AG1-2007-052

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222644	WR	WR	333	6/1/2007	6/1/2017	6/1/2011	6/1/2021	$ 32,140,877	$ -	$ 32,140,877	$ 83,822,653
									$ 32,140,877	$ -	$ 32,140,877	$ 83,822,653

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222644	ALLEN - LEHIGH TAP 69KV CKT 1	11/1/2008	6/1/2011		No	$ 1,883,692	$ 2,363,907	$ 4,913,569
	ALLEN 69KV Capacitor	11/1/2008	6/1/2010		No	$ 491,390	$ 607,500	$ 1,360,170
	ALTOONA EAST 69KV Capacitor	11/1/2008	6/1/2010	10/1/2009	No	$ 142,721	$ 240,000	$ 395,052
	ARKANSAS CITY - PARIS 69KV CKT 1 #1 Displacement	11/1/2008	6/1/2009	10/1/2008		$ 2,876	$ 9,889	$ 8,825
	ASH GROVE JCT2 - TIOGA 69KV CKT 1	6/1/2010	6/1/2011		Yes	$ 780,886	$ 958,500	$ 2,048,397
	ATHENS 69KV Capacitor	11/1/2008	6/1/2010		No	$ 491,390	$ 607,500	$ 1,360,170
	Athens to Owl Creek 69 kV	11/1/2008	6/1/2011		No	$ 1,017,743	$ 1,208,769	$ 2,654,760
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	11/1/2008	6/1/2011		Yes	$ 3,915,602	$ 8,400,000	$ 10,078,160
	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	11/1/2008	6/1/2011		No	$ 2,724,589	$ 3,240,000	$ 7,147,059
	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	11/1/2008	6/1/2011		No	$ 1,238,893	$ 1,845,000	$ 3,249,827
	CHANUTE TAP - TIOGA 69KV CKT 1	6/1/2010	6/1/2011		Yes	$ 90,974	$ 112,500	$ 238,640
	CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1	11/1/2008	6/1/2011		Yes	$ 1,467,279	$ 1,800,000	$ 3,848,922
	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	11/1/2008	6/1/2011		No	$ 3,488,987	$ 4,149,000	$ 9,152,205
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 152,859	$ 200,000	$ 435,165
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 6,106,474	$ 13,100,000	$ 15,524,837
	CRESWELL - OAK 69KV CKT 1 #1 Displacement	11/1/2008	6/1/2009	10/1/2008		$ 11,688	$39,545.00	$ 35,531
	DEARING 138KV Capacitor Displacement	12/1/2012	12/1/2012			$ 29,275	$ 38,445	$ 70,759
	Green to Vernon 69 kV	11/1/2008	6/1/2011		No	$ 2,494,368	$ 2,966,229	$ 6,506,505
	LEHIGH TAP - OWL CREEK 69KV CKT 1	11/1/2008	6/1/2011		No	$ 2,942,077	$ 3,494,292	$ 7,674,344
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	11/1/2008	6/1/2011		Yes	$ 199,033	$ 236,391	$ 519,173
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2009	6/1/2009			$ 183,106	$ 250,000	$ 561,883
	TIOGA 69KV Capacitor	11/1/2008	6/1/2010		No	$ 491,390	$ 607,500	$ 1,360,170
	Vernon to Athens 69 kV	11/1/2008	6/1/2011		No	$ 1,793,586	$ 2,132,879	$ 4,678,530
					Total	$ 32,140,877	$ 48,607,846	$ 83,822,653

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	11/1/2008	12/1/2008		Yes
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		Yes
	Sooner to Rose Hill 345 kV OKGE	11/1/2008	1/1/2011	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	11/1/2008	1/1/2011	10/1/2010	Yes

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

*Reservation 1222644 and 1222955 were studied as one request
**A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-054

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
KPP	1222904	WPEK	WPEK	3	6/1/2007	6/1/2017	11/1/2008	11/1/2018	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222904	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Reservation 1223078 and 1222904 were studied as one request

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-055

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222932	WR	WR	45	6/1/2007	6/1/2027	6/1/2011	6/1/2031	$ 11,918,683	$ -	$ 11,918,683	$ 42,203,881
									$ 11,918,683	$ -	$ 11,918,683	$ 42,203,881

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222932	ALLEN - LEHIGH TAP 69KV CKT 1	11/1/2008	6/1/2011		No	$ 480,215	$ 2,363,907	$ 1,688,518
	ALLEN 69KV Capacitor	11/1/2008	6/1/2010		No	$ 116,110	$ 607,500	$ 433,077
	ALTOONA EAST 69KV Capacitor	11/1/2008	6/1/2010	10/1/2009	No	$ 97,279	$ 240,000	$ 362,839
	ARKANSAS CITY - PARIS 69KV CKT 1 #1 Displacement	11/1/2008	6/1/2009	10/1/2008		$ 7,013	$ 9,889	$ 28,999
	ASH GROVE JCT2 - TIOGA 69KV CKT 1	6/1/2010	6/1/2011		Yes	$ 177,614	$ 958,500	$ 628,039
	ATHENS 69KV Capacitor	11/1/2008	6/1/2010		No	$ 116,110	$ 607,500	$ 433,077
	Athens to Owl Creek 69 kV	11/1/2008	6/1/2011		No	$ 191,026	$ 1,208,769	$ 671,680
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	11/1/2008	6/1/2011		Yes	$ 1,005,726	$ 8,400,000	$ 3,598,989
	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	11/1/2008	6/1/2011		No	$ 515,411	$ 3,240,000	$ 1,822,480
	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	11/1/2008	6/1/2011		No	$ 606,107	$ 1,845,000	$ 2,143,179
	CHANUTE TAP - TIOGA 69KV CKT 1	6/1/2010	6/1/2011		Yes	$ 21,526	$ 112,500	$ 76,115
	CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1	11/1/2008	6/1/2011		Yes	$ 332,721	$ 1,800,000	$ 1,176,493
	CITY OF WINFIELD - RAINBOW 69KV CKT 1	11/1/2008	6/1/2011		No	$ 1,645,279	$ 1,645,279	$ 5,785,082
	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	11/1/2008	6/1/2011		No	$ 660,013	$ 4,149,000	$ 2,333,789
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 44,641	$ 200,000	$ 171,248
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,568,454	$ 13,100,000	$ 5,544,041
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 4,858	$ 50,000	$ 22,585
	CRESWELL - OAK 69KV CKT 1 #1 Displacement	11/1/2008	6/1/2009	10/1/2008		$ 27,857	$39,545.00	$ 114,112
	DEARING 138KV Capacitor Displacement	12/1/2012	12/1/2012			$ 8,568	$ 38,445	$ 27,905
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1 Displacement	6/1/2013	6/1/2013			$ 184,922	$ 394,512	$ 585,947
	East Manhattan to Mcdowell 230 kV Displacement	6/1/2011	6/1/2011			$ 14,298	$ 115,877	$ 52,920
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 18,180	$ 23,265	$ 69,739
	Green to Vernon 69 kV	11/1/2008	6/1/2011		No	$ 471,861	$ 2,966,229	$ 1,659,144
	LEHIGH TAP - OWL CREEK 69KV CKT 1	11/1/2008	6/1/2011		No	$ 552,215	$ 3,494,292	$ 1,941,682
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	11/1/2008	6/1/2011		Yes	$ 37,358	$ 236,391	$ 131,357
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2009	6/1/2009			$ 63,916	$ 250,000	$ 264,290
	OAK - RAINBOW 69KV CKT 1	11/1/2008	6/1/2011	10/1/2010	No	$ 1,900,000	$ 1,900,000	$ 6,680,725
	OXFORD 138KV Capacitor Displacement	11/1/2008	6/1/2010		No	$ 129,941	$ 192,066	$ 484,665
	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1 Displacement	11/1/2008	6/1/2011		No	$ 444,111	$ 444,111	$ 1,561,570
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 19,950	$ 238,266	$ 83,506
	TIOGA 69KV Capacitor	11/1/2008	6/1/2010		No	$ 116,110	$ 607,500	$ 433,077
	Vernon to Athens 69 kV	11/1/2008	6/1/2011		No	$ 339,293	$ 2,132,879	$ 1,193,012
					Total	$ 11,918,683	$ 53,611,222	$ 42,203,881

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	6/1/2015	6/1/2015		
	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	6/1/2015	6/1/2015		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	HARPER 138KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	PRATT 115KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	11/1/2008	12/1/2008		Yes
	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2016	6/1/2016		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		
	Summit - NE Saline 115 kV	11/1/2008	12/1/2009		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	6/1/2017	6/1/2017		
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	CHAPMAN - CLAY CENTER JUNCTION 115KV CKT 1	11/1/2008	6/1/2011		Yes
	CLAY CENTER - GREENLEAF 115KV CKT 1	11/1/2008	6/1/2011		Yes
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		Yes
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	11/1/2008	6/1/2011		Yes

Transmission Owner Planned Project - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	CHASE - WHITE JUNCTION 69KV CKT 1	11/1/2008	6/1/2009	10/1/2008	
	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

*A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KPP
Study Number AG1-2007-056

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222937	WR	WPEK	5	6/1/2007	6/1/2027	6/1/2011	6/1/2031	$ 834,166	$ -	$ 2,456,020	$ 2,099,290
									$ 834,166	$ -	$ 2,456,020	$ 2,099,290

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222937	CONCORDIA - JEWELL 3 115KV CKT 1	6/1/2013	6/1/2013			$ 342,095	$ 6,447,839	$ 857,431
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 239	$ 50,000	$ 885
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1 Displacement	6/1/2013	6/1/2013			$ 37,467	$ 394,512	$ 98,442
	East Manhattan to Mcdowell 230 kV Displacement	6/1/2011	6/1/2011			$ 425	$ 115,877	$ 1,303
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 2,825	$ 23,265	$ 8,988
	JEWELL 3 - SMITH CENTER 115KV CKT 1	6/1/2013	6/1/2013			$ 449,497	$ 8,472,161	$ 1,126,625
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 1,618	$ 238,266	$ 5,616
					Total	$ 834,166	$ 15,741,920	$ 2,099,290

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	6/1/2015	6/1/2015		
	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	6/1/2015	6/1/2015		
	Cimarron Plant Substation Expansion	6/1/2012	6/1/2012		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	HARPER 138KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	HOLCOMB - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	NORTH CIMARRON CAPACITOR	6/1/2012	6/1/2012		
	PIONEER TAP - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	PRATT 115KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2016	6/1/2016		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	11/1/2008	12/1/2009		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	6/1/2017	6/1/2017		
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	CHAPMAN - CLAY CENTER JUNCTION 115KV CKT 1	11/1/2008	6/1/2011		Yes
	CLAY CENTER - GREENLEAF 115KV CKT 1	11/1/2008	6/1/2011		Yes
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 MIDW	6/1/2016	6/1/2016		
	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 WERE	6/1/2016	6/1/2016		
	HUNTSVILLE - ST_JOHN 115KV CKT 1	6/1/2016	6/1/2016		
	PRATT - ST JOHN 115KV CKT 1	6/1/2017	6/1/2017		
	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	6/1/2015	6/1/2015		
	TUCO INTERCHANGE 345/115KV TRANSFORMER CKT 1	6/1/2017	6/1/2017		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	11/1/2008	6/1/2011		Yes

Transmission Owner Planned Project - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	CHASE - WHITE JUNCTION 69KV CKT 1	11/1/2008	6/1/2009	10/1/2008	
	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

**A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-058

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
KPP	1222955	WR	WR	20	6/1/2007	6/1/2017	11/1/2008	11/1/2018	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222955	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Reservation 1222644 and 1222955 were studied as one request

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
KPP	AG1-2007-064

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1223078	WPEK	WPEK	15	6/1/2007	6/1/2017	6/1/2011	6/1/2021	$ 564,364	$ -	$ 564,364	$ 994,044
									$ 564,364	$ -	$ 564,364	$ 994,044

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223078	CONCORDIA - JEWELL 3 115KV CKT 1	6/1/2013	6/1/2013			$ 243,896	$ 6,447,839	$ 429,587
	JEWELL 3 - SMITH CENTER 115KV CKT 1	6/1/2013	6/1/2013			$ 320,468	$ 8,472,161	$ 564,457
					Total	$ 564,364	$ 14,920,000	$ 994,044

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	Cimarron Plant Substation Expansion	6/1/2012	6/1/2012		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	HARPER 138KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	HOLCOMB - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	NORTH CIMARRON CAPACITOR	6/1/2012	6/1/2012		
	PIONEER TAP - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	PRATT 115KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	11/1/2008	12/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	CHAPMAN - CLAY CENTER JUNCTION 115KV CKT 1	11/1/2008	6/1/2011		Yes
	CLAY CENTER - GREENLEAF 115KV CKT 1	11/1/2008	6/1/2011		Yes
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	TUCO INTERCHANGE 345/115KV TRANSFORMER CKT 1	6/1/2017	6/1/2017		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	11/1/2008	6/1/2011		Yes

*Reservation 1223078 and 1222904 were studied as one request

**A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
SPRM	AG1-2007-042

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
SPRM	1220082	SPA	SPA	275	10/1/2010	10/1/2050			$ 120,000	$ -	$ 120,000	$ 555,320
									$ 120,000	$ -	$ 120,000	$ 555,320

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1220082	BROOKLINE - JUNCTION 161KV CKT 1	6/1/2013	6/1/2013			$ 120,000	$ 120,000	$ 555,320
					Total	$ 120,000	$ 120,000	$ 555,320

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	JAMES RIVER - TWIN OAKS 69KV CKT 1	6/1/2015	6/1/2015		
	KICKAPOO - SUNSET 69KV CKT 1	6/1/2014	6/1/2014		
	NEERGARD - NORTON 69KV CKT 1	10/1/2010	10/1/2010	6/1/2010	
	NIXA 161KV CAP BANK	6/1/2013	6/1/2013		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	SPRINGFIELD (SPF X3) 161/69/13.8KV TRANSFORMER CKT 1	10/1/2010	6/1/2012		

Transmission Owner Planned Project - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	6/1/2013	6/1/2013	6/1/2009	

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
UCU	AG1-2007-023D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1214269	MPS	KCPL	2	6/1/2007	6/1/2012	6/1/2013	6/1/2018	$ -	$ 105,600	$ 205	$ 442
									$ -	$ 105,600	$ 205	$ 442

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1214269	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 188	$ 50,000	$ 404
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 17	$ 238,266	$ 38
					Total	$ 205	$ 288,266	$ 442

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	BELTON SOUTH - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	11/1/2008	6/1/2010		Yes
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		Yes
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		Yes
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		Yes
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes
	South Harper - Freeman 69 kV	11/1/2008	11/1/2008		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
UCU	AG1-2007-025D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1214263	MPS	WR	1	6/1/2007	6/1/2012	6/1/2013	6/1/2018	$ -	$ 94,500	$ 2,062	$ 4,893
									$ -	$ 94,500	$ 2,062	$ 4,893

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1214263	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 197	$ 200,000	$ 442
	DEARING 138KV Capacitor Displacement	12/1/2012	12/1/2012			$ 74	$ 38,445	$ 140
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 332	$ 23,265	$ 746
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2009	6/1/2009			$ 345	$ 250,000	$ 835
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 1,115	$ 238,266	$ 2,730
					Total	$ 2,062	$ 749,976	$ 4,893

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	BELTON SOUTH - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	HARPER 138KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	PRATT 115KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		
	Summit - NE Saline 115 kV	11/1/2008	12/1/2009		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	11/1/2008	6/1/2010		Yes
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV CKT 1	11/1/2008	6/1/2011		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		Yes
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		Yes
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		Yes
	South Harper - Freeman 69 kV	11/1/2008	11/1/2008		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	11/1/2008	6/1/2011		Yes

Transmission Owner Planned Project - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer UCU
Study Number AG1-2007-060D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1223092	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	$ -	$ 28,998,000	$ 3,403,769	$ 12,870,440
UCU	1223093	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	$ -	$ 28,998,000	$ 3,403,769	$ 12,870,440
UCU	1223094	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	$ -	$ 28,998,000	$ 3,403,769	$ 12,870,440
UCU	1223095	EES	MPS	75	3/1/2009	3/1/2029	6/1/2013	6/1/2033	$ -	$ 28,998,000	$ 3,403,769	$ 12,870,440
									$ -	$ 115,992,000	$ 13,615,076	$ 51,481,760

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223092	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000	$ -
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	11/1/2008	6/1/2011		Yes	$ 745,056	$ 8,400,000	$ 2,456,108
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,161,933	$ 13,100,000	$ 3,783,497
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2010			$ 1,028,390	$ 4,400,000	$ 4,834,739
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 2,989	$ 50,000	$ 12,721
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 428,206	$ 2,000,000	$ 1,735,907
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 12,195	$ 238,266	$ 47,468
					Total	$ 3,403,769	$ 28,288,266	$ 12,870,440
1223093	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009		$ 25,000	$ 100,000	$ -
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	11/1/2008	6/1/2011		Yes	$ 745,056	$ 8,400,000	$ 2,456,108
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,161,933	$ 13,100,000	$ 3,783,497
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2010			$ 1,028,390	$ 4,400,000	$ 4,834,739
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 2,989	$ 50,000	$ 12,721
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 428,206	$ 2,000,000	$ 1,735,907
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 12,195	$ 238,266	$ 47,468
					Total	$ 3,403,769	$ 28,288,266	$ 12,870,440
1223094	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000	$ -
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	11/1/2008	6/1/2011		Yes	$ 745,056	$ 8,400,000	$ 2,456,108
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,161,933	$ 13,100,000	$ 3,783,497
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2010			$ 1,028,390	$ 4,400,000	$ 4,834,739
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 2,989	$ 50,000	$ 12,721
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 428,206	$ 2,000,000	$ 1,735,907
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 12,195	$ 238,266	$ 47,468
					Total	$ 3,403,769	$ 28,288,266	$ 12,870,440
1223095	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000	$ -
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	11/1/2008	6/1/2011		Yes	$ 745,056	$ 8,400,000	$ 2,456,108
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,161,933	$ 13,100,000	$ 3,783,497
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2010			$ 1,028,390	$ 4,400,000	$ 4,834,739
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 2,989	$ 50,000	$ 12,721
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 428,206	$ 2,000,000	$ 1,735,907
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 12,195	$ 238,266	$ 47,468
					Total	$ 3,403,769	$ 28,288,266	$ 12,870,440

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	ARKOMA - FT SMITHW 161KV CKT 1	6/1/2014	6/1/2014		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2009	6/1/2010		Yes
	EAST 20MVAR CAPACITOR # 1	6/1/2009	6/1/2010	10/1/2009	No
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		
1223093	ARKOMA - FT SMITHW 161KV CKT 1	6/1/2014	6/1/2014		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2009	6/1/2010		Yes
	EAST 20MVAR CAPACITOR # 1	6/1/2009	6/1/2010	10/1/2009	No
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		
1223094	ARKOMA - FT SMITHW 161KV CKT 1	6/1/2014	6/1/2014		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2009	6/1/2010		Yes
	EAST 20MVAR CAPACITOR # 1	6/1/2009	6/1/2010	10/1/2009	No
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		
1223095	ARKOMA - FT SMITHW 161KV CKT 1	6/1/2014	6/1/2014		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2009	6/1/2010		Yes
	EAST 20MVAR CAPACITOR # 1	6/1/2009	6/1/2010	10/1/2009	No
	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	11/1/2008	6/1/2013		Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	11/1/2008	6/1/2010		Yes
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDMOND SUB	6/1/2009	6/1/2010		Yes
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		Yes
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		Yes
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		Yes
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes
	South Harper - Freeman 69 kV	11/1/2008	11/1/2008		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		
1223093	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	11/1/2008	6/1/2010		Yes
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDMOND SUB	6/1/2009	6/1/2010		Yes
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		Yes
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		Yes
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		Yes
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes
	South Harper - Freeman 69 kV	11/1/2008	11/1/2008		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		
1223094	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	11/1/2008	6/1/2010		Yes
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDMOND SUB	6/1/2009	6/1/2010		Yes
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		Yes
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		Yes
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		Yes
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes
	South Harper - Freeman 69 kV	11/1/2008	11/1/2008		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		
1223095	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	11/1/2008	6/1/2010		Yes
	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDMOND SUB	6/1/2009	6/1/2010		Yes
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		Yes
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		Yes
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		Yes
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		Yes
	South Harper - Freeman 69 kV	11/1/2008	11/1/2008		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	CLARKSVILLE - DARDANELLE 161KV CKT 1	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		No
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		No
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	Sooner to Rose Hill 345 kV OKGE	11/1/2008	1/1/2011	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	11/1/2008	1/1/2011	10/1/2010	Yes
1223093	CLARKSVILLE - DARDANELLE 161KV CKT 1	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		No
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		No
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	Sooner to Rose Hill 345 kV OKGE	11/1/2008	1/1/2011	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	11/1/2008	1/1/2011	10/1/2010	Yes
1223094	CLARKSVILLE - DARDANELLE 161KV CKT 1	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		No
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		No
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	Sooner to Rose Hill 345 kV OKGE	11/1/2008	1/1/2011	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	11/1/2008	1/1/2011	10/1/2010	Yes
1223095	CLARKSVILLE - DARDANELLE 161KV CKT 1	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		No
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		No
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	Sooner to Rose Hill 345 kV OKGE	11/1/2008	1/1/2011	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	11/1/2008	1/1/2011	10/1/2010	Yes

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	WICHITA - RENO 345KV	11/1/2008	12/1/2008		
1223093	WICHITA - RENO 345KV	11/1/2008	12/1/2008		
1223094	WICHITA - RENO 345KV	11/1/2008	12/1/2008		
1223095	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
WRGS	AG1-2007-001D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
WRGS	1197077	EDE	WR	32	9/1/2007	9/1/2018	6/1/2013	6/1/2024	$ 24,124	$ -	$ 24,124	$ 79,101
									$ 24,124	$ -	$ 24,124	$ 79,101

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1197077	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 2,304	$ 200,000	$ 7,829
	DEARING 138KV Capacitor Displacement	12/1/2012	12/1/2012			$ 529	$ 38,445	$ 1,526
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1 Displacement	6/1/2013	6/1/2013			$ 5,184	$ 394,512	$ 14,547
	EAST MANHATTAN - NW MANHATTAN 230/115KV Displacement	6/1/2011	6/1/2011			$ 2,640	$ 2,001,944	$ 8,415
	East Manhattan to Mcdowell 230 kV Displacement	6/1/2011	6/1/2011			$ 197	$ 115,877	$ 645
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 1,928	$ 23,265	$ 6,551
	LITCHFIELD - AQUARIUS - HUDSON JUNCTION 69KV CKT 1 Displacement	6/1/2014	6/1/2014			$ 1,846	$ 1,846	$ 4,499
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2009	6/1/2009			$ 2,633	$ 250,000	$ 9,644
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 6,863	$ 238,266	$ 25,445
					Total	$ 24,124	$ 3,264,155	$ 79,101

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	6/1/2017	6/1/2017		
	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	HARPER 138KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	PRATT 115KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	6/1/2015	6/1/2015		
	SUB 389 - JOPLIN SOUTHWEST - SUB 422 - JOPLIN 24TH & CONNECTICUT 161KV CKT 1	11/1/2008	6/1/2009	10/1/2008	
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2011		
	Summit - NE Saline 115 kV	11/1/2008	12/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV CKT 1	11/1/2008	6/1/2011		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	JOPLIN 59 - SUB 439 - STATELINE 161KV CKT 1	6/1/2012	6/1/2013		
	JOPLIN 59 - SUB 59 - JOPLIN 26TH ST. 161/69kV TRANSFORMER CKT 1	6/1/2012	6/1/2013		
	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	6/1/2015	6/1/2015		
	SUB 124 - AURORA H.T. - SUB 383 - MONETT 161KV CKT 1	6/1/2017	6/1/2017		
	SUB 124 - AURORA H.T. 161KV	6/1/2013	6/1/2013		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	11/1/2008	6/1/2010		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	11/1/2008	6/1/2010		
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	11/1/2008	6/1/2011		

Transmission Owner Planned Project - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
WRGS	AG1-2007-047D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
WRGS	1222005	WR	EES	106	10/1/2007	10/1/2010	6/1/2011	6/1/2014	$ -	$ 3,434,400	$ 442,413	$ 952,337
									$ -	$ 3,434,400	$ 442,413	$ 952,337

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222005	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2010	6/1/2010			$ 9,518	$ 50,000	$ 23,646
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1 Displacement	6/1/2013	6/1/2013			$ 166,940	$ 394,512	$ 310,520
	EAST MANHATTAN - NW MANHATTAN 230/115KV Displacement	6/1/2011	6/1/2011			$ 13,483	$ 2,001,944	$ 28,477
	East Manhattan to Mcdowell 230 kV Displacement	6/1/2011	6/1/2011			$ 13,620	$ 115,877	$ 29,586
	MARTIN CITY - REDEL 161KV CKT 1	6/1/2009	6/1/2011			$ 111,624	$ 2,000,000	$ 264,115
	OXFORD 138KV Capacitor Displacement	11/1/2008	6/1/2010			$ 62,125	$ 192,066	$ 136,026
	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	6/1/2009	6/1/2009			$ 65,104	$ 238,266	$ 159,967
					Total	$ 442,413	$ 4,992,665	$ 952,337

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	HARPER 138KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	PRATT 115KV Capacitor	11/1/2008	6/1/2009	10/1/2008	
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	11/1/2008	12/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	BLUE SPRINGS EAST CAP BANK	6/1/2010	6/1/2010		
	EDWARDSVILLE 115KV Capacitor	6/1/2012	6/1/2012		
	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	11/1/2008	6/1/2010		
	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	6/1/2009	6/1/2010		
	LONGVIEW - SAMPSON 161KV CKT 1	6/1/2009	6/1/2010		
	REDEL - STILWELL 161KV CKT 1	11/1/2008	6/1/2011		

Transmission Owner Planned Project - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	CHASE - WHITE JUNCTION 69KV CKT 1	11/1/2008	6/1/2009	10/1/2008	
	WICHITA - RENO 345KV	11/1/2008	12/1/2008		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	WICHITA - RENO 345KV	11/1/2008	12/1/2008	12/1/2008	

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AEPW	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	Rebuild 8.37 miles of 795 ACSR with 1590 ACSR & reset relays @ BSE	11/1/2008	6/1/2011	$8,400,000.00
AEPW	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	Rebuild 13.11 miles of 795 ACSR with 1590 ACSR	6/1/2009	6/1/2011	$13,100,000.00
EMDE	SUB 271 - BAXTER SPRINGS WEST - SUB 404 - HOCKERVILLE 69KV CKT 1 Displacement	Change CT setting on Breaker #6973 at Baxter #271	12/1/2008	4/1/2009	$10,000.00
KACP	Craig 161kV 20MVar Cap Bank Upgrade	Additional 20 MVAR to make a total of 70 MVAR at Craig 542978	6/1/2010	6/1/2010	$50,000.00
KACP	MARTIN CITY - REDEL 161KV CKT 1	Reconductor 1192 acss upgrade terminal equip 2000 am	6/1/2009	6/1/2011	$2,000,000.00
MKEC	CONCORDIA - JEWELL 3 115KV CKT 1	Rebuild 25.8 mile line	6/1/2013	6/1/2013	$6,447,839.00
MKEC	JEWELL 3 - SMITH CENTER 115KV CKT 1	Rebuild 33.9 mile line	6/1/2013	6/1/2013	$8,472,161.00
SJLP	COOK - ST JOE 161KV CKT 1	Conductor, Switch, Relay	6/1/2010	6/1/2010	$4,400,000.00
SPRM	BROOKLINE - JUNCTION 161KV CKT 1	Brookline: Replace 1,200 amp switches with 2,000 amp units and replace metering CTs. Junction: Replace 1,200 amp switches with 2,000 amp units.	6/1/2013	6/1/2013	$120,000.00
SWPA	5CALCR - NORFORK 161KV CKT 1 SWPA	Replace buswork within bay and change metering CT ratio, replace wavetraps. Entergy must also reconductor their line to increase the rating.	6/1/2009	6/1/2010	$100,000.00
WERE	ALLEN - LEHIGH TAP 69KV CKT 1	Tear down / Rebuild 5.69-mile line; 954 kcmil ACSR	11/1/2008	6/1/2011	$2,363,907.00
WERE	ALLEN 69KV Capacitor	Allen 69 kV 15 MVAR Capacitor Addition	11/1/2008	6/1/2010	$607,500.00
WERE	ALTOONA EAST 69KV Capacitor	ALTOONA EAST 69KV 6 MVAR Capacitor Addition	11/1/2008	6/1/2010	$240,000.00
WERE	ARKANSAS CITY - PARIS 69KV CKT 1 #1 Displacement	Replace Disconnect Switches and Bus Jumpers at Paris and Ark City 69 kV substations	11/1/2008	6/1/2009	$50,000.00
WERE	ASH GROVE JCT2 - TIOGA 69KV CKT 1	Rebuild 2.13 miles	6/1/2010	6/1/2011	$958,500.00
WERE	ATHENS 69KV Capacitor	Athens 69 kV 15 MVAR Capacitor Addition	11/1/2008	6/1/2010	$607,500.00
WERE	Athens to Owl Creek 69 kV	Rebuild Athens to Owl Creek (138kV/69kV Operation	11/1/2008	6/1/2011	$1,208,769.00
WERE	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	Rebuild 7.2 miles (138kV/69kV Operation)	11/1/2008	6/1/2011	$3,240,000.00
WERE	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	Rebuild 4.1 miles (138kV/69kV Operation	11/1/2008	6/1/2011	$1,845,000.00
WERE	CHANUTE TAP - TIOGA 69KV CKT 1	Replace Jumpers	6/1/2010	6/1/2011	$112,500.00
WERE	CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1	Tear down / Rebuild 4-mile 69 kV line; 954 kcmiol ACSR	11/1/2008	6/1/2011	$1,800,000.00
WERE	CITY OF WINFIELD - RAINBOW 69KV CKT 1	Rebuild 3.99-mile Rainbow-Winfield 69 kV line, 954 ACSR	11/1/2008	6/1/2011	$1,645,279.00
WERE	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	Rebuild 9.22 miles (138kV/69kV Operation	11/1/2008	6/1/2011	$4,149,000.00
WERE	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers	6/1/2010	6/1/2010	$200,000.00
WERE	CRESWELL - OAK 69KV CKT 1 #1 Displacement	Replace jumpers and bus, and reset CTs and relaying. Rebuild substations.	11/1/2008	6/1/2009	$250,000.00
WERE	DEARING 138KV Capacitor Displacement	Dearing 138 kV 20 MVAR Capacitor Addition	12/1/2012	12/1/2012	$810,000.00
WERE	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1 Displacement	Uprate JEC- E.Manhattan 230 kV line to 100 deg C operation by raising structures	6/1/2013	6/1/2013	$17,085,937.50
WERE	EAST MANHATTAN - NW MANHATTAN 230/115KV Displacement	Tap the Concordia - East Manhattan 230kV line and add a new substation"NW Manhattan"; Add a 230kV/115kV transformer and tap the KSU - Wildcat 115kV line into NW Manhattan	6/1/2011	6/1/2011	$17,437,500.00
WERE	East Manhattan to Mcdowell 230 kV Displacement	The East Manhattan-McDowell 115 kV is built as a 230 kV line, but is operated at 115 kV. Substation work will have to be performed in order to convert this line.	6/1/2011	6/1/2011	$1,000,000.00
WERE	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers	6/1/2010	6/1/2010	$200,000.00
WERE	Green to Vernon 69 kV	Rebuild 7.19 miles Green to Vernon 69 kV (138kV/69kV Operation)	11/1/2008	6/1/2011	$2,966,229.00
WERE	LEHIGH TAP - OWL CREEK 69KV CKT 1	Tear down / Rebuild 8.47-mile 69 kV line; 954 kcmil ACSR	11/1/2008	6/1/2011	$3,494,292.00
WERE	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	Tear down / Rebuild 0.91-mile 69 kV line; 954 kcmiol ACSR	11/1/2008	6/1/2011	$236,391.00
WERE	LITCHFIELD - AQUARIUS - HUDSON JUNCTION 69KV CKT 1 Displacement	Replace 69 kV disconnect switches at Aquarius	6/1/2014	6/1/2014	$30,000.00
WERE	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	Replace bus and Jumpers at NE Parsons 138 kV substation	6/1/2009	6/1/2009	$250,000.00
WERE	OAK - RAINBOW 69KV CKT 1	Tear down / Rebuild 5.10-mile Oak-Rainbow 69 kV using 954 kcmil ACSR	11/1/2008	6/1/2011	$1,900,000.00
WERE	OXFORD 138KV Capacitor Displacement	Install 30 MVAR Capacitor Bank at Oxford 138 kV	11/1/2008	6/1/2010	$1,215,000.00
WERE	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1 Displacement	Rebuild 5.43 mile Rose Hill Junction-Richland as a 138 kV line but operate at 69 kV.	11/1/2008	6/1/2011	$2,240,142.00
WERE	TECUMSEH ENERGY CENTER - MIDLAND 115KV CKT 1 Displacement	Convert 161 kV Line to 115 kV Operation	6/1/2009	6/1/2009	$2,000,000.00
WERE	TIOGA 69KV Capacitor	Tioga 69 kV 15 MVAR Capacitor Addition	11/1/2008	6/1/2010	$607,500.00
WERE	Vernon to Athens 69 kV	Rebuild 5.17 miles Green to Vernon 69 kV (138kV/69kV Operation)	11/1/2008	6/1/2011	$2,132,879.00

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Construction Pending Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission custom

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	Tie Line, Reconductor 1.09 miles of 795 ACSR with 1590 ACSR.	11/1/2008	6/1/2010
AEPW	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	Rebuild 7.43 miles of 250 CWC with 795 ACSR	6/1/2009	6/1/2009
OKGE	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	Rebuild 7.43 miles of 250 CWC with 795 ACSR	6/1/2009	6/1/2009
OKGE	Sooner to Rose Hill 345 kV OKGE	New 345 kV line from Sooner to Oklahoma/Kansas	11/1/2008	1/1/2011
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1	Reconductor Clarksville-Dardanelle line	6/1/2012	6/1/2012
WERE	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	Tie Line, Rebuild 3.93 miles of 795 ACSR with 1590 ACSR	11/1/2008	6/1/2010
WERE	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	Add third 345-138 kV transformer at Rose Hill	11/1/2008	6/1/2011
WERE	Sooner to Rose Hill 345 kV WERE	New 345 kV line from Oklahoma/Kansas Stateline to Rose Hi	11/1/2008	1/1/2011

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
SPRM	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1: Reconductor 161kV Line 1192 MCM AAC to 954 kcmil ACSS/TW 0.67 miles and Upgrade Teminal Equipment	6/1/2013	6/1/2013
WERE	CHASE - WHITE JUNCTION 69KV CKT 1	Tear down / Rebuild 7.3-mile Chase - White Junction 69 kV line Replace existing 2/0 copper conductor with 795 kcmil ACSR conductor.	11/1/2008	6/1/2009
WERE	WICHITA - RENO 345KV	40 mile 345 kV transmission line from existing Wichita 345 kV substation to a new 345-115 kV substation in Reno County east northeast of Hutchinson (Wichita to Reno)	11/1/2008	12/1/2008

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Expansion Plan Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission custom

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	BONANZA - NORTH HUNTINGTON 69KV	Convert from 69KV to 161KV	6/1/2014	6/1/2014
AEPW	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR	6/1/2009	6/1/2009
AEPW	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	Install new 345kV line from FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE	6/1/2017	6/1/2017
EMDE	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 EMDE	Replace Jumpers to breaker #6950 at Blackhawk Jct	6/1/2014	6/1/2014
EMDE	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	Install new line from Sub #383 to new Sub MONETT 5. Install 3-wind transformer from 161 kV new bus to Monett city south 69kV	6/1/2015	6/1/2015
EMDE	SUB 389 - JOPLIN SOUTHWEST - SUB 422 - JOPLIN 24TH & CONNECTICUT 161KV CKT 1	Change CT Ratio at Sub #389 on Breaker #16170 for 268 MVA Rate B	11/1/2008	6/1/2009
EMDE	SUB 438 - RIVERSIDE 161KV	Install 3 - stages of 22 MVAR each for a total of 66 MVAR capacitor bank at Riverside Sub #438 547497	6/1/2011	6/1/2011
EMDE	SUB 73 - BOLIVAR BURNS 69KV	Add 14 MVAR cap bank at Bolivar Sub# 73 bus# 547528	6/1/2015	6/1/2015
GRDA	KERR - PENSACOLA 115KV CKT 1	Rebuild 22 miles of line from 4/0 Cu to 795 ACSR for 161kV	12/1/2012	12/1/2012
KACP	MERRIAM - ROELAND PARK 161KV CKT 1	reconductor with 1192 acsr; upgrade term equip 1200 A	6/1/2017	6/1/2017
MIPU	BELTON SOUTH - TURNER ROAD SUBSTATION 161KV CKT 1	Reconductor to Bundled Drake	11/1/2008	6/1/2013
MIPU	MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1	Upgrade to bundled 795 26/7 ACSR conducto	11/1/2008	6/1/2013
MKEC	Cimarron Plant Substation Expansion	Integrate SUNC North Cimarron Top into reconfigured WEPL Cimarron Plant Sub	6/1/2012	6/1/2012
MKEC	HARPER 138KV Capacitor	Install 1 - 20 MVar capacitor bank	11/1/2008	6/1/2009
MKEC	PRATT 115KV Capacitor	Install (2) 12 Mvar cap banks at Pratt 115kV	11/1/2008	6/1/2009
OKGE	ARKOMA - FT SMITHW 161KV CKT 1	Replace 1200A terminal equipment at Arkoma to 2000A and rebuild 4.47 miles of line to 1590AS52.	6/1/2014	6/1/2014
OKGE	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR	6/1/2009	6/1/2009
SJLP	EAST 20MVAR CAPACITOR # 1	Add 20MVAR capacitor at East 161kV	6/1/2009	6/1/2010
SPRM	JAMES RIVER - TWIN OAKS 69KV CKT 1	Reconductor 69kV Line 636 MCM ACSR to 762.8 kcmil ACSS/TW 3.103 miles.	6/1/2015	6/1/2015
SPRM	KICKAPOO - SUNSET 69KV CKT 1	Reconductor 69kV Line 636 MCM ACSR to 762.8 kcmil ACSS/TW 1.35 miles.	6/1/2014	6/1/2014
SPRM	NEERGARD - NORTON 69KV CKT 1	Transfer load & Reconductor 336.4 kcmil ACSR with 477 ACSS/TW	10/1/2010	10/1/2010
SUNC	HOLCOMB - PLYMELL 115KV CKT 1	Rebuild Holcomb to Plymel	12/1/2009	12/1/2009
SUNC	NORTH CIMARRON CAPACITOR	Install 24 MVAR Capacitor bank at North Cimarron	6/1/2012	6/1/2012
SUNC	PHILLIPSBURG - RHOADES 115 kV	Install 35 miles 115 kV from Phillipsburgsubstion to Rhoade	11/1/2008	6/1/2009
SUNC	PIONEER TAP - PLYMELL 115KV CKT 1	Rebuild Plymell to Pioneer Tap	12/1/2009	12/1/2009
SWPA	BULL SHOALS - BULL SHOALS 161KV CKT 1	Replace buswork in Bull Shoals switchyard	6/1/2009	6/1/2010
SWPA	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	Replace wave trap, disconnect switches, current transformers, and breaker. Bus will limit rating to 1340 amps.	6/1/2009	6/1/2010
SWPA	NIXA 161KV CAP BANK	25Mvar Cap at Nixa	6/1/2013	6/1/2013
WERE	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	Add second Auburn 230-115 kV transformer	6/1/2016	6/1/2016
WERE	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	Rebuild 2.9 mi 115 kV line Bismark to COOP	6/1/2015	6/1/2015
WERE	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	Rebuild 5.2 miles Bismark to Midland 115 kV line	6/1/2015	6/1/2015
WERE	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	Reconductor 8.02 miles with Bundled 1192.5 ACSR	6/1/2016	6/1/2016
WERE	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	Rebuild 1.53-mile Co-op-Wakarusa 115 kV line.	6/1/2017	6/1/2017
WERE	Fort Scott - SW Bourbon 161 kV	Tap Litchfield-Marmaton 161 kV with new SW Bourbon Sub to Ft Scott, and new 161/69 kV transformer at Ft Scott.	6/1/2010	6/1/2010
WERE	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	Replace wave trap	6/1/2016	6/1/2016
WERE	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	Rebuild 5.49 mile line	6/1/2017	6/1/2017
WERE	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	Rebuild 5.73 mile Weaver-Rose Hill Junction as a 138 kV line bu operate at 69 kV.	11/1/2008	12/1/2008
WERE	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	Rebuild 4.09 mile SW Lawrence-Wakarusa 115 kV line	6/1/2016	6/1/2016
WERE	STRANGER CREEK - NW LEAVENWORTH 115KV	Rebuild 11.62-mile Jarbalo-NW Leavenworth 115 kV line and tap ir & out of Stranger 115 kV	6/1/2011	6/1/2011
WERE	STRANGER CREEK TRANSFORMER CKT 2	Install second Stranger Creek 345-115 transforme	6/1/2009	6/1/2009
WERE	Summit - NE Saline 115 kV	Build 6.5-mile Summit-Southgate 115 kV, 1192.5 kcmil ACSR Tear down Northview-South Gate 115 kV	11/1/2008	12/1/2009

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission custom

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
EMDE	JOPLIN 59 - SUB 439 - STATELINE 161KV CKT 1	Install new line from Sub #439 to new Sub Joplin 59	6/1/2012	6/1/2013
EMDE	JOPLIN 59 - SUB 59 - JOPLIN 26TH ST. 161/69kV TRANSFORMER CKT 1	Install 3-wind transformer from 161 kV Joplin 59 bus to Sub #59 Joplin 26th St.	6/1/2012	6/1/2013
EMDE	SUB 124 - AURORA H.T. - SUB 152 - MONETT H.T. 69KV CKT 1	Change CT Ratio on breaker #6936 at Aurora #124	6/1/2009	6/1/2009
EMDE	SUB 124 - AURORA H.T. - SUB 383 - MONETT 161KV CKT 1	Change CT Ratio at Sub #383 on Breaker #16186 for 268 MVA Rate B	6/1/2017	6/1/2017
EMDE	SUB 124 - AURORA H.T. 161KV	Install 3 - stages of 22 MVAR each for total of 66 MVAR capacitor bank at Aurora Sub #124 bus# 547537	6/1/2013	6/1/2013
EMDE	SUB 145 - JOPLIN WEST 7TH - SUB 64 - JOPLIN 10TH ST. 69KV CKT 1	Replace Disconnect Switches and Leads on Breaker #6965 at Sub #64 and #6932 at Sub #145	6/1/2010	6/1/2010
EMDE	SUB 170 - NICHOLS ST. - SUB 80 - MARSHFIELD JCT. 69KV CKT 1	Reconductor line from Sub #80 to Sub #170 from 1/0 CU to 556 ACSR and replace Jumpers in Sub #80	6/1/2012	6/1/2012
INDN	SUBSTATION M 161/69KV TRANSFORMER CKT 2	Add second 100 MVA xfr at Subsation M	6/1/2010	6/1/2010
KACP	REDEL - STILWELL 161KV CKT 1	Reconductor line with 1192 ACSS and upgrade terminal equipment for 2000 amps	11/1/2008	6/1/2011
MIDW	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 MIDW	Tear down and rebuild 73.4% Ownership 28.79 mile HEC-Huntsville 115 kV line and replace CT, wavetrap and relays.	6/1/2016	6/1/2016
MIDW	HUNTSVILLE - ST_JOHN 115KV CKT 1	Rebuild 26.5 miles Huntsville - St. John 115 kV line and replace CT, wavetrap, breakers, and relays.	6/1/2016	6/1/2016
MIPU	ALABAMA - LAKE ROAD 161KV CKT 1	re-set the over current relay to trip the Lake Road-Alabama section when flow goes above 161 MVA	6/1/2010	6/1/2010
MIPU	BLUE SPRINGS EAST - DUNCAN ROAD 161KV CKT 1	Upgrade to conductor Bundled Drake	11/1/2008	6/1/2010
MIPU	BLUE SPRINGS EAST CAP BANK	Add 50 MVAR cap bank at Blue Springs East	6/1/2010	6/1/2010
MIPU	EDMOND SUB	Add a new 161/34.5 kV Sub at Edmond tapping the Cook to Lake Road 161 kV line	6/1/2009	6/1/2010
MIPU	GRANDVIEW EAST - MARTIN CITY 161KV CKT 1 #2	Reconductor to Bundled Drake	11/1/2008	6/1/2010
MIPU	GRANDVIEW EAST - SAMPSON 161KV CKT 1 # 1	Replace wavetraps	6/1/2009	6/1/2010
MIPU	LONGVIEW - SAMPSON 161KV CKT 1	Increase the normal/emergency ratings to 233/265 MVA by replacing wave trapes	6/1/2009	6/1/2010
MIPU	RALPH GREEN 12MVAR CAPACITOR	12MVAR at Ralph Green	6/1/2010	6/1/2010
MIPU	South Harper - Freeman 69 kV	Manually open the SouthHarper-Freeman 69 kV line	11/1/2008	11/1/2008
MKEC	CLAY CENTER - GREENLEAF 115KV CKT 1	Building a new 115 kV tie with Westar from Greenleaf to Clay Center	11/1/2008	6/1/2011
MKEC	PRATT - ST JOHN 115KV CKT 1	Replace terminal equipment	6/1/2017	6/1/2017
SPS	TUCO INTERCHANGE 345/115KV TRANSFORMER CKT 1	Install 345/115 kV Transformer at Tuco	6/1/2017	6/1/2017
SWPA	SPRINGFIELD (SPF X3) 161/69/13.8KV TRANSFORMER CKT 1	Add Third Transformer	10/1/2010	6/1/2012
WERE	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	Rebuild 7.61 miles from 95th & Waverly-Captain Junction 115 kV line.	6/1/2017	6/1/2017
WERE	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV CKT 1	Rebuild Line	11/1/2008	6/1/2011
WERE	CHAPMAN - CLAY CENTER JUNCTION 115KV CKT 1	Reset terminal equipment	11/1/2008	6/1/2011
WERE	EDWARDSVILLE 115KV Capacitor	Install 30 Mvar cap at Edwardsville 115 kV	6/1/2012	6/1/2012
WERE	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 WERE	Tear down and rebuild 26.6% Ownership 28.79 mile HEC-Huntsville 115 kV line and replace CT, wavetrap and relays.	6/1/2016	6/1/2016
WERE	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	Install second 17th St. 138-69 kV transforme	6/1/2015	6/1/2015

Previously Assigned Aggregate Study Upgrades requiring credits to Previous Aggregate Study Customer

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
WERE	WICHITA - RENO 345KV	40 mile 345 kV transmission line from existing Wichita 345 kV substation to a new 345-115 kV substation in Reno County east northeast of Hutchinson (Wichita to Reno)	11/1/2008	12/1/2008

Table 5 - Third Party Facility Constraints

Transmission Owner	UpgradeName	Solution	Earliest Date	Estimated Date of	Estimated Engineering &
AECI	HUBEN (HUBEN) 345/161/13.8KV TRANSFORMER CKT 1	Install a second Huben 345/161kV transformer	6/1/2016	6/1/2016	$6,500,000.00
AECI	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 AECI	Reset CT	6/1/2014	6/1/2014	$1,000.00

EXHIBIT NO. OGE-13

Southwest
Power Pool

Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers

SPP Engineering, SPP Tariff Studies

Table of Contents

1. Executive Summary

Pursuant to Attachment Z1 of the Southwest Power Pool Open Access Transmission Tariff (OATT), 1359 MW of long-term transmission service requests have been restudied in this Aggregate Facility Study (AFS). The first phase of the AFS consisted of a revision of the impact study to reflect the withdrawal of requests for which an Aggregate Facility Study Agreement was not executed. The principal objective of the AFS is to identify system problems and potential modifications necessary to facilitate these transfers while maintaining or improving system reliability as well as summarizing the operating limits and determination of the financial characteristics associated with facility upgrades. Facility upgrade costs are allocated on a prorated basis to all requests positively impacting any individual overloaded facility. Further, Attachment Z2 provides for facility upgrade cost recovery by stating that "Transmission Customers paying Directly Assigned Upgrade Costs for Service Upgrades or that are in excess of the Safe Harbor Cost Limit for Network Upgrades associated with new or changed Designated Resources and Project Sponsors paying Directly Assigned Upgrade Costs for Sponsored Upgrades shall receive revenue credits in accordance with Attachment Z2. Generation Interconnection Customers paying for Network Upgrades shall receive credits for new transmission service using the facility as specified in Attachment Z1."

The total assigned facility upgrade Engineering and Construction (E &C) cost determined by the AFS is $60 Million. Additionally $145 Thousand of assigned E & C cost for 3rd party facility upgrades are assignable to the customer. The total upgrade levelized revenue requirement for all transmission requests is $ 170 Million. This is based on full allocation of levelized revenue requirements for upgrades to customers without consideration of base plan funding. AFS data table 3 reflects the allocation of upgrade costs to each request without potential base plan funding based on either the requested reservation period or the deferred reservation period if applicable. Total upgrade levelized revenue requirements for all transmission requests after consideration of potential base plan funding is $58 Million.

Third-party facilities must be upgraded when it is determined they are constrained in order to accommodate the requested Transmission Service. These include both first-tier neighboring facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are listed in Table 5.

The Transmission Provider tendered a Letter of Intent on December 10th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by December 25th, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

At the conclusion of the ATSS, Service Agreements for each request for service will be tendered identifying the terms and conditions of the confirmed service.

If customers withdraw from the ATSS after posting of this AFS, the AFS will be re-performed to determine final cost allocation and Available Transmission Capability (ATC) in consideration of the remaining ATSS participants. All allocated revenue requirements for facility upgrades are assigned to the customer in the AFS data tables. Potential base plan funding allowable is contingent upon validation of designated resources meeting Attachment J, Section III B criteria.

2. Introduction

On January 21, 2005, the Federal Energy Regulatory Commission accepted Southwest Power Pool's proposed aggregate transmission study procedures in Docket ER05-109 to become effective February 1, 2005. In compliance with this Order, the first open season of 2007 commenced on October 1, 2006. All requests for long-term transmission service received prior to February 1, 2007 with a signed study agreement were then included in this first Aggregate Transmission Service Study (ATSS) of 2007.

Approximately 1359 MW of long-term transmission service has been restudied in this Aggregate Facility Study (AFS) with over $60 Million in transmission upgrades being proposed. The results of the AFS are detailed in Tables 1 through 7. A highly tangible benefit of studying transmission requests aggregately under the SPP OATT Attachment Z1 is the sharing of costs among customers using the same facility. The detailed results show individual upgrade costs by study as well as potential base plan allowances as determined by Attachments J and Z1. The following URL can be used to access the SPP OATT: (http://www.spp.org/Publications/SPP_Tariff.pdf). In order to understand the extent to which base plan upgrades may be applied to both point-to-point and network transmission services, it is necessary to highlight the definition of Designated Resource. Per Section 1.9a of the SPP OATT, a Designated Resource is "[a]ny designated generation resource owned, purchased or leased by a Transmission Customer to serve load in the SPP Region. Designated Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Transmission Customer's load on a non-interruptible basis." Therefore, not only network service, but also point-to-point service has potential for base plan funding if the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J are met.

Pursuant to Attachment J, Section III B of the SPP OATT, the Transmission Customer must provide SPP information necessary to verify that the new or changed Designated Resource meets the following conditions:

1. Transmission Customer's commitment to the requested new or changed Designated Resource must have a duration of at least five years.

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

According to Attachment Z1 Section VI.A, Point-to-Point customers pay the higher of the monthly transmission access charge (base rate) or the monthly revenue requirement associated with the assigned facility upgrades including any prepayments for redispatch required during construction.

Network Integration Service customers pay the total monthly transmission access charges and the monthly revenue requirement associated with the facility upgrades including any prepayments for redispatch during construction.

Transmission Customers paying for a directly assigned network upgrade shall receive credits for new transmission service using the facility as specified in Attachment Z2.

Facilities identified as limiting the requested Transmission Service have been reviewed to determine the required in-service date of each Network Upgrade. The year that each Network Upgrade is required to accommodate a request is determined by interpolating between the applicable model years given the respective loading data. Both previously assigned facilities and the facilities assigned to this request for Transmission Service were evaluated.

In some instances due to lead times for engineering and construction, Network Upgrades may not be available when required to accommodate a request for Transmission Service. When this occurs, the ATC with available Network Upgrades will be less than the capacity requested during either a portion of or all of the requested reservation period. As a result, the lowest seasonal allocated ATC within the requested reservation period will be offered to the Transmission Customer on an applicable annual basis as listed in Table 1. The ATC may be limited by transmission owner planned projects, expansion plan projects, or customer assigned upgrades.

Some constraints identified in the AFS were not assigned to the Customer as the Transmission Provider determined that upgrades are not required due to various reasons or the Transmission Owner has construction plans pending for these upgrades. These facilities are listed by reservation in Table 3. This table also includes constrained facilities in the current planning horizon that limit the rollover rights of the Transmission Customer. Table 6 lists possible redispatch pairs to allow start of service prior to completion of assigned network upgrades. Table 7 (if applicable) lists deferment of expansion plan projects with different upgrades with the new required in service date as a result of this AFS.

A. <u>Financial Analysis</u>

The AFS utilizes the allocated customer E & C cost in a present worth analysis to determine the monthly levelized revenue requirement of each facility upgrade over the term of the reservation. In some cases, network upgrades cannot be completed within the requested reservation period, thus deferred reservation periods will be utilized in the present worth analysis. If the Customer chose Option 2, Redispatch, in the Letter of Intent sent coincident with the initial AFS, the present worth analysis of revenue requirements will be based on the deferred term with redispatch in the subsequent AFS. The upgrade levelized revenue requirement includes interest, depreciation, and carrying costs.

Each request for Transmission Service is evaluated independently as the cost associated with each Network Upgrade is assigned to a request. When facilities are upgraded throughout the reservation period, the Transmission Customer shall 1) pay the total E & C costs and other annual operating costs associated with the new facilities, and 2) receive credits associated with the depreciated book value of removed usable facilities, salvage value of removed non-usable facilities, and the carrying charges, excluding depreciation, associated with all removed usable facilities based on their respective book values.

In the event that the engineering and construction of a previously assigned Network Upgrade may be expedited, with no additional upgrades, to accommodate a new request for Transmission Service, then the levelized present worth of only the incremental expenses though the reservation period of the new request, excluding depreciation, shall be assigned to the new request. These incremental expenses, excluding depreciation, include 1) the levelized difference in present worth of the engineering and construction expenses given the change in date to complete construction to account for additional interest expense and reduced engineering and construction expense due to inflation, 2) the levelized present worth of all expediting fees, and 3) the levelized present worth of the incremental annual carrying charges, excluding depreciation and interest, during the new reservation period taking into account both a) the reservation in which the project was originally assigned, and b) a reservation, if any, in which the project was previously expedited.

Achievable Base Plan Avoided Revenue Requirements in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.B methodology. A deferred Base Plan upgrade being defined as a different requested network upgrade needed at an earlier date that negates the need for the initial base plan upgrade within the planning horizon. A displaced Base Plan upgrade being defined as the same network upgrade being displaced by a requested upgrade needed at an earlier date. Assumption of a 40 year service life is utilized for Base Plan funded projects unless provided otherwise by the Transmission Owner. A present worth analysis of revenue requirements on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan revenue requirements due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The difference in present worth between the Base Plan and Requested Upgrades is assigned to the transmission requests impacting this upgrade based on the displacement or deferral.

B. Third Party Facilities

For third-party facilities listed in Table 3 and Table 5, the Transmission Customer is responsible for funding the necessary upgrades of these facilities per Section 21.1 of the Transmission Provider's OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are listed in Table 5. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making arrangements for necessary engineering, permitting, and construction of the third-party facilities. Third-party facility upgrade engineering and construction cost estimates are not utilized to determine the present worth value of levelized revenue requirements for SPP system network upgrades.

All modeled facilities within the Transmission Provider system were monitored during the development of this Study as well as certain facilities in first-tier neighboring systems. Third-party facilities must be upgraded when it is determined that they are overloaded while accommodating the requested Transmission Service. An agreement between the Customer and 3rd Party Owner detailing the mitigation of the 3rd party impact must be provided to the Transmission Provider prior to tendering of a Transmission Service Agreement. These facilities also include those owned by members of the Transmission Provider who have not placed their facilities under the Transmission Provider's OATT. Upgrades on the Southwest Power Administration network requires prepayment of the upgrade cost prior to construction of the upgrade.

Third-party facilities are evaluated for only those requests whose load sinks within the SPP footprint. The Customer must arrange for study of 3rd party facilities for load that sinks outside the SPP footprint with the applicable Transmission Providers.

3. Study Methodology

A. Description

The system impact analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier Non - SPP control area systems. The steady-state analysis was done to ensure current SPP Criteria and NERC Reliability Standards requirements are fulfilled. The Southwest Power Pool conforms to the NERC Reliability Standards, which provide the strictest requirements, related to voltage violations and thermal overloads during normal conditions and during a contingency. It requires that all facilities be within normal operating ratings for normal system conditions and within emergency ratings after a contingency. Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP MDWG models, respectively. The upper bound and lower bound of the normal voltage range monitored is 105% and 95%. The upper bound and lower bound of the emergency voltage range monitored is 105% and 90%. Transmission Owner voltage monitoring criteria is used if more restrictive. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations. The WERE Wolf Creek 345 kV bus voltage is monitored at 103.5% and 98.5% due to transmission operating procedure.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non - SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the control areas with SPP reserve share program redispatch. The monitor elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non – SPP control area branches and ties 115 kV and above. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier Non – SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN, and ENTR and a 2 % TDF cutoff was applied to MEC, NPPD, and OPPD. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer or modeling upgrades to be considered a valid limit to the transfer.

B. Model Development

SPP used eleven seasonal models to study the aggregate transfers of 1359 MW over a variety of requested service periods. The SPP MDWG 2007 Series Cases Update 2 2008 April (08AP), 2008 Spring Peak (08G), 2008 Summer Peak (08SP), 2008 Summer Shoulder (08SH), 2008 Fall Peak (08FA), 2008/09 Winter Peak (08WP), 2009 Summer Peak (09SP), 2009/10 Winter Peak (09WP), 2012 Summer Peak (12SP), 2012/13 Winter Peak (12WP),and 2017 Summer Peak (17SP) were used to study the impact of the requested service on the transmission system. The Spring Peak models apply to April and May, the Summer Peak models apply to June through September, the Fall Peak models apply to October and November, and the Winter Peak models apply to December through March.

The chosen base case models were modified to reflect the most current modeling information. Five groups of requests were developed from the aggregate of 1359 MW in order to minimize counter flows among requested service. Each request was included in at least two of the four groups depending on the requested path. All requests were included in group five. From the twelve seasonal models, five system scenarios were developed. Scenario 1 includes SWPP OASIS transmission requests not already included in the SPP 2007 Series Cases flowing in a West to East direction with ERCOTN HVDC Tie South to North, ERCOTE HVDC Tie East to West, SPS exporting, and SPS importing from the Lamar HVDC Tie. Scenario 2 includes transmission requests not already included in the SPP 2007 Series Cases flowing in an East to West direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS exporting to the Lamar HVDC Tie. Scenario 3 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a South to North direction with ERCOTN HVDC tie South to North, ERCOTE HVDC tie East to West, SPS exporting, and SPS exporting to the Lamar HVDC Tie. Scenario 4 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a North to South direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC tie. Scenario 5 include all transmission not already included in the SPP 2007 Series Cases with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to the Lamar HVDC tie. The system scenarios were developed to minimize counter flows from previously confirmed, higher priority requests not included in the MDWG Base Case.

C. <u>Transmission Request Modeling</u>

Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation transfers. The Generation to Load modeling is accomplished by developing a pre-transfer case by redispatching the existing designated network resource(s) down by the new designated network resource request amount and scaling down the applicable network load by the same amount proportionally. The post-transfer case for comparison is developed by scaling the network load back to the forecasted amount and dispatching the new designated network resource being requested. Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to

Generation to Generation because the requested Network Integration Transmission Service is a request to serve network load with the new designated network resource and the impacts on transmission system are determined accordingly. If the Network Integration Transmission Service request application clearly documents that the existing designated network resource(s) is being replaced or undesignated by the new designated network resource then MW impact credits will be given to the request as is done for a redirect of existing transmission service. Point-To-Point Transmission Service requests are modeled as Generation to Generation transfers. Generation to Generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the request source and redispatching the request sink.

