Southwest Power Pool

Aggregate Facility Study
SPP-2007-AG1-AFS-11
For Transmission Service
Requested by
Aggregate Transmission Customers

SPP Engineering, SPP Tariff Studies

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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. <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 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. <u>Model Development</u>

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. <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. <u>Transfer Analysis</u>

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. <u>Curtailment and Redispatch Evaluation</u>

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. <u>Appendix A</u>

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 - <u>X</u> 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 - <u>X</u> 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	Study Number
KCPS	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	**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	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	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	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	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	6/1/2013	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 amp	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 lin	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-win 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# 54752	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 161k\	12/1/2012	12/1/2012
KACP	MERRIAM - ROELAND PARK 161KV CKT 1	reconductor with 1192 acsr; upgrade term equip 1200 /	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 banl	11/1/2008	6/1/2009
MKEC	PRATT 115KV Capacitor	Install (2) 12 Mvar cap banks at Pratt 115k\	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 Cimarror	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 ACSF	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 transformer	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