ORIGINAL

Department of Energy
Western Area Power Administration
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PART 5 of 6

September 30, 2009

2009 OCT -1 A 10: 00

Honorable Kimberly D. Bose
Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Room 1A, East
Washington, DC 20426

Re: Western Area Power Administration
Docket No. NJ10-1-000

Dear Secretary Bose:

Pursuant to the Federal Energy Regulatory Commission's (Commission) Order Nos. 890, 890-A, 890-B, and 890-C,[1] and sections 35.28(e) and (f)(iv)(2) of the Commission's Regulations,[2] the United States Department of Energy, Western Area Power Administration (Western) hereby submits proposed revisions to its non-jurisdictional Open Access Transmission Tariff (Tariff). The primary purpose of this filing is to revise the terms of Western's Tariff to incorporate various modifications directed by the Commission in the aforementioned orders.

Enclosed please find the original and 14 copies of the proposed Tariff revisions. I have also enclosed an additional copy that I would appreciate being time-stamped and returned in the self-addressed envelope.

Western is a Federal Power Marketing Administration (PMA) that markets Federal power and owns and operates transmission facilities throughout 15 western and central states, encompassing a geographic area of 1.3 million square-miles. Western was established pursuant to section 302 of the DOE Organization Act.[3] Western's primary mission is to market Federal power and transmission resources constructed with congressional authorization. The Federal generation marketed by Western resulted from the construction of power plants by the Federal generating agencies, principally the Department of the Interior's Bureau of Reclamation and the U.S. Army Corps of Engineers. The power and transmission requirements of project use loads, which are designated by Congress and carry out purposes such as pumping of irrigation water, by law, must

[1] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 FR 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), order on reh'g, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 73 Fed. Reg. 39,092 (Jul. 8, 2008), 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 74 Fed. Reg. 12,540 (March 25, 2009), 126 FERC ¶ 61,228 (2009) (collectively, Order No. 890).
[2] 18 C.F.R. § 35.28(e) and (f) (2008).
[3] 42 U.S.C. § 7152(a) (2003).

be met first for the life of those projects. Power in excess of these requirements is available for marketing by Western to its preference customers. Western's statutory obligation to market Federal hydropower from a particular Federal project extends for the life of that project. Western owns and operates over 17,000 miles of high-voltage transmission lines, and has entered into long-term transmission contracts for widespread distribution of Federal hydro generation to project use and preference customers comprised of non-profit public entities such as electric cooperatives, Native American tribes, municipal utilities, and Federal and state government entities. Western's transmission system resides within both the Midwest Reliability Organization (MRO) and the Western Electricity Coordinating Council (WECC). Western has four Regional offices located in Phoenix, Arizona (Desert Southwest Region), Sacramento, California (Sierra Nevada Region), Loveland, Colorado (Rocky Mountain Region), and Billings, Montana (Upper Great Plains Region), as well as the Colorado River Storage Project Management Center located in Salt Lake City, Utah (collectively, Regions), and a Corporate Services Office located in Lakewood, Colorado. Western's Regions have reserved sufficient transmission capacity on the systems they manage to meet their existing statutory obligations regarding project use and preference power deliveries. Those obligations are accounted for in each project's marketing plan, which is, in turn, implemented through existing contracts for the provision of hydroelectric capacity and/or energy.[4] In addition, Western's transmission system is used by third parties for network and point-to-point transmission service purposes; therefore, Western has contractual obligations it must meet under a myriad of existing transmission agreements which were executed before and after Western's Tariff became effective.

Western is not a public utility subject to the Commission's jurisdiction under sections 205 and 206 of the Federal Power Act (FPA).[5] Western is, however, a transmitting utility subject to FPA sections 210-213,[6] and has provided open access transmission service since its inception in 1977. The revisions Western proposes below are primarily intended to revise the terms and conditions of Western's existing Commission-approved Tariff to incorporate various modifications directed in Order No. 890.[7] Western also proposes relatively minor revisions to its Commission-approved Large Generator Interconnection Procedures and Agreement and Small Generator Interconnection Procedures and Agreement (LGIP, LGIA, SGIP, and SGIA, respectively),[8] mostly to eliminate certain discrepancies with Western's governing statutes and long-standing contractual practices that have come to light as Western has gained more experience administering the Commission's standard interconnection procedures.

Western has two points of clarification regarding its compliance with Order No. 890. First, with respect to the matter of redispatch cost posting, Western notes that Order No. 890 directed transmission providers to calculate and post on the OASIS a monthly average cost of redispatch for each internal congested transmission facility or interface over which it provides redispatch

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[4] The majority of these contracts do not terminate until December 31, 2020, at the earliest.

[5] 16 U.S.C. §§ 824d and 824e (2000).

[6] 16 U.S.C. §§ 824i-824l (2000).

[7] Insofar as Western is not subject to the Commission's jurisdiction under FPA section 205, Western is not seeking the Commission's approval under FPA section 205 to continue including previously-approved non-rate terms and conditions in its Tariff that differ from those set forth in Order No. 890. See Order No. 890 at P 135.

[8] See Western Area Power Administration, 112 FERC ¶ 61,044 (2005). See also Western Area Power Administration, 119 FERC ¶ 61,239 (2007); and the Commission's delegated letter order issued on September 6, 2007, in Docket No. NJ07-2-001.

service using planning redispatch or reliability redispatch under the pro forma Tariff. Nonetheless, the Commission indicated in Order No. 890-A that a transmission provider may propose a variation from the pro forma Tariff to allow for the posting of actual billing data if the transmission provider believes it is too burdensome to average the data prior to posting.[9]

At this time, however, it is not possible for Western to foresee the amount of redispatch that will be provided in the future by its Regions given the markedly differing circumstances among the various Federal projects; therefore, it is not possible for Western to foretell the associated cost calculation and posting workload and whether it will constitute a burden on Western's limited staff resources. Consequently, rather than attempt to revise its Tariff to provide a case-by-case approach to posting the data, Western hereby commits for the sake of transparency to post a notification on the applicable OASIS site if and when future workload and resource issues necessitate that a Region begin posting actual billing data in lieu of average data.

Second, with respect to the designation and undesignation of network resources, although Western's Regional Available Transfer Capability (ATC) methodologies do not currently account for the effects on ATC of short-term undesignations of network resources, it is probable that they will do so in the future, meaning that in certain cases Western reasonably could allow its network customers to forego undesignating network resources to make firm sales of less than one year. However, it is unlikely that all of Western's Regional ATC methodologies will reach this point at the same time; therefore, rather than attempt to revise its Tariff to provide a case-by-case approach on this matter, if and when each of Western's Regions decide to revise their ATC methodologies to account for the effects on ATC of short-term undesignations of network resources, they will post on the OASIS a business practice allowing network customers to forego undesignating network resources to make firm sales of less than one year. At the point where all of Western's Regional ATC methodologies make such an account, Western will revise its Tariff accordingly.

As provided by sections 35.28(e) and (f)(2) of the Commission's Regulations[10], Western requests that the Commission issue a declaratory order determining that with this filing, Western's Tariff maintains its status as a "safe harbor" Tariff, ensuring that it may not be denied transmission access by any Commission-jurisdictional public utility. Western has already developed transmission rates for use in the Tariff under separate public processes pursuant to applicable Federal law and regulation, and those rates have already been approved by the Commission. To the extent a specific rate does not exist for a service provided under the Tariff (i.e., Schedule 9 and Schedule 10), Western will adopt rates for those services in Region specific rate proceedings as described in more detail below.

The Commission found in Order No. 890 that a non-public utility such as Western that already has a safe harbor Tariff must amend its Tariff so that its provisions substantially conform or are superior to the revised pro forma Tariff if it wishes to continue to qualify for safe harbor treatment.[11] Western respectfully submits that this filing complies with the Commission's mandate.

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[9] Order No. 890 at P 1162, and Order No. 890-A at P 625, respectively.

[10] 18 C.F.R. § 35.28(e) (2008) and 18 C.F.R. § 35.28(f)(2) (2008).

[11] Order No. 890 at P 191.

I. PROPOSED REVISIONS TO WESTERN'S TARIFF DOCUMENTS

A. Tariff

1. Sections 1.5 and 19.2

To address the requirement in Order No. 890 that transmission providers include Tariff language in their compliance filings describing how the transmission provider will process requests for cluster studies and how it will structure transmission customers' obligations when they have joined a cluster, Western proposes to add a new term "Clustering" in section 1.5 of its Tariff, and also to add the requisite clustering provisions to section 19.2. Western's proposed language is based largely on that filed by Public Service Company of New Mexico (PNM), which the Commission accepted without modification.[12] To the extent that Western's proposed language is more restrictive than that filed by PNM, Western notes that Order No. 890 gave each transmission provider discretion to develop the clustering procedures it will use, because the transmission provider is in the best position to determine the clustering procedures that it can accommodate and that will prevent a customer from strategically participating in clusters to avoid costs for needed transmission system upgrades.[13]

2. Sections 1.29 and 1.43

During the informal public process that Western conducted regarding the revisions proposed in this filing,[14] a commenter suggested that Western add ancillary services into the definition of the term "New Rate" in section 1.29 of Western's reciprocity Tariff. Western agreed with the commenter's suggestion. The term "New Rate" was incorporated into Western's Tariff through a previous revision process. This was done to accommodate new language added concurrently in section 1.0 of Attachment J to Western's Tariff regarding change of rates. However, Western's review indicated that the phrase "ancillary services" was inadvertently omitted from the term's definition.[15] Consequently, Western has modified section 1.29 of its Tariff so that the term "New Rate" is now defined as "the modification of a Rate for transmission or ancillary services provided by the Transmission Provider, ~~that~~ which has been promulgated pursuant to the rate development process outlined in Power And Transmission Rates, 10 C.F.R. Part 903 (2006)."

Western's review also indicated the presence of a ministerial error in section 1.43 of its revised Tariff. For that reason, Western has revised this provision so that the term "Rate Adjustment" is now defined, in pertinent part, as "a change in an existing rate or rates, or the establishment ~~or~~ of a rate or rates for a new service."

[12] Public Service Co. of New Mexico, 122 FERC ¶ 61,176 at P 14 (2008).
[13] Order No. 890 at P 1371.
[14] See the relevant documents posted at http://www.wapa.gov/transmission/oatt.htm.
[15] See Western's August 3, 2005 and June 20, 2007 filings in Docket Nos. NJ05-1-001 and -002, respectively.

3. Sections 1.45, 10.1, 16.2, 19.3, 19.4, 21.1, 29.3, 30.6, 31.5, 32.3, and 32.4

As Western has explained in previous filings,[16] Western is a non-profit Federal PMA that implements strict cost controls on all aspects of its business, including the establishment of cost-effective staffing levels relative to Western's role as a transmission owner and provider throughout multiple states. In addition, as a Federal entity, Western is subject to executive and congressional oversight regarding staffing, funding, and authorization limits. Funding levels for these items may be established that limit Western's ability to meet various transmission and interconnection study deadlines. For these reasons, Western proposed in its previous filings, and the Commission approved in its subsequent orders, global modifications to Western's LGIP, LGIA, SGIP, and SGIA intended to allow Western to meet its interconnection study and other deadlines using "Reasonable Efforts," as that term is defined in the aforementioned documents. Similarly, to alleviate the conflict between Western's statutory staffing and funding limitations and the Commission's goal of strict adherence by jurisdictional transmission providers to the Tariff's 60-day transmission study timelines, Western proposes to include in section 1 of its Tariff the term "Reasonable Efforts" and to use that term in its Tariff's transmission study timeline and metric provisions rather than the undefined term "due diligence." Further, Western has capitalized existing instances of the phrase "reasonable efforts" in the Tariff to reflect this definition.

4. Sections 7.2(b) and 11, and Attachment Q

Western has revised section 7.2(b) of its Tariff for the purpose of implementing new Attachment Q to its Tariff,[17] and has also revised section 11 to conform it to the relevant modifications directed by Order No. 890. As a result of these revisions, Western has modified changes to this section approved by the Commission in Western's January 25, 2005, Filing because Western's earlier changes to these sections are no longer necessary with the inclusion of the new Attachment Q to the Tariff.

New Attachment Q to Western's Tariff provides for the creditworthiness review procedures as directed by Order No. 890. In developing these procedures, Western evaluated industry best practices for determining creditworthiness based on compliance filings submitted by various transmission providers, and on clarifications and findings stated by the Commission in its related orders. Western's proposed creditworthiness review procedures are relatively limited in scope and administrative complexity. Nonetheless, they specify the qualitative and quantitative criteria that Western will use to determine the level of secured and unsecured credit required, and they contain the procedural and other elements described in Order No. 890.

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[16] See Western's January 25, 2005, and March 1, 2007, filings in Docket Nos NJ05-1-000 and NJ07-2-000, respectively (January 25, 2005 Filing and March 1, 2007 Filing, respectively).

[17] Western notes that it submitted through an informational filing, and the Commission acknowledged in a subsequent delegated letter order, language added to section 7.1 of Western's Tariff regarding potential advance payment for transmission services. Western equated the Commission's acknowledgment to its approval of the added language, and, as such, Western did not redlined that language in this filing. See Western's October 31, 2007 filing in Docket No. NJ08-1-000; and the Commission's relevant delegated letter order issued on November 16, 2007.

5. Section 9

Western's original safe harbor Tariff filing removed pro forma language from section 9 of its Tariff.[18] This language was removed to reflect the fact that Western is not a public utility, and is not subject to the Commission's jurisdiction under FPA sections 205 and 206. Because Western does not fall under the jurisdiction of the Commission in those sections, Western does not submit its Tariff agreements for Commission approval, nor does it seek Commission approval to terminate those agreements. An unintended consequence of this change, however, is the potential for confusion on the part of interconnection and transmission customers regarding how any future changes to Western's Tariff would apply to them.

Rather than continue to eliminate the entire first paragraph of the pro forma language from section 9, Western has reintroduced the first paragraph of section 9 from the Commission's original pro forma Tariff with succinct modifications. These modifications make it clear that any future Tariff changes regarding terms and conditions, classification of service, or Tariff agreements will be consistent with the Commission's rules and regulations and will apply to Western's existing Tariff documents, while retaining the elimination of applicability of FPA sections 205 and 206.

Western believes these changes more closely reflect the intent behind the removal of the entire first paragraph of section 9 in Western's original safe harbor Tariff filing, while still accommodating Western's unique status as a non-jurisdictional Federal PMA. In that regard, Western has left intact the second paragraph of section 9 of its Tariff, which does not affect the ability of a transmission or interconnection customer taking service under the Tariff to exercise any rights it has under the FPA and the Commission's rules and regulations.

6. Section 13.1

Two of Western's Regions (Desert Southwest and Sierra Nevada) currently offer hourly firm point-to-point transmission service due to customer demand for such a product, and those Regions fully account for the transmission usage in their respective ATC methodologies. Because all of Western's Regions currently do not offer this voluntary product, the Regions that do offer it have established the terms and conditions for its use under Regional business practices posted on their OASIS sites. To date, however, Western's Tariff did not explicitly recognize this fact, and Western has revised section 13.1 of its Tariff to correct this oversight.

7. Section 13.2

To address Order No. 890's requirements regarding the implementation of a simultaneous submission window by transmission providers who set a "no earlier than" time limit for transmission service requests, Western proposes to add the necessary language to section 13.2 of its Tariff. Western's proposed language uses a lottery capacity allocation methodology that

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[18] See Western's December 31, 1997 filing in Docket No. NJ98-1-000 (December 31, 1997 Filing); and Missouri Basin Municipal Power Agency, United States Department of Energy – Western Area Power Administration, 99 FERC ¶ 61,062 (2002) (April 12, 2002 Order).

largely mirrors the methodology filed by the Mid-Continent Area Power Pool (MAPP) and approved by the Commission.[19]

8. Sections 13.7(c), 14.5, and 28.6, and Schedule 10

As discussed in more detail below, Western determines its transmission and related rate methodologies on a Federal project-by-project basis under public rate processes as required by Federal regulation.[20] Those specific rates and methodologies are promulgated under individual rate schedules applicable to each project and incorporated by reference into Western's Tariff.[21] Consistent with this approach, Western proposes to include a new Schedule 10 in its Tariff to incorporate by reference any project-specific unreserved use penalty rate schedules that Western chooses to establish in the future, and to revise the relevant Tariff provisions (i.e., sections 13.7(c), 14.5, and 28.6) to reference new Schedule 10 to accommodate the unreserved use penalty methodology established in Order No. 890. Individual project rate schedules will be made effective on or after the later of either the date Western's Tariff revisions become effective or the date any existing rate schedule implementing an unauthorized use penalty rate expires.

9. Section 15.4

A key requirement of the Federal Anti-Deficiency Act[22] restricts Western from obligating funds which have not yet been congressionally appropriated or authorized for expenditure, and thus, Western's obligation under the Tariff to expand or modify transmission facilities must be limited accordingly. Section 28.2 of Western's Tariff contains Commission-approved non-pro forma language that codifies such a limitation for network service requests;[23] however, Western's prior Tariff filings inadvertently omitted this language from the equivalent provision in section 15.4 for firm point-to-point service requests. Therefore, Western has revised section 15.4 so that it now includes the requisite language.

10. Sections 17.3 and 29.2

In a previous filing, Western added language to sections 17.3 and 29.2 of its Tariff to re-introduce the deposit requirement for transmission requests of one year or longer, and also to introduce an escrow alternative to the deposit.[24] However, in so doing, Western erred by using the term "Transmission Customer" in certain instances rather than the proper term "Eligible Customer." Consequently, Western has revised sections 17.3 and 29.2 to remedy this error.

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[19] See Mid-Continent Area Power Pool, 123 FERC ¶ 61,177 (2008); and the Commission's delegated letter order issued on September 23, 2008, in Docket No. OA07-51-002.
[20] 10 C.F.R. Part 903 (2009).
[21] See Western's December 31, 1997 Filing.
[22] 31 U.S.C. § 1341(a)(1)(2003).
[23] See Western's December 31, 1997 Filing.
[24] See Western's January 25, 2005 Filing.

11. Sections 19.10 and 32.5

Western has omitted the language in its filing that subjects the transmission provider to payment of monetary penalties for failing to complete transmission studies within 60 days, as well as the requirement to file a notice with the Commission with respect to late studies. However, Western has retained the requirement under which the transmission provider tracks the number of studies it fails to complete on time. Western intends to use Reasonable Efforts to meet the study deadlines and intends to track its performance. Western is omitting only the penalty provision itself.

The Commission has already approved a reciprocity Tariff that omitted the requirement to file a notice with the Commission regarding late studies[25] and payment of penalties.[26] Western is also omitting the payment of the penalties themselves for three reasons. First, Western is a non-jurisdictional entity and the Commission's penalty authority regarding late studies does not extend to Western. Therefore, it would not be appropriate for Western to include the penalty provision in its reciprocity Tariff.

Second, under the pro forma Tariff, the transmission provider must pay the penalties to its customers. The Commission has said that public utilities may not include the penalties in their rates.[27] Western is statutorily required to set its rates to fully recover its costs, and the Commission is required to approve Western's rates if the revenue generated by the rates are sufficient to recover Western's costs consistent with its statutory and regulatory obligations.[28] One significant statutory obligation Western must meet is to set its rates as low as possible consistent with sound business principles.[29] Therefore, Western must include any penalties it pays within its rates to comply with these unique statutory obligations, and paying penalties to customers that must then be recovered from those same customers in accordance with existing statutes would only impose administrative costs on Western and its ratepayers with no tangible benefit. Third, Western is a non-public utility and not subject to the Commission's penalty authority regarding the payment of late studies. The Commission has approved a similar approach in Bonneville Power Administration's Tariff filing (BPA Filing).[30]

Except for the penalty provisions, Western intends to adhere to the directives in Order No. 890 regarding the completion of studies. That is, Western will use Reasonable Efforts to complete the studies within the study deadlines, it will track the percent of non-affiliates' studies that it completes outside of the deadlines, and it will post study metrics regarding its performance under these sections as provided in Order No. 890. Therefore, instead of simply deleting new sections 19.9 and 32.5 of the pro forma Tariff, which provide for the study penalties, Western has amended them to provide that Western will use Reasonable Efforts in the completion of studies,

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[25] East Kentucky Power Coop, Inc., 121 FERC ¶ 61,012 (2007).
[26] United States Department of Energy - Bonneville Power Administration, 128 FERC ¶ 61,057 (2009) at P 65
[27] Order No. 890 at P 1357.
[28] 43 U.S.C. § 485h(c) (2007), 16 U.S.C. § 825(s) (2000), 18 C.F.R. Part 300 (2008), and 10 C.F.R. Part 903 (2009)

[29] 16 U.S.C. § 825s (2000).
[30] United States Department of Energy - Bonneville Power Administration, 128 FERC ¶ 61,057 (2009) (Bonneville) at P 65.

and will track and post its performance in completing studies for both point-to-point and network service. Western intends to adhere to the Commission's study penalty regime up to the point at which legal issues intrude.