D. Transfer Analysis

Using the selected cases both with and without the requested transfers modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility overloads caused or impacted by the transfer. Transfer distribution factor cutoffs (SPP and 1st-Tier) and voltage threshold (0.02 change) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

E. Curtailment and Redispatch Evaluation

During any period when SPP determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission System, SPP will take whatever actions that are reasonably necessary to maintain the reliability of the Transmission System. To the extent SPP determines that the reliability of the Transmission System can be maintained by redispatching resources, SPP will evaluate interim curtailment of existing confirmed service or interim redispatch of units to provide service prior to completion of any assigned network upgrades. Any redispatch may not unduly discriminate between the Transmission Owners' use of the Transmission System on behalf of their Native Load Customers and any Transmission Customer's use of the Transmission System to serve its designated load.

Redispatch was evaluated to provide only interim service during the time frame prior to completion of any assigned network upgrades. Curtailment of existing confirmed service is evaluated to provide only interim service. Curtailment of existing confirmed service is only evaluated at the request of the transmission customer.

SPP determined potential relief pairs to relieve the incremental MW impact on limiting facilities as identified in Table 6. Using the selected cases where the limiting facilities were identified, potential incremental and decremental units were identified by determining the generation amount available for increasing and decreasing from the units generation amount, maximum generation amount, and minimum generation amount. If the incremental or decremental amount was greater than 1 MW, the unit was considered as a potential incremental or decremental unit. Generation shift factors were calculated for the potential incremental and decremental units using Managing and Utilizing System Transmission (MUST). Relief pairs from the generation shift factors for the incremental and decremental units with a greater than 3% TDF on the limiting constraint were determined from the incremental units with the lowest generation shift factors and decremental units with highest generation shift factors. If the aggregate redispatch amount for the potential relief pair was determined to be three times greater than the lower of the increment or decrement then the pair was determined not to be feasible and is not included. If transmission customer would like to see additional relief pairs beyond the relief pairs determined, the transmission customer can request SPP to provide the additional pairs. The potential relief pairs **were not** evaluated to determine impacts on limiting facilities in the SPP and 1st-Tier systems. The redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

4. Study Results

A. Study Analysis Results

Tables 1 through 6 contain the steady-state analysis results of the AFS. Table 1 identifies the participating long-term transmission service requests included in the AFS. This table lists deferred start and stop dates both with and without redispatch (based on customer selection of redispatch if available), the minimum annual allocated ATC without upgrades and season of first impact. Table 2 identifies total E & C cost allocated to each Transmission Customer, letter of credit requirements, third party E & C cost assignments, potential base plan E & C funding (lower of allocated E & C or Attachment J Section III B criteria) , total revenue requirements for assigned upgrades without consideration of potential base plan funding, point-to-point base rate charge, total revenue requirements for assigned upgrades with consideration of potential base plan funding, and final total cost allocation to the Transmission Customer. In addition, Table 2 identifies SWPA upgrade costs which require prepayment in addition to other allocated costs. Table 3 provides additional details for each request including all assigned facility upgrades required, allocated E & C costs, allocated revenue requirements for upgrades, upgrades not assigned to customer but required for service to be confirmed, credits to be paid for previously assigned AFS or GI network upgrades, and any third party upgrades required. Table 4 lists all upgrade requirements with associated solutions needed to provide transmission service for the AFS, Minimum ATC per upgrade with season of impact, Earliest Date Upgrade is required (DUN), Estimated Date the upgrade will be completed and in service (EOC), and Estimated E & C cost. Table 5 lists identified Third-Party constrained facilities. Table 6 identifies potential redispatch pairs available to relieve the aggregate impacts on identified constraints to prevent deferral of start of service. Table 7 (if applicable) identifies deferred expansion plan projects that were replaced with requested upgrades at earlier dates.

The potential base plan funding allowable is contingent upon meeting each of the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in

Section III.B of Attachment J. If the additional capacity of the new or changed designated resource exceeds the 125% resource to load forecast for the year of start of service, the requested resource is not eligible for base plan funding of required network upgrades and the full cost of the upgrades is assignable to the customer. If the 5 year term and 125% resource to load criteria are met, the lesser of the planned maximum net dependable capacity (NDC) or the requested capacity is multiplied by $180,000 to determine the potential base plan funding allowable. When calculating Base Plan Funding amounts that include a wind farm, the amount used is 10% of the requested amount of service, or the NDC. The Maximum Potential Base Plan Funding Allowable may be less than the potential base plan funding allowable due to the E & C Cost allocated to the customer being lower than the potential amount allowable to the customer. The customer is responsible for any assigned upgrade costs in excess of Potential Base Plan Engineering and Construction Funding Allowable.

Regarding application of base plan funding for PTP requests, if PTP base rate exceeds upgrade revenue requirements without taking into effect the reduction of revenue requirements by potential base plan funding, then the base rate revenue pays back the Transmission Owner for upgrades and no base plan funding is applicable as the access charge must be paid as it is the higher of "OR" pricing.

However, if initially the upgrade revenue requirements exceed the PTP base rate, then potential base plan funding would be applicable. The test of the higher of "OR" pricing would then be made against the remaining assignable revenue requirements versus PTP base rate. Examples are as follows:

Example A:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 47 million with the difference of 27 million E & C assignable to the customer. If the revenue requirements for the assignable portion is 54 million and the PTP base rate is 101 million, the customer will pay the higher "OR" pricing of 101 million base rate of which 54 million revenue requirements will be paid back to the Transmission Owners for the upgrades and the remaining revenue requirements of (140-54) or 86 million will be paid by base plan funding.

Example B:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 10 million with the difference of 64 million E & C assignable to the customer. If the revenue requirements for this assignable portion is 128 million and the PTP base rate is 101 million the customer will pay the higher "OR" pricing of 128 million revenue requirements to be paid back to the Transmission Owners and the remaining revenue requirements of (140-128) or 12 million will be paid by base plan funding.

Example C:

E & C allocated for upgrades is 25 million with revenue requirements of 50 million and PTP base rate of 101 million. Potential base plan funding is 10 million. Base plan funding is not applicable as the higher "OR" pricing of PTP base rate of 101 million must be paid and the 50 million revenue requirements will be paid from this.

The 125% resource to load determination is performed on a per request basis and is not based on a total of designated resource requests per Customer. A footnote will provide the maximum resource designation allowable for base plan funding consideration per Customer basis per year.

Base plan funding verification requires that each Transmission Customer with potential for base plan funding provide SPP attestation statements verifying that the firm capacity of the requested designated resource is committed for a minimum five year duration.

B. Study Definitions

The Date Upgrade Needed Date (DUN) is the earliest date the upgrade is required to alleviate a constraint considering all requests. End of Construction (EOC) is the estimated date the upgrade will be completed and in service. The Total Engineering and Construction Cost (E & C) is the upgrade solution cost as determined by the transmission owner. The Transmission Customer Allocation Cost is the estimated engineering and construction cost based upon the allocation of costs to all Transmission Customers in the AFS who positively impact facilities by at least 3% subsequently overloaded by the AFS. Minimum ATC is the portion of the requested capacity that can be accommodated with out upgrading facilities. Annual ATC allocated to the Transmission Customer is determined by the least amount of allocated seasonal ATC within each year of a reservation period.

5. Conclusion

The results of the AFS show that limiting constraints exist in many areas of the regional transmission system. Due to these constraints, transmission service cannot be granted unless noted in Table 3.

The Transmission Provider tendered a Letter of Intent on December 10th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by December 25th, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

The Transmission Provider must receive an unconditional and irrevocable letter of credit in the amount of the total allocated Engineering and Construction costs assigned to the Customer. This letter of credit is not required for those facilities that are base plan funded. This amount is for all assignable Network Upgrades less pre-payment requirements. The amount of the letter of credit will be adjusted down on an annual basis to reflect amortization of these costs. The Transmission Provider will issue notifications to construct facility upgrades to the constructing Transmission Owner. This date is determined by the engineering and construction lead time provided for each facility upgrade.

6. Appendix A

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASES:
Solutions - Fixed slope decoupled Newton-Raphson solution (FDNS)
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits – Apply immediately
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

ACCC CASES:
Solutions – AC contingency checking (ACCC)
MW mismatch tolerance – 0.5
Contingency case rating – Rate B
Percent of rating – 100
Output code – Summary
Min flow change in overload report – 3mw
Excld cases w/ no overloads form report – YES
Exclude interfaces from report – NO
Perform voltage limit check – YES
Elements in available capacity table – 60000
Cutoff threshold for available capacity table – 99999.0
Min. contng. case Vltg chng for report – 0.02
Sorted output – None
Newton Solution:
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits - Apply automatically
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

Table 1 - Long-Term Transmission Service Requests Included in Aggregate Facility Study

Customer	Study Number	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date without interim redispatch	Deferred Stop Date without interim redispatch	Start Date with interim redispatch	Stop Date with interim redispatch	Minimum Allocated ATC (MW) withing reservation period	Season of Minimum Allocated ATC within reservation period
EDE	AG1-2007-051	1222640	WPEK	EDE	100	11/1/2008	11/1/2028	6/1/2013	6/1/2033	2/1/2009	2/1/2029	0	09SP
INDP	AG1-2007-045	1221966	OPPD	INDN	6	6/1/2009	6/1/2034	6/1/2011	6/1/2036	6/1/2009	6/1/2034	0	09SP
KBPU	AG1-2007-043D	1221923	SPA	KACY	39	7/1/2010	7/1/2020	6/1/2011	6/1/2021	7/1/2010	7/1/2020	0	17SP
KBPU	AG1-2007-044D	1221925	WR	KACY	25	1/1/2008	1/1/2028	6/1/2011	6/1/2031	5/1/2009	5/1/2029	0	08SP
KCPS	AG1-2007-080	1223159	KCPL	EES	52	6/1/2007	6/1/2012	6/1/2011	6/1/2016	5/1/2009	5/1/2014	0	07SP
KPP	AG1-2007-052	1222644	WR	WR	333	6/1/2007	6/1/2017	4/1/2014	4/1/2024	5/1/2009	5/1/2019	0	07SP
KPP	AG1-2007-054	1222904	WPEK	WPEK	3	6/1/2007	6/1/2017	1/1/2011	1/1/2021	5/1/2009	5/1/2019	0	07SP
KPP	AG1-2007-055	1222932	WR	WR	45	6/1/2007	6/1/2027	4/1/2014	4/1/2034	5/1/2009	5/1/2029	0	07SP
KPP	AG1-2007-056	1222937	WR	WPEK	5	6/1/2007	6/1/2027	1/1/2011	1/1/2031	5/1/2009	5/1/2029	0	07SP
KPP	AG1-2007-058	1222955	WR	WR	20	6/1/2007	6/1/2017	4/1/2014	4/1/2024	5/1/2009	5/1/2019	0	07SP
KPP	AG1-2007-064	1223078	WPEK	WPEK	15	6/1/2007	6/1/2017	1/1/2011	1/1/2021	5/1/2009	5/1/2019	0	07SP
SPRM	AG1-2007-042	1220082	SPA	SPA	275	10/1/2010	10/1/2050	10/1/2010	10/1/2050	10/1/2010	10/1/2050	0	17SP
UCU	AG1-2007-025D	1214263	MPS	WR	1	6/1/2007	6/1/2012	6/1/2011	6/1/2016	5/1/2009	5/1/2014	0	07SP
UCU	AG1-2007-023D	1214269	MPS	KCPL	2	6/1/2007	6/1/2012	6/1/2011	6/1/2016	5/1/2009	5/1/2014	0	07SP
UCU	AG1-2007-060D	1223092	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
UCU	AG1-2007-060D	1223093	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
UCU	AG1-2007-060D	1223094	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
UCU	AG1-2007-060D	1223095	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
WRGS	AG1-2007-001D	1197077	EDE	WR	32	9/1/2007	9/1/2018	6/1/2013	6/1/2024	6/1/2013	6/1/2024	0	08SP
WRGS	AG1-2007-047D	1222005	WR	EES	106	10/1/2007	10/1/2010	6/1/2011	6/1/2014	5/1/2009	5/1/2012	0	08SP
					1359								

Note 1: Disregard Redispatch shown in Table 6 for limitations identified earlier than the start date with redispatch with the exception of limitations identified in the 2008 Summer Shoulder, and 2008 Fall Peak

Note 2: Start and Stop Dates with interim redispatch are determined based on customers choosing option to pursue redispatch to start service at Requested Start and Stop Dates or earliest date possible.

Table 2 - Total Revenue Requirements Associated with Long-Term Transmission Service Requests

Customer	Study Number	Reservation	Engineering and Construction Cost of Upgrades Allocated to Customer for Revenue Requirements	[1]Letter of Credit Amount Required	[2]Potential Base Plan Engineering and Construction Funding Allowable	Notes	[4]Additional Engineering and Construction Cost for 3rd Party Upgrades	[3] Total Revenue Requirements for Assigned Upgrades Over Term of Reservation WITHOUT Potential Base Plan Funding Allocation	[3 5] Total Revenue Requirements for Assigned Upgrades Over Term of Reservation WITH Potential Base Plan Funding Allocation	Point-to-Point Base Rate Over Reservation Period	[4]Total Cost of Reservation Assignable to Customer Contingent Upon Base Plan Funding
EDE	AG1-2007-051	1222640	$ 14,074	$ -	$ 14,074		$ -	$ 51,511	$ -	$ -	Schedule 9 Charges
INDP	AG1-2007-045	1221966	$ 60,805	$ -	$ -			$ 301,338	$ 301,338	$ 1,584,000	$ 1,584,000
KBPU	AG1-2007-043D	1221923	$ 1,531,640	$ -	$ -			$ 4,115,216	$ 4,115,216	$ 4,118,400	$ 4,118,400
KBPU	AG1-2007-044D	1221925	$ 202,479	$ -	$ -			$ 840,070	$ 840,070	$ 5,280,000	$ 5,280,000
KCPS	AG1-2007-080	1223159	$ -	$ -	$ -			$ -	$ -	$ 2,964,000	$ 2,964,000
KPP	AG1-2007-052	1222644	$ 33,385,752	$ -	$ 33,385,752			$ 77,517,217	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-054	1222904	$ -	$ -	$ -			$ -	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-055	1222932	$ 10,731,093	$ -	$ 10,731,093			$ 33,976,175	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-056	1222937	$ 24,921	$ -	$ 24,921			$ 85,863	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-058	1222955	$ -	$ -	$ -			$ -	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-064	1223078	$ -	$ -	$ -			$ -	$ -	$ -	Schedule 9 Charges
SPRM	AG1-2007-042	1220082	$ 120,000	$ -	$ 120,000			$ 619,237	$ -	$ -	Schedule 9 Charges
UCU	AG1-2007-023D	1214269	$ 179	$ -	$ -			$ 389	$ 389	$ 105,600	$ 105,600
UCU	AG1-2007-025D	1214263	$ 3,807	$ -	$ -			$ 8,220	$ 8,220	$ 143,940	$ 143,940
UCU	AG1-2007-060D	1223092	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
UCU	AG1-2007-060D	1223093	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
UCU	AG1-2007-060D	1223094	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
UCU	AG1-2007-060D	1223095	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
WRGS	AG1-2007-001D	1197077	$ 28,867	$ -	$ 28,867		$ -	$ 73,595	$ -	$ -	Schedule 9 Charges
WRGS	AG1-2007-047D	1222005	$ 637,995	$ -	$ -			$ 1,248,037	$ 1,248,037	$ 3,625,200	$ 3,625,200
Grand Total			$ 60,221,920		$ 44,304,707			$ 170,209,076	$ 57,885,477		

Table 2 - Total Revenue Requirements Associated with Long-Term Transmission Service Requests

Note 1: Letter of Credit required for financial security for transmission owner for network upgrades is determined by allocated engineering and construction costs less engineering and construction costs for upgrades when network customer is the transmission owner less the E & C allocation of expedited projects. Letter of Credit is not required for base plan funded upgrades or if upgrades are funded by point to point base rate. The Letter Of Credit Amount listed is based on meeting OATT Attachment J requirements for base plan funding.

Note 2. If potential base plan funding is applicable, this value is the lesser of the Engineering and Construction costs of assignable upgrades or the value of base plan funding calculated pursuant to Attachment J, Section III B criteria. Allocation of base plan funding is contingent upon verification of customer agreements meeting Attachment J, Section II B criteria. Not applicable if Point-to-Point base rate exceeds revenue requirements.

Note 3: Revenue Requirements (RR) are based upon deferred end dates if applicable. Deferred dates are based upon customer's choice to pursue redispatch. Achievable Base Plan Avoided RR in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.C methodology. Assumption of a 40 year service life is utilized for Base Plan funded projects. A present worth analysis of RR on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan RR due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The incremental increase in present worth of a Requested Upgrade on a common year basis as a Base Plan upgrade is assigned to the transmission requests impacting the upgrade based on the displacement or deferral. If the displacement analysis results in lower RR due to the shorter amortization period of the requested upgrade when compared to a base plan amortization period, then no direct assignment of the upgrade cost is made due to the displacement to an earlier start date.

Note 4. For Point-to-Point requests, total cost is based on the higher of the base rate or assigned upgrade revenue requirements. For Network requests, the total cost is based on the assigned upgrade revenue requirement. Allocation of base plan funding will be determined after verification of designated resource meeting Attachment J, Section II B Criteria. Additionally E & C of 3rd Party upgrades is assignable to Customer. This includes prepayments required for any SWPA upgrades. Revenue requirements for 3rd Party facilities are not calculated. Total cost to customer is based on assumption of Revenue Requirements with confirmation of base plan funding. Customer is responsible for negotiating redispatch costs if applicable. Customer is also responsible to pay credits for previously assigned upgrades that are impacted by their request. Credits can be paid from base plan funding if applicable.

Note 5: RR with base plan funding may increase or decrease even if no base plan funding is applicable to a particular request if another request that shares the upgrade is now full base plan funded resulting in a different amortization period for the upgrade and thus different RR.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
EDE	AG1-2007-051

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
EDE	1222640	WPEK	EDE	100	11/1/2008	11/1/2028	6/1/2013	6/1/2033	$ 14,074	$ -	$ 14,074	$ 51,511
									$ 14,074	$ -	$ 14,074	$ 51,511

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222640	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 14,074	$ 50,000	$ 51,511
					Total	$ 14,074	$ 50,000	$ 51,511

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BULL SHOALS - BULL SHOALS 161KV CKT 1	6/1/2009	6/1/2011		Yes
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	6/1/2017	6/1/2017		
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	6/1/2015	6/1/2015		
	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161KV CKT 1	6/1/2015	6/1/2015		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 EMDE	6/1/2014	6/1/2012		
	KERR - PENSACOLA 115KV CKT 1	12/1/2012	6/1/2011		
	Multi - Stateline - Joplin - Reinmiller conversion	6/1/2012	6/1/2013		Yes
	SUB 124 - AURORA H.T. - SUB 152 - MONETT H.T. 69KV CKT 1	6/1/2009	6/1/2010	10/1/2009	
	SUB 145 - JOPLIN WEST 7TH - SUB 64 - JOPLIN 10TH ST. 69KV CKT 1	6/1/2010	6/1/2010		
	SUB 170 - NICHOLS ST. - SUB 80 - SEDALIA 69KV CKT 1	6/1/2012	6/1/2012		
	SUB 271 - BAXTER SPRINGS WEST - SUB 404 - HOCKERVILLE 69KV CKT 1	12/1/2010	6/1/2010		

Planned Projects

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	6/1/2013	6/1/2012		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

*EMDE has worked out a contractual arrangement regarding the Huben transformer with AECI. The executed contractual arrangement between AECI and EMDE will facilitate the ability of SPP to provide the firm transmission service to EMDE.
**Entergy limitations were identified through the ICT Affected System Study ASA-2008-003. ST. JOE – HILL TOP 161KV CKT 1 and EVERTON - HARRISON-EAST 161KV CKT 1 can be mitigated by redispatch identified in Table 6.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer INDP
Study Number AG1-2007-045

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
INDP	1221966	OPPD	INDN	6	6/1/2009	6/1/2034	6/1/2011	6/1/2036	$ -	$ 1,584,000	$ 60,805	$ 301,338
									$ -	$ 1,584,000	$ 60,805	$ 301,338

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221966	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes*	$ 40,075	$ 4,400,000	$ 204,509
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 748	$ 50,000	$ 3,279
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes*	$ 19,982	$ 2,200,000	$ 93,550
					Total	$ 60,805	$ 6,650,000	$ 301,338

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221966	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes*
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes*
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	SUBSTATION M 161/69KV TRANSFORMER CKT 2	6/1/2010	6/1/2011	10/1/2010	Yes*

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221966	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	MERRIAM - ROELAND PARK 161KV CKT 1	6/1/2017	6/1/2017		

*Requested evaluation of the curtailment of existing service is provided in addition to redispatch in report tables. Refer to INDN Curtailment tab.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
KBPU	AG1-2007-043D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KBPU	1221923	SPA	KACY	39	7/1/2010	7/1/2020	6/1/2011	6/1/2021	$ -	$ 4,118,400	$ 1,531,640	$ 4,115,216
									$ -	$ 4,118,400	$ 1,531,640	$ 4,115,216

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221923	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 498,594	$ 8,400,000	$ 1,299,516
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 777,569	$ 13,100,000	$ 1,984,267
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 147,349	$ 4,400,000	$ 493,877
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,317	$ 50,000	$ 9,716
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 104,811	$ 2,200,000	$ 327,840
					Total	$ 1,531,640	$ 28,150,000	$ 4,115,216

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KBPU	AG1-2007-044D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KBPU	1221925	WR	KACY	25	1/1/2008	1/1/2028	6/1/2011	6/1/2031	$ -	$ 5,280,000	$ 202,479	$ 840,070
									$ -	$ 5,280,000	$ 202,479	$ 840,070

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221925	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 99,516	$ 4,400,000	$ 430,008
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 4,420	$ 50,000	$ 16,529
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 98,543	$ 2,200,000	$ 393,533
					Total	$ 202,479	$ 6,650,000	$ 840,070

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KCPS
Study Number AG1-2007-080

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KCPS	1223159	KCPL	EES	52	6/1/2007	6/1/2012	6/1/2011	6/1/2016	$ -	$ 2,964,000	$ -	$ -
									$ -	$ 2,964,000	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223159	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
KPP	AG1-2007-052

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222644	WR	WR	333	6/1/2007	6/1/2017	4/1/2014	4/1/2024	$ 33,385,752	$ -	$ 33,385,752	$ 77,517,217
									$ 33,385,752	$ -	$ 33,385,752	$ 77,517,217

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222644	ALLEN - LEHIGH TAP 69KV CKT 1	6/1/2009	6/1/2012		Yes	$ 2,040,323	$ 2,560,500	$ 4,629,105
	ALLEN 69KV Capacitor	5/1/2009	6/1/2012		Yes***	$ 491,390	$ 607,500	$ 1,177,343
	ALTOONA EAST 69KV Capacitor	6/1/2009	6/1/2014			$ 350,750	$ 607,500	$ 862,348
	ATHENS 69KV Capacitor	5/1/2009	6/1/2013		Yes***	$ 491,390	$ 607,500	$ 1,139,251
	Athens to Owl Creek 69 kV	5/1/2009	4/1/2011		Yes***	$ 1,194,323	$ 1,418,500	$ 2,813,948
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 3,920,148	$ 8,400,000	$ 9,280,660
	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	5/1/2009	7/1/2013		Yes***	$ 2,808,717	$ 3,340,000	$ 6,494,183
	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	5/1/2009	1/1/2013		Yes***	$ 1,306,071	$ 1,945,000	$ 3,069,608
	CHANUTE TAP - TIOGA 69KV CKT 1	6/1/2010	6/1/2010			$ 92,996	$ 115,000	$ 224,973
	~~CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1~~	~~6/1/2009~~	~~6/1/2011~~		~~Yes~~	~~$ 1,467,168~~	~~$ 1,800,000~~	~~$ 3,501,701~~
	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	5/1/2009	4/1/2014		Yes***	$ 3,573,125	$ 4,249,000	$ 8,055,645
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 458,585	$ 600,000	$ 1,109,394
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 6,113,563	$ 13,100,000	$ 14,170,900
	Green to Vernon 69 kV	5/1/2009	7/1/2010		Yes***	$ 2,804,933	$ 3,335,500	$ 6,768,017
	LEHIGH TAP - OWL CREEK 69KV CKT 1	5/1/2009	12/1/2011		Yes***	$ 3,209,137	$ 3,811,500	$ 7,400,336
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	6/1/2009	6/1/2011		Yes***	$ 483,983	$ 593,775	$ 1,178,500
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 183,112	$ 250,000	$ 493,839
	Rice County to Ellinwood 34.5KV	6/1/2009	6/1/2010		Yes***	$ 1,331,292	$ 1,812,500	$ 2,587,479
	TIOGA 69KV Capacitor	5/1/2009	6/1/2011			$ 491,390	$ 607,500	$ 1,216,105
	Vernon to Athens 69 kV	5/1/2009	1/1/2011		Yes***	$ 2,040,524	$ 2,426,500	$ 4,845,584
					Total	$ 33,385,752	$ 50,387,775	$ 77,517,217

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	Fort Scott 161/69kV Transformer CKT 1	6/1/2010	6/1/2010		
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	6/1/2009	12/1/2010		Yes
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	6/1/2009	6/1/2011		Yes***
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012		Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013		Yes
	Sumner County to Timber Junction 138/69 kV	6/1/2009	6/1/2011		Yes***

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		

*Reservation 1222644 and 1222955 were studied as one request
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KPP
Study Number AG1-2007-054

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222904	WPEK	WPEK	3	6/1/2007	6/1/2017	1/1/2011	1/1/2021	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222904	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Reservation 1223078 and 1222904 were studied as one request

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
KPP	AG1-2007-055

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222932	WR	WR	45	6/1/2007	6/1/2027	4/1/2014	4/1/2034	$ 10,731,093	$ -	$ 10,731,093	$ 33,976,175
									$ 10,731,093	$ -	$ 10,731,093	$ 33,976,175

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222932	ALLEN - LEHIGH TAP 69KV CKT 1	6/1/2009	6/1/2012		Yes	$ 520,177	$ 2,560,500	$ 1,590,294
	ALLEN 69KV Capacitor	5/1/2009	6/1/2012		Yes***	$ 116,110	$ 607,500	$ 374,865
	ALTOONA EAST 69KV Capacitor	6/1/2009	6/1/2014			$ 256,750	$ 607,500	$ 850,596
	~~ARKANSAS CITY - PARIS 69KV CKT 1 #1 Displacement~~	~~6/1/2009~~	~~6/1/2010~~	~~10/1/2009~~	~~Yes~~	~~$ 3,983~~	~~$ 3,983~~	~~$ 14,435~~
	ATHENS 69KV Capacitor	5/1/2009	6/1/2013		Yes***	$ 116,110	$ 607,500	$ 362,736
	Athens to Owl Creek 69 kV	5/1/2009	4/1/2011		Yes***	$ 224,177	$ 1,418,500	$ 711,727
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,006,487	$ 8,400,000	$ 3,314,094
	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	5/1/2009	7/1/2013		Yes***	$ 531,283	$ 3,340,000	$ 1,655,277
	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	5/1/2009	1/1/2013		Yes***	$ 638,929	$ 1,945,000	$ 2,023,471
	CHANUTE TAP - TIOGA 69KV CKT 1	6/1/2010	6/1/2010			$ 22,004	$ 115,000	$ 71,729
	~~CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1~~	~~6/1/2009~~	~~6/1/2011~~		~~Yes~~	~~$ 332,832~~	~~$ 1,800,000~~	~~$ 1,070,416~~
	CITY OF WINFIELD - RAINBOW 69KV CKT 1	6/1/2009	6/1/2011		Yes***	$ 1,645,279	$ 1,645,279	$ 5,240,607
	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	5/1/2009	4/1/2014		Yes***	$ 675,875	$ 4,249,000	$ 2,053,273
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 133,906	$ 600,000	$ 436,510
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,569,640	$ 13,100,000	$ 5,060,382
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 4,834	$ 50,000	$ 18,077
	~~CRESWELL - OAK 69KV CKT 1 #1 Displacement~~	~~6/1/2009~~	~~6/1/2010~~	~~10/1/2009~~	~~Yes~~	~~$ 13,655~~	~~$ 13,655~~	~~$ 48,696~~
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 156,994	$ 201,238	$ 540,449
	Green to Vernon 69 kV	5/1/2009	7/1/2010		Yes***	$ 530,567	$ 3,335,500	$ 1,725,073
	LEHIGH TAP - OWL CREEK 69KV CKT 1	5/1/2009	12/1/2011		Yes***	$ 602,363	$ 3,811,500	$ 1,871,758
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	6/1/2009	6/1/2011			$ 109,792	$ 593,775	$ 360,245
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 63,914	$ 250,000	$ 232,270
	~~OAK - RAINBOW 69KV CKT 1~~	~~6/1/2009~~	~~6/1/2011~~	~~10/1/2010~~	~~Yes***~~	~~$ 1,900,000~~	~~$ 1,900,000~~	~~$ 6,051,954~~
	~~OXFORD 138KV Capacitor Displacement~~	~~6/1/2009~~	~~6/1/2011~~		~~Yes***~~	~~$ 17,871~~	~~$ 27,618~~	~~$ 57,475~~
	Rice County to Ellinwood 34.5KV	6/1/2009	6/1/2010		Yes***	$ 481,208	$ 1,812,500	$ 1,270,649
	TIMBER JCT CAP BANK	6/1/2009	6/1/2011		Yes***	$ 822,608	$ 1,215,000	$ 2,589,813
	TIOGA 69KV Capacitor	5/1/2009	6/1/2011			$ 116,110	$ 607,500	$ 387,206
	Vernon to Athens 69 kV	5/1/2009	1/1/2011		Yes***	$ 385,976	$ 2,426,500	$ 1,235,074
					Total	$ 10,731,093	$ 53,499,292	$ 33,976,175

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	6/1/2015	6/1/2015		
	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	6/1/2015	6/1/2015		
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	Fort Scott 161/69kV Transformer CKT 1	6/1/2010	6/1/2010		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	KELLY - SOUTH SENECA 115KV CKT 1	5/1/2009	1/1/2011		Yes
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	~~RICHLAND - ROSE HILL JUNCTION 69KV CKT 1~~	~~4/1/2009~~	~~6/1/2011~~		~~Yes***~~
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	6/1/2009	12/1/2010		Yes
	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2016	6/1/2016		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	6/1/2017	6/1/2017		
	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CHASE - WHITE JUNCTION 69KV CKT 1	6/1/2009	6/1/2010		Yes
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	6/1/2009	6/1/2011		Yes***
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	Sumner County to Timber Junction 138/69 kV	6/1/2009	6/1/2011		Yes***

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

*A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-056

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222937	WR	WPEK	5	6/1/2007	6/1/2027	1/1/2011	1/1/2031	$ 24,921	$ -	$ 24,921	$ 85,863
									$ 24,921	$ -	$ 24,921	$ 85,863

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222937	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 243	$ 50,000	$ 909
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 24,678	$ 201,238	$ 84,954
					Total	$ 24,921	$ 251,238	$ 85,863

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	6/1/2015	6/1/2015		
	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	6/1/2015	6/1/2015		
	Cimarron Plant Substation Expansion	6/1/2012	1/1/2010		
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		Yes***
	HOLCOMB - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	KELLY - SOUTH SENECA 115KV CKT 1	5/1/2009	1/1/2011		Yes
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	PIONEER TAP - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2016	6/1/2016		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	6/1/2017	6/1/2017		
	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	CHASE - WHITE JUNCTION 69KV CKT 1	6/1/2009	6/1/2010		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 MIDW	6/1/2016	6/1/2016		
	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 WERE	6/1/2016	6/1/2016		
	HUNTSVILLE - ST_JOHN 115KV CKT 1	6/1/2016	6/1/2016		
	NORTH CIMARRON CAPACITOR	6/1/2012	12/1/2008		
	PRATT - ST JOHN 115KV CKT 1	6/1/2017	6/1/2017		
	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	6/1/2015	6/1/2015		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

**A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-058

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222955	WR	WR	20	6/1/2007	6/1/2017	4/1/2014	4/1/2024	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222955	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Reservation 1222644 and 1222955 were studied as one request

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-064

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1223078	WPEK	WPEK	15	6/1/2007	6/1/2017	1/1/2011	1/1/2021	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223078	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	Cimarron Plant Substation Expansion	6/1/2012	1/1/2010		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		Yes***
	HOLCOMB - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	KELLY - SOUTH SENECA 115KV CKT 1	5/1/2009	1/1/2011		Yes
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	PIONEER TAP - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	NORTH CIMARRON CAPACITOR	6/1/2012	12/1/2008		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

*Reservation 1223078 and 1222904 were studied as one request
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

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Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
SPRM	AG1-2007-042

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
SPRM	1220082	SPA	SPA	275	10/1/2010	10/1/2050			$ 120,000	$ -	$ 120,000	$ 619,237
									$ 120,000	$ -	$ 120,000	$ 619,237

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1220082	BROOKLINE - JUNCTION 161KV CKT 1	6/1/2013	6/1/2013			$ 120,000	$ 120,000	$ 619,237
					Total	$ 120,000	$ 120,000	$ 619,237

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	KICKAPOO - SUNSET 69KV CKT 1	6/1/2014	6/1/2012		
	NEERGARD - NORTON 69KV CKT 1	10/1/2010	6/1/2010		
	SPRINGFIELD (SPF X1) 161/69/13.8KV TRANSFORMER CKT 1	6/1/2016	6/1/2016		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	JAMES RIVER - TWIN OAKS 69KV CKT 1	6/1/2015	6/1/2014		

Planned Projects

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	6/1/2013	6/1/2012		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
UCU	AG1-2007-023D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1214269	MPS	KCPL	2	6/1/2007	6/1/2012	6/1/2011	6/1/2016	$ -	$ 105,600	$ 179	$ 389
									$ -	$ 105,600	$ 179	$ 389

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1214269	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 179	$ 50,000	$ 389
					Total	$ 179	$ 50,000	$ 389

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
UCU	AG1-2007-025D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1214263	MPS	WR	1	6/1/2007	6/1/2012	6/1/2011	6/1/2016	$ -	$ 143,940	$ 3,807	$ 8,220
									$ -	$ 143,940	$ 3,807	$ 8,220

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1214263	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 589	$ 600,000	$ 1,208
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 2,874	$ 201,238	$ 6,225
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 344	$ 250,000	$ 787
					Total	$ 3,807	$ 1,051,238	$ 8,220

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV	6/1/2009	6/1/2011		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
UCU	AG1-2007-060D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1223092	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
UCU	1223093	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
UCU	1223094	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
UCU	1223095	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
									$ -	$ 115,992,000	$ 13,480,308	$ 51,372,210

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223092	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052
1223093	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052
1223094	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052
1223095	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
1223093	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
1223094	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
1223095	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes
1223093	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes
1223094	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes
1223095	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
1223093	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
1223094	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
1223095	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		
1223093	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		
1223094	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		
1223095	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Third Party Limitations.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Start Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1223092	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000
1223093	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000
1223094	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000
1223095	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer WRGS
Study Number AG1-2007-001D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
WRGS	1197077	EDE	WR	32	9/1/2007	9/1/2018	6/1/2013	6/1/2024	$ 28,867	$ -	$ 28,867	$ 73,595
									$ 28,867	$ -	$ 28,867	$ 73,595

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1197077	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 6,920	$ 600,000	$ 17,279
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 16,692	$ 201,238	$ 44,015
	LITCHFIELD - AQUARIUS - HUDSON JUNCTION 69KV CKT 1 Displacement	6/1/2014	6/1/2014			$ 2,626	$ 2,626	$ 4,983
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 2,629	$ 250,000	$ 7,318
					Total	$ 28,867	$ 1,053,864	$ 73,595

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	6/1/2017	6/1/2017		
	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	Fort Scott 161/69kV Transformer CKT 1	6/1/2010	6/1/2010		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	6/1/2015	6/1/2015		
	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161KV CKT 1	6/1/2015	6/1/2015		
	SUB 389 - JOPLIN SOUTHWEST - SUB 422 - JOPLIN 24TH & CONNECTICUT 161KV CKT 1	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV	6/1/2009	6/1/2011		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	Multi - Stateline - Joplin - Reinmiller conversion	6/1/2012	6/1/2013		
	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	6/1/2015	6/1/2015		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012		
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013		
	SUB 124 - AURORA H.T. - SUB 383 - MONETT 161KV CKT 1	6/1/2017	6/1/2017		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	12/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
WRGS	AG1-2007-047D

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
WRGS	1222005	WR	EES	106	10/1/2007	10/1/2010	6/1/2011	6/1/2014	$ -	$ 3,625,200	$ 637,995	$ 1,248,037
									$ -	$ 3,625,200	$ 637,995	$ 1,248,037

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222005	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 9,401	$ 50,000	$ 18,786
	~~OXFORD 138KV Capacitor Displacement~~	~~6/1/2009~~	~~6/1/2011~~			~~$ 9,747~~	~~$ 27,618~~	~~$ 18,402~~
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes****	$ 236,202	$ 2,200,000	$ 504,055
	TIMBER JCT CAP BANK	6/1/2009	6/1/2011			$ 392,392	$ 1,215,000	$ 725,196
					Total	$ 637,995	$ 3,465,000	$ 1,248,037

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes****
	~~SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1~~	~~6/1/2016~~	~~6/1/2016~~		
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes****
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	CHASE - WHITE JUNCTION 69KV CKT 1	6/1/2009	6/1/2010		
	Sumner County to Timber Junction 138/69 kV	6/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

****Requested evaluation of the curtailment of existing service is provided in addition to redispatch in report tables. Refer to WRGS Curtailment tab.

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AEPW	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	Rebuild 8.37 miles of 795 ACSR with 1590 ACSR & reset relays @ BSE	6/1/2009	6/1/2011	$8,400,000.00
AEPW	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	Rebuild 13.11 miles of 795 ACSR with 1590 ACSR.	6/1/2009	6/1/2011	$13,100,000.00
KACP	Craig 161kV 20MVar Cap Bank Upgrade	Additional 20 MVAR to make a total of 70 MVAR at Craig 542978	6/1/2011	6/1/2011	$50,000.00
	REDEL - STILWELL 161KV CKT 1	Reconductor line with 1192 ACSS and upgrade terminal equipment for 2000 amps	6/1/2009	6/1/2011	$2,200,000.00
MIDW	Rice County to Ellinwood 34.5KV	Rebuild 14.5 miles of 34.5 kV line between Rice County to Ellinwood	6/1/2009	6/1/2010	$1,812,500.00
SJLP	COOK - ST JOE 161KV CKT 1	Conductor, Switch, Relay	6/1/2010	6/1/2011	$4,400,000.00
SPRM	BROOKLINE - JUNCTION 161KV CKT 1	Brookline: Replace 1,200 amp switches with 2,000 amp units and replace metering CTs. Junction: Replace 1,200 amp switches with 2,000 amp units.	6/1/2013	6/1/2013	$120,000.00
WERE	ALLEN - LEHIGH TAP 69KV CKT 1	Tear down / Rebuild 5.69-mile line; 954-KCM ACSR	6/1/2009	6/1/2012	$2,560,500.00
WERE	ALLEN 69KV Capacitor	Allen 69 kV 15 MVAR Capacitor Addition	5/1/2009	6/1/2012	$607,500.00
WERE	ALTOONA EAST 69KV Capacitor	ALTOONA EAST 69KV 6 MVAR Capacitor Addition	6/1/2009	6/1/2014	$607,500.00
~~WERE~~	~~ARKANSAS CITY - PARIS 69KV CKT 1 #1 Displacement~~	~~Replace Disconnect Switches and Bus Jumpers at Paris and Ark City 69 kV substations~~	~~6/1/2009~~	~~6/1/2010~~	~~$ 3,983~~
WERE	ATHENS 69KV Capacitor	Athens 69 kV 15 MVAR Capacitor Addition	5/1/2009	6/1/2013	$607,500.00
WERE	Athens to Owl Creek 69 kV	Rebuild 2.93 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	4/1/2011	$1,418,500.00
WERE	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	Rebuild 7.2 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	7/1/2013	$3,340,000.00
WERE	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	Rebuild 4.1 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	1/1/2013	$1,945,000.00
WERE	CHANUTE TAP - TIOGA 69KV CKT 1	Replace Jumpers	6/1/2010	6/1/2010	$115,000.00
~~WERE~~	~~CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1~~	~~Tear down / Rebuild 4-mile 69 kV line; 954 kcmiol ACSR~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 1,800,000~~
~~WERE~~	~~CITY OF WINFIELD - RAINBOW 69KV CKT 1~~	~~Rebuild 3.99-mile Rainbow-Winfield 69 kV line, 954 ACSR~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 1,645,279~~
WERE	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	Rebuild 9.22 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	4/1/2014	$4,249,000.00
WERE	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers	6/1/2010	6/1/2010	$600,000.00
~~WERE~~	~~CRESWELL - OAK 69KV CKT 1 #1 Displacement~~	~~Replace jumpers and bus, and reset CTs and relaying. Rebuild substations.~~	~~6/1/2009~~	~~6/1/2010~~	~~$ 13,655~~
WERE	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers	6/1/2010	6/1/2010	$201,238.00
WERE	Green to Vernon 69 kV	Rebuild 7.19 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	7/1/2010	$3,335,500.00
WERE	LEHIGH TAP - OWL CREEK 69KV CKT 1	Tear down / Rebuild 8.47-mile 69 kV line with 954-KCM ACSR (138kV/69kV Operation)	5/1/2009	12/1/2011	$3,811,500.00
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	Tear down / Rebuild 0.91-mile 69 kV line; 954-KCM ACSR (138kV/69kV Operation)	6/1/2009	6/1/2011	$593,775.00
WERE	LITCHFIELD - AQUARIUS - HUDSON JUNCTION 69KV CKT 1 Displacement	Replace 69 kV disconnect switches at Aquarius.	6/1/2014	6/1/2014	$2,626.00
WERE	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	Replace bus and Jumpers at NE Parsons 138 kV substation	6/1/2011	6/1/2011	$250,000.00
~~WERE~~	~~OAK - RAINBOW 69KV CKT 1~~	~~Tear down / Rebuild 5.10-mile Oak-Rainbow 69 kV using 954 kcmil ACSR~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 1,900,000~~
~~WERE~~	~~OXFORD 138KV Capacitor Displacement~~	~~Install 30 MVAR Capacitor Bank at Oxford 138 kV~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 27,618~~
WERE	TIMBER JCT 138 kV Capacitor	Install 30 MVAR Cap bank at new Timber Junction 138kV	6/1/2009	6/1/2011	$1,215,000.00
WERE	TIOGA 69KV Capacitor	Tioga 69 kV 15 MVAR Capacitor Addition	5/1/2009	6/1/2011	$607,500.00
WERE	Vernon to Athens 69 kV	Rebuild 5.17 miles with 954 KCM-ACSR (138kV/69kV Operation)	5/1/2009	1/1/2011	$2,426,500.00

Construction Pending Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	Tie Line, Reconductor 1.09 miles of 795 ACSR with 1590 ACSR.	6/1/2009	6/1/2010
AEPW	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	Rebuild 7.43 miles of 250 CWC with 795 ACSR	6/1/2009	6/1/2009
OKGE	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	Rebuild 7.43 miles of 250 CWC with 795 ACSR	6/1/2009	6/1/2009
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	Reconductor Clarksville-Dardanelle line	6/1/2012	6/1/2012
WERE	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	Tie Line, Rebuild 3.93 miles of 795 ACSR with 1590 ACSR.	6/1/2009	6/1/2010
WERE	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	Add third 345-138 kV transformer at Rose Hill	5/1/2009	6/1/2011

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
SPRM	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1: Reconductor 161kV Line 1192 MCM AAC to 954 kcmil ACSS/TW 0.67 miles and Upgrade Teminal Equipment	6/1/2013	6/1/2012

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Expansion Plan Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	6/1/2009	6/1/2009
AEPW	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	Install new 345kV line from FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE	6/1/2017	6/1/2014
EMDE	SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	Install 3-wind transformer from 161 kV new Sub MONETT 5 to Monett city south 69kV	6/1/2015	6/1/2015
EMDE	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161KV CKT 1	Install new line from Sub #383 to new Sub MONETT 5	6/1/2015	6/1/2015
EMDE	SUB 389 - JOPLIN SOUTHWEST - SUB 422 - JOPLIN 24TH & CONNECTICUT 161KV CKT 1	Change CT Ratio at Sub #389 on Breaker #16170 for 268 MVA Rate B	6/1/2009	6/1/2009
EMDE	SUB 438 - RIVERSIDE 161KV	Install 3 - stages of 22 MVAR each for a total of 66 MVAR capacitor bank at Riverside Sub #438 547497	6/1/2011	12/1/2010
INDN	SUBSTATION M 161/69KV TRANSFORMER CKT 2	Add second 100 MVA xfr at Subsation M	6/1/2010	6/1/2011
MIPU	ALABAMA - LAKE ROAD 161KV CKT 1	re-set the over current relay to trip the Lake Road-Alabama section when flow goes above 161 MVA	6/1/2010	6/1/2010
MIPU	EDMOND SUB	Add a new 161/34.5 kV Sub at Edmond tapping the Cook to Lake Road 161 kV line	6/1/2009	6/1/2011
MIPU	Grandview East - Sampson - Longview 161kV Ckt 1	Replace wavetraps at Grandview East and Longview.	6/1/2009	6/1/2009
MIPU	Loma Vista - Montrose 161kV Tap into K.C. South	To tap the Montrose-LomaVista 161 kV Line into KC South 161 kV sub.	6/1/2009	6/1/2011
MIPU	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	To tap Stilwell-Archie JCT 161 kV line into South Harper 161 kV sub and make it two new 161 kV sections: Stilwell-South Harper and Archie JCT- South Harper .	6/1/2009	11/1/2010
MKEC	Cimarron Plant Substation Expansion	Integrate SUNC North Cimarron Top into reconfigured WEPL Cimarron Plant Sub	6/1/2012	1/1/2010
MKEC	HARPER 138KV Capacitor	Install 1 - 20 MVar capacitor bank	6/1/2009	10/1/2009
OKGE	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	6/1/2009	6/1/2009
SPRM	KICKAPOO - SUNSET 69KV CKT 1	Reconductor 69kV Line 636 MCM ACSR to 762.8 kcmil ACSS/TW 1.35 miles.	6/1/2014	6/1/2012
SPRM	NEERGARD - NORTON 69KV CKT 1	Transfer load & Reconductor 336.4 kcmil ACSR with 477 ACSS/TW	10/1/2010	6/1/2010
SUNC	HOLCOMB - PLYMELL 115KV CKT 1	Rebuild Holcomb to Plymell	12/1/2009	12/1/2009
SUNC	PIONEER TAP - PLYMELL 115KV CKT 1	Rebuild Plymell to Pioneer Tap	12/1/2009	12/1/2009
SWPA	BULL SHOALS - BULL SHOALS 161KV CKT 1	Replace buswork in Bull Shoals switchyard.	6/1/2009	6/1/2011
SWPA	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	Replace wave trap, disconnect switches, current transformers, and breaker. Bus will limit rating to 1340 amps.	6/1/2009	6/1/2010
SWPA	SPRINGFIELD (SPF X1) 161/69/13.8KV TRANSFORMER CKT 1	Replace Springfield xfmr #1 three winding transformer with 70 MVA auto transformer.	6/1/2016	6/1/2016
WERE	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	Add second Auburn 230-115 kV transformer.	6/1/2016	6/1/2016
WERE	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	Rebuild 2.9 mi 115 kV line Bismark to COOP	6/1/2015	6/1/2015
WERE	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	Rebuild 5.2 miles Bismark to Midland 115 kV line	6/1/2015	6/1/2015
WERE	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	Uprate JEC- E.Manhattan 230 kV line to 100 deg C operation by raising structures	6/1/2013	6/1/2013
WERE	EAST MANHATTAN - NW MANHATTAN 230/115KV	Tap the Concordia - East Manhattan 230kV line and add a new substation"NW Manhattan"; Add a 230kV/115kV transformer and tap the KSU - Wildcat 115kV line into NW Manhattan	6/1/2011	6/1/2012
WERE	East Manhattan to Mcdowell 230 kV	The East Manhattan-McDowell 115 kV is built as a 230 kV line, but is operated at 115 kV. Substation work will have to be performed in order to convert this line.	6/1/2011	6/1/2011
WERE	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	Rebuild 1.53-mile Co-op-Wakarusa 115 kV line.	6/1/2017	6/1/2017
WERE	Fort Scott - SW Bourbon 161 kV	Tap Litchfield-Marmaton 161 kV with new SW Bourbon Sub to Ft Scott.	6/1/2010	6/1/2010
WERE	Fort Scott 161/69kV Transformer CKT 1	New 161/69 kV transformer at Ft Scott.	6/1/2010	6/1/2010
WERE	KELLY - SOUTH SENECA 115KV CKT 1	Rebuild 10.28 mile line with 1192.5 kcmil ACSR and replace CTs.	5/1/2009	1/1/2011
WERE	Knob Hill - Steele City 115 kV	New 115 kV Line from Knob Hill to Kansas/Nebraska state line.	6/1/2010	6/1/2010
WERE	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	Rebuild 5.49 mile line	6/1/2017	6/1/2017
WERE	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	Rebuild 5.73 mile Weaver-Rose Hill Junction as a 138 kV line but operate at 69 kV.	6/1/2009	12/1/2010
WERE	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	Rebuild 4.09 mile SW Lawrence-Wakarusa 115 kV line	6/1/2016	6/1/2016
WERE	STRANGER CREEK - NW LEAVENWORTH 115KV	Rebuild 11.62-mile Jarbalo-NW Leavenworth 115 kV line and tap in & out of Stranger 115 kV	6/1/2011	6/1/2011
WERE	STRANGER CREEK TRANSFORMER CKT 2	Install second Stranger Creek 345-115 transformer	6/1/2009	6/1/2009
WERE	Summit - NE Saline 115 kV	Build 6.5-mile Summit-Southgate 115 kV, 1192.5 kcmil ACSR Tear down Northview-South Gate 115 kV	5/1/2009	12/1/2010

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	BONANZA - NORTH HUNTINGTON 69KV	Convert from 69KV to 161KV	6/1/2014	6/1/2014
EMDE	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 EMDE	Replace Jumpers to breaker #6950 at Blackhawk Jct.	6/1/2014	6/1/2012
EMDE	Multi - Stateline - Joplin - Reinmiller conversion	Tear down the Riverton to Joplin 59 69 kV line, rebuilding the line to 161 kV from Stateline to outside Joplin 59 sub. Tear down and rebuild Joplin 59 to Gateway to Pillsbury to Reinmiller, converting those 69 kV lines to 161 kV. Tap the 161 kV line betwe	6/1/2012	6/1/2013
EMDE	SUB 124 - AURORA H.T. - SUB 152 - MONETT H.T. 69KV CKT 1	Change CT Ratio on breaker #6936 at Aurora #124	6/1/2009	6/1/2010
EMDE	SUB 124 - AURORA H.T. - SUB 383 - MONETT 161KV CKT 1	Change CT Ratio at Sub #383 on Breaker #16186 for 268 MVA Rate B	6/1/2017	6/1/2017
EMDE	SUB 145 - JOPLIN WEST 7TH - SUB 64 - JOPLIN 10TH ST. 69KV CKT 1	Replace Disconnect Switches and Leads on Breaker #6965 at Sub #64 and #6932 at Sub #145	6/1/2010	6/1/2010
EMDE	SUB 170 - NICHOLS ST. - SUB 80 - SEDALIA 69KV CKT 1	Reconductor 8.92 mile line from 1/0 CU to 556 ACSR and replace Jumpers in Sub #80 and Upgrade CTs	6/1/2012	6/1/2012
EMDE	SUB 271 - BAXTER SPRINGS WEST - SUB 404 - HOCKERVILLE 69KV CKT 1	Change CT setting on Breaker #6973 at Baxter #271	12/1/2010	6/1/2010
GRDA	KERR - PENSACOLA 115KV CKT 1	Rebuild 22 miles of line from 4/0 Cu to 795 ACSR for 161kV	12/1/2012	6/1/2011
KACP	MERRIAM - ROELAND PARK 161KV CKT 1	reconductor with 1192 acsr; upgrade term equip 1200 A	6/1/2017	6/1/2017
MIDW	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 MIDW	Tear down and rebuild 73.4% Ownership 28.79 mile HEC-Huntsville 115 kV line and replace CT, wavetrap and relays.	6/1/2016	6/1/2016
MIDW	HUNTSVILLE - ST_JOHN 115KV CKT 1	Rebuild 26.5 miles Huntsville - St. John 115 kV line and replace CT, wavetrap, breakers, and relays.	6/1/2016	6/1/2016
MIPU	BLUE SPRINGS EAST CAP BANK	Add 50 MVAR cap bank at Blue Springs East	6/1/2011	6/1/2011
MIPU	RALPH GREEN 12MVAR CAPACITOR	12MVAR at Ralph Green	6/1/2010	6/1/2010
MIPU	South Harper - Freeman 69 kV	re-set the overcurrent relay at South Harper 69 kV Bus to open SouthHarper-Freeman 69 kV line	6/1/2009	6/1/2010
MKEC	PRATT - ST JOHN 115KV CKT 1	Replace terminal equipment	6/1/2017	6/1/2017
OKGE	Sooner to Rose Hill 345 kV OKGE	New 345 kV line from Sooner to Oklahoma/Kansas	6/1/2009	1/1/2013
SPRM	JAMES RIVER - TWIN OAKS 69KV CKT 1	Reconductor 69kV Line 636 MCM ACSR to 762.8 kcmil ACSS/TW 3.103 miles.	6/1/2015	6/1/2014
SUNC	NORTH CIMARRON CAPACITOR	Install 24 MVAR Capacitor bank at North Cimarron	6/1/2012	12/1/2008
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	Remove wavetrap. Install fiber	6/1/2012	6/1/2012
WERE	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	Rebuild 7.61 miles from 95th & Waverly-Captain Junction 115 kV line.	6/1/2017	6/1/2017
WERE	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV CKT 1	Rebuild Line	6/1/2009	6/1/2011
WERE	CHASE - WHITE JUNCTION 69KV CKT 1	Tear down / Rebuild 7.3-mile Chase - White Junction 69 kV line. Replace existing 2/0 copper conductor with 795 kcmil ACSR conductor.	6/1/2009	6/1/2010
WERE	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	Reconductor 8.02 miles with Bundled 1192.5 ACSR	6/1/2016	6/1/2016
WERE	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	Replace wave trap	6/1/2016	6/1/2016
WERE	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 WERE	Tear down and rebuild 26.6% Ownership 28.79 mile HEC-Huntsville 115 kV line and replace CT, wavetrap and relays.	6/1/2016	6/1/2016
WERE	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	Rebuild 5.43 mile Rose Hill Junction-Richland as a 138 kV line but operate at 69 kV.	6/1/2009	6/1/2011
WERE	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	Install second 17th St. 138-69 kV transformer	6/1/2015	6/1/2015
WERE	Sooner to Rose Hill 345 kV WERE	New 345 kV line from Oklahoma/Kansas Stateline to Rose Hill	6/1/2009	1/1/2013
WERE	Sumner County to Timber Junction 138/69 kV	Tap Belle Plaine-Oxford 138 kV line, build a 3-breaker ring bus switching station, build 12-mile 138 kV line from Sumner County 138 kV to Timber Junction 138 kV, and Install Timber Junction. 138-69 kV 100 MVA transformer with LTC.	6/1/2009	6/1/2011

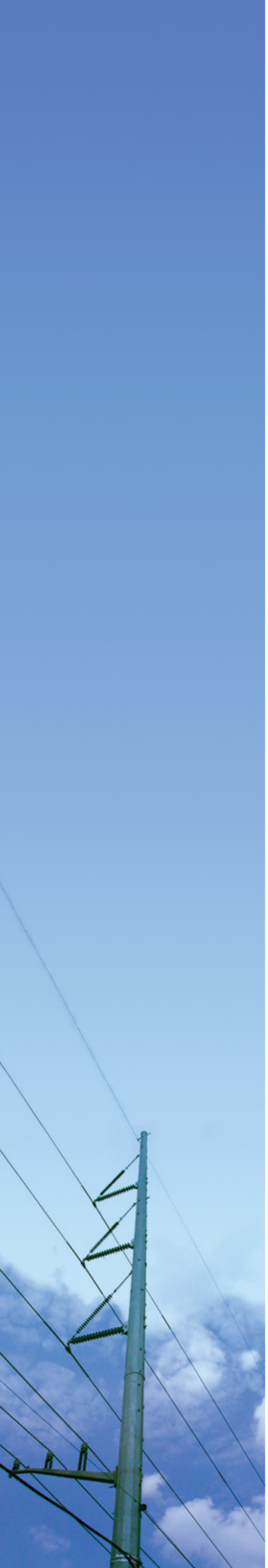
Previously Assigned Aggregate Study Upgrades requiring credits to Previous Aggregate Study Customers.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	HUGO POWER PLANT - VALLIANT 345 KV AEPW	Vallient 345 KV line terminal	7/1/2012	7/1/2012
KACP	LACYGNE - WEST GARDNER 345KV CKT 1	KCPL Sponsored Project to Reconductor Line to be In-Service by 6/1/2006	6/1/2006	6/1/2006
WERE	RENO 345/115KV CKT 1	New stepdown transformer at a new substation in Reno County east northeast of Hutchinson	12/15/2008	12/15/2008
WERE	RENO 345/115KV CKT 2	Install 2nd stepdown transformer at Reno County substation east northeast of Hutchinson	12/1/2009	8/1/2009
WERE	SUMMIT - RENO 345KV	Install new 50.55-mile 345 kV line from Reno county to Summit; 31 miles of 115 kV line between Circle and S Philips would be rebuilt as double circuit with the 345 kV line to minimize ROW impacts; Substation work required at Summit for new 345 kV terminal	6/1/2010	6/1/2010
WERE	WICHITA - RENO 345KV	40 mile 345 kV transmission line from existing Wichita 345 kV substation to a new 345-115 kV substation in Reno County east northeast of Hutchinson (Wichita to Reno)	12/15/2008	12/15/2008
WFEC	HUGO POWER PLANT - VALLIANT 345 KV WFEC	New 19 miles 345 KV	7/1/2012	7/1/2012

Table 5 - Third Party Facility Constraints

Transmission Owner	UpgradeName	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
SWPA	5CALCR - NORFORK 161KV CKT 1 SWPA	At Norfork Sub, Replace bus between bay MOD switch 67 and disconnect switch 63, reset metering CT ratio and replace wavetrap	6/1/2009	6/1/2010	$ 100,000
SWPA	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	Replace the bus between auxilliary bus and MOD switch 57, between disconnect switch 57 and disconnect switch 53, and between disconnect switch 51 and the main bus.	6/1/2009	6/1/2010	$ 45,000

EXHIBIT NO. OGE-14



SPP Balanced Portfolio Report

MAINTAINED BY
Engineering/Planning

PUBLISHED: 06/23/2009
CAWG Accepted 06/05/2009
MOPC Accepted 06/12/2009
LATEST REVISION: 06/23/2009

SPP Southwest Power Pool

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Executive Summary

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. “Balanced” is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio.

After development and review of the Balanced Portfolio, the CAWG endorsed Portfolio 3E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3E “Adjusted” provides a significant benefit vs. cost to the SPP region, and would require lower transfer requirements necessary to achieve balance. The CAWG along with the Economics Modeling and Methods Task Force (“EMMTF”, now called the Economic Studies Working Group “ESWG”) reviewed and approved the study assumptions used in the analysis of the Balanced Portfolio. These assumptions are listed in the appendix. Portfolio 3E “Adjusted” contains a diverse group of 345kV transmission projects addressing many of the top SPP flowgates. The projects associated with Portfolio 3E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The CAWG endorsed Balanced Portfolio was presented to the Markets and Operations Policy Committee (MOPC) on April 15th, 2009. The MOPC reviewed and discussed the portfolio options and the impact on the SPP footprint. After discussion, the MOPC endorsed the Balanced Portfolio 3E “Adjusted” pending issuance of the final report, according to SPP Tariff.

Portfolio 3E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58.

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Million of Dollars

Portfolio 3-E "Adjusted"	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual
2012	$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017	$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022	$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8

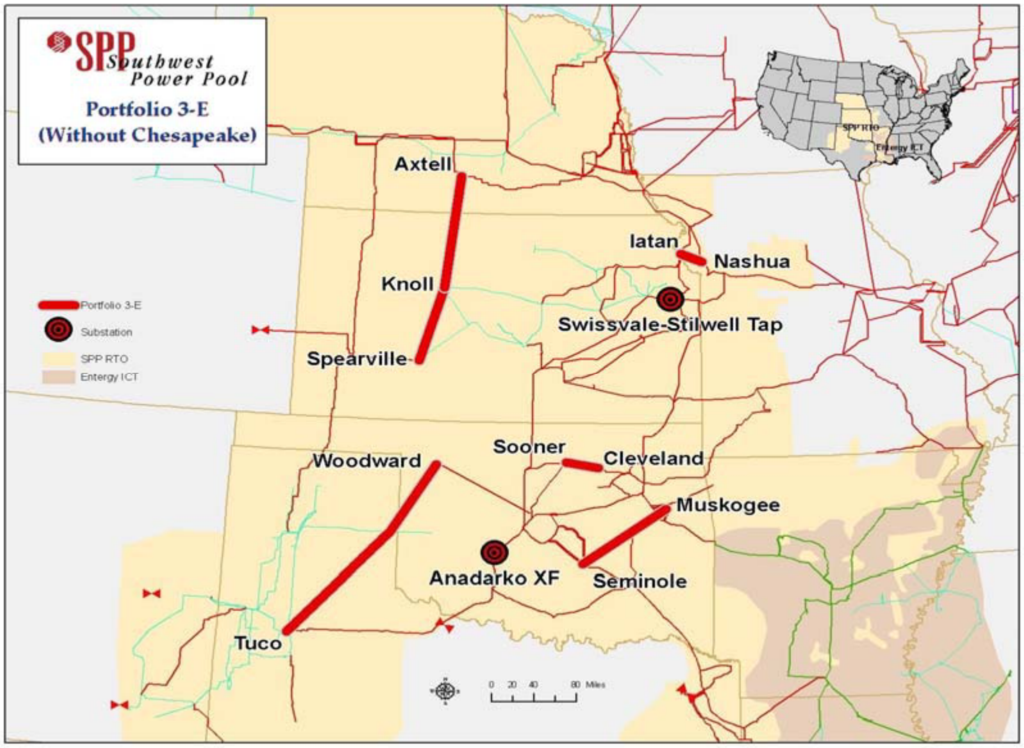
Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	**1.87**

The table below outlines the benefits by zones for the 10 year analysis of Portfolio 3E "adjusted".

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		**$176**	**$95**	**-$31**	**$31**	**$0**	**$81**	**1.86**

Portfolio 3-E "Adjusted"



Introduction

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV[*] projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e. increasing reliability and lowering reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. “Balanced” is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio[†].

Economic Benefits: Adjusted Production Cost

Balanced Portfolio development began with an economic screening of projects identified by stakeholders and SPP staff. After receiving stakeholder feedback, SPP staff compiled a list of economic projects with potential for a positive return.

The first step is to conduct an economic analysis individually on each project considered for the Balanced Portfolio. This process is done by determining the adjusted production cost metric for each project in the screen. Adjusted production cost is defined as:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases

Where:

Revenues from Sales = Export x Zonal $LMP_{\text{Gen Weighted}}$

and

Cost of Purchases = Import x Zonal $LMP_{\text{Load Weighted}}$

Production cost for each unit is based on fuel, variable O&M costs, environmental costs and both scheduled and forced outages[‡]. Adjusted production cost savings account for the economy purchase and sale of power in the modeling footprint. This is important when benefits are being calculated for zones within the SPP as well as in differentiating overall benefits from the portfolio compared to the benefits accruing to SPP members.

To calculate adjustments to production costs due to an economic transmission project, commercial production cost analysis software is used to estimate hourly unit commitment and dispatch of modeled

[*] Upgrades of voltages less than 345 kV can be included if needed to deliver the benefits of the extra high voltage (EHV) upgrade, where the cost of the lower voltage facilities does not exceed the cost of the EHV facilities.

[†] The Tariff allows for deficient zones to be balanced by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual transmission Revenue Requirement from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement.

[‡] SPP is currently using probabilistic techniques to simulate a single draw of outages to simulate forced outages

generators within a context of a modeled transmission system and load delivery points. The commitment and dispatch of the generators is constrained by the software to ensure that no overloads will occur on any monitored transmission element, typically referred to as the NERC book of flowgates, but can include additional congestion points of interest. The software produces a security constrained economic dispatch and unit commitment.

Adjusted Production Cost was the only benefit metric used in the economic analysis. There are other potential benefits which have not been directly quantified such as lowering reserve margins, reducing losses, and providing environmental benefits. For the purpose of this study, these benefit metrics are not used to determine overall portfolio benefits to the region.

Balanced Portfolio Development

The following table provides a timeline for the development of the various candidate portfolios that were developed by the SPP staff and presented during the regularly scheduled CAWG meetings

Table: CAWG Timeline for Balanced Portfolio Development

Months/Year	Key Discussions at CAWG
Aug-Nov 2007	Screening of Candidate Upgrades for Portfolio
Feb –Apr 2008	Initial Portfolios 1, 2, 3 and 4
May 2008	Trapped Generation Issues Discussion Begins
Jun 2008	Spearville-Knoll-Axtell Added to Portfolios 2 and 3
Jul 2008	Portfolios 2 and 3 at 2008 Wind Levels and Turk
Aug 2008	Portfolios 2 and 3: Firm Wind Sensitivities
Sep 2008	Introduction of Portfolios 3-A and 3-B at 345 and 765 kV costs
Oct 2008	Portfolio 3 (high wind) and 3-A (current wind) Analysis
Dec 2008	Portfolio 3-C (modify 3 for high wind)
Jan 2009	Further Analysis of Portfolios 3-A and 3-C with Nebraska
Feb 2009	EMMTF Effort initiated to update and refine economic models
Mar 2009	Final Balanced Portfolio Analysis
Apr 2009	Balanced Portfolio Summit & Balanced Portfolio Recommendation

<u>August-November, 2007</u>: Screening of Candidate Upgrades for Portfolios

Over fifty candidate transmission upgrades for screening were gathered by SPP staff. As agreed by stakeholders, the initial screening analysis was performed based on using only the summer months. A discussion at the CAWG led to additional analyses to include spring-fall months in the calculations of adjusted production cost benefits. The screening analysis was then performed for the summer months and the spring-fall months starting with the spring of March 1, 2012. These estimates of annual benefits were compared to the estimates of engineering and construction (E&C) cost obtained by SPP staff from transmission owners. All projects screened were ranked from highest to lowest according to their benefit-to-cost (B/C) ratios. The SPP staff then used these rankings as a basis for developing a collection of economic upgrades as alternative portfolios[§].

<u>February-April, 2008</u>: Initial Four Portfolios

SPP staff developed four initial portfolios, labeled as Portfolios 1, 2, 3 and 4. Each portfolio had specific criteria for determining which projects to include.

1. Portfolio 1 was a collection of every project from the economic project screening process that had a B/C ratio greater than 1.0.

[§] Note: Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note in the original analysis was the inclusion of Holcomb 2, Red Rock, Hugo 2 as well as 4,600 MW of generic wind capacity which affected the calculated benefits of certain projects.

2. Portfolio 2 was a subset of Portfolio 1 where projects with similar benefits were narrowed to remove upgrades that would not provide additional benefits.

3. Portfolio 3 was assembled with the intent of ensuring each Zone within the SPP region received a project (projects that crossed multiple zones were considered for each zone), with the most beneficial project chosen in each zone.

4. Portfolio 4 was a collection of projects that would be mutually beneficial, thereby raising the overall benefit of the entire portfolio.

These four portfolios, along with their B/C screening ratios, are shown in the following exhibits.

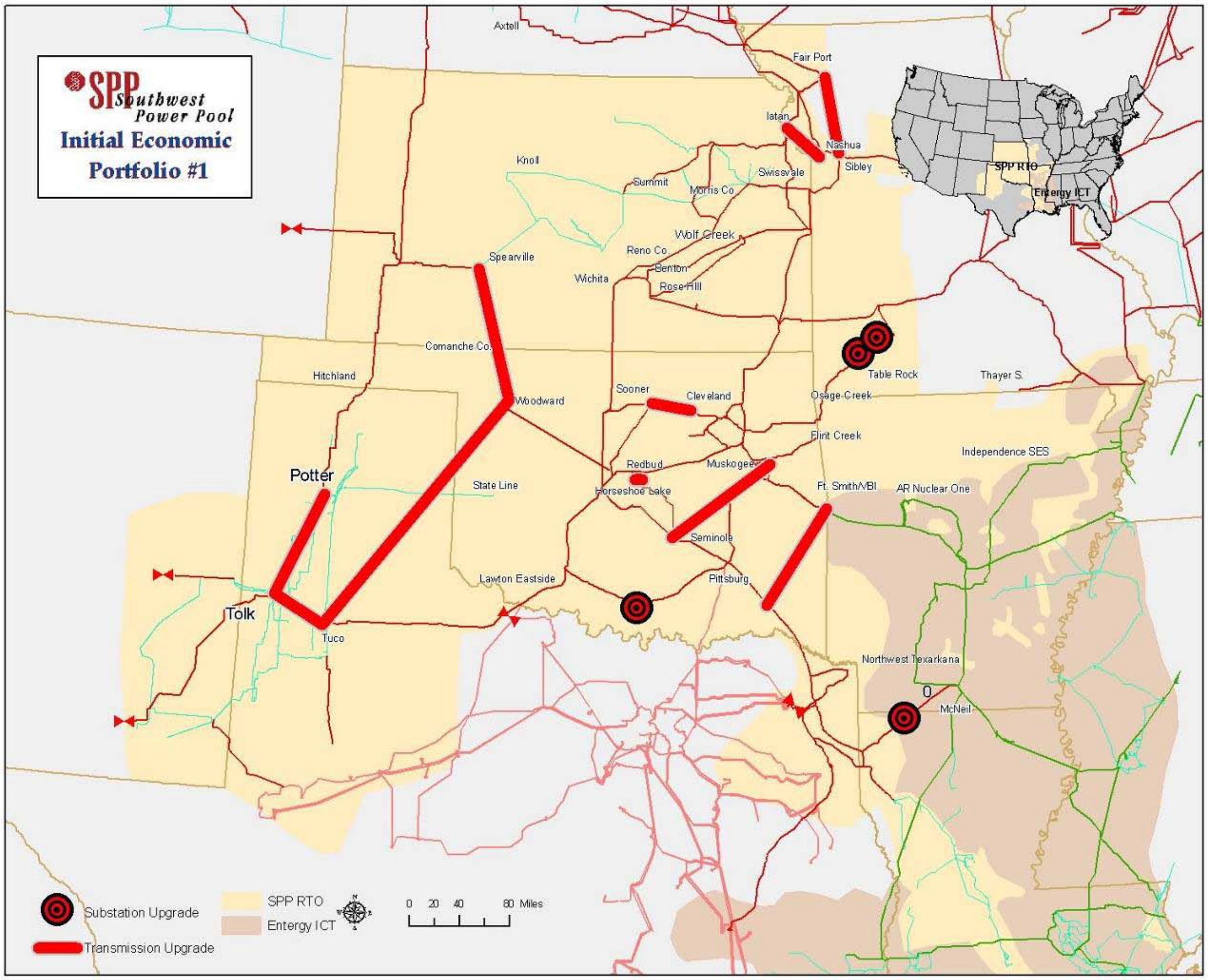
Screening of Proposed Economic Upgrades

Project	Screening B/C Ratio	P1	P2	P3	P4
Tolk - Potter	7.20			+	
El Dorado - Longwood	3.36	+	+	+	
Iatan - Nashua	2.95	+	+	+	+
SWPS - Battlefield	2.66	+	+		
Chesapeake XF	2.26	+	+	+	
Tuco - Tolk - Potter	1.73	+	+		+
Fairport - Sibley	1.31	+			+
Pittsburg - Ft Smith	1.17	+	+	+	
Spearville-Mooreland/Woodward-Tuco	1.13	+	+	+	+
Seminole - Muskogee	1.08	+			
Monett XF	1.04	+			
Redbud - Horseshoe Lake	1.01	+			
Cleveland - Sooner	0.91	+	+	+	+
Sunnyside XF	0.89	+	+		
Northwest XF	0.89	+	+		+
Swissvale - Stilwell	0.67			+	
Anadarko XF	0.48			+	
Turk - McNeil	0.46				+
Mooreland/Woodward - Wichita	0.14				+
Mooreland/Woodward - Northwest	(0.00)				+

(NOTE: "Tolk – Potter" project is a subset of the "Tuco – Tolk – Potter" project.)

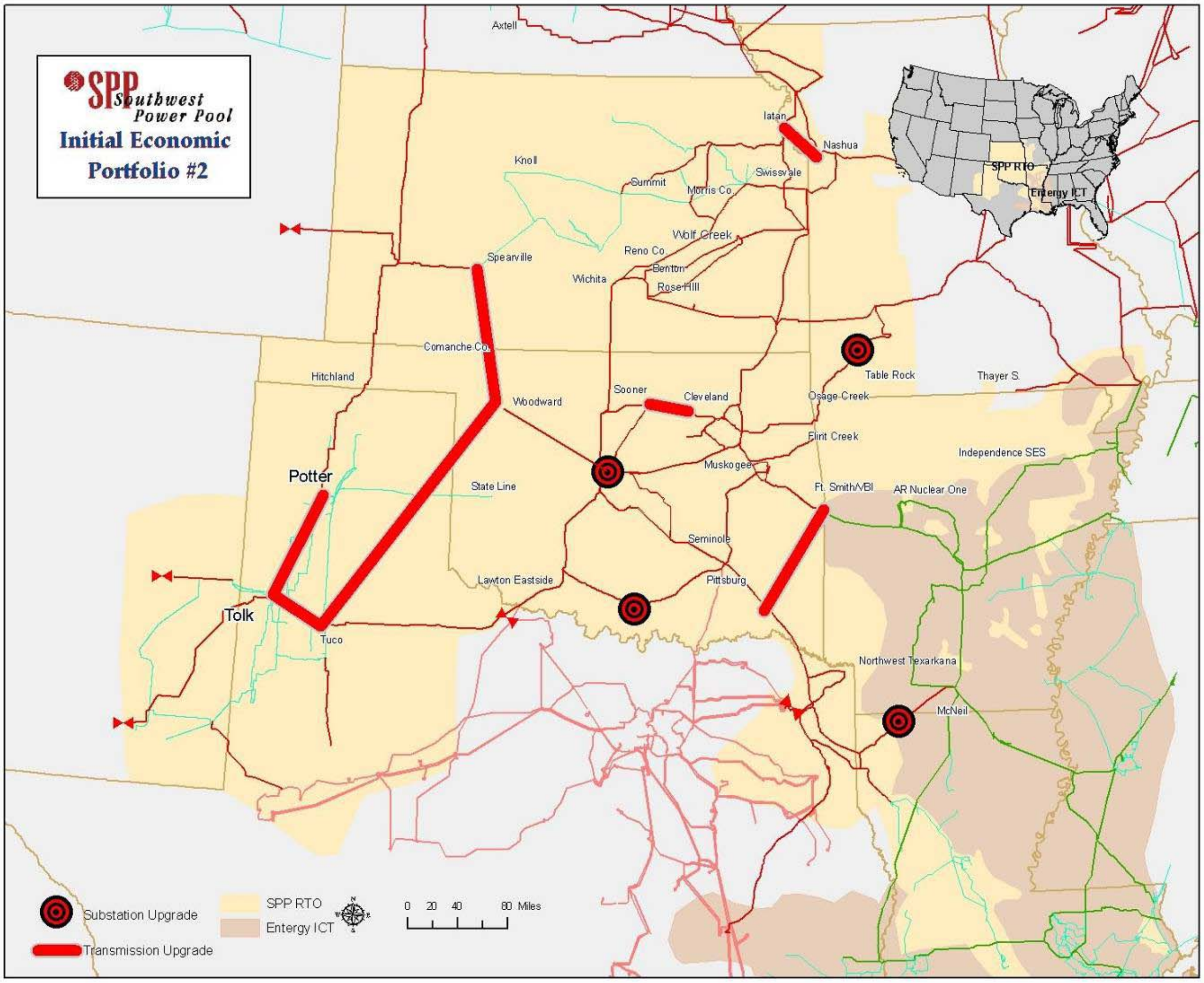
The Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note was the inclusion of Holcomb 2, Red Rock, and Hugo 2 as well as 4,600 MW of generic wind capacity, each of which affected the calculated benefits of certain projects.

Portfolio 1

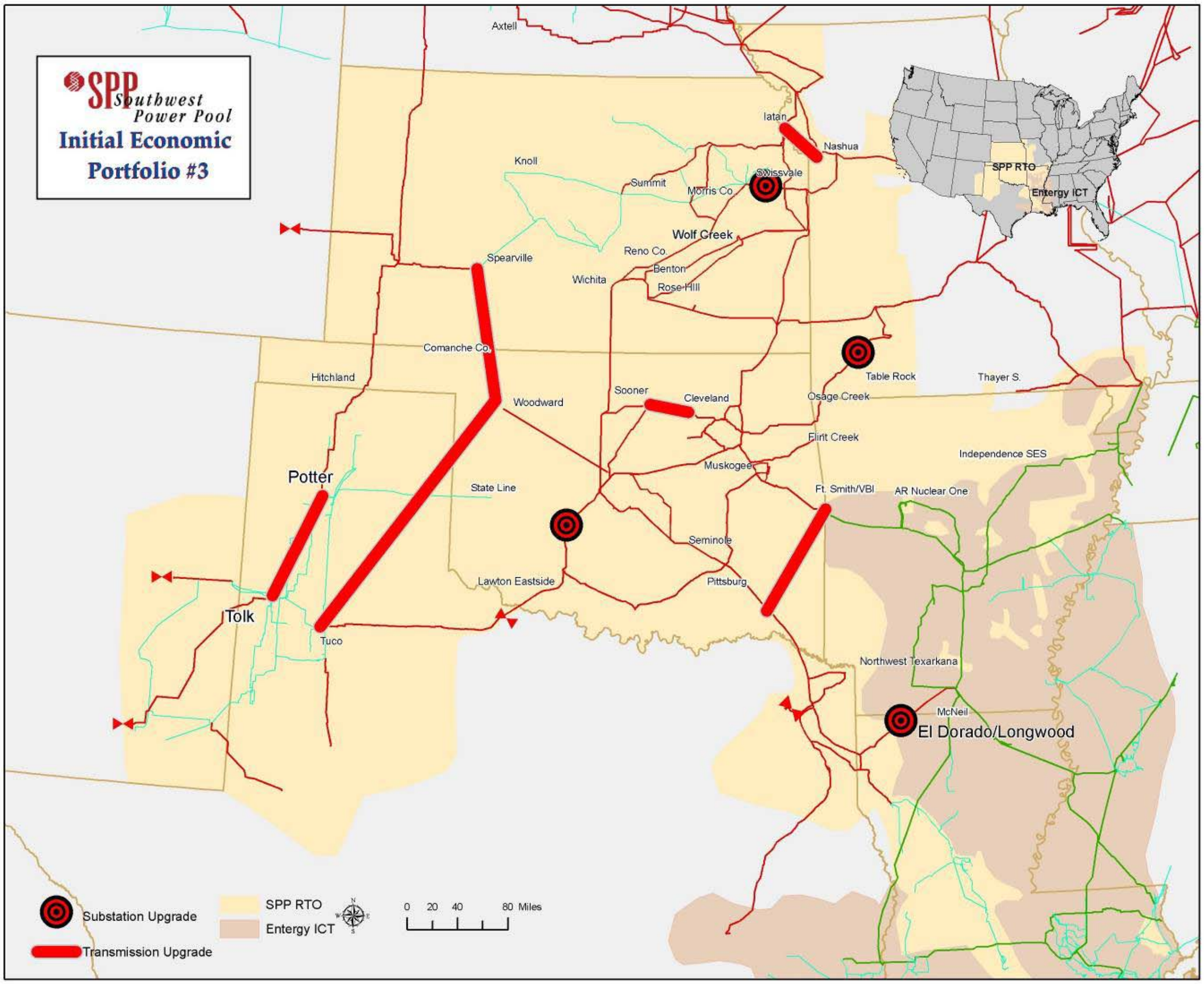


Because Portfolio 2 eliminated duplicative upgrades from Portfolio 1, Portfolio 1 was not carried forward as a possible Balanced Portfolio candidate.

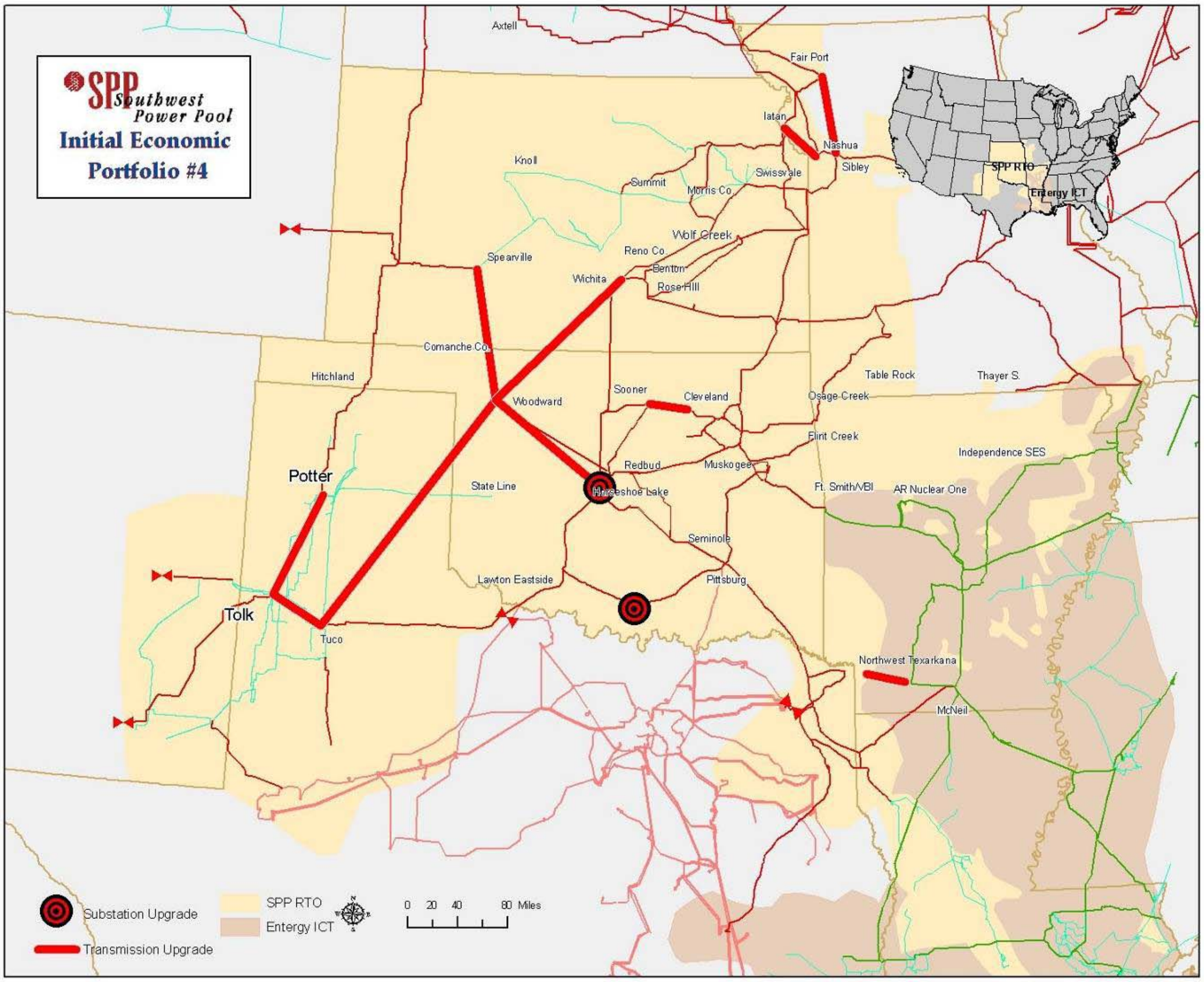
Portfolio 2


Southwest Power Pool
Initial Economic Portfolio #2
Axtell
Iatan
Nashua
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Reno Co.
Spearville
Benton
Wichita
Rose Hill
Comanche Co.
Table Rock
Thayer S.
Hitchland
Sooner
Cleveland
Osage Creek
Woodward
Flint Creek
Potter
Muskogee
Independence SES
State Line
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

Portfolio 3


Southwest Power Pool
Initial Economic Portfolio #3
Axtell
Iatan
Nashua
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Spearville
Reno Co.
Benton
Wichita
Rose Hill
Comanche Co.
Hitchland
Woodward
Sooner
Cleveland
Table Rock
Thayer S.
Osage Creek
Flint Creek
Independence SES
Muskogee
Potter
State Line
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
El Dorado/Longwood
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

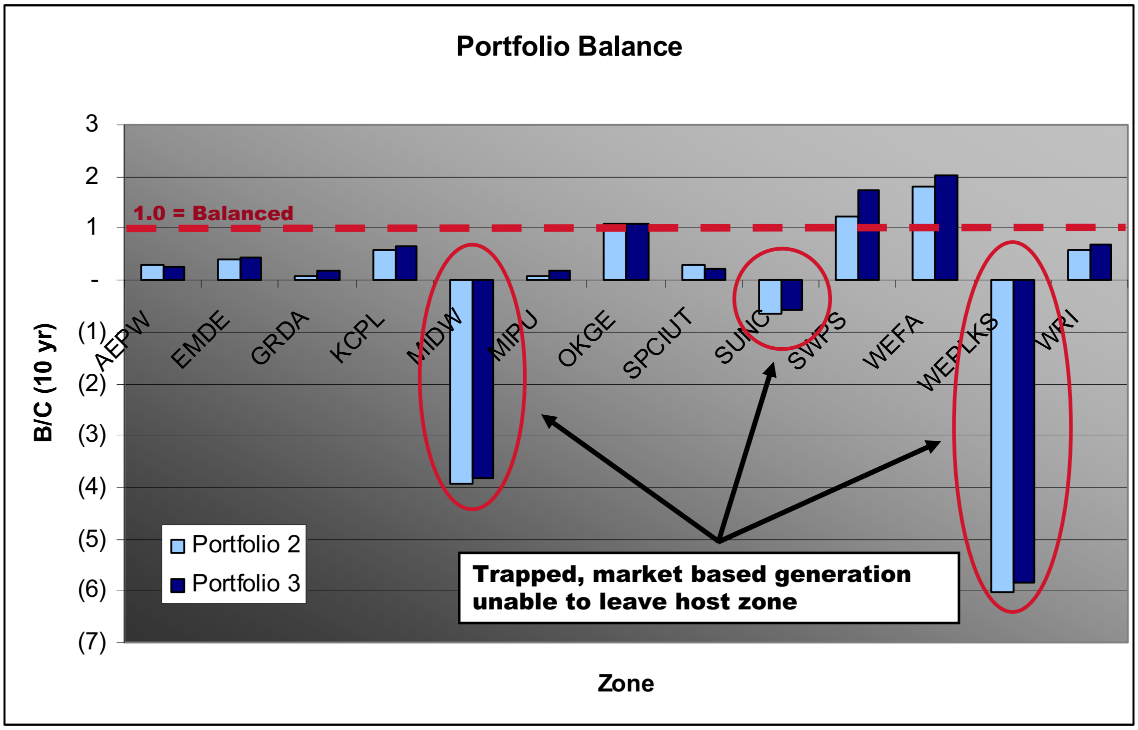
Portfolio 4


Southwest Power Pool
Initial Economic Portfolio #4
Axtell
Fair Port
Iatan
Nashua
Sibley
Knoll
Summit
Swissvale
Morris Co
Wolf Creek
Spearville
Reno Co
Benton
Wichita
Rose Hill
Comanche Co
Hitchland
Woodward
Sooner
Cleveland
Table Rock
Thayer S.
Osage Creek
Flint Creek
Independence SES
Potter
State Line
Redbud
Muskogee
Ft. Smith/VBI
AR Nuclear One
Horseshoe Lake
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

<u>May 2008</u>: Trapped Generation

The CAWG review of the four portfolios, including high wind sensitivities, discovered that the production cost analysis contained significant levels of "trapped generation" (generation that cannot get power out of the host zone due to transmission constraints, significantly impacting the modeling results) related to wind generation. The CAWG initiated the Trapped Generation Task Force (TGTF) to address this issue. The following graph demonstrates effects of trapped generation on portfolio B/C ratios.

Trapped Generation in Economic Models



The TGTF developed guidelines for including generation in the production cost modeling, that were reviewed by the Economic Modeling and Methods Task Force ("EMMTF", now called the Economic Studies Working Group, "ESWG"). The TGTF decided that the base case models should contain wind levels consistent with current wind in service. These models contained 2,600 MW of nameplate wind,** down from 4,600 MW of generic wind included in previous models. Change cases could include additional wind generation, but the TGTF recommended that the additional wind above existing levels must be matched with the transmission upgrades that would be needed to deliver the additional wind to the SPP energy market.

<u>June 2008</u>: Wind and Spearville-Knoll-Axtell (SKA)

SPP staff updated the study models after the TGTF determined that 2,600 MW of wind should be used in the base case. The following table illustrates the resultant B/C ratios for Portfolios 2 through 4, where 2,600 MW of wind is also included in the change case. The adjusted production costs

** This coincides with the amount of wind in the SPP footprint at the end of 2008, as well as the transmission upgrades required to delivery wind with firm service.

shown are changes in adjusted production costs. Therefore, a red parenthetical represents lower adjusted production costs after an upgrade takes place, and it is the estimate of overall benefit.

Preliminary Portfolio Results, post-TGTF (June 26, 2008 CAWG Meeting)

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_June08	($50,482,000)	($41,409,000)	($9,073,000)	$ 371	0.92
Economic Portfolio - P3_June08	($53,325,000)	($42,060,000)	($11,266,000)	$ 347	1.04
Economic Portfolio - P4_June08	($48,429,000)	($38,581,000)	($9,848,000)	$ 608	0.54

SPP staff conducted a sensitivity analysis of Spearville-Knoll-Axtell on the above portfolios to determine its impact. The Spearville-Knoll-Axtell (SKA) 345kV line is a transmission upgrade for which the Kansas Electric Transmission Authority (KETA) issued a Notice of Intent to Proceed with Construction on July 25, 2007. Additionally, the SPP Board of Directors approved this transmission upgrade for inclusion in the SPP Transmission Expansion Plan (STEP). The SPP Board of Directors requested that all projects of 345 kV and above approved for inclusion in the STEP also be considered candidates in the Balanced Portfolio analyses. It was found in the analyses that the SKA project uniformly raised the B/C ratios of all portfolios, and it appeared that the SKA project should be included for consideration, although a similar analysis was not conducted for other low B/C ratio projects that were not included in the original portfolios. The results are shown in the following table.

Impact of Spearville – Knoll – Axtell

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_SKA_June08	($90,215,000)	($71,327,000)	($18,889,000)	$ 539	1.13
Economic Portfolio - P3_SKA_June08	($92,307,000)	($72,235,000)	($20,072,000)	$ 515	1.22
Economic Portfolio - P4_SKA_June08	($84,031,000)	($64,709,000)	($19,322,000)	$ 776	0.73

Because Portfolio 4 had a B/C ratio well below one, it was not included in further analyses in the Balanced Portfolio development process.

<u>July 2008</u>: Update Designated Resources

Portfolios 2 and 3 were updated to include the Turk Plant, a Designated Resource planned to be on line by 2012. This change lowered the benefit to cost ratios below one, as shown in the following table. These results were based on the 2008 wind levels in SPP (2,600 MW) but do not include the Spearville-Knoll-Axtell line.

Impact of Updates on Portfolios 2 and 3

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C	SPP B/C
Portfolio 2 - July 08	($38,291,000)	($28,825,000)	($9,466,000)	$ 371	0.70	0.53
Portfolio 3 - July 08	($42,033,000)	($32,281,000)	($9,751,000)	$ 347	0.82	0.63

<u>August 2008</u>: Firm Wind Sensitivities

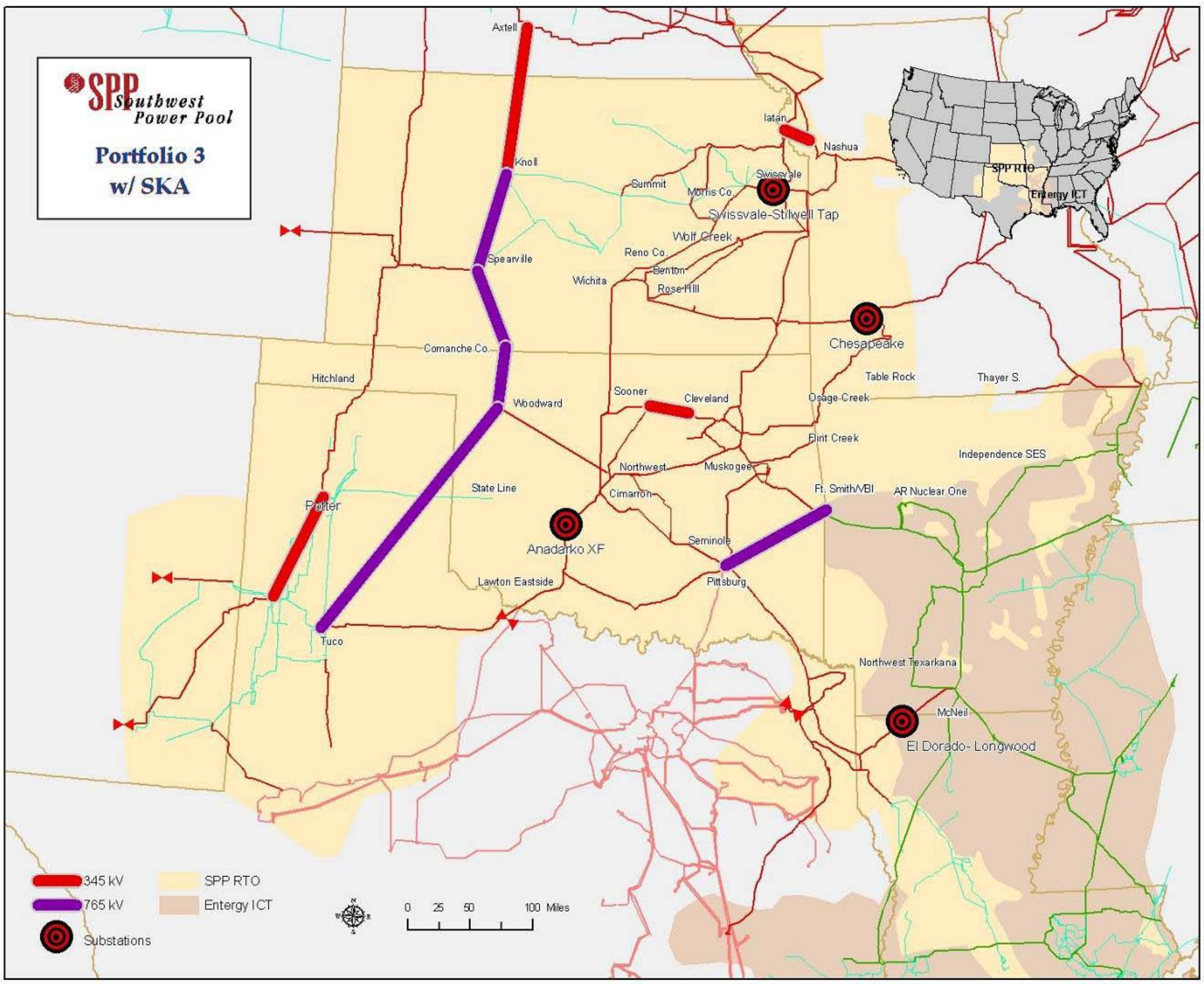
Additional wind sensitivities were conducted for Portfolios 2 and 3 to determine the impact that the amount of wind assumed in the model would have on the benefits. Benefits were estimated for 700 MW of firm wind in the base case and an additional 1,900 MW of market-based wind in the change case. The results showed a significant increase in production cost savings for both Portfolios 2 and 3. The changes in benefits from adding the market-based wind without transmission upgrades were calculated to show the impact of trapped generation. Stakeholders supported the inclusion of all existing wind in the portfolios even though wind without firm transmission service would lower the B/C ratios.

<u>September 2008</u>: Introduction of Portfolio Variations 3-A and 3-B

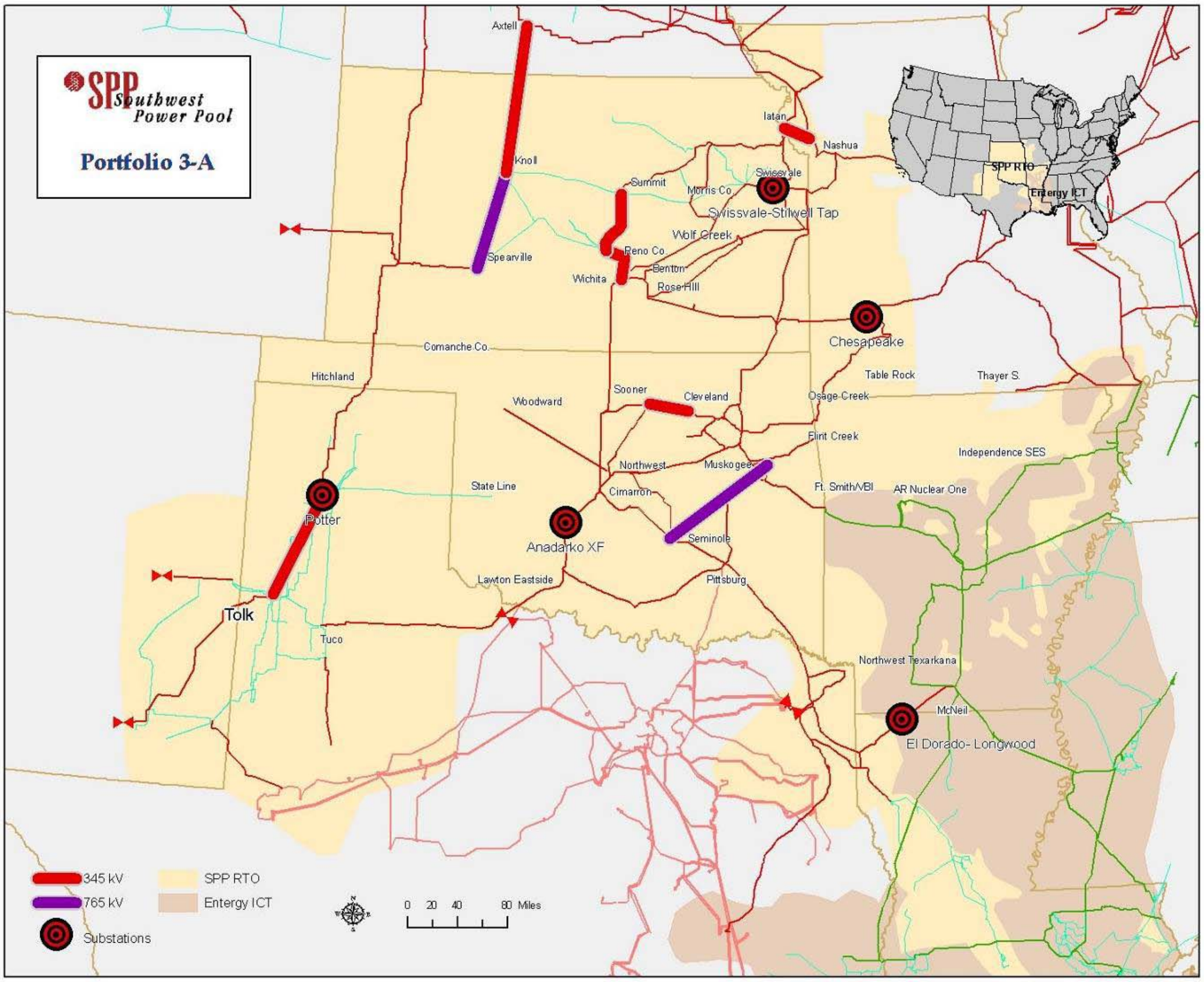
SPP staff developed two modified portfolios based on Portfolio 3. Adjustments to Portfolio 3 included an upgrade of the Wichita – Reno Co - Summit line and carried through the addition of Spearville-Knoll-Axtell. From this modification of Portfolio 3 two variations were developed and labeled 3-A and 3-B. These portfolios are shown pictorially below.

Since many sections of Portfolio 3 included transmission paths that are also in the proposed EHV Overlay Plan, the CAWG decided to consider these common corridor projects for 765 kV construction in the balanced portfolio. The purple lines in the following maps illustrate this construction.

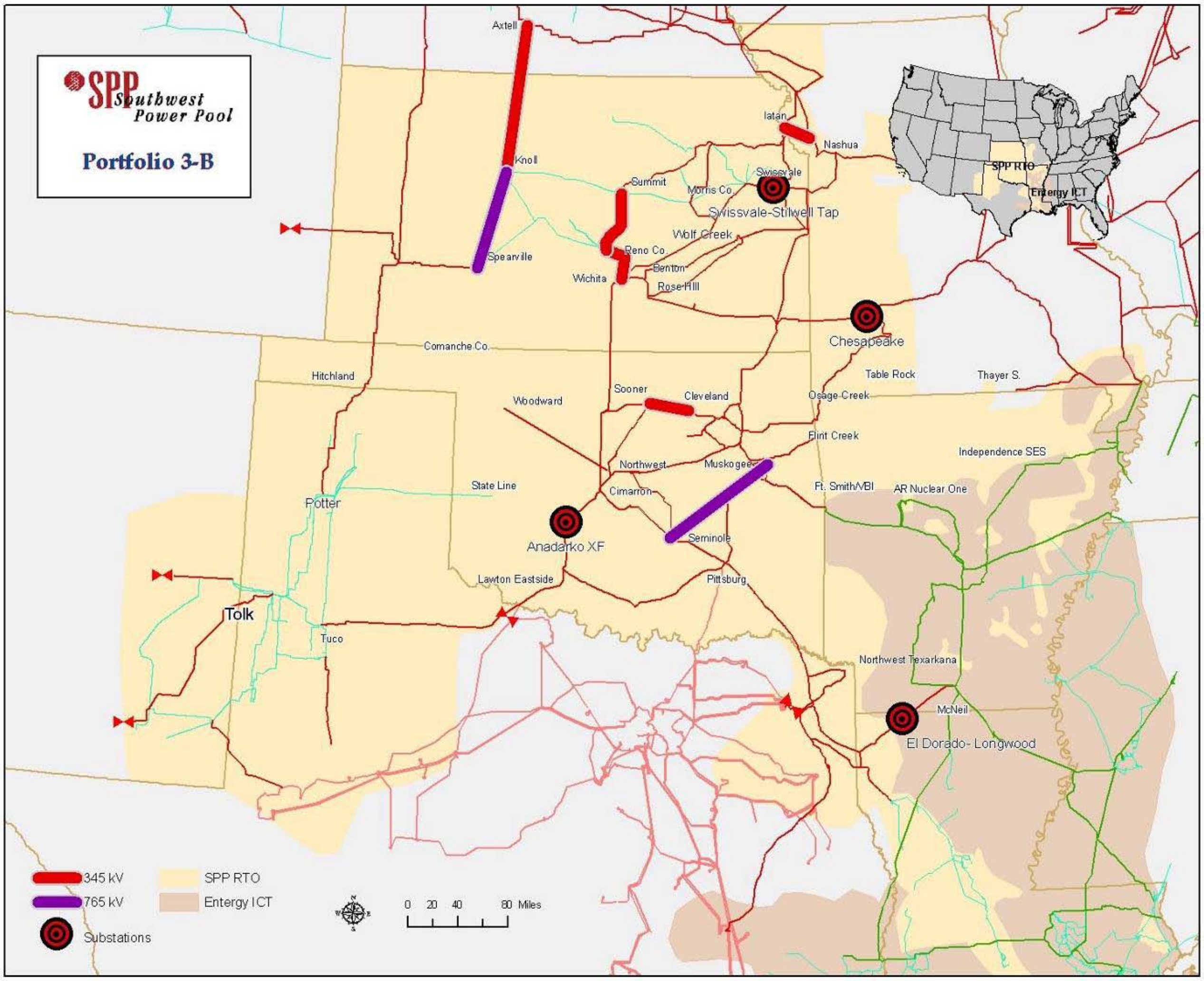
Portfolio 3, with Spearville – Knoll – Axtell (SKA)



Portfolio 3-A with Wichita - Reno Co - Summit



Portfolio 3-B with Wichita – Reno Co - Summit



Modeling assumptions for the dispatch of wind were still an issue in these results where SPP staff used a wind offer price of $20/MWh. Given this caveat, the results showed that both Portfolios 3-A and 3-B had B/C ratios greater than one using 345 kV costs, but were marginal when 765 kV costs were used in the calculations. Portfolio 3-B is a sensitivity of Portfolio 3-A used to test whether or not the Tolk-Potter upgrades would increase the B/C ratio. Since they did, the SPP staff recommended going forward with Portfolio 3-A, as well as subsequent consideration of additional variations of Portfolio 3.

Initial Results for Portfolios 3-A and 3-B

Project	Cost ($M)	Proj 10 Year SPP Benefit ($M)	SPP B/C
345 kV Construction			
Portfolio 3-A	$585	$776	1.33
Portfolio 3-B	$545	$693	1.27
765 kV Construction			
Portfolio 3-A	$761	$776	1.02
Portfolio 3-B	$721	$693	0.96

<u>October 2008</u>: Portfolio 3 (High Wind) and 3-A (Current Wind)

Two different types of analyses were considered for Portfolios 3 and 3-A. Since Portfolio 3 has upgrades similar to those on the western portion of the proposed EHV system, the SPP staff evaluated Portfolio 3 using a high wind (7 GW) scenario with specific wind locations for wind capacity above the current 2008 level of 2.6 GWs. In particular, the B/C ratio was calculated for both 345 kV and 765 kV costs to get a feel for whether or not Portfolio 3 could support a portion of the EHV upgrades in the western SPP region.

High Wind (7 GW) for Portfolio 3

Scenario	SPP 10 Yr Benefit	Cost ($M)	B/C
Portfolio 3 - 345 kV	$ 1,920,593,438	829	2.32
Portfolio 3 - 765 kV*	$ 1,920,593,438	1,213	1.58

SPP staff used Portfolio 3-A to test the sensitivity of a carbon tax on the estimate of benefits from savings in the adjusted production costs. The results indicated that keeping wind at its current levels and imposing a carbon tax would, as expected, result in a significant decrease in benefits for Portfolio 3-A.

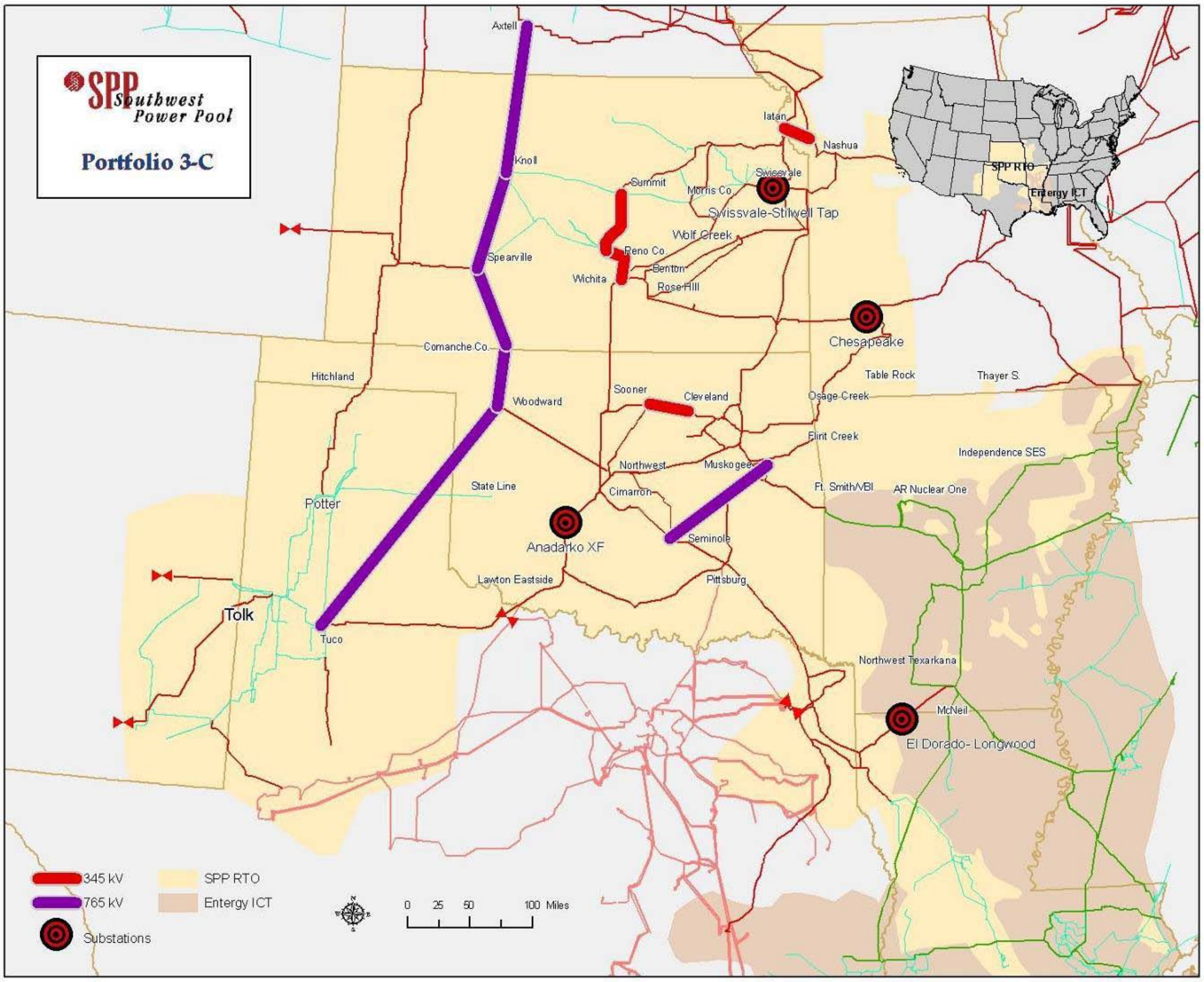
Carbon Tax Sensitivity Results for Portfolio 3-A at Current Wind (2.6 GW)

Project	Total Adjusted Production Cost	SPP NON-OATT	SPP OATT	TIER1	Cost	SPP B/C
Portfolio - P3A - Base	($119,180,000)	($2,454,920)	($111,931,080)	($4,794,000)	$ 597	1.27
Portfolio - P3A - $15 Carbon Tax	($60,140,000)	($4,000)	($52,699,000)	($5,543,000)	$ 597	0.60
Portfolio - P3A - $40 Carbon Tax	($17,992,000)	($317,000)	($16,926,000)	($1,630,000)	$ 597	0.19

December 2008: Portfolio 3-C (Modify Portfolio 3)

Portfolio 3-C was developed as a hybrid of Portfolios 3 and 3-A by removing the Tolk - Potter upgrades but adding the Spearville – Knoll - Axtell and Wichita – Reno Co - Summit lines. The following graph pictorially represents Portfolio 3-C.

Portfolio 3-C



It should be noted that by this time SPP staff had resolved a problem with its application of the PROMOD that had resulted in dispatching wind on a small number of days, resulting in what appeared to be a significant “trapped generation” problem. With the resolution of that issue, wind was now being dispatched from specified injection points at $0.05/MWh. Note that this was an offer price for the wind injection into the market since using an offer price of $0/MWh which caused problems in the modeling. The final clearing price of wind is at the marginal zonal market price for each hour, which is significantly higher than the offer price; i.e. wind in the actual production cost models is priced at the marginal zonal market price.

SPP staff used Portfolio 3-C to perform an analysis of an integration plan for the EHV Overlay. For this effort, scenarios were conducted at 3,300 MW of wind injection in 2012, 7,000 MW of wind injection in 2017, and 13,500 MW of wind injection in 2023, with 765 kV transmission being added to the analysis to accommodate the higher wind levels assumed for wind. The following table shows the B/C ratio that would apply had the results of year 2012 been distributed uniformly over a ten-year period and compared to the ten-year cost. In addition, the results are shown using ten years of Annual Transmission Revenue Requirements (ATRR) for the EHV projects contained in the study periods 2012, 2017 and 2023.

Portfolio 3-C + EHV Build Out		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C (P3-C)	0.74	0.66
10 yr vs E&C (P3-C+West EHV)	0.79	0.72
10 yr vs E&C (P-3C+West & Central EHV)	2.43	1.45
10 yr vs ATRR	**0.71**	**0.49**
Annual B/C (final year)	1.99	1.19

SPP staff reran portfolio 3-A at 3,300 MW of wind to determine the impact of adding 700 MW of market-based wind to the benefits of this portfolio. The following table gives the results for Portfolio 3-A using 765 kV costs.

Portfolio 3-A		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C	1.46	1.30
10 yr vs ATRR	**1.19**	**1.06**
Annual B/C (final year)	1.46	1.29

In addition to the adjusted production cost and cost benefit analysis, SPP Staff analyzed the impacts of the portfolio options on basic reliability. Portfolios 3-C and 3-A were considered in this analysis. The results of the total Engineering and Construction (E&C) cost impacts on regional reliability are shown in the table below with 3-C yielding the greatest benefits by reducing reliability needs to a net amount of $31M. More detailed impacts are shown in Appendix D.

P3-A and 3-C impact on STEP reliability assessment

Project	New Violations	Solved Violations	Net
Portfolio 3-A	$4,385,000	$4,004,900	**-$380,100**
Portfolio 3-C	$4,585,000	$35,265,250	**$30,680,250**

<u>January 2009</u>: Further Analysis of Portfolios 3-A and 3-C With Nebraska

At the December 2008 CAWG meeting, further analysis of Portfolios 3-A and 3-C was requested, including the addition of the three pricing zones in Nebraska as a result of the Nebraska entities decision to join the Southwest Power Pool. The emphasis on Portfolio 3-A was in regard to the balance of this portfolio when the Nebraska zones were added, and to compare this balance when Portfolio 3-A upgrades are priced at 345 kV versus 765 kV costs. With the addition of Nebraska, the B/C ratio for Portfolio 3-A at 765 kV increased from 1.06 to 1.11, and at 345 kV from 1.27 to 1.50. The higher costs at 765 kV resulted in significant levels of cost transfers needed to balance the portfolio compared to the lower costs at 345 kV.

Portfolio Balance With Transfers for Portfolio 3-A at 345 KV Costs

#	Zone	Benefits	Costs	Transfer Allocation	Transfer Out	Transfer Net	Net Benefit	B/C	Original B/C
1	AEPW	$20,880,672	$24,939,597	$14,640,350	-$18,699,275	-$4,058,925	$0	1.00	0.84
2	EMDE	$5,828,820	$2,923,755	$1,716,339	$0	$1,716,339	$1,188,726	1.26	1.99
3	GRDA	$1,797,527	$2,170,293	$1,274,032	-$1,646,798	-$372,766	$0	1.00	0.83
4	KCPL	$8,337,354	$8,571,771	$5,031,907	-$5,266,324	-$234,417	$0	1.00	0.97
5	MIDW	$1,590,879	$798,241	$468,593	$0	$468,593	$324,045	1.26	1.99
6	MIPU	$1,598,074	$4,491,010	$2,636,368	-$5,529,303	-$2,892,935	$0	1.00	0.36
7	MKEC	$5,294,897	$1,243,893	$730,206	$0	$730,206	$3,320,798	2.68	4.26
8	OKGE	$44,982,968	$15,731,003	$9,234,607	$0	$9,234,607	$20,017,358	1.80	2.86
9	SPRM	-$29,773	$1,719,556	$1,009,435	-$2,758,764	-$1,749,329	$0	1.00	-0.02
10	SUNC	$389,069	$1,185,151	$695,722	-$1,491,804	-$796,082	$0	1.00	0.33
11	SWPS	$43,102,775	$12,809,661	$7,519,685	$0	$7,519,685	$22,773,429	2.12	3.36
12	WEFA	$11,792,345	$3,508,023	$2,059,323	$0	$2,059,323	$6,224,999	2.12	3.36
13	WRI	$23,072,688	$12,818,241	$7,524,722	$0	$7,524,722	$2,729,725	1.13	1.80
14	NPPD	-$608,956	$8,896,109	$5,222,303	-$14,727,368	-$9,505,065	$0	1.00	-0.07
15	OPPD	-$472,047	$6,896,029	$4,048,192	-$11,416,267	-$7,368,075	$0	1.00	-0.07
16	LES	-$145,808	$2,130,072	$1,250,421	-$3,526,301	-$2,275,880	$0	1.00	-0.07
Total		**$167,411,485**	**$110,832,404**	**$65,062,205**	**-$65,062,205**	**$0**	**$56,579,080**	**1.51**	**1.51**

All numbers in the above table represent annualized costs for Portfolio 3-A over a ten-year period.

Transfers out of a zone represent the dollars that must be moved from the zonal rates to a region-wide rate in order to achieve balance. Two measures of the degree of balance of a portfolio include: a) the number of zones with positive net benefits after the transfers (in this case: 7 of 16 total zones); and b) the ratio of the transfers out to the costs of the upgrades (in this case: 58.7%).

Additional analysis of the EHV upgrades in Portfolio 3-C were performed with and without Portfolio 3-A to determine whether or not portfolio 3-A added more benefits than costs to a zone that would include parts of the EHV (765 kV) overlay. The results indicated that Portfolio 3-A did add more benefits than costs.

Analysis of Portfolio 3-C showed a B/C ratio of 0.58 using 765kV costs and a ratio of 0.94 using 345 kV costs.

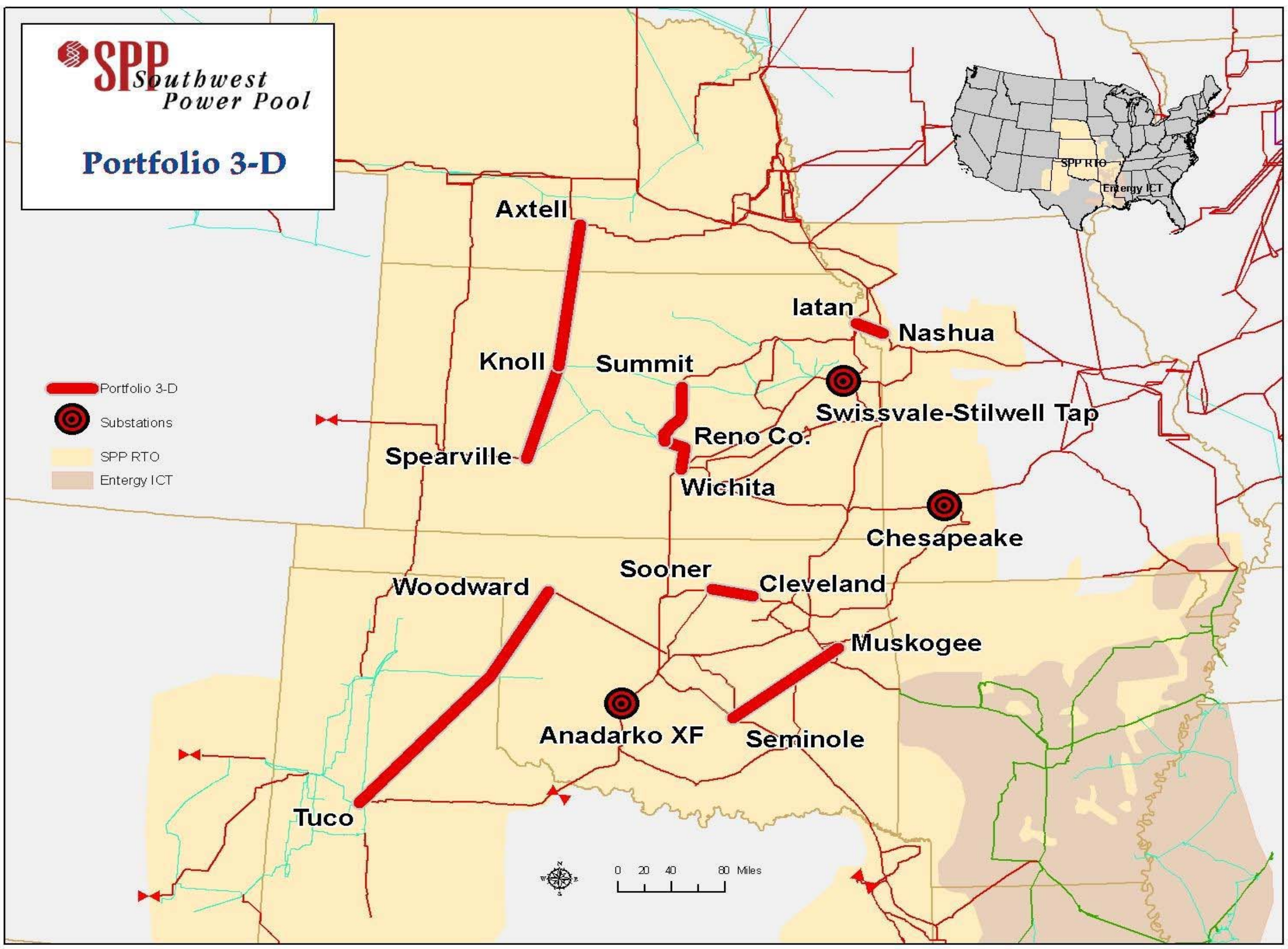
CAWG Response

Due to the difficulty in balancing a portfolio that includes 765 kV projects, as well the high level of uncertainty concerning the level of wind available to the SPP footprint on the planning horizon, it was decided in February 2009 that the Balanced Portfolio should include only existing wind generation in service or under construction. The CAWG directed SPP staff to update the economic models to reflect these changes and to work through the EMMTF to ensure that the models were vetted through the stakeholder process to ensure that all member data was represented accurately. Additionally, the CAWG requested that the Nebraska modeling parameters be updated to include a better, more expansive representation for utilities beyond Nebraska to better account for the economic interchange of energy beyond the Nebraska zones. Lastly, the CAWG requested that SPP Staff work with the EMMTF to update all costs associated with the construction of portfolio projects. The E&C costs had shown a significant degree of variability throughout the course of the Balanced Portfolio effort to date due to changes in the economic climate, leading the CAWG to seek an accurate, updated account of these associated construction costs from each respective constructing member.