Finally, Western has renumbered section 19.9 of the Tariff to reflect new section 19.2 discussed previously, and also has replaced in sections 19.9 and 32.5 instances of the term "due diligence" to accommodate Western's use of Reasonable Efforts to complete transmission studies within the 60-day timelines, as discussed previously.

12. Sections 19.11 and 32.6, and Attachment J

Western noted in previous filings that it must comply with its statutory obligations regarding the National Environmental Policy Act (NEPA).[31] However, Western has experienced difficulty in having transmission and interconnection customers execute the necessary documents in a timely manner to comply with NEPA and other environmental and natural resource statutes. As a result, Western in this filing has generally outlined its NEPA compliance obligations in section 16.0 of Attachment J to its Tariff, and has inserted mandatory deadlines for execution of environmental agreements in sections 19.11 and 32.6 of its Tariff.

Because the standard pro forma documents do not generally inform customers of Western's obligations to comply with applicable environmental and natural resource laws, such as NEPA, Western added a provision in section 16.0 of Attachment J to its Tariff to notify both transmission and interconnection customers of Western's obligations. Western has historically used Attachment J to reference any unique obligations it has due to its status as a Federal PMA.[32] The additional provisions also make clear to Western's transmission and interconnection customers that they must comply with all environmental laws, regulations and resource protection measures, including but not limited to any mitigation measures and Best Management Practices associated with the approval of a project and the associated Transmission [or Interconnection] Customer's requested service. Attachment J also informs a customer that Western's decision to execute an agreement is dependent on the conclusions reached in the record of decision under NEPA, or other appropriate NEPA decision document.

Western has also added specific language into its Tariff at sections 19.11 and 32.6 to inform transmission and interconnection customers of the obligation to execute an environmental review agreement that outlines the environmental obligations required for a specific project. Western has posted examples of the generic clauses that will be included in the environmental review agreement on its OASIS.[33] To the extent that projects require specific mitigation measures or other Best Management Practices, those requirements will be included in the individual project's service agreements, construction contracts, or environmental compliance contracts, as appropriate. The parameters for entering into those agreements are contained in the generic environmental review agreement clauses described above. The purpose of these provisions is to

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[31] 42 U.S.C. § 4321, et seq. (2003). [?]
[32] See, generally, Western's January 25, 2005 Filing at p. 9-11.
[33] See the EIS and EA Environmental Review Agreement templates posted at http://www.wapa.gov/transmission/oatt.htm.

obligate the customer to any initial as well as ongoing environmental obligations it has as a result of any transmission service taken or interconnection permitted on Federal transmission facilities. The Commission has already approved a similar approach in the BPA Tariff filing.[34]

13. Section 23.1

Western has not adopted the provisions of Order No. 890 removing the price cap on the resale of transmission capacity. Western will retain the original pro forma language that allows a transmission customer to reassign its transmission capacity. Accordingly, the rate for capacity reassignment will continue to be capped at the original transmission rate charged to the assignor, Western's maximum stated firm transmission rate in effect at the time of reassignment, or the assignor's own opportunity costs capped at Western's costs of expansion.

Western is not removing the price cap on the resale of transmission capacity because doing so would be inconsistent with Western's obligations under Reclamation Law. Specifically, removal of the price cap and allowing resale of Western's transmission capacity conflicts with the spirit and intent, if not the letter, of the preference clause embodied in both section 9(c) of the Reclamation Project Act of 1939 (Section 9(c)) and section 5 of the Flood Control Act of 1944 (Section 5).[35] These two clauses primarily establish the guidelines that govern Western's mission.

Section 5 refers to the transmitting of power as well as the construction of transmission facilities. Section 5 of the Flood Control Act requires the Secretary to ". . . transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles . . . ." Further, the authority and principals Western is required to use to set rates for the sale of power and energy under Section 9(c) are applicable to its ratemaking authority used to set transmission rates. As a result, Western is required to set its transmission rates to recover sufficient revenue to cover its construction, operation, and maintenance costs and an appropriate share of any fixed costs as determined by Western's Administrator. The courts have interpreted Section 9(c) as granting wide discretion to Western's Administrator in marketing Federal power.[36]

Because Western does not make a profit on the sales of the use of its transmission facilities, it would not be appropriate for Western to allow a third party to resell Western's Federal transmission system capacity at a profit. Doing so would be inconsistent with Western's obligation to "transmit and dispose of power and energy" at the "lowest possible rates to consumers." That is, Western cannot establish rates for the sale of its transmission assets over and above its associated costs, and Western interprets the aforementioned statutes as not providing for third parties to do so either. It appears the Commission's resale proposal is an attempt to create economic incentives in an industry that generally has a broader purpose than Western does. Western's mission is more narrowly focused and, as a result, the Commission's

[34] See Bonneville Power Administration's October 3, 2008 filing in Docket No. NJ09-1-000 at p. 17-18; and United States Department of Energy - Bonneville Power Administration, 128 FERC ¶ 61,057 (2009) at P 12.

[35] 16 U.S.C. § 825(s) and 43 U.S.C. § 485h(c), respectively.

[36] City of Santa Clara v. Andrus, 572 F.2d 660, 667-668 (9^{th} Cir. 1978), cert. den., 439 U.S. 859 (1979).

proposal is not consistent with the requirements for providing service over Western's Federal transmission system, which was not created, nor is it intended to be marketed, for purely economic purposes.

Additionally, Western has deleted the language from section 23.1 of the pro forma Tariff pertaining to the transmission provider charging and crediting the reseller and assignee for the reassigned service. This is due to the fact that Western will not act as the financial intermediary between the reseller and assignee; instead, as provided in revised Attachment A-1 of Western's Tariff, Western will continue to charge the original reselling transmission customer as set forth under the original Tariff agreement, and that customer will in turn charge the assignee for the reassigned capacity at their negotiated rate, subject to the pricing cap retained in section 23.1 of Western's Tariff. Therefore, Western will not charge the assignee for reassigned capacity, and the mechanism to account for any difference between the rates charged by Western to the reseller and by the reseller to the assignee will be provided under separate billing arrangements to be negotiated and executed by the reseller and the assignee.

14. Section 29.2(v)

Western has revised section 29.2(v) of the pro forma Tariff so that it conditionally requires network customers to identify the source control area of off-system network resources at the time of designation. Such information is unnecessary for Western's Regions that are situated in WECC, insofar as they use the rated path methodology to determine ATC.[37] Conversely, Western's Upper Great Plains Region uses a flow-based methodology to determine ATC, and, as such, it is necessary for that Region to require its network customers to identify the source control area of off-system network resources.

15. Section 30.9

As modified by Order No. 890, the first revised sentence in section 30.9 of the pro forma Tariff includes the phrase "[the effective date of a Final Rule in RM05-25-000]." To prevent confusion among Western's transmission customers, Western has replaced that phrase with the actual effective date of Order No. 890, and has also added a clarifying note regarding that date.

16. Section 35.2

Order No. 890 deleted from section 35.2 of the pro forma Tariff references to the North American Electric Reliability Council and the regional reliability councils and substituted references to the Electric Reliability Organization (ERO). However, as noted previously, Western's multi-state transmission service territory resides within both MRO and WECC. Each of these regional reliability organizations (RRO) has been delegated certain responsibilities for reliability standards compliance monitoring and enforcement, and WECC in particular actively continues to develop and institute region-specific reliability standards and associated business practices. For these reasons, Western has modified section 35.2 so that it references the reliability guidelines of the ERO and the applicable RRO, rather than only those of the ERO.

[37] See, e.g., Puget Sound Energy, Inc., 120 FERC ¶ 61,232 at P 10 (2007).

17. Schedules 4 and 9

Western has modified Schedule 4 and new Schedule 9 of the pro forma Tariff to reflect the fact that Western determines its transmission and ancillary service rates and formula methodologies on a Federal project-by-project basis under public rate guidelines as consistent with existing statute and regulation,[38] and that Western promulgates those rates and formula methodologies under the appropriate rate schedules applicable to each project. In so doing, Western removed the language from Schedules 4 and 9 pertaining to the tiered imbalance methodology, and included in Schedule 9 non-pro forma Tariff language previously accepted by the Commission indicating that the specific charges for Generator Imbalance Service are to be set forth in the appropriate rate schedule and providing for changes to the rate methodology.[39] These changes ensure that the outcome of the statutorily mandated public processes related to project-specific imbalance service rates will not be improperly predetermined by language in Western's voluntary reciprocity Tariff. Further, Western made a ministerial revision to Schedule 4 to remove language that has been rendered obsolete due to the fact that all of Western's Regions now have Energy Imbalance rate schedules in effect.

18. Attachment A-1

Similar to certain Commission-approved modifications that Western made in the past,[40] Western has revised new Attachment A-1 of the pro forma Tariff to ensure conformance between Western's long-standing Federal contractual practices and its as-filed forms of service agreement, and to make it consistent with the other forms of agreement in its Tariff. The Commission has previously accepted similar revisions.[41] In addition, Western has modified Attachment A-1 to clarify that the reassignment service agreement is subject to the terms and conditions of the relevant service agreement between Western and the original transmission customer, and to reflect Western's modifications to the billing provisions in revised section 23.1 of the Tariff, as discussed previously.

19. Attachment C

Western has modified Attachment C to its Tariff to provide Western's ATC methodologies as directed by Order No. 890. Western's Attachment C is bifurcated to reflect the fact that Western's transmission system resides within both MRO and WECC. Western's development of Attachment C was informed by the related Order No. 890 compliance filings of certain parties in the MAPP and WestConnect footprints, as well as by the Commission's findings pertaining to those filings.[42]

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[38] 43 U.S.C. § 485h(c) (2007), 16 U.S.C. § 825(s) (2000), 18 C.F.R. Part 300 (2008), and 10 C.F.R. Part 903 (2009)

[39] See Western's December 31, 1997 Filing; and the April 12, 2002 Order.

[40] See Western's January 25, 2005 Filing and March 1, 2007 Filing.

[41] E.g., Western's March 1, 2007 Filing at p. 5.

[42] E.g., Arizona Public Service Co., 123 FERC ¶ 61,024 (2008); and the Commission's delegated letter orders issued on March 28, 2008, and August 21, 2008, in Docket Nos. OA07-90-000, et al., and OA07-90-003, respectively.

20. Attachment D

Western has revised Attachment D to its Tariff to reflect the fact that WECC annually submits to the Commission a System Impact Study Methodology on behalf of each of its member systems, including Western's Regions that are situated within WECC.

21. Attachment K

Inasmuch as Order No. 890 directed that all instances in the pro forma Tariff of the term "Available Transmission Capability" be replaced with "Available Transfer Capability," Western has made a conforming change in the third paragraph of Attachment K to its Tariff. Western has also made some minor ministerial corrections to Attachment K.

22. Attachment N

Western has modified Attachment N to its Tariff to incorporate by reference the revised North American Electric Standards Board Wholesale Electric Quadrant standards as required by Order No. 676-C.[43]

23. Attachment O

New Attachment O ("Procedures for Addressing Parallel Flows") to Western's Tariff incorporates the language required by the Commission in its orders accepting, as modified, certain Order No. 890 compliance filings submitted by public utility transmission providers.[44]

24. Attachment P

Proposed new Attachment P to Western's Tariff sets forth its transmission planning processes as directed by Order No. 890. Like revised Attachment C, Attachment P is bifurcated to reflect the fact that Western's transmission system resides within both MRO and WECC. Western's development of Attachment P was informed by the related Order No. 890 compliance filings of certain parties in the MAPP and WestConnect footprints,[45] as well as by the Commission's findings pertaining to such filings.[46]

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[43] Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-C, 73 Fed. Reg. 43,848 (July 29, 2008), FERC Stats. & Regs. ¶ 31,274 (July 21, 2008).

[44] E.g., Duke Energy Carolinas, LLC, 122 FERC ¶ 61,077 at P 19 (2008); and Idaho Power Co., 122 FERC ¶ 61,243 at P 36 (2008).

[45] See, e.g., the September 14, 2009 compliance filings submitted by Arizona Public Service Company and Public Service Company of New Mexico in Docket Nos. OA08-33-002 and OA08-34-002, respectively.

[46] E.g., El Paso Electric Co., et al., 124 FERC ¶ 61,051 (2008); and MidAmerican Energy Co., 123 FERC ¶ 61,160 (2008).

phrase "and Filing" from the title of section 11.3 to be consistent with other areas of its tariff documents, so there is no inadvertent confusion regarding whether or not Western will file an unexecuted agreement with the Commission should a dispute arise.

C. LGIA - Article 19.1

In Western's previous filings it noted that it must comply with the Federal Anti-Assignment Act,[51] and Western, therefore, made changes to the pro forma LGIA language to require Western's written approval prior to any assignment by the interconnection customer. An unintended consequence of this change has been some confusion on the part of interconnection customers regarding their ability to assign the LGIA to third parties for security purposes, e.g., in several instances, the interconnection customer was concerned that it was only permissible to assign the agreement to one of its affiliates for security purposes. This was not Western's intent. Assignment of the LGIA may occur to any party provided a potential assignee meets the assignment requirements in Article 19.1. Further, the ability to assign the LGIA for security purposes may occur to any third party, not just affiliates of the interconnection customer. Consequently, Western has made changes to Article 19.1 to remedy this confusion.

D. SGIP – Section 3.3

Western has added a new section 3.3 to its SGIP to incorporate environmental compliance language in conformance with what Western included in its Tariff at sections 19.11 and 32.6 and Attachment J, as discussed previously.

E. SGIA – Article 7.1

Western has modified the assignment provisions in Article 7.1 of its SGIA to conform them to the revisions Western made to Article 19.1 of the LGIA, as discussed previously.

II. PETITION FOR AN EXEMPTION FROM FILING FEES

Western hereby seeks an exemption in lieu of paying a filing fee applicable to petitions for declaratory orders. As an agency of the United States Department of Energy, Western is engaged in official business of the Federal Government in filing this petition for a declaratory order from the Commission that the revisions to its non-jurisdictional Tariff, including the LGIA, LGIP, SGIA, and SGIP, continue to be an acceptable reciprocity Tariff. Western is an agency of the United States and, therefore, is exempt from filing fees.[52]

III. EFFECTIVE DATE

Western requests that the revised Tariff become effective on December 1, 2009. Western notes that due to the year-end holiday period and in order to synchronize Western's tracking of its transmission study performance metrics with the calendar quarter posting requirement in Order

[51] 41 U.S.C. § 15 (2008).
[52] 18 C.F.R. §§ 381.102(a), 381.108(a), and 381.302(c) (2008).

No. 890, Western will begin tracking such metrics on January 1, 2010. As a result, Western will post its first set of quarterly metrics within 15 days of the end of the quarter,[53] or by April 15, 2010.

IV. REQUEST FOR WAIVER OF SERVICE REQUIREMENTS

Western has informed all interested parties regarding the proposed Tariff changes through an informal public process. Western has notified all customers that have indicated a desire to be kept informed of the Tariff development of this filing. Western shall make copies of this filing available for public inspection on its Web site at www.wapa.gov/transmission/oatt.htm. Therefore, Western will not file a copy of this tariff upon all interested parties.

V. CONTENTS OF THE FILING

Along with this transmittal letter, the documents submitted with this filing include:[54]

Attachment A – A clean version of Western's proposed Tariff, including the LGIP, LGIA, SGIP, and SGIA.

Attachment B – A redlined version of Western's proposed Tariff, including the LGIP, LGIA, SGIP, and SGIA compared with all of those documents as previously approved by the Commission up to and including the October 31, 2007, filing in Docket No. NJ08-1-000 and the Commission's relevant delegated letter order issued on November 16, 2007.

VI. COMMUNICATION

Western requests that all correspondence, pleadings, and other communications concerning this filing be served upon:

Ronald J. Klinefelter
Attorney
Western Area Power Administration
Office of General Counsel
12155 W. Alameda Parkway
P.O. Box 281213
Lakewood, CO 80228-8213
(720) 962-7010
klinefelter@wapa.gov

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[53] Order No. 890 at P 1309.
[54] In light of the Notice Announcing New Combined Notice of Filings issued by the Commission on May 13, 2005, Western has not included a Notice of Filing and a diskette containing the same.

Edward F. Hulls
Chair, Power Systems Operations Council
Western Area Power Administration
Rocky Mountain Region
5555 E. Crossroads Blvd.
P.O. Box 3700
Loveland, CO 80539-3003
(970) 461-7566
hulls@wapa.gov

Dated this 30th day of September, 2009.

Respectfully submitted,

Ronald J. Klinefelter

Ronald J. Klinefelter
Attorney
Office of General Counsel
Western Area Power Administration

Attachments

B. LGIP

1. Section 1 - Definition of "Reasonable Efforts"

Western has revised the LGIP's pro forma definition of the term "Reasonable Efforts" to reference the LGIP rather than the LGIA. Western made this change to eliminate confusion that has arisen regarding applicability of the term and to parallel the definition of "Reasonable Efforts" that Western added to its SGIP in a previous filing.[47]

2. Section 3.3.5

Western added a new section 3.3.5 to its LGIP to incorporate environmental compliance language in conformance with the language Western included in its Tariff at sections 19.11, 32.6 and Attachment J, as discussed previously.

3. Section 8.1, and Section 5.0 of the Interconnection Facilities Study Agreement

As Western explained in a previous filing,[48] Western requires advance payment to perform work related to transmission and interconnection requests consistent with the Federal Contributed Funds Act and the Federal Anti-Deficiency Act.[49] Western has in certain instances used, with the interconnection customer's concurrence, the Interconnection Facilities Study deposit for the performance of other work such as environmental review activities and development of an Engineering & Procurement Agreement and the LGIA. In addition, Western's cost of performing the Interconnection Facilities Study and such other work at times does not exceed the required $100,000 deposit, yet the LGIP implicitly assumes that the deposit will always be exceeded. All that being the case, Western proposes to revise section 8.1 of the LGIP and section 5.0 of the LGIP's Interconnection Facilities Study Agreement to eliminate potential issues regarding the Interconnection Facilities Study deposit and its use, and to provide more transparency in that respect to the Commission and Western's prospective interconnection customers.

4. Section 11

In a previous filing, Western revised the LGIA-related tender, offer and negotiation provisions in section 11 of the pro forma LGIP to accommodate changes Western made to that section regarding its obligations under NEPA.[50] In so doing, however, Western inadvertently created confusion among its customers related to the tender, offer, and negotiation of a LGIA. Here, Western has made changes to the section 11 of its LGIP to remedy such confusion by clarifying the deadlines provided in sections 11.1 and 11.2. Western has also changed the location of language it previously inserted regarding cost recovery of Western's efforts related to the negotiation of the LGIA. Finally, as a non-jurisdictional entity, Western does not file its agreements with the Commission as previously noted. As such, Western has also removed the

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[47] See Western's March 1, 2007 Filing.
[48] Id. at p. 7-8.
[49] 43 U.S.C. § 395 (2007) and 31 U.S.C. § 1341(a)(1)(2003), respectively.
[50] See Western's January 25, 2005 Filing.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Lakewood, Colorado, this 30th day of September, 2009.

By: Ronald J. Klinefelter

Ronald J. Klinefelter
Attorney
Office of General Counsel
Western Area Power Administration
P.O. Box 281213
Lakewood, CO 80228-8213
(720) 962-7010 (voice)
(720) 962-7009 (fax)

Transmission Provider:

____
____
____

Assignee:

____
____
____

Each Party may change the designation of its representative upon oral notice to the other, with confirmation of that change to be submitted in writing within ten (10) days thereafter.

6.0 The Tariff ~~is~~, Service Agreement No. ________________ between the Transmission Provider and the initial Reseller, and, if applicable, the "Specifications For The Resale, Reassignment Or Transfer of Long-Term Firm Point-To-Point Transmission Service," as presently constituted or as they may be revised or superseded, are incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

~~Transmission Provider:~~
~~By:~~ ____
~~Name~~ ~~Title~~ ~~Date~~

~~Assignee:~~
~~By:~~ ____
~~Name~~ ~~Title~~ ~~Date~~

WESTERN AREA POWER ADMINISTRATION

By ______________________________

Title ____________________________

Address __________________________

____

Date ______________________

(ASSIGNEE)

(SEAL) ______________ By ______________________

Attest: ______________ Title ______________________

By ______________ Address ______________________

Title ______________________

______________ Date ______________________

(Service Agreement Number)
(Assignee)
Attachment A-1

Specifications For The Resale, Reassignment Or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ______
Start Date: ______
Termination Date: ______

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

______

3.0 Point(s) of Receipt: ______
Delivering Party: ______

4.0 Point(s) of Delivery: ______
Receiving Party: ______

5.0 Maximum amount of reassigned capacity: ______

6.0 Designation of party(ies) subject to reciprocal service obligation:

______
______
______
______

7.0 Name of the Control Area from which capacity and energy will be delivered to the Transmission Provider for Transmission Service:

______

Name of the Control Area to which capacity and energy will be delivered by the Transmission Provider:

______

Name(s) of any Intervening Systems providing transmission service:

______
______

8.0 ~~Service under this Agreement may be subject to some combination of~~ The Reseller and the Assignee have negotiated the charges detailed below~~. (The appropriate charges for individual transactions will be determined~~ in accordance with the terms and conditions of the Tariff, including the price cap specified in Section 23.1 of the Tariff.~~)~~

8.1 Transmission Charge: ______

______

8.2 System Impact and/or Facilities Study Charge(s): ______

8.3 Direct Assignment Facilities Charge: ______

8.4 Ancillary Services Charges: ______

9.0 Name of Reseller of the reassigned transmission capacity: ______

ATTACHMENT B

Service Agreement for Non-Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ______________________________, is entered into, by and between the (Region) of Western Area Power Administration (Transmission Provider), and _______ (Transmission Customer), each of whom are sometimes hereinafter individually called Party and both of whom are sometimes hereinafter collectively called the Parties. For purposes of this Service Agreement, the Transmission Provider's Transmission System consists of the applicable facilities described in Attachment K to the Tariff. The Transmission Provider may revise charges or losses for Non-Firm Point-to-Point Transmission Service provided under this Service Agreement pursuant to applicable Federal laws, regulations and policies upon written notice to the Transmission Customer.