SPP Staff Action Plan

SPP staff, in response to the CAWG, developed an action plan to address the issues raised and also developed a timeline for the completion of the Balanced Portfolio analysis that would conclude with a staff recommendation in April 2009. This action plan detailed how SPP staff would work with the EMMTF to address any outstanding modeling and cost issues for the simulation of the Balanced Portfolio. Additionally, the action plan, corresponding to the suggestion by the CAWG, defined that the analysis would consider only existing wind resources. SPP staff worked with stakeholders to determine the exact levels of existing wind resources on the system in the process of facilitating the modeling refinements through the EMMTF. Also, as the RSC directed, Portfolios 3, 3-A and 3-C were used as a starting point for these additional analyses. Lastly, Portfolio 3-D (shown below) was developed and included in the analysis. This action plan was presented to the CAWG at the end of January 2009.

Portfolio 3-D



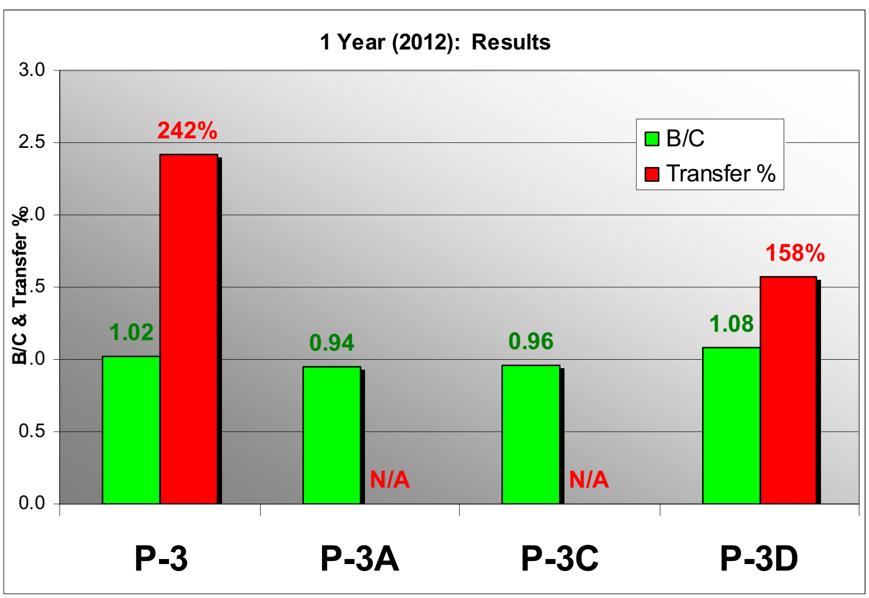
March 2009: Final Balanced Portfolio Analysis

Further material pertaining to the Balanced Portfolio was not presented until the March 2009 CAWG meeting. staff and stakeholders spent the majority of February working through the EMMTF on updating process and refining the engineering models used for the analysis. Additionally, the EMMTF members reviewed their respective output data and provided feedback to SPP staff. The data was checked for the reasonableness of the output results as well as the accuracy of the input into the production cost modeling. These changes were included in the Balanced Portfolio analysis.

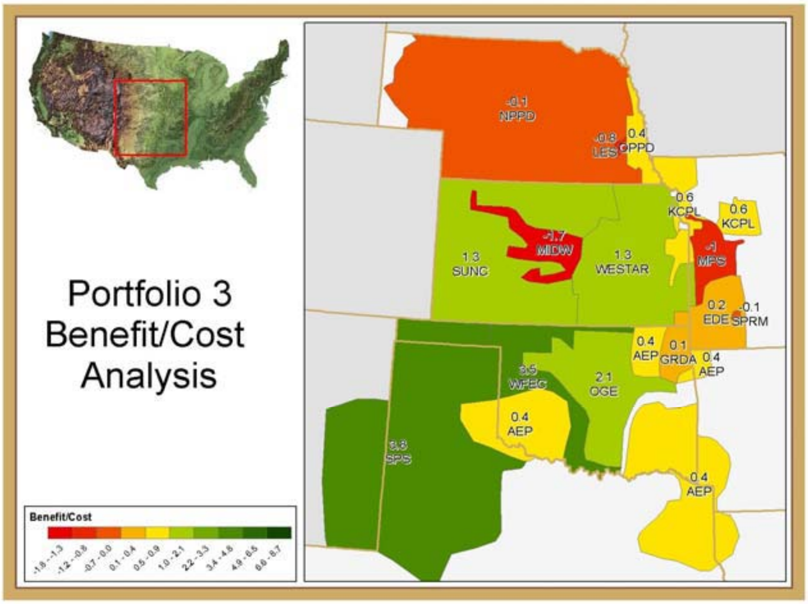
During the March 2009 CAWG meeting, the results from the analysis described above were presented. SPP staff started with a screening analysis on Portfolios 3, 3-A, 3-C, and 3-D. This analysis was conducted on the 2012 model and taken as an annual benefit to cost basis. The results are shown in the following exhibits.

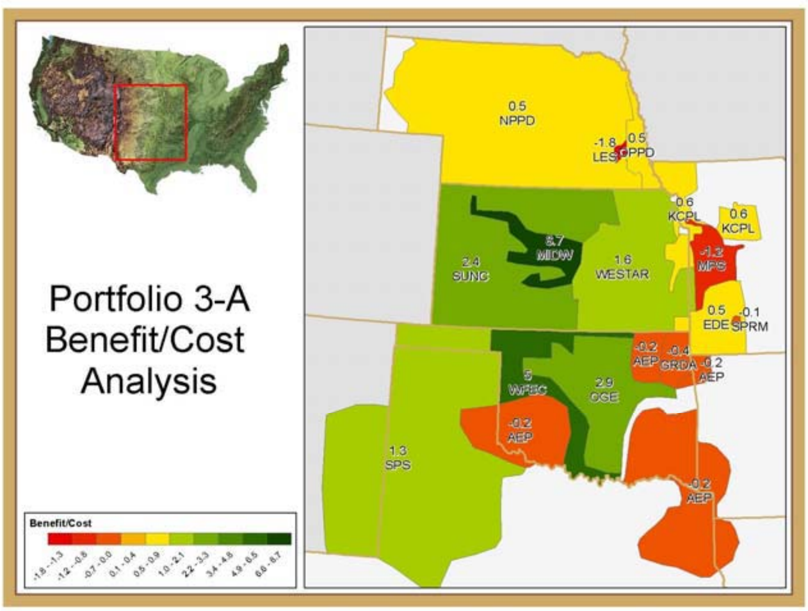
1 Year (2012) Screening Results

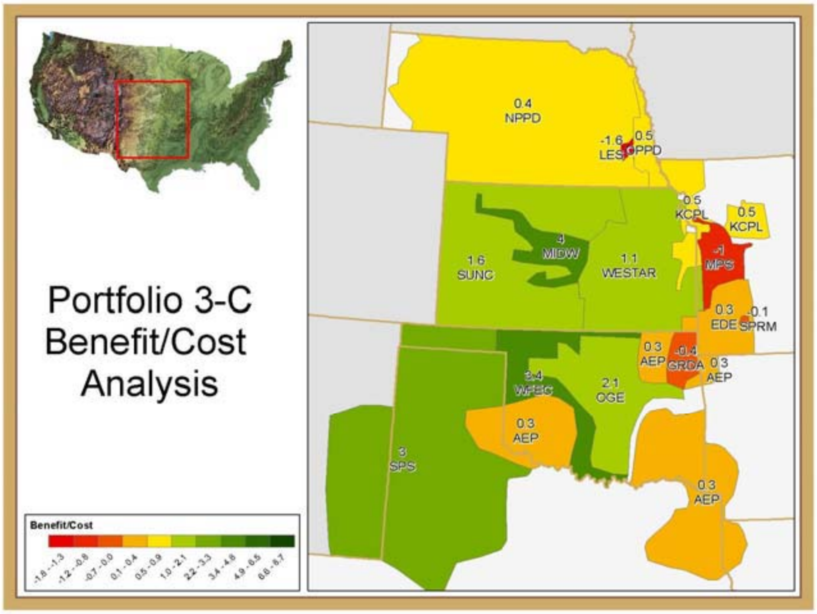
Project	Total APC Benefit ($M)	SPP OATT Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3	$124	$122	$2.6	$ 120	**1.02**	**242%**
P-3A	$117	$114	$2.7	$ 121	**0.94**	**n/a**
P-3C	$159	$159	($0.4)	$ 166	**0.96**	**n/a**
P-3D	**$148**	**$149**	**($1.3)**	***$ 139***	**1.08**	**158%**

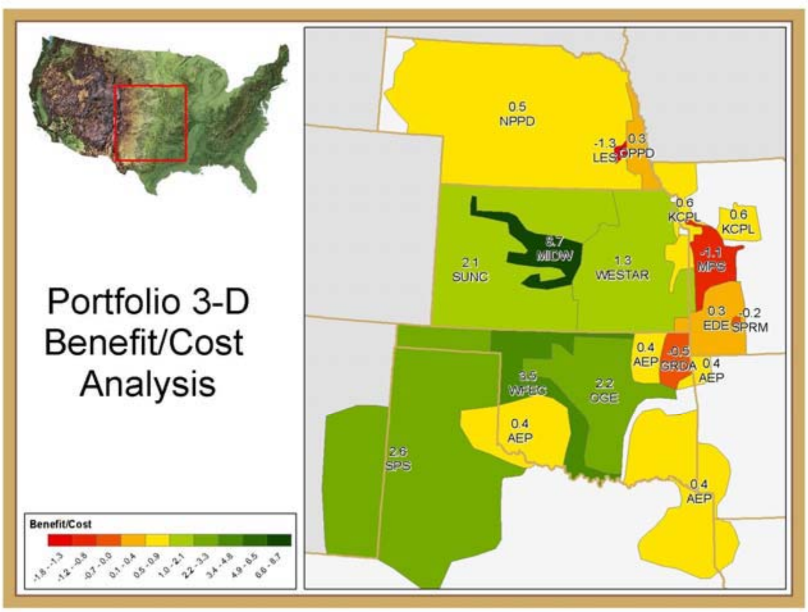


The Benefit to Cost ratio per zone is shown for the respective portfolios in the following pictures. The B/Cs shown here are before transfers have been conducted to balance the respective portfolios.









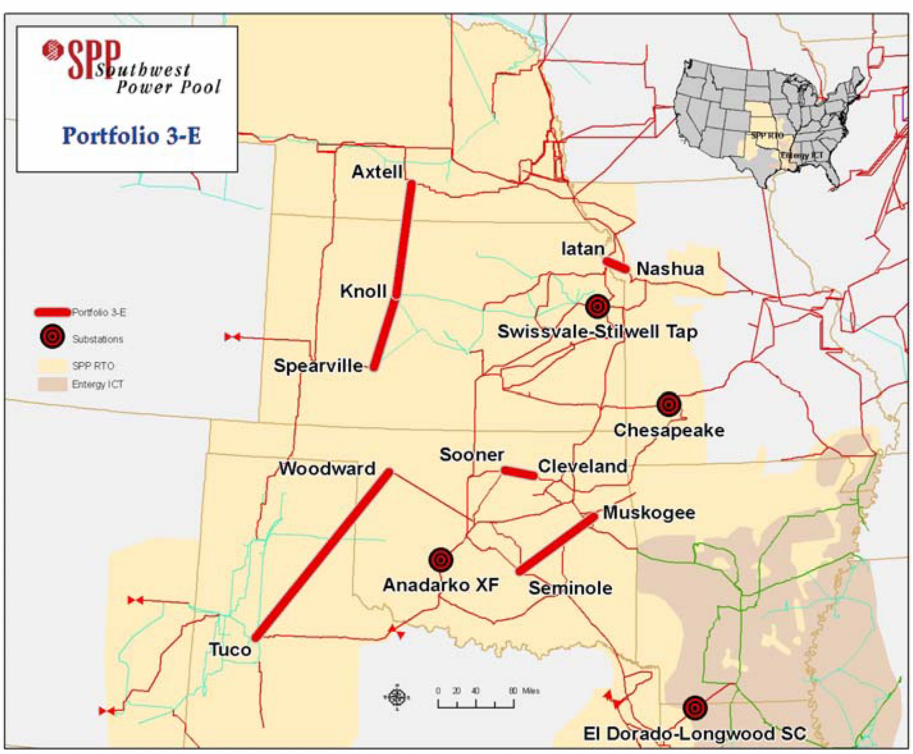
Portfolio 3-D had the highest B/C ratio of the four portfolios screened and was selected for further development. In this analysis, each of the individual projects in the Portfolio was removed to determine the impact of the project on the portfolio as a whole. These results are shown in the following table. The table is divided into total Adjusted Production Cost (APC) benefit, benefit for SPP Open Access Transmission Tariff (OATT) members as well as benefits to areas outside the region, shown here as Tier 1 benefits. The transfer percentage (%) shown is the percentage of the total portfolio cost in dollars that must be transferred, following tariff provisions, to balance the respective portfolios shown below. Ideally, the goal is a lower transfer percentage is desirable with a higher B/C.

Portfolio 3-D Refinement Analysis

Project	Total APC Benefit ($M)	SPP Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3D	$148	$149	($1.3)	$ 139	1.08	158%
Portfolio 3D sensitivities						
no WRS (P-3E)	**$137**	**$132**	**$4.3**	**$ 107**	**1.24**	**121%**
no SKA	**$127**	**$128**	**($0.8)**	**$ 114**	**1.12**	**111%**
no TW	$121	$116	($1.1)	$ 105	1.10	324%
no Ches	$146	$148	($1.4)	$ 136	1.09	156%
no SM	$116	$122	($6.6)	$ 115	1.06	183%
no IN	$143	$142	$0.5	$ 132	1.08	168%
no WGard	$152	$149	($1.6)	$ 138	1.08	160%
no ADK	$146	$147	($0.9)	$ 137	1.07	159%
no SC	$120	$122	($1.2)	$ 135	0.90	n/a

The projects that were the best candidates for removal from Portfolio 3-D were (1) Wichita – Reno Co. – Summit, (2) Spearville – Knoll – Axtell and (3) the Chesapeake Transformer. SPP staff recommended during the March 2009 CAWG meeting that the Wichita – Reno Co. – Summit line be removed from the portfolio, but also recommended Spearville – Knoll – Axtell and Chesapeake stay in the portfolio to maintain balance. This Portfolio was labeled Portfolio 3-E and is shown in the following map.

Portfolio 3-E



Portfolio 3-D and 3-E were selected as the candidates for the full 10-year analysis of portfolios as required by the Tariff. The following tables demonstrate the results of the 10-year analysis, with interpolation between simulated years, 2012, 2017 and 2022. The results are discounted back to present worth, using an 8% discount rate. Levelized annual values were also calculated. The annual cost of the each portfolio is given such that the host utility carrying charge rate is assumed to be used for the construction of the project.

Portfolio 3-D: 10 Year Benefit vs. Costs

Portfolio 3-D			Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
			Million of Dollars				
2012			$ 149.0		$ 138.55		826.4
2017			$ 208.5	$ 11.904	$ 138.55	$ -	**Annual**
2022			$ 260.3	$ 10.364	$ 138.55	$ -	138.5

Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 149	$ 149	$ 139	$ 139	**1.08**
2013	2	0.93	$ 161	$ 149	$ 139	$ 128	1.16
2014	3	0.86	$ 173	$ 148	$ 139	$ 119	1.25
2015	4	0.79	$ 185	$ 147	$ 139	$ 110	1.33
2016	5	0.74	$ 197	$ 145	$ 139	$ 102	1.42
2017	6	0.68	$ 209	$ 142	$ 139	$ 94	**1.50**
2018	7	0.63	$ 219	$ 138	$ 139	$ 87	1.58
2019	8	0.58	$ 229	$ 134	$ 139	$ 81	1.65
2020	9	0.54	$ 240	$ 129	$ 139	$ 75	1.73
2021	10	0.50	$ 250	$ 125	$ 139	$ 69	1.80
2022	11	0.46	$ 260	$ 121	$ 139	$ 64	**1.88**
Ten Year Totals	Yrs 1-10	7.25	$ 2,010	$ 1,405	$ 1,385	$ 1,004	**1.40**
Per Year Levelized				**$ 194**		**$ 139**	**1.40**

Portfolio 3-DE: 10 Year Benefit vs. Costs

Portfolio 3-E			Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
				Million of Dollars			
2012			$ 132.3		$ 106.63		657.4
2017			$ 181.2	$ 9.786	$ 106.63	$ -	**Annual**
2022			$ 229.5	$ 9.652	$ 106.63	$ -	106.6
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 132	$ 132	$ 107	$ 107	**1.24**
2013	2	0.93	$ 144	$ 133	$ 107	$ 99	1.35
2014	3	0.86	$ 156	$ 134	$ 107	$ 91	1.46
2015	4	0.79	$ 168	$ 133	$ 107	$ 85	1.58
2016	5	0.74	$ 180	$ 132	$ 107	$ 78	1.69
2017	6	0.68	$ 181	$ 123	$ 107	$ 73	**1.70**
2018	7	0.63	$ 192	$ 121	$ 107	$ 67	1.80
2019	8	0.58	$ 202	$ 118	$ 107	$ 62	1.89
2020	9	0.54	$ 212	$ 115	$ 107	$ 58	1.99
2021	10	0.50	$ 223	$ 111	$ 107	$ 53	2.09
2022	11	0.46	$ 229	$ 106	$ 107	$ 49	**2.15**
Ten Year Totals	Yrs 1-10	7.25	$ 1,790	$ 1,253	$ 1,066	$ 773	**1.62**
Per Year Levelized				**$ 173**		**$ 107**	**1.62**

A reliability impact analysis was conducted on the portfolio projects to determine the impact of the Balanced Portfolio on the STEP reliability analysis as well as on Tier 1 entities, third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in the 2008 STEP 10 year reliability analysis. The analysis was conducted for the entire collection of portfolio projects considered for the March CAWG meeting. The results are broken into (1) advanced projects, those projects that would be moved up in the reliability timeline due to the Balanced Portfolio; (2) new projects, projects which are now needed that were not identified in the original 10 year reliability planning horizon, but may have been needed beyond that horizon; (3) third party impacts or projects needed on neighboring systems due to the Balanced Portfolio; and (4) deferred projects, projects which are either deferred beyond the planning horizon or mitigated entirely due to the portfolio. A summary of these results is shown in the table below.

Reliability Impact (E&C Dollars)

Portfolio	Advanced Projects	New Projects	3rd Party Impacts	Deferred Projects	Net Benefit
P-3	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3A	$ 1.0	$ 3.4	$ 10.2	$ 27.7	$ 13.1
P-3C	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3D	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7
P-3E	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7

April 2009: Balanced Portfolio Summit

The material from the March 2009 CAWG meeting was presented at an open meeting in Dallas, TX, April 1, 2009 as an SPP open stakeholder summit. Stakeholder comments and feedback were collected during this summit and incorporated in the final analysis used in the subsequent recommendation to the CAWG on an April 10th conference call.

Feedback from stakeholders and the CAWG included a request to consider the inclusion of a portion of the Wichita – Reno Co – Summit in the final recommendation, if it was feasible, and to include the project given its benefit and costs. Additionally, Empire District Electric Company staff requested that the Chesapeake transformer project be removed from the Balanced Portfolio recommendation due to the complex nature of the project and the associated third party impacts. Also, the CAWG directed SPP to further refine cost estimates of the projects in the portfolio to include greater granularity in the itemization of project costs associated with the portfolio projects, including but not limited to material costs, right of way requirements, labor, etc. Lastly, SPP staff was directed to determine the appropriate carrying charge rates to be used for each host zone to ensure that consistent values were being applied to all projects so that they could be considered on a consistent and reasonable basis.

April 2009: CAWG Conference Call

The work presented during the April SPP open stakeholder summit was refined to reflect the stakeholder feedback and comments and presented to the CAWG on April 10 via conference call.

The first portfolio change was to consider the removal of the Chesapeake transformer. The results are shown in the following tables.

Portfolio 3-E No Chesapeake: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches			Million of Dollars Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012			$ 132.3		$ 93.73		691.9
2017			$ 181.2	$ 9.79	$ 93.73	$ -	Annual
2022			$ 229.5	$ 9.65	$ 93.73	$ -	93.7

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 132	$ 132	$ 94	$ 94	**1.41**
2013	2	0.93	$ 145	$ 134	$ 94	$ 87	1.55
2014	3	0.86	$ 158	$ 135	$ 94	$ 80	1.68
2015	4	0.79	$ 171	$ 136	$ 94	$ 74	1.82
2016	5	0.74	$ 184	$ 135	$ 94	$ 69	1.96
2017	6	0.68	$ 181	$ 123	$ 94	$ 64	**1.93**
2018	7	0.63	$ 191	$ 120	$ 94	$ 59	2.04
2019	8	0.58	$ 201	$ 117	$ 94	$ 55	2.14
2020	9	0.54	$ 210	$ 114	$ 94	$ 51	2.24
2021	10	0.50	$ 220	$ 110	$ 94	$ 47	2.35
2022	11	0.46	$ 229	$ 106	$ 94	$ 43	**2.45**
Ten Year Totals	Yrs 1-10	7.25	$ 1,792	$ 1,257	$ 937	$ 679	**1.85**
Per Year Levelized				**$ 173**		**$ 94**	**1.85**

The transfer analysis for portfolio 3-E without Chesapeake is shown in the following table. The analysis concluded that $32M of transfers were required to balance this portfolio.

Attachment H Transfer Adjustments - Portfolio 3E no Ches - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.8	$21.1	$0.0	$7.2	$7.2	$2.5	**1.1**
2	EMDE	($0.4)	$2.5	($3.7)	$0.8	($2.8)	$0.0	**1.0**
3	GRDA	$0.8	$1.8	($1.6)	$0.6	($1.0)	$0.0	**1.0**
4	KCPL	$8.3	$7.2	($1.4)	$2.5	$1.1	$0.0	**1.0**
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	**14.1**
6	MIPU	($1.6)	$3.8	($6.7)	$1.3	($5.4)	$0.0	**1.0**
7	MKEC	$11.7	$1.1	$0.0	$0.4	$0.4	$10.2	**8.3**
8	OKGE	$26.5	$13.3	$0.0	$4.6	$4.6	$8.6	**1.5**
9	SPRM	($0.2)	$1.5	($2.1)	$0.5	($1.6)	$0.0	**1.0**
10	SUNC	$3.2	$1.0	$0.0	$0.3	$0.3	$1.9	**2.4**
11	SWPS	$56.0	$10.8	$0.0	$3.7	$3.7	$41.5	**3.9**
12	WEFA	$7.9	$3.0	$0.0	$1.0	$1.0	$3.9	**2.0**
13	WRI	$14.2	$10.8	($0.4)	$3.7	$3.4	$0.0	**1.0**
14	NPPD	$5.5	$7.5	($4.6)	$2.6	($2.0)	$0.0	**1.0**
15	OPPD	$2.2	$5.8	($5.7)	$2.0	($3.7)	$0.0	**1.0**
16	LES	($3.5)	$1.8	($5.9)	$0.6	($5.3)	$0.0	**1.0**
Total		**$174**	**$94**	**-$32**	**$32**	**$0**	**$80**	**1.9**

Next, the inclusion of the Reno Co – Summit portion of the Wichita – Reno Co. – Summit Project was considered for inclusion after the removal of the Chesapeake transformer. These results are shown below.

Portfolio 3-E No Chesapeake, with Reno Co. - Summit: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches, With RS — Million of Dollars

	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012	$ 178.0		$ 105.56		789.0
2017	$ 242.1	$ 12.816	$ 105.56	$ -	**Annual**
2022	$ 290.4	$ 9.658	$ 105.56	$ -	105.6

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 178	$ 178	$ 106	$ 106	**1.69**
2013	2	0.93	$ 191	$ 177	$ 106	$ 98	1.81
2014	3	0.86	$ 204	$ 175	$ 106	$ 90	1.93
2015	4	0.79	$ 216	$ 172	$ 106	$ 84	2.05
2016	5	0.74	$ 229	$ 169	$ 106	$ 78	2.17
2017	6	0.68	$ 242	$ 165	$ 106	$ 72	**2.29**
2018	7	0.63	$ 252	$ 159	$ 106	$ 67	2.38
2019	8	0.58	$ 261	$ 153	$ 106	$ 62	2.48
2020	9	0.54	$ 271	$ 146	$ 106	$ 57	2.57
2021	10	0.50	$ 281	$ 140	$ 106	$ 53	2.66
2022	11	0.46	$ 290	$ 135	$ 106	$ 49	**2.75**
Ten Year Totals	Yrs 1-10	7.25	$ 2,325	$ 1,632	$ 1,056	$ 765	**2.13**
Per Year Levelized				**$ 225**		**$ 106**	**2.13**

The transfer analysis for portfolio 3-E without Chesapeake but including with Reno Co. - Summit is shown in the following table. The analysis concluded that $62M of transfers were required to balanced this portfolio

Attachment H Transfer Adjustments - Portfolio 3E no Ches with RS - Annualized

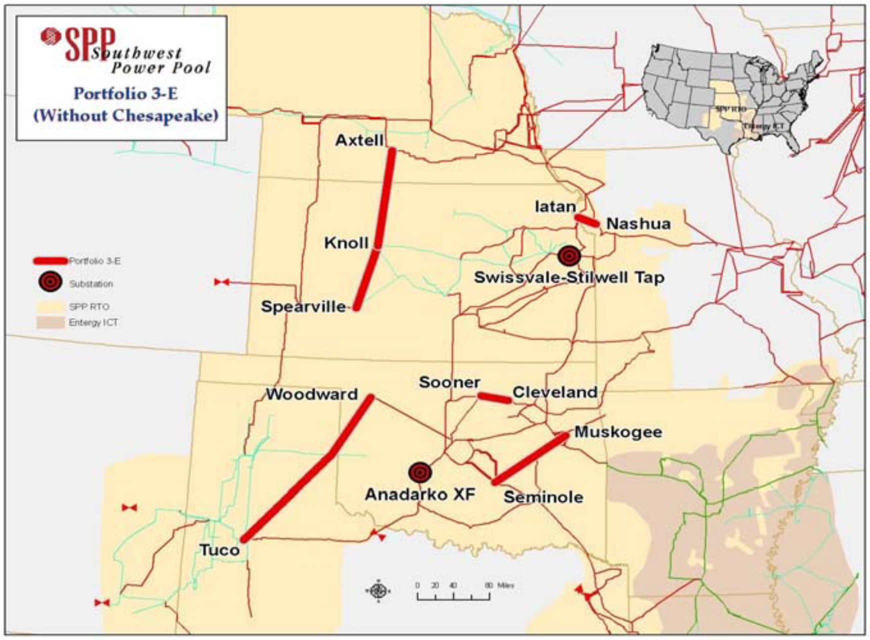
#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$25.8	$23.7	($11.8)	$13.9	$2.1	$0.0	1.0
2	EMDE	($0.1)	$2.8	($4.5)	$1.6	($2.9)	$0.0	1.0
3	GRDA	$0.1	$2.1	($3.2)	$1.2	($1.9)	$0.0	1.0
4	KCPL	$8.7	$8.2	($4.2)	$4.8	$0.5	$0.0	1.0
5	MIDW	$12.8	$0.8	$0.0	$0.4	$0.4	$11.6	10.7
6	MIPU	($5.6)	$4.3	($12.4)	$2.5	($9.9)	$0.0	1.0
7	MKEC	$11.3	$1.2	$0.0	$0.7	$0.7	$9.4	6.0
8	OKGE	$36.8	$15.0	$0.0	$8.8	$8.8	$13.0	1.5
9	SPRM	($0.3)	$1.6	($2.9)	$1.0	($1.9)	$0.0	1.0
10	SUNC	$3.6	$1.1	$0.0	$0.7	$0.7	$1.8	2.0
11	SWPS	$55.9	$12.2	$0.0	$7.1	$7.1	$36.6	2.9
12	WEFA	$11.8	$3.3	$0.0	$2.0	$2.0	$6.5	2.2
13	WRI	$59.9	$12.2	$0.0	$7.1	$7.1	$40.6	3.1
14	NPPD	$5.4	$8.5	($8.0)	$5.0	($3.0)	$0.0	1.0
15	OPPD	$2.7	$6.6	($7.7)	$3.8	($3.8)	$0.0	1.0
16	LES	($3.9)	$2.0	($7.1)	$1.2	($5.9)	$0.0	1.0
Total		**$225**	**$106**	**-$62**	**$62**	**$0**	**$120**	**2.1**

An analysis was conducted to determine the impact on total Annual Transmission Revenue Requirement (ATRR) for each zone in the tariff. The results are shown for portfolio 3-E, "3-E no Chesapeake" and "3-E no Chesapeake with Reno Co – Summit". These results are shown in the following table.

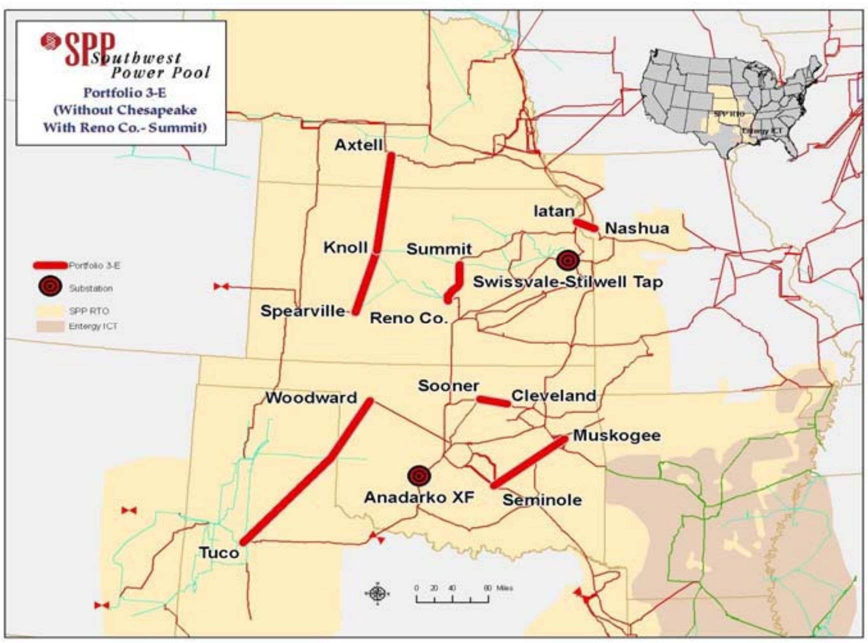
Total ATRR for Proposed Balanced Portfolios

	BP 3E	3E no Ches	BP 3E no Ches w RS
Zone	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR
AEPW	$ 175,484,688	$ 177,104,393	$ 174,641,806
SPRM	$ 8,934,262	$ 8,659,884	$ 8,524,079
EMDE	$ 14,660,746	$ 14,007,997	$ 14,294,209
GRDA	$ 25,891,875	$ 26,032,862	$ 25,312,950
KCPL	$ 43,661,239	$ 44,709,872	$ 45,060,781
OKGE	$ 118,952,010	$ 116,849,771	$ 122,735,245
MIDW	$ 5,277,346	$ 5,170,672	$ 5,469,320
MIPU	$ 19,618,726	$ 19,420,118	$ 15,471,824
SWPA	$ 9,431,500	$ 9,431,500	$ 9,431,500
SWPS	$ 104,700,870	$ 102,989,030	$ 107,781,536
SUNC	$ 16,092,722	$ 15,934,343	$ 16,377,746
WEFA	$ 25,545,806	$ 25,077,005	$ 26,389,469
WRI	$ 128,845,823	$ 129,135,340	$ 134,286,149
MKEC	$ 7,723,354	$ 7,557,124	$ 8,022,505
LES	$ 8,877,057	$ 8,718,252	$ 8,313,564
NPPD	$ 53,140,390	$ 53,181,895	$ 53,125,563
OPPD	$ 38,645,990	$ 38,661,265	$ 39,227,136
	$ 805,484,404	**$ 802,641,325**	**$ 814,465,382**

Portfolio 3-E "Adjusted"



Portfolio 3-E with Reno Co – Summit, without Chesapeake



Recommendation

The CAWG endorsed portfolio 3-E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3-E “Adjusted” provides a significant benefit vs. cost to the SPP region, as well as having lower balance transfer requirements. Portfolio 3-E “Adjusted” contains a comprehensive group of economic projects addressing many of the top constraints in the SPP. The projects associated with portfolio 3-E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The supporting material for portfolio 3-E was presented to the Markets and Operations Policy Committee (MOPC) in April 2009. The MOPC reviewed and discussed the portfolio options and the impact on the footprint. After discussion, the MOPC endorsed the recommendation for Balanced Portfolio 3-E “Adjusted” pending issuance of the final report, according to the SPP Tariff.

Portfolio 3-E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58. Additionally, it should be noted that the Portfolio could incur a construction cost increase of up to 113%, or more than double the estimated construction cost, and still provide a benefit to cost ratio of 1.0 for the region. Therefore, the Balanced Portfolio could have a total E&C final cost of over $1.4B and still provide benefits greater than costs.

Estimated SPP average customer impact (based on 1,000 kWh/month usage)

Existing Zonal ATRR	Base Plan		New Base Plan NTCs		P-3E Costs
	1/3	2/3	1/3	2/3	Annual
$688M	$7M	$14M	$33M	$66M	$106 M
Total: $808M					13%
Avg. Cost Per Customer Per Month: $7.58					**88 ¢**

P-3E "Adjusted" Benefit = $1.66

The CAWG and MOPC recommendation of Portfolio 3-E “Adjusted” was presented to the SPP Regional State Committee (RSC) during their April 27, 2009 meeting in Oklahoma City where Portfolio 3-E “Adjusted” was endorsed by the RSC. Staff then presented to the MOPC and RSC the recommended Portfolio during the SPP Board of Directors meeting on April 28th. The SPP Board approved the projects in Balanced Portfolio 3-E “Adjusted” for inclusion in the SPP Transmission Expansion Plan. The SPP Board went on to direct staff to finalize the Balanced Portfolio Report in accordance with the SPP tariff. Furthermore, the Board directed that Notification To Construct letters for the Projects in the Balanced Portfolio be issued once the required Balanced Portfolio Report is finalized after CAWG review and MOPC approval.

Balanced Portfolio Stakeholder Process
The SPP Regional State Committee (**RSC**) requested the Cost Allocation Working Group (CAWG) to consider alternative cost allocations for economic upgrades.

Cost Allocation Working Group (**CAWG**)
The CAWG has been the primary stakeholder group overseeing development of the Balanced Portfolio. The CAWG created the Economic Concepts whitepaper. Many representatives from other SPP stakeholder groups attend the CAWG's monthly meetings.

Trapped Generation Task Force (**TGTF**)
This CAWG Task Force determined wind assumptions in the Adjusted Production Cost (**APC**) models.

Economic Modeling and Methods Task Force (EMMTF)
The EMMTF focused on the planning process and development of additional economic benefit metrics. It initially worked to acquire detailed data on generation units in the model. The EMMTF addressed confidential issues. The EMMTF is currently the Economic Studies Working Group (ESWG)

Regional Tariff Working Group (RTWG)
The RTWG facilitated acquiring FERC approval of Attachment O language for the Balanced Portfolio process.

Markets and Operations Policy Committee (MOPC), Board of Directors (BOD), Regional State Committee (RSC)
These groups will review and approve the Balanced Portfolio.

Planning Summits
Proposed Balanced Portfolios and related concepts were shared at planning summits in May and August.

Posting
Portfolios and associated information are posted on SPP.org:
http://www.spp.org/section.asp?pageID=120

Appendix

Final Benefit to Cost Results for the Balanced Portfolio

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Portfolio 3-E "Adjusted" 10 yr B/C with Reliability Impact

Portfolio 3-E "Adjusted"	Million of Dollars				
	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual
2012	$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017	$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022	$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	**1.87**

The following three tables break out the benefits from the economic analysis. These tables do not include the reliability benefits. The numbers represent a change between the change and base cases, with the change case including the Balanced Portfolio. A negative number denotes a reduction in cost which is considered a benefit. Likewise a positive number is a cost increase.

2012 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$21,285,000	($14,003,000)	$31,439,000	($24,155,000)
EMDE	$2,990,000	($2,096,000)	$207,000	$687,000
GRDA	$72,000	$159,000	$982,000	($751,000)
KCPL	$4,273,000	($637,000)	$9,994,000	($6,358,000)
LES	$1,297,000	$1,226,000	$0	$2,523,000
MIDW	($350,000)	($8,783,000)	$0	($9,133,000)
MIPU	$6,027,000	($3,968,000)	($5,000)	$2,064,000
MKEC	($7,563,000)	($2,015,000)	($925,000)	($8,653,000)
NPPD	$6,519,000	($28,000)	$11,726,000	($5,235,000)
OKGE	($85,787,000)	$52,737,000	($9,386,000)	($23,664,000)
OPPD	$2,165,000	$160,000	$4,247,000	($1,922,000)
SPRM	$734,000	($42,000)	$668,000	$24,000
SUNC	($5,206,000)	($2,096,000)	($5,171,000)	($2,131,000)
SWPS	($70,516,000)	$31,769,000	($519,000)	($38,228,000)
WEFA	($13,163,000)	$4,105,000	($375,000)	($8,682,000)
WRI	($5,257,000)	($359,000)	$2,131,000	($7,747,000)

2017 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$55,943,000	($17,738,000)	$71,548,000	($33,344,000)
EMDE	$3,525,000	($3,272,000)	$100,000	$153,000
GRDA	($28,000)	$163,000	$889,000	($754,000)
KCPL	$6,229,000	($3,576,000)	$11,897,000	($9,244,000)
LES	$2,019,000	$1,970,000	$0	$3,989,000
MIDW	($764,000)	($14,046,000)	$0	($14,810,000)
MIPU	$5,483,000	($3,915,000)	$79,000	$1,489,000
MKEC	($10,893,000)	($2,667,000)	($793,000)	($12,767,000)
NPPD	$5,842,000	($779,000)	$10,741,000	($5,678,000)
OKGE	($129,794,000)	$88,180,000	($14,032,000)	($27,582,472)
OPPD	$3,030,000	$276,000	$5,663,000	($2,357,000)
SPRM	$603,000	($60,000)	$251,000	$292,000
SUNC	($7,575,000)	($2,386,000)	($6,776,000)	($3,185,000)
SWPS	($80,497,000)	$18,914,000	($924,000)	($60,659,000)
WEFA	($22,863,000)	$14,785,000	($468,000)	($7,610,000)
WRI	($14,392,000)	($1,073,000)	$1,674,000	($17,139,000)

2022 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$67,322,000	($22,618,000)	$83,884,000	($39,181,000)
EMDE	$4,703,000	($4,421,000)	$91,000	$191,000
GRDA	($480,000)	$123,000	$1,003,000	($1,360,000)
KCPL	$6,624,000	($2,828,000)	$14,974,000	($11,178,000)
LES	$2,249,000	$2,150,000	$0	$4,399,000
MIDW	($736,000)	($14,659,000)	$0	($15,395,000)
MIPU	$2,680,000	($1,044,000)	($19,000)	$1,655,000
MKEC	($14,429,000)	($1,525,000)	($287,000)	($15,667,000)
NPPD	$6,488,000	($1,250,000)	$10,748,000	($5,510,000)
OKGE	($138,499,000)	$85,998,000	($22,388,000)	($30,113,000)
OPPD	$3,787,000	$378,000	$6,258,000	($2,093,000)
SPRM	$637,000	($317,000)	$301,000	$19,000
SUNC	($7,360,000)	($2,495,000)	($3,923,000)	($5,932,000)
SWPS	($89,381,000)	$2,205,000	($1,184,000)	($85,992,000)
WEFA	($20,837,000)	$13,197,000	($575,000)	($7,065,000)
WRI	($11,595,000)	($6,705,000)	$2,730,000	($21,030,000)

The following table demonstrates the benefits, costs and transfers on an annualized basis after the resulting reliability impacts, both the advancement and deferral, are accounted for. The net B/C impact of the reliability projects was an approximate marginal increase of .01 of the total Portfolio.

Portfolio 3-E "Adjusted" Annualized Benefits, Costs and Transfers, including Reliability Impacts

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		$176	$95	-$31	$31	$0	$81	1.86

The spreadsheet which was used to calculate the transfers in the above table can be found on the Balanced Portfolio section of the SPP Website.[††]

[††] http://www.spp.org/section.asp?pageID=120

The table shown below demonstrates the MW-mi impact of the deferred reliability projects. This impact is used to determine who receives the benefit for the deferral of each reliability project from the portfolio.

Portfolio 3-E – Reliability Impact MW-mi analysis

	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	CLEARWATER-GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	EL RENO- EL RENO SW 69KV CKT 1 - Upgrade	LONGVIEW-WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps
Date	**2015**	**2015**	**2016**	**2017**	**2018**
AEPW		1.6%			
EMDE					
GRDA					
KCPL					
MIDW	46.7%	16.2%			
MIPU					100.0%
MKEC	19.4%	36.0%			
OKGE	1.3%	5.3%		24.7%	
SPRM					
SUNC	9.9%	10.9%			
SWPS		4.4%			
WEFA				75.3%	
WRI	22.6%	22.1%	100.0%		
NPPD		3.6%			
OPPD					
LES					
	100.0%	100.0%	100.0%	100.0%	100.0%

Reliability Results

The reliability results for the Portfolio 3E "Adjusted" are shown in the following table. The projects are broken into "deferred" and "mitigated" issues and "new" issues. Additionally, projects are shown for potential third party impacts. Note that a project highlighted in yellow (e.g. EARLSBORO – FIXICO) indicates that the project is merely advanced in time and not an entirely new issue.

Portfolio 3e without Chesapeake

Costs of STEP Projects Solved by Portfolio 3e, with STEP date

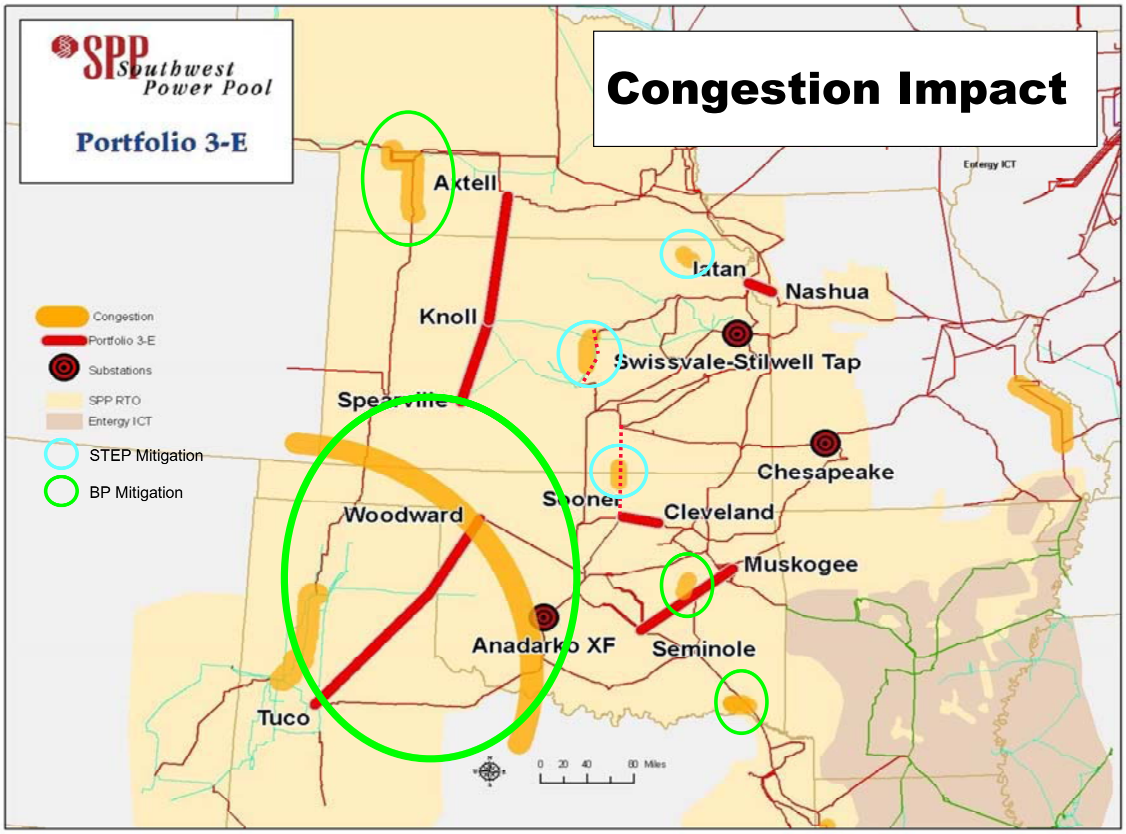
Issue Type	Project Name	Area	STEP Date	Deferred costs to TO: STEP projects solved by BP
Overload	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	WERE	16SP	$3,324,375
Overload	EL RENO - EL RENO SW 69KV CKT 1 - Upgrade	WFEC	17SP	$1,950,000
Overload	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	WERE	15SP	$12,487,500
Overload	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	MIDW	15SP	$7,965,000
Overload	LONGVIEW - WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps	MIPU	18SP	$50,000
Voltages	None			
			Totals	**$25,776,875**

Cost of potential mitigation for New issues due to implementation of portfolio improvements

Description	Project Name	Area	Date of Needed Mitigation	SPP New Issues, Cost	Third Party Issues: Cost
Overloads-SPP	EARLSBORO - FIXICO 69KV CKT 1 - Increase limits (trap, CT ratio)	OKGE	13SP	$150,000	
Overloads-SPP	MED LODGE-PRATT, ST.JOHN-GREATBENDTAP 115 KV LINE REBUILD	MKEC	18SP	$15,840,000	
Overloads-Third Party	PLATTE CITY 161/69KV TRANSFORMER CKT 1 - Replace AECI XFMR	MIPU-AECI	13WP		$7,500,000
Voltages	None				
			Totals	**$15,990,000**	**$7,500,000**
			Grand Total	**$23,490,000**	
			Net: Solved Minus SPP New	**$9,786,875**	
			Net: Solved Minus Total New	**$2,286,875**	

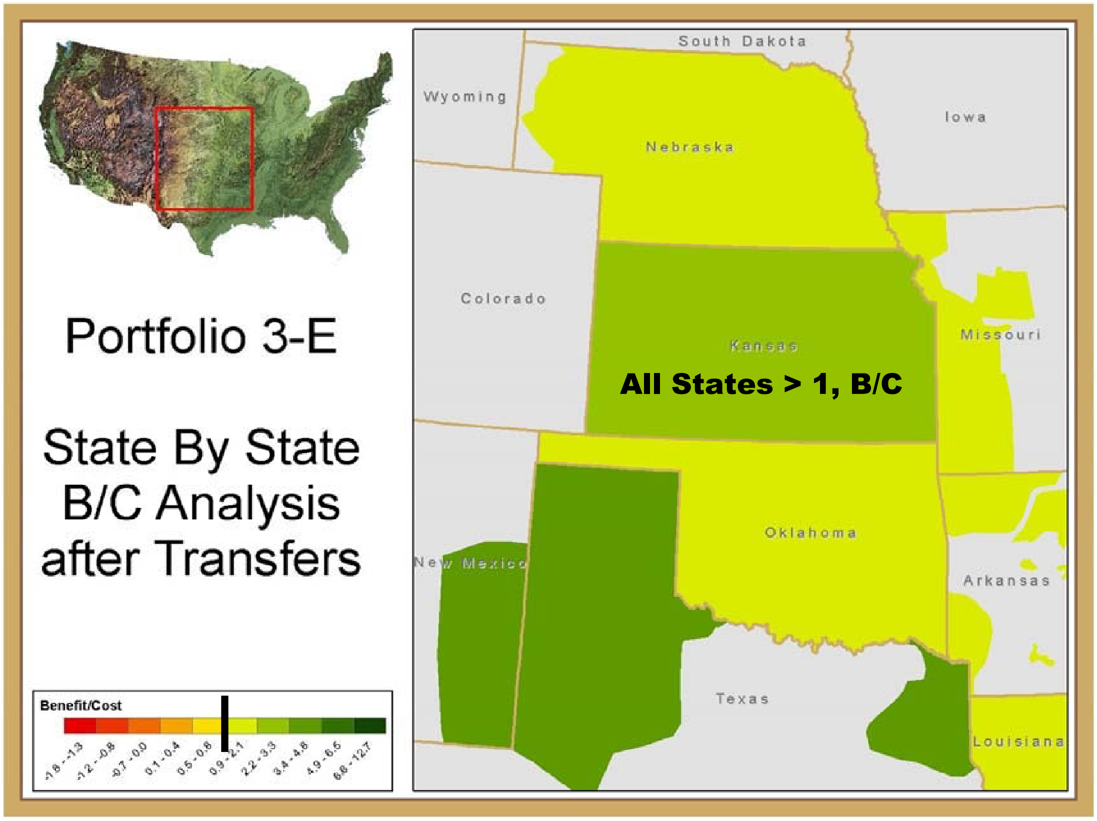
It should be noted that the third party impact of Platte City 161/69 kV transformer was coordinated with Associated Electric Cooperative, Inc. (AECI) staff. AECI staff did not see the same issue in their analysis.

Congestion Impact



The graphic shown above represents the top flowgates in the SPP EIS Market as they exist today. Congestion here is shown as an orange highlight. Portfolio projects, shown on the map as bold red highlight lines, relieve or mitigate much of the congestion that exists today. The congestion relief provided by the portfolio is shown as a green circle. Projects in the 10-year STEP plan that provide additional congestion relief are shown in light blue.

B/C by State



The diagram above demonstrates the B/C ratio of the Balanced Portfolio divided by state boundaries. While it should be noted that the portfolio of projects provides broad, regional benefits to all SPP members, this diagram is a good representation of the balance aspect of the portfolio broken into the respective state boundaries. This picture represents the balance of the portfolio after transfers have taken place in order to balance all zones. As can be seen from the diagram, all states have a B/C ratio greater than 1

SPP Balanced Portfolio Report

	Zone	OKGE	OKGE	OKGE	SPS	KCPL	NPPD	ITC	KCPL	OKGE
	Project	Sooner - Cleveland	Seminole - Muskogee	Tuco - Woodward	Tuco - Woodward	Iatan - Nashua	Knoll - Axtell	Spearville - Knoll - Axtell	Swissvale - Stilwell Tap	Andadarko Sub
	Projected In-Service Date	12/31/2012	12/31/2013	5/19/2014	5/19/2014	6/1/2015	6/1/2013	6/1/2013	6/1/2012	12/31/2011
Cost	Total Cost	$33,530,000	$129,000,000	$79,000,000	$148,727,500	$54,444,000	$71,377,015	$165,180,000	$2,00,000	$8,000,000
	Cost Per Mile	$900,000	$1,250,000	$900,000	$688,750	$1,214,800	$1,416,667	$846,000		$666,666
	Miles	36	100	72	178	30	45	170		3
	Substation Cost	$1,130,000	$4,000,000	$15,000,000	$26,130,000	$18,000,000	$6,827,000	$16,800,000		
	Fixed Charge Rates	15.1%	15.1%	15.1%	12.1%	15.1%	13.5%	12.0%	15.1%	15.1%
Conductor	Size	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1192.5, 38/19 Grackle TW	2 Conductor Bundle 477 T2 Hawk	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	138 kV line
	Design	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit		
	Electrical Capacity	2578 Amps 1540 MVA at 345kV	3000 Amps 1800 MVA at 345kV	2578 Amps 1540 MVA at 345kV	2468 Amps Normal	4,100A	2,324 amps per bundle	3,000 amps		
	Other	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire					
Structure	Type	H-frame	Single Pole	H-frame	H-frame	H-frame	Single Pole	H-frame		
	Materials	Steel	Steel	Steel	Steel	Steel	Steel	Steel		
	Base	Direct buried w/ aggregate backfill	Steel base plate reinforced concrete	Direct buried w/ aggregate backfill	Direct buried with aggregate or natural backfill	Direct Embed	Poured concrete anchor bolt	Direct embed concrete piers		
	NESC Assumption	Heavy	Heavy	Heavy	Heavy	Heavy	Heavy, 1.5 inch ice load			
	Dead Ends	Unknown	Unknown	Unknown	Unknown @ $65,000 each	16 @ $50,000 each	20 @ $140,000 each	60 @ $50,000 each	2 to 3 Deadends	
	Under build	No	No	No	No	No	No	No		
Substations	Transformers	Breakers and Relays	Two 345/138kV	345/138kV 50 MVAR reactor bank	345/230kV 560 MVA	600 MVA	None	345/230kV 200 MVA		345/138 kV
	Breaker Scheme	Ring-bus	Ring-bus, replace 2 2,000 A breakers	Ring-bus	345kV Ring	Ring-bus	Ring-bus	Ring-bus	2 breakers, breaker disconnects, line panels	
	Protection Scheme	included in sub cost	included in sub cost	included in sub cost	$1,000,000	$400,000	$156,000	$220,000		included in sub cost
	Voltage Control			+\- 50 MVAR						
	Cost (millions)	$1	$4	$15	$26	$18	$4	$14		
Construction Labor	Amount	1/3 of line construction	1/3 of line construction	1/3 of line construction						
	Cost (millions)	$14	$52	$27	$18	$7	$17	$49		
Eng Design, Project Management, Permitting	ROW	150ft @$5,500 an acre	200ft @$5,500 an acre	150ft @ $5,500 an acre	150ft	160ft	200ft	150ft		
	ROW Condition	rural, pasture	rural, pasture, hill, rock, high tree clearing cost	rural, pasture	Farmland and Pasture	50% Urban 50% Rural	rural farmland rainwater basin	rural, agri, pasture, range land	No ROW acquisition required	
	Permitting/Certifications	RR and Highway	RR and Highway	RR and Highway	Texas CCN, Highway, storm water, RR, County roads	Yes	NE Power Review Board, NPSC, RR, Airport, etc	Included		
	Escalation Rate	2.5% per year	2.5% per year	2.5% per year		2.5% per year	3% per year	0% for 2 years		
	Eng. Design / Proj. Mang.				Included	$349,000	$8,798,000	$13,770,000		
	Total Cost (millions)	cost included	cost included	cost included	$15	$26	$18	$24		
Loadings and Overheads	Type 1	Included in total cost	Included in total cost	Included in total cost	Included in total cost	$123,000	Included in total cost	20% of line and substation work, $26.7 million		
Other Cost Factors and Notes			$25,000/ mile cost included for tree clearing		Included in substation cost is $6.52 mil for mid-point reactor station	Large portion involves developed urban areas	Environmentally sensitive areas, possible double-circuit for 10 miles	$4.56 mil addition contingency added		

Study Assumptions

Fuel Price Assumptions – Fuel price assumptions are taken from EIA forecasts and updated according to member specific data for particular plants. For the purpose of this study, the average gas price is $6.50/MMBtu starting in 2012. The price is then escalated for inflation for the years 2017 and 2022 at the rate of 1.81%.

Environmental Costs - Carbon sensitivities have been conducted, but were not included in the portfolio selection process. A price of $15 and $40 per metric ton was used in these sensitivities. No sensitivity analysis was conducted for higher SO_2 or NO_X prices. SO_2 and NO_X were priced at $466.50 and $1742.16 per ton respectively.

Plant Outages – Stakeholders provided outage and maintenance rates to SPP staff through the EMMTF data collection effort. Forced outages were taken as a single draw and locked for the change and the base case. Similarly, maintenance outages were also locked down from a single scheduled pattern. These outage rages were plant specific and provided by each member.

Load Forecast – Load forecasts for the region were provided by each stakeholder in early 2009 for the projected years of 2012, 2017 and 2022 through the EMMTF update effort. These non coincident peak loads for the region were, in aggregate, as follows: 2012 - 43,068MW, 2017 – 47,109 MW, 2022 – 51,530 MW. The zonal shares of the 2012 load submittals were used to allocate the costs on a load ratio share basis.

Resource Forecast – The CAWG and EMMTF determined the criteria for inclusion of new resources into the Balanced Portfolio analysis. It was determined that only plants with firm transmission service and signed agreements or plants that were currently under construction would be included in the analysis. The following units are those which were included as a future resource.

- Turk (618 MW)
- Whelan Energy Center 2 (220 MW)
- Iatan 2 (900 MW)
- Central Plains (99 MW)
- Cloud County (201 MW)
- Flat Ridge (100 MW)
- Red Hills (120 MW)
- Smoky Hills (359 MW)

Hurdle Rates – A dispatch hurdle rate of $5/MW and a commit hurdle rate of $8/MW was used to commit resources across regional boundaries.

Demand Side Management – Interruptible load was modeled as supplied by the LSE's.

Market Structure – The simulation was conducted considering a single balancing authority and a day-ahead market structure for the SPP region.

Flowgate Assumptions – The NERC Book of Flowgates was used as the source for flowgates used in the analysis.

DC Tie Profiles - Historical DC Tie profiles were used to simulate best known profiles for all DC Ties in the SPP region.

Wind Profiles – Historical wind profiles were used to simulate the wind output at each wind farm.

Load Profiles – Load profiles were simulated as supplied by each LSE through the EMMTF effort.

RMR Requirements – Each Balancing Authority submitted their respective Reliability Must Run (RMR) requirements to be simulated in the analysis.

Operating Reserves – SPP's current reserve sharing program (as of 2008) was used in the simulation for operating reserves.

EXHIBIT NO. OGE-15

U.S. FISH AND WILDLIFE SERVICE
SPECIES ASSESSMENT AND LISTING PRIORITY ASSIGNMENT FORM

SCIENTIFIC NAME: *Tympanuchus pallidicinctus*

COMMON NAME: lesser prairie-chicken

LEAD REGION: 2

INFORMATION CURRENT AS OF: April, 2009

STATUS/ACTION

___ Species assessment - determined we do not have sufficient information on file to support a proposal to list the species and, therefore, it was not elevated to Candidate status
___ New candidate
_X_ Continuing candidate
 ___ Non-petitioned
 _X_ Petitioned - Date petition received: October 5, 1995
  _ 90-day positive - FR date: July 8, 1997
  _ 12-month warranted but precluded - FR date: June 9, 1998
  _ Did the petition request a reclassification of a listed species? NO

FOR PETITIONED CANDIDATE SPECIES:
a. Is listing warranted (if yes, see summary of threats below)? YES
b. To date, has publication of a proposal to list been precluded by other higher priority listing actions? YES
c. If the answer to a. and b. is "yes", provide an explanation of why the action is precluded.
Higher priority listing actions, including court-approved settlements, court-ordered statutory deadlines for petition findings and listing determinations, emergency listing determinations, and responses to litigation, continue to preclude the proposed and final listing rules for the species. We continue to monitor populations and will change its status or implement an emergency listing if necessary. The "Progress on Revising the Lists" section of the current CNOR (*http://endangered.fws.gov/*) provides information on listing actions taken during the last 12 months.

___ Listing priority change
 Former LP: ___
 New LP: ___

Date when the species first became a Candidate (as currently defined): June 9, 1998

___ Candidate removal: Former LPN: ___
 ___ A – Taxon is more abundant or widespread than previously believed or not subject to the degree of threats sufficient to warrant issuance of a proposed listing or

As described above, LPC populations can fluctuate considerably from year to year. Fluctuations in wildlife populations are natural responses to variable weather and habitat conditions. The fluctuations add to the difficulty of evaluating population trends, particularly short-term trends, e.g., periods less than 5 years. Short-term analyses could reveal statistically significant changes from one year to the next, but actually represent a statistically stable population when evaluated over a longer period of time. This situation makes it difficult to interpret very recent declines, such as the decline in 2007, as it is not clear whether it is a natural fluctuation related to drought, or represents a decline for other reasons and will persist. Table 1 summarizes the information described above regarding LPC populations in each state.

Table 1. Range and current population indices for LPC by state.

State	Historic Range	Current Range	Current Population Estimates	Current Lek Density (#/km^2) 2006	2007	2008
Colorado	6 counties	4 counties	1,500 (in 2000)	Unknown		
Kansas	38 counties	35 counties 29,987 sq km (11,578 sq mi)	19,700 – 31,100 (in 2006)	0.08	0.07	0.06
New Mexico	7 counties 22,390 sq km (8,645 sq mi)	7 counties 5,698 sq km (2,200 sq mi)	9,443 (in 2008)	0.06	0.06	0.08
Oklahoma	22 counties	8 counties 950 sq km (367 sq mi)	< 3,000 (in 2000)	0.02	0.02	0.03
Texas	34 counties (1940's-50's)	13 counties 7,234 sq km (2,793 sq mi)	6,077 – 24, 132 (in 2007)	Permian Basin/Western Panhandle 0.29 Northeastern Panhandle 0.08	 0.19 0.04	 NA NA

THREATS

A. <u>The present or threatened destruction, modification, or curtailment of its habitat or range</u>.

Wind Energy Development

According to the American Wind Energy Association (AWEA), a non-profit organization that promotes the wind energy industry, the 5 states within the historic range of the LPC are all among the top 12 states having the highest wind energy potential in the United States (AWEA 2009, p. 1). The tubular towers of most commercial, utility scale onshore wind turbines are between 65 m (213 ft) and 100 m (328 ft) tall. The most common system utilizes three rotor blades and can have a diameter of as much as 100 m (328 ft). The total height of the system is measured when a turbine blade is in the 12 o'clock position and will vary depending on the length of the blade. With blades in place, a typical system will easily exceed 100 m (328 ft) in height. A wind farm will vary in size depending on the size of the turbines and amount of land available. Spacing between turbines is usually 5 to 10 rotor diameters to avoid interference between turbines.

Commercial wind energy developments cannot be a viable enterprise without the ability to transmit the power to the users. Any discussion of the effects of wind energy development must also take into consideration the influence of the transmission lines critical to distribution of the energy generated by these structures. Transmission lines can traverse long distances across the landscape and can be both above ground and underground. Most of the impacts associated with transmission lines are with the above ground systems. Support structures vary in height depending on the size of the line. Most high voltage powerline towers are 30 to 38 m (98 to 125 ft) high but can be higher if the need arises. Local distribution lines are usually much shorter in height but all contribute to vertical fragmentation of the landscape.

As discussed in the previous section on structural habitat fragmentation, prairie grouse, including the LPC, did not evolve with tall vertical structures present on the landscape. The addition of wind turbines and their supporting infrastructure represents a significant change in the species' environment. Placement of vertical structures is a relatively new phenomenon over the evolutionary history of these species and the effects of these structures on their life history are only beginning to be evaluated. However, some information on the behavioral response of prairie grouse to these structures is available.

2009 Candidate Assessment – lesser prairie-chicken

In general, prairie grouse have low tolerance to tall structures. Anderson (1969, pp. 640-641) observed that greater prairie-chickens abandoned lek territories when a 4 m (13 ft) tall wind break was artificially erected 52 m (170 ft) from an active lek. Robel (2002) estimates that a single commercial-scale wind turbine creates a habitat avoidance zone for the greater prairie-chicken that extends as far as 1.6 km (1 mi) from the structure. Structural habitat fragmentation caused by energy development also has been shown to cause LPC to avoid or abandon otherwise suitable habitats due to potential for increased predation by raptors or due to visual obstructions on the landscape (Hagen *et al.* 2004, pp. 74-75). Pitman (2005, pp. 1267-1268) observed that female LPC selected nest sites that were significantly further from powerlines, roads, buildings, and oil and gas wellheads than would be expected at random. Specifically, they seldom found LPC nests within 400 m (1,312 ft) of transmission lines and improved roads. Similarly, Hagen *et al* (2004, p. 75) indicated that areas used by LPC were significantly further from these same types of features than areas that were not used by LPC. The Service has recommended that, due to behavioral avoidance of wind turbines, an 8 km (5 mi) voluntary no construction buffer be established around prairie grouse leks (Manville 2004, p. 1). Although considerably more study is needed, the available information clearly demonstrates that vertical structures are avoided by LPC and likely render otherwise suitable habitat unsuitable.

Wind energy development and its associated infrastructure is already occurring within the historic range of the LPC, some of which has impacted occupied habitat. As of June 30, 2008, AWEA's database of existing and planned wind projects showed 24 existing wind projects within the current occupied range of the LPC (*www.awea.org/projects*). Four of those projects were located in Colorado, four in Kansas, five in New Mexico, six in Oklahoma, and five in Texas. Within the historic range of the LPC, but excluding the occupied range, another 72 projects were in the AWEA database, 68 of those projects were in Texas. By the end of 2008, Texas had the greatest installed megawatt capacity for wind energy of all states and Colorado had the sixth greatest (AWEA 2009, p. 1).

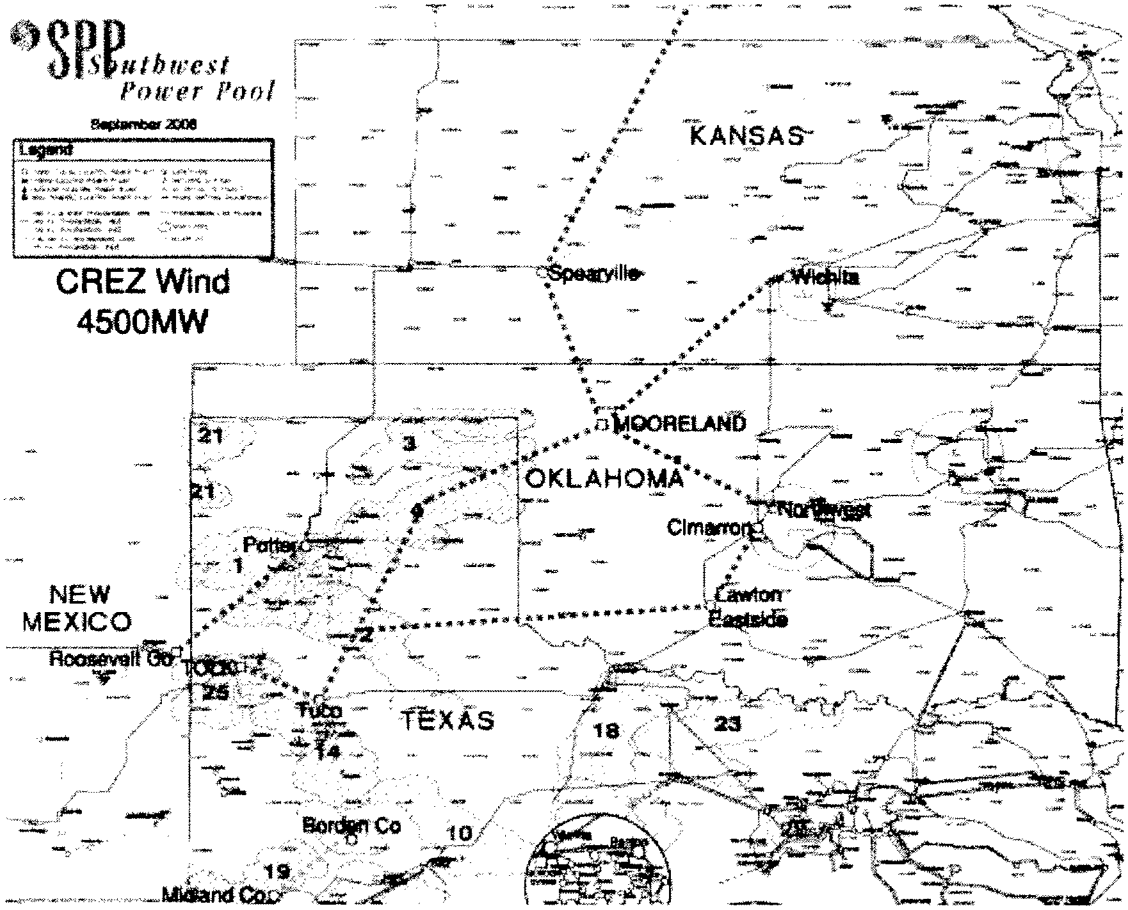
The potential influence of anticipated wind energy development to the status of the LPC can readily be evaluated for Oklahoma. In cooperation with ODWC, Service personnel in 2005 quantified the potential degree of wind energy development in relation to existing populations of LPC in Oklahoma. Using ArcView mapping software, all active and historic LPC lek locations in Oklahoma, as of the mid 1990s (n = 96), and the current occupied range, were compared with the Oklahoma Neural Net Wind Power Development Potential Model map created by the Oklahoma Wind Power Assessment project. The mapping analysis revealed that 35 percent of the recently occupied range in Oklahoma is within areas designated by the Oklahoma Wind Power Assessment as "excellent" for wind energy development. When both the "excellent" and "good" wind energy development classes are combined, some 55 percent of the occupied range lies within those two classes.

When leks were examined, the same analysis revealed a nearly complete overlap on all known active and historic lek locations, based on the known active leks during the mid 1990s. Roughly 91 percent of the known LPC lek sites in Oklahoma are within 8 km (5 mi) of land classified as "excellent" for wind development (C. O'Meilia, Service, pers. comm. 2005). The analysis revealed that over half (53 percent) of all known lek sites occur within 1.6 km (1 mi) of lands classified as "excellent" for commercial wind energy development. This second metric is particularly relevant given the average home range for a LPC is about 10 sq km (4 sq mi) and that a majority of LPC nesting generally occurs, on average, within 1.2 and 3.4 km (0.7 and 2.1 mi) of active leks (Hagen and Giesen 2005, p. 2). Using Robel's (2002) estimate derived for the greater prairie chicken of the zone of avoidance for a single commercial-scale wind turbine (1.6 km or 1 mi), development of commercial wind farms likely will have a significant adverse influence on reproduction of the LPC.

Unfortunately, similar analyses are not available for the other states due to a lack of appropriate data layers for those states. However, southwestern Kansas currently supports the largest population and distribution of LPC of all states. The influence of wind energy development on the LPC in Kansas would likely be no less severe than in Oklahoma. In 2006, the Governor of Kansas initiated the Governor's 2015 Renewable Energy Challenge, an objective of which is to have 1,000 megawatts (MW) of renewable energy capacity in Kansas by 2015 (Cita *et al.* 2008, p. 1). A cost-benefit study (Cita *et al.* 2008, appendix B) found that wind was the most cost effective and likely renewable energy resource for Kansas. Modestly assuming an average of 2 MW per turbine—most commercial scale turbines are between 1.5 and 2.5 MW—some 500 turbines would be erected in Kansas if this goal is to be met. While not all of those turbines would directly overlap occupied range, the best wind potential in Kansas occurs in the western portions of the state (U.S. Department of Energy 2009, p. 1). Inappropriate siting of wind energy facilities and associated facilities, including electrical transmission lines, appears to be a serious threat to LPC in western Kansas within the near future (R. Rodgers, KDWP, pers. comm. 2007).

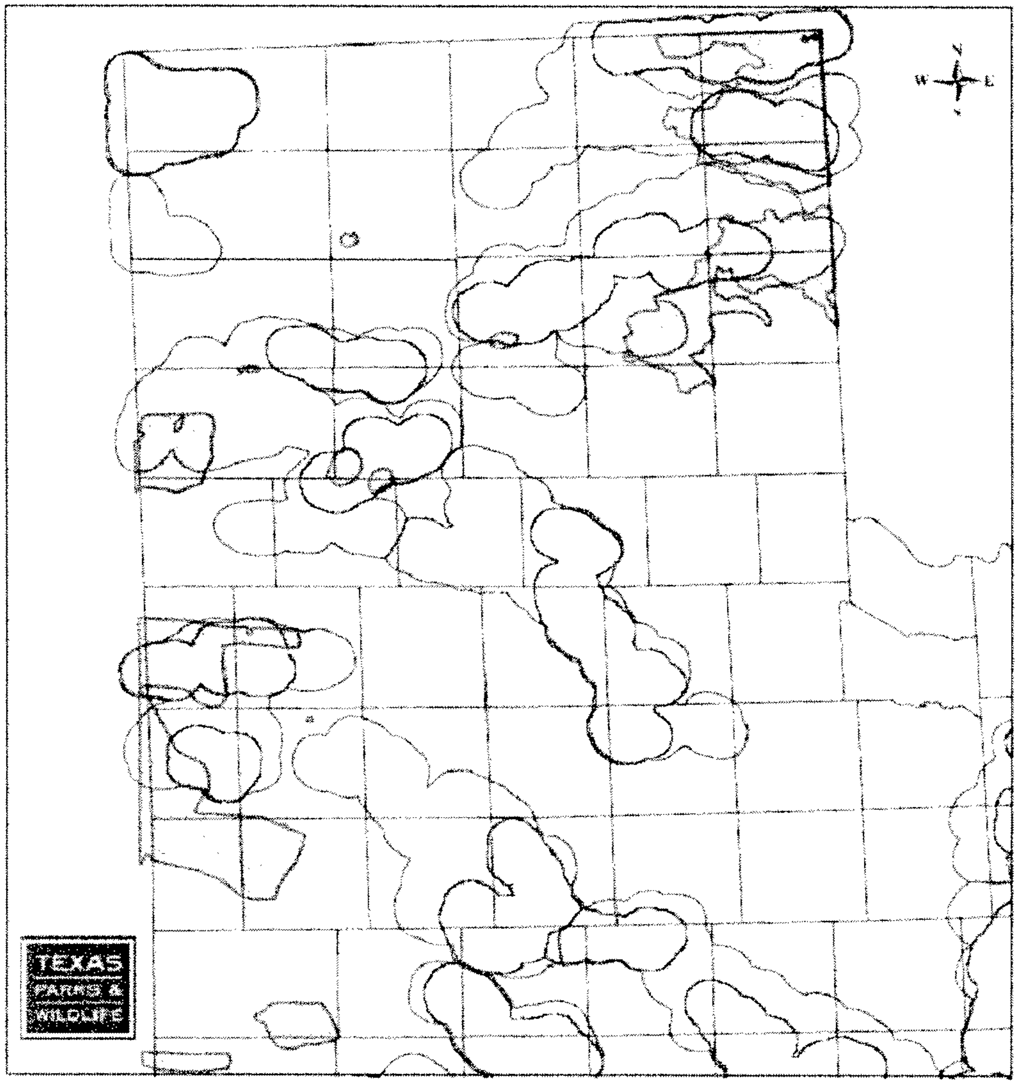
In Texas, the Public Utility Commission of Texas recently directed the Electric Reliability Council of Texas (ERCOT) to develop transmission plans for wind capacity to accommodate between 10,000 and 25,000 MW of power (AWEA 2007b, pp. 2-3). ERCOT is a regional transmission organization with jurisdiction over most of Texas. The remainder of Texas, largely the Texas panhandle, lies within the jurisdiction of the Southwest Power Pool. A recent assessment from ERCOT identified more than 130,000 MW of high-quality wind sites in Texas, more electricity than the entire state currently uses. The establishment of Competitive Renewable Energy Zones by ERCOT within the state of Texas will facilitate wind energy development throughout western Texas (see Figure 2). The Competitive Renewable Energy Zones, as shown on Figure 2, are identified by a number that indicates the development priority of each zone. The top four zones are located within occupied and historic LPC habitat in the Texas panhandle.

Figure 2. Competitive Renewable Energy Zones (in blue) and planned transmission lines (dashed red lines) in portions of New Mexico, Texas, Oklahoma, and Kansas.



The TPWD reports that commercial wind energy development, based on the existing Competitive Renewable Energy Zones, threatens remaining LPC populations in both the Permian Basin/Western Panhandle and the Northeastern Panhandle regions of Texas (Whitlaw 2007; see Figure 2). The high level of overlap between the LPC currently occupied range in Texas and the Competitive Renewable Energy Zones which are designated for future wind energy development in the Texas panhandle is shown in Figure 3.

Figure 3. Map depicting the degree of overlap between occupied LPC habitat in Texas (shaded) and Competitive Renewable Energy Zones designated for future wind energy development in the Texas panhandle.



Development of high capacity transmission lines is critical to the development of the anticipated wind energy resources. According to ERCOT (AWEA 2007a, p. 9), every $1 billion invested in new transmission capacity enables the construction of $6 billion of new wind farms. Depicted on Figure 2 are the currently proposed electric transmission line upgrades which were provided to the Service by the Southwest Power Pool. This map identifies approximately 423 km (263 mi) of proposed new transmission lines, commonly referred to as the "X Plan", that would be constructed to facilitate the completion of six proposed wind energy projects within LPC range in Oklahoma (Southwest Power Pool 2006). Completion of the "X Plan" also is intended to connect transmission capacity throughout all or portions of occupied LPC range in the four remaining states. Some portions of the "X Plan" have already been improved and completion of these and other sections of the plan will undoubtedly catalyze extensive wind energy development throughout much of the remaining occupied LPC range in Kansas, Oklahoma, and Texas.

Wind energy development in the Texas panhandle and portions of west Texas represents a serious threat to extant LPC populations in the state. Once established, wind farms and associated transmission features would severely hamper future efforts to restore population connectivity and gene flow between existing populations which are currently separated by unfavorable land use in the Texas panhandle.

In Colorado, the U.S. Department of Energy (2009, p. 1) rated the southeastern corner of Colorado as having good wind resources, the largest area of Colorado with that ranking. The area almost completely overlaps the currently occupied range of the LPC in Colorado. CDOW reported that commercial wind development is occurring in Colorado, but that most of the effort is currently centered north of the occupied range of LPC in southeastern Colorado.

Wind energy development in New Mexico is a lower priority than other states within the range of the LPC. In New Mexico, the potential for wind energy development in the currently occupied range of the LPC are only rated as fair (U.S. Department of Energy 2009, p. 1). However some parts of northeastern New Mexico within LPC historical range have been rated as excellent. Northeastern New Mexico is important to LPC conservation because this area is vital to efforts to re-establish or re-connect the New Mexico LPC population to those in Colorado and the Texas panhandle.

In summary, wind energy and associated infrastructure development is occurring within occupied portions of LPC habitat. Where such development has occurred, these areas are no longer suitable for LPC even though many of the typical habitat components used by LPC remain. Proposed transmission line improvements will serve to facilitate further development of additional wind energy resources. Future wind energy developments, based on the known locations of areas with excellent to good wind energy development potential, likely will have substantial overlap with known LPC populations. Additional areas that are currently unoccupied but lie within the historic range and provide suitable habitat for the LPC also could be developed. These areas of unfragmented habitat are crucial to ongoing efforts to conserve the LPC. Fragmentation of these areas would further modify or curtail the range of the LPC and hamper efforts to conserve the species. Therefore, the Service considers the ongoing and large-scale potential for commercial wind power development, particularly in western Kansas, northwestern Oklahoma, and the Texas panhandle, to be a high-level threat to the survival of the species in the near future. Siting of wind farms and transmission lines in a manner that avoids fragmentation of LPC habitat is important and some wind power developers appear sensitive to concerns about siting such facilities.

<u>Oil and Gas Development</u>

SUMMARY OF THREATS (including reasons for addition or removal from candidacy, if appropriate)

The most serious threats to the LPC are loss of habitat from conversion of native rangelands to introduced forages and cultivation, recent and anticipated conversion of CRP lands to cropland, cumulative habitat degradation caused by inappropriate livestock grazing practices, wind energy development, oil and gas development, woody plant invasion of open prairies due to fire suppression, inappropriate herbicide applications, and habitat fragmentation caused by structural and transportation developments. Many of these threats may exacerbate the normal effects of periodic drought on LPC populations. In many cases, the remaining suitable habitat has become fragmented by the spatial occurrence of these individual threats. Habitat fragmentation can be a threat to the species through several mechanisms: remaining habitat patches may become smaller than necessary to meet the requirements of individuals and populations, necessary habitat heterogeneity may be lost to areas of homogeneous habitat structure, areas between habitat patches may harbor high levels of predators or brood parasites, and the probability of recolonization decreases as the distance between suitable habitat patches expands. Existing regulatory mechanisms have not been adequate to halt the decline of LPC populations and habitat.

Based on the information described above, we find that this species is warranted for listing throughout all of its range. Therefore, it is unnecessary to analyze whether it is threatened or endangered in a significant portion of its range.

For species that are being removed from candidate status:
____Is the removal based in whole or in part on one or more individual conservation efforts that you determined met the standards in the Policy for Evaluation of Conservation Efforts When Making Listing Decisions (PECE)?

RECOMMENDED CONSERVATION MEASURES:

1. Reduce or eliminate upland construction of fence lines and utility lines within occupied habitat and for 8 km (5 mi) surrounding all occupied habitat, especially near leks. If fence lines cannot be removed, it is recommended that the top and third wires of lines near active LPC leks be conspicuously marked to minimize collision mortality.

2. Limit or eliminate the federally-funded application of tebuthiuron herbicide in remaining shinnery oak habitats and 2, 4-D herbicide in sand sagebrush habitats.
3. Encourage rangewide adherence to the Service's Voluntary Interim Guidelines to Avoid and Minimize Wildlife Impacts from Wind Turbines, released in July 2003, (*http://www.fws.gov/habitatconservation/wind.pdf*)
4. Work cooperatively with energy-related industry to avoid, minimize, and compensate for impacts to LPC populations and habitats.
5. Work with partners to target re-enrollments and new contracts under CRP and related agricultural conservation programs to benefit LPC.
6. Minimize further fragmentation of remaining Federal lands within current and historic LPC range by abandoning the use of ineffective timing, noise, and distance stipulations near active or historic leks. Instead, future energy leasing, exploration, and development, or other fragmenting human land uses within essential LPC habitats should be limited.
7. Establish secure and well-funded financial incentive mechanisms for private landowners to provide light to moderately grazed native rangeland habitats that are suitable for LPC use, and are not subject to herbicidal shrub control practices.
8. Encourage increased use of prescribed fire and patch burn grazing concepts to facilitate habitat heterogeneity in LPC range and decrease encroachment of woody vegetation. Patch burn grazing is a system that utilizes prescribed fire to encourage intensive grazing on a portion of a pasture each year while resting the remainder of the pasture.

LISTING PRIORITY

THREAT			
Magnitude	Immediacy	Taxonomy	Priority
High	**Imminent**	Monotypic genus	1
		Species	**2***
		Subspecies/population	3
	Non-imminent	Monotypic genus	4
		Species	5
		Subspecies/population	6
Moderate to Low	Imminent	Monotypic genus	7
		Species	8
		Subspecies/population	9
	Non-imminent	Monotypic genus	10
		Species	11
		Subspecies/population	12

Rationale for listing priority number:

Magnitude: We have determined that the overall magnitude of threats to the LPC throughout its range is high. The magnitude of threats to LPC depends primarily on the quality, integrity, and scale of remaining habitat. At present, long term habitat destruction and modification due to ongoing and increasing agricultural activities, increasing energy development, tree invasion due to fire suppression, collision mortality from fences and power lines, and fragmentation are continuing and significant throughout the entire range. Foreseeable threats to habitat degradation caused by human land use also exist. Reports indicate that funding for and construction of primary transmission lines to facilitate extensive wind generation construction throughout LPC occupied portions of Kansas, Oklahoma, and Texas is likely to begin in the near future, concomitant with wind energy development in all LPC states. In addition, projected, near-term changes in CRP enrollments, largely due to escalating commodity prices and emphasis on biofuel production, are likely to result in massive conversion of important LPC habitat to cropland production. This is especially problematic in Kansas where native CRP plantings have resulted in increased LPC populations and range over the last decade. As a result of the coalescence and interaction of these threats, the Service concludes that the cumulative magnitude of threats to the LPC and its habitat is high.

Imminence: The majority of threats to remaining LPC populations are ongoing and foreseeable within the near term, thus they are considered imminent. Remaining populations are becoming increasingly isolated and vulnerable to stochastic environmental impacts (e.g., drought) as well as the effects of human habitat fragmentation. This is particularly true for isolated populations of LPC in the Permian Basin/western panhandle of Texas, populations residing on USFS lands in southeastern Colorado and areas south of Highway 380 in southeastern New Mexico.

COORDINATION WITH STATES

Indicate which State(s) (within the range of the species) provided information or comments on the species or latest species assessment: Colorado, Kansas, New Mexico, Oklahoma, and Texas

Indicate which State(s) did not provide any information or comments: None

LITERATURE CITED

Addison, E.M. and R.C. Anderson. 1969. *Oxyspirura lumsdeni* n. sp. (Nematoda: Thelaziidae) from Tetraonidae in North America. Can. J. Zool. 47(6):1223-1227.

Aldrich, J.W. 1963. Geographic orientation of American Tetraonidae. J. Wildl. Manage. 27(4):529-545.

American Wind Energy Association (AWEA). 2007a. Wind Energy Weekly, Vol. 25, #1225, 26 January 2007.

American Wind Energy Association. 2007. Wind Energy Weekly, Vol. 26, #1249, 20 July 2007.

American Wind Energy Association. 2008a. Top 20 states with wind energy resource potential. Fact Sheet. 2 pp. Viewed April 21, 2008 at www.awea.org/pubs/factsheets/.

American Wind Energy Association. 2008b. AWEA 2007 market report. 12 pp. Viewed April 21, 2008 at www.awea.org/Market_Report_Jan08.pdf).

American Ornithologist's Union. 1998. Checklist of North American birds. Seventh edition.

EXHIBIT NO. OGE-16

List of Regulatory Agencies

- U.S. Army Corps or Engineers, Tulsa District, Tulsa, Oklahoma
- U.S. Department of Interior, U.S. Fish and Wildlife Service, Oklahoma Field Office, Tulsa, Oklahoma
- Federal Aviation Administration, Southwest Region Headquarters, Fort Worth, Texas
- Oklahoma Department of Environmental Quality, Oklahoma City, Oklahoma
- U.S. Department of Agriculture, Natural Resources Conservation Service, Woodward Tech. Service Office, Woodward Oklahoma
- Oklahoma Biological Survey, Norman, Oklahoma
- Oklahoma Archeological Survey, The University of Oklahoma, Norman, Oklahoma
- Oklahoma Water Resources Board, Planning & Management Division, Oklahoma City, Oklahoma
- Oklahoma Department of Transportation, Division VI, Buffalo, Oklahoma
- Oklahoma Historical Society, State Historic Preservation Office, Oklahoma City, Oklahoma
- State of Oklahoma, Secretary of the Environment, Oklahoma City, Oklahoma
- Tribal Historic Preservation Office, Osage Nation, Pawhuska, Oklahoma

ATTACHMENT 6

DIRECT TESTIMONY AND EXHIBITS OF DAVID L. KAYS

Exhibit No. OGE-17

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER10-___-000

DIRECT TESTIMONY AND EXHIBITS OF
DAVID L. KAYS

October 12, 2010

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER10-___-000

<u>DIRECT TESTIMONY AND EXHIBITS OF DAVID L. KAYS</u>

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is David L. Kays. My business address is 321 N. Harvey Ave., P.O. Box 321, Oklahoma City, Oklahoma 73101. I am the Lead Transmission Activities Engineer at Oklahoma Gas and Electric Company ("OG&E").

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am OG&E's representative on the Southwest Power Pool, Inc. ("SPP") Regional Tariff Working Group ("RTWG"), which is responsible for development, implementation, and oversight of SPP's Open Access Transmission Tariff ("OATT"). In this capacity, I have participated on numerous task forces related to Generation Interconnection Procedures and Agreements, Transmission Definition, Delivery Point Additions, Generation Station Power, and Multi-Owner Compensation to name a few. I served as the chairman of the Inter-zonal Cost Allocation task force reviewing the SPP procedures on MW-mile allocation methods. I currently am chairing the Crediting Process task force whose purpose is to aid SPP in the implementation of a process to identify what facilities are "creditable" and who should be receiving revenues credits according to the provisions of Attachment Z2 of the SPP OATT. Also, I represent OG&E in matters before the Regional State Committee's Cost Allocation Working Group ("CAWG"), which makes recommendations to the Regional State Committee regarding cost allocation of potential transmission investments.

At OG&E I am responsible for administering OG&E's formula transmission service rates, including the annual update process through which the OG&E Formula Rate is "trued-up" based on actual costs and expenses. Another duty I perform is verification of charges and revenues received by OG&E from SPP's Transmission Settlement system. A part of this responsibility is providing subject matter expertise to OG&E's accounting department about the nature of various charges and revenues, what they are for and why OG&E receives them.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received an Associate of Applied Arts and Science in Electronic Technology degree in 1980 and a Bachelor of Applied Arts and Science in Business Administration degree in 1989 from Midwestern State University in Wichita Falls, Texas. In September 1979 I began my career in the electric utility industry with Texas Electric Service Company ("TESCo") (an operating company of Texas Utilities) where I held several positions until my early retirement in November 1992. My last position at TESCo was as an Engineering Technician II. In 1997 I received a Bachelor of Science in Electrical Engineering degree from the University of Oklahoma. Six months later, in June 1998, I began my career at OG&E in the Transmission Planning group in Oklahoma City. I was promoted to Design Engineer in the System Protection & Control group of Power Delivery in

2000. In 2004, I was promoted to Lead Transmission Activities Engineer in the Corporate Costing and Pricing group. I moved to the Transmission group in 2006 where I continued in the same capacity. I am a Licensed Professional Engineer in the State of Oklahoma.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION OR BEFORE A STATE REGULATORY AGENCY?

A. No, I have not.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS TESTIMONY.

A. OG&E has submitted revised tariff sheets to implement certain transmission incentives related to specific transmission projects to be constructed in SPP ("Projects"). The Projects are identified and described in Mr. Crissup's testimony. My testimony describes the specific changes to the SPP OATT and the OG&E OATT that will implement the two incentives requested in this proceeding (*i.e.*, including in rate base 100 percent of construction work in progress, or "CWIP," and recovery of 100 percent of prudently incurred expenses should the Projects be abandoned for reasons outside OG&E's control, "Abandoned Plant"). The revised *pro forma* SPP OATT sheets are included with this filing as Attachment 1 (clean) and Attachment 2 (red-line), and the revised OG&E OATT sheets are included as Attachment 3 (clean) and Attachment 4 (red-line).

II. PROPOSED REVISIONS TO THE FORMULA RATE

Q. PLEASE DESCRIBE OG&E'S CURRENT TRANSMISSION FORMULA RATE.

A. In 2007, OG&E filed proposed tariff sheets to implement formulaic transmission service rates for service under the OG&E OATT and for service under the SPP OATT within the OG&E pricing zone ("Formula Rate"). The Formula Rate became effective July 1, 2008, pursuant to a settlement approved by the Federal Energy Regulatory Commission ("Commission").[1] Under the Formula Rate, the annual transmission revenue requirement ("ATRR") pursuant to the SPP OATT within the OG&E pricing zone and pursuant to the OG&E OATT is derived from a formula that tracks increases and decreases in actual costs and projected capital additions every year, subject to an annual true-up, through which amounts over-collected or under-collected are returned to or collected from customers, with interest. Generally speaking, the Formula Rate has two parts: the formula template, which is used to calculate such matters as the applicable ATRR and point-to-point service rates, and the Implementation Protocols, which specify the procedures that govern the periodic revisions to the Formula Rate.

Q. WHAT ARE THE SPECIFIC TRANSMISSION INCENTIVES THAT OG&E SEEKS TO IMPLEMENT IN CONNECTION WITH THE PROJECTS?

A. In today's filing, OG&E seeks Commission approval to implement two transmission incentives in accordance with Order No. 679. The revised tariff

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1 *Oklahoma Gas & Electric Co*., 127 FERC ¶ 61,296 (2009).

sheets will (a) authorize recovery of 100 percent of prudently-incurred CWIP associated with the Projects in rate base, and (b) provide for recovery of all prudently-incurred development and construction costs if the Projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control.

Q. PLEASE DESCRIBE THE SPECIFIC CHANGES TO THE FORMULA RATE TEMPLATE THAT WILL PROVIDE FOR 100 PERCENT OF PRUDENTLY-INCURRED CONSTRUCTION WORK IN PROGRESS TO BE INCLUDED IN RATE BASE.

A. OG&E proposes two revisions to the Formula Rate template to provide for recovery of 100 percent of the CWIP associated with the eight specific transmission projects through rate base. These revisions will be reflected in both the OG&E OATT and in the relevant portion of the SPP OATT that governs transmission service in the OG&E pricing zone.

First, OG&E proposes to add a new Worksheet P to its Formula Rate template. Section II of Worksheet P will calculate the average of the 13-monthly balances and the Return and Income Taxes associated with the Return on the average balances. The sum of the Return and Income Taxes will be the ATRR for each associated project. The ATRR for each Project will be summarized in Section I of Worksheet P.

Second, OG&E proposed to add a new Line 60a to the Formula Rate template, titled "Construction Work in Progress." Line 60a will reflect the sum of the average CWIP balances for each transmission project that FERC has granted rate base treatment. Note Z to line 60a clarifies that the CWIP may be recovered only for those projects for which FERC has specifically authorized this incentive.

Q. HOW WILL THE REVISED FORMULA RATE TEMPLATE PROVIDE FOR THE RECOVERY OF 100 PERCENT OF THE CWIP BALANCES ASSOCIATED WITH THE SPECIFIC TRANSMISSION PROJECTS?

A. Section II of Worksheet P calculates the ATRRs associated with the specific projects receiving CWIP incentive treatment. These amounts will be included in the amount at Line 17 on page 2 of the Formula Rate template, which is titled "SPP OATT RELATED UPGRADES REVENUE REQUIREMENT," and will be recovered by SPP under the cost allocation mechanisms in the SPP OATT. To avoid double-recovery, this same amount is subtracted from the Net Revenue Requirement at Line 16 to produce the OG&E Zonal Revenue Requirement that is recovered from Network Customers and used to determine OG&E's Point to Point rates. The text of Note X referenced on Line 17 has been revised to include the revenue requirements for facilities receiving CWIP incentive treatment. OG&E still has two remaining customers taking transmission service under the OG&E OATT. Since the CWIP incentive will be recovered through the SPP OATT and these customers are not subject to the SPP OATT, they will not pay any CWIP related charges.

Q. HAVE YOU PREPARED AN EXHIBIT THAT ILLUSTRATES HOW OG&E'S PROJECTED CWIP BALANCES WILL BE INCLUDED IN ITS FORMULA RATE?

A. Yes. Attached to my testimony as Exhibit No. OGE-18 is a fully populated version of OG&E's 2011 Projected Formula Rate template that includes the CWIP incentives. This template (absent the proposed CWIP incentives) was provided to OG&E's and SPP's transmission service customers on September 1, 2010, in accordance with the Formula Rate annual update process. A revised version of the 2011 Projected Formula Rate template was posted on September 28, 2010. Exhibit No. OGE-18 reflects the revenue requirements to be collected by SPP for the projects receiving CWIP incentive treatment, Base Plan treatment and the zonal OG&E ATRR to be paid by Network Customers in the zone. The total ATRR of all the projects receiving CWIP incentive treatment in 2011 is projected to be $19,030,570. The sum of the average CWIP balances is projected to be $147,322,308**.** Mr. Rowlett's testimony addresses the amount of CWIP OG&E anticipates recovering over the next five years and compares the operation of the CWIP incentive to the AFUDC mechanism provided for under the current tariff.[2]

[2] *See* Direct Testimony of Donald R. Rowlett Exhibit No. OGE-19 at 9-10.

Q. PLEASE DESCRIBE HOW OG&E PROPOSES TO REVISE ITS FORMULA RATE TEMPLATE TO ALLOW FOR THE FUTURE RECOVERY OF ABANDONED PLANT COSTS.

A. OG&E's Formula Rate template (at lines 60 and 94 and note R) currently includes a place-holder for abandoned plant costs, which is populated with $0. The proposed tariff changes will supplement and clarify the specific mechanism for recovery of abandoned plant costs. Specifically, Section III of the proposed Worksheet P will reflect the amortization of any Abandoned Plant that is allowed recovery including the Abandoned Plant Balance, Amortization Period (in months), and the Monthly Amortization Amount. This section will calculate the 13-month average of the unamortized portion, the Return, the Taxes on the Return, the annual Amortization amount, and the ATRR associated with the amortization.

Q. HOW WILL THE REVISED FORMULA RATE TEMPLATE PROVIDE FOR THE RECOVERY OF ABANDONED PLANT COSTS ASSOCIATED WITH THE SPECIFIC TRANSMISSION PROJECTS?

A. Section III of Worksheet P calculates the average monthly balance related to the costs of abandoned plant attributable to the specific projects. These values will be an input to Line 60 on page 3 of the Formula Rate template and the annual Amortization amount will be input to Line 94 on page 4 of the Formula Rate template. Lines 60 and Line 94 currently exist in OG&E's Formula Rate template as place holders for Abandoned Plant. Section III of Worksheet P will also serve as a place holder in the Formula Rate template. The ATRR for Abandoned Plant will be reflected in the Section III and summarized in Section I of Worksheet P, and will be added to Line 17 on page 2 of the Formula Rate template in the same manner as described earlier for CWIP.

Q. DOES OG&E SEEK TO RECOVER AT THIS TIME ANY COSTS ASSOCIATED WITH THE ABANDONED PLANT INCENTIVE?

A. No. Pursuant to Order No. 679,[3] in the event any of the Projects are abandoned for reasons outside the control of OG&E, OG&E will make a Federal Power Act ("FPA") Section 205 filing with the Commission seeking approval to recover all prudently incurred costs. OG&E will maintain a value of zero in the Formula Rate unless and until it receives Commission approval to recover specific Abandoned Plant costs in such future FPA Section 205 filing.[4]

Q. HAS OG&E PROPOSED ANY FURTHER CHANGES TO THE FORMULA RATE TEMPLATE?

A. Yes. In this filing OG&E proposes two additional revisions that correct aspects of the current Formula Rate template. The first correction is at Line 1 of page 1, which is titled "BASE PLAN REVENUE REQUIREMENT." The reference on this line currently states that Transmission Amount is Ln 17 + Ln 18. This reference is incorrect and should state that Transmission Amount is Ln 17 – Ln 18, since Transmission Amount should reflect the difference in the SPP OATT RELATED UPGRADE REVENUE REQUIREMENT on Line 17 and the SPP

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[3] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 166 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

[4] *See* Exhibit No. OGE-18 at 7, note R ("OG&E must make the appropriate filing at FERC before inputting or changing amounts on lines 60 & 94 (abandoned plant)").

OATT RELATED UPGRADE REV. REQ. TRUE-UP on Line 18. In addition, Line 1 has been revised to the proper label, "NET SPP OATT RELATED UPGRADE REV. REQ."

The second correction is at Line 68a. Currently, Line 68a references Note Y, but the text of Note Y is missing from the Formula Rate template. The revised tariff sheets restore the omitted text.

Q. WILL CWIP BALANCES AND ABANDONED PLANT COSTS BE SUBJECT TO REVIEW AND TRUE-UP IN THE SAME MANNER AS THE OTHER ASPECTS OF THE FORMULA RATE?

A. Yes. CWIP balances and any future costs associated with Abandoned Plant will be included in OG&E's annual True-Up calculation in the same manner as all other aspects of the Formula Rate.

Q. PLEASE DESCRIBE HOW OG&E PROPOSES TO REVISE THE FORMULA RATE IMPLEMENTATION PROTOCOLS TO REFLECT THE REQUESTED INCENTIVES.

A. OG&E proposes two sets of revisions to the Protocols. The first set of revisions is reflected in Sections 1.1, 1.3(a)(1), and 1.3(a)(3) because in each, references to Base Plan Upgrades have been amended to add a reference to Balanced Portfolio Upgrades. Under the SPP OATT, the defined term "Base Plan Upgrades," refers to upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan to ensure the reliability of the Transmission System, Services Upgrades required for new or changed Designated Resources, Integrated Transmission Planning Upgrades approved for construction by the SPP Board of

Directors, and high priority upgrades (excluding Balanced Portfolio Upgrades) approved by the SPP Board of Directors. Balanced Portfolio Upgrades are a very specific set of upgrades that provide economic benefit across the SPP Region and that meet the requirements of Attachment O, Sections IV.3 and IV.4 of the SPP OATT. OG&E's request for CWIP incentive treatment includes transmission projects that have been approved by SPP as Balanced Portfolio Upgrades.[5] This revision will ensure that the Implementation Protocols are applicable to CWIP associated with these projects in the same manner as other costs addressed in the Formula Rate template.

The second set of revisions to the Protocols occurs in Sections 1.3(a)(1) and 1.3(a)(4). OG&E proposes to amend the Implementation Protocols to include references to the 13-month average CWIP balances together with the reference to 13-month average net plant balances. These changes will ensure that the CWIP balances are subject to the Implementation Protocol procedures in the same manner as other actual and projected plant balances.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

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5 *See* Direct Testimony of Philip L. Crissup, Exhibit No. OGE-1 at 20-23 (describing the Balanced Portfolio).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company) **Docket No. ER10-___-000**

AFFIDAVIT

State of Oklahoma

County of Oklahoma

I, David L. Kays, being first duly sworn, depose and state that I am the witness identified in the foregoing Direct Testimony and Exhibits, that I prepared the testimony and exhibits and am familiar with their content, and that the facts set forth therein are true and correct to the best of my knowledge, information and belief.

David L. Kays

David L. Kays

Subscribed and sworn before me this 6th day of October, 2010.

Amanda Reyes

Notary Public

AMANDA REYES
NOTARY
07003269
EXP. 04/03/11
PUBLIC
STATE OF OKLAHOMA

My commission expires: 4/3/11

EXHIBIT NO. OGE-18

Attachment H
Addendum 2-A

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

Oklahoma Gas and Electric Company

Index of Worksheets

1	Worksheet	Description
2	Attachment H - Addendum 2-A	Rate Formula Template Utilizing FERC Form 1 for the 12 months ended 12/31/2009 and "Actual Data"
3	Worksheet A	Account 454, Rent from Electric Property
4		Account 456, Other Electric Revenues
4		Account 456.1, Revenues from Transmission of Electricity of Others, Current Year Less Credits
5		Revenue from Grandfathered Interzonal Transactions and amounts received from SPP for PTP service
6	Worksheet B	Transmission Network Load (MW)
7	Worksheet C	Account 281, Accumulated Deferred Income Taxes - Accelerated Amortization Property
8		Account 282, Accumulated Deferred Income Taxes - Other Property
9		Account 283, Accumulated Deferred Income Taxes - Other
10		Account 190, Accumulated Deferred Income Taxes
11		Account 255, Accumulated Deferred Investment Tax Credits
12	Worksheet D	Account 928, Regulatory Commission Expense Allocations
13		Account 930.1, General Advertising Allocations (safety related only to trans.)
14		Account 930.2, Miscellaneous General Expenses
15		Transmission Lease Payments
16	Worksheet E	Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility
17	Worksheet F	Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase
18		Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase
19		Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives
20	Worksheet G	Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities
21	Worksheet H	Transmission Plant Adjustments
22	Worksheet I	Plant Held for Future Use
23	Worksheet J	Development of Composite State Income Tax Rates
24	Worksheet K	13 Month Balances for Plant & Accumulated Depreciation, Material & Stores and Debt & Equity
25		Account 165, Prepayments Calculation
26		Long Term Debt Cost Calculation
27	Worksheet L	True-Up Adjustment with Interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation
28	Worksheet M	Depreciation Rates
29	Worksheet N	Unfunded Reserves Calculation
30	Worksheet O	Amortizations for Extraordinary O&M and Storm Costs
31	Worksheet P	Construction Work in Progress and Abandoned Plant Balances

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

For rates effective January 1, 2011

Line No.					Transmission Amount
1	NET SPP OATT RELATED UPGRADES REV. REQ.	(Addendum 2-A, ln 17 - ln 18)			$ 22,559,031
2	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(Addendum 2-A, ln 21)			85,325,538
3	DIVISOR				
4	TO's Transmission Network Load	(Worksheet B, ln 14)			4,854,836
5	RATES				
6	Annual Cost ($/kW/Yr)	(ln 2 / ln 4)	17.575		
7	P-to-P Rate ($/kW/Mo)	(ln 6 / 12)	1.465		
			Peak		Off-Peak
8	Weekly P-To-P Rate ($/kW/Wk)	(ln 6 / 52; ln 6 / 52)	0.338		0.338
9	Daily P-To-P Rate ($/kW/Day)	(ln 8 / 5; ln 8 / 7)	0.068	Capped at weekly rate	0.048
10	Hourly P-To-P Rate ($/MWh)	(ln 9 / 16; ln 9 / 24 both x 1,000)	4.225	Capped at weekly & daily rate	2.012

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.			Total	Allocator			Transmission Amount
11	REVENUE REQUIREMENT (w/o incentives)	(ln 117)				$	125,301,675
12	REVENUE CREDITS	(Note A)	Total	Allocator			
13						$	-
14	Other Transmission Revenue	(Worksheet A)	11,525,696	DA	1.00000	$	11,525,696
15	Total Revenue Credits		11,525,696			$	11,525,696
16	NET REVENUE REQUIREMENT (w/o incentives)	(ln 11 less ln 15)				$	113,775,979
17	SPP OATT RELATED UPGRADES REVENUE REQUIREMENT	(Worksheet G & P) (Note X)				$	22,876,592
18	SPP OATT RELATED UPGRADES REV. REQ. TRUE-UP	(Worksheet L)				$	317,562
19	PRIOR YEAR TRUE-UP ADJUSTMENT w/INTEREST	(Worksheet L)				$	5,256,287
20	ADDITIONAL REVENUE REQUIREMENT (w/ incentives)	(Note C) & (Worksheet F, ln 61)				$	-
21	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(ln 16 - ln 17 - ln 18 - ln 19 + ln 20)				$	85,325,538
22	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)					
23	Annual Rate	((ln 16 / ln 46) x 100)					20.80%
24	Monthly Rate	(ln 23 / 12)					1.73%
25	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)					
26	Annual Rate	(((ln 16 - ln 92) / ln 46) x 100)					17.23%
27	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)					
28	Annual Rate	(((ln 16 - lns 92 - ln 115 - ln 116) / lns 46) x 100)					2.63%

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
29	GROSS PLANT IN SERVICE					
30	Production	(Worksheet K)	3,094,645,765	NA		
31	Transmission	(Worksheet K)	942,744,528	TP	0.93085	877,550,515
32	Distribution	(Worksheet K)	2,804,714,234	NA		
33	General Plant	(Worksheet K) (Note J)	221,648,326	W/S	0.05740	12,723,367
34	Intangible Plant	(Worksheet K) (Note V)	30,534,454	W/S	0.05740	1,752,781
35	TOTAL GROSS PLANT	(sum lns 30 to 34)	7,094,287,307			892,026,664
36	GROSS PLANT ALLOCATOR	(ln 35 - Col. 5 / Col. 3)		**GP=**	**0.125739**	
37	ACCUMULATED DEPRECIATION					
38	Production	(Worksheet K)	1,509,338,480	NA		
39	Transmission	(Worksheet K)	355,134,240	TP	0.93085	330,575,491
40	Distribution	(Worksheet K)	946,822,367	NA		
41	General Plant	(Worksheet K) (Note J)	84,528,061	W/S	0.05740	4,852,198
42	Intangible Plant	(Worksheet K) (Note V)	21,353,013	W/S	0.05740	1,225,735
43	TOTAL ACCUMULATED DEPRECIATION	(sum lns 38 to 42)	2,917,176,161			336,653,424
44	NET PLANT IN SERVICE					
45	Production	(ln 30 - ln 38)	1,585,307,285	NA		
46	Transmission	(ln 31 - ln 39)	587,610,288			546,975,024
47	Distribution	(ln 32 - ln 40)	1,857,891,867	NA		
48	General Plant	(ln 33 - ln 41)	137,120,265			7,871,169
49	Intangible Plant	(ln 34 - ln 42)	9,181,441			527,046
50	TOTAL NET PLANT IN SERVICE	(sum lns 45 to 49)	4,177,111,146			555,373,239
51	NET PLANT ALLOCATOR	(ln 50 - Col. 5 / Col. 3)		**NP=**	**0.132956**	
52	ADJUSTMENTS TO RATE BASE	(Note D)				
53	Account No. 281	(Worksheet C)	-			-
54	Account No. 282	(Worksheet C)	(805,926,447)			(97,127,482)
55	Account No. 283	(Worksheet C)	(107,025,154)			(2,330,707)
56	Account No. 190	(Worksheet C)	104,239,996			3,473,834
57	Account No. 255	(Worksheet C)	(15,213,997)			-
58	Unfunded Reserves	(Worksheet N)	(1,647,242)	DA	1.00000	(1,647,242)
59	TOTAL ADJUSTMENTS	(sum lns 53 to 57)	(825,572,844)			(97,631,596)
60	UNAMORTIZED ABANDONED PLANT	(Worksheet P) (Note R)	0	DA	1.00000	0
60a	Construction Work in Progress (CWIP)	(Worksheet P) (Note Z)	147,322,308	DA	1.00000	147,322,308
61	LAND HELD FOR FUTURE USE	(Worksheet I) (Note F)	780,532	TP	0.93085	726,556
62	WORKING CAPITAL	(Note G)				
63	CWC	(1/8 * ln 90)	12,564,069			2,160,973
64	Materials & Supplies -- Transmission Related	(Worksheet K) (Note S)	17,494,137	TP	0.93085	16,284,358
65	Prepayments (Account 165)	(Worksheet K)	8,244,622	GP	0.12574	1,036,668
66	TOTAL WORKING CAPITAL	(sum lns 63 to 65)	38,302,829			19,481,999
67	RATE BASE (sum lns 50, 59, 60, 61, 66)		3,390,621,663			625,272,506

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
68	Transmission	321.112.b	29,685,276			
68a	Less Extraordinary & Storm Cost Amortization	(Worksheet O)	-			
69	Less expenses for LSE cost responsibility	(Worksheet E, ln 14)	5,827,805			
70	Less Account 561 (Load Dispatching)	321.84-92.b (Note P & U)	9,773,191			
71	Less Account 565	321.96.b (Note I)	1,058,012			
72	Plus Acct 565 native load, zonal or pool	(Note I)	-			
73	Transmission Subtotal	(ln 68-ln 68a-ln 69-ln 70-ln 71+ln 72)	13,026,268	TP	0.93085	12,125,457
74	Administrative and General	323.197.b (Note J)	90,790,720	NA		
75	Less: Acct. 924, Property Insurance	323.185.b	1,651,034	NA		
76	Less: Acct. 928, Reg. Com. Exp.	323.189.b	4,522,890	NA		
77	Less: Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,625	NA		
78	Less: Acct. 930.2, Misc. General Exp.	323.192.b	14,919,172			
79	Less: PBOP amount included in Line 74	(Note T)	11,100,000			
80	Balance of A & G	(ln 74 - sum ln 75 to ln 79)	58,595,999	W/S	0.05740	3,363,609
81	Plus: Acct. 924	(ln 75)	1,651,034	GP	0.12574	207,599
82	Plus: Acct. 928 - Transmission Direct Assigned	(Note K) (Worksheet D)	11,018	DA	1.00000	11,018
83	Plus: Acct. 928 - Transmission Allocated	(Note K) (Worksheet D)	18,152	DA	1.00000	18,152
84	Plus: Acct. 930.1 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
85	Plus: Acct. 930.1 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
86	Plus: Acct. 930.2 - Adj. Misc. General Expenses	(Worksheet D)	14,810,084	W/S	0.05740	850,149
87	Plus: PBOP Amount	(Note T)	12,400,000	W/S	0.05740	711,802
88	A & G Subtotal	(sum lns 80 to 87)	87,486,287			5,162,329
89	Transmission Lease Payments	(Worksheet D)	-	DA	1.00000	-
90	TOTAL O & M EXPENSE	(ln 73 + ln 88 + ln 89)	100,512,555			17,287,786
91	DEPRECIATION AND AMORTIZATION EXPENSE					
92	Transmission	336.7.b	20,977,544	TP	0.93085	19,526,875
93	Plus: Extraordinary & Storm Cost O&M Amortization	(Worksheet O) (Note W)	10,464	TP	0.93085	9,741
94	Plus: Recovery of Abandoned Incentive Plant	(Worksheet P) (Note R)	0	DA	1.00000	0
95	General	336.10.b	12,995,380	W/S	0.05740	745,979
96	Intangible	336.1.f	4,216,474	W/S	0.05740	242,040
97	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 92 to 96)	38,199,862			20,524,634
98	TAXES OTHER THAN INCOME	(Note L)				
99	Labor Related					
100	Payroll	263.i	8,598,019	W/S	0.05740	493,556
101	Plant Related					
102	Property	263.i	56,728,987	GP	0.12574	7,133,031
103	Gross Receipts	263.i	-			
104	Other	263.i	111,689	GP	0.12574	14,044
105	TOTAL OTHER TAXES	ln 100 + (sum lns 102 to 104)	65,438,695			7,640,630
106	INCOME TAXES	(Note M)				
107	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.97%			
108	CIT=(T/1-T) * (1-(WCLTD/R)) =		43.53%			
109	where WCLTD=(ln 137) and R= (ln 140)					
110	and FIT, SIT & p are as given in Note M.					
111	1 / (1 - T) = (from ln 107)		1.6385			
112	Amortized Investment Tax Credit	266.8.f (enter negative)	(4,231,644)			
113	Income Tax Calculation	(ln 108 * ln 116)	132,838,164	NA		24,496,998
114	ITC adjustment	(ln 111 * ln 112)	(6,933,446)	NP	0.132956	(921,845)
115	TOTAL INCOME TAXES	(sum lns 113 to 114)	125,904,718			23,575,153
116	RETURN (Rate Base * Rate of Return)	(ln 67 * ln 140)	305,150,237	NA		56,273,472
117	REVENUE REQUIREMENT	(sum lns 90, 97, 105, 115, 116)	635,206,067			125,301,675

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

SUPPORTING CALCULATIONS

ln No.	(1)	(2)	(3)		(4)		(5)
	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
118	Total transmission plant	(ln 31)					942,744,528
119	Less transmission plant excluded from SPP Tariff	(Worksheet H) (Note N)					18,521,292
120	Less Production Related Transmission Facilities	(Worksheet H) (Note O)					46,672,721
121	Transmission plant included in SPP Tariff	(ln 118 - ln 119 - ln 120)					877,550,515
122	Percent of transmission plant in SPP Tariff	(ln 121 / ln 118)				**TP=**	**0.93085**
123	WAGES & SALARY ALLOCATOR (W/S)						
124	Production	354.20.b	51,909,552	NA			-
125	Transmission	354.21.b	7,237,937	TP	0.93085		6,737,409
126	Distribution	354.23.b	35,161,973	NA			-
127	Other (Excludes A&G)	354.24,25,26.b	23,060,052	NA			-
128	Total	(sum lns 124 to 127)	117,369,514				6,737,409
129	Transmission related amount	(ln 128 - Col. 5 / Col. 3)				**W/S=**	**0.05740**
130	RETURN (R)						
131	Preferred Dividends	(118.29.c) (positive number)	0				-
132	Development of Common Stock:						
133	Long Term Debt	(Worksheet K) (Note Q)			44.72%		1,545,303,846
134	Preferred Stock	(Worksheet K) (Note Q)			0.00%		-
135	Common Stock	(Worksheet K) (Note Q)			55.28%		1,910,285,534
136	Total	(sum lns 133 to 135)					3,455,589,381
			$	%	Cost (Note Q)		Weighted
137	Long Term Debt		1,545,303,846	44.72%	0.0640		0.0286
138	Preferred Stock	112.3.c	-	0.00%	0.0000		0.0000
139	Common Stock		1,910,285,534	55.28%	0.1110		0.0614
140	Total (sum lns 137 to 139)		3,455,589,381			**R**	**0.0900**

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes

General Notes: a) References to data from Form 1 are indicated as: page#.line#.col.#
b) If transmission owner ("TO") functionalizes its costs to transmission on its books, those costs are shown above and on any supporting workpapers rather than using the allocations above.

Note Letter	
A	The revenues credited shall include a) amounts received directly from the SPP for service under this tariff reflecting the TO's integrated transmission facilities and b) amounts from customers taking service under grandfathered agreements. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the definition of transmission facilities under this tariff shall not be included as revenue credits. Revenues from coincident peak loads included in the DIVISOR are also not included as revenue credits unless this revenue is offset by a corresponding expense. See Worksheet A for details.
B	The annual and monthly net plant carrying charges on page 2 are to be used to compute the revenue requirement for directly assigned transmission facilities, Base Plan Upgrades, Transmission Service Upgrades, Sponsored, Economic Portfolio Upgrades and Generator Interconnection Facilities, etc. whose revenue requirement is calculated in Worksheet G and recoverd pursuant to Attachments J and Z, or successor attachments, of the SPP OATT.
C	This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet F shows the calculation of the additional revenue requirements for each project receiving incentive rate treatment, as accepted by FERC. These individual additional revenue requirements shall be summed, for the relevant year, and included here. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year being projected.
D	Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190 and 255 as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M. Transmission allocations shall be shown on Worksheet C, including amounts excluded through direct assignment to incentive plant, as shown on separate workpapers.
E	Reserved for future use.
F	Identified as being only transmission related or functionally booked to transmission.
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 90. Prepayments are limited to electric related items.
H	Reserved for future use
I	Only include transmission costs paid to others by the TO for which the transmission customer under the tariff receives a benefit (such as the payment of Base Plan Charges allocated to the TO's zone and not otherwise recovered by SPP from customers). Charges related to Base Plan Upgrades under Attachment J, Future Roll-Ins under Attachment Z and replacement of Existing Facilities are to be included. Direct Assignment Facilities, Economic Upgrades, Requested Upgrades and generator related to Network Upgrades (as defined in Attachment J) are to be excluded.
J	General Plant and Administrative and General expenses will be functionalized based on the indicated allocator on each line.
K	Includes all Regulatory Commission expense itemized in FERC Form 1 at 351.h. Show in Worksheet D how these expense items are allocated to transmission. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Account 930.1 shall Include only safety-related advertising cost booked to the account.
L	Includes only FICA, unemployment, highway, property and other assessments charged in the relevant year. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year being projected. Gross receipts tax and taxes related to income are excluded.
M	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 112) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:			
	FIT =	35.00%	
	SIT=	6.10%	(State Income Tax Rate or Composite SIT - Worksheet J)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

N	Removes the dollars of plant booked to transmission plant that is excluded from the Tariff because it does not meet the Tariff's definition of Transmission Facilities or is otherwise not eligible to be recovered under this Tariff.
O	Removes the dollars of plant booked to transmission (e.g. step-up transformers) that are included in the development of OATT ancillary services rates and not already removed in Note N above.
P	Removes the dollars of expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
Q	Long Term Debt cost rate calculated in Section V of Worksheet K. Preferred Stock cost rate = preferred dividends (ln 131) / preferred outstanding (ln 138). Common Stock cost rate (ROE) = 11.10%, the rate accepted by FERC in Docket No. ER08-281 It includes an additional 50 basis points for the TO remaining a member of the SPP RTO. This rate shall not change until a new rate is accepted by FERC in a subsequent filing under the FPA, including Sections 205 and 206. The percentage of equity used in determining the weighted cost of equity for OG&E for purposes of the Settlement Formula Rate shall not exceed 56% ("Equity Cap") as accepted by FERC in Docket No. ER09-281 regardless of OG&E's actual percentage of equity. To the extent OG&E's actual percentage of equity exceeds the Equity Cap, such amount in excess of the Equity Cap shall be treated as Long-Term Debt for purposes of the Settlement Formula Rate. The Equity Cap shall not change until a new Equity Cap is accepted by FERC in a subsequent filing under the FPA, including Sections 205 and 206. Include in the interest on Debt from Associated Companies only the interest on Long-Term Debt.
R	OG&E must make the appropriate filing at FERC before inputting or changing amounts on lines 60 & 94 (abandoned plant).
S	The Formula Rate will functionalize Material and Supplies for Construction on the basis of a single-year usage ratio in accordance with the most recent FERC Form 1, and will true-up these costs based on the trued-up year's Form 1. M&S for Construction will utilize 13 month average balances as reflected in Worksheet K, Section II and exclude any M&S booked in Account 107.
T	PBOP base amount, initially set at $12,400,000, shall not be changed absent a separate filing made with the FERC.
U	Transmission Service Study and Generation Interconnection Study costs shall be recorded in FERC Accounts 561.6 and 561.7, respectively. Costs of studies performed by SPP on behalf of OG&E, costs of studies performed by OG&E at SPP's request, reimbursement of study costs from SPP for studies performed by OG&E at SPP's request and studies for OG&E's retail load shall be recorded in FERC Accounts 561.6 & 561.7. FERC Accounts 561.6 and 561.7 are excluded from the Formula Rate.