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Service Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer. For purposes of this Service Agreement, the Transmission Provider's Transmission System consists of the facilities of the (Region) as described in Attachment K.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff, and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

Transmission Customer:

____

____

____

Each Party may change the designation of its representative upon oral notice to the other, with confirmation of that change to be submitted in writing within ten (10) days thereafter.

7.0 The Tariff as presently constituted or as it may be revised or superseded is incorporated herein and made a part hereof.

8.0 Power Factor: The Transmission Customer will be required to maintain a power factor between __-percent lagging and __-percent leading for all deliveries of capacity and energy to and from the Transmission Provider's Transmission System.

9.0 Transmission Losses:

9.1 Loss Factors:

9.1.1 If, based on operating experience and technical studies, the Transmission Provider determines that any of the transmission loss factors on the Transmission Provider's Transmission System differs from the loss factors set forth in this Service Agreement, the Transmission Provider will notify the Transmission Customer of the revised loss factor(s) pursuant to Section 1.0 of this Service Agreement.

9.1.2 Transmission Provider Transmission Loss Factor: Transmission Provider transmission losses shall initially be __% and shall be assessed on the power scheduled and transmitted to a point of delivery on the Transmission Provider's Transmission System.

10.0 Ancillary Services

10.1 Provided by Transmission Provider

10.1.1 Scheduling, System Control, and Dispatch Service
10.1.2 Reactive Supply and Voltage Control from Generation Sources Service

10.2 Provided by Transmission Customer

10.2.1 (To be filled in if appropriate)
10.2.2

10.3 Provided by

10.3.1 (To be filled in if appropriate)
10.3.2

11.0 Net Billing and Bill Crediting Option: The Parties have agreed to implement [Net Billing, Bill Crediting, both Net Billing and Bill Crediting, or neither Net Billing nor Bill Crediting] as set forth in Attachment J.

12.0 Charges for Service: Charges for Non-Firm Point-to-Point Transmission Service and associated Ancillary Services shall be calculated in accordance with the applicable Rate Schedules(s) attached hereto and made a part of this Service Agreement. The rates or rate methodology used to calculate the charges for service under that schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations and policies.

[The following section will be included as appropriate at the Transmission Provider's discretion]

13.0 Independent System Operator: The Parties understand that the Transmission Provider may join an independent system operator under Commission jurisdiction. In the event the Transmission Provider either joins or is required to conform to protocols of the independent system operator, the Parties agree that the Transmission Provider either may (1) make any changes necessary to conform to the terms and conditions required by Commission approval of the independent system operator, or (2) terminate this Service Agreement by providing a one-year written notice to the Transmission Customer.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

WESTERN AREA POWER ADMINISTRATION

By ______________________________

Title ______________________________

Address ______________________________

____

Date ______________________________

(TRANSMISSION CUSTOMER)

(SEAL)	By ____________________
Attest:	Title ____________________
By ____________________	Address ____________________
Title ____________________	____________________
	Date ____________________

ATTACHMENT C

Methodology to Assess Available ~~Transmission~~ Transfer Capability

~~The Transmission Provider will compute the transmission transfer capability available on a point-to-point basis from the Delivering Party to the Receiving Party using Good Utility Practice and the engineering and operating principles, standards, guidelines and criteria of the Transmission Provider, the applicable Regional Reliability Council, any entity of which the Transmission Provider is a member and is approved by the Commission to promulgate or apply regional or national reliability planning standards (such as a Regional Transmission Group, RTG), or any similar organization that may exist in the future of which the Transmission Provider is then a member. Principal items used to determine maximum transmission transfer capability available shall include reliability, transmission element loading, system contingency performance, voltage levels, and stability. In determining Available Transmission Capability, the Transmission Provider will reserve sufficient transmission capability to meet its current and forecasted power service obligations, current and forecasted Network Customer loads, and existing transmission service obligations.~~~~The Transmission Provider must include, at a minimum, the following information concerning its ATC calculation methodology:~~

~~(1) A detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon);~~

~~(2) A process flow diagram that illustrates the various steps through which ATC/AFC is calculated; and~~

~~(3) A detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons.~~

~~(a) For TTC, a Transmission Provider shall: (i) explain its definition of TTC; (ii) explain its TTC calculation methodology; (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.~~

~~(b) For ETC, a transmission provider shall explain: (i) its definition of ETC; (ii) the calculation methodology used to determine the transmission capacity to be set aside for native load (including network load), and non OATT customers (including, if applicable, an explanation of assumptions on the selection of generators that are modeled in service); (iii) how point-to point transmission service requests are incorporated; (iv) how rollover rights are accounted for; (v) its processes for ensuring that non-firm capacity is released properly (e.g., when real time schedules replace the associated transmission service requests in its real-time calculations) ; and (vi) describe the step-by-step modeling study methodology and criteria for adding or eliminating flowgates (permanent and temporary).~~

~~(c) If a Transmission Provider uses an AFC methodology to calculate ATC, it shall: (i) explain~~

~~its definition of AFC; (ii) explain its AFC calculation methodology; (iii) explain its process for converting AFC into ATC for OASIS posting; (iv) list the databases used in its AFC assessments; and (v) explain the assumptions used in its AFC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.~~

~~(d) For TRM, a Transmission Provider shall explain: (i) its definition of TRM; (ii) its TRM calculation methodology (e.g., its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (iii) the databases used in its TRM assessments; (iv) the conditions under which the transmission provider uses TRM. A Transmission Provider that does not set aside transfer capability for TRM must so state.~~

~~(e) For CBM, the Transmission Provider shall state include a specific and self-contained narrative explanation of its CBM practice, including: (i) an identification of the entity who performs the resource adequacy analysis for CBM determination; (ii) the methodology used to perform generation reliability assessments (e.g., probabilistic or deterministic); (iii) an explanation of whether the assessment method reflects a specific regional practice; (iv) the assumptions used in this assessment; and (v) the basis for the selection of paths on which CBM is set aside.~~

~~(f) In addition, for CBM, a Transmission Provider shall: (i) explain its definition of CBM; (ii) list the databases used in its CBM calculations; and (iii) demonstrate that there is no double-counting of contingency outages when performing CBM, TTC, and TRM calculations.~~

~~(g) The Transmission Provider shall explain its procedures for allowing the use of CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). If the Transmission Provider's practice is not to set aside transfer capability for CBM, it shall so state.~~**Part I - Colorado River Storage Project Management Center, Desert Southwest Region, Rocky Mountain Region, and Sierra Nevada Region**

(1) Detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC for scheduling, operating and planning horizons.

Scheduling Horizon

a. Firm ATC = TTC – TRM – ETC~~– MI~~

b. Non-Firm ATC = TTC – TRM*Coef – ETC~~– MI.~~

Operating Horizon

a. Firm ATC = TTC – TRM – ETC~~– MI~~

b.~~–~~ Non-Firm ATC = TTC – TRM*Coef – ETC~~– MI~~

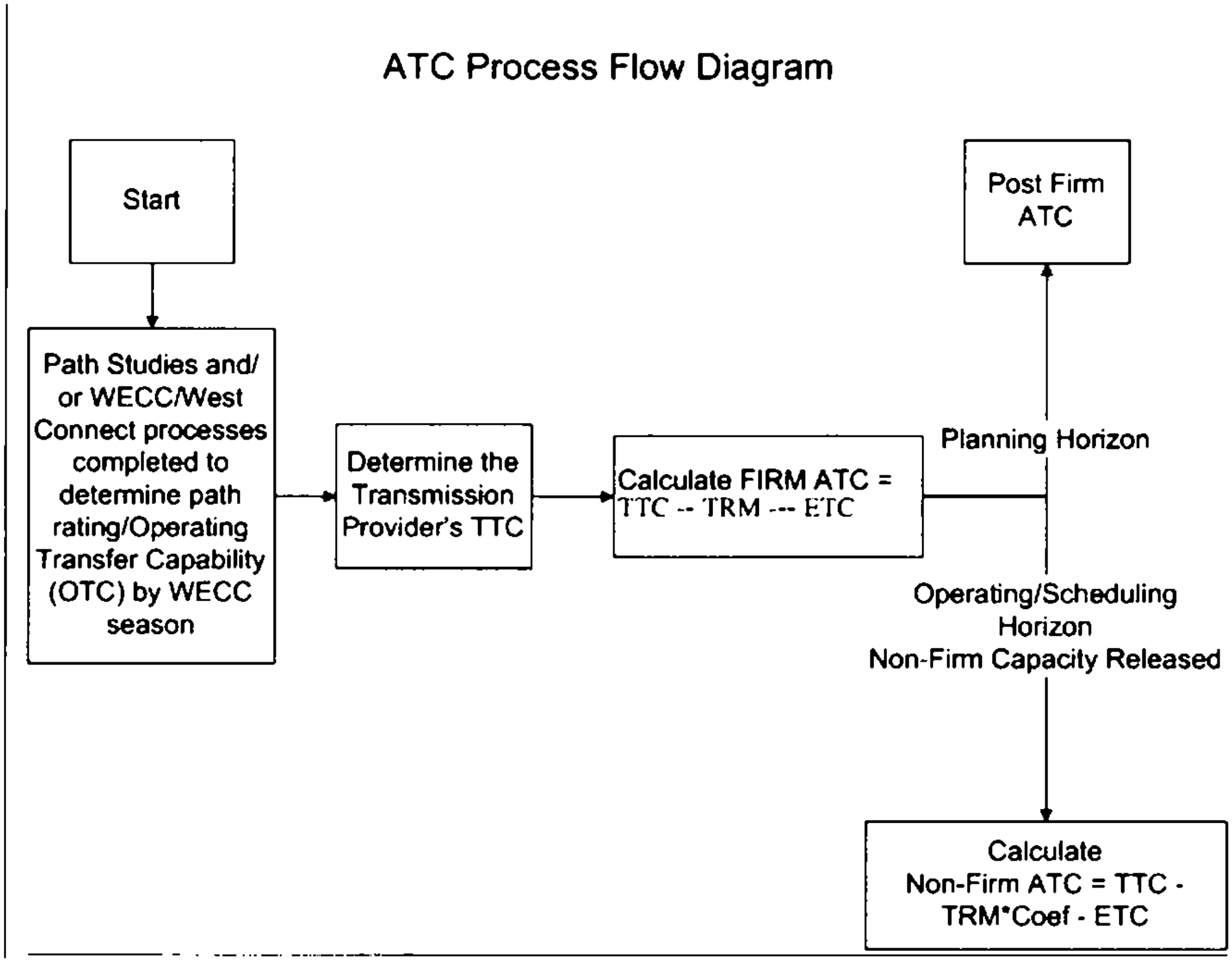
Planning Horizon

a. Firm ATC = TTC -- TRM - ETC~~-MI~~

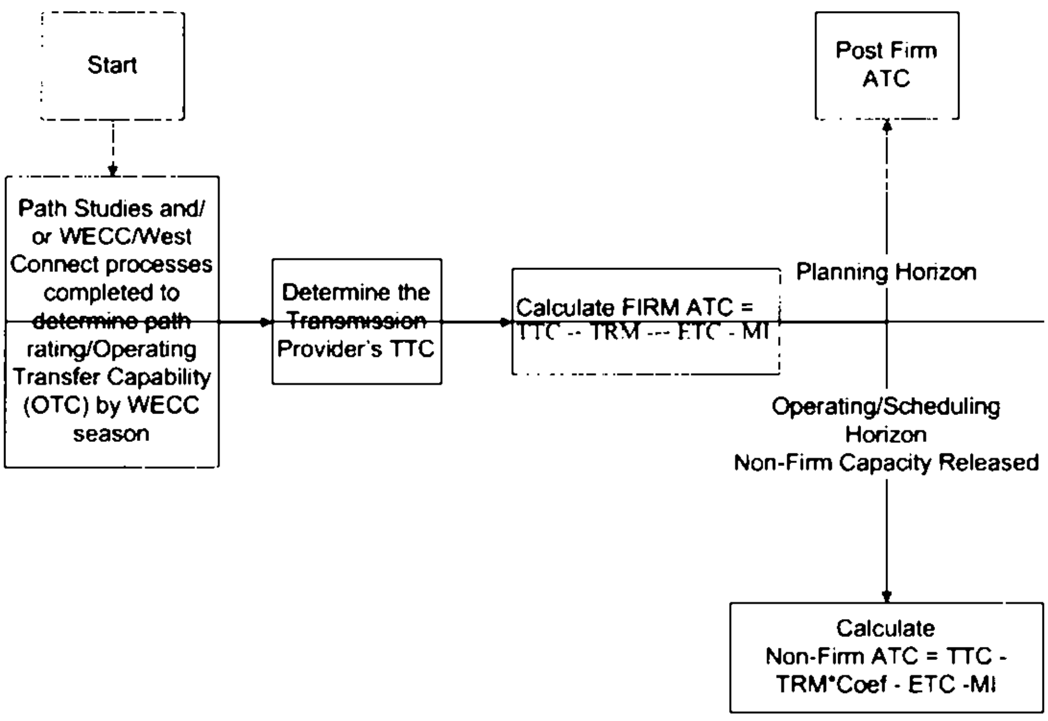
b. Non-Firm ATC = TTC - ETC~~-MI~~

The Transmission Provider's ATC algorithms are also available on the Transmission Provider's OASIS website.

(2) A process flow diagram that illustrates the various steps through which ATC/AFC is calculated


ATC Process Flow Diagram
Start
Path Studies and/ or WECC/West Connect processes completed to determine path rating/Operating Transfer Capability (OTC) by WECC season
Determine the Transmission Provider's TTC
Calculate FIRM ATC = TTC -- TRM --- ETC
Planning Horizon
Post Firm ATC
Operating/Scheduling Horizon
Non-Firm Capacity Released
Calculate Non-Firm ATC = TTC - TRM*Coef - ETC

ATC Process Flow Diagram



(3) Detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons

a. For TTC:

i. Definition of TTC:

Total Transfer Capability (TTC): The amount of electric power that can be transferred over a specific path within the Transmission Provider's interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post- contingency system conditions. TTC is a variable quantity, dependent upon operating conditions in the near term and forecasted conditions in the long term. TTC shall be calculated consistent with the requirements of FERC, NERC and WECC as needed to represent system conditions, but no less frequently than seasonally. TTC cannot exceed the path rating.

ii. TTC calculation methodology.

- For transmission facilities that will affect the Western Interconnection, the determination of TTC is accomplished through the WECC Path

Rating Process. The Transmission Provider follows the ATC methodology adopted by WECC and presented in the WECC Document Determination of Available Transfer Capability Within the Western Interconnection. Seasonal Operating Transfer Capability (OTC) studies are completed to determine the limit at which a transmission path can be operated at and still meet reliability requirement under an N-1 (single contingency) condition. The study results are reviewed and approved through WECC Operating Transfer Capability Planning Committee (OTCPC) regional processes.

- TTC is determined either prior to a new transmission component being brought into service or when a modification to a transmission component would affect the TTC.

- Once the TTC determination is made, it remains fixed and changes only if there is a physical or operational change to the transmission system or a transmission component which requires a change to TTC.

- When transmission facilities are jointly owned, the capacity is allocated among the owners based on the joint ownership or participation agreement; therefore, the TTC of the jointly owned facilities will be based upon the capacity allocated to each Transmission Provider.

- If a WECC defined path must be separated into components to properly allow for the commercial use of the path and its components, the components' TTCs will be based on the same studies used to determine the path OTC or the thermal rating of the components. The sum of the components' TTCs will not exceed the path OTC.

- For internal constraints, the net of local load and local generation may be used to determine TTC and/or ATC.

- Narratives explaining changes to monthly and/or yearly TTC are posted on the Transmission Provider's OASIS.

iii. List of databases used in TTC assessments:

The Transmission Provider utilizes the NERC and WECC contract path methodology to determine TTC on its transmission system. The determination of the TTC for paths on the Transmission Provider system is segment dependent. However, the tools used to determine TTC is the same for all segments, i.e., the GE PSLF powerflow and stability programs using system modeling data obtained through WECC.

iv. Assumptions used in TTC assessments:

Paths with established transfer capabilities will not be evaluated unless there is a valid reason for doing so, such as a component change or new configuration, which could affect the transfer capability. Should a change in a WECC rated path warrant restudying, the required studies for the path will be performed through the WECC Path Rating Process. Should a change in a non-WECC rated path warrant restudying, the required studies for the path will follow the WECC rated path methodology, but not be brought through the WECC Path Rating Process. However, the study process will be performed through the applicable Regional or SubRegional Planning group.

b. For ETC:

i. Definition of ETC.

Existing Transmission Commitments (ETC): ETC is transmission that is already committed for use.
There are four types of committed uses: 1) native load uses; 2) existing commitments for purchase/exchange/deliveries/sales;3) existing commitments for transmission service (Pre-Order 888, Post-Order 888, Point-to-Point and Network); and 4) other pending potential uses of transfer capability (non-confirmed Transmission Service Requests). The Transmission Provider determines ETC as the total of all contracts using a contract path methodology.

ii. Explanation of calculation methodology used to determine the transmission capacity to be set aside for native load and non-OATT customers:

The Transmission Service Provider shall determine the impact of firm ETCs based on the following inputs:

- The transmission capability utilized in serving Firm Electric Service, congressionally mandated power deliveries to Transmission Provider's preference customers from the Federally owned generating plants.

- The impact of Firm Network Integration Transmission Service serving Load, to include Load forecast error and losses not otherwise included in TRM.

- The impact of grandfathered firm Transmission Service agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Provider's Open Access Transmission Tariff or Safe Harbor Tariff accepted by FERC.

- The impact of Firm Point-to-Point Transmission Service.
- The impact of any Ancillary Services not otherwise included in TRM,
- Post-backs of redirected or released Firm services.
- The impact of any other services, contracts, or agreements not specified above using transmission that serves Firm Electric Service or Firm Network Integration Transmission Service.

iii. How point to point transmission service requests are incorporated.