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes - continued

V Accumulated Amortization for Intangible Plant shall be reflected as a Rate Base Adjustment under "Accumulated Depreciation".
W OG&E may only include the amortization of transmission-related extraordinary property losses if; (1) OG&E makes a filing with the Oklahoma Corporation Commission requesting approval for the new amount to be recovered and the amortization period and (2) OG&E makes a single issue FPA Section 205 filing that requests the same recovery treatment from the FERC. OG&E shall be obligated to make such a single issue FPA Section 205 filing whenever it requests amortized extraordinary property loss costs recovery from the Oklahoma Corporation Commission.
X SPP OATT Related Upgrades include Base Plan Upgrades, Sponsored, Economic Portfolio Upgrades, Transmission Service Upgrades and Generator Interconnection Facilities, etc. whose individual Revenue Requirements are calculated and summarized in Worksheet G. Also included are the individual Revenue Requirements of facilities receiving Construction Work in Progress and Abandoned Plant incentive, as calculated and summarized in Worksheet P. The sum of the individual Revenue Requirements is credited to zonal network customers on line 17 above.
Y Exclude annualized amortization amounts booked back into O&M accounts that costs would have been booked had not a Regulatory Asset and amortization period been approved by the Oklahoma Corportion Commission and the FERC. This amount should equal amount reflected on line 93.
Z OG&E may only recover CWIP on projects that the FERC has specifically authorized the incentive.

List of Allocators:		
Direct Assigned	DA	1.000000
Gross Plant	GP	0.125739
Net Plant	NP	0.132956
Trans. Plant in SPP	TP	0.930847
Wages & Salaries	W/S	0.057403
No Allocator	NA	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet A

Line No.

I. Account 454, Rent from Electric Property - Relevant Year = 2009 (Note 1)

(Revenue related to transmission facilities for pole attachments, rentals, etc. Provide data sources and explanations in Section V, Notes below)

Line No.		Data Sources	2009 YE Balance	GP Allocator	Allocated to Transmission
1	Rent from Electric Property	300.19.b	$1,285,452	12.5739%	$161,631
2					
3					
4	**Net Account 454 - Credited as transmission pole rentals =**				**$161,631**

II. Account 456, Other Electric Revenue - Relevant Year = 2009 (Notes 1 & 2)

(Other electric revenues including miscellaneous transmission revenues. Provide data sources and explanations in Section V, Notes below)

Line No.			(A) 2009 YE Balance	(B) Power Production	(C) Distribution	(D) Utility Commercial	(E) Utility A & G	(F) Miscellaneous	(G) Transmission (Load in Divisor)	(H) Other Transmission
5		300.21.b	$92,225,167							
6	Miscellaneous - McClain Adder									
7	Miscellaneous - Scrap Sales			$19,127						
8	Miscellaneous - OMPA Admin Fee			$120,801						
9	Miscellaneous			$72	$30,790			$9,269		
10	Miscellaneous - Honeywell Energy Management									
11	Miscellaneous - Sale of Residual Oil									
12	Reimbursed Payroll Costs			$1,253	$3,832	$2,832	$50			
13	Remuneration Sales Taxes Collection - OK & AR						$115,159			
14	Franchise & Privilege Tax Adjustment						$152			
15	Oil Lease & Royalties						$10,124			
16	Pace Payments									
17	Transmission Service Revenues - from OG&E LSE								$83,852,324	
18	Transmission Service Revenues - Unbundled OK & AR								$277,758	
19	Transmission Service Revenues - Direct Assigned Facilities									
20	Salvage Clearing			$2,880	$54,131	$1,748				
21	Off-System Sales Credit - Oklahoma							$1,715,839		
22	Discount on Purchased Wind Credits							$86,197		
23	Renewable Energy Certificate Sales - OK & AR						$612,037			
24	Base Plan Revenues - 2008 & 2009								$3,851,809	$1,456,983
25										
26	TOTALS (Sum lns 6 - 25)		$92,225,167	$144,133	$88,753	$4,580	$737,522	$1,811,305	$87,981,891	$1,456,983
27	**Net Account 454 - Credited as Transmission Revenues** [(A)-(B)-(C)-(D)-(E)-(F)-(G)] =									**$1,456,983**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet A

III. Account 456.1, Revenues from Transmission of Electricity of Others - Relevant Year = 2009 (Notes 1 & 3) 328-330.Total.n $17,615,928

(Provide data sources and any detailed explanations necessary in Section V, Notes below)

Line		Transmission (Load in Divisor)	
	Less:		
28	TO's LSE Direct Assignment Revenue Credits		
29	TO's LSE Sponsored (Requested or Economic) Upgrade Revenue Credits		
30	TO's LSE Network Upgrades for Generation Interconnection - Credits		
31	TO's Point-To-Point Revenue for GFA's Associated with Load Included in the Divisor		
32	Network Service Revenue (Schedule 9) Associated With Load Included in the Divisor	$6,980,799	
33	TO's Revenue Associated with Transmission Plant Excluded From SPP Tariff		
34	Wholesale Distribution charges	$311,758	
35	TO's LSE Revenue from Ancillary Services Provided		
36	Network Service Ancillary Revenues (Schedule 1) Associated With Load Included in the Divisor	$416,289	
37			
38			
39			
40	**Total Revenues Adjusted from Account 456.1 (Revenues retained by OG&E for load included in the divisor) =** (Sum lns 28 thru 39)		$7,708,846
41	**Net Account 456.1 Included in Template (PTP revenues to be credited) =** [(328-330.Total.n) - ln 40]		**$9,907,082**

IV. Revenue from Grandfathered Interzonal Transactions - Revelant Year = 2009 (Note 3)

(Provide data sources and any detailed explanations necessary in Section V, Notes below)

Line			
42	Revenues from Grandfathered Interzonal Transactions	0	
43			
44	Revenues received from SPP for PTP service	0	
45			
46	**Sum of Parts I, II & III**	(Addendum 2-A, ln 14)	**$11,525,696**

V. Notes

(Provide data sources for Sections I, II, III and IV along with any detailed explanations necessary.)

47 1. When calculating the Baseline ATRR, the "Revelant Year" is the year being trued-up. When calculating the Projected ATRR, the "Revelant Year" is the year of the most recent FERC Form 1.

48 2. Section II, Other Electric Revenues reflects revenues received from SPP for Directly Assigned Upgrades and Other Transmission Revenues to be credited to customers.
of this Attachment H - Addendum 2-A.

49 3. Section III, Net Account 456.1 reflects SPP Point-to-Point revenues to be credited to customers.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet B

I. Transmission Network Load (MW)

Line No.	Month, Day and Year[1]	Hour Ending[1]	OG&E Peak Load	WFEC Peak Load	OMPA Peak Load	AECI/KAMO Peak Load				TO's Transmission Peak Load[1]
1	15-Jan-09	1900	4,203	105	254	18				4,579
2	4-Feb-09	800	3,879	100	218	15				4,212
3	2-Mar-09	800	3,668	100	203	15				3,987
4	23-Apr-09	1500	3,626	71	245	8				3,950
5	31-May-09	1800	4,143	87	320	12				4,562
6	24-Jun-09	1700	5,728	114	452	16				6,311
7	13-Jul-09	1700	5,947	110	471	17				6,544
8	4-Aug-09	1700	5,570	113	439	15				6,137
9	9-Sep-09	1700	4,984	92	354	11				5,441
10	1-Oct-09	1500	3,684	75	238	8				4,005
11	16-Nov-09	1900	3,560	92	211	12				3,875
12	9-Dec-09	2000	4,274	108	259	16				4,656
13	Total		53,265	1,167	3,665	161				58,258
14	12-CP		4,439	97	305	13				4,855

II. Notes

1 These are the dates, hour ending and loads at the time of the TO's transmission peak, as reported in FERC Form 1, page 400. Peak Load for Point-to-Point services sold under the SPP Tariff are not reflected in the totals above. Revenues from Point-to-Point services are shared according to Attachment L of the SPP OATT and revenues received provide revenue credits to network customers.

2 "GFA PTP Scheduled Load" is the firm load in kW scheduled by Grandfathered Agreements' (GFA) customers taking firm point-to-point (PTP) service at the time of TO's monthly transmission peak load. Details are as follows:

Ln No.	Month, Day and Year	Hour ending								GFA PTP Scheduled Load
15	15-Jan-09	1900								0
16	4-Feb-09	800								0
17	2-Mar-09	800								0
18	23-Apr-09	1500								0
19	31-May-09	1800								0
20	24-Jun-09	1700								0
21	13-Jul-09	1700								0
22	4-Aug-09	1700								0
23	9-Sep-09	1700								0
24	1-Oct-09	1500								0
25	16-Nov-09	1900								0
26	9-Dec-09	2000								0

3 "GFA PTP Contract Demand" is the contract demand in kW for GFA customers taking firm PTP service at the time of TO's monthly peak load. Details are as follows:

Ln No.	Month, Day and Year	Hour ending								GFA PTP Contract Demand
27	15-Jan-09	1900								0
28	4-Feb-09	800								0
29	2-Mar-09	800								0
30	23-Apr-09	1500								0
31	31-May-09	1800								0
32	24-Jun-09	1700								0
33	13-Jul-09	1700								0
34	4-Aug-09	1700								0
35	9-Sep-09	1700								0
36	1-Oct-09	1500								0
37	16-Nov-09	1900								0
38	9-Dec-09	2000								0

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet B

II. Notes (cont.)

4 "Non-Firm Sales in TO's Zone" are non-firm loads in kW at the time of, and include in, TO's monthly transmission system peak load associated with sales to customers in TO's zone. Details are as follows:

Line No.	Month, Day and Year	Hour ending								Non-Firm Sales in TO's Zone
39	15-Jan-09	1900								0
40	4-Feb-09	800								0
41	2-Mar-09	800								0
42	23-Apr-09	1500								0
43	31-May-09	1800								0
44	24-Jun-09	1700								0
45	13-Jul-09	1700								0
46	4-Aug-09	1700								0
47	9-Sep-09	1700								0
48	1-Oct-09	1500								0
49	16-Nov-09	1900								0
50	9-Dec-09	2000								0

5 "Non-TO Generation" in kW is load served by non-TO generators operating synchronously with the TO's transmission system. Details are as follows:

Line No.	Month, Day and Year	Hour ending								Non-Firm Sales in TO's Zone
51	15-Jan-09	1900								0
52	4-Feb-09	800								0
53	2-Mar-09	800								0
54	23-Apr-09	1500								0
55	31-May-09	1800								0
56	24-Jun-09	1700								0
57	13-Jul-09	1700								0
58	4-Aug-09	1700								0
59	9-Sep-09	1700								0
60	1-Oct-09	1500								0
61	16-Nov-09	1900								0
62	9-Dec-09	2000								0

6 "Non-TO Load in TO's Zone" is load in kW for firm-service customers in TO's zone that is electronically transferred to other TO zones. Details are as follows:

Line No.	Month, Day and Year	Hour ending								Non-TO Load in TO's Zone
63	15-Jan-09	1900								0
64	4-Feb-09	800								0
65	2-Mar-09	800								0
66	23-Apr-09	1500								0
67	31-May-09	1800								0
68	24-Jun-09	1700								0
69	13-Jul-09	1700								0
70	4-Aug-09	1700								0
71	9-Sep-09	1700								0
72	1-Oct-09	1500								0
73	16-Nov-09	1900								0
74	9-Dec-09	2000								0

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

I. Account 281 - ADIT - Accelerated Amortization Property

Relevant Year = 2009 (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
1									
2	Net Total Property and Accumulated Depreciation	-	-	-	-	-	-	-	Accumulated deferred income taxes-Accelerated amortization property.
3	Other	-	-	-	-	-	-	-	
4		-	-	-	-	-	-	-	
5		-	-	-	-	-	-	-	
6		-	-	-	-	-	-	-	
7		-	-	-	-	-	-	-	
8		-	-	-	-	-	-	-	
9		-	-	-	-	-	-	-	
10		-	-	-	-	-	-	-	
11		-	-	-	-	-	-	-	
12		-	-	-	-	-	-	-	
13		-	-	-	-	-	-	-	
14		-	-	-	-	-	-	-	
15		-	-	-	-	-	-	-	
16		-	-	-	-	-	-	-	
17		-	-	-	-	-	-	-	
18		-	-	-	-	-	-	-	
19		-	-	-	-	-	-	-	
20		-	-	-	-	-	-	-	
21		-	-	-	-	-	-	-	
22		-	-	-	-	-	-	-	
23									
24	**Subtotal - Form 1, p273**	-	-	-	-	-	-		
25	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
26	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
27	**Total (ln 24 - ln 25 - ln 26)**	-	-	-	-	-	-		
28	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
29	**Total (ln 27 * ln 28)**		0	0	0	0	0	0	

II. Account 282 - ADIT - Other Property

Relevant Year = 2009 (Note 2)

Line No.	(A) Identification	Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
30									
31	Net Total Property and Accumulated Depreciation	(772,454,785)	-	-	-	(772,454,785)	-	(772,454,785)	Accumulated deferred income taxes-Other property.
32	Income Taxes Recoverable/Refundable, net	(33,471,662)	(33,471,662)	-	-	-	-	-	Deferred tax per SFAS 109 related to property and Retail S. Georgia.
33	Other		-	-	-	-	-	-	
34			-	-	-	-	-	-	
35			-	-	-	-	-	-	
36			-	-	-	-	-	-	
37			-	-	-	-	-	-	
38			-	-	-	-	-	-	
39			-	-	-	-	-	-	
40			-	-	-	-	-	-	
41			-	-	-	-	-	-	
42			-	-	-	-	-	-	
43			-	-	-	-	-	-	
44			-	-	-	-	-	-	
45			-	-	-	-	-	-	
46			-		-	-	-	-	
47			-	-	-	-	-	-	
48			-	-	-	-	-	-	
49			-	-	-	-	-	-	
50									
51	**Subtotal - Form 1, p275**	(805,926,447)	(33,471,662)	-	-	(772,454,785)	-		
52	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
53	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
54	**Total (ln 51 - ln 52 - ln 53)**	(805,926,447)	(33,471,662)	-	-	(772,454,785)	-		
55	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
56	**Total (ln 54 * ln 55)**		0	0	0	(97,127,482)	0	(97,127,482)	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

III. Account 283 - ADIT - Other **Relevant Year = 2009** (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
	Accumulated Deferred Income Tax:								
57									
58	Prepaid Expenses	(2,160,820)	-	-	-	(1,080,410)	(1,080,410)	(2,160,820)	Book accrual vs. actual payments for tax.
59	Pension Plans	(79,161,220)	(79,161,220)	-	-	-	-	-	ADIT related to Pre-paid Pension Expense.
60	Bond Redemption - Unamortized Call Premium Costs	(5,444,354)	-	-	-	(5,444,354)	-	(5,444,354)	Expenses amortized for books; deducted for tax prior years when incurred/paid.
61	Reg Asset - Deferred Excess 2007 Storm Expenses - OK	(11,444,010)	-	-	-	(11,444,010)	-	(11,444,010)	Costs deducted for tax purposes, recorded as Regulatory Assets for book
62	Reg Asset - Deferred McClain Plant Costs - OK	(1,205,143)	(1,205,143)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book
63	Reg Asset - Deferred Red Rock Plant Costs - OK	(2,814,213)	(2,814,213)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book
64	Reg Asset - Deferred Excess 2007 Storm Expenses - AR	(74,096)	-	-	-	(74,096)	-	(74,096)	Costs deducted for tax purposes, recorded as Regulatory Assets for book
65	Reg Asset - Deferred Excess Pension Expenses - OK	(2,491,900)	(2,491,900)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book
66	Reg Asset - Deferred Excess Pension Expenses - AR	33,741	33,741	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book
67	Deferred Other - Rate Case Consult/Expert Witness Costs	(235,369)	(235,369)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book
68	Deferred Rate Case Expense - OK	(113,972)	(113,972)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book
69	LIFO Inventory Adjustments - Fuels Stock	(1,913,799)	(1,913,799)	-	-	-	-	-	Full Adj charged to 2008 Book Income vs Taxable Income over 4 yrs per Sec 481.
70			-	-	-	-	-	-	
71			-	-	-	-	-	-	
72			-	-	-	-	-	-	
73			-	-	-	-	-	-	
74			-	-	-	-	-	-	
75			-	-	-	-	-	-	
76			-	-	-	-	-	-	
77			-	-	-	-	-	-	
78			-	-	-	-	-	-	
79			-	-	-	-	-	-	
80			-	-	-	-	-	-	
81			-	-	-	-	-	-	
82			-	-	-	-	-	-	
83			-	-	-	-	-	-	
84			-	-	-	-	-	-	
85			-	-	-	-	-	-	
86			-	-	-	-	-	-	
87			-	-	-	-	-	-	
88			-	-	-	-	-	-	
89			-	-	-	-	-	-	
90			-	-	-	-	-	-	
91			-	-	-	-	-	-	
92			-	-	-	-	-	-	
93			-	-	-	-	-	-	
94			-	-	-	-	-	-	
95			-	-	-	-	-	-	
96			-	-	-	-	-	-	
97			-	-	-	-	-	-	
98			-	-	-	-	-	-	
99			-	-	-	-	-	-	
100			-	-	-	-	-	-	
101			-	-	-	-	-	-	
102			-	-	-	-	-	-	
103			-	-	-	-	-	-	
104			-	-	-	-	-	-	
105			-	-	-	-	-	-	
106			-	-	-	-	-	-	
107			-	-	-	-	-	-	
108									
109	**Subtotal - Form 1, p277.9.k**	(107,025,154)	(87,901,875)	-	-	(18,042,870)	(1,080,410)		
110	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
111	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
112	**Total (ln 109 - ln 110 - ln 111)**	(107,025,154)	(87,901,875)	-	-	(18,042,870)	(1,080,410)		
113	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
114	**Total (ln 112 * ln 113)**		0	0	0	(2,268,687)	(62,019)	(2,330,707)	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

IV. Account 190 - ADIT **Relevant Year =** **2009** (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
115	Accrued Vacation	4,202,206	-	-	-	-	4,202,206	4,202,206	Book accrual vs. actual payments for tax.
116	Derivative Instruments	129,259	129,259	-	-	-	-	-	Tax deduction for Mark-to-Market discount permitted by Section 465.
117	Bad Debts	883,243	883,243	-	-	-	-	-	Book accrual vs. actual payments for tax.
118	Accrued Interest	1,030,526	-	-	-	1,030,526	-	1,030,526	Book accrual vs. actual payments for tax.
119	Accrued Liability-Public Liability	724,556	-	-	-	362,278	362,278	724,556	Book accrual vs. actual payments for tax. Split 50% labor, 50% plant
120	Accrued Liability-Employee Related	590,758	-	-	-	-	590,758	590,758	Book accrual vs. actual payments for tax.
121	Regulatory Liabilities- Deferred Gains - Property Sales	6,397	6,397	-	-	-	-	-	Taxable gains recorded as Regulatory Liabilities for book.
122	Rate Refund Accrual	244,723	244,723	-	-		-	-	Deferred revenue accrual per books vs. actual revenue for tax purposes.
123	Income Taxes Recoverable, net (Pens & Medicare Part D)	6,442,710	-	-	-	-	6,442,710	6,442,710	Anticipated Medicare subsidy.
124	Post-Retirement Benefits	29,233,798	-	-	-	-	29,233,798	29,233,798	Book accrual vs. actual payments for tax purposes.
125	Consumer Loans	-	-						Income, losses and expenses recognized for tax but not for book.
126	Deferred Fed Investment Tax Credits	5,893,853	5,893,853						ADIT for Unamortized ITC balance. ITC utilized for tax purposes in prior years.
127	Tax Credit Carryover	33,296,514	33,296,514	-	-	-	-	-	ADIT for Tax Credit Carryover
128	Net Operating Loss	230,811	230,811	-	-	-	-	-	ADIT for Net Operating Loss carryover
129	Medicare Part D Subsidy	16,633,572	-	-	-	-	16,633,572	16,633,572	ADIT for Non-taxable government subsidy (IRC Section 139A) FAS 158
130	Other - Investments in Partnerships	72,491	72,491	-	-	-	-	-	ADIT for Book vs. Tax Partnership Income and Expense differences.
131	Kaw Water Storage Agreement Liability	3,137,726	3,137,726	-	-	-	-	-	ADIT for Book vs. Tax Differences due to differences in Imputed Interest Rates
132	Charitable Contributions Carryover	1,486,853	1,486,853	-	-	-	-	-	ADIT for Limited Charitable Contributions Carryover
133									
134									
135							-	-	
136									
137									
138				-	-	-	-	-	
139									
140									
141									
142									
143				-	-	-	-	-	
144			-	-	-	-	-	-	
145			-	-	-	-	-	-	
146			-	-	-	-	-	-	
147			-	-	-	-	-	-	
148			-	-	-	-	-	-	
149			-	-	-	-	-	-	
150									
151	**Subtotal - Form 1, p234.8.c**	104,239,996	45,381,870	-	-	1,392,804	57,465,323		
152	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
153	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
154	**Total (ln 151 - ln 152 - ln 153)**	104,239,996	45,381,870	-	-	1,392,804	57,465,323		
155	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
156	**Total (ln 154 * ln 155)**		0	0	0	175,129	3,298,705	3,473,834	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

V. Account 255 - Accumulated Deferred Investment Tax Credits **Relevant Year = 2009** (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)
157	Accumulated Deferred Investment Tax Credits	(15,213,997)	(15,213,997)	-	-	-	-	-
158			-	-	-	-	-	-
159			-	-	-	-	-	-
160			-	-	-	-	-	-
161			-	-	-	-	-	-
162			-	-	-	-	-	-
163			-	-	-	-	-	-
164			-	-	-	-	-	-
165			-	-	-	-	-	-
166			-	-	-	-	-	-
167			-	-	-	-	-	-
168			-	-	-	-	-	-
169			-	-	-	-	-	-
170			-	-	-	-	-	-
171			-	-	-	-	-	-
172			-	-	-	-	-	-
173			-	-	-	-	-	-
174			-	-	-	-	-	-
175								
176	**Subtotal - Form 1, p267.8.h**	(15,213,997)	(15,213,997)	-	-	-	-	
177	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-	
178	**Less FASB 106 Above if not separately removed**	-	-					
179	**Less Post 1971 ITC Property Under F2 Option**	-	-	-	-	-	-	
180	**Total (ln 176 - ln 177 - ln 178 - ln 179)**	(15,213,997)	(15,213,997)	-	-	-	-	
181	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%	
182	**Total (ln 180 * ln 181)**		0	0	0	0	0	0

NOTE:

1. A worksheet will be provided to support the average of beginning and ending balances for items in ADIT Accounts 281, 282, 283, 190 & 255.
2. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Revelant Year" is the year of the most recent FERC Form 1.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet D

I. Account 928 - Regulatory Comm. Expenses

Relevant Year = 2009

(A) Item No.	(B) Description	(C) 2007 Expense	(D) Non-Transmission	(E) Transmission Allocation	(F) Transmission Direct Assigned	(G) Explanation
	Regulatory Commission Expenses:					
1	FERC Assessment for Annual Charges	1,510,964	1,510,964		-	
2	Arkansas Public Service Commission for Annual Charges	275,471	275,471	-	-	
3	Oklahoma Corporation Commission for Annual Charges	1,373,781	1,373,781	-	-	
4	Arkansas Rate Case (08-103-U)	122,601	122,601	-	-	
5	Arkansas Rate Review - 2010	57,995	57,995	-	-	
6	FERC Transmission Rate Case (ER08-281-000)	11,018	-	-	11,018	
7	OU Spirit (PUD 2009-167)	56,126	56,126	-	-	
8	Oklahoma Rate Case 2009 (PUD 2008-398)	933,872	933,872	-	-	
9	Oklahoma Fuel Audit (PUD 2008-299)	9,646	9,646	-	-	
10	2008 FCA Prudence (PUD 2008-398)	22,549	22,549	-	-	
11	Arkansas Energy Efficiency Programs (06-004-R)	4,508	4,508	-	-	
12	Security	19,973	17,462	2,511	-	Allocated based on gross plant
13	System Hardening Project	36,083	31,546	4,537	-	Allocated based on gross plant
14	Minor Items	88,303	77,200	11,103	-	Allocated based on gross plant
15			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
NOTE:	FERC Assessments are to be included in Column (D)		-	-	-	
	Total - Form I, pg 351.46.h+k	4,522,890	4,493,720	18,152	11,018	

II. Account 930.1 - General Advertising Expense

Relevant Year = 2009

(A) Item No.	(B) Description	(C) 2007 Expense	(D) Non-Transmission	(E) Transmission Allocation	(F) Transmission Direct Assigned	(G) Explanation
1	General Advertising Expense	1,625	1,625	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
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			-	-	-	
			-	-	-	
	Total - Form I, pg 323.191.b	1,625	1,625	-	-	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet D

III. Transmission Lease Payments

Relevant Year = 2009

(A) Item No.	(B) Description	(C) Expense

Total Transmission Lease Payments

IV. Account 930.2 - Misc. General Expenses

Relevant Year = 2009

Item No.	Description	Date Sources	TO Total	Explanation
1	Miscellaneous General Expenses	323.192.b	14,919,172	
2	Less: Industry Association Dues	335.1.b	626,487	
3	Plus: EEI Dues		511,399	
4	Plus: SPP Dues		6,000	
5	Adjusted Miscellaneous General Expenses	(ln 1-ln 2+ln 3+ln 4)	14,810,084	

NOTE:

1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the most recent FERC Form 1.
2. All Industry Assn. Dues shall be removed from Acct. 930.2 and the Formula Rate except for EEI and SPP.
3. In sections I and II, the explanation will include why the cost is related to transmission service as the basis for the allocation

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet E

Additional Revenue Requirement from
Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility

			Relevant Year
			2009
1	Other Expenses:		
2	Direct Assignment Charge		
3	Sponsored (Requested or Economic) Upgrades Charge		
4	Firm and Non-Firm Point-To-Point Charges		
5	Base Plan Charges		4,837,746
6	Schedule 9 Charges		935,695
7	SPP Schedule 1-A		
8	SPP Annual Assessment		
9	NERC Assessment		
10	Ancillary Services Expenses		54,364
11	Other		
12	Other		
13	Other		
14	Total	(Sum of lns 2 through 13)	$ 5,827,805

Notes:
1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Revelant Year" is the year of the most recent FERC Form No. 1.
2. Adjustment to charges that are booked to transmission accounts that are the responsibility of the TO's LSE.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet F

I. Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase.

A. Determine "R" with hypothetical 100 basis point increase in ROE.

Line No.					
1	ROE w/o incentives (Addendum 2-A, ln 139)				11.10%
2	ROE with additional 100 basis point incentive				12.10%
3	Determine R (cost of long term debt, cost of preferred stock and percent is from Addendum 2-A, lns 137 through139)				
4		%	Cost		Weighted cost
5	Long Term Debt	44.72%	0.0640		0.0286
6	Preferred Stock	0.00%	0.0000		0.0000
7	Common Stock	55.28%	0.1210		0.0669
				R =	0.0955

B. Determine Return using "R" with hypothetical 100 basis point ROE increase.

8	Rate Base (Addendum 2-A, ln 67)	625,272,506
9	R (from A. above)	0.0955
10	Return (Rate Base x R)	59,730,043

C. Determine Income Taxes using Return with hypothetical 100 basis point ROE increase.

11	Return (from B. above)	59,730,043
12	CIT (Addendum 2-A, ln 108)	43.53%
13	Income Tax Calculation (Return x CIT)	26,001,714
14	ITC Adjustment (Addendum 2-A, ln 114)	(921,845)
15	Income Taxes	25,079,869

II. Calculate Net Plant Carrying Charge Rate (NPCC) with hypothetical 100 basis point ROE increase.

A. Determine Net Revenue Requirement less Return and Income Taxes.

16	Net Revenue Requirement (Addendum 2-A, ln 16)	113,775,979
17	Return (Addendum 2-A, ln 116)	56,273,472
18	Income Taxes (Addendum 2-A, ln 115)	23,575,153
19	Net Revenue Requirement, Less Return and Taxes	33,927,354

B. Determine Net Revenue Requirement with hypothetical 100 basis point increase in ROE.

20	Net Revenue Requirement, Less Return and Taxes	33,927,354
21	Return (from I.B. above)	59,730,043
22	Income Taxes (from I.C. above)	25,079,869
23	Net Revenue Requirement, with 100 Basis Point ROE increase	118,737,266
24	Transmission Plant Depreciation Expense (Addendum 2-A, lns 92)	19,526,875
25	Net Rev. Req, w/100 Basis Point ROE increase, less Depreciation	99,210,391

C. Determine NPCC with hypothetical 100 basis point ROE increase.

26	Net Transmission Plant (Addendum 2-A, lns 46)	546,975,024	
27	Net Revenue Requirement, with 100 Basis Point ROE increase	118,737,266	
28	NPCC with 100 Basis Point increase in ROE	21.71%	
29			
30	Net Rev. Req, w/100 Basis Point ROE increase, less Dep.	99,210,391	
31	NPCC with 100 Basis Point ROE increase, less Depreciation	18.14%	(use when no CIAC is associated with facilities receiving incentives)
32	NPCC w/o 100 Basis Point ROE increase, less Depreciation	17.23%	(Addendum 2-A, ln 26)
33	NPCC w/o Return, income taxes and Depreciation	2.63%	(use when CIAC is associated with facilities receiving incentives)
34	100 basis point ROE increase (line 31 - 32)	0.91%	

III. Calculation of Composite Depreciation Rate.

35	Transmission Plant @ Beginning of Period (p.206, ln 58, col. b)	789,771,070
36	Transmission Plant @ End of Period (p.207, ln 58, col. g)	860,448,242
37		1,650,219,312
38	Average Balance of Transmission Investment	825,109,656
39	Annual Depreciation (p.336, ln 7, col. f)	20,977,731
40	Composite Depreciation Rate	2.54%
41	Depreciable Life for Composite Depreciation Rate	39.33
42	Depreciable Life Rounded to Nearest Whole Year	39

NOTE:
Incentives shall not be included in the revenue requirement calculation unless approved by the FERC in a separate single issue filing.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet F

IV. Summary of Additional Revenue Requirements Detailed in Section V below.

Line No.	Proj. No.	SUMMARY OF ADDITIONAL REVENUE REQUIREMENT FOR FACILITIES RECEIVING INCENTIVES			
		Project Description Summary	In-Service	Investment	Additional Rev. Requirement
43	1				$ -
44	2				
45	3				
46	4				
47	5				
48	6				
49	7				
50	8				
51	9				
52	10				
53	11				
54	12				
55	13				
56	14				
57	15				
58	16				
59					
60					
61		TOTALS		$ -	$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet F

V. Determine the Additional Revenue Requirement for facilities receiving incentives.

A. Facilities receiving incentives

Project 1. Approved by FERC in Docket No. (e.g. ER05-925-000)

Line No.	Details			
62	Investment	-	Current Year	**2009**
63	Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	50
64	Service Month (1-12)	6	NPCC w/o incentives, less depreciation	17.23%
65	Useful Life	39	NPCC w/incentives approved for these facilities, less dep.	17.68%
66	CIAC (Yes or No)	No	Annual Depreciation Expense (Investment / Useful Life)	-

Line No.		Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Additional Rev. Requirement
67-68							
69	w/o incentives	2009	-	-	-	$ -	
70	w/incentives	2009	-	-	-	$ -	$ -
71	w/o incentives	2010	-	-	-	-	
72	w/incentives	2010	-	-	-	-	$ -
73	w/o incentives	2011	-	-	-	-	
74	w/incentives	2011	-	-	-	-	$ -
75	w/o incentives	2012	-	-	-	-	
76	w/incentives	2012	-	-	-	-	$ -
77	w/o incentives	2013	-	-	-	-	
78	w/incentives	2013	-	-	-	-	$ -
79	w/o incentives	2014	-	-	-	-	
80	w/incentives	2014	-	-	-	-	$ -
81	w/o incentives	2015	-	-	-	-	
82	w/incentives	2015	-	-	-	-	$ -
83	w/o incentives	2016	-	-	-	-	
84	w/incentives	2016	-	-	-	-	$ -
85	w/o incentives	2017	-	-	-	-	
86	w/incentives	2017	-	-	-	-	$ -
87	w/o incentives	2018	-	-	-	-	
88	w/incentives	2018	-	-	-	-	$ -
89	w/o incentives	2019	-	-	-	-	
90	w/incentives	2019	-	-	-	-	$ -
91	w/o incentives	2020	-	-	-	-	
92	w/incentives	2020	-	-	-	-	$ -
93	w/o incentives	2021	-	-	-	-	
94	w/incentives	2021	-	-	-	-	$ -
95	w/o incentives	2022	-	-	-	-	
96	w/incentives	2022	-	-	-	-	$ -
97	w/o incentives	2023	-	-	-	-	
98	w/incentives	2023	-	-	-	-	$ -
99	w/o incentives	2024	-	-	-	-	
100	w/incentives	2024	-	-	-	-	$ -
101	w/o incentives	2025	-	-	-	-	
102	w/incentives	2025	-	-	-	-	$ -
103	w/o incentives	2026	-	-	-	-	
104	w/incentives	2026	-	-	-	-	$ -
105	w/o incentives	2027	-	-	-	-	
106	w/incentives	2027	-	-	-	-	$ -
107	w/o incentives	2028	-	-	-	-	
108	w/incentives	2028	-	-	-	-	$ -
109	w/o incentives	2029	-	-	-	-	
110	w/incentives	2029	-	-	-	-	$ -
111	w/o incentives	2030	-	-	-	-	
112	w/incentives	2030	-	-	-	-	$ -
113	w/o incentives	2031	-	-	-	-	
114	w/incentives	2031	-	-	-	-	$ -
115	w/o incentives	2032	-	-	-	-	
116	w/incentives	2032	-	-	-	-	$ -
117	w/o incentives	2033	-	-	-	-	
118	w/incentives	2033	-	-	-	-	$ -
119	w/o incentives	2034	-	-	-	-	
120	w/incentives	2034	-	-	-	-	$ -
121	w/o incentives	2035	-	-	-	-	
122	w/incentives	2035	-	-	-	-	$ -
123	w/o incentives	2036	-	-	-	-	
124	w/incentives	2036	-	-	-	-	$ -
125	w/o incentives	2037	-	-	-	-	
126	w/incentives	2037	-	-	-	-	$ -
127	w/o incentives	2038	-	-	-	-	
128	w/incentives	2038	-	-	-	-	$ -
129	w/o incentives	2039	-	-	-	-	
130	w/incentives	2039	-	-	-	-	$ -
131	w/o incentives	....		....	.....	....	
132	w/incentives	....	....	.....	.....	....	....
133							$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

I. Project Summary

Proj. No.	A. BASE PLAN UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	In-Service	Investment	ATRR
1	Reno-Sunny Lane 69kV Line - replace wave trap & current transformer to allow 1200A limit	6/1/2006	$ 67,511	$ 11,853
2	Richards Tap-Richards 138kV Line - construct new 138kV line	6/1/2006	$ 2,765,703	$ 485,572
3	Van Buren AVEC-Van Buren Interconnect 69kV Line - replace wave trap and current transformer to allow 1200A limit	6/1/2006	$ 107,896	$ 18,943
4	Brown Explorer Tap 138kV Line - upgrade current transformer at Brown Substation	6/1/2006	$ 31,518	$ 5,534
5	NE Enid-Glenwood 138kV Line - construct new 138kV line	12/1/2006	$ 3,897,313	$ 693,084
6	Razorback-Short Mountain 69kV Line - construct new 69kV line	12/1/2006	$ 9,320,377	$ 1,657,501
7	Richards-Piedmont 138kV Line - construct new 138kV line	10/1/2007	$ 3,790,016	$ 688,324
8	OG&E Windfarm-WFEC Mooreland 138kV Line - upgrade conductor to 795AS33	6/1/2007	$ 85,105	$ 15,328
9	Ft. Smith-Colony 161kV Line - replace 1200A terminal equipment with 2000A terminal equipment	12/1/2008	$ 136,512	$ 25,515
10	Cedar Lane-Canadian 138kV Line - replace 800A wave trap to allow 1200A limit	6/1/2008	$ 23,213	$ 4,286
11	Bodle Substation - Install 138kV Circuit Breaker, Line Relaying, Wave Traps, CCVTs and Communications	6/1/2010	$ 726,650	$ 140,630
12	Ardmore - Rocky Point 69kV Line - rebuild and reconductor 0.82 miles of line with 477AS33	6/1/2011	$ 461,000	$ 52,162
13	Tiger Creek Substation - install 69kV, 9MVAR capacitor bank	2/1/2011	$ 266,000	$ 47,291
14				
15				
16				
17				
18				
19				
	BASE PLAN UPGRADE TOTALS		**$ 21,678,814**	**$ 3,846,023**

Proj. No.	B. TRANSMISSION SERVICE UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	In-Service	Investment	ATRR
1				
2				
3				
4				
5				
6				
7				
	TRANSMISSION SERVICE UPGRADE TOTALS			

Proj. No.	C. SPONSORED OR ECONOMIC PORTFOLIO UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	In-Service	Investment	ATRR
1				
2				
3				
4				
5				
6				
7				
	SPONSORED OR ECONOMIC PORTFOLIO UPGRADE TOTALS			

Proj. No.	D. GENERATOR INTERCONNECTION FACILITIES ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	In-Service	Investment	ATRR
1				
2				
3				
4				
5				
6				
7				
	GENERATOR INTERCONNECTION FACILITIES TOTALS			

TOTAL SPP OATT RELATED UPGRADES REVENUE REQUIREMENT (Sum of Parts A, B, C & D above) **$ 3,846,023**

NOTES:
1. Base Plan Upgrades and Economic Portfolio revenue requirement are estimates and will be trued-up to actual amounts in the True-up Adjustment.
2. Base Plan and Economic Portfolio revenue requirements in the Summaries will be provided to SPP for their Cost Allocation calculations.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

II. Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities.

A. Base Plan facilities.

Project 1: Reno - Sunny Lane 69kV Line -- Replace wave trap and current transformers to allow 1200A limit. 2006-2016 STEP project.

The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
1	Investment	$ 67,511	Current Year			2011
2	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation			17.23%
3	Service Month (1-12)	6				
4	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 1,731
5	CIAC (Yes or No)	No				

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
8	2006	$ 67,511	$ 888	$ 66,623	$ 7,038	$ 7,038
9	2007	$ 66,623	$ 1,777	$ 64,846	$ 12,060	$ 12,060
10	2008	$ 64,846	$ 1,777	$ 63,070	$ 11,782	$ 11,782
11	2009	$ 63,070	$ 1,731	$ 61,339	$ 10,378	$ 10,378
12	2010	$ 61,339	$ 1,731	$ 59,608	$ 12,151	$ 12,151
13	2011	$ 59,608	$ 1,731	$ 57,877	$ 11,853	$ 11,853
14	2012	$ -	$ -	$ -	$ -	$ -
15	2013	$ -	$ -	$ -	$ -	$ -
16	2014	$ -	$ -	$ -	$ -	$ -
17	2015	$ -	$ -	$ -	$ -	$ -
18	2016	$ -	$ -	$ -	$ -	$ -
19	2017	$ -	$ -	$ -	$ -	$ -
20	2018	$ -	$ -	$ -	$ -	$ -
21	2019	$ -	$ -	$ -	$ -	$ -
22	2020	$ -	$ -	$ -	$ -	$ -
23	2021	$ -	$ -	$ -	$ -	$ -
24	2022	$ -	$ -	$ -	$ -	$ -
25	2023	$ -	$ -	$ -	$ -	$ -
26	2024	$ -	$ -	$ -	$ -	$ -
27	2025	$ -	$ -	$ -	$ -	$ -
28	2026	$ -	$ -	$ -	$ -	$ -
29	2027	$ -	$ -	$ -	$ -	$ -
30	2028	$ -	$ -	$ -	$ -	$ -
31	2029	$ -	$ -	$ -	$ -	$ -
32	2030	$ -	$ -	$ -	$ -	$ -
33	2031	$ -	$ -	$ -	$ -	$ -
34	2032	$ -	$ -	$ -	$ -	$ -
35	2033	$ -	$ -	$ -	$ -	$ -
36	2034	$ -	$ -	$ -	$ -	$ -
37	2035	$ -	$ -	$ -	$ -	$ -
38	2036	$ -	$ -	$ -	$ -	$ -
39	2037	$ -	$ -	$ -	$ -	$ -
40	2038	$ -	$ -	$ -	$ -	$ -
41	2039	$ -	$ -	$ -	$ -	$ -
42	2040	$ -	$ -	$ -	$ -	$ -
43	2041	$ -	$ -	$ -	$ -	$ -
44	2042	$ -	$ -	$ -	$ -	$ -
45	2043	$ -	$ -	$ -	$ -	$ -
46	2044	$ -	$ -	$ -	$ -	$ -
47	2045	$ -	$ -	$ -	$ -	$ -
48	2046	$ -	$ -	$ -	$ -	$ -
49	2047	$ -	$ -	$ -	$ -	$ -
50	2048	$ -	$ -	$ -	$ -	$ -
51	2049	$ -	$ -	$ -	$ -	$ -
52	2050	$ -	$ -	$ -	$ -	$ -
53						
54	Project Totals				$ 65,262	$ 65,262

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 2: Richards Tap-Richards 138kV Line -- Construct new 138kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details										
55	Investment	$	2,765,703	Current Year							2011
56	Service Year (yyyy)		2006	NPCC w/o incentives, less depreciation							17.23%
57	Service Month (1-12)		6								
58	Useful Life		39	Annual Depreciation Expense		(Investment / Useful Life)				$	70,915
59	CIAC (Yes or No)		No								

Line No.	Investment Year		Beginning Balance		Depreciation Expense		Ending Balance		Revenue Requirement		Rev. Req. for SPP Allocation
62	2006	$	2,765,703	$	36,391	$	2,729,312	$	288,312	$	288,312
63	2007	$	2,729,312	$	72,782	$	2,656,531	$	494,074	$	494,074
64	2008	$	2,656,531	$	72,782	$	2,583,749	$	482,687	$	482,687
65	2009	$	2,583,749	$	70,915	$	2,512,834	$	425,166	$	425,166
66	2010	$	2,512,834	$	70,915	$	2,441,918	$	497,791	$	497,791
67	2011	$	2,441,918	$	70,915	$	2,371,003	$	485,572	$	485,572
68	2012	$	-	$	-	$	-	$	-	$	-
69	2013	$	-	$	-	$	-	$	-	$	-
70	2014	$	-	$	-	$	-	$	-	$	-
71	2015	$	-	$	-	$	-	$	-	$	-
72	2016	$	-	$	-	$	-	$	-	$	-
73	2017	$	-	$	-	$	-	$	-	$	-
74	2018	$	-	$	-	$	-	$	-	$	-
75	2019	$	-	$	-	$	-	$	-	$	-
76	2020	$	-	$	-	$	-	$	-	$	-
77	2021	$	-	$	-	$	-	$	-	$	-
78	2022	$	-	$	-	$	-	$	-	$	-
79	2023	$	-	$	-	$	-	$	-	$	-
80	2024	$	-	$	-	$	-	$	-	$	-
81	2025	$	-	$	-	$	-	$	-	$	-
82	2026	$	-	$	-	$	-	$	-	$	-
83	2027	$	-	$	-	$	-	$	-	$	-
84	2028	$	-	$	-	$	-	$	-	$	-
85	2029	$	-	$	-	$	-	$	-	$	-
86	2030	$	-	$	-	$	-	$	-	$	-
87	2031	$	-	$	-	$	-	$	-	$	-
88	2032	$	-	$	-	$	-	$	-	$	-
89	2033	$	-	$	-	$	-	$	-	$	-
90	2034	$	-	$	-	$	-	$	-	$	-
91	2035	$	-	$	-	$	-	$	-	$	-
92	2036	$	-	$	-	$	-	$	-	$	-
93	2037	$	-	$	-	$	-	$	-	$	-
94	2038	$	-	$	-	$	-	$	-	$	-
95	2039	$	-	$	-	$	-	$	-	$	-
96	2040	$	-	$	-	$	-	$	-	$	-
97	2041	$	-	$	-	$	-	$	-	$	-
98	2042	$	-	$	-	$	-	$	-	$	-
99	2043	$	-	$	-	$	-	$	-	$	-
100	2044	$	-	$	-	$	-	$	-	$	-
101	2045	$	-	$	-	$	-	$	-	$	-
102	2046	$	-	$	-	$	-	$	-	$	-
103	2047	$	-	$	-	$	-	$	-	$	-
104	2048	$	-	$	-	$	-	$	-	$	-
105	2049	$	-	$	-	$	-	$	-	$	-
106	2050	$	-	$	-	$	-	$	-	$	-
107											
108	Project Totals							$	2,673,602	$	2,673,602

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 3: Van Buren AVEC - Van Buren Interconnect 69kV Line -- Wave trap and current transformer ratio work to increase limit to 1200A. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details				
109	Investment	$ 107,896	Current Year		2011
110	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation		17.23%
111	Service Month (1-12)	6			
112	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)	$ 2,767
113	CIAC (Yes or No)	No			

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
116	2006	$ 107,896	$ 1,420	$ 106,477	$ 11,248	$ 11,248
117	2007	$ 106,477	$ 2,839	$ 103,637	$ 19,275	$ 19,275
118	2008	$ 103,637	$ 2,839	$ 100,798	$ 18,831	$ 18,831
119	2009	$ 100,798	$ 2,767	$ 98,031	$ 16,587	$ 16,587
120	2010	$ 98,031	$ 2,767	$ 95,265	$ 19,420	$ 19,420
121	2011	$ 95,265	$ 2,767	$ 92,498	$ 18,943	$ 18,943
122	2012	$ -	$ -	$ -	$ -	$ -
123	2013	$ -	$ -	$ -	$ -	$ -
124	2014	$ -	$ -	$ -	$ -	$ -
125	2015	$ -	$ -	$ -	$ -	$ -
126	2016	$ -	$ -	$ -	$ -	$ -
127	2017	$ -	$ -	$ -	$ -	$ -
128	2018	$ -	$ -	$ -	$ -	$ -
129	2019	$ -	$ -	$ -	$ -	$ -
130	2020	$ -	$ -	$ -	$ -	$ -
131	2021	$ -	$ -	$ -	$ -	$ -
132	2022	$ -	$ -	$ -	$ -	$ -
133	2023	$ -	$ -	$ -	$ -	$ -
134	2024	$ -	$ -	$ -	$ -	$ -
135	2025	$ -	$ -	$ -	$ -	$ -
136	2026	$ -	$ -	$ -	$ -	$ -
137	2027	$ -	$ -	$ -	$ -	$ -
138	2028	$ -	$ -	$ -	$ -	$ -
139	2029	$ -	$ -	$ -	$ -	$ -
140	2030	$ -	$ -	$ -	$ -	$ -
141	2031	$ -	$ -	$ -	$ -	$ -
142	2032	$ -	$ -	$ -	$ -	$ -
143	2033	$ -	$ -	$ -	$ -	$ -
144	2034	$ -	$ -	$ -	$ -	$ -
145	2035	$ -	$ -	$ -	$ -	$ -
146	2036	$ -	$ -	$ -	$ -	$ -
147	2037	$ -	$ -	$ -	$ -	$ -
148	2038	$ -	$ -	$ -	$ -	$ -
149	2039	$ -	$ -	$ -	$ -	$ -
150	2040	$ -	$ -	$ -	$ -	$ -
151	2041	$ -	$ -	$ -	$ -	$ -
152	2042	$ -	$ -	$ -	$ -	$ -
153	2043	$ -	$ -	$ -	$ -	$ -
154	2044	$ -	$ -	$ -	$ -	$ -
155	2045	$ -	$ -	$ -	$ -	$ -
156	2046	$ -	$ -	$ -	$ -	$ -
157	2047	$ -	$ -	$ -	$ -	$ -
158	2048	$ -	$ -	$ -	$ -	$ -
159	2049	$ -	$ -	$ -	$ -	$ -
160	2050	$ -	$ -	$ -	$ -	$ -
161						
162	Project Totals				$ 104,304	$ 104,304

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 4: Brown Explorer Tap 138kV Line -- Upgrade current transformers at Brown Substation. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details										
163	Investment	$	31,518	Current Year						2011	
164	Service Year (yyyy)		2006	NPCC w/o incentives, less depreciation							17.23%
165	Service Month (1-12)		6								
166	Useful Life		39	Annual Depreciation Expense		(Investment / Useful Life)				$	808
167	CIAC (Yes or No)		No								
168-169	**Investment Year**	**Beginning Balance**		**Depreciation Expense**		**Ending Balance**		**Revenue Requirement**		**Rev. Req. for SPP Allocation**	
170	2006	$	31,518	$	415	$	31,103	$	3,286	$	3,286
171	2007	$	31,103	$	829	$	30,274	$	5,630	$	5,630
172	2008	$	30,274	$	829	$	29,444	$	5,501	$	5,501
173	2009	$	29,444	$	808	$	28,636	$	4,845	$	4,845
174	2010	$	28,636	$	808	$	27,828	$	5,673	$	5,673
175	2011	$	27,828	$	808	$	27,020	$	5,534	$	5,534
176	2012	$	-	$	-	$	-	$	-	$	-
177	2013	$	-	$	-	$	-	$	-	$	-
178	2014	$	-	$	-	$	-	$	-	$	-
179	2015	$	-	$	-	$	-	$	-	$	-
180	2016	$	-	$	-	$	-	$	-	$	-
181	2017	$	-	$	-	$	-	$	-	$	-
182	2018	$	-	$	-	$	-	$	-	$	-
183	2019	$	-	$	-	$	-	$	-	$	-
184	2020	$	-	$	-	$	-	$	-	$	-
185	2021	$	-	$	-	$	-	$	-	$	-
186	2022	$	-	$	-	$	-	$	-	$	-
187	2023	$	-	$	-	$	-	$	-	$	-
188	2024	$	-	$	-	$	-	$	-	$	-
189	2025	$	-	$	-	$	-	$	-	$	-
190	2026	$	-	$	-	$	-	$	-	$	-
191	2027	$	-	$	-	$	-	$	-	$	-
192	2028	$	-	$	-	$	-	$	-	$	-
193	2029	$	-	$	-	$	-	$	-	$	-
194	2030	$	-	$	-	$	-	$	-	$	-
195	2031	$	-	$	-	$	-	$	-	$	-
196	2032	$	-	$	-	$	-	$	-	$	-
197	2033	$	-	$	-	$	-	$	-	$	-
198	2034	$	-	$	-	$	-	$	-	$	-
199	2035	$	-	$	-	$	-	$	-	$	-
200	2036	$	-	$	-	$	-	$	-	$	-
201	2037	$	-	$	-	$	-	$	-	$	-
202	2038	$	-	$	-	$	-	$	-	$	-
203	2039	$	-	$	-	$	-	$	-	$	-
204	2040	$	-	$	-	$	-	$	-	$	-
205	2041	$	-	$	-	$	-	$	-	$	-
206	2042	$	-	$	-	$	-	$	-	$	-
207	2043	$	-	$	-	$	-	$	-	$	-
208	2044	$	-	$	-	$	-	$	-	$	-
209	2045	$	-	$	-	$	-	$	-	$	-
210	2046	$	-	$	-	$	-	$	-	$	-
211	2047	$	-	$	-	$	-	$	-	$	-
212	2048	$	-	$	-	$	-	$	-	$	-
213	2049	$	-	$	-	$	-	$	-	$	-
214	2050	$	-	$	-	$	-	$	-	$	-
215											
216	Project Totals							$	30,468	$	30,468

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 5: NE Enid - Glenwood 138kV Line -- Construct new 138kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
217	Investment	$ 3,897,313	Current Year			**2011**
218	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation			17.23%
219	Service Month (1-12)	12				
220	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 99,931
221	CIAC (Yes or No)	No				
222-223	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
224	2006	$ 3,897,313	$ -	$ 3,897,313	$ 50,809	$ 50,809
225	2007	$ 3,897,313	$ 102,561	$ 3,794,752	$ 704,251	$ 704,251
226	2008	$ 3,794,752	$ 102,561	$ 3,692,191	$ 688,206	$ 688,206
227	2009	$ 3,692,191	$ 99,931	$ 3,592,260	$ 606,254	$ 606,254
228	2010	$ 3,592,260	$ 99,931	$ 3,492,329	$ 710,303	$ 710,303
229	2011	$ 3,492,329	$ 99,931	$ 3,392,398	$ 693,084	$ 693,084
230	2012	$ -	$ -	$ -	$ -	$ -
231	2013	$ -	$ -	$ -	$ -	$ -
232	2014	$ -	$ -	$ -	$ -	$ -
233	2015	$ -	$ -	$ -	$ -	$ -
234	2016	$ -	$ -	$ -	$ -	$ -
235	2017	$ -	$ -	$ -	$ -	$ -
236	2018	$ -	$ -	$ -	$ -	$ -
237	2019	$ -	$ -	$ -	$ -	$ -
238	2020	$ -	$ -	$ -	$ -	$ -
239	2021	$ -	$ -	$ -	$ -	$ -
240	2022	$ -	$ -	$ -	$ -	$ -
241	2023	$ -	$ -	$ -	$ -	$ -
242	2024	$ -	$ -	$ -	$ -	$ -
243	2025	$ -	$ -	$ -	$ -	$ -
244	2026	$ -	$ -	$ -	$ -	$ -
245	2027	$ -	$ -	$ -	$ -	$ -
246	2028	$ -	$ -	$ -	$ -	$ -
247	2029	$ -	$ -	$ -	$ -	$ -
248	2030	$ -	$ -	$ -	$ -	$ -
249	2031	$ -	$ -	$ -	$ -	$ -
250	2032	$ -	$ -	$ -	$ -	$ -
251	2033	$ -	$ -	$ -	$ -	$ -
252	2034	$ -	$ -	$ -	$ -	$ -
253	2035	$ -	$ -	$ -	$ -	$ -
254	2036	$ -	$ -	$ -	$ -	$ -
255	2037	$ -	$ -	$ -	$ -	$ -
256	2038	$ -	$ -	$ -	$ -	$ -
257	2039	$ -	$ -	$ -	$ -	$ -
258	2040	$ -	$ -	$ -	$ -	$ -
259	2041	$ -	$ -	$ -	$ -	$ -
260	2042	$ -	$ -	$ -	$ -	$ -
261	2043	$ -	$ -	$ -	$ -	$ -
262	2044	$ -	$ -	$ -	$ -	$ -
263	2045	$ -	$ -	$ -	$ -	$ -
264	2046	$ -	$ -	$ -	$ -	$ -
265	2047	$ -	$ -	$ -	$ -	$ -
266	2048	$ -	$ -	$ -	$ -	$ -
267	2049	$ -	$ -	$ -	$ -	$ -
268	2050	$ -	$ -	$ -	$ -	$ -
269						
270	Project Totals				$ 3,452,906	$ 3,452,906

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 6: Razorback - Short Mountain 69kV Line -- Construct new 69kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details				
271	Investment	$ 9,320,377	Current Year		2011
272	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation		17.23%
273	Service Month (1-12)	12			
274	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)	$ 238,984
275	CIAC (Yes or No)	No			

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
278	2006	$ 9,320,377	$ -	$ 9,320,377	$ 121,510	$ 121,510
279	2007	$ 9,320,377	$ 245,273	$ 9,075,104	$ 1,684,207	$ 1,684,207
280	2008	$ 9,075,104	$ 245,273	$ 8,829,831	$ 1,645,835	$ 1,645,835
281	2009	$ 8,829,831	$ 238,984	$ 8,590,847	$ 1,449,850	$ 1,449,850
282	2010	$ 8,590,847	$ 238,984	$ 8,351,863	$ 1,698,681	$ 1,698,681
283	2011	$ 8,351,863	$ 238,984	$ 8,112,879	$ 1,657,501	$ 1,657,501
284	2012	$ -	$ -	$ -	$ -	$ -
285	2013	$ -	$ -	$ -	$ -	$ -
286	2014	$ -	$ -	$ -	$ -	$ -
287	2015	$ -	$ -	$ -	$ -	$ -
288	2016	$ -	$ -	$ -	$ -	$ -
289	2017	$ -	$ -	$ -	$ -	$ -
290	2018	$ -	$ -	$ -	$ -	$ -
291	2019	$ -	$ -	$ -	$ -	$ -
292	2020	$ -	$ -	$ -	$ -	$ -
293	2021	$ -	$ -	$ -	$ -	$ -
294	2022	$ -	$ -	$ -	$ -	$ -
295	2023	$ -	$ -	$ -	$ -	$ -
296	2024	$ -	$ -	$ -	$ -	$ -
297	2025	$ -	$ -	$ -	$ -	$ -
298	2026	$ -	$ -	$ -	$ -	$ -
299	2027	$ -	$ -	$ -	$ -	$ -
300	2028	$ -	$ -	$ -	$ -	$ -
301	2029	$ -	$ -	$ -	$ -	$ -
302	2030	$ -	$ -	$ -	$ -	$ -
303	2031	$ -	$ -	$ -	$ -	$ -
304	2032	$ -	$ -	$ -	$ -	$ -
305	2033	$ -	$ -	$ -	$ -	$ -
306	2034	$ -	$ -	$ -	$ -	$ -
307	2035	$ -	$ -	$ -	$ -	$ -
308	2036	$ -	$ -	$ -	$ -	$ -
309	2037	$ -	$ -	$ -	$ -	$ -
310	2038	$ -	$ -	$ -	$ -	$ -
311	2039	$ -	$ -	$ -	$ -	$ -
312	2040	$ -	$ -	$ -	$ -	$ -
313	2041	$ -	$ -	$ -	$ -	$ -
314	2042	$ -	$ -	$ -	$ -	$ -
315	2043	$ -	$ -	$ -	$ -	$ -
316	2044	$ -	$ -	$ -	$ -	$ -
317	2045	$ -	$ -	$ -	$ -	$ -
318	2046	$ -	$ -	$ -	$ -	$ -
319	2047	$ -	$ -	$ -	$ -	$ -
320	2048	$ -	$ -	$ -	$ -	$ -
321	2049	$ -	$ -	$ -	$ -	$ -
322	2050	$ -	$ -	$ -	$ -	$ -
323						
324	Project Totals				$ 8,257,584	$ 8,257,584

$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 7: Richards - Piedmont 138kV Line -- Construct new 138kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details										
325	Investment	$	3,790,016	Current Year							2011
326	Service Year (yyyy)		2007	NPCC w/o incentives, less depreciation							17.23%
327	Service Month (1-12)		10								
328	Useful Life		39	Annual Depreciation Expense		(Investment / Useful Life)				$	97,180
329	CIAC (Yes or No)		No								
330-331	**Investment Year**		**Beginning Balance**		**Depreciation Expense**		**Ending Balance**		**Revenue Requirement**		**Rev. Req. for SPP Allocation**
332	2007	$	3,790,016	$	16,623	$	3,773,393	$	165,505	$	165,505
333	2008	$	3,773,393	$	99,737	$	3,673,656	$	682,261	$	682,261
334	2009	$	3,673,656	$	97,180	$	3,576,476	$	601,118	$	601,118
335	2010	$	3,576,476	$	97,180	$	3,479,296	$	705,069	$	705,069
336	2011	$	3,479,296	$	97,180	$	3,382,116	$	688,324	$	688,324
337	2012	$	-	$	-	$	-	$	-	$	-
338	2013	$	-	$	-	$	-	$	-	$	-
339	2014	$	-	$	-	$	-	$	-	$	-
340	2015	$	-	$	-	$	-	$	-	$	-
341	2016	$	-	$	-	$	-	$	-	$	-
342	2017	$	-	$	-	$	-	$	-	$	-
343	2018	$	-	$	-	$	-	$	-	$	-
344	2019	$	-	$	-	$	-	$	-	$	-
345	2020	$	-	$	-	$	-	$	-	$	-
346	2021	$	-	$	-	$	-	$	-	$	-
347	2022	$	-	$	-	$	-	$	-	$	-
348	2023	$	-	$	-	$	-	$	-	$	-
349	2024	$	-	$	-	$	-	$	-	$	-
350	2025	$	-	$	-	$	-	$	-	$	-
351	2026	$	-	$	-	$	-	$	-	$	-
352	2027	$	-	$	-	$	-	$	-	$	-
353	2028	$	-	$	-	$	-	$	-	$	-
354	2029	$	-	$	-	$	-	$	-	$	-
355	2030	$	-	$	-	$	-	$	-	$	-
356	2031	$	-	$	-	$	-	$	-	$	-
357	2032	$	-	$	-	$	-	$	-	$	-
358	2033	$	-	$	-	$	-	$	-	$	-
359	2034	$	-	$	-	$	-	$	-	$	-
360	2035	$	-	$	-	$	-	$	-	$	-
361	2036	$	-	$	-	$	-	$	-	$	-
362	2037	$	-	$	-	$	-	$	-	$	-
363	2038	$	-	$	-	$	-	$	-	$	-
364	2039	$	-	$	-	$	-	$	-	$	-
365	2040	$	-	$	-	$	-	$	-	$	-
366	2041	$	-	$	-	$	-	$	-	$	-
367	2042	$	-	$	-	$	-	$	-	$	-
368	2043	$	-	$	-	$	-	$	-	$	-
369	2044	$	-	$	-	$	-	$	-	$	-
370	2045	$	-	$	-	$	-	$	-	$	-
371	2046	$	-	$	-	$	-	$	-	$	-
372	2047	$	-	$	-	$	-	$	-	$	-
373	2048	$	-	$	-	$	-	$	-	$	-
374	2049	$	-	$	-	$	-	$	-	$	-
375	2050	$	-	$	-	$	-	$	-	$	-
376	2051	$	-	$	-	$	-	$	-	$	-
377											
378	Project Totals							$	2,842,277	$	2,842,277

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 8: OG&E Windfarm - WFEC Mooreland 138kV Line -- Upgrade conductor to 795AS33. 2006 Aggregate Study 1 and 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
379	Investment	$ 85,105	Current Year			2011
380	Service Year (yyyy)	2007	NPCC w/o incentives, less depreciation			17.23%
381	Service Month (1-12)	6				
382	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 2,182
383	CIAC (Yes or No)	No				
384-385	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
386	2007	$ 85,105	$ 1,120	$ 83,985	$ 8,872	$ 8,872
387	2008	$ 83,985	$ 2,240	$ 81,746	$ 15,203	$ 15,203
388	2009	$ 81,746	$ 2,182	$ 79,564	$ 13,394	$ 13,394
389	2010	$ 79,564	$ 2,182	$ 77,382	$ 15,704	$ 15,704
390	2011	$ 77,382	$ 2,182	$ 75,199	$ 15,328	$ 15,328
391	2012	$ -	$ -	$ -	$ -	$ -
392	2013	$ -	$ -	$ -	$ -	$ -
393	2014	$ -	$ -	$ -	$ -	$ -
394	2015	$ -	$ -	$ -	$ -	$ -
395	2016	$ -	$ -	$ -	$ -	$ -
396	2017	$ -	$ -	$ -	$ -	$ -
397	2018	$ -	$ -	$ -	$ -	$ -
398	2019	$ -	$ -	$ -	$ -	$ -
399	2020	$ -	$ -	$ -	$ -	$ -
400	2021	$ -	$ -	$ -	$ -	$ -
401	2022	$ -	$ -	$ -	$ -	$ -
402	2023	$ -	$ -	$ -	$ -	$ -
403	2024	$ -	$ -	$ -	$ -	$ -
404	2025	$ -	$ -	$ -	$ -	$ -
405	2026	$ -	$ -	$ -	$ -	$ -
406	2027	$ -	$ -	$ -	$ -	$ -
407	2028	$ -	$ -	$ -	$ -	$ -
408	2029	$ -	$ -	$ -	$ -	$ -
409	2030	$ -	$ -	$ -	$ -	$ -
410	2031	$ -	$ -	$ -	$ -	$ -
411	2032	$ -	$ -	$ -	$ -	$ -
412	2033	$ -	$ -	$ -	$ -	$ -
413	2034	$ -	$ -	$ -	$ -	$ -
414	2035	$ -	$ -	$ -	$ -	$ -
415	2036	$ -	$ -	$ -	$ -	$ -
416	2037	$ -	$ -	$ -	$ -	$ -
417	2038	$ -	$ -	$ -	$ -	$ -
418	2039	$ -	$ -	$ -	$ -	$ -
419	2040	$ -	$ -	$ -	$ -	$ -
420	2041	$ -	$ -	$ -	$ -	$ -
421	2042	$ -	$ -	$ -	$ -	$ -
422	2043	$ -	$ -	$ -	$ -	$ -
423	2044	$ -	$ -	$ -	$ -	$ -
424	2045	$ -	$ -	$ -	$ -	$ -
425	2046	$ -	$ -	$ -	$ -	$ -
426	2047	$ -	$ -	$ -	$ -	$ -
427	2048	$ -	$ -	$ -	$ -	$ -
428	2049	$ -	$ -	$ -	$ -	$ -
429	2050	$ -	$ -	$ -	$ -	$ -
430	2051	$ -	$ -	$ -	$ -	$ -
431						
432	Project Totals				$ 68,501	$ 68,501

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 9: Ft. Smith - Colony 161kV Line - Replace 1200A terminal equipment with 2000A equipment to utilize line rating.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
433	Investment	$ 136,512	Current Year			2011
434	Service Year (yyyy)	2008	NPCC w/o incentives, less depreciation			17.23%
435	Service Month (1-12)	12				
436	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 3,500
437	CIAC (Yes or No)	No				
438-439	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
440	2008	$ 136,512	$ -	$ 136,512	$ 1,780	$ 1,780
441	2009	$ 136,512	$ 3,500	$ 133,012	$ 22,234	$ 22,234
442	2010	$ 133,012	$ 3,500	$ 129,511	$ 26,118	$ 26,118
443	2011	$ 129,511	$ 3,500	$ 126,011	$ 25,515	$ 25,515
444	2012	$ -	$ -	$ -	$ -	$ -
445	2013	$ -	$ -	$ -	$ -	$ -
446	2014	$ -	$ -	$ -	$ -	$ -
447	2015	$ -	$ -	$ -	$ -	$ -
448	2016	$ -	$ -	$ -	$ -	$ -
449	2017	$ -	$ -	$ -	$ -	$ -
450	2018	$ -	$ -	$ -	$ -	$ -
451	2019	$ -	$ -	$ -	$ -	$ -
452	2020	$ -	$ -	$ -	$ -	$ -
453	2021	$ -	$ -	$ -	$ -	$ -
454	2022	$ -	$ -	$ -	$ -	$ -
455	2023	$ -	$ -	$ -	$ -	$ -
456	2024	$ -	$ -	$ -	$ -	$ -
457	2025	$ -	$ -	$ -	$ -	$ -
458	2026	$ -	$ -	$ -	$ -	$ -
459	2027	$ -	$ -	$ -	$ -	$ -
460	2028	$ -	$ -	$ -	$ -	$ -
461	2029	$ -	$ -	$ -	$ -	$ -
462	2030	$ -	$ -	$ -	$ -	$ -
463	2031	$ -	$ -	$ -	$ -	$ -
464	2032	$ -	$ -	$ -	$ -	$ -
465	2033	$ -	$ -	$ -	$ -	$ -
466	2034	$ -	$ -	$ -	$ -	$ -
467	2035	$ -	$ -	$ -	$ -	$ -
468	2036	$ -	$ -	$ -	$ -	$ -
469	2037	$ -	$ -	$ -	$ -	$ -
470	2038	$ -	$ -	$ -	$ -	$ -
471	2039	$ -	$ -	$ -	$ -	$ -
472	2040	$ -	$ -	$ -	$ -	$ -
473	2041	$ -	$ -	$ -	$ -	$ -
474	2042	$ -	$ -	$ -	$ -	$ -
475	2043	$ -	$ -	$ -	$ -	$ -
476	2044	$ -	$ -	$ -	$ -	$ -
477	2045	$ -	$ -	$ -	$ -	$ -
478	2046	$ -	$ -	$ -	$ -	$ -
479	2047	$ -	$ -	$ -	$ -	$ -
480	2048	$ -	$ -	$ -	$ -	$ -
481	2049	$ -	$ -	$ -	$ -	$ -
482	2050	$ -	$ -	$ -	$ -	$ -
483	2051	$ -	$ -	$ -	$ -	$ -
484	2052	$ -	$ -	$ -	$ -	$ -
485						
486	Project Totals				$ 75,647	$ 75,647

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 10: Cedar Lane - Canadian 138kV Line - Replace 800A wave trap at Cedar Lane

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
487	Investment	$ 23,213	Current Year			2011
488	Service Year (yyyy)	2008	NPCC w/o incentives, less depreciation			17.23%
489	Service Month (1-12)	6				
490	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 595
491	CIAC (Yes or No)	No				

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
494	2008	$ 23,213	$ 305	$ 22,908	$ 2,420	$ 2,420
495	2009	$ 22,908	$ 595	$ 22,313	$ 3,738	$ 3,738
496	2010	$ 22,313	$ 595	$ 21,718	$ 4,389	$ 4,389
497	2011	$ 21,718	$ 595	$ 21,122	$ 4,286	$ 4,286
498	2012	$ -	$ -	$ -	$ -	$ -
499	2013	$ -	$ -	$ -	$ -	$ -
500	2014	$ -	$ -	$ -	$ -	$ -
501	2015	$ -	$ -	$ -	$ -	$ -
502	2016	$ -	$ -	$ -	$ -	$ -
503	2017	$ -	$ -	$ -	$ -	$ -
504	2018	$ -	$ -	$ -	$ -	$ -
505	2019	$ -	$ -	$ -	$ -	$ -
506	2020	$ -	$ -	$ -	$ -	$ -
507	2021	$ -	$ -	$ -	$ -	$ -
508	2022	$ -	$ -	$ -	$ -	$ -
509	2023	$ -	$ -	$ -	$ -	$ -
510	2024	$ -	$ -	$ -	$ -	$ -
511	2025	$ -	$ -	$ -	$ -	$ -
512	2026	$ -	$ -	$ -	$ -	$ -
513	2027	$ -	$ -	$ -	$ -	$ -
514	2028	$ -	$ -	$ -	$ -	$ -
515	2029	$ -	$ -	$ -	$ -	$ -
516	2030	$ -	$ -	$ -	$ -	$ -
517	2031	$ -	$ -	$ -	$ -	$ -
518	2032	$ -	$ -	$ -	$ -	$ -
519	2033	$ -	$ -	$ -	$ -	$ -
520	2034	$ -	$ -	$ -	$ -	$ -
521	2035	$ -	$ -	$ -	$ -	$ -
522	2036	$ -	$ -	$ -	$ -	$ -
523	2037	$ -	$ -	$ -	$ -	$ -
524	2038	$ -	$ -	$ -	$ -	$ -
525	2039	$ -	$ -	$ -	$ -	$ -
526	2040	$ -	$ -	$ -	$ -	$ -
527	2041	$ -	$ -	$ -	$ -	$ -
528	2042	$ -	$ -	$ -	$ -	$ -
529	2043	$ -	$ -	$ -	$ -	$ -
530	2044	$ -	$ -	$ -	$ -	$ -
531	2045	$ -	$ -	$ -	$ -	$ -
532	2046	$ -	$ -	$ -	$ -	$ -
533	2047	$ -	$ -	$ -	$ -	$ -
534	2048	$ -	$ -	$ -	$ -	$ -
535	2049	$ -	$ -	$ -	$ -	$ -
536	2050	$ -	$ -	$ -	$ -	$ -
537	2051	$ -	$ -	$ -	$ -	$ -
538	2052	$ -	$ -	$ -	$ -	$ -
539						
540	Project Totals				$ 14,833	$ 14,833

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 11: Bodle Substation - Install 138kV Circuit Breaker, Line Relaying, Wave Traps, CCVTs and Communications

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
541	Investment	$ 726,650	Current Year			2011
542	Service Year (yyyy)	2010	NPCC w/o incentives, less depreciation			17.23%
543	Service Month (1-12)	6				
544	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 18,632
545	CIAC (Yes or No)	No				

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
548	2010	$ 726,650	$ 9,316	$ 717,334	$ 82,221	$ 82,221
549	2011	$ 717,334	$ 18,632	$ 698,702	$ 140,630	$ 140,630
550	2012	$ -	$ -	$ -	$ -	$ -
551	2013	$ -	$ -	$ -	$ -	$ -
552	2014	$ -	$ -	$ -	$ -	$ -
553	2015	$ -	$ -	$ -	$ -	$ -
554	2016	$ -	$ -	$ -	$ -	$ -
555	2017	$ -	$ -	$ -	$ -	$ -
556	2018	$ -	$ -	$ -	$ -	$ -
557	2019	$ -	$ -	$ -	$ -	$ -
558	2020	$ -	$ -	$ -	$ -	$ -
559	2021	$ -	$ -	$ -	$ -	$ -
560	2022	$ -	$ -	$ -	$ -	$ -
561	2023	$ -	$ -	$ -	$ -	$ -
562	2024	$ -	$ -	$ -	$ -	$ -
563	2025	$ -	$ -	$ -	$ -	$ -
564	2026	$ -	$ -	$ -	$ -	$ -
565	2027	$ -	$ -	$ -	$ -	$ -
566	2028	$ -	$ -	$ -	$ -	$ -
567	2029	$ -	$ -	$ -	$ -	$ -
568	2030	$ -	$ -	$ -	$ -	$ -
569	2031	$ -	$ -	$ -	$ -	$ -
570	2032	$ -	$ -	$ -	$ -	$ -
571	2033	$ -	$ -	$ -	$ -	$ -
572	2034	$ -	$ -	$ -	$ -	$ -
573	2035	$ -	$ -	$ -	$ -	$ -
574	2036	$ -	$ -	$ -	$ -	$ -
575	2037	$ -	$ -	$ -	$ -	$ -
576	2038	$ -	$ -	$ -	$ -	$ -
577	2039	$ -	$ -	$ -	$ -	$ -
578	2040	$ -	$ -	$ -	$ -	$ -
579	2041	$ -	$ -	$ -	$ -	$ -
580	2042	$ -	$ -	$ -	$ -	$ -
581	2043	$ -	$ -	$ -	$ -	$ -
582	2044	$ -	$ -	$ -	$ -	$ -
583	2045	$ -	$ -	$ -	$ -	$ -
584	2046	$ -	$ -	$ -	$ -	$ -
585	2047	$ -	$ -	$ -	$ -	$ -
586	2048	$ -	$ -	$ -	$ -	$ -
587	2049	$ -	$ -	$ -	$ -	$ -
588	2050	$ -	$ -	$ -	$ -	$ -
589	2051	$ -	$ -	$ -	$ -	$ -
590	2052	$ -	$ -	$ -	$ -	$ -
591	2053	$ -	$ -	$ -	$ -	$ -
592	2054	$ -	$ -	$ -	$ -	$ -
593						
594	Project Totals				$ 222,851	$ 222,851

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 12: Ardmore - Rocky Point 69kV Line - rebuild and reconductor 0.82 miles of line with 477AS33

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details				
595	Investment	$ 461,000	Current Year		2011
596	Service Year (yyyy)	2011	NPCC w/o incentives, less depreciation		17.23%
597	Service Month (1-12)	6			
598	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)	$ 11,821
599	CIAC (Yes or No)	No			

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
602	2011	$ 461,000	$ 5,910	$ 455,090	$ 52,162	$ 52,162
603	2012	$ -	$ -	$ -	$ -	$ -
604	2013	$ -	$ -	$ -	$ -	$ -
605	2014	$ -	$ -	$ -	$ -	$ -
606	2015	$ -	$ -	$ -	$ -	$ -
607	2016	$ -	$ -	$ -	$ -	$ -
608	2017	$ -	$ -	$ -	$ -	$ -
609	2018	$ -	$ -	$ -	$ -	$ -
610	2019	$ -	$ -	$ -	$ -	$ -
611	2020	$ -	$ -	$ -	$ -	$ -
612	2021	$ -	$ -	$ -	$ -	$ -
613	2022	$ -	$ -	$ -	$ -	$ -
614	2023	$ -	$ -	$ -	$ -	$ -
615	2024	$ -	$ -	$ -	$ -	$ -
616	2025	$ -	$ -	$ -	$ -	$ -
617	2026	$ -	$ -	$ -	$ -	$ -
618	2027	$ -	$ -	$ -	$ -	$ -
619	2028	$ -	$ -	$ -	$ -	$ -
620	2029	$ -	$ -	$ -	$ -	$ -
621	2030	$ -	$ -	$ -	$ -	$ -
622	2031	$ -	$ -	$ -	$ -	$ -
623	2032	$ -	$ -	$ -	$ -	$ -
624	2033	$ -	$ -	$ -	$ -	$ -
625	2034	$ -	$ -	$ -	$ -	$ -
626	2035	$ -	$ -	$ -	$ -	$ -
627	2036	$ -	$ -	$ -	$ -	$ -
628	2037	$ -	$ -	$ -	$ -	$ -
629	2038	$ -	$ -	$ -	$ -	$ -
630	2039	$ -	$ -	$ -	$ -	$ -
631	2040	$ -	$ -	$ -	$ -	$ -
632	2041	$ -	$ -	$ -	$ -	$ -
633	2042	$ -	$ -	$ -	$ -	$ -
634	2043	$ -	$ -	$ -	$ -	$ -
635	2044	$ -	$ -	$ -	$ -	$ -
636	2045	$ -	$ -	$ -	$ -	$ -
637	2046	$ -	$ -	$ -	$ -	$ -
638	2047	$ -	$ -	$ -	$ -	$ -
639	2048	$ -	$ -	$ -	$ -	$ -
640	2049	$ -	$ -	$ -	$ -	$ -
641	2050	$ -	$ -	$ -	$ -	$ -
642	2051	$ -	$ -	$ -	$ -	$ -
643	2052	$ -	$ -	$ -	$ -	$ -
644	2053	$ -	$ -	$ -	$ -	$ -
645	2054	$ -	$ -	$ -	$ -	$ -
646	2055	$ -	$ -	$ -	$ -	$ -
647						
648	Project Totals				$ 52,162	$ 52,162

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 13: Tiger Creek Substation - install 69kV, 9MVAR capacitor bank

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details			
649	Investment	$ 266,000	Current Year	2011
650	Service Year (yyyy)	2011	NPCC w/o incentives, less depreciation	17.23%
651	Service Month (1-12)	2		
652	Useful Life	39	Annual Depreciation Expense (Investment / Useful Life)	$ 6,821
653	CIAC (Yes or No)	No		

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
656	2011	$ 266,000	$ 5,684	$ 260,316	$ 47,291	$ 47,291
657	2012	$ -	$ -	$ -	$ -	$ -
658	2013	$ -	$ -	$ -	$ -	$ -
659	2014	$ -	$ -	$ -	$ -	$ -
660	2015	$ -	$ -	$ -	$ -	$ -
661	2016	$ -	$ -	$ -	$ -	$ -
662	2017	$ -	$ -	$ -	$ -	$ -
663	2018	$ -	$ -	$ -	$ -	$ -
664	2019	$ -	$ -	$ -	$ -	$ -
665	2020	$ -	$ -	$ -	$ -	$ -
666	2021	$ -	$ -	$ -	$ -	$ -
667	2022	$ -	$ -	$ -	$ -	$ -
668	2023	$ -	$ -	$ -	$ -	$ -
669	2024	$ -	$ -	$ -	$ -	$ -
670	2025	$ -	$ -	$ -	$ -	$ -
671	2026	$ -	$ -	$ -	$ -	$ -
672	2027	$ -	$ -	$ -	$ -	$ -
673	2028	$ -	$ -	$ -	$ -	$ -
674	2029	$ -	$ -	$ -	$ -	$ -
675	2030	$ -	$ -	$ -	$ -	$ -
676	2031	$ -	$ -	$ -	$ -	$ -
677	2032	$ -	$ -	$ -	$ -	$ -
678	2033	$ -	$ -	$ -	$ -	$ -
679	2034	$ -	$ -	$ -	$ -	$ -
680	2035	$ -	$ -	$ -	$ -	$ -
681	2036	$ -	$ -	$ -	$ -	$ -
682	2037	$ -	$ -	$ -	$ -	$ -
683	2038	$ -	$ -	$ -	$ -	$ -
684	2039	$ -	$ -	$ -	$ -	$ -
685	2040	$ -	$ -	$ -	$ -	$ -
686	2041	$ -	$ -	$ -	$ -	$ -
687	2042	$ -	$ -	$ -	$ -	$ -
688	2043	$ -	$ -	$ -	$ -	$ -
689	2044	$ -	$ -	$ -	$ -	$ -
690	2045	$ -	$ -	$ -	$ -	$ -
691	2046	$ -	$ -	$ -	$ -	$ -
692	2047	$ -	$ -	$ -	$ -	$ -
693	2048	$ -	$ -	$ -	$ -	$ -
694	2049	$ -	$ -	$ -	$ -	$ -
695	2050	$ -	$ -	$ -	$ -	$ -
696	2051	$ -	$ -	$ -	$ -	$ -
697	2052	$ -	$ -	$ -	$ -	$ -
698	2053	$ -	$ -	$ -	$ -	$ -
699	2054	$ -	$ -	$ -	$ -	$ -
700	2055	$ -	$ -	$ -	$ -	$ -
701						
702	Project Totals				$ 47,291	$ 47,291

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 14:

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
703	Investment		Current Year			2011
704	Service Year (yyyy)	2008	NPCC w/o incentives, less depreciation			17.23%
705	Service Month (1-12)					
706	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ -
707	CIAC (Yes or No)	No				
708-709	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
710	2008	$ -	$ -	$ -	$ -	$ -
711	2009	$ -	$ -	$ -	$ -	$ -
712	2010	$ -	$ -	$ -	$ -	$ -
713	2011	$ -	$ -	$ -	$ -	$ -
714	2012	$ -	$ -	$ -	$ -	$ -
715	2013	$ -	$ -	$ -	$ -	$ -
716	2014	$ -	$ -	$ -	$ -	$ -
717	2015	$ -	$ -	$ -	$ -	$ -
718	2016	$ -	$ -	$ -	$ -	$ -
719	2017	$ -	$ -	$ -	$ -	$ -
720	2018	$ -	$ -	$ -	$ -	$ -
721	2019	$ -	$ -	$ -	$ -	$ -
722	2020	$ -	$ -	$ -	$ -	$ -
723	2021	$ -	$ -	$ -	$ -	$ -
724	2022	$ -	$ -	$ -	$ -	$ -
725	2023	$ -	$ -	$ -	$ -	$ -
726	2024	$ -	$ -	$ -	$ -	$ -
727	2025	$ -	$ -	$ -	$ -	$ -
728	2026	$ -	$ -	$ -	$ -	$ -
729	2027	$ -	$ -	$ -	$ -	$ -
730	2028	$ -	$ -	$ -	$ -	$ -
731	2029	$ -	$ -	$ -	$ -	$ -
732	2030	$ -	$ -	$ -	$ -	$ -
733	2031	$ -	$ -	$ -	$ -	$ -
734	2032	$ -	$ -	$ -	$ -	$ -
735	2033	$ -	$ -	$ -	$ -	$ -
736	2034	$ -	$ -	$ -	$ -	$ -
737	2035	$ -	$ -	$ -	$ -	$ -
738	2036	$ -	$ -	$ -	$ -	$ -
739	2037	$ -	$ -	$ -	$ -	$ -
740	2038	$ -	$ -	$ -	$ -	$ -
741	2039	$ -	$ -	$ -	$ -	$ -
742	2040	$ -	$ -	$ -	$ -	$ -
743	2041	$ -	$ -	$ -	$ -	$ -
744	2042	$ -	$ -	$ -	$ -	$ -
745	2043	$ -	$ -	$ -	$ -	$ -
746	2044	$ -	$ -	$ -	$ -	$ -
747	2045	$ -	$ -	$ -	$ -	$ -
748	2046	$ -	$ -	$ -	$ -	$ -
749	2047	$ -	$ -	$ -	$ -	$ -
750	2048	$ -	$ -	$ -	$ -	$ -
751	2049	$ -	$ -	$ -	$ -	$ -
752	2050	$ -	$ -	$ -	$ -	$ -
753	2051	$ -	$ -	$ -	$ -	$ -
754	2052	$ -	$ -	$ -	$ -	$ -
755						
756	Project Totals				$ -	$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

B. Transmission Service Upgrades.

Project 1, (Describe)

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details			
757	Investment	-	Current Year	2011
758	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation	17.23%
759	Service Month (1-12)	-	Rev. Req. allocated to TO's Identified Customers	100.00%
760	Useful Life	50	Annual Depreciation Expense (Investment / Useful Life)	-
761	CIAC (Yes or No)	no		

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
764	2006	-	-	-	$ -	$ -
765	2007	-	-	-	-	$ -
766	2008	-	-	-	-	$ -
767	2009	-	-	-	-	$ -
768	2010	-	-	-	-	$ -
769	2011	-	-	-	-	$ -
770	2012	-	-	-	-	$ -
771	2013	-	-	-	-	$ -
772	2014	-	-	-	-	$ -
773	2015	-	-	-	-	$ -
774	2016	-	-	-	-	$ -
775	2017	-	-	-	-	$ -
776	2018	-	-	-	-	$ -
777	2019	-	-	-	-	$ -
778	2020	-	-	-	-	$ -
779	2021	-	-	-	-	$ -
780	2022	-	-	-	-	$ -
781	2023	-	-	-	-	$ -
782	2024	-	-	-	-	$ -
783	2025	-	-	-	-	$ -
784	2026	-	-	-	-	$ -
785	2027	-	-	-	-	$ -
786	2028	-	-	-	-	$ -
787	2029	-	-	-	-	$ -
788	2030	-	-	-	-	$ -
789	2031	-	-	-	-	$ -
790	2032	-	-	-	-	$ -
791	2033	-	-	-	-	$ -
792	2034	-	-	-	-	$ -
793	2035	-	-	-	-	$ -
794	2036	-	-	-	-	$ -
795	2037	-	-	-	-	$ -
796	2038	-	-	-	-	$ -
797	2039	-	-	-	-	$ -
798	2040	-	-	-	-	$ -
799	2041	-	-	-	-	$ -
800	2042	-	-	-	-	$ -
801	2043	-	-	-	-	$ -
802	2044	-	-	-	-	$ -
803	2045	-	-	-	-	$ -
804	2046	-	-	-	-	$ -
805	2047	-	-	-	-	$ -
806	2048	-	-	-	-	$ -
807	2049	-	-	-	-	$ -
808	2050	-	-	-	-	$ -
809	2051	-	-	-	-	$ -
810	2052	-	-	-	-	$ -
811	2053	-	-	-	-	$ -
812	2054	-	-	-	-	$ -
813	2055	-	-	-	-	$ -
814	2056	-	-	-	-	$ -
815	....	....	.....	.....	....	....
816						

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

C. Sponsored or Economic Portfolio Upgrades.

Project 1, (Describe)

The calculated Rev. Req. from Sponsor and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details			
817	Investment	-	Current Year	2011
818	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation	17.23%
819	Service Month (1-12)	-	Rev. Req. allocated to Sponsoring Entity	100.00%
820	Useful Life	50	Annual Depreciation Expense (Investment / Useful Life)	-
821	CIAC (Yes or No)	no		

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
824	2006	-	-	-	$ -	$ -
825	2007	-	-	-	-	$ -
826	2008	-	-	-	-	$ -
827	2009	-	-	-	-	$ -
828	2010	-	-	-	-	$ -
829	2011	-	-	-	-	$ -
830	2012	-	-	-	-	$ -
831	2013	-	-	-	-	$ -
832	2014	-	-	-	-	$ -
833	2015	-	-	-	-	$ -
834	2016	-	-	-	-	$ -
835	2017	-	-	-	-	$ -
836	2018	-	-	-	-	$ -
837	2019	-	-	-	-	$ -
838	2020	-	-	-	-	$ -
839	2021	-	-	-	-	$ -
840	2022	-	-	-	-	$ -
841	2023	-	-	-	-	$ -
842	2024	-	-	-	-	$ -
843	2025	-	-	-	-	$ -
844	2026	-	-	-	-	$ -
845	2027	-	-	-	-	$ -
846	2028	-	-	-	-	$ -
847	2029	-	-	-	-	$ -
848	2030	-	-	-	-	$ -
849	2031	-	-	-	-	$ -
850	2032	-	-	-	-	$ -
851	2033	-	-	-	-	$ -
852	2034	-	-	-	-	$ -
853	2035	-	-	-	-	$ -
854	2036	-	-	-	-	$ -
855	2037	-	-	-	-	$ -
856	2038	-	-	-	-	$ -
857	2039	-	-	-	-	$ -
858	2040	-	-	-	-	$ -
859	2041	-	-	-	-	$ -
860	2042	-	-	-	-	$ -
861	2043	-	-	-	-	$ -
862	2044	-	-	-	-	$ -
863	2045	-	-	-	-	$ -
864	2046	-	-	-	-	$ -
865	2047	-	-	-	-	$ -
866	2048	-	-	-	-	$ -
867	2049	-	-	-	-	$ -
868	2050	-	-	-	-	$ -
869	2051	-	-	-	-	$ -
870	2052	-	-	-	-	$ -
871	2053	-	-	-	-	$ -
872	2054	-	-	-	-	$ -
873	2055	-	-	-	-	$ -
874	2056	-	-	-	-	$ -
875	....	....	.....	.....	....	....
876						

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

D. Generator Interconnect Upgrades.

i. Project 1, (Describe)

The calculated Rev. Req. from Generator and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
877	Investment	-	Current Year			2011
878	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation			17.23%
879	Service Month (1-12)	-	Rev. Req. allocated to TO's Zone			100.00%
880	Useful Life	50	Annual Depreciation Expense	(Investment / Useful Life)		-
881	CIAC (Yes or No)	no				
882-883	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
884	2006	-	-	-	$ -	$ -
885	2007	-	-	-	-	$ -
886	2008	-	-	-	-	$ -
887	2009	-	-	-	-	$ -
888	2010	-	-	-	-	$ -
889	2011	-	-	-	-	$ -
890	2012	-	-	-	-	$ -
891	2013	-	-	-	-	$ -
892	2014	-	-	-	-	$ -
893	2015	-	-	-	-	$ -
894	2016	-	-	-	-	$ -
895	2017	-	-	-	-	$ -
896	2018	-	-	-	-	$ -
897	2019	-	-	-	-	$ -
898	2020	-	-	-	-	$ -
899	2021	-	-	-	-	$ -
900	2022	-	-	-	-	$ -
901	2023	-	-	-	-	$ -
902	2024	-	-	-	-	$ -
903	2025	-	-	-	-	$ -
904	2026	-	-	-	-	$ -
905	2027	-	-	-	-	$ -
906	2028	-	-	-	-	$ -
907	2029	-	-	-	-	$ -
908	2030	-	-	-	-	$ -
909	2031	-	-	-	-	$ -
910	2032	-	-	-	-	$ -
911	2033	-	-	-	-	$ -
912	2034	-	-	-	-	$ -
913	2035	-	-	-	-	$ -
914	2036	-	-	-	-	$ -
915	2037	-	-	-	-	$ -
916	2038	-	-	-	-	$ -
917	2039	-	-	-	-	$ -
918	2040	-	-	-	-	$ -
919	2041	-	-	-	-	$ -
920	2042	-	-	-	-	$ -
921	2043	-	-	-	-	$ -
922	2044	-	-	-	-	$ -
923	2045	-	-	-	-	$ -
924	2046	-	-	-	-	$ -
925	2047	-	-	-	-	$ -
926	2048	-	-	-	-	$ -
927	2049	-	-	-	-	$ -
928	2050	-	-	-	-	$ -
929	2051	-	-	-	-	$ -
930	2052	-	-	-	-	$ -
931	2053	-	-	-	-	$ -
932	2054	-	-	-	-	$ -
933	2055	-	-	-	-	$ -
934	2056	-	-	-	-	$ -
935	....	....	.....	.....	....	....
936						

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet H - Transmission Plant Adjustments

I. Transmission Plant Adjusted for SPP Tariff

Line No.	(A) Plant Description		(B) Amount
1	Radial Lines		$ 18,521,292
2			
3	Other Adjustments - Transfers:		
4	Distribution Assets Reclassified as Transmission Assets		-
5	Transmission Assets Reclassified as Distribution Assets		-
6			
7	Plant Transfers Excluded from SPP Tariff	(line 119)	**$ 18,521,292**
8			
9			

II. Production Related Transmission Facilities

Line No.	(A) Plant Description		(B) Amount
10	Generation Radial Ties (Centennial)		$ 12,586,522
11	Generation Step Up Transformers (GSU's) and Related Equipment		34,086,199
12			
13	Total	(line 120)	**$ 46,672,721**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet I - Account 105 - Electric Plant Held for Use

Form I - Page 214 Detail

I. Non-Transmission

Line No.	LOC CODE &/OR REG	PLANT NAME	ACQUISITION DATE	ACQUISITION VALUE	ACCUM DEPR	AVG BOY and EOY	EST. YEAR IN SERVICE	COMMENT
1	9114-D	Johnson Sub	1974	42,059.21		42,059.21	2013	
2	9114-D	Johnson Sub	1974	364.80		364.80	2013	
3	9335-D	Mountainburg Sub	1966	8,823.55		8,823.55	2012	
4	9335-D	Mountainburg Sub	1966	375.40		375.40	2012	
5	9216-D	Central Sub	2006	362,717.38		362,717.38	2014	
6	5110-D	Springdale Sub	1972	11,372.48		11,372.48	2018	
7	7322-D	Sacred Heart Sub	1973	2,631.89		2,631.89	2020	
8	7507-D	Seran Sub	1974	12,051.45		12,051.45	2020	
9	3336-D	Taft Sub	1973	5,236.53		5,236.53	2020	
10	8411-D	Acorn Sub	1969	5,907.07		5,907.07	2015	
11	8482-D	Aluma Sub	1970	10,303.87		10,303.87	2018	
12	8615-D	Anderson Road Sub	1965	5,543.15		5,543.15	2015	
13	7104-D	Bellcow Sub	2008	53,795.46		53,795.46	2010	
14	8210-D	Freeway Sub	1970	28,049.14		28,049.14	2011	
15	8493-D	Kelley Ave Sub	1962	11,055.26		11,055.26	2015	
16	8592-D	Post Road Sub	1970	18,589.47		18,589.47	2015	
17	8531-D	Ridgeview Sub	1967	16,928.49		16,928.49	2020	
18	8415-D	State Center Sub	1971	4,308.46		4,308.46	2015	
19	8164-D	SW 29th Street Sub	1974	22,359.07		22,359.07	2018	
20	8716-D	Midwest Blvd Sub	1987	5,281.72		5,281.72	2015	
21	8111-D	Newcastle Sub	1987	10,487.68		10,487.68	2011	
22	4152-D	Banner Sub	1969	9,576.66		9,576.66	2015	
23	8109-D	Canadian River Sub	1966	5,899.99		5,899.99	2018	
24	4319-D	Lovell Sub	1968	3,269.47		3,269.47	2018	
25	4117-D	Purdue Sub	1972	7,272.86		7,272.86	2018	
26	8165-D	Rancho Sub	1974	28,181.47		28,181.47	2016	
27	8699-D	S E 134th Sub	1967	5,231.43		5,231.43	2018	
28	8718-D	Sooner Road Sub	1967	10,167.51		10,167.51	2015	
29	8159-D	Wheatland Sub	1973	17,388.43		17,388.43	2020	
30	3610-D	Shady Grove Sub	2002	68,833.80		68,833.80	2018	
31	3216-D	Sahoma Lake Sub	2002	102,519.25		102,519.25	2018	
32	8359-D	Yukon Sub	2007	136,027.43		136,027.43	2015	
33	8133-D	Will Rogers Sub	2006	320,944.78		320,944.78	2014	
34	4229-D	Oil Sands Sub	2007	36,209.65		36,209.65	2015	
35	8135-D	Racer Sub	2007	7,543		7,543	2010	
36								
37								
38								
39								
40		**TOTAL ARKANSAS**		414,340		414,340		
41		**TOTAL OKLAHOMA**		982,968		982,968		
42		**TOTAL ALL**		1,397,308		1,397,308		
43								
44								
45		**NON TRANSMISSION TOTAL**		1,397,308				

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet I - Account 105 - Electric Plant Held for Use

II. Transmission

Line No.	LOC CODE &/OR REG	PLANT NAME	ACQUISITION DATE	ACQUISITION VALUE	ACCUM DEPR	AVG BOY and EOY	EST. YEAR IN SERVICE	COMMENT
46	34501-H	345 KV H-Frame -	1983	54,656.25		54,656.25	2018	
47		W. Ft. Smith Loop						
48	16101-H	161 KV H-Frame -	1989	37,601.73		37,601.73	2018	
49		W. Ft. Smith Loop						
50	34501-T	345 KV Tower -	1983 & 1989	164,719.48		164,719.48	2018	
51		W. Ft. Smith Loop						
52	13802-S	138 KV Piedmont-Haymaker	2004	149,208.47		149,208.47	2015	
53	3609-T	Garrison Sub	1978	140,076.15		140,076.15	2017	
54	7707-T	Jaycee Sub	1974	30,196.68		30,196.68	2016	
55	7210-T	Diamond Sub	1971	6,336.16		6,336.16	2018	
56	7120-T	Lincoln County Sub	1972	4,126.09		4,126.09	2012	
57	4160-T	Breckenridge Sub	1984	36,881		36,881	2016	
58	8329-T	Matthewson Sub	2009	156,729.95		156,729.95	2017	
59								
60								
61								
62								
63								
64								
65								
66								
67								
68								
69								
70								
71		**TOTAL ARKANSAS**		256,977		256,977		
72		**TOTAL OKLAHOMA**		523,555		523,555		
73		**TOTAL ALL**		780,532		780,532		
74								
75								
76		**TRANSMISSION ONLY**	(line 61)	**780,532**				
77								
78		**TOTAL COMPANY**	Form I, p.214	2,177,840				
79								

NOTE:

1. To be included in transmission rate base, the land held for future use must be estimated to be in service within 10 years
2. When calculating the Baseline ATRR, use data from the year being trued-up to calculate "AVG BOY and EOY"; when calculating the Projected ATRR, use data from the most recent FERC Form 1 to calculate the "AVG BOY and EOY."

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet J - Tax Apportionments by State

I. DEVELOPMENT OF COMPOSITE STATE INCOME TAX RATES

Line No.		For Tax Year 2008		
1	State Income Tax Rate - Oklahoma	Note 1	6.00%	
2	Apportionment Factor	Note 2	93.7%	
3	Oklahoma State Income Tax Rate	(ln 1 * ln 2)		5.6223%
4	State Income Tax Rate - Arkansas		6.50%	
5	Apportionment Factor	Note 2	7.41%	
6	Arkansas State Income Tax Rate	(ln 4 * ln 5)		0.4818%
7	Total State Income Tax Rate	(sum ln 3 & ln 6)		6.1041%

Note 1: The Oklahoma State Income Tax Rate of 6% can be reduced to 5.66% in years where credits are not available or offset tax. In 2008, a tax rate of 6% applies since all tax due was offset by credits. A deduction of Oklahoma State Income Taxes on the State Income Tax return cannot be taken when tax is not due because of offsetting credits.

Note 2: Apportionment Factors are to be based on most recent annual income tax filings as calculated in Parts II. & III. below

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet J - Tax Apportionments by State

II. Calculation of Oklahoma Apportionment Factor

		Column A Total Within Oklahoma	Column B Without Oklahoma	A divided by B Percentage Within Oklahoma
1.	Value of real and tangible personal property used in the unitary business (by averaging the value at the beginning and ending of the tax period).			
	(a) Owned property (at original cost):			
	(I) Inventories	113,871,954	115,004,314	
	(II) Depreciable property	5,490,850,182	5,767,977,552	
	(III) Land			
	(IV) Total of section 1(a)	5,604,722,136	5,882,981,866	
	(b) Rented property (capitalize at 8 times net rental paid)	5,396,024	5,663,920	
	(c) TOTAL (sum of 1(a) and 1(b))	5,610,118,160	5,888,645,786	95.2701%
2.	(a) Payroll	148,628,887	153,755,794	
	(b) Less: Officers salaries	1,882,975	1,882,975	
	(c) TOTAL (subtract 2(b) from 2(a))	146,745,912	151,872,819	96.6242%
3.	Sales:			
	(a) Sales delivered or shipped to Oklahoma purchasers:			
	(I) Shipped from outside Oklahoma	-		
	(II) Shipped from within Oklahoma	1,771,270,832		
	(b) Sales shipped from Oklahoma to:			
	(I) The United States Government	-		
	(II) Purchasers in a state or country where the corporation is not taxable (i.e. under Public Law 85-272)	-		
	(c) TOTAL (sum of 3(a) and 3(b))	1,771,270,832	1,985,257,004	89.2212%
	TOTAL PERCENTAGES (sum of items 1(c), 2(c) and 3(c))			281.1155%
	Average of TOTAL PERCENTAGES (1/3 of total percent)			**93.7052%**

III. Calculation of Arkansas Apportionment Factor

		(A) Amounts in Arkansas	(B) Total Amounts	(C) Percentage (A) / (B)
1.	Property Used in Business:			
	(a) Tangible Assets Used in Business and Inventories Less Construction in Progress:			
	1. Amount Beginning of Year:	246,765,867	5,395,467,851	
	2. Amount End of Year	309,753,593	6,370,495,880	
	3. Total: (sum of 1(a) 1 and 1(a) 2)	556,519,460	11,765,963,731	
	4. Average Tangible Assets: (divide 1(a) 3 by 2)	278,259,730	5,882,981,866	
	(b) Rental Property: (8 times annual rent)	267,896	5,663,920	
	(c) Average Value of Intangible Property:	-	-	
	(d) TOTAL PROPERTY (sum of lines 1(a) 4, 1(b) and 1(c))	278,527,626	5,888,645,786	4.729910%
2.	Salaries, Wages, Commissions and Other Compensation Related to the Production of Business Income:	5,126,907	153,755,794	3.334448%
3.	Sales/Receipts:			
	(a) Destination Shipped From Within Arkansas:	213,986,172		
	(b) Destination Shipped From Without Arkansas	-		
	(c) Origin Shipped From Within Arkansas to U.S. Govt:	-		
	(d) Origin Shipped From Within Arkansas to Other Non-taxable Jurisdictions:	-		
	(e) Other Gross Receipts:	261,781		
	(f) TOTAL SALES / RECEIPTS: (sum of lines 3(a) to 3(e))	214,247,953	1,985,167,032	10.792440%
	(g) DOUBLE WEIGHTED (Applies to tax years beginning on or after January 1, 1995) (Column C, Line 3(f) times 2)			21.584880%
4.	TOTAL PERCENTAGES: (Column C sum of lines 1(d), 2 and 3(g))			29.649238%
5.	Average of TOTAL PERCENTAGES (Column C, Line 4 divided 4)			**7.412310%**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet K - 13 Month Average Balances and Long Term Debt Costs

I. Plant Additions & Accumulated Depreciation Balances

Line No.	Gross Plant (Note 1)	End. Balance Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	End. Balance Dec-11	13 Months Avg Balance
1	**Intangible**	28,034,452	28,451,119	28,867,786	29,284,453	29,701,120	30,117,787	30,534,454	30,951,121	31,367,788	31,784,455	32,201,122	32,617,789	33,034,456	30,534,454
2	**Production-Redbud**	526,109,692	526,193,025	526,276,358	526,359,691	526,443,024	526,526,357	526,609,690	526,693,023	526,776,356	526,859,689	526,943,022	527,026,355	527,109,688	526,609,690
3	**Production**	2,523,266,846	2,525,600,179	2,527,933,512	2,530,266,845	2,532,600,178	2,534,933,511	2,537,266,844	2,539,600,177	2,541,933,510	2,544,266,843	2,546,600,176	2,548,933,509	2,951,266,842	2,568,036,075
4	**Transmission**	900,705,107	902,134,690	903,830,273	905,259,856	907,489,439	910,619,022	963,185,605	964,615,188	966,044,771	967,474,354	968,903,937	996,993,520	998,423,107	942,744,528
5	**Distribution**	2,754,714,236	2,763,047,569	2,771,380,902	2,779,714,235	2,788,047,568	2,796,380,901	2,804,714,234	2,813,047,567	2,821,380,900	2,829,714,233	2,838,047,566	2,846,380,899	2,854,714,232	2,804,714,234
6	**General Plant**	218,148,328	218,731,661	219,314,994	219,898,327	220,481,660	221,064,993	221,648,326	222,231,659	222,814,992	223,398,325	223,981,658	224,564,991	225,148,324	221,648,326
7	**Total**	6,950,978,661	6,964,158,243	6,977,603,825	6,990,783,407	7,004,762,989	7,019,642,571	7,083,959,153	7,097,138,735	7,110,318,317	7,123,497,899	7,136,677,481	7,176,517,063	7,589,696,649	7,094,287,307

Line No.	Accumulated Depreciation and Amortization (Note 2)	End. Balance Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	End. Balance Dec-11	13 Months Avg Balance
8	**Intangible**	21,053,013	21,103,013	21,153,013	21,203,013	21,253,013	21,303,013	21,353,013	21,403,013	21,453,013	21,503,013	21,553,013	21,603,013	21,653,013	21,353,013
9	**Production-Redbud**	90,500,149	91,700,149	92,900,149	94,100,149	95,300,149	96,500,149	97,700,149	98,900,149	100,100,149	101,300,149	102,500,149	103,700,149	104,900,149	97,700,149
10	**Production**	1,395,533,767	1,398,200,767	1,400,867,767	1,403,534,767	1,406,201,767	1,408,868,767	1,411,535,767	1,414,202,767	1,416,869,767	1,419,536,767	1,422,203,767	1,424,870,767	1,428,871,100	1,411,638,331
11	**Transmission**	346,648,213	348,051,144	349,454,620	350,857,550	352,262,121	353,668,537	355,176,298	356,579,229	357,982,159	359,385,090	360,788,021	362,245,604	363,646,535	355,134,240
12	**Distribution**	922,822,367	926,822,367	930,822,367	934,822,367	938,822,367	942,822,367	946,822,367	950,822,367	954,822,367	958,822,367	962,822,367	966,822,367	970,822,367	946,822,367
13	**General Plant**	82,028,059	82,444,726	82,861,393	83,278,060	83,694,727	84,111,394	84,528,061	84,944,728	85,361,395	85,778,062	86,194,729	86,611,396	87,028,063	84,528,061
14	**Total**	2,858,585,568	2,868,322,166	2,878,059,309	2,887,795,906	2,897,534,144	2,907,274,227	2,917,115,655	2,926,852,253	2,936,588,850	2,946,325,448	2,956,062,046	2,965,853,296	2,976,921,227	2,917,176,161

Line No.	Net Plant (Gross Plant less Accumulated Depreciation and Amortization)	End. Balance Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	End. Balance Dec-11	13 Months Avg Balance
15	**Intangible**	6,981,439	7,348,106	7,714,773	8,081,440	8,448,107	8,814,774	9,181,441	9,548,108	9,914,775	10,281,442	10,648,109	11,014,776	11,381,443	9,181,441
16	**Production-Redbud**	435,609,543	434,492,876	433,376,209	432,259,542	431,142,875	430,026,208	428,909,541	427,792,874	426,676,207	425,559,540	424,442,873	423,326,206	422,209,539	428,909,541
17	**Production**	1,127,733,079	1,127,399,412	1,127,065,745	1,126,732,078	1,126,398,411	1,126,064,744	1,125,731,077	1,125,397,410	1,125,063,743	1,124,730,076	1,124,396,409	1,124,062,742	1,522,395,742	1,156,397,744
18	**Transmission**	554,056,894	554,083,546	554,375,653	554,402,306	555,227,318	556,950,485	608,009,307	608,035,959	608,062,612	608,089,264	608,115,916	634,747,916	634,776,572	587,610,288
19	**Distribution**	1,831,891,869	1,836,225,202	1,840,558,535	1,844,891,868	1,849,225,201	1,853,558,534	1,857,891,867	1,862,225,200	1,866,558,533	1,870,891,866	1,875,225,199	1,879,558,532	1,883,891,865	1,857,891,867
20	**General Plant**	136,120,269	136,286,935	136,453,601	136,620,267	136,786,933	136,953,599	137,120,265	137,286,931	137,453,597	137,620,263	137,786,929	137,953,595	138,120,261	137,120,265
21	**Total**	4,092,393,093	4,095,836,077	4,099,544,516	4,102,987,501	4,107,228,845	4,112,368,344	4,166,843,498	4,170,286,482	4,173,729,467	4,177,172,451	4,180,615,435	4,210,663,767	4,612,775,422	4,177,111,146

Notes:
1. When calculating the Baseline ATRR, use the actual 13 month account balancees for the year being trued-up. When calculating the Projected ATRR, the values for "Gross Plant" shall include net plant additions.
2. When calculating the Projected ATRR, the values for Accumulated Depreciation and Amortization shall include both accumulated depreciation and amortization on new plant projected to be in service as well as the accumulated depreciation and amortization on existing plant through the end of the projected year.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet K

II. Material and Supplies for Construction Balances

		End Balance Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	End Balance Dec-09	13 Months Avg. Balance
22	Production O&M	20,946,297	21,890,004	22,057,074	22,343,192	22,498,214	21,570,345	21,741,347	22,277,664	22,585,545	22,316,660	19,401,217	20,070,271	20,648,180	21,565,078
23	Transmission O&M	232,238	392,235	364,535	294,968	207,590	204,595	279,286	278,618	208,949	253,127	248,948	295,280	299,184	273,812
24	Distribution O&M	1,765,006	1,743,269	1,913,807	1,720,647	1,556,926	1,483,317	1,843,289	1,950,324	2,037,250	1,974,392	2,041,372	2,017,744	2,144,149	1,860,884
25	Prod. Construction	874,641	114,423	70,809	78,475	85,819	49,726	43,570	53,595	49,798	42,483	3,098,165	2,961,943	2,957,833	806,252
26	Trans. Construction	7,277,133	11,381,130	11,484,437	16,986,607	21,191,225	21,668,847	22,466,470	21,333,642	19,956,404	18,396,045	17,593,723	17,099,832	17,028,736	17,220,325
27	Dist. Construction	36,298,511	30,065,084	31,804,054	30,159,124	28,941,789	27,792,114	31,268,210	32,160,947	30,034,588	30,001,864	29,905,528	29,800,419	30,391,859	30,663,392
28	Total	67,393,826	65,586,145	67,694,716	71,583,013	74,481,563	72,768,944	77,642,172	78,054,790	74,872,534	72,984,571	72,288,953	72,245,489	73,469,941	72,389,743

Notes:
1. When calculating the Baseline ATRR, use the actual 13 month account balances for the year being trued-up. When calculating the Projected ATRR, use the 13 month account balances ending December of the most recent FERC Form No. 1.
2. Transmission O&M (ln 23) and Transmission Construction (ln 26) are summed and reflected on page 3 of 6, line 64 of the Attachment H - Addendum 2-A.

III. Debt and Equity Balances

		End Balance Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	End Balance Dec-09	13 Months Avg. Balance
29	Long Term Debt (Face Value)	1,545,250,000	1,545,250,000	1,545,250,000	1,545,250,000	1,545,250,000	1,545,250,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,303,846
30	Propriety Capital	1,824,359,077	1,827,756,872	1,826,247,396	1,825,702,797	1,829,794,350	1,842,807,212	1,882,073,082	1,928,238,799	1,979,560,371	2,005,311,703	2,018,773,223	2,018,331,303	2,024,389,844	1,910,257,387
31	Less: Acct. 204	-													-
32	Less: Acct. 216.1	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,871	102,530
33	Less: Acct. 219	-	-	-	-	-	-	-	(260,501)	(572,565)	54,963	(147,910)	(363,514)	(409,287)	(130,678)
34	Common Stock	1,824,256,575	1,827,654,370	1,826,144,894	1,825,600,295	1,829,691,848	1,842,704,710	1,881,970,580	1,928,396,798	1,980,030,434	2,005,154,238	2,018,818,631	2,018,592,315	2,024,696,260	1,910,285,534
35	LTD / (LTD + Common Stock)	45.9%	45.8%	45.8%	45.8%	45.8%	45.6%	45.1%	44.5%	43.8%	43.5%	43.4%	43.4%	43.3%	44.7%

Notes:
1. Outstanding Long Term Debt are reported in Accts. 221-224 (112.18-21.c & d) and the calculation shall include only current period costs and shall not include any deferred costs, (except as authorized by FERC), interest rate hedging costs/gains/losses, or credit facility expenses related to short-term indebtedness. Remove the value of any hedge contracts from Accts. 222-224 (257.h) for this purpose.
2. When calculating the Baseline ATRR, use the actual 13 month account balances for the year being trued-up. When calculating the Projected ATRR, use the 13 month account balances ending December of the most recent FERC Form No. 1.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet K

IV. Account 165 - Prepayments

		BOY Balance Relevant Year	EOY Balance Relevant Year	Average Balance
36		(111.57.d)	(111.57.c)	
37	Prepayments	8,022,198	8,467,046	8,244,622

Notes:
1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the most recent FERC Form No. 1.

V. Long-Term Debt Costs

	Accounts	Reference	Calculation	Comments / Explanations
38	Acct 427 - Long-term interest expense	(117.62.c)	$ 96,574,200	
39	Acct. 428 - Amortization of debt discount and expense	(117.63.c)	$ 1,194,630	
40	Acct. 428.1 - Amortization of loss on reacquired debt	(117.64.c)	$ 1,186,698	
41	Acct. 430 - Interest on Long-term debt to Associated Companies in Acct. 223 (112.20.c)	(117.67.c)	$ -	(per note on pg 450.1 for pg 256, col. i)
42	Less: Acct. 429 - Premium on debt discount	(117.65.c) (enter negative)	$ -	
43	Less: Acct. 429.1 - Amortization of gain on reacquired debt	(117.66.c) (enter negative)	$ -	
44	**Total Long Term Interest**	(sum lns 38 to 43)	**$ 98,955,528**	
45	Average of the 13 month balances outstanding long-term debt	(ln 29)	$ 1,545,303,846	
46	**LONG TERM DEBT COST**	(ln 44 / ln 45)	**6.404%**	

Notes:
1. Unless approved in a Section 205 filing by FERC, gains and losses on interest rate hedging on long term debt shall not be flowed through interest expense; and the value of hedge contracts shall not be included in long term debt balances.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L - True-Up Adjustment with interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation.

Line No.

I. Prior Year True-Up with Interest Calculation

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year.

Line No.			Rate Year
1	Projected Revenue Requirement	$ 85,301,630	2009
2	Baseline Revenue Requirement	$ 80,372,300	2009
3	True Up Adjustment Without Interest (TUA)	**$ 4,929,330**	

4 Average Interest Rate on Amount of Refunds or Surcharges
5 calculated per Section V below **0.2708%**

Line No.	Year		[A] Amount	[B] Interest Rate	[C] Months	[D] Interest cols [A] x [B] x [C]	[E] Refund / (Surcharge) cols [A] + [D]
6	2009	6 months interest	$ 4,929,330	0.2708%	6	$ 80,102	$ 5,009,431
7	2010	12 months interest	$ 5,009,431	0.2708%	12	$ 162,807	$ 5,172,238
8	2011	6 months interest	$ 5,172,238	0.2708%	6	$ 84,049	$ 5,256,287

II. Prior Period Correction True-Up with Interest Calculation

This section will calculate the interest on the True-up Adjustment (refund or surcharge) on a correction made in a Prior Period.

Line No.			Correction Rate Year
9	Baseline Revenue Requirement	$ -	0
10	Revised Baseline Revenue Requirement	$ -	0
11	True Up Adjustment Without Interest (TUA)	**$ -**	

12 Average Interest Rate on Amount of Refunds or Surcharges
13 calculated per Section V below **0.0284%**

Line No.	Year		[A] Amount	[B] Interest Rate	[C] Months	[D] Interest cols [A] x [B] x [C]	[E] Refund / (Surcharge) cols [A] + [D]
14		6 months interest	$ -	0.0284%	6	$ -	$ -
15		months interest	$ -	0.0284%		$ -	$ -
16		6 months interest	$ -	0.0284%	6	$ -	$ -

17	**TOTAL PRIOR YEAR TRUE-UP ADJUSTMENT**	(ln 8[E] + ln 16[E])	**$ 5,256,287**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

III. Base Plan Upgrade True-Up Calculations

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year on Base Plan Upgrade Projects.

18 Average Interest Rate on Amount of Refunds or Surcharges calculated per Section V below.

	Proj. No.		Projected ATRR - Prior Year (1)	Baseline ATRR - Prior Year (2)	True-Up Adjustment Without Interest	Refund / (Surcharge) 2009	Refund / (Surcharge) 2010	Refund / (Surcharge) 2011
19	1	Reno-Sunny Lane 69kV Line	$ 11,444	$ 10,378	$ 1,066	$ 1,084	$ 1,119	$ 1,137
20	2	Richards Tap-Richards 138kV Line	$ 468,836	$ 425,166	$ 43,670	$ 44,379	$ 45,822	$ 46,566
21	3	Van Buren AVEC-Van Buren Interconnect 69kV Line	$ 18,290	$ 16,587	$ 1,703	$ 1,731	$ 1,787	$ 1,816
22	4	Brown Explorer Tap 138kV Line	$ 5,343	$ 4,845	$ 498	$ 506	$ 522	$ 531
23	5	NE Enid-Glenwood 138kV Line	$ 668,242	$ 606,254	$ 61,988	$ 62,995	$ 65,042	$ 66,099
24	6	Razorback-Short Mountain 69kV Line	$ 1,598,092	$ 1,449,850	$ 148,242	$ 150,651	$ 155,547	$ 158,075
25	7	Richards-Piedmont 138kV Line	$ 662,125	$ 601,118	$ 61,007	$ 61,999	$ 64,014	$ 65,054
26	8	OG&E Windfarm-WFEC Mooreland 138kV Line	$ 14,758	$ 13,394	$ 1,364	$ 1,386	$ 1,431	$ 1,454
27	9	Ft. Smith-Colony 161kV Line	$ 1,681	$ 22,234	$ (20,553)	$ (20,588)	$ (20,659)	$ (20,694)
28	10	Cedar Lane-Canadian 138kV Line	$ 1,278	$ 3,738	$ (2,460)	$ (2,464)	$ (2,472)	$ (2,477)

29	**TOTAL PRIOR YEAR BASE PLAN UPGRADE PROJECTS TRUE-UP ADJUSTMENT**	(sum ln 19 thru ln 28)	**$**	**317,562**

NOTE: (1) Projected ATRR for individual Base Plan Projects comes from the Prior Year's Projected ATRR calculation, Worksheet G and Worksheet P - Summary page
(2) Baseline ATRR for individual Base Plan Projects comes from the Prior Year Baseline ATRR calculation, Worksheet G and Worksheet P - Summary page

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

IV. Calculation of Optional Prepayment and Prepayment Credit

			"Customer 1"	"Customer 2"	"Customer 3"	"Customer 4"
30	Prepayment Amount					
31	TUA with first year's interest	Line 6[E] above	$ 5,009,431	$ 5,009,431	$ 5,009,431	$ 5,009,431
32	Line 31 plus 6 Months of year 2 Interest	(6 x Interest Rate on Line 7[B]+1) * Line 31	$ 5,090,835	$ 5,090,835	$ 5,090,835	$ 5,090,835
33	Customer's Load in year preceeding the current Rate Year	(MW)				
34	System Load in year preceeding the current Rate Year	(MW)				
35	Amount of Prepayment	Line 32 x (Line 33 / Line 34)	$0	$0	$0	$0
36	Prepayment Adjustment (Note 1)					
37	Customer's Load applicable in the current Rate Year	(MW)				
38	System Load applicable in the current Rate Year	(MW)				
39	Prepayment Adjustment	[(Line 37 / Line 38) / (Line 33 / Line 34) - 1] x Line 35	$0.00	$0.00	$0.00	$0.00
40	Line 39 plus 6 Months Interest	(6 x Interest Rate on Line 7[B]+1) * Line 39	$0.00	$0.00	$0.00	$0.00
41	Prepayment Credit					
42	Total TUA with interest	Line 8[E] above	$ 5,256,287	$ 5,256,287	$ 5,256,287	$ 5,256,287
43	Monthly Prepayment Credit	[Line 42 x (Line 33 / Line 34) / 12]	$0	$0	$0	$0

Note;

1. The Prepayment Adjustment is made to reflect any difference between the Network Customer's load ratio share percentage used to determine the Prepayment and the actual load ratio share percentage applicable in the Rate Year during which the True-Up Adjustment would otherwise have been collected.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

V. Average Interest Rate / Debt Cost Calculations

	Quarter	Year	[A] FERC Quarterly Interest Rate	[B] OG&E Short Term Debt Rate	[C] Rate for Surcharges (lesser of A or B)	[D] Rate for Refunds (column A)
44	3rd	2009	3.25%	0.39%	0.39%	3.25%
45	4th	2009	3.25%	0.39%	0.39%	3.25%
46	1st	2010	3.25%	0.25%	0.25%	3.25%
47	2nd	2010	3.25%	0.34%	0.34%	3.25%

48	Average Interest Rate Applicable to Surcharges from column [C]	0.34%
49	Average Interest Rate Applicable to Refunds from column [D]	3.25%

NOTE: (1) The FERC Quarterly Interest Rate in column [A] is the interest applicable to the quarter indicated.
(2) The OG&E Short Term Debt Rate in column [B] is the weighted average Short Term Debt cost applicable to the quarter indicated.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet M - Depreciation Rates

Source: 2006 Form I, page 337.1 & 337.2, column (e)

Transmission Plant Account	Account Description	Rate
350	Land and Land Rights	1.56%
352	Structures and Improvements	0.92%
353	Station Equipment	1.79%
354	Towers and Fixtures	1.81%
355	Poles and Fixtures	3.65%
356	Overhead Conductors and Devices	3.13%
358	Underground Conductors and Devices	

General Plant Account	Account Description	Rate
389	Land and Land Rights	2.19%
390	Structures and Improvements	3.19%
391	Office Furniture and Equipment	5.01%
392	Transportation Equipment	10.99%
393	Stores Equipment	2.89%
394	Tools, Shop and Garage Equipment	5.32%
395	Laboratory Equipment	9.77%
396	Power Operated Equipment	1.78%
397	Communication Equipment	5.34%
398	Miscellaneous Equipment	3.50%
Intangibles		10.28%

Note: These rates are fixed and will be changed only by a separate FPA 205 filing.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet N - Unfunded Reserves

I. Labor Related

Line No.	Account No.	Account Title		Beginning Balance		Ending Balance		Average
1	228.2	Accumulated Provision for Injuries and Damages	$	2,216,375	$	1,414,000	$	1,815,188
2	242	Severance	$	-	$	-	$	-
3	242	Accrued Vacation Pay	$	13,048,848	$	13,681,770	$	13,365,309
4	242	Workers Compensation	$	1,702,233	$	1,946,698	$	1,824,466
5	242	Post Retirement Life Insurance	$	999,006	$	92,967	$	545,987
6	242	Incentive Compensation	$	7,835,045	$	12,688,443	$	10,261,744
7	242	Public Liability	$	285,000	$	114,000	$	199,500
8	242	Miscellaneous	$	403,441	$	963,955	$	683,698
9	xxx	Reserved for future					$	-
10		Sub-Total	$	26,489,948	$	30,901,833	$	28,695,891
11		Wage & Salary Allocator						0.057403
12		Total Labor Related Reserves (ln 10 times ln 11)					$	1,647,242

II. Plant Related

Line No.	Account No.	Account Title		Beginning Balance		Ending Balance		Average
13	xxx	Reserved for future	$	-	$	-	$	-
14	xxx	Reserved for future	$	-	$	-	$	-
15	xxx	Reserved for future	$	-	$	-	$	-
16		Sub-Total	$	-	$	-	$	-
17		Gross Plant Allocator						0.125739
18		Total Labor Related Reserves (ln 16 times ln 17)					$	-
19		**TOTAL REDUCTION TO RATE BASE (negative of ln 12 plus ln 18)**					**$**	**(1,647,242)**

Note:

The average of the beginning and ending balances of reserves that are unfunded (i.e. not set aside in an escrow) and whose balances have been included in the expenses recovered under the formula, will be deducted from rate base. This total will be represented as a negative amount on Line 58 of the Data tab.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet O - Amortizations

I. Extraordinary O&M Amortization

Line No.	Justification	FERC Docket No	Effective Year	Amortization Term (yrs)	Beginning O&M Expense	Annual Amortization	Annual Year End Balance
1						$ -	$ -
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12	Total Extraordinary O&M Amortization					$ -	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet O - Amortizations

II. Storm Cost Amortization

	Justification	FERC Docket No	Effective Year	Amortization Term (yrs)	Beginning O&M Expense	Annual Amortization	Annual Year End Balance
13	2007 Ice Storm expenses		2008	5	$ 52,321	$ 10,464	$ 41,857
14			2009			$ 10,464	$ 31,393
15			2010			$ 10,464	$ 20,929
16			2011			$ 10,464	$ 10,465
17			2012			$ 10,464	$ 1
18							
19							
20							
21							
22							
23							
24							
25							
26	Total Storm Costs Amortization					$ 10,464	
27	**TOTAL AMORTIZATIONS** (entered in Data tab on ln 93) (sum of lns 12 and 26)					**$ 10,464**	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

I. Project Summary

Proj. No.	A. CWIP Annual Transmission Revenue Requirements Project Description	ATRR
1	Sooner - Rose Hill 345kV Line (Base Plan Upgrade)	$ 3,881,603
2	Sooner - Cleveland 345kV Line (Balanced Portfolio Upgrade)	$ 1,049,419
3	Woodward District EHV - Tuco 345kV Line (Balanced Portfolio Upgrade)	$ 235,499
4	Gracemont Substation (Balanced Portfolio Upgrade)	$ 1,040,725
5	Woodward District EHV - Hitchland 345kV Line (Balanced Portfolio Upgrade)	$ 268,786
6	Woodward District EHV - Comanche County 345kV Line (Balanced Portfolio Upgrade)	$ 253,881
7	Seminole - Muskogee 345kV Line (Balanced Portfolio Upgrade)	$ 473,581
8	Sunnyside - Hugo 345kV Line (Base Plan Upgrade)	$ 11,827,076
9		
10		
11		
	CWIP Totals	**$ 19,030,570**

Proj. No.	B. Abandoned Plant Annual Transmission Revenue Requirements Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	Abandoned Plant Totals	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant Balances

II. Construction Work in Progress (CWIP) Balances

Line No.	Month	Year	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
			Sooner-Rose Hill 345kV Line	Sooner-Cleveland 345kV Line	Woodward District EHV-Tuco 345kV Line	Gracemont Substation	Woodward District EHV-Hitchland 345kV Line	Woodward District EHV-Comanche Co. 345kV Line	Seminole-Muskogee 345kV Line	Sunnyside-Hugo 345kV Line			
1	**December**	2010	$ 10,858,000	$ 2,385,000	$ -	$ 1,000,000	$ -	$ -	$ -	$ 25,105,000			$ 39,348,000
2	**January**	2011	$ 11,154,000	$ 2,888,000	$ 200,000	$ 1,050,000	$ 50,000	$ 50,000	$ 20,000	$ 28,255,000			$ 43,667,000
3	**February**	2011	$ 16,323,000	$ 3,388,000	$ 400,000	$ 1,150,000	$ 100,000	$ 100,000	$ 40,000	$ 36,776,000			$ 58,277,000
4	**March**	2011	$ 21,388,000	$ 4,384,000	$ 700,000	$ 1,550,000	$ 250,000	$ 200,000	$ 500,000	$ 48,827,000			$ 77,799,000
5	**April**	2011	$ 25,629,000	$ 4,873,000	$ 1,000,000	$ 2,950,000	$ 500,000	$ 400,000	$ 1,000,000	$ 62,293,000			$ 98,645,000
6	**May**	2011	$ 29,784,000	$ 5,358,000	$ 1,300,000	$ 6,450,000	$ 850,000	$ 700,000	$ 1,500,000	$ 76,218,000			$ 122,160,000
7	**June**	2011	$ 31,905,000	$ 6,339,000	$ 1,600,000	$ 9,450,000	$ 1,300,000	$ 1,100,000	$ 2,000,000	$ 90,932,000			$ 144,626,000
8	**July**	2011	$ 34,593,000	$ 7,303,000	$ 1,900,000	$ 11,450,000	$ 1,800,000	$ 1,600,000	$ 2,700,000	$ 107,096,000			$ 168,442,000
9	**August**	2011	$ 37,707,000	$ 8,661,000	$ 2,300,000	$ 12,450,000	$ 2,800,000	$ 2,600,000	$ 4,200,000	$ 121,282,000			$ 192,000,000
10	**September**	2011	$ 40,797,000	$ 10,009,000	$ 2,700,000	$ 13,450,000	$ 3,800,000	$ 3,600,000	$ 6,000,000	$ 132,757,000			$ 213,113,000
11	**October**	2011	$ 42,100,000	$ 12,548,000	$ 3,200,000	$ 14,450,000	$ 4,800,000	$ 4,600,000	$ 8,200,000	$ 143,233,000			$ 233,131,000
12	**November**	2011	$ 43,608,000	$ 16,016,000	$ 3,700,000	$ 14,668,000	$ 5,300,000	$ 5,100,000	$ 10,400,000	$ 152,089,000			$ 250,881,000
13	**December**	2011	$ 44,789,000	$ 21,459,000	$ 4,700,000	$ 14,668,000	$ 5,500,000	$ 5,500,000	$ 11,100,000	$ 165,385,000			$ 273,101,000
14	**Average Balances**		$ 30,048,846	$ 8,123,923	$ 1,823,077	$ 8,056,615	$ 2,080,769	$ 1,965,385	$ 3,666,154	$ 91,557,538			$ 147,322,308
15	**Return**	(Data Ln 140 * Ln 14)	$ 2,704,346	$ 731,139	$ 164,074	$ 725,082	$ 187,266	$ 176,881	$ 329,948	$ 8,240,024			$ 13,258,759
16	**Taxes**	(Data Ln 108 * Ln 15)	$ 1,177,257	$ 318,280	$ 71,425	$ 315,643	$ 81,521	$ 77,000	$ 143,633	$ 3,587,052			$ 5,771,810
17	**ATRR**	(Ln 15 + Ln 16)	$ 3,881,603	$ 1,049,419	$ 235,499	$ 1,040,725	$ 268,786	$ 253,881	$ 473,581	$ 11,827,076			$ 19,030,570

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

III. Abandoned Plant

Line No.			Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
18	**Abandoned Plant Balance**												
19	**Amortization Period (months)**												
20	**Monthly Amortization Amount**												
	Month	Year											
21	**December**	2010											
22	**January**	2011											
23	**February**	2011											
24	**March**	2011											
25	**April**	2011											
26	**May**	2011											
27	**June**	2011											
28	**July**	2011											
29	**August**	2011											
30	**September**	2011											
31	**October**	2011											
32	**November**	2011											
33	**December**	2011											
34	**Average Balances**		-										
35	**Return**	(Data Ln 140 * Ln 34)	0										
36	**Taxes**	(Data Ln 108 * Ln 35)	0										
37	**Amortization Abandoned Plant** (Beg. Bal. less End. Bal.)		0										
38	**ATRR**	(Ln 35 + Ln 36 + Ln 37)	0	-	-	-	-	-					

ATTACHMENT 7

DIRECT TESTIMONY AND EXHIBITS OF DONALD R. ROWLETT

Exhibit No. OGE-19

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER10-___-000

DIRECT TESTIMONY AND EXHIBITS OF
DONALD R. ROWLETT

October 12, 2010

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company) Docket No. ER10-___-000

DIRECT TESTIMONY AND EXHIBITS OF DONALD R. ROWLETT

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Donald R. Rowlett. My business address is 321 N. Harvey Ave., P.O. Box 321, Oklahoma City, Oklahoma 73101. I am the Director of Regulatory Policy and Compliance at Oklahoma Gas and Electric Company ("OG&E").

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for the analysis, development and communication of regulatory policy for OG&E. This includes establishing policies to be followed by OG&E in the Oklahoma and Arkansas and the Federal Energy Regulatory Commission ("FERC" or "Commission") jurisdictions and monitoring compliance with those policies.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I earned a Bachelor of Science degree in Business with an accounting emphasis (1980) and a Masters in Business Administration (1992), from Oklahoma City University. In 1983, I became a Certified Public Accountant, licensed to practice in Oklahoma. Prior to joining OG&E, I was employed by Arthur Anderson & Co. as a financial consultant and audit manager. I joined OG&E in 1989 and have worked in a number of positions including Vice President and Controller and my present position.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION OR BEFORE A STATE REGULATORY AGENCY?

A. Yes. At the FERC, I submitted testimony in 2007 in support of a Federal Power Act Section 205 filing by Oklahoma Gas and Electric Company in Docket No. ER08-281-000. I also submitted testimony in 2008 on behalf of Tallgrass Transmission LLC in Docket No. ER09-35-000. I have filed testimony in numerous proceedings before the Oklahoma Corporation Commission ("OCC") and the Arkansas Public Service Commission ("APSC"). Additionally, I have submitted testimony and appeared before the United States Senate Environmental and Public Works Committee.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS TESTIMONY.

A. OG&E proposes to construct eight major 345-kV regional transmission projects (the "Projects"), which are further described in the testimony of Philip L. Crissup at Exhibit No. OGE-1. The purpose of my testimony is to describe the transmission rate incentives that OG&E is seeking in this proceeding for the Projects, as well as the financial risks and challenges presented by, and the benefits to OG&E and its customers provided by, the requested incentives. I also will describe the Construction Work In Progress ("CWIP") related accounting procedures that OG&E plans to implement in accordance with the Commission's regulations.

II. COSTS OF THE PROJECTS

Q. WHAT ARE THE ESTIMATED COSTS OF THE PROJECTS?

A. The estimated total cost of the Projects is approximately $936 million. These costs will be incurred over the next four years, as detailed in the following table:

Year	2010	2011	2012	2013	2014	Total
Project Cost (millions)	39	234	257	286	120	936

Q. HOW DOES OG&E'S LEVEL OF INVESTMENT IN THE PROJECTS COMPARE TO OG&E'S OTHER INVESTMENTS IN TRANSMISSION?

A. The estimated total cost of the Projects, approximately $936 million, is greater than OG&E's current net transmission plant, which is $534 million. New transmission investments of this magnitude are unprecedented for OG&E. Over the past several years, OG&E's annual expenditures for capital additions has averaged approximately $20 million.

Q. HOW DOES OG&E INTEND TO FINANCE THE DEVELOPMENT AND CONSTRUCTION OF THE PROJECTS?

A. OG&E intends to finance these projects with a mix of long-term debt and equity consistent with the current capital structure.

III. FINANCIAL RISKS AND CHALLENGES

Q. PLEASE SUMMARIZE THE FINANCIAL RISKS AND CHALLENGES OG&E FACES WITH RESPECT TO THE DEVELOPMENT AND CONSTRUCTION OF THE PROJECTS.

A. The size of the investment required for the Projects – over $900 million – will present a number of financial challenges for OG&E. First, funding projects of this size and scope will require significant outlays of cash, decreasing OG&E's cash flow. Second, these expenditures will increase OG&E's debt and will burden OG&E's financial metrics, raising the risk of a credit downgrade. Third, internal competition for capital with other OG&E expenditures raises additional financing challenges. Fourth, the long lead times associated with the Projects will compound each of these risks.

Q. PLEASE DESCRIBE THE IMPACT ON CASH FLOW OF THE PROJECTS.

A. The large investment required by the Projects will depress OG&E's cash flow during the construction phase of the Projects. Over the next five years, OG&E will face a negative cash flow position as a result of meeting the extensive level of capital expenditures required by the Projects. Cash flows generated from operations will not be sufficient to cover these transmission projects over the next five years. The decreased cash flow will put stress on OG&E's credit metrics. A decreased cash flow increases the risk that a utility may not be able to satisfy its financial obligations and can harm a utility's credit ratings. A recent S&P report highlighted the importance of cash flow in connection with large-scale capital projects:

> Especially during upswings in the capital expenditure cycle, such as we are experiencing now, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true for ventures with big budgets and long lead times, such as baseload coal-fired or nuclear power plants and high-voltage transmission lines that are susceptible to construction delays.[1]

Q. PLEASE DESCRIBE HOW NEGATIVE CASH FLOW IMPACTS CREDIT RATINGS.

A. When assessing a company's ability to meet its financial obligations, the credit ratings agencies rely largely on two financial ratios to determine if the company has a sufficient level of cash flow to satisfy its obligations. These two metrics are Funds From Operations to Interest Expense ("FFO/Interest") and the ratio of Funds From Operations to Total Debt ("FFO/Total Debt"). Funds From Operations is largely composed of net income and depreciation expense. The more debt and other fixed contractual obligations a company has, the higher the adjusted interest expense and total adjusted debt and the lower the cash flow coverage ratios. This problem is most acute during the construction cycle of large projects at which time the denominator of both formulas increases while the numerator decreases.

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[1] Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor's Global Credit Portal: RatingsDirect* (March 11, 2010), Exhibit No. OGE-24 at 6.

Q. IS THERE ANY SPECIFIC EVIDENCE THAT OG&E'S PLANNED TRANSMISSION EXPENDITURES MAY HAVE AN IMPACT ON OG&E'S CREDIT RATINGS?

A. Yes. On June 29, 2010, Fitch Ratings downgraded the Issuers Default Rating ("IDR") of OG&E to A from A+. Fitch stated

> The one-notch downgrade of OG&E is driven by downward-trending credit metrics at the utility as it continues with a capital expenditure program that is significantly higher than the historical norm. The cap-ex, which is being primarily channeled into wind, transmission and smart grid investments, is expected to remain elevated over the next several years based on known and committed projects. While OG&E enjoys constructive regulatory treatment for these investments and has minimal regulatory lag once these projects become operational, there is expected to be pressure on credit metrics during the construction period.[2]

Q. WHY ARE A UTILITY'S CREDIT RATINGS IMPORTANT?

A. Credit ratings determine the cost of borrowing funds for the utility, *i.e.*, the stronger the rating, the lower the borrowing cost. Therefore, such reduced borrowing costs reduce costs to customers. Credit ratings also determine the ability to access capital markets and define a company's overall risk profile.

Q. ARE THERE OTHER FINANCIAL RISKS AND CHALLENGES ASSOCIATED WITH THE PROJECTS?

A. Yes. OG&E has a number of additional capital expenditures that will compete with the Projects for financing. OG&E is facing aging utility infrastructure that will require investments higher than historical levels several years into the future. Additionally, OG&E is investing in new Smart Grid technology over the next three years and has additional obligations in renewable energy and environmental

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[2] Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" (June 28, 2010) (Exhibit No. OGE-23).

initiatives. OG&E's total projected base transmission, distribution, generation and other capital expenditures through year 2014, plus the expenditures for the Projects, will be over $3.2 billion. To put this in perspective, these projected expenditures are only slightly less than the Company's current total rate base. The sheer volume of these capital expenditures means that a lot of capital projects will be competing with the Projects in question for funding priority.

Q. HOW DO THE LONG LEAD TIMES ASSOCIATED WITH THE PROJECTS IMPACT THE FINANCIAL RISKS ON OG&E?

A. Several of the Projects will not be placed into service until 2014, even though OG&E will incur significant costs in connection with those Projects starting right away. These Projects face long lead times with regard to acquisition of rights-of-way and materials and securing labor resources. This creates risk in terms of cost increases, construction delays and continually building carrying costs.

IV. REQUEST FOR INCENTIVES

Q. WHICH TRANSMISSION RATE INCENTIVES IS OG&E SEEKING FOR THE PROJECTS?

A. OG&E seeks approval to recover 100 percent of construction work in progress, or CWIP, in rate base and to recover 100 percent of prudently incurred costs should the Projects need to be abandoned for reasons outside OG&E's control ("Abandoned Plant").

Q. HOW DID OG&E DECIDE WHICH INCENTIVES TO REQUEST?

A. OG&E considered which incentives would help alleviate the risks and challenges presented by the Projects. The requested incentives are specific to the Projects and will help facilitate the timely completion of the Projects while allowing OG&E to continue to meet its other financial obligations.

V. BENEFITS OF THE CWIP INCENTIVE

Q. PLEASE DESCRIBE THE BENEFITS TO OG&E OF THE CWIP INCENTIVE.

A. The ability to recover 100 percent of CWIP in rate base will give OG&E upfront regulatory certainty and rate stability. The CWIP incentive also will improve cash flow. As discussed above, OG&E will face a negative cash flow position as a result of its investment in the Projects. As the credit rating agencies have recognized, certain regulatory mechanisms – including CWIP – can strengthen a utility's cash flow. For example, S&P stated "[a]llowance of a cash return on construction work-in-progress or similar ratemaking methods historically were considered extraordinary measures for use in unusual circumstances, but in today's environment of rising construction costs and possible inflationary pressures, cash flow support could be crucial in maintaining credit quality through the spending program."[3]

A more stable cash flow, in turn, bolsters a utility's credit ratings. In its report describing the recent downgrade in OG&E's IDR, Fitch noted that "[o]ther favorable regulatory mechanisms if implemented, such as cash recovery of capital costs during construction work in progress, would be viewed as credit enhancing by Fitch."[4] As noted by Fitch, the CWIP incentive can prevent a possible credit

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[3] Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor's Global Credit Portal: RatingsDirect* (March 11, 2010), Exhibit No. OGE-24 at 6.

[4] Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" (June 28, 2010) (Exhibit No. OGE-23).

downgrade by providing more stable cash flow and decreasing financial risk. Because 100 percent CWIP recovery reduces downward pressure on OG&E's credit ratings, OG&E would be able to borrow money at a lower cost. Not having to finance AFUDC costs would also help OG&E to minimize the final amount of capital expenditures incurred to complete the Projects.

Q. WHAT IS THE ALTERNATIVE TO 100 PERCENT CWIP RECOVERY?

A. With 100 percent CWIP recovery, OG&E would earn a return on the financing costs of construction on a current basis rather than recovering these costs in rate base after construction is complete. The alternative to 100 percent CWIP recovery is to recover the cost to finance construction in the form of Allowance for Funds Used During Construction ("AFUDC") when the Projects go into service. Just like with the AFUDC approach, under the CWIP approach, a project does not begin to depreciate until it is placed into service. As discussed in more detail below, overall construction costs ultimately will be lower under the CWIP approach, as compared to the AFUDC approach, benefiting OG&E's transmission customers.

Q. WHAT IS THE IMPACT ON CASH FLOW OF THE PROJECTS TAKING INTO ACCOUNT THE CWIP INCENTIVE VERSUS THE AFUDC APPROACH?

A. I have included an exhibit, summarized in the table below, that demonstrates the difference in cash flow OG&E would experience between receiving 100 percent CWIP as compared to AFUDC treatment.[5]

($ millions)	2011	2012	2013	2014	Total
100% CWIP	**$11.3**	**$33.0**	**$62.4**	**$92.5**	**$199.2**
AFUDC	**(2.1)**	**11.6**	**40.2**	**82.9**	**$132.6**
Difference	**$13.4**	**$21.4**	**$22.2**	**$9.6**	**$66.6**

Also included as Exhibit No. OGE-21 is a summary of the cash flow to debt impact of CWIP in rate base. These exhibits demonstrate that without CWIP in rate base OG&E's ability to pay the interest on its debt decreases. This is expressed as a percentage of funds generated from operations as a percent of debt.

Q. HOW WILL THE CWIP INCENTIVE BENEFIT OG&E'S CUSTOMERS?

A. As discussed above, a decrease in cash flow can impact credit ratings. Because investors consider credit ratings when determining the return they require to lend money, if the credit rating of a utility such as OG&E is downgraded, it increases the cost of debt. This, in turn, increases costs paid by OG&E transmission customers.

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[5] *See* Exhibit No. OGE- 20.

Q. ARE THERE OTHER WAYS IN WHICH THE CWIP INCENTIVE LOWERS RATES FOR CUSTOMERS?

A. Yes. Under the AFUDC approach, customers essentially pay a return (*i.e.*, the utility's authorized return) on a return (*i.e.*, the utility's carrying costs on CWIP), which results in higher overall construction costs and higher depreciation amounts. These expenses are lower with the CWIP incentive in place. Exhibit No. OGE-20 shows the difference in OG&E's net cash from operations that would result with CWIP included in rate base as compared to the AFUDC approach. As shown in the exhibit, over four years, OG&E would avoid the need to finance approximately $66.6 million of costs through the inclusion of CWIP in rate base. In this example, interest costs would be approximately $8.9 million less when CWIP is included in rate base.

Q. ARE THERE ANY OTHER BENEFITS TO CUSTOMERS OF THE CWIP INCENTIVE?

A. Yes. Rate shock can result when large-scale projects such as the ones included in this filing are placed into service and several years of construction costs are included in rate base all at once. By providing for a current return on construction costs, the CWIP incentive will stabilize rates and help avoid rate shock to OG&E's transmission customers.

VI. BENEFIT OF ABANDONED PLANT INCENTIVE

Q. WHAT IS THE BENEFIT TO OG&E OF THE ABANDONED PLANT INCENTIVE?

A. The Abandoned Plant incentive will provide OG&E, as well as potential lenders, the assurance that all prudently incurred costs will be recoverable even if the Projects need to be abandoned due to the substantial risks presented by the Projects, which are described in detail in Exhibit No. OGE-1 by Mr. Crissup.

VII. ACCOUNTING AND OTHER CWIP REQUIREMENTS

Q. PLEASE DESCRIBE HOW OG&E WILL CHANGE ITS ACCOUNTING PROCEDURES TO ACCOUNT FOR THE CWIP INCENTIVE.

A. The Commission's regulations require that any utility that includes CWIP in rate base must discontinue the capitalization of AFUDC in rate base with respect to the projects at issue.[6] The regulations also require that such utility propose accounting procedures that "[e]nsure that wholesale customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP proposed to be included in rate base;" and "[e]nsure that wholesale customers will not be charged for any corresponding AFUDC capitalized as a result of different accounting or ratemaking treatments accorded CWIP by state or local regulatory authorities."[7] To satisfy these requirements, OG&E will not accrue AFUDC in Account 107, Construction Work in Progress. Moreover, OG&E will use the SAP plant accounting system to maintain its accounting records for CWIP electric plant assets during construction and after the Projects are placed into service. The SAP

[6] 18 C.F.R. § 35.25(e) (2010).

[7] 18 C.F.R. § 35.25(f) (2010).

system includes the capability to identify specific work orders that should not be included in the calculation and capitalization of AFUDC. The work orders related to the Projects will be identified in SAP, and no AFUDC will be calculated on their balances. This will prevent a double-recovery of CWIP and capitalized AFUDC on the same rate base items. If OG&E is accorded different ratemaking treatment of CWIP by the OCC or APSC, any accrued AFUDC would be recorded in FERC Account 182.3 Other Regulatory Assets. The AFUDC regulatory asset would be amortized over the depreciable life of the Projects. The amortization amount would be debited to FERC Account 407.3 Regulatory Debits. The AFUDC regulatory asset and associated amortization would not be included in the rate charged to OG&E's wholesale transmission customers.

Q. HOW DOES OG&E PROPOSE TO COMPLY WITH THE SPECIFIC ACCOUNTING TREATMENT THE COMMISSION HAS REQUIRED WHEN A UTILITY PROPOSES TO RECOVER A CURRENT RETURN ON CWIP?

A. The Commission has noted that, where a utility proposes to recover a current return on CWIP, this cost is recovered in a different period than ordinarily would occur under the Uniform System of Accounts. Accordingly, to maintain the comparability of financial information among entities, the Commission has required utilities recovering a current return on CWIP to "debit through FERC Account 407.3, Regulatory Debits, and credit through FERC Account 254, Other Regulatory Liabilities, in accordance with the objectives of those accounts. Amounts recorded in FERC Account 254 related to return on the proposed

Project[s] must be deducted from the rate base."[8] However, the Commission has granted waiver of that accounting treatment and permitted utilities, in lieu, to use of footnote disclosures.[9] Consistent with this precedent, OG&E requests waiver of the specific accounting treatment and proposes instead to use footnote disclosures.

Q. HAS OG&E PREPARED STATEMENT BM, CONSTRUCTION PROGRAM STATEMENT?

A. Yes. Statement BM, Construction Program Statement, is attached to my testimony as Exhibit No. OGE-22.

Q. PLEASE SUMMARIZE THE CONTENTS OF THE STATEMENT BM YOU HAVE PREPARED.

A. Statement BM explains how the proposed Projects are prudent and consistent with a least-cost energy supply program. This statement describes how the SPP planning processes relevant to the Projects identify reliability and economic upgrades and how alternatives were considered to reduce costs to customers.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

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[8] *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058 at P 106 (2006), *order on reh'g*, 118 FERC ¶ 61,042 (2007).

[9] *See, e.g.*, *Tallgrass Transmission*, LLC, 125 FERC ¶ 61,248 at P 80 (2008) (referencing *American Transmission Company LLC*, 105 FERC ¶ 61,388 (2003), *order on reh'g*, 107 FERC ¶ 61,117 at PP 16-17 (2004); *Trans-Allegheny Interstate Line Company*, 119 FERC ¶ 61,219 (2007), *order on reh'g*, 121 FERC ¶ 61,009 (2007); and *Southern California Edison Company*, 122 FERC ¶ 61,187 (2008)).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company) Docket No. ER10-___-000

AFFIDAVIT

State of Oklahoma

County of Oklahoma

I, DONALD R. ROWLETT, being first duly sworn, depose and state that I am the witness identified in the foregoing Direct Testimony and Exhibits, that I prepared the testimony and exhibits and am familiar with their content, and that the facts set forth therein are true and correct to the best of my knowledge, information and belief.

Donald R. Rowlett

Donald R. Rowlett

Subscribed and sworn before me this 6th day of October, 2010.

Amanda Reyes

Notary Public

My commission expires: 4/3/11

AMANDA REYES
NOTARY
07003269
EXP. 04/03/11
PUBLIC
STATE OF OKLAHOMA

EXHIBIT NO. OGE-20

Summary of Cash Flow and Interest Impact

	2011	2012	2013	2014	4yr Total
No CWIP in Rate Base					
Net Cash from Operations	$ (2,079,253)	$ 11,688,133	$ 40,199,958	$ 82,929,787	$132,738,625
Interest on Debt	$ 4,964,070	$ 11,398,859	$ 17,373,855	$ 19,234,738	$ 52,971,522
Debt	$128,546,518	$227,667,838	$315,265,118	$285,820,451	N/A
CWIP in Rate Base					
Net Cash from Operations	$ 11,338,637	$ 33,039,883	$ 62,418,267	$ 92,569,378	$199,366,164
Interest on Debt	$ 4,534,698	$ 9,856,858	$ 14,437,612	$ 15,279,043	$ 44,108,211
Debt	$115,128,629	$192,898,198	$258,277,170	$219,192,912	N/A
Increase (Decrease)					
Net Cash from Operations	$ 13,417,889	$ 21,351,750	$ 22,218,309	$ 9,639,591	$ 66,627,540
Interest on Debt	$ (429,372)	$ (1,542,001)	$ (2,936,243)	$ (3,955,696)	$ (8,863,312)
Debt	$(13,417,889)	$(34,769,639)	$(56,987,949)	$(66,627,540)	N/A

Notes:

1. The projections shown above only represent the incremental cash from operations and interest expense associated with the 345kv transmission projects and do not contain any impacts from OG&E's other business
2. These projections make simplifying assumptions concerning timing of cap-ex spend and in-service dates
   a. Spending is assumed to be made ratably throughout the year
   b. Individual projects go in-service mid-year in the final year of planned cap-ex spend
   c. As a result, 2011 values may not be entirely consistent with OG&E's formula rate filing

EXHIBIT NO. OGE-21

Summary of Cash Flow to Debt Impact

2009 FFO/Debt	
Net income	$ 200,400,000
Depreciation	187,400,000
Change in deferred tax	202,800,000
Adj deferred tax to 5yr avg	(139,518,168)
Other non working capital	(64,400,000)
FFO	$ 386,681,832
Debt	$1,541,800,000
FFO / Debt	25.1%

2011-2014 Pro forma FFO/Debt, 345kv transmission projects without CWIP in Rate Base

	2011	2012	2013	2014
Base FFO	$ 386,681,832	$ 386,681,832	$ 386,681,832	$ 386,681,832
Change in cash flow	(2,079,253)	11,688,133	40,199,958	82,929,787
Pro forma FFO	$ 384,602,580	$ 398,369,965	$ 426,881,790	$ 469,611,619
Debt	$1,541,800,000	$1,541,800,000	$1,541,800,000	$1,541,800,000
Incremental debt	128,546,518	227,667,838	315,265,118	285,820,451
Pro forma debt	$1,670,346,518	$1,769,467,838	$1,857,065,118	$1,827,620,451
Pro forma FFO / Debt	23.0%	22.5%	23.0%	25.7%

2011-2014 Pro forma FFO/Debt, 345kv transmission projects with CWIP in Rate Base

	2011	2012	2013	2014
Base FFO	$ 386,681,832	$ 386,681,832	$ 386,681,832	$ 386,681,832
Change in cash flow	11,338,637	33,039,883	62,418,267	92,569,378
Pro forma FFO	$ 398,020,469	$ 419,721,715	$ 449,100,100	$ 479,251,210
Debt	$1,541,800,000	$1,541,800,000	$1,541,800,000	$1,541,800,000
Incremental debt	115,128,629	192,898,198	258,277,170	219,192,912
Pro forma debt	$1,656,928,629	$1,734,698,198	$1,800,077,170	$1,760,992,912
Pro forma FFO / Debt	24.0%	24.2%	24.9%	27.2%
Increase due to CWIP in Rate Base	**1.0%**	**1.7%**	**2.0%**	**1.5%**

EXHIBIT NO. OGE-22

STATEMENT BM
OKLAHOMA GAS AND ELECTRIC COMPANY
CONSTRUCTION PROGRAM STATEMENT

OG&E seeks authorization to include 100 percent of Construction Work In Progress ("CWIP") costs associated with the OG&E Projects ("Projects") in rate base. This Statement supplements the information provided elsewhere in this filing and provides the information required to satisfy the Commission's CWIP regulations at 18 C.F.R. § 35.13(h)(38) (2010) (Statement BM).

Under Section 35.13(h)(38) of the Commission's regulations, an applicant seeking to include CWIP in rate base is required to submit Statement BM in support of its request. Statement BM requires the applicant to explain, among other things, that the proposed project is prudent and consistent with a least-cost energy supply program. OG&E submits that the information provided below and elsewhere in this filing demonstrate that the Projects are prudent and consistent with a least-cost energy supply program.

As discussed in detail in the Crissup Testimony (Exhibit No. OGE-1), the Southwest Power Pool ("SPP") implements its Transmission Expansion Plan ("STEP") each year to plan ahead for transmission needs. STEP identifies both reliability and economic upgrades, and it accounts for upgrades paid for by SPP stakeholders and upgrades requested by customers during open seasons. The Projects are eight 345-kV transmission projects within the State of Oklahoma that have been approved by SPP through STEP. These Projects include:

1. The Hitchland-Woodward Project ("Hitchland-Woodward") is a double-circuit 345-kV, 120-mile transmission line that will extend from OG&E's Woodward District extra high voltage ("EHV") substation to Southwestern Public Service Company's

Hitchland substation, together with associated upgrades to the Woodward District EHV substation. The OG&E portion of the Hitchland-Woodward 345-kV line is estimated to be 82 miles in length, will cost approximately $178.6 million, and has an estimated in-service date of June 30, 2014;

2. The Woodward-Kansas Project ("Woodward-Kansas") is a double-circuit 345-kV, 80-mile transmission line to be built from OG&E's Woodward District EHV substation to the Prairie Wind LLC interception point at the Oklahoma-Kansas state line, together with associated upgrades to the Woodward District EHV substation. Woodward-Kansas is estimated to cost $134.4 million and has an estimated in-service date of December 31, 2014;

3. The Sooner-Cleveland Project ("Sooner-Cleveland") is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's Cleveland substation, plus associated upgrades to the Sooner substation. OG&E will construct the entire Sooner-Cleveland line. This project is estimated to cost $64 million, and has an expected in-service date of March 31, 2013;

4. The Seminole-Muskogee Project ("Seminole-Muskogee") is a single-circuit, 345-kV, 120-mile transmission line to be built from OG&E's Seminole substation to OG&E's Muskogee substation, as well as associated upgrades to both the Seminole and the Muskogee substations. Seminole-Muskogee has an estimated cost of $179.1 million and an estimated in-service date of December 31, 2013;

5. The Tuco-Woodward Project ("Tuco-Woodward") is a 345-kV, 250-mile transmission line from OG&E's Woodward District EHV to the SPS Tuco substation.

The OG&E portion of the Tuco-Woodward project is 72 miles in length and will terminate at a reactor station to be constructed at approximately the Oklahoma-Texas state border south of Interstate 40. The project has an estimated cost of $120 million with an estimated in-service date of May 19, 2014;

6. The Anadarko Project ("Anadarko") is a 345/138-kV substation to be constructed on the OG&E line from Cimarron towards the AEP Lawton East Side 345-kV line near the town of Gracemont, Oklahoma. Anadarko, also known as the Gracemont substation project, is expected to cost $14.6 million and has an estimated in-service date of December 31, 2011;

7. The Sunnyside-Hugo Project ("Sunnyside-Hugo") is a 345-kV, 120-mile transmission line to be built from OG&E's Sunnyside substation to the Western Farmers Electric Cooperative's Hugo Generation Plant, as well as associated upgrades to the Sunnyside substation. Sunnyside-Hugo is estimated to cost $187 million and has an estimated in-service date of April 1, 2012; and

8. The Sooner-Rose Hill Project ("Sooner-Rose Hill") is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation to an interface with a Westar Energy line segment at the Oklahoma-Kansas state line. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length, is estimated to cost $57.8 million and has an estimated in-service date of June 1, 2012.

The Projects are consistent with SPP planning studies, will improve reliability, eliminate existing and anticipated congestion on the transmission system and will reduce losses. The Projects are also part of a greater SPP regional Extra High Voltage ("EHV") transmission network that, in addition to the benefits listed above, will bring the benefits of wind generation developed in the western half of the SPP to load centers throughout the SPP region and, potentially, to densely populated areas outside of the region.

As discussed in detail in the Crissup Testimony (Exhibit No. OGE-1), each of the Projects was evaluated and approved by SPP through regional planning processes and subsequently included in the 2009 SPP Transmission Expansion Plan. Projects vetted and selected through SPP's planning processes strengthen the reliability of SPP's system and provide regional benefits by relieving congestion that already exists or that will exist due to requests for new transmission service. Each approved project must demonstrate a benefit-to-cost ratio of 1:1.

These SPP processes consider multiple alternatives that include general location of the transmission assets, voltage, costs, economic benefits and reliability considerations. For example, SPP's Priority Projects, which include Woodward-Kansas and Woodward-Hitchland and are intended to reduce grid congestion, were selected based in part on the results of engineering and economic analyses of potential projects.[1] An alternative group of projects was considered and rejected because the benefit-to-cost ratio was not as high as with the final project group.[2] Similarly, the primary goals of the Aggregate Facilities Study ("AFS") process, through which SPP determined Sunnyside-Hugo and Sooner-Rose Hill are necessary upgrades, are identifying and resolving system constraints and maintaining reliability.[3] Through the AFS process, SPP also must determine which "alternative solutions would reduce overall costs to

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[1] *See* 2009 SPP Transmission Expansion Plan at 13.

[2] *See* SPP Priority Projects Phase II Final Report at 5 (April 27, 2010).

[3] SPP OATT, Attachment Z1.

customers."[4] Finally, SPP's Balanced Portfolio projects, which include Sooner-Cleveland, Seminole-Muskogee, Tuco-Woodward, and Anadarko, are intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs."[5] To select these projects, SPP conducted an analysis of the adjusted production cost of several alternative projects. A final group of projects was selected based on a comparison of costs to benefits.[6] These SPP studies resulted in the inclusion of the OG&E Projects in the 2009 SPP Transmission Expansion Plan and subsequent approval by the SPP Board of Directors.

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4 *Id.*

5 SPP Balanced Portfolio Report (last revised June 23, 2009) at 3.

6 *Id.* at 6.

EXHIBIT NO. OGE-23

Fitch Downgrades OG&E's IDR to 'A'; Outlook Stable; Affirms OGE Energy and Enogex Ratings
28 Jun 2010 4:45 PM (EDT)

Fitch Ratings-New York-28 June 2010: Fitch Ratings has downgraded the Issuer Default Rating (IDR) of Oklahoma Gas & Electric Company (OG&E) to 'A' from 'A+'. In addition, Fitch has affirmed the 'A' IDR of OGE Energy Corp (OGE) and 'BBB' IDR of Enogex LLC (Enogex). The Outlook for all entities is Stable. Around $2.1 billion of debt is affected by these actions. See the full list of rating actions at the end of this release.

The one-notch downgrade of OG&E is driven by downward-trending credit metrics at the utility as it continues with a capital expenditure program that is significantly higher than the historical norm. The capex, which is being primarily channeled into wind, transmission and smart grid investments, is expected to remain elevated over the next several years based on known and committed projects. While OG&E enjoys constructive regulatory treatment for these investments and has minimal regulatory lag once these projects become operational, there is expected to be pressure on credit metrics during the construction period. Post 2011, as capex subsides, the credit metrics improve, but are forecasted to remain below Fitch's guideline ratios for the 'A+' category. Fitch expects OG&E's funds flow from operations (FFO)-to-total debt to stabilize around 22% and total debt to EBITDA at 3.4 times (x).

While evaluating the ratings for OG&E, Fitch acknowledges the positive regulatory environment that the utility enjoys, the diversity and size of capital projects being undertaken, and the constructive regulatory mechanisms for recovery on those projects. OG&E has been quite successful in obtaining pre-approval and recovery for the capital projects it has undertaken through rate riders that minimize regulatory lag by permitting it to recover costs associated with the project upon completion before the next general rate case proceeding. The riders ensure recovery of capital, operating costs and a return on investment. Notable examples include riders for the Redbud acquisition, storm recovery, system hardening, Windspeed transmission line and OU Spirit Wind project. Recently, OG&E reached a settlement with all the intervenors on its smart grid application. It also has an application pending before the Oklahoma Corporation Commission (OCC) regarding pre-approval and rider recovery for the Crossroads Wind project, a 200 megawatt (MW) proposed wind farm in Oklahoma.

Fitch's financial projections for OG&E assume a 1%-1.5% growth rate in electric sales over the forecast period, continued control over O&M expenses, and constructive regulatory outcomes in the pending and future rate proceedings. It is Fitch's expectation that OG&E will not undertake any large capital investment without obtaining a pre-approval from OCC that ensures a clear recovery mechanism. Other favorable regulatory mechanisms if implemented, such as cash recovery of capital costs during construction work in progress, would be viewed as credit enhancing by Fitch.

Enogex's ratings are supported by strong cash flows generated by its existing portfolio of natural gas transportation, storage, gathering and processing businesses that reflect moderate business risk. The ratings reflect the success management has achieved in shifting its processing revenue toward more fixed-fee contracts and hedging a majority of its commodity exposure over the next two years. Volume of fixed-fee contracts in the processing segment has increased from 8% in 2006 to a projected 30% in 2010. Furthermore, a majority of commodity risk in its keep-whole and percentage of liquids contracts has been hedged for years 2010 and 2011, respectively, providing visibility to credit metrics. In addition, the curtailment of capex and O&M over the last two years has benefited cash flows in times of commodity stress.

Enogex's assets are strategically located in the Oklahoma and Texas Panhandle, two areas that are very strong for natural gas production. Gathering operations have remained strong and are forecasted to grow by 7% in 2010. The unhedged processing segment is expected to benefit from the recovery in natural gas liquids prices in 2010. Looking forward, it is Fitch's expectation that Enogex would continue to migrate its commodity linked contracts to fixed fee and/or hedge a majority of its commodity risk.

Fitch expects Enogex to generate free cash flow after known and committed capex and upstream dividend payments to the parent over the forecast period. Fitch views Enogex's affiliation with its parent, OGE Energy, positively. Management has run Enogex conservatively with the aim to generate consistent stable cash flows and maintain an investment grade profile.

Despite strong credit metrics, the 'BBB' IDR is appropriate for Enogex in Fitch's view given the company is exposed to relatively higher commodity risk beyond 2011, since a very small amount of processing margin has been hedged. In addition, management's past attempts to monetize its interest in Enogex induce a level of uncertainty regarding future strategy for the company that Fitch is mindful of. Fitch would be concerned if management were to pursue a riskier business model, debt financed expansion strategy, or disproportionately grow commodity sensitive, non-fee based businesses.

OGE's ratings are supported by upstream dividend payments from its subsidiaries, OG&E and Enogex, relatively low leverage, consistent credit quality over our forecast period and prudent management of commodity exposure. Fitch expects OGE to derive more than 72% of its consolidated operating income from regulated businesses in 2010 and this proportion is expected to increase over Fitch's forecast period given the scale of capital expenditure at the utility. In Fitch's estimate, another 23% of consolidated income over the next two years is derived from predictable, stable cash flow businesses at Enogex that constitute natural gas transportation, storage, gathering and processing hedged and fixed-fee contracts, leaving the balance (5%) exposed to commodity prices. OGE and its subsidiaries have access to short-term liquidity through $1.23 billion of revolving credit facilities, of which $0.84 billion is currently available. There are no maturities of long-term debt till 2014.

Fitch would be concerned if OGE takes on additional leverage to support the heavy capex program at its utility. Other concerns include management of commodity risk at its Enogex subsidiary and uncertainty around future transactions involving Enogex.

The Stable Outlook for OGE, OG&E and Enogex assumes that the electric utility and the midstream businesses will continue to perform well, and the sensitivity of cash flows and working capital needs to changes in commodity prices will remain low. The Stable Outlook also assumes that the proportion of regulated and non-regulated fee-based businesses will continue to increase as a percentage of the consolidated operating income.

What would lead to consideration of a negative rating action?

--Increase in the proportion of commodity sensitive non-regulated businesses or a change in hedging strategy that would increase company's exposure to commodity prices;
--Aggressive capital expenditure program at OG&E not supported by pre-approved regulatory riders;
--Pursuing a more aggressive business model at Enogex.

What would lead to consideration of a positive rating action?

--At Enogex, a long-dated hedged profile or higher proportion of fixed-fee businesses that improve predictability of cash flows.

Fitch has downgraded the following ratings:

Oklahoma Gas & Electric Company
--Long-term IDR to 'A' from 'A+';
--Senior unsecured febt to 'A+' from 'AA-'.

Fitch affirms the following ratings:

Oklahoma Gas & Electric Company
--Short-term IDR and commercial paper (CP) at 'F1';

--Outlook Stable.

OGE Energy Corp
--Long-term IDR at 'A';
--Senior Unsecured Debt at 'A';
--Short-term IDR and CP at 'F1';
--Outlook Stable.

Enogex LLC
--Long-term IDR at 'BBB';
--Senior unsecured debt at 'BBB';
--Outlook Stable.

Applicable criteria available on Fitch's website at 'www.fitchratings.com' include:

--'Corporate Rating Methodology' Nov. 24, 2009;
--'Credit Rating Guidelines for Regulated Utility Companies' July 31, 2007;
--'U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines' Aug. 22, 2007;
-- 'Utilities Sector Notching and Recovery Ratings' (March 16, 2010); and
-- Parent and Subsidiary Ratings Linkage (Fitch's Approach to Rating Entities within the Corporate Group Structure)' (June 19, 2007).

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Additional information is available at 'www.fitchratings.com'.

EXHIBIT NO. OGE-24

STANDARD
&POOR'S

Global Credit Portal
RatingsDirect®

March 11, 2010

Assessing U.S. Utility Regulatory Environments

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Assessing U.S. Utility Regulatory Environments

*(**Editor's Note:** For our latest comments on regulated utility subsidiaries, please see "Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent," published March 11, 2010, on RatingsDirect.)*

The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most. In our credit analysis, we evaluate regulatory risk on a company-specific basis. A utility management's skill in managing regulatory risk can in many cases overcome a difficult regulatory environment. Conversely, other companies can experience greater regulatory risk even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. Operating in a state with a regulatory structure that is conducive to maintaining credit quality will improve the chances for a utility to successfully negotiate the regulatory maze.

This commentary discusses our views on what constitutes a favorable regulatory climate. We then use those factors to create assessments of the regulatory environments in states that regulate the electric and gas utilities that we rate. (See the table at the end of this article.) Our intention is to provide a common base for our own analysis of regulatory risk and to better communicate to investors, issuers, and regulators how various elements of regulation can affect credit quality. The exercise is also expected to enhance our ability to evaluate management by highlighting instances where our opinion of a company's regulatory risk diverges significantly from the fundamental quality of the regulatory jurisdictions where it operates.

The assessments of relevant jurisdictions are based on quantitative and qualitative factors. Importantly, we make our assessments from a credit perspective. We plan to update them annually or when significant events occur that have an important impact on the regulatory climate in a particular jurisdiction. The new regulatory assessment information augments the methodology applied to regulated utilities today.

Our introduction of these regulatory assessments coincides with what we view as the increasing influence of regulatory matters on the rated utilities' risk profiles and greater credit market awareness of the importance of understanding the regulatory process. Our goal in explaining our views on regulatory practices and policies and their effect on Standard & Poor's analysis of the credit quality of utilities is to provide additional transparency to the market.

Background

State utility regulation is almost as old as credit ratings. Standard & Poor's predecessor, Standard Statistics Bureau, was formed in 1906, and the first state utility commissions, as we know them today, appeared in 1907. Regulation has always been a factor in Standard & Poor's analysis of utility ratings, but its importance to our analysis has shifted with industry trends over time.

Before the 1970s, regulators presided for the most part over stable or decreasing rates as economic growth, rising consumption, and economies of scale drove costs down. The advent of inflation, rising and volatile fuel costs, and nuclear power missteps led to higher rates and, in our view, greater regulatory influence on credit quality during the 1980s. Restructuring in the natural gas and then the electric industries marked the 1990s and the first years of the new millennium, and the importance of regulatory issues in our analysis again started to subside. In our view, we are now in another era of increasing and unstable costs and some semblance of a return to traditional utility regulation. Consequently, the quality of regulation is at the forefront of our analysis of utility creditworthiness.

We have historically focused on regulatory risk on a company-specific basis. Nothing in what follows will change that approach. Utility commissions regulate diverse industries and adopt different approaches to different types of businesses. Treatment of utilities within the same industry can vary significantly in the same jurisdiction. The quality of the regulation experienced by a company is often the product of the company's management and business strategy as much as its regulators. The regulatory climate assessments only serve as a baseline of our opinion on the fundamental attitude of a jurisdiction toward the credit quality of the utilities in that state, and they are the starting point for Standard & Poor's analysis of the regulatory risk of each rated utility. Our goal is to achieve greater consistency and continuity in utility ratings.

Assessing Regulatory Jurisdictions

We assess jurisdictions on one basic attribute--the fundamental approach to controlling utility rates--and then in three major categories. The resulting assessments are based primarily on various measures of regulatory risk that are discussed briefly below. With respect to qualitative factors, we look for long-term, historical characteristics of the jurisdiction, as well as transient regulatory and political developments.

The foundation of our opinion of the regulation in a jurisdiction is the degree to which competitive market forces are allowed to influence rates. In order of credit-friendliness, a state will rely either on full cost-based regulation for all components of the utility bill, market-based mechanisms for generation, and (more rarely) retail markets, or a hybrid of the two to control the amount charged and the terms on which that service is offered. It may surprise some to learn that we consider a hybrid setup, which in most cases exists because the transition to some sort of competition has stalled, to harbor more risk for bondholders than a system that is committed to letting market prices set a major part of the customer's bill.

The risk inherent in the market-based model is straightforward: the price for electricity can be more volatile when based on a market than when it is based on embedded costs, and regulators are apt to resist full and timely recovery when changes in generation costs are abrupt and substantial (and perhaps misunderstood). The risks in a hybrid or transitional model are less apparent, but, in our opinion, potentially more significant. First, we consider the uncertainty of the timing of reaching the end state--and what that end state will look like--to be a negative factor from a credit perspective. Second, in some cases, the hybrid model may result in a "lower-of-cost-or-market" approach that allows generation rates to reflect one or the other at different times depending on which one suits ratepayers best. A utility and its bondholders may then face a prolonged period of potential exposure to market risk (the downside) with little or no opportunity to participate in the benefits of competition (the upside of greater returns).

After identifying the fundamental regulatory paradigm, our analysis turns to factors that influence the utility's business risk climate in the jurisdiction. The factors fall into three broad categories: ratemaking, political environment, and financial stability. Broadly speaking, the ratemaking and financial stability factors influence our assessments more than the paradigm and political factors.

Ratemaking Practices And Procedures

The main, and often the most contentious, task of a regulator is to set the rates a utility may charge its customers. We analyze specific rate decisions as part of the surveillance of each utility. Our regulatory assessments focus on the jurisdiction's overall approach to setting rates and the process it uses to conduct and manage base rate filings. Practices pertaining to separate tariff clauses for large expense items are examined in the third category of the analysis (see below). In this part of the assessment, we concentrate on whether established base rates fairly reflect the cost structure of a utility and allow management an opportunity to earn a compensatory return that provides bondholders with a financial cushion that promotes credit quality.

Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc. Although, in general, the absolute level of financial returns is less important to our analysis than how that return is earned, we recognize that, all else being equal, higher earned returns translate into better credit metrics and a more comfortable equity cushion for bondholders. A regulatory approach that allows utilities the opportunity to consistently earn a reasonable return is a positive factor in our view of credit quality.

The rates of return and capital structures used to generate the revenue requirement in rate proceedings may not be the primary focus of the assessment, but those and other decisions made in the ratemaking process are still noted. We consider those decisions to be potential signals from regulators on their attitude toward credit quality. We believe that the capital structure in particular is a handy and direct indication from the regulator as to whether or not creditworthiness is an important consideration in its deliberations when setting rates. Obviously, any pronouncements from a regulator that explicitly address credit ratings or ratemaking practices that incorporate credit-minded adjustments (e.g., the use of double-leveraged capital structures or off-balance-sheet debt-like obligations) are considered in the Standard & Poor's assessment.

We analyze the issue of "regulatory lag" in a comprehensive manner and not just as a matter of the efficiency of the regulator in completing rate cases. As part of this analysis, we evaluate the timeliness of rate decisions, coupled with an evaluation of the test year. In addition, we take into account the timing of interim rates, and other practices that affect the appropriateness of rates periodically established by the regulator. We do not view the issue of regulatory lag as an intermittent concern, consequential only during times of acute inflation or rising capital spending, but as a consistent part of our credit analysis. Accordingly, in our regulatory assessments we focus on whether the regulator efficiently prosecutes rate requests and bases its decisions with respect to rate setting on the most current information.

In our view, the prevalence of rate case settlements is not necessarily an important credit consideration. Although the common assumption among market participants seems to be that a settlement must be in the best interest of a utility, we believe this assumption disregards the possibility that management will sometimes make decisions based on its effect on earnings at the expense of cash flow considerations. This does not mean we dismiss the ability of stipulations to reach a fair resolution of difficult matters that help regulators issue timely and constructive rate decisions. It just means that frequent settlements do not, in our view, directly lead to a conclusion that the regulatory environment in a state enhances credit quality.

An important policy-related issue outside of individual rate cases that falls under this part of the assessment is the regulatory oversight of large capital projects with long lead times that carry out-sized risks to a utility and its bondholders. In our opinion, practices such as legislative or regulatory recognition of the need for pre-approval of such endeavors, periodic reviews that substantively involve the regulator in the progress of the project, and rolling prudence determinations during construction can reduce the general level of risk associated with a utility committing substantial capital well in advance of the rate proceeding that results in the project being placed into rate base. Before committing to such projects, a resource-procurement process that uses objective guidelines to evaluate competing proposals to meet load obligations and keeps the regulator informed and involved in the decisions can, in our view, help to reduce the risk of subsequent disallowances. If the jurisdiction has an Integrated Resource Plan or similar mechanism that includes the participation of many parties and is used to definitively establish the need for new generation, we consider credit risk to be further diminished.

One more factor that we examine in this part of the analysis is whether a jurisdiction employs nontraditional ratemaking practices. Examples of what we may view to be potentially credit-enhancing regulatory mechanisms include weather normalization and incentive ratemaking. We believe that the beneficial effect on credit quality of a tariff clause that smooths out cash flows that can vary with outside influences like weather is self evident. The benefits of incentives incorporated into the regulatory regime may be less clear. Well-designed incentives can be at least credit neutral. A moderate amount of incentives can be credit supportive. We generally view incentive provisions (whether tied to cost control, reliability, or operational performance) as being beneficial for credit quality if they are linked to fair and objective benchmarks. Incentives that lack some or all of those features, such as a plain, long-term rate freeze, can be, in our opinion, detrimental to credit quality.

Political Insulation

The role of politics in utility regulation is often misunderstood. In most jurisdictions, legislatures created regulatory commissions and invested them with the power to set and enforce utility rates and service standards. Regardless of how a regulatory commission is statutorily organized, its function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service but for other constituents as well. In this regard, bondholders should recognize that the setting of utility rates invariably reflects political as well as economic factors. Therefore, the potential for political considerations to affect utility regulation can be a key determinant when we assess a regulatory jurisdiction.

A primary factor in this part of our assessment is the method of selecting utility commissioners. In some jurisdictions, the governors appoint regulatory commissioners. In others, the same voters who pay utility bills directly elect commissioners. The regulatory risk associated with that model can sometimes be managed, but there is an inherent level of risk in elected regulatory bodies that we reflect in the assessment. Standard & Poor's also analyzes the track record of the involvement of the executive branch or the legislature in utility matters, and the relative visibility of utility issues in the political arena.

The ability of a regulator to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utility managers in managing business and financial risk can be affected by the overall atmosphere that it operates in. The tone can be set by the governor or legislature, the history and tradition of independence accorded to the regulatory body, and the behavior of important constituent groups that intervene in utility proceedings.

Cash Flow Support And Stability

The final set of factors in our assessment of regulatory environments is arguably the most important. The phrase "cash is king" can be overused, but it does highlight an essential part of the credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision making is one that will appeal to bondholders. Generating cash is a function of the actions of utility management, but the regulator can supply (or withhold) the tools that can affect the company's essential ability to actually realize the intended level of cash flow.

The most prominent factor in this part of the analysis is the application of separate tariff provisions for major expenses such as fuel and purchased power. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of the control of utility management is a key component of a credit-enhancing regulatory jurisdiction. We analyze the quality of special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect the analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part in the regulatory assessment.

The commission's policies and oversight covering hedging activities may also be a factor in this part of the review if a utility has sought regulatory approval. For utilities that attempt to manage commodity risks, we look for a clearly-stated hedging policy and a track record of activity that conforms to that policy. The responsibility for communicating the policy and demonstrating the prudence of the hedging activity rests with the utility, but the initial response to a hedging program and the history of the regulator's treatment of the results of the program could influence our assessment.

Regulators can employ other ratemaking techniques that promote stable cash flows. We consider a commission's decisions on rate design in assessing its attitude on credit quality. For example, we take into account the relative size of the typical monthly customer charge, a decoupling mechanism that severs the direct relationship between revenues and customer usage, or other rate design features that bolster credit quality.

Especially during upswings in the capital expenditure cycle, such as we are experiencing now, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true for ventures with big budgets and long lead times, such as baseload coal-fired or nuclear power plants and high-voltage transmission lines that are susceptible to construction delays. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were considered extraordinary measures for use in unusual circumstances, but in today's environment of rising construction costs and possible inflationary pressures, cash flow support could be crucial in maintaining credit quality through the spending program.

Jurisdictional Assessments

The table below shows Standard & Poor's assessments of regulatory jurisdictions. The category titles are designed to communicate one other important point regarding utility regulation and its effect on ratings. All categories are denoted as "credit-supportive". To one degree or another, all U.S. utility regulation sustains credit quality when compared with the rest of corporate ratings at Standard & Poor's. The presence of regulators, no matter where in the spectrum of our assessments, reduces business risk and generally supports all U.S. utility ratings.

Regulatory Jurisdictions For Utilities Among U.S. States

Most credit supportive	More credit supportive	Credit supportive	Less credit supportive	Least credit supportive
	Alabama	Arkansas	Louisiana	Arizona
	California	Colorado	Maine	Delaware
	Florida	Connecticut	Missouri	Dist. of Columbia
	Georgia	Hawaii	Montana	Illinois
	Indiana	Idaho	New York	Maryland
	Iowa	Kansas	Oklahoma	New Mexico
	South Carolina	Kentucky	Rhode Island	
	Wisconsin	Massachusetts	Texas	
		Michigan	Utah	
		Minnesota	Vermont	
		Mississippi	Washington	
		Nevada	West Virginia	
		New Hampshire	Wyoming	
		New Jersey		
		North Carolina		
		North Dakota		
		Ohio		
		Oregon		
		Pennsylvania		
		South Dakota		
		Virginia		

ATTACHMENT 8

ATTESTATION AS REQUIRED BY 18 C.F.R. § 35.13(D)(6) (2010)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Oklahoma Gas and Electric Company	)	Docket No. ER10-__-000
	)	

ATTESTATION

R. Sean Trauschke, being duly sworn, attests that he is **Vice President, Chief Financial Officer** for Oklahoma Gas and Electric Company, and that, to the best of his knowledge, information, and belief, the cost of service statements and other supporting data submitted as part of this filing are true, accurate, and current representations of the utility's books, budgets, or other corporate documents.

R. Sean Trauschke
R. Sean Trauschke
Vice President, Chief Financial Officer

Subscribed and sworn before me, this 7th day of

October, 2010.

Susie White
Notary Public

My Commission expires:

10/25/11