Point-to-point type contracts are modeled using the specified megawatt quantity, point of receipt, point of delivery, and contract term.

iv. How rollover rights are accounted for:

Currently a component does not exist to maintain rollover rights for existing transmission customers past the current stop date/time. Requests for the posted ATC by other customers are held until the existing right holder exercises those rights to rollover.

v. Processes for ensuring that non-firm capacity is released properly:

The Transmission Provider uses an Offset value to account for unused transmission capacity which has not been scheduled (tagged) including the impact of netting schedules in the opposite direction. A portion of the unused capacity is added to the non-firm ATC formula, thus increasing the ATC posting on OASIS. Due to uncertainty nature of this process and to prevent over-posting and subsequent curtailment of schedules, the Transmission Provider uses larger value of Offset for the immediate hours than several hours in the future.

c. If a Transmission Provider uses an AFC methodology to calculate ATC, it shall. (i) explain its definition of AFC; (ii) explain its AFC calculation methodology, (iii) explain its process for converting AFC into ATC for OASIS posting, (iv) list the databases used in its AFC assessments; and (v) explain the assumptions used in its AFC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

The Transmission Provider does not use an AFC methodology to calculate ATC.

d. For TRM:

i. Definition of TRM:

Transmission Reliability Margin (TRM): The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure, TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

ii. TRM calculation methodology:

The Transmission Provider currently reserves TRM to support the activation of operating reserves via participation in Rocky Mountain Reserve Sharing Group and/or Southwest Reserve Sharing Group. The Transmission Provider's obligation to deliver reserves is calculated at a minimum of twice a year by the Reserve Sharing Group. In addition, the Transmission Provider may include an additional transmission capacity to account for its network customers load forecast error and at certain paths to account for unscheduled flow..

iii. Databases used in TRM assessments:

The Transmission Provider uses a value between 0 to 1 for TRM Coefficient to release a portion of the capacity reserved under TRM as non-firm. The Transmission Provider uses its scheduling system, PI, and SCADA, WECC bases cases, and PSS E or GE PSLF in its calculation of TRM.

iv. Conditions under which the Transmission Provider uses TRM:

The Transmission Provider may use TRM for any of the following:

- Transmission necessary for the activation of operating reserves;
- Unplanned transmission outages;
- Simultaneous limitations associated with operating under a nomogram;
- Loading variations due to balancing of generation and load;
- Uncertainty in load distribution and/or load forecast;
- Allowanced for unscheduled flow.

e. For CBM:

i. Identification of the entity who performs the resource adequacy for CBM determination:

The Transmission Provider does not utilize CBM.

ii. The methodology used to perform the generation reliability assessment:

The Transmission Provider has established CBM of zero on all transmission paths when calculating ATC.

iii. Explanation of whether the assessment method reflects a specific regional practice:

The Transmission Provider has established CBM of zero on all transmission paths when calculating ATC.

iv. Assumptions used in this assessment:

The Transmission Provider has established CBM of zero on all transmission paths when calculating ATC.

v. Basis for the selection of paths on which CBM is set aside:

The Transmission Provider has established CBM of zero on all transmission paths when calculating ATC.

f. Additionally for CBM:

i. Explain definition of CBM:

The transmission Provider has established CBM of zero on all transmission paths when calculating ATC.

ii. List of databases used in CBM calculations:

The Transmission Provider does not use any databases in its CBM calculation.

iii. Demonstration that there is no double-counting of outages when performing CBM, TTC and TRM calculations:

Since the Transmission Provider has established CBM as zero on all transmission paths, the Transmission Provider can't double count for outages.

~~g. for Miscellaneous Impact (MI) value~~

~~i. Explain definition of MI:~~

~~The MI Value can be used as either an offset to account for unused transmission capacity as defined in section (3).h.v. or a flow value as calculated through a power flow analysis process. The MI value provides the transmission provider with the ability to determine ATC using modeled flows or unused transmission capacity which has not been scheduled.~~

g~~h~~. Procedures for allowing use of CBM during emergencies (with explanation of what constitutes an emergency, entities that are permitted to use CBM during emergencies and procedure which is followed by the Transmission Provider's merchant function and other load-serving entities when they need to access CBM:

At this time, the Transmission Provider's Network Customers have not requested CBM set aside, therefore the Transmission Provider does not have CBM set aside.

Part II - Upper Great Plains Region

The Transmission Provider must include, at a minimum, the following information concerning its ATC calculation methodology:

(1) A detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon);

The Transmission Provider utilizes the Mid-Continent Area Power Pool ("MAPP") procedures for calculating firm and non-firm ATC for those Control Area to Control Area and Controlled Interface contract paths expected to be constraining to sales of transmission service and for calculating all firm and non-firm AFC. The rated system path methodology (contract path) is utilized for contract paths between the UGPR system and other Transmission Providers with whom UGPR has interconnections and for Controlled Interfaces.

UGPR's Controlled Interfaces are those transmission facilities or tie-lines included in its Transmission System where the flow of power across such facilities is controlled to a desired value utilizing a High Voltage Direct Current (HVDC) technology or a phase-shifting transformer. The Controlled Interfaces included in UGPR's Transmission System include: 1) the Miles City Converter Station, which is a 200MW back-to-back HVDC tie-line located in its Miles City 230-kV Substation in eastern Montana; 2) the east-side AC transmission connection to the Rapid City DC Tie, which is a 200MW back-to-back HVDC tie-line located in western South Dakota; 3) the 300 MVA Crossover phase-shifter located on the Crossover-Yellowtail 230-kV transmission line located in eastern Montana, and 4) the Tioga-Boundary Dam 230-kV transmission tie-line between the United States and Saskatchewan, which is controlled by a 200 MVA phase-shifting transformer owned by SaskPower and located at the north end of the transmission line in SaskPower's Boundary Dam 230-kV Substation.

The network response flowgate methodology (network AFC) is utilized for the Transmission Provider's system for facilities expected to be constraining to sales of transmission service and expected to be congested in real-time operations.

The MAPP region, including the Transmission Provider's system, utilizes two horizons for AFC/ATC calculations:

- ~~1.~~The Operating Horizon AFC/ATC calculation evaluates hourly non-firm and secondary non-firm service. The Operating Horizon AFC/ATC calculation determines AFC/ATC values for a sliding 36-hour period. The Operating Horizon includes the "scheduling horizon" (same day and real-time) as well as the "operating horizon" (day ahead and pre-schedule) as such terms are referred to in the FERC Order No. 890.

- ~~2.~~ The Planning Horizon AFC/ATC calculation evaluates transmission service with a NERC curtailment priority of 3 or higher except for secondary non-firm service. The Planning Horizon AFC/ATC calculation determines AFC/ATC values for a sliding 3 year period beyond the Operating Horizon.

Appendix F of MAPP's document "MAPP Policies and Procedures for Transmission Operations" (MAPP Policies and Procedures) contains the detailed mathematical algorithms used to calculate firm and non-firm AFC/ATC. A summary of the mathematical algorithms is provided below.

a. Non-Recallable (Firm) AFC

Under the MAPP AFC process, non-recallable AFC represents firm AFC. The MAPP formula for Non-recallable AFC is available at:

http://toinfo.oasis.mapp.org/oasisinfo/afc_calculation.pdf

Under this formula, Non-recallable AFC is Total Flowgate Capability reduced by: (i) the capacity benefit margin (CBM); (ii) the transmission reliability margin (TRM); (iii) the non-recallable Existing Transmission Commitments (ETC); and (iv) non-recallable transmission reservation impacts.

b. Recallable (Non-Firm) AFC

Under the MAPP AFC process, recallable AFC represents non-firm AFC. The MAPP formula for Recallable AFC is available at:

http://toinfo.oasis.mapp.org/oasisinfo/afc_calculation.pdf

Under this formula, Recallable AFC is Total Flowgate Capability reduced by: (i) CBM; (ii) TRM; (iii) Recallable Existing Transmission Commitments; (iv) Non-Recallable transmission reservation impacts; (v) Non-Recallable Existing Transmission Commitments; (vi) Recallable transmission reservation impacts.

c. Non-recallable ATC Computation on a Contract Path

Non-recallable ATC on a contract path is the TTC on the contract path reduced by: (i) CBM, (ii) TRM, (iii) Non-Recallable Existing Transmission Commitments, and (iv) Non-Recallable Transmission Reservation Impacts on the path.

d. Recallable ATC Computation on a Contract Path

Recallable ATC for a MAPP Transmission Provider Flowgate is the TTC reduced by: (i) CBM; (ii) TRM; (iii) Recallable Existing Transmission Commitments; (iv) Non-Recallable transmission reservation impacts; (v) Non-Recallable Existing Transmission Commitments; (vi) Recallable transmission reservation impacts.

(2) A process flow diagram that illustrates the various steps through which ATC/AFC is calculation; and

The process flow diagram of the steps involved in calculating ATC/AFC is provided as Appendix 1 to this Attachment C-2.

(3) A detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons.

a. For TTC, a Transmission Provider shall: (i) explain its definition of TTC; (ii) explain its TTC calculation methodology; (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

With respect to requirement 3(a)(i), UGPR defines TTC as follows:

For UGPR Control Area to Control Area contract paths:

The TTC is defined as the sum of the seasonal normal facility ratings of the tie lines between the UGPR Control Area and the other Control Area with whom UGPR has an interconnection. The Control Area to Control Area contract path TTC is determined separately for each adjoining Control Area. The seasonal normal facility rating is determined in accordance with the UGPR Transmission Facility Ratings Methodology (as posted on the UGPR OASIS page).

For UGPR Controlled Interface contract paths:

The TTC is defined as the seasonal normal facility rating of the HVDC line (in each direction), or the seasonal normal facility rating of the phase-shifting transformer (in each direction).

For UGPR flowgates:

For Outage Transfer Distribution Factor ("OTDF") flowgates, the TTC is defined as the seasonal emergency facility rating of the limiting facility. The seasonal emergency facility rating is determined in accordance with the UGPR Transmission Facility Ratings Methodology (as posted on the UGPR OASIS page).

For Power Transfer Distribution Factor ("PTDF") flowgates where the limiting phenomenon is stability related, the TTC is defined as the flow on the monitored facilities above which the limiting phenomenon no longer meets criteria.

With respect to requirement 3(a)(ii), UGPR's TTC calculation methodology is:

For UGPR Control Area to Control Area contract paths:

The TTC is calculated as the sum of the seasonal normal facility ratings of the tie lines between the UGPR Control Area and the other Control Area with whom UGPR has an interconnection. For tie-lines that are jointly-owned, only the UGPR ownership share of the tie-line capacity is included. The Control Area to Control Area contract path TTC is determined separately for each adjoining Control Area. The seasonal normal facility rating is determined in accordance with the UGPR Transmission Facility Ratings Methodology (as posted on the UGPR OASIS page).

For UGPR Controlled Interface contract paths:

The TTC is calculated as the lesser of the seasonal normal facility rating of the HVDC line (in each direction) or the flow on the HVDC line (in each direction) above which the limiting phenomenon (i.e. thermal, voltage angle, or stability related) no longer meets criteria. The TTC is calculated as the lesser of the seasonal normal facility rating of the phase-shifting transformer (in each direction) or the flow on the phase-shifting transformer (in each direction) above which the limiting phenomenon (i.e. thermal, voltage angle, or stability related) no longer meets criteria.

Power flow simulations are performed to determine the flow on the monitored facilities at which the UGPR Transmission Planning Criteria (as posted on the UGPR OASIS) are not met. Stability simulations are performed, if applicable, to determine the flow on the monitored facilities at which the UGPR Transmission Planning Criteria (as posted on the UGPR OASIS) are not met. If applicable, in the case of a voltage angle related limit, power flow simulations are performed to determine the flow on the monitored facilities at which a line outage results in a breaker angle differential at which, when the breaker is reclosed, the instantaneous generator response of the most critical generators is such that its delta-power reaches its maximum safe limit (generator shaft torque is within the limits of the generator)

For UGPR flowgates:

For OTDF flowgates, the TTC is calculated as equal to the seasonal emergency facility rating of the limiting facility. The seasonal emergency facility rating is determined in accordance with the UGPR Transmission Facility Ratings Methodology (as posted on the UGPR OASIS page).

For PTDF flowgates where the limiting phenomenon is voltage angle or stability related, the TTC is calculated as equal to the flow on the monitored facilities above which the limiting phenomenon no longer meets criteria. Stability simulations are performed to determine the flow on the monitored facilities at which the UGPR Transmission Planning Criteria (as posted on the UGPR OASIS) are not met. In the case of a voltage angle related limit, power flow simulations are performed to determine the flow on the monitored facilities at which a line outage results in a breaker angle differential at which, when the breaker is reclosed, the instantaneous generator response of the most critical generators is such that its delta-power reaches its maximum safe limit (generator shaft torque is within the limits of the generator).

The methodologies and studies used to determine TTC for each flowgate in the MAPP Region are reviewed and sanctioned through the MAPP Regional Transmission Committee (RTC).

With respect to requirement 3(a)(iii), the databases used in UGPR's TTC assessments are:

For thermal limitations, the seasonal normal and emergency facility ratings and impedance data for UGPR's transmission equipment are documented in internal spreadsheets and provided to MAPP, and to UGPR's Reliability Coordinator, the Midwest ISO, for real-time operations and long-term planning and model development purposes.

For stability limitations, MAPP maintains a database of generator and other equipment modeling data which are used in stability simulations. The North Dakota Export (NDEX) flowgate that is jointly owned by UGPR is limited by stability considerations. For voltage angle limitations, transmission line relaying synchro-check settings may be maintained by MAPP transmission owners in a computer-aided protection engineering computer database. MAPP transmission owners may also use generator shaft torque fatigue capabilities that are developed on an as-needed basis by generator manufacturers.

UGPR considers the information in these databases to be Critical Energy Infrastructure Information ("CEII").

With respect to requirement 3(a)(iv), the assumptions used in TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages are:

For Control Area to Control Area contract paths:

Load levels, generation dispatch and planned and contingency outages are not considered in determining the TTC.

For Controlled Interface contract paths:

For Controlled Interface contract paths where the limiting phenomenon is stability related, in accordance with MAPP practice, load levels for the entire MAPP area are modeled at 100% and 85% of peak summer load for summer studies and 100% and 90% of peak winter loads for winter studies. Load levels internal to the stability limited NDEX and other interdependent northern MAPP flowgates are modeled according to MAPP practice for stability simulations. Such modeling of load levels is appropriate for stability simulations because load can be a damping influence on angular instability. Generators in the electrical vicinity of the stability issue are typically dispatched at their maximum outputs in order to provide for a high level of acceleration power to appropriately analyze angular instability. Planned and contingency outages are analyzed in accordance with the UGPR Transmission Planning Criteria (as posted on the UGPR OASIS).

For Controlled Interface contract paths where the limiting phenomenon is voltage angle related, the TTC is dependent on the relative interaction between the voltage differential across an open breaker and the resultant generator shaft torque response relative to the maximum safe limits of the generator. Generation dispatch may be a significant factor with respect to the critical generator (in terms of the generator most sensitive to a delta power fluctuation in excess of its maximum safe shaft torque) and other generators electrically near the critical generator. The critical generator is dispatched at its minimum dispatch level in the power flow simulations because that is the appropriate assumption for a delta power analysis. To the extent that other marginal generators (generators that may or may not be on-line in real-time due to their dispatch costs) are on-line in the base case models, such generators are either taken off-line or dispatched down to minimum output. This assumption results in the critical machine participating to a greater extent in the delta power analysis. Planned and contingency outages are not currently considered in determining the TTC for voltage angle related limitations.

For Controlled Interface contract paths where the limiting phenomenon is thermal loading related, summer load levels are used in the determination of summer season TTC and winter load levels are used in the determination of winter TTC. Generation dispatch is not considered in determining the TTC. Planned and contingency outages of a monitored facility or another facility in the immediate vicinity of a monitored facility are considered in the determination of the TTC. Typically, the posted TTC is based on a system intact (no outages) assumption. During times of outages of facilities near the monitored facilities, the TTC is based on the outage condition.

For flowgates:

For OTDF flowgates, the TTC is only dependent on the facility rating. Load levels, generation dispatch and planned and contingency outages are not considered in determining the TTC.

For PTDF flowgates where the limiting phenomenon is stability related, in accordance with MAPP practice, load levels for the entire MAPP area are modeled at 100% and 85% of peak summer load for summer studies and 100% and 90% of peak winter loads for winter studies. Load levels internal to the stability limited NDEX and other non-UGPR owned interdependent northern MAPP flowgates are modeled according to MAPP practice for stability simulations. Such modeling of load levels is appropriate for stability simulations because load can be a damping influence on angular instability. Generators in the electrical vicinity of the stability issue are typically dispatched at their maximum outputs in order to provide for a high level of acceleration power to appropriately analyze angular instability. Planned and contingency outages are analyzed in accordance with the UGPR Transmission Planning Criteria (as posted on the UGPR OASIS).

For PTDF flowgates where the limiting phenomenon is voltage angle related, the TTC is dependent on the relative interaction between the voltage differential across an open breaker and the resultant generator shaft torque response relative to the maximum safe limits of the generator. Generation dispatch may be a significant factor with respect to the critical generator (in terms of the generator most sensitive to a delta power fluctuation in excess of its maximum safe shaft torque) and other generators electrically near the critical generator. The critical generator is dispatched at its minimum dispatch level in the power flow simulations because that is the appropriate assumption for a delta power analysis. To the extent that other marginal generators (generators that may or may not be on-line in real-time due to their dispatch costs) are on-line in the base case models, such generators are either taken off-line or dispatched down to minimum output. This assumption results in the critical machine participating to a greater extent in the delta power analysis. Planned and contingency outages are not currently considered in determining the TTC for voltage angle related limitations.

For PTDF flowgates where the limiting phenomenon is thermal loading related, summer load levels are used in the determination of summer season TTC and winter load levels are used in the determination of winter TTC. Generation dispatch is not considered in determining the TTC. Planned and contingency outages of a monitored facility or another facility in the immediate vicinity of a monitored facility are considered in the determination of the TTC. Typically, the posted TTC is based on a system intact (no outages) assumption. During times of outages of facilities near the monitored facilities, the TTC is based on the outage condition.

b. For ETC, a transmission provider shall explain: (i) its definition of ETC; (ii) the calculation methodology used to determine the transmission capacity to be set aside for native load (including network load), and non-OATT customers including, if applicable, an explanation of assumptions on the selection of generators that are modeled in service); (iii)how point-to-point transmission service requests are incorporated; (iv) how rollover rights are accounted for; and (v) its processes for ensuring that non-firm capacity is released properly (e.g., when real time schedules replace the associated transmission service requests in its real-time calculations); and (vi) describe the step-by-step modeling study methodology and criteria for adding or eliminating flowgates (permanent and temporary).

With respect to requirement 3(b)(i), within the MAPP region the ETC value is used to account for committed use of a flowgate or contract path other than transmission reservations made after November 1, 1996. For flowgates, ETC accounts for the impacts on a flowgate due to load serving and grandfathered transmission commitments. For contract paths, ETC accounts for grandfathered transmission commitments. ETC used in firm AFC/ATC calculations includes the effect of only firm transmission commitments, and may reflect flows expected under the most limiting conditions for a given time period. ETC used in non-firm AFC/ATC calculations includes the effects of firm transmission commitments, and may reflect average conditions for a given time period.

With respect to requirement 3(b)(ii), the Planning Horizon flowgate ETC value is comprised of several components including:

- MAPP Transmission Provider Generation-to-Load Impacts. These impacts are calculated as follows:
  - MAPP Transmission Providers upload, on a daily basis, hourly control area load forecasts for the next seven days and, on a monthly basis, monthly load forecasts for the next 36 months. For UGPR, the load forecast information correlates to the UGPR native load forecast with an adjustment to account for the non-IS loads within UGPR's load balancing area. The adjustment is based on historical average ratios of UGPR native load to total control area load.
  - MAPP Transmission Providers supply designated network resource lists for all generators in the control area. For load serving entities within the UGPR Control Area that are not network integration transmission service customers, UGPR relies on data supplied by these entities through the annual MAPP model building process.
  - MAPP Transmission Providers supply joint-owned generator information. This information includes information concerning the joint owners and the transmission arrangements for delivering joint owned shares to the joint owners.
  - MAPP Transmission Providers supply control area generating unit merit order (block loading) information. The merit order information is used to develop the generation dispatch to serve the load in the Transmission Provider's control area. To the extent resources outside the UGPR Control Area are used to serve load in the UGPR Control Area, these deliveries are represented by the transmission service requests on OASIS, except for generators directly connected to the UGPR system through UGPR transmission facilities. In these cases, the resource us represented in the merit order file and UGPR's share of the resource is not reflected in the calculation of the adjoining control area's generation to load impacts.
  - MAPPCOR calculates, for each MAPP flowgate including UGPR flowgates, the generation to load impacts of each MAPP Transmission Provider serving load within its control area. MAPP's calculation is based on determining a generation dispatch for each applicable time horizon. The dispatch is based on dispatching generation in merit order up to the designated network resource limits, respecting joint-ownership shares of jointly owned units, until the load plus net interchange are balanced for each control area. The calculation includes the effects of generation and transmission outages included in the NERC System Data Exchange (SDX). Further details of MAPP's calculation

OTDF flowgates measure the system intact flow on a limiting facility (called the "monitored element") and calculate (by a network response analysis) how much flow from a contingent facility will flow on the limiting facility should an outage of the contingent facility occur. OTDF flowgates are typically only used where the limiting phenomenon is thermal loading on the limiting facility.

PTDF flowgates measure flow for conditions with the transmission system intact and are typically used where the limiting phenomenon is stability or voltage angle related or for thermal loading issues where the limiting facility and the contingent facility are both extra high voltage facilities (e.g., 345 kV lines).

UGPR flowgates include both OTDF and PTDF flowgates.

With respect to requirement 3(c)(ii), UGPR utilizes the MAPP region AFC calculation methodology. In summary, AFC is calculated as the Total Flowgate Capability (referred to as the "TFC" or, equivalently, the "TTC") less CBM less TRM less ETC less transmission service reservation impacts. Detailed information regarding the algorithms used by MAPP for calculating firm and non-firm ATC/AFC is available at: http://toinfo.oasis.mapp.org/oasisinfo/afc_calculation.pdf.

In addition, as part of the Seams Agreement between the UGPR and the Midwest ISO, the MAPP region also calculates Available Share of Total Flowgate Capability ("ASTFC"). The calculation of ASTFC is in accordance with the regional process of allocation of flowgate capability between MAPP and MISO (as well as between other Reciprocal Entities such as PJM, SPP, and TVA). The details of the MAPP's calculation of ASTFC can be found in Section 14 of Appendix F to the latest version of the MAPP Policies and Procedures, which can be found at the MAPP OASIS Information Page at http://toinfo.oasis.mapp.org/oasisinfo/. The Policies and Procedures are listed under the "Business Practices" area.

With respect to requirement 3(c)(iii), MAPP does not presently convert AFC into ATC. Within the MAPP region, ATC is utilized for contract path limitations and AFC is utilized for specific transmission facilities expected to be constraining to sales of transmission service and expected to be congested in real-time operations. Within the MAPP region, both an ATC evaluation and an AFC evaluation are performed for every request for transmission service. After NERC develops rules within the MOD-001 standard for converting AFC into ATC, MAPP will comply with the NERC rules. While MAPP does not convert its AFC values into ATC values, the MAPP Scenario Analyzer is available on the MAPP OASIS to evaluate AFC impacts on ATC on a Control Area to Control Area contract path.

With respect to requirement 3(c)(iv), the databases utilized in AFC assessments are broken down into two areas. First, the databases utilized by UGPR to develop the data inputs it supplies to MAPP for flowgate AFC calculations are the same as those listed in the response to requirement (iii) under Item 3(a) above (for the TTC calculation), as well as those listed in the response to requirement (ii) under 3(b) above (for the ETC calculation) and the data bases listed in the response to requirement 3(d) below (for the TRM calculation). Second, the databases utilized by MAPP in performing the AFC calculation after having been provided the MAPP Transmission Provider data inputs are described in Appendix F to the latest version of the MAPP Policies and Procedures, which can be found at the MAPP OASIS Information Page at http://toinfo.oasis.mapp.org/oasisinfo/. The Policies and Procedures are listed under the "Business Practices" area.

UGPR considers the information in these databases to be Critical Energy Infrastructure Information ("CEII").

With respect to requirement 3(c)(v), the assumptions used in AFC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages are the same as those listed in the response to requirement (iv) under Item 3(a) above (for the TTC calculation), as well as those listed in the response to requirement (ii) under 3(b) above (for the ETC calculation) and the assumptions listed in the response to requirement 3 (d) below (for the TRM calculation).

d. For TRM, a Transmission Provider shall explain: (i) its definition of TRM; (ii) its TRM calculation methodology (e.g., its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (iii) the databases used in its TRM assessments; (iv) the conditions under which the transmission provider uses TRM. A Transmission Provider that does not set aside transfer capability for TRM must so state.

With respect to requirement 3(d)(i), within MAPP, TRM is defined as the Transmission Reliability Margin. TRM provides a reserve that ensures the reliability of the interconnected transmission network. TRM accounts for the inherent uncertainty associated with TTC, ETC and ATC/AFC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change.

With respect to requirement 3(d)(ii), UGPR calculates TRM in accordance with MAPP policies and methodologies. The nature of interfaces dictates how TRM is calculated. MAPP's TRM calculation methodology for flowgates includes the following sub-components, which are described below:

- General Uncertainty. ATC/AFC calculations utilize many assumptions and projections of system conditions, which may include such items as transmission system topology, projected customer demand and its distribution, generation dispatch, future weather conditions, and parallel path flows. Therefore, calculations of future TTC and AFC values must consider the inherent uncertainties in projecting such system parameters over longer time periods. Consistent with MAPP region policies for flowgates, UGPR sets the general uncertainty component of TRM at a value equal to 2% of the flowgate TTC. The 2% value is reasonable based on the many uncertainties discussed above.

- Delivery of Operating Reserves. The operating reserve component of the TRM is defined within MAPP to be the amount of transmission capability on a flowgate required to provide the amount of operating reserves associated with 100% of the greatest single generator contingency impacting the flowgate in the direction of the constraint. For UGPR, the greatest generator outage affecting each flowgate is determined by studying the effect of tripping various generators within the MAPP region and dispatching generators within each Midwest Contingency Reserve Sharing Group ("MCRSG") member's area to reflect their share of the operating reserves required to be delivered to replace the output of the generator that tripped. The generator outages are analyzed with the contingent facility out of service. The greatest generator outage affecting the flowgate is the outage that results in the greatest incremental flow over the flowgate. The highest incremental flow on the flowgate is the amount of TRM required to deliver operating reserves.

- Interdependency of Interfaces. The difference between TTC values developed using simultaneous and non-simultaneous study procedures and the related interdependency of interfaces may be handled by computing a variable TRM. This applies to the North Dakota Export (NDEX) interface.

Within MAPP, the release of TRM on a non-firm basis is allowed provided the flowgate can be operated in compliance with NERC standards. UGPR releases TRM for non-firm AFC postings in three ways. First, the uncertainty sub-component is removed from the TRM for non-firm AFC postings. The removal of the general uncertainty component is appropriate for non-firm AFC postings because non-firm service can be curtailed prior to interrupting firm transmission service. Second, the TRM sub-component related to reserve sharing is reduced to 60% for non-firm ATC postings. This is appropriate because MAPP requires that 40% of the operating reserve must be delivered immediately via spinning reserves and the other 60% must be delivered via fast-start units to be provided within 30-60 minutes. Non-firm curtailments would be expected to be effective before the fast-start 60% portion of the operating reserves needs to be delivered. Third, the TRM sub-component related to TTC values developed using simultaneous and non-simultaneous study procedures is reduced to allow for selling of non-firm capacity identified in a non-simultaneous study; provided that the Transmission Provider has coordinated a procedure for posting of non-firm capability above the simultaneous limit with other affected Transmission Providers.

The methodologies and studies used to determine TRM for each flowgate in the MAPP Region are reviewed and sanctioned through the MAPP Regional Transmission Committee (RTC).

With respect to requirement 3(d)(iii), the databases utilized in TRM assessments include the flowgate TTCs (for the general uncertainty sub-component) and the MCRSG requirements as documented in spreadsheets maintained by the MCRSG and MAPP power flow models, both used for the operating reserve delivery calculation. MAPP, including UGPR, considers the information in these databases to be Critical Energy Infrastructure Information ("CEII").

With respect to requirement 3(d)(iv), TRM is utilized for all firm and non-firm flowgate AFC calculations. 100% of the TRM value is utilized for firm flowgate AFC calculations. Portions of the TRM are released for non-firm flowgate AFC calculations as discussed in the response to requirement 3(d)(ii) above. TRM is not utilized for contract path ATC calculations.

e. For CBM, the Transmission Provider shall include a specific and self-contained narrative explanation of its CBM practice, including: (i) an identification of the entity who performs the resource adequacy analysis for CBM determination; (ii) the methodology used to perform generation reliability assessments (e.g., probabilistic or deterministic); (iii) an explanation of whether the assessment method reflects a specific regional practice; (iv) the assumptions used in this assessment; and (v) the basis for the selection of paths on which CBM is set aside.

UGPR does not include CBM on any of its contract paths or flowgates. These requirements are therefore not applicable to UGPR and no response is provided.

f. In addition, for CBM, a Transmission Provider shall: (i) explain its definition of CBM; (ii) list the databases used in its CBM calculations; and (iii) demonstrate that there is no double-counting of contingency outages when performing CBM, TTC, and TRM calculations.

UGPR does not include CBM on any of its contract paths or flowgates. These requirements are therefore not applicable to UGPR and no response is provided.

g. The Transmission Provider shall explain its procedures for allowing the use of CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). If the Transmission Provider's practice is not to set aside transfer capability for CBM, it shall so state.

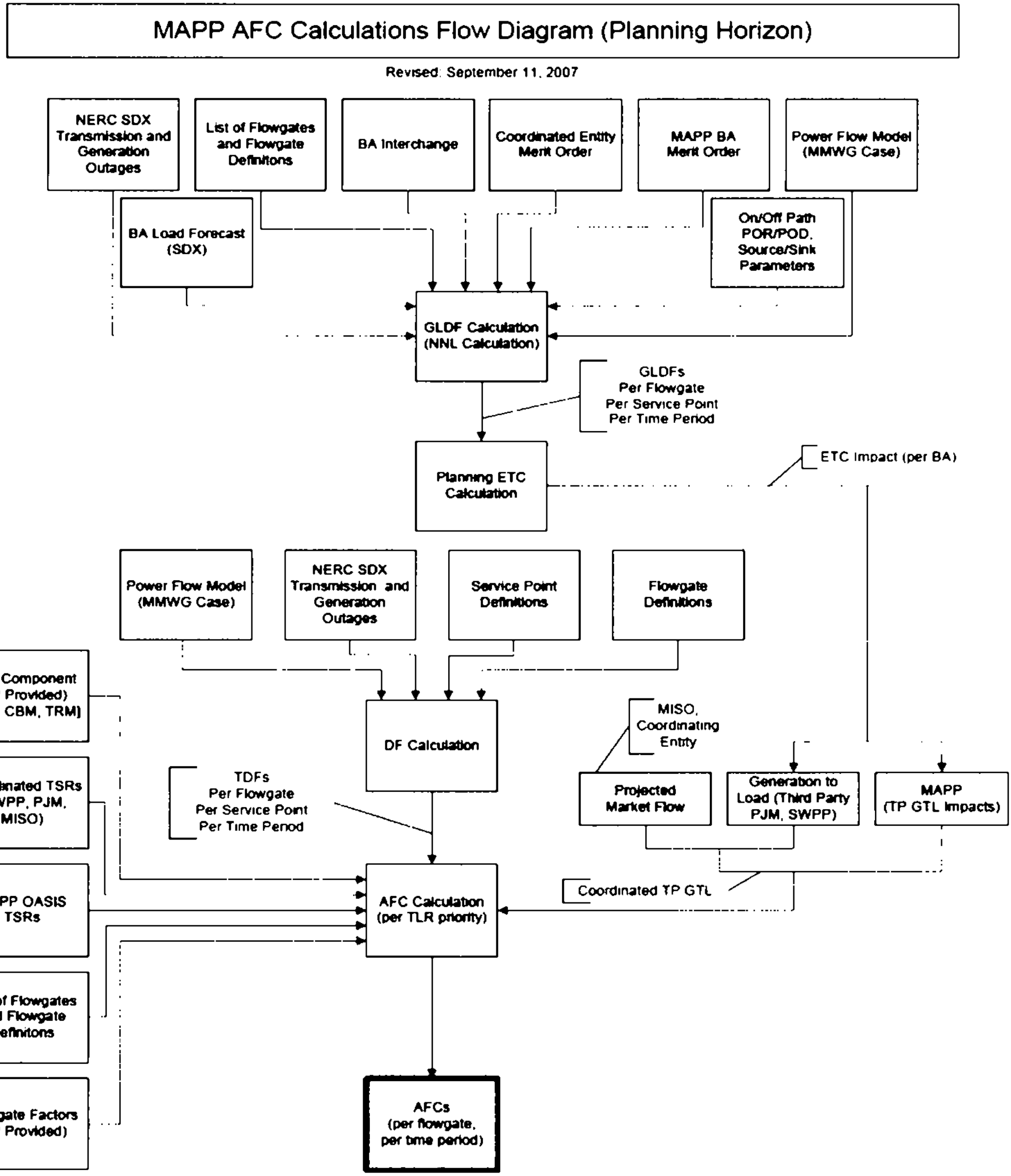
UGPR does not include CBM on any of its contract paths or flowgates. These requirements are therefore not applicable to UGPR and no response is provided.

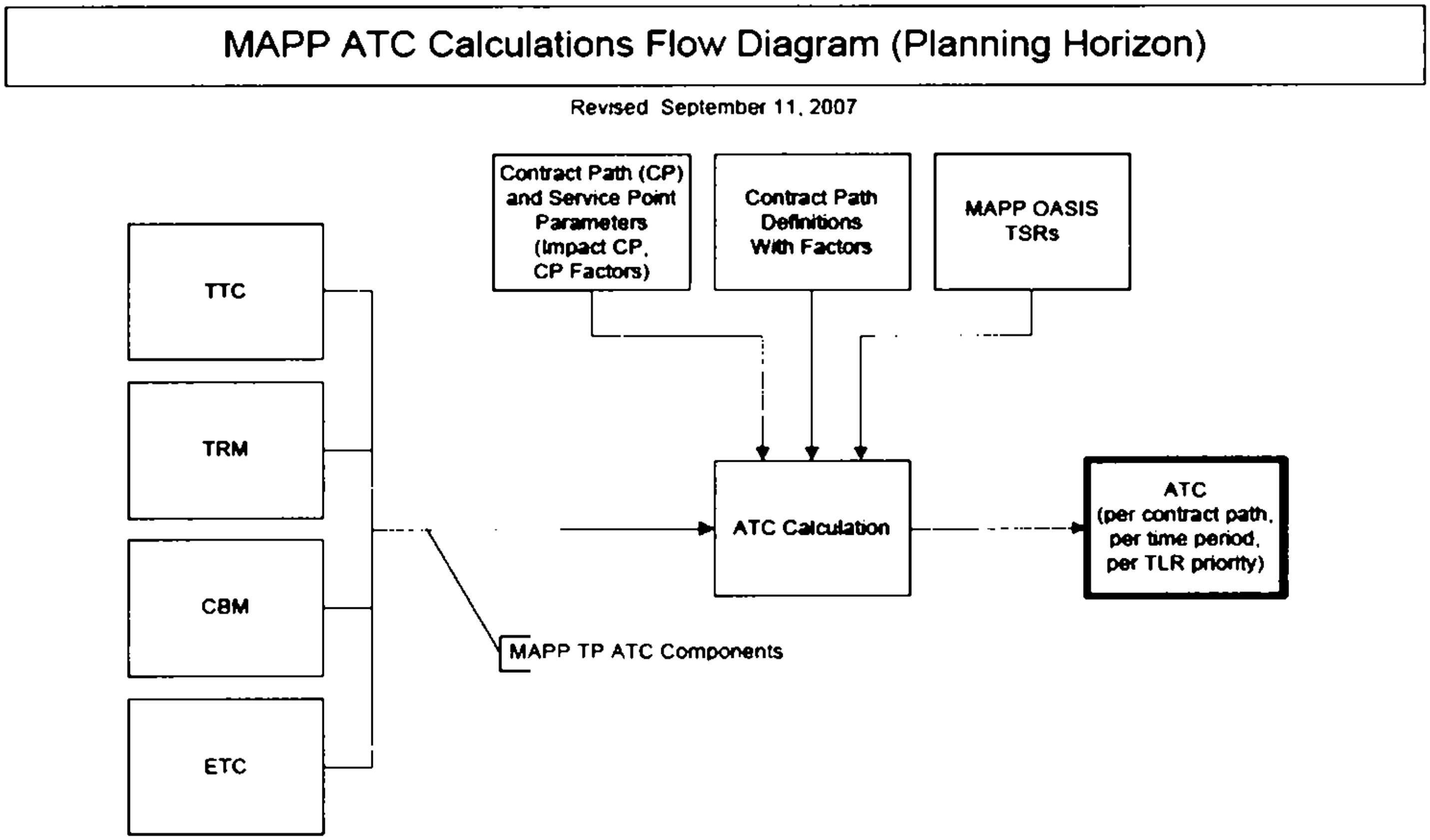
(4) An explanation of the process for coordinating ATC calculations with neighboring systems.

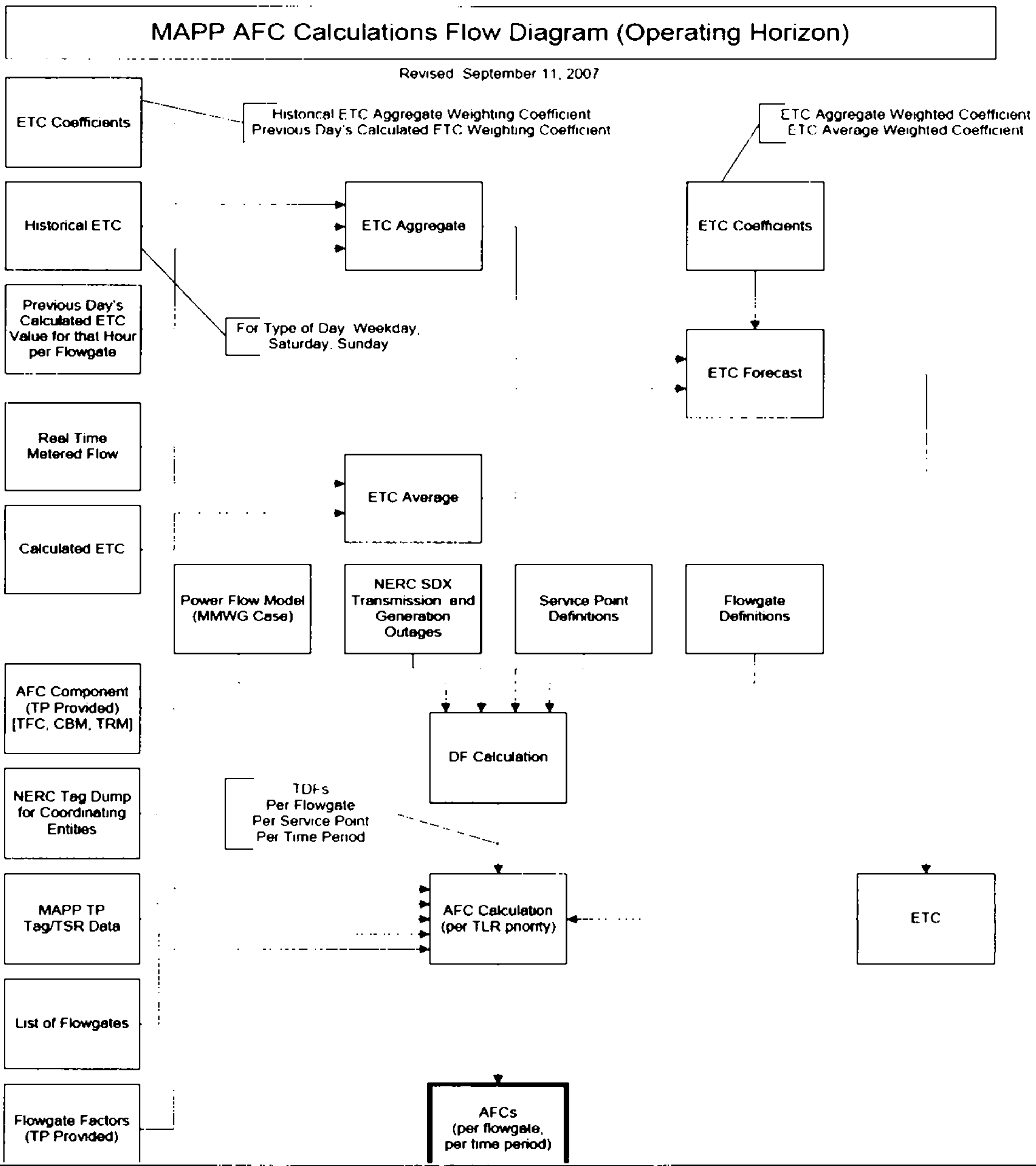
MAPP and the Transmission Provider coordinate ATC calculations with neighboring systems in a number of ways:

- MAPP utilizes the coordination procedures outlined in the Seams Agreement between UGPR and the Midwest ISO. Under that agreement:
    - Flowgates are subjected to a number of tests to determine if the flowgate will be reciprocally coordinated between entities subject to the Congestion Management Process (as such term is used in the Seams Agreement) which entities include not only the Midwest ISO but also PJM, SPP and TVA.
    - MAPP monitors in its evaluation of transmission service requests all flowgates for which it is deemed to be reciprocal. MAPP does not calculate the AFC for these flowgates but rather uses the values provided by the owner of the flowgate.
    - MAPP provides AFC values for all MAPP flowgates to the other reciprocal entities to the various seams agreements. Those entities then monitor the MAPP flowgates in their evaluations of transmission service.
    - MAPP makes its reservations available to other parties for their use in calculating reservation impacts on their flowgates.
    - As discussed in the response to 3(b)(ii), the MAPP process can accept flow information from adjoining centralized dispatch markets. In the case of the Midwest ISO, the flow information is provided for all MAPP Transmission Provider flowgates that meet the coordination requirements in the Congestion Management Process described in the Seams Agreement.
    - As discussed in the response to 3(b)(iii), MAPP downloads OASIS reservations from the Midwest ISO, PJM and SPP OASIS nodes. MAPP includes these reservations in its calculation of point-to-point transmission service request impacts for MAPP Transmission Provider flowgates.
    - As discussed in the response to 3(b)(iv), MAPP and the Midwest ISO have agreed to take into account the roll-over rights of the other party.
    - As discussed in the response to 3(c)(ii), the MAPP region also calculates Available Share of Total Flowgate Capability ("ASTFC"). The calculation of ASTFC is in accordance with the regional process of allocation of flowgate capability between MAPP and MISO (as well as between other Reciprocal Entities such as PJM, SPP, and TVA).

- The Transmission Provider coordinates its calculation of TTC with neighboring systems such that the appropriate facility ratings of the tie-lines are used for setting the Control Area to Control Area contract path TTC. For flowgates that involve tie-lines with other entities, UGPR utilizes the appropriate facility ratings in the determining the flowgate TFC.

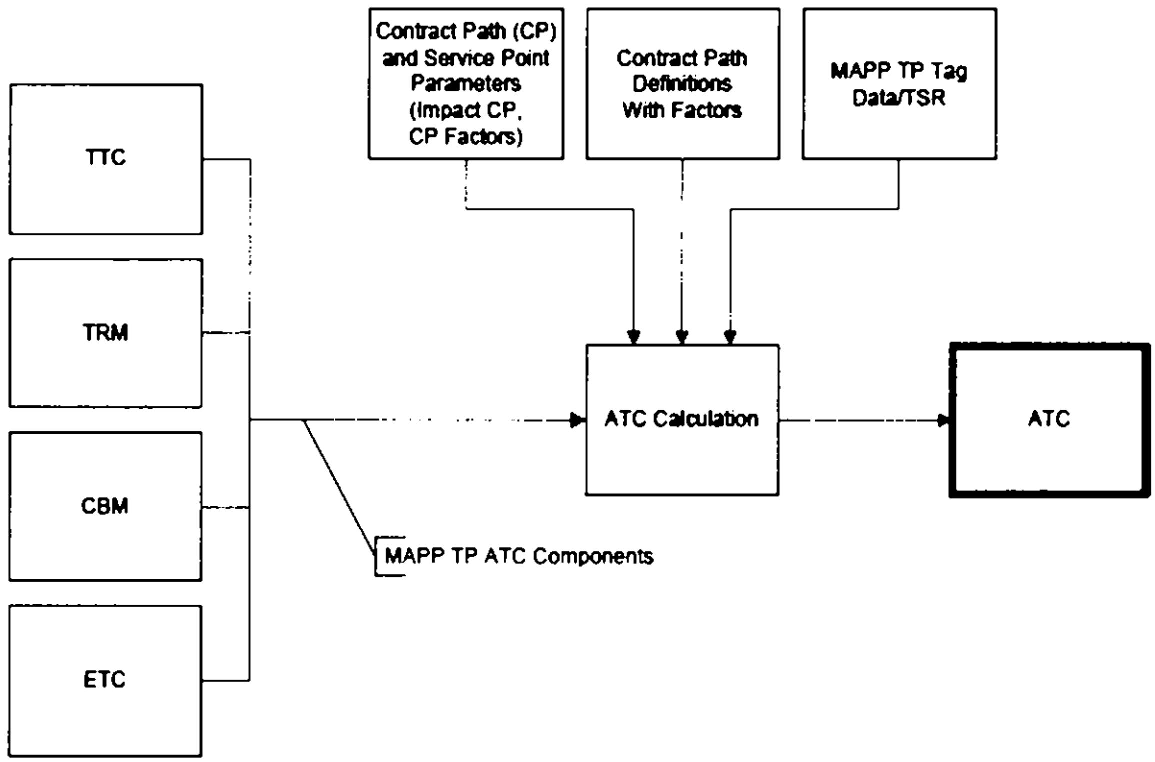

MAPP AFC Calculations Flow Diagram (Planning Horizon)
Revised: September 11, 2007
NERC SDX Transmission and Generation Outages
List of Flowgates and Flowgate Definitons
BA Interchange
Coordinated Entity Merit Order
MAPP BA Merit Order
Power Flow Model (MMWG Case)
BA Load Forecast (SDX)
On/Off Path POR/POD, Source/Sink Parameters
GLDF Calculation (NNL Calculation)
GLDFs Per Flowgate Per Service Point Per Time Period
Planning ETC Calculation
ETC Impact (per BA)
Power Flow Model (MMWG Case)
NERC SDX Transmission and Generation Outages
Service Point Definitions
Flowgate Definitions
AFC Component (TP Provided) [TFC, CBM, TRM]
DF Calculation
MISO, Coordinating Entity
Coordinated TSRs (SWPP, PJM, MISO)
TDFs Per Flowgate Per Service Point Per Time Period
Projected Market Flow
Generation to Load (Third Party PJM, SWPP)
MAPP (TP GTL Impacts)
MAPP OASIS TSRs
AFC Calculation (per TLR priority)
Coordinated TP GTL
List of Flowgates and Flowgate Definitons
Flowgate Factors (TP Provided)
AFCs (per flowgate, per time period)


MAPP ATC Calculations Flow Diagram (Planning Horizon)
Revised September 11, 2007
Contract Path (CP) and Service Point Parameters (Impact CP, CP Factors)
Contract Path Definitions With Factors
MAPP OASIS TSRs
TTC
TRM
CBM
ETC
ATC Calculation
ATC (per contract path, per time period, per TLR priority)
MAPP TP ATC Components


MAPP AFC Calculations Flow Diagram (Operating Horizon)
Revised September 11, 2007
ETC Coefficients
Historical ETC Aggregate Weighting Coefficient
Previous Day's Calculated ETC Weighting Coefficient
ETC Aggregate Weighted Coefficient
ETC Average Weighted Coefficient
Historical ETC
ETC Aggregate
ETC Coefficients
Previous Day's Calculated ETC Value for that Hour per Flowgate
For Type of Day Weekday, Saturday, Sunday
ETC Forecast
Real Time Metered Flow
ETC Average
Calculated ETC
Power Flow Model (MMWG Case)
NERC SDX Transmission and Generation Outages
Service Point Definitions
Flowgate Definitions
AFC Component (TP Provided) [TFC, CBM, TRM]
DF Calculation
NERC Tag Dump for Coordinating Entities
TDFs
Per Flowgate
Per Service Point
Per Time Period
MAPP TP Tag/TSR Data
AFC Calculation (per TLR priority)
ETC
List of Flowgates
Flowgate Factors (TP Provided)
AFCs (per flowgate, per time period)

MAPP ATC Calculations Flow Diagram (Operating Horizon)

Revised. September 11, 2007



ATTACHMENT D

Methodology for Completing a System Impact Study

The Transmission Provider will assess the capability of the Transmission System to provide the service requested using the criteria and process for this assessment as detailed in Sections 4 and 5 of ~~the Transmission Provider's annual~~ FERC Form 715 submitt~~al~~ed to the Commission ~~in those instances where~~on behalf of the Transmission Provider ~~is a member of~~by the Western Electricity Coordinating Council (WECC), in those instances where the Transmission Provider is a member of WECC or successor entity (Colorado River Storage Project, Desert Southwest Region, Rocky Mountain Region, and Sierra Nevada Region). The Transmission Provider will use the Mid-Continent Area Power Pool (MAPP) System Impact Study Methodology when the Transmission Provider is a member of MAPP, or successor entity (Upper Great Plains Region).

ATTACHMENT E

Index of Point-To-Point Transmission Service Customers

Customer	Date of Service Agreement

ATTACHMENT F

Service Agreement for Network Integration Transmission Service

1.0 This Service Agreement, dated as of ____________________, is entered into, by and between the (Region) of Western Area Power Administration (Transmission Provider), and __________________ (Transmission Customer), each of whom are sometimes hereinafter individually called Party and both are sometimes hereinafter collectively called the Parties. For purposes of this Service Agreement, the Transmission Provider's Transmission Systems consist of the applicable facilities described in Attachment K to the Tariff.

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff. The Transmission Customer has provided to the Transmission Provider a deposit and nonrefundable application processing fee in accordance with the provisions of Section 29.2 of the Tariff.

3.0 Service under this Service Agreement shall commence on the later of (1) __________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as is mutually agreed. Service under this Service Agreement shall terminate on ______________________________.

4.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff, and this Service Agreement.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

Each Party may change the designation of its representative upon oral notice to the other, with confirmation of that change to be submitted in writing within ten (10) days thereafter.

6.0 The Tariff and the "Specifications for Network Integration Transmission Service" as presently constituted or as they may be revised or superseded are incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

WESTERN AREA POWER ADMINISTRATION

By ______________________

Title ______________________

Address ______________________

____

Date ______________________

(TRANSMISSION CUSTOMER)

(SEAL) By ______________________

Attest: Title ______________________

By ______________ Address ______________________

Title ______________ ______________________

Date ______________________

Specifications for Network Integration Transmission Service

For purposes of this Service Agreement, the Transmission Provider's Transmission System consists of the facilities of the (Region) as described in Attachment K.

1.0 The Transmission Provider will provide Network Integration Transmission Service over the Transmission Provider's Transmission System for the delivery of capacity and energy from the Network Customer's designated Network Resources to the Network Customer's designated Network Load. The Transmission Provider will also provide non-firm transmission service from non-designated Network Resources under the terms of this Service Agreement. The loss factors associated with this Network Integration Transmission Service are set forth below. Such losses shall be applied and accounted for as set forth in Section 4.

2.0 Designated Network Resources:

Designated Network Resources & Estimated Maximum Resource (MW)	Point of Receipt	Delivering Party & Voltage

3.0 Designated Network Loads:

Designated Network Load & Estimated Maximum Resource (MW)	Point of Delivery	Voltage

4.0 Transmission Losses:

4.1 Loss Factors:

4.1.1 If, based on operating experience and technical studies, the Transmission Provider determines that any of the transmission loss factors on the Transmission Provider's Transmission System differs from the loss factors set forth in this Service Agreement, the Transmission Provider will notify the Transmission Customer of the revised loss factor(s) pursuant to Section 1.0 of this Service Agreement.

4.1.2 Transmission Provider Transmission Loss Factor: For deliveries to the Network Customer Network Load, Transmission Provider transmission losses shall initially be __% and shall be assessed on the power scheduled and transmitted to a point of delivery on the Transmission Provider's Transmission System.

4.2 Transmission losses may be revised by written notice from the Transmission Provider to the Transmission Customer.

5.0 The Network Customer's transmission facilities that are integrated with the Transmission Provider's Transmission System will receive _____ credit (To be filled in if appropriate). These facilities include the following:

5.1 (To be filled in if appropriate)
5.2 (To be filled in if appropriate)

6.0 Names of any intervening systems with whom the Network Customer has arranged for transmission service to the Transmission Provider's Transmission System.

6.1 ______________________
6.2 ______________________

7.0 Power Factor: The Transmission Customer will be required to maintain a power factor between -percent lagging and -percent leading for all deliveries of capacity and energy to and from the Transmission Provider's Transmission System.

8.0 Ancillary Services

8.1 Provided by Transmission Provider

8.1.1 Scheduling, System Control, and Dispatch Service
8.1.2 Reactive Supply and Voltage Control from Generation Sources Service

8.2 Provided by Transmission Customer

8.2.1 (To be filled in if appropriate)
8.2.2

8.3 Provided by

8.3.1 (To be filled in if appropriate)
8.3.2

9.0 Net Billing and Bill Crediting Option: The Parties have agreed to implement [Net Billing, Bill Crediting, both Net Billing and Bill Crediting, or neither Net Billing nor Bill Crediting] as set forth in Attachment J.

10.0 Charges for Service: Charges for Network Integration Transmission Service and associated Ancillary Services shall be calculated in accordance with the applicable Rate Schedule(s) attached hereto and made a part of this Service Agreement. The rates or rate methodology used to calculate the charges for service under that schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations and policies.

[The following section will be included as appropriate at the Transmission Provider's discretion]

11.0 Independent System Operator: The Parties understand that the Transmission Provider may join an independent system operator under Commission jurisdiction. In the event the Transmission Provider either joins or is required to conform to protocols of the independent system operator, the Parties agree that the Transmission Provider either may (1) make any changes necessary to conform to the terms and conditions required by Commission approval of the independent system operator, or (2) terminate this Service Agreement by providing a one-year written notice to the Transmission Customer.

ATTACHMENT G

Network Operating Agreement

To be executed by the Transmission Provider if necessary, at such time as the Transmission Provider has negotiated or offered a Network Integration Transmission Service Agreement. The terms and conditions under which the Network Customer will be required to operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service and this Service Agreement will be specified in a separate Network Operating Agreement.

The Network Operating Agreement will include provisions addressing the following:

Authorized Representatives of the Parties
Network Operating Committee
Load Following
System Protection
Redispatch to Manage Transmission Constraints
Maintenance of Facilities
Load Shedding
Operation Impacts
Service Conditions
Data, Information and Reports
Metering
Communications
System Regulation and Operating Reserves
Assignment
Notices
Accounting for Transmission Losses

ATTACHMENT H

Annual Transmission Revenue Requirement for Network Integration Transmission Service

1.0 The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service is to be set forth in a separate Rate Schedule.

2.0 The amount in 1 shall be effective until amended by the Transmission Provider or modified by the Commission pursuant to applicable Federal laws, regulations and policies, and may be revised upon written notice to the Transmission Customer.

ATTACHMENT I

Index of Network Integration Customers

Customer	Date of Service Agreement

ATTACHMENT J

Provisions Specific to the Transmission Provider

1.0 Change of Rates

Rates applicable under the Service Agreements shall be subject to change by Transmission Provider in accordance with appropriate Rate Adjustment procedures. If at any time the Transmission Provider promulgates a rate changing a rate then in effect under a Service Agreement, it will promptly notify the Transmission Customer thereof. Rates shall become effective as to the Service Agreements as of the effective date of such rate. If the adjustment in the formula or rate results in an increase in the charges for Transmission Customers, the Transmission Customer may terminate the service billed by the Transmission Provider under the Rate Formula Adjustment or Rate Adjustment by providing written notice to the Transmission Provider within ninety (90) days after the effective date of the Rate Formula Adjustment or Rate Adjustment. Said termination shall be effective on the last day of the billing period requested by the Transmission Customer not later than two (2) years after the effective date of the New Rate. Service provided by the Transmission Provider shall be paid for at the New Rate regardless of whether the Transmission Customer exercises the option to terminate service. This provision does not apply in those instances where rates change because the Transmission Provider updates charges pursuant to an existing formula rate.

2.0 Appropriations and Authorizations

2.1 Contingent Upon Appropriations

Where activities provided for in the Service Agreement extend beyond the current fiscal year, continued expenditures by the Transmission Provider are contingent upon Congress making necessary appropriations required for the continued performance of the Transmission Provider's obligations under the Service Agreement. In case such appropriation is not made, the Transmission Customer hereby releases the Transmission Provider from its contractual obligations and from all liability due to the failure of Congress to make such appropriation.

2.2 Contingent Upon Authorization Language

In order to receive and expend funds advanced from the Transmission Customer necessary for the continued performance of the obligations of the Transmission Provider under the Service Agreement, additional authorization may be required. In case such authorization is not received, the Transmission Customer hereby releases the Transmission Provider from those contractual obligations and from all liability due to the lack of such authorization.

3.0 Covenant Against Contingent Fees

The Transmission Customer warrants that no person or selling agency has been employed or retained to solicit or secure the Service Agreement upon a contract or understanding for a commission, percentage, brokerage, or contingent fee, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Transmission Customer for the purpose of securing business. For breach or violation of this warranty, the Transmission Provider shall have the right to annul the Service Agreement without liability or in its discretion to deduct from the Service Agreement price or consideration the full amount of such commission, percentage, brokerage, or contingent fee.

4.0 Contract Work Hours and Safety Standards

The Service Agreement, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act (Act), 40 U.S.C. § ~~329~~3701, as amended or supplemented, is subject to the provisions of the Act, 40 U.S.C. §§ ~~327-333~~3701-3708, as amended or supplemented, and to regulations promulgated by the Secretary of Labor pursuant to the Act.

5.0 Equal Opportunity Employment Practices

Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), as amended or supplemented, which provides, among other things, that the Transmission Customer will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Service Agreement the same as if the specific language had been written into the Service Agreement, except that Indian Tribes and tribal organizations may apply Indian preference to the extent permitted by Federal law.

6.0 Use of Convict Labor

The Transmission Customer agrees not to employ any person undergoing sentence of imprisonment in performing the Service Agreement except as provided by 18 U.S.C. § 3622(c), as amended or supplemented, and Executive Order 11755, 39 Fed. Reg. 779 (1973), as amended or supplemented.

7.0 Entire Agreement

The Service Agreements, including the Tariff, together with the specifications under such Service Agreement and any completed scheduling forms shall constitute the entire understanding between the Transmission Provider and the Transmission Customer with respect to Transmission Service thereunder.

8.0 Power Supply Obligations

The Transmission Provider shall not be obligated to supply capacity and energy from its own sources or from its purchases from other neighboring systems during Interruptions or Curtailments in the delivery by the Transmission Provider or delivery to the Transmission Provider by the Delivering Party of capacity and energy for Transmission Service hereunder, and nothing in the Service Agreement or in the Transmission Customer's agreements with others shall have the effect of making, nor shall anything in the Service Agreement or said agreements with others be construed to require the Transmission Provider to take any action which would make the Transmission Provider, directly or indirectly, a source of power supply to the Transmission Customer, to any Delivering Party or Receiving Party, or to any ultimate recipient other than through the provision of Operating Reserve Service.

9.0 Federal Law

Performance under the Tariff and Service Agreement shall be governed by applicable Federal law.

10.0 Continuing Obligations

The applicable provisions of the Service Agreement will continue in effect after termination of the Service Agreement to the extent necessary to provide for final billing, billing adjustments and payments, and with respect to liability and indemnification from acts or events that occurred while this Service Agreement was in effect.

11.0 Net Billing

As mutually agreed in the Service Agreement, payments due the Transmission Provider by a Transmission Customer may be offset against payments due the Transmission Customer by the Transmission Provider for the use of transmission facilities, operation and maintenance of electric facilities, and other services. For services included in net billing procedures, payments due one Party in any month shall be offset against payments due the other Party in such month, and the resulting net balance shall be paid to the Party in whose favor such balance exists. The Parties shall exchange such reports and information that either Party requires for billing purposes. Net billing shall not be used for any amounts due which are in dispute.

12.0 Bill Crediting

As mutually agreed in the Service Agreement, payments due the Transmission Provider by a Transmission Customer shall be paid by a Transmission Customer to a third party when so directed by the Transmission Provider. Any third party designated to receive payment in lieu of the Transmission Provider, and the amount to be paid to that party, will be so identified in writing to a Transmission Customer with the monthly power bill. The payment to the third party shall be due and payable by the payment due date specified on the Transmission Provider's bill. When remitting payment to a designated third party, a Transmission Customer shall indicate that such payment is being made on behalf of the Transmission Provider. The Transmission Provider shall credit a Transmission Customer for the amount paid as if payment had been made directly to the Transmission Provider. All other payment provisions shall remain in full force and effect.

13.0 Costs Associated with United States Bureau of Reclamation and United States Army Corps of Engineers Interconnections

The Transmission Provider and the United States Bureau of Reclamation (Bureau) and the United States Army Corps of Engineers (Corps) have a unique statutory relationship which requires the Transmission Provider to repay to the United States Treasury obligations incurred by those two entities related to the production of power. Requiring the Bureau or Corps to submit deposits to the Transmission Provider or to directly pay for costs associated with interconnection study work under the Tariff, including the Large Generator Interconnection Agreement or Large Generator Interconnection Procedures, will result in additional unnecessary administrative burdens and overhead charges. Therefore, Transmission Provider reserves the right, at the Transmission Provider's discretion, to not require the Bureau or the Corps to pay negotiation costs under the Large Generation Interconnection Procedures, or submit deposits in whole or in part for study work or for placing reservations in the queue. Transmission ~~p~~Provider will account for these costs under the Transmission Provider's Tariff as if such costs had been paid by the Bureau or Corps, including costs associated with the Standard Large Generator Interconnection Agreement (LGIA) or Standard Large Generator Interconnection Procedures (LGIP) found in Attachment L of the Transmission Provider's Tariff.

14.0 Participant Funding

The Transmission Provider reserves the right to negotiate participant funding provisions if and when it deems necessary, and to incorporate the results of such negotiations into the LGIA. This will allow Transmission Provider to properly and equitably fulfill its responsibility as the transmission provider for various facilities owned by other entities, including facilities in which Transmission Provider has joint ownership.

15.0 Liability

The Transmission Provider is only liable for negligence on the part of its officers and employees in accordance with the Federal Tort Claims Act, 28 U.S.C. § 1346(b), 1346(c), 2401(b), 2402, 2671, 2672, 2674-2680, as amended or supplemented.

16.0 Environmental Compliance

Transmission [or Interconnection] Customer recognizes that as a Federal agency, Transmission Provider must comply with various environmental and natural resource laws regulating the construction, operation and maintenance of its transmission facilities, including but not limited to the National Historic Preservation Act, 16 U.S.C § 470 to 470x-6, the National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321-4347, the Endangered Species Act, 16 U.S.C. §§ 1531-1544, and the Archaeological Resources Protection Act of 1979, 16 U.S.C. § 470aa-470mm

(2006); and regulations, and executive orders implementing these laws, as they may be amended or supplemented, as well as any other existing or subsequent applicable laws, regulations and executive orders. Transmission [or Interconnection] Customer shall comply with all environmental laws, regulations and resource protection measures, including but not limited to, any mitigation measures and Best Management Practices associated with the Transmission [or Interconnection] Customer's requested service. Transmission [or Interconnection] Customer understands that the Transmission Provider's decision to execute the LGIA is dependent on conclusions reached in the record of decision under NEPA, or other such appropriate NEPA document, concerning the respective project and that Transmission Provider's NEPA review could result in a decision not to execute a Tariff agreement or to delay Tariff agreement execution. This decision shall not be subject to dispute resolution.

ATTACHMENT K

Authorities and Obligations

Western was established on December 21, 1977, pursuant to Section 302 of the Department of Energy (DOE) Organization Act, Public Law 95-91, dated August 4, 1977. By law, the Bureau of Reclamation provides Federal power resources to its project use customers. By law, Western markets Federal power resources to its electric service customers. Western's transmission system was built primarily to enable the delivery of Federal power to satisfy these ~~contractual~~ obligations.

Western is not a public utility under Sections 205 and 206 of the Federal Power Act and is not specifically subject to the requirements of the Commission's Final Orders related to Open Access Transmission or Generator Interconnections. Western is a transmitting utility subject to Sections 21~~1~~0-213 of the Federal Power Act ~~as amended by the Energy Policy Act of 1992~~. The Department of Energy has issued a Power Marketing Administration Open Access Transmission Policy that supports the intent of the Commission's Notice of Proposed Rulemaking for Open Access Transmission.

Use of transmission facilities that Western owns, operates, or to which it has contract rights for delivery of Federal long-term firm capacity and energy to project use and electric service customers is a Western responsibility under the terms and conditions of marketing criteria and electric service contracts implementing statutory obligations to market Federal power. This is complementary with the provisions of the Tariff. Transmission service provided by Western under the Tariff is solely for the use of Available ~~Transmission~~ Transfer Capability (ATC) in excess of the capability Western requires for the delivery of long-term firm capacity and energy to project use and electric service customers of the Federal government. Western will offer to provide others transmission service equivalent to the service Western provides itself.

Western's Regional Offices' reserved transmission capacity shall therefore include capacity sufficient to deliver Federal power resources to customers of the Federal government. Nothing in this Tariff shall alter, amend or abridge the statutory or contractual obligations of Western to market and deliver Federal power resources and to repay the Federal investment in such projects. The Tariff provides for transmission service, including each Regional Office's use of those facilities for Third Party Sales, on the unused capability of transmission facilities under the jurisdiction or control of each of Western's Regional Offices not required for the delivery of long-term firm capacity and energy to customers of the Federal government in a manner consistent with the spirit and intent of the Commission's Order Nos. 888 and ~~888-A~~890, et seq.

Western has prepared this Tariff and Service Agreements to provide transmission service comparable to that required of public utilities by ~~T~~the Commission's ~~Order Nos. 888 and 888-A~~ open access orders, and to implement those ~~O~~orders consistent with the DOE Policy. An entity desiring transmission service from Western must comply with the application procedures outlined herein. The review and approval requirements detailed herein will apply to all requesting parties. Western will perform the necessary studies or assessments for evaluating requests for transmission service as set forth in the Tariff. Any facility construction or interconnection necessary to provide transmission service will be subject to Western's General Requirements for Interconnection which are available upon request.

Western will provide Firm and Non-Firm Point-to-Point Transmission Service and Network Integration Transmission Service under this Tariff. The specific terms and conditions for providing transmission service to a customer will be included in a Service Agreement. Operating Procedures, ATC, and System Impact Methodology are defined in the Attachments. Western's rates are developed under separate public processes pursuant to applicable Federal law and regulations. Therefore, rates and charges for specific services will be set forth in the appropriate Regional rate schedules attached to each Service Agreement.

Western has marketed the maximum practical amount of power from each of its projects, leaving little or no flexibility for provision of additional power services. Changes in water conditions frequently affect the ability of hydroelectric projects to meet obligations on a short-term basis. The unique characteristics of the hydro resource, Western's marketing plans and the limitations of the resource due to changing water conditions limit Western's ability to provide generation-related services including Ancillary Services and redispatching using Federal hydro resources.

Western operates in 15 central and western states encompassing a geographic area of 3.38 million-square-kilometers (1.3 million-square-miles). Western has four Customer Service Regional Offices, the Desert Southwest Region, Rocky Mountain Region, Sierra Nevada Region, Upper Great Plains Region, and the Colorado River Storage Project Management Center. Each office is referred to in the Tariff as Regional Office. The addresses for submitting applications to Western's Regional Offices by mail, as well as the respective OASIS links, are available on Western's web site at www.wapa.gov.

Colorado River Storage Project Management Center

The Colorado River Storage Project Management Center (CRSP MC), located in Salt Lake City, Utah, markets power from three Federal multipurpose water development projects: the Colorado River Storage Project (CRSP), the Collbran Project, and the Rio Grande Project, collectively called the Integrated Projects. The hydroelectric facilities associated with these projects include: Flaming Gorge and Fontenelle powerplants on the Green River; Blue Mesa, Morrow Point, and Crystal powerplants on the Gunnison River; Upper and Lower Molina powerplants of the Collbran Project in Western Colorado; the largest of the CRSP facilities, Glen Canyon powerplant on the Colorado River; and Elephant Butte powerplant, part of the Rio Grande Project on the Rio Grande River in South Central New Mexico; McPhee powerplant and Towaoc Canal on the Dolores River in southwestern Colorado. The CRSP transmission system consists of high-voltage transmission lines and attendant facilities extending from Arizona, into New Mexico, through Colorado, and into portions of Utah and Wyoming. The CRSP MC uses the CRSP transmission system to meet its commitments to its Federal customers, point-to-point transmission customers, and exchange power contractors. The CRSP MC must, therefore, reserve sufficient transmission capacity to meet these long-term obligations. The CRSP MC also needs to reserve capacity in its transmission system to enable it to deliver power produced by the

Integrated Projects hydroelectric powerplants during periods when flood control water releases produce greater than normal generation levels.

The CRSP MC office, located in Salt Lake City, is a member of the Western Electricity Coordinating Council (WECC).

The CRSP MC does not operate a Control Area and as such may be unable to provide some or all of the services under the Tariff from its Integrated Projects hydroelectric resources, including, but not limited to, ancillary services and Network Integration Transmission Service.

Desert Southwest Region

The Desert Southwest Region (DSR) manages transmission facilities in the states of Arizona, California, and Nevada. The DSR transmission facilities are interconnected with transmission facilities of several non-Federal entities and its system is operated in the WECC. For the purpose of implementing this Tariff the transmission facilities of the Parker-Davis Projects and the Pacific Northwest-Pacific Southwest Intertie Project (Pacific AC Intertie) will be utilized. For the purpose of implementing this Tariff, references in the Tariff to "deliveries of long-term firm capacity and energy" include the deliveries of Boulder Canyon Project electric service over the DSR Transmission System. DSR manages a control area operations center through its Desert Southwest Regional Office located in Phoenix, Arizona.

Rocky Mountain Region

The Rocky Mountain Region (RMR) manages transmission facilities in the states of Colorado, Wyoming, Nebraska, and Kansas which were constructed for the primary purpose of marketing power from the Pick-Sloan Missouri Basin Program - Western Division. The RMR office and Control Area operations center is located in Loveland, Colorado and its system is operated in the WECC.

For RMR, the rates for Point-to-Point and Network Integration Transmission Service charged pursuant to the Tariff will be calculated using the costs of the transmission facilities of the Pick-Sloan Missouri Basin Program - Western Division. The rates for the Ancillary Services will be calculated using the costs of the generation facilities of the CRSP within the RMR control area, Pick-Sloan Missouri Basin Program - Western Division and the Fryingpan-Arkansas Project.

Sierra Nevada Region

The Sierra Nevada Customer Service Region (SNR), located in Folsom, California, manages the Central Valley Project (CVP) transmission facilities in the State of California. These facilities were constructed for the primary purpose of marketing power resources from the CVP. SNR also has ownership rights to capacity in three multi-party transmission systems, the Pacific AC Intertie, the California-Oregon Transmission Project (COTP), and the Los Banos-Gates Transmission Upgrade Project (Path 15). Congress authorized SNR's participation in the Pacific

AC Intertie for the purpose of importing power from the Pacific Northwest. COTP rights were acquired pursuant to Public Laws 98-360 and 99-88, primarily for the purpose of delivering power to the United States Department of Energy Laboratories and Federal Fish and Wildlife refuges. Path 15 upgrade rights were also acquired pursuant to Public Laws 98-360 and 99-88. Long-term use of the Pacific AC Intertie, CVP and COTP by third parties is restricted under existing contracts. SNR has turned over operational control of its Path 15 upgrade rights to the California Independent System Operator (CAISO). Therefore, the CAISO, or its successor will offer transmission service on Path 15. SNR is a member of the WECC.

The SNR does not operate a Control Area and as such may be unable to provide some or all of the services under the Tariff, including but not limited to, Ancillary Services and Network Integration Transmission Service.

Upper Great Plains Region

The Upper Great Plains Region (UGPR) manages transmission facilities in the states of Montana, North Dakota, South Dakota, Nebraska, Minnesota, and Iowa which were constructed for the primary purpose of marketing power from the Pick-Sloan Missouri Basin Program - Eastern Division. The UGPR office is located in Billings, Montana. The UGPR manages a Control Area operations center in Watertown, South Dakota. The eastern portion of the UGPR system is operated in the MAPP reliability council, or successor entity. The western portion of the system is operated in the WECC.

The UGPR transmission facilities are integrated with the transmission facilities of Basin Electric Power Cooperative (Basin) and Heartland Consumers Power District (Heartland) such that transmission services are provided over an integrated transmission system. UGPR rates for Point-to-Point and Network Integration Transmission Service charged pursuant to the Tariff will be calculated using the costs of the transmission facilities of UGPR, Basin, and Heartland that are included in the Transmission System. This Transmission System is also called the Integrated System (IS) and the rates are identified as IS Rates.

Both Basin and Heartland also own generating facilities and must commit to deliver the output of those resources to their respective members. Basin and Heartland will therefore reserve sufficient capacity in their transmission facilities to deliver that output.

Any Transmission Customer taking service under this Tariff shall be subject to a Stranded Cost Charge payable to either UGPR, Basin or Heartland if such service is used for the transmission of power or energy that replaces wholly or in part, power or energy supplied by Western, Basin or Heartland, respectively.

The Stranded Cost Charge of Basin shall be applicable regardless of whether the transmission relates to power and/or energy that is purchased by or on behalf of a Generation and Transmission Cooperative member of Basin (G&T), a Distribution Cooperative member of Basin or G&T, or a retail customer of a Distribution Cooperative member of Basin or a G&T.

The Stranded Cost Charge of Heartland shall be applicable whether the transmission service relates to power and/or energy that is purchased by or on behalf of a municipal customer of Heartland or a retail customer of a municipal customer of Heartland.

Stranded costs will be recovered only from a Transmission Customer who obtains transmission service under access rights granted through the Transmission Provider's compliance tariff developed pursuant to The Commission's Final Order Nos. 888 and 888-A and causes either UGPR, Basin or Heartland to incur stranded costs. Stranded costs will be recovered through the terms and conditions of a separate contract entered into either by UGPR and the Transmission Customer or Basin and the Transmission Customer or Heartland and the Transmission Customer.

ATTACHMENT L

Standard Large Generator Interconnection Procedures Including Standard Large Generator Interconnection Agreement

[This Attachment L reserved for Western's Commission-approved Standard Large Generator Interconnection Procedures and Agreement, as filed with the Commission and posted on Western's OASIS.]

ATTACHMENT M

Standard Small Generator Interconnection Procedures Including Standard Small Generator Interconnection Agreement

[This Attachment M reserved for Western's Commission-approved Standard Small Generator Interconnection Procedures and Agreement, as filed with the Commission and posted on Western's OASIS.]

ATTACHMENT N

North American Energy Standards Board Wholesale Electric Quadrant Standards

The following North American Energy Standards Board Wholesale Electric Quadrant standards are incorporated by reference into Transmission Provider's Tariff as described in section 4.2 therein:

- Business Practices for Open Access Same-Time Information Systems (OASIS), Version 1.4 (WEQ-001, Version 0001, ~~January 15, 2005~~October 31, 2007, with minor corrections applied on ~~March 25, 2005~~~~Nov~~November 16, 2007~~, and additional numbering added October 3, 2005~~) including Standards 001-0.2 through 001-0.8, 001-0.14 through 001-0.20, 001-2.0 through 001-9.6.2, 001-9.8 through 001-~~10.8.6~~12.5.2, and 001-A through 001-B ~~and Examples 001-8.3-A, 001-9.2-A, 001-10.2-A, 001-9.3-A, 001-10.3-A, 001-9.4.1-A, 001-10.4.1-A, 001-9.4.2-A, 001-10.4.2-A, 001-9.5-A, 001-10.5-A, 001-9.5.1-A, and 001-10.5.1-A~~;

- Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.4 (WEQ-002, Version 0001, ~~January 15, 2005~~October 31, 2007, with minor corrections applied on ~~March 25, 2005~~November 16, 2007~~, and additional numbering added October 3, 2005~~) including Standards 002-0.1 through 002-5.10;

- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.4 (WEQ-003, Version 0001, ~~January 15, 2005~~October~~.~~ 31, 2007, with minor corrections applied on ~~March 25, 2005~~November~~.~~ 16, 2007~~, and additional numbering added October 3, 2005~~) including Standard 003-0;

- Coordinate Interchange (WEQ-004, Version 0001, ~~January 15, 2005~~October 31, 2007, with minor corrections applied on ~~March 25, 2005~~November 16, 2007~~, and additional numbering added October 3, 2005~~) including Purpose, Applicability, and Standards 004-0.1 through 004-1~~3~~7.2, and 004-A through 004-D;

- Area Control Error (ACE) Equation Special Cases Standards (WEQ-005, Version 0001, ~~January 15, 2005~~October 31, 2007, with minor corrections applied on ~~March 25, 2005~~November 16, 2007~~, and additional numbering added October 3, 2005~~) including Purpose, Applicability, and Standards 005-0.1 through 005-3.1.3, and 005-A;

- Manual Time Error Correction (WEQ-006, Version 0001, ~~January 15, 2005~~October 31, 2007, with minor corrections applied on ~~March 25, 2005~~November 16, 2007~~, and additional numbering added October 3, 2005~~) including Purpose, Applicability, and Standards 006-0.1 through 006-12;~~ and~~

- Inadvertent Interchange Payback (WEQ-007, Version 0001, ~~January 15, 2005~~October 31, 2007, with minor corrections applied on ~~March 25, 2005~~November 16, 2007~~, and additional~~

~~numbering added October 3, 2005~~) including Purpose, Applicability, and Standards 007-0.1 through 007-2, and 007-A.;

- Transmission Loading Relief Eastern Interconnection (WEQ-008, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007) including Purpose, Applicability, and Standards 008-0.1 through 008-3.11.2.8, and 008-A through 008-D;
- Gas/Electric Coordination (WEQ-011, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007) including Standards 011-0.1 through 011-1.6;
- Public Key Infrastructure (PKI) (WEQ-012, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007) including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5; and
- Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ-013, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007) including Introduction and Standards 013-0.1 through 013-4.2.

ATTACHMENT O

Procedures for Addressing Parallel Flows

~~To be filed by the Transmission Provider~~
For the Transmission Provider's facilities in the Western Electricity Coordinating Council:

The North American Electric Reliability Corporation's ("NERC") Qualified Path Unscheduled Flow Relief for the Western Electricity Coordinating Council ("WECC"), Reliability Standard WECC-IRO-STD-006-0 filed by NERC in Docket No. RR07-11-000 on March 26, 2007, and approved by the Commission on June 8, 2007, and any amendments thereto, are hereby incorporated and made part of this Tariff. See www.nerc.com for the current version of the NERC's Qualified Path Unscheduled Flow Relief Procedures for WECC.

For the Transmission Provider's facilities in the Eastern Interconnection:

NERC's TLR Procedures originally filed March 18, 1998, which are now the mandatory Reliability Standards that address TLR, and any amendments thereto, on file and accepted by the Commission, are hereby incorporated and made part of this Tariff. See www.nerc.com for the current version of the NERC's TLR Procedures.

ATTACHMENT P

Transmission Planning Process

~~The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.~~

~~The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05-25-000.~~

~~The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:~~

~~(i) The process for consulting with customers and neighboring transmission providers;~~

~~(ii) The notice procedures and anticipated frequency of meetings;~~

~~(iii) The methodology, criteria, and processes used to develop transmission plans;~~

~~(iv) The method of disclosure of criteria, assumptions and data underlying transmission system plans;~~

~~(v) The obligations of and methods for customers to submit data to the transmission provider;~~

~~(vi) The dispute resolution process;~~

~~(vii) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and~~

~~(viii) The relevant cost allocation procedures or principles.~~

Overview of Western's Transmission Planning Processes

The Western Area Power Administration (Western) is a Federal agency under the Department of Energy that markets and transmits wholesale electrical power from 56 federal hydropower plants and one coal-fired plant. Western sells about 40 percent of regional hydroelectric generation in a service area that covers 1.3 million square miles in 15 states. To provide this reliable electric power to most of the western half of the United States, Western markets and transmits about 10,000 megawatts of hydropower across an integrated 17,000-circuit mile, high-voltage transmission system.

Western's customers include municipalities, cooperatives, public utility and irrigation districts, Federal and state agencies, investor-owned utilities (only one of which has an allocation of Federal hydropower from Western), marketers and Native American tribes. They, in turn, provide retail electric service to millions of consumers in Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming.

Western's role in delivering power also includes managing 10 different rate-setting systems. These rate systems are made up of 14 multipurpose water resource projects and one transmission project. The systems include Western's transmission facilities along with power generation facilities owned and operated primarily by the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers and the U.S. State Department's International Boundary and Water Commission. Western sets power rates to recover all costs associated with our activities, as well as the Federal investment in the power facilities (with interest) and certain costs assigned to power from repayment, such as aid to irrigation development.

Western employees sell power and transmission service, operate transmission and provide maintenance and engineering services. These duty locations include Western's Corporate Services Office in Lakewood, Colo., and four regions with offices in Billings, Mont.; Loveland, Colo.; Phoenix, Ariz.; and Folsom, Calif. Western also markets power from the Management Center in Salt Lake City, Utah, and also manages Upper Great Plains Region system operations and maintenance from offices in Bismarck, N.D.; Fort Peck, Mont.; Huron, S.D. and Watertown, S.D.

Since its inception on December 21, 1977, Western and its employees have been dedicated to providing public service, including promoting environmental stewardship, energy efficiency and renewable energy and implementing new technologies to ensure its transmission system is the most reliable possible.

Western's Attachment P is divided into Part I and Part II – Part I outlines the transmission planning process Western uses in the Upper Great Plains Region (UGPR) on both the Eastern and Western Interconnections, while Part II outlines the process used in the remaining Western regions in the Western Interconnection.

Western's transmission planning process is based on three core objectives:

- Maintain reliable electric service.
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to its transmission facilities.

- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

Western's transmission planning process is intended to facilitate a timely, coordinated and transparent process that fosters the development of electric infrastructure that maintains reliability and meets Network load growth, so that Western can continue to provide reliable low cost electric power to its customers.

The transmission planning process conducted by Western includes a series of open planning meetings that allow anyone, including, but not limited to, network and point-to-point transmission customers, interconnected neighbors, sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, and other stakeholders, input into and participation in all stages of development of Western's transmission plan.

PART I - Upper Great Plains Region

Part I of this Attachment P addresses the rights and obligations of Transmission Customers, Affected Generators, other relevant stakeholders, and the Western Upper Great Plains Region (Transmission Provider) related to Transmission Planning within the UGPR. Specifically, Part I of Attachment P addresses: (a) the Mid-Continent Area Power Pool ("MAPP") regional planning process adopted by the Regional Transmission Committee ("RTC") Members of MAPP in the RTC Region, as those terms are defined by the MAPP Restated Agreement (Sections 1.0 to 12.0); (b) the Transmission Provider's local planning process for local facilities not covered by the respective regional planning processes (Section 13.0); and (c) the Western Electricity Coordinating Council (WECC) regional planning in relation to Western's UGPR facilities within the Western Interconnection (Section 14.0). Supporting documents related to Transmission Planning within the UGPR, Part I of this Attachment P are available on the Transmission Provider's (Western's UGPR) OASIS page located at http:/ www.oatioasis.com/wapa index.html under the Transmission Planning Process folder. Within this folder, Western's UGPR posts an Attachment P links document that provides URLs for both Part I a , the Regional Planning Process within MAPP, Part I B, the Local Planning Process, and Part I c, the Regional Planning Process with WECC for Western's UGPR as noted above.

1.0 Introduction to the MAPP Sub-regional Planning Process

The MAPP Regional Plan integrates the transmission plans developed by individual MAPP Members through the RTC's Transmission Planning Subcommittee ("TPSC") and by subregional planning groups ("SPGs"), in order to meet the transmission needs in the MAPP Region of Members and interested parties on a consistent, reliable, environmentally acceptable and economic basis. The MAPP Regional Plan shall be consistent with applicable standards and requirements established by the MAPP Members Reliability Criteria and Study Procedures Manual and by the North American Electric Reliability Council ("NERC") and Midwest Reliability Organization ("MRO") Planning Standards.

2.0 Definitions

2.1 Host Transmission Owner ("Host TO"). The transmission owner on whose transmission system a proposed Economic Network Upgrade is to be located. The Host TO shall conduct all related project management activities associated with the Economic Network Upgrade. If facility upgrades are required on more than one transmission owner's transmission system for a given set of transmission facilities comprising an Economic Network Upgrade, the affected Host TOs shall provide a single joint Facilities Agreement to the Subscription Rights buyers.

2.2. Affected Generator. A generator owner whose existing or proposed generating unit(s) is directly affected by a proposed Economic Network Upgrade as demonstrated in the study analysis performed in conjunction with Section 11, Economic Planning Studies of this Attachment P.

2.3 Affected System. The transmission owner's system, including the Host TO, that is affected by the allocations in an economic benefits study performed by the MAPP RTC in accordance with Section 11 of this Attachment P.

2.4 Affected System Operator. The transmission owner/operator that operates an Affected System.

2.5 Economic Network Upgrade. A project, or set of projects, that is designed to relieve a constrained facility by providing additional transmission capacity, and which has been identified to be: (a) a local economically beneficial project within a single transmission owner's system; or (b) an economically beneficial project classified as a Regionally Beneficial Project in the MAPP Plan, and defined by an Economic Planning Study authorized by the MAPP RTC in Section 11 of this Attachment P as having project benefits exceeding project costs.

2.6 Physical Transmission Rights. Rights held by a party to a Facilities Agreement to schedule transmission service across a defined portion of a NERC flowgate or other transmission facility and/or to collect revenue credits, if applicable, against transmission service charges. Physical Transmission Rights will exist for the life of the facility if the holder is an owner, or for the term stated in the Facilities Agreement. The facility's capabilities that are to be allocated as Physical Transmission Rights, shall be consistent with the owner's or joint-owners' methodologies for determining facility ratings, system operating limits and, if applicable, TTC and ATC in accordance with NERC standards.

2.7 Renewable Energy Zone. A geographic region recognized by the TPSC that has limited or constrained ability to transport electric energy from generating units that had such units been in production they would have utilized renewable resources for the production of electric energy.

2.8 Subscription Rights. Contractual rights to use the transmission capacity associated with an Economic Network Upgrade defined in a Facilities Agreement with the Host TO in exchange for payments to the Host TO for facility charges and continuing operation and maintenance charges.

2.9 Other Defined Terms. All other terms will have the meanings set forth in the MAPP Restated Agreement, the TPSC procedures, and the SPG guidelines.

3.0 MAPP Regional Transmission Planning

3.1 Member Plans. As part of the MAPP regional transmission planning process, each RTC Member that has transmission facilities under MAPP's Restated Agreement shall prepare and maintain a plan for its transmission facilities ("Member Plan"). Such Member Plans shall conform to applicable reliability standards and requirements, and to applicable methods and assessment practices and other transmission planning standards and requirements established by the RTC. Each Member Plan shall adhere to Local Transmission Planning Standards set forth in Section 13 of this Attachment P. Such plans shall take into account:

(a) the RTC Member's current and anticipated requirements for transmission to provide all-requirements and partial requirements service and service to its end-use loads;

(b) the current and anticipated requirements for transmission to provide network transmission service to those entities for which the RTC Member provides such service;

(c) the RTC Member's other contractual and tariff obligations to provide firm transmission service;

(d) any other contractual obligations of the RTC Member affecting the use of its transmission facilities;

(e) any requirements for future transmission service of a Member or interested party communicated to the RTC Member under procedures, standards and requirements established by the RTC;

(f) the coordination of the RTC Member's transmission plan with the transmission plans of neighboring systems, and in particular any coordination parameters or requirements identified by the relevant subregional working groups used by the RTC; and

(g) the obligation of the RTC Member under FERC requirements, the MAPP Restated Agreement, and applicable standards and requirements established by the RTC to provide transmission service to other entities on a basis comparable to its own use of its transmission facilities.

3.2 Availability of Plans and Information. The RTC Members' transmission plans, along with the information on which the plans are based, shall be made available to the RTC on a regular basis as established by the RTC. Each RTC Member shall make its transmission plan available upon request to any other RTC Member, independent Regional Transmission Organization or relevant non-MAPP neighboring transmission owning utilities. Sufficient additional information should be made available to enable the requesting entity to perform planning analyses on the same basis as the RTC Member providing the information. Such information shall be provided in accordance with the MAPP Critical Energy Infrastructure Information ("CEII") policy and the Commission's Standards of Conduct regulations.

3.3 Planning Procedures and Requirements. The RTC shall establish procedures and requirements for:

(a) The communication to an RTC Member by Members and interested parties of their *bona fide* requirements for transmission service;

(b) The utilization of SPGs for the coordination of RTC Members' transmission plans and the resolution of subregional transmission planning issues on an informal, collaborative basis, which working groups shall be open to any interested RTC Member or other interested party, and shall maintain such records as shall be required by the RTC;

(c) The incorporation of asserted *bona fide* requirements for transmission service into RTC Member, subregional, and regional transmission plans; and

(d) The development of integrated transmission plans by the subregional working groups, and the integration of the subregional plans into a transmission plan for the MAPP RTC Region.

3.4 The MAPP Regional Plan. No less often than biennially, the RTC shall develop and approve a coordinated transmission plan, including alternatives, for the ensuing 10 years, or other planning period specified by NERC, for all transmission facilities in the MAPP RTC Region at a capacity of 115 kV or greater. The MAPP Regional Plan shall integrate the transmission plans developed by individual RTC Members and by subregional working groups, for the purpose of enabling the transmission needs in the MAPP RTC Region of Member and interested parties to be met on a consistent, reliable, environmentally acceptable and economic basis.

The MAPP Regional Plan shall avoid unnecessary duplication of facilities or the imposition of unreasonable costs on any RTC Member, shall take into account the legal and contractual rights and obligations of all Members, may provide alternative means for meeting transmission needs in the MAPP RTC Region, and shall differentiate proposed transmission projects from projects for which a definitive commitment of resources has been made *e.g.*, projects under the Subscription Rights process or under a Facilities Agreement.

The MAPP Regional Plan shall be consistent with standards and requirements established by the applicable reliability entity. The RTC shall develop policies and procedures for updating or modifying the Plan between biennial planning cycles as may be appropriate. Any Member, Regulatory Participant, or interested party may attend any meeting of the RTC or any of its subcommittees dealing with the MAPP Regional Plan.

4.0 MAPP Regional Planning Process

4.1 MAPP Regional Plan Development Process. The TPSC, the RTC Subcommittee responsible for planning in the MAPP region, shall collect the individual Member Plans of the MAPP Members and integrate these Member Plans utilizing Subregional Planning Groups into four coordinated Subregional Plans. All MAPP Members are obligated to submit their transmission Member Plans to the TPSC under the MAPP Restated Agreement. These Members Plans are to include the needs of all stakeholders in the Member's service area. The Subregional Plans primarily address local load serving needs and subregional issues, but are not precluded from providing for regional transmission needs.

The TPSC collects these Subregional Plans and integrates them into a single coordinated preliminary MAPP Regional Plan. The TPSC assesses the adequacy and security of the preliminary MAPP Regional Plan to meet the local, subregional, regional and inter-regional reliability and market needs, and where required, identifies and evaluates alternatives and recommends preferred plans to address deficiencies. The final MAPP Regional Plan is submitted to the RTC for approval. The appropriate Transmission Owning Members of MAPP, as that term is defined in the MAPP Restated Agreement, are responsible for designing, constructing and placing into service the various transmission projects comprising the MAPP Regional Plan, after satisfying applicable regulatory requirements.

The TPSC initiates several activities as part of a planning process to produce the MAPP Regional Plan. These activities included collection of planning input data, preparation of study models, the formation of SPGs to collect and coordinate individual Member Plans, collaboration with regulatory agencies, and a procedure to study and evaluate the effectiveness of proposed enhancements in addressing regional and inter-regional problems.

4.2 Process Steps for MAPP Regional Plan Development. The TPSC shall prepare the MAPP Regional Plan as set forth in the MAPP Restated Agreement and this Attachment P and as detailed in the TPSC procedures. The TPSC uses milestone dates as established in the MAPP Regional Transmission Planning Procedures Manual for the following items:

4.2.1 TPSC Data Collection from Members (Annually)

(a) Ongoing studies of the SPG Member and Working Group.

(b) Subregional Plan Addendum report submitted to TPSC.

4.2.2 Data Analysis by TPSC (during the MAPP Regional Plan year):

(a) Analyze history of constrained interface performance.

(b) Analyze history of transmission loading relief requests.

(c) Review of reliability assessment studies and reports.

4.2.3 TPSC Model Preparation:

(a) Select base case models from appropriate MRO Model Series.

(b) Add Member and SPG plans to models.

(c) Solicit input from stakeholders including additions or changes to transmission, generation, and demand resources, in developing base-line assumptions and models.

(d) Validate firm transactions, major new loads, transmission and new generation.

4.2.4 TPSC Study Procedures:

(a) Evaluate base system with Member/SPG planned additions (local plans).

(b) Identify and evaluate alternative plans to meet regional and inter-regional reliability and market requirements (assess impacts on local plans).

(c) Utilize an appropriate combination of technical analysis and engineering judgment to determine preferred solutions when competing solution options proposed to meet system needs are received from a SPG. Technical analysis may include, but is not limited to, load flow (steady state, contingency and loss analysis), transient stability, voltage stability, small signal stability and economic analysis as deemed necessary by the SPG Members. Engineering judgment may include such factors as the extent to which proposed alternative solutions meet applicable planning criteria and other regulatory requirements, expected levels of public acceptance and projected environmental impacts.

(d) Perform cost analysis.

4.2.5 Regulatory Collaboration

(a) Regulatory participation at SPG and TPSC meetings.

(b) Regulatory input at preliminary planning stages.

(c) Process to address "why project needed" and "why it is better than other alternatives considered" through SPG Meeting process.

4.2.6 MAPP Regional Plan Report and Approval

(a) Submit MAPP Regional Plan Report to the RTC for approval of the MAPP Regional Plan year.

4.3 Updating the MAPP Regional Plan. The TPSC shall update or modify the MAPP Regional Plan between biennial planning cycles in accordance with the procedures below. This update to the MAPP Regional Plan, shall be issued to the RTC for approval. The established SPGs shall remain active in the planning process for their respective subregions. Individual utility Member Plans and detailed documentation should be submitted to the SPGs.

In order to accomplish this update process, the SPGs shall:

(a) review the individual utility Member Plans;

(b) coordinate the individual utility Member Plans within their subregion;

(c) evaluate the impacts of the individual Member Plans on their subregion and possibly require additional evaluation or study work;

(d) identify to the TPSC the proposed solution alternatives included in individual Member Plans or proposed by stakeholders in instances where there is no SPG consensus on a preferred alternative; and

(e) submit subregional plan modifications to the TPSC each off-year.

The TPSC shall:

(a) evaluate the subregional plan modifications for their impact on the MAPP Regional Plan;

(b) provide feedback to the SPGs regarding the regional impacts;

(c) utilize an appropriate combination of technical analysis and engineering judgment to determine preferred solutions when competing solution options proposed to meet system needs are received from a SPG. Technical analysis may include, but is not limited to, load flow (steady state, contingency and loss analysis), transient stability, voltage stability, small signal stability and economic analysis as deemed necessary by the SPG Members. Engineering judgment may include such factors as the extent to which proposed alternative solutions meet applicable planning criteria and other regulatory requirements, expected levels of public acceptance and projected environmental impacts; and

(d) approve or deny all final modifications to the MAPP Regional Plan each off-year.

Modifications to the MAPP Regional Plan may include: (a) commitments to new generation; (b) new transmission facilities; (c) changes in construction schedules; or (d) changes in project scope. All approved MAPP Regional Plan modifications must be included in the MRO Model building process and should be submitted to the MRO Model Building Subcommittee by the responsible transmission owning entity.

4.4 Identification of Transmission Requirements. The following process is used to communicate to the TPSC the transmission requirements identified by the Member and interested parties:

(a) Interested parties may contact the Member transmission provider in the area where service is required. If it is unclear as to who is the appropriate transmission provider, the interested parties should contact any member of the TPSC.

(b) The Member is required to take both the Member Plans and interested parties' plans to the appropriate SPGs. The SPG Guidelines indicate the required format Members are to use to submit the data.

(c) The SPGs must prepare coordinated subregional plans incorporating the member and interested parties' needs.

(d) The SPG plans are forwarded to the TPSC.

(e) The TPSC develops a coordinated MAPP Regional Plan addressing SPG, regional and inter-regional needs.

(f) The TPSC forwards the MAPP Regional Plan to the RTC for approval.

The TPSC will establish liaisons with existing neighboring regional planning entities to facilitate addressing inter-regional transmission issues.

5.0 The Transmission Planning Subcommittee

5.1 Procedures for Conduct of TPSC Meetings

5.1.1 TPSC Role. The MAPP TPSC, under the direction of the RTC, shall develop the MAPP Regional Plan. The TPSC shall utilize the following procedures in developing the MAPP Regional Plan. Costs incurred related to regional planning activities shall be recovered under the provisions of the MAPP Restated Agreement and related RTC policies.

5.1.2 TPSC Representatives. The TPSC shall be constituted as defined by the MAPP Restated Agreement. In accordance with the MAPP Restated Agreement, such Representatives shall be elected by the RTC, and the RTC sets the size, duties and responsibilities of the TPSC. The TPSC Representatives shall elect the TPSC Chair and Vice-Chair.

5.1.3 TPSC Meeting Notification. The notice of a TPSC meeting shall state the time and place of the meeting and shall include an agenda sufficient to notify an interested party of the substance of the matters considered at the meeting. The TPSC meeting notice and agenda shall be sent at least 10 days prior to the meeting. All meeting notices are communicated electronically through MAPP e-mail distribution lists, and subsequently posted at www.mapp.org. All meeting notices shall be publicly available.

5.1.4 TPSC Meeting Agenda Development. The TPSC agenda shall include the time and place of its meetings. An interested party shall submit a request to the Chair and the Secretary of the TPSC to have an item considered at the next TPSC meeting at least fifteen (15) days in advance, subject to any limitations set forth in the TPSC procedures manual. The Chair of the TPSC has authority to determine action items for the meeting agenda. All action items shall be shown and communicated clearly so that any interested party can determine what is being acted upon.

The TPSC meeting agenda shall be posted at www.mapp.org and sent via the TPSC e-mail distribution list at least ten (10) days prior to the meeting. The TPSC will make the best effort attempt to communicate all supporting information for the meeting agenda at least ten (10) days prior to the meeting. The supporting information shall be posted on the www.mapp.org after communicating it via the e-mail distribution list, unless the information has been deemed CEII.

5.1.5 TPSC Action. The publication of an agenda of actions to be voted upon by the TPSC shall include the wording of any proposed motion, and a brief discussion, as needed, of the reasons for the motion to be offered and voted. The member of the TPSC or other entity sponsoring the motion shall provide the wording of the motion and the discussion points. A best effort attempt shall be made by those sponsoring items on a TPSC meeting agenda to have background material, and the action to be voted, distributed with the meeting agenda in a timely manner. In general, an action may not be brought to a vote of the TPSC unless it is noticed on a published agenda at least ten (10) days prior to the meeting date upon which action is to be voted. This requirement for a 10-day notice may be waived either by the approval of the TPSC Chair or by 90% affirmative vote of the TPSC's voting members present at a TPSC meeting at which a quorum has been established, subject to any limitations set forth in the TPSC procedures.

5.1.6 TPSC Meeting Procedures. The TPSC shall utilize Robert's Rules of Order for guidance regarding conduct of subcommittee meetings. A quorum is necessary to conduct TPSC business. A quorum is established when 50 percent or more of TPSC Representatives are present as currently stated in the MAPP Restated Agreement. A vacant position on the TPSC does not count towards the quorum requirement. All interested parties can attend TPSC and working group meetings subject to signing a MAPP non-disclosure agreement.

5.1.7 Affirmative Votes. Actions or decisions by a subcommittee requires an affirmative vote of two-thirds of both the TPSC Transmission Owning Members and the Transmission Using Members as set forth in the MAPP Restated Agreement.

5.1.8 TPSC Meeting Minutes. All TPSC meetings shall be recorded through accurate and timely meeting minutes. Draft TPSC meeting minutes shall be distributed to TPSC Representatives ten (10) business days following the meeting date for review and comment. The TPSC will attempt to approve their previous meeting's minutes at their next meeting. Once the meeting minutes are approved by the TPSC, the minutes are sent to the TPSC and RTC e-mail distribution lists and posted at www.mapp.org.

5.1.9 Review of TPSC Action. An RTC Member or Regulatory Participant may request a review of TPSC actions, in accordance with the MAPP Restated Agreement.

5.2 TPSC Responsibilities. The TPSC shall:

(a) develop and recommend for approval by the RTC the biennial MAPP Regional Plan required by the MAPP Restated Agreement;

(b) develop procedures and policies for updating and modifying the MAPP Regional Plan between biennial planning cycles, and approve modifications to the MAPP Regional Plan;

(c) develop and approve procedures, standards and requirements for the communication of the future transmission requirements of Members and interested parties to the appropriate Transmission Owning Members, and for the inclusion of *bona fide* requirements in the transmission Member Plans of the Transmission Owning Members, and in the MAPP Regional Plan.

(d) establish procedures, standards and requirements for the coordination of the transmission Member Plans of the Transmission Owning Members with the plans of neighboring transmission systems, including establishing of subregional planning groups for resolution of subregional planning issues on a cooperative basis;

(e) establish procedures, standards, and requirements for making available Member Plans and the information on which the Member Plans are based, as required by the MAPP Restated Agreement;

(f) establish procedures, standards and requirements for public input, including input from Regulatory Participants, in the development of the MAPP Regional Plan;

(g) determine, subject to RTC approval, the appropriate Member or Members to construct and own, or to receive Rights Equivalent to Ownership in, transmission facilities;

(h) coordinate with the subcommittees of the RTC, the MRO and Adjacent Systems pertinent to reliability issues, standards, requirements, procedures, models and studies, and conduct or request the MRO to conduct such studies as appropriate to carry out the responsibilities of the TPSC;

(i) conduct appropriate transmission economic planning studies;

(j) conduct appropriate transmission cost allocation analysis for new projects;

(k) assume responsibility for submission of FERC Form 715 information for MAPP;

(l) conduct transmission adequacy and security assessments as appropriate, including assessments of the intra- and inter-regional transfer capability of the MAPP system,

(m) oversee the duties and responsibilities of Working Groups; and

(n) utilize an appropriate combination of technical analysis and engineering judgment to determine preferred solutions when competing solution options proposed to meet system needs are received from a SPG.

5.3 Transmission Customer Responsibilities. Transmission Customers in the RTC region shall provide annually to the Transmission Provider the following types of information:

(a) Generators: all planned additions or upgrades (including status and expected in-service date), planned retirements, and environmental restrictions.

(b) Demand Response Resources: existing and planned demand resources and their impacts on demand and peak demand.

(c) Network Customers: forecast information for load and resource requirements over the planning horizon and identification of demand response reductions.

(d) Point-to-Point Transmission Customers: projections of need for service over the planning horizon, including transmission capacity, duration, and receipt and delivery points.

(e) Transmission Customers should provide the Transmission Provider with timely written notice of material changes in any information previously provided relating to its load, its resources, or other aspects of its facilities or operations affecting the transmission provider's ability to provide service.

6.0 Sub-regional Planning Groups

6.1 Current SPGs. The TPSC has established and recognized the following SPGs to carry out the task of coordinating transmission plans among Members:

(a) Northern MAPP;

(b) Missouri Basin;

(c) Iowa Transmission Working Group;

(d) Nebraska.

6.2 Establishment of SPGs. The TPSC can establish new or recognize additional SPGs to carry out the task of coordinating transmission plans among Members. The TPSC may also recognize and coordinate its MAPP Regional Plan with existing or future transmission planning study groups concerned with transmission facilities located outside the MAPP region.

6.3 SPG Membership. Membership in a SPG is open to any interested party and any actual or potential user of the relevant transmission facilities. Participation in any SPG meeting is open to any interested party who has signed the MAPP Non-Disclosure Agreement (NDA). A MAPP NDA is obtained by contacting the Secretary of the MAPP TPSC. Neighboring transmission owning utilities and regulatory participants are eligible and encouraged to join the SPG to promote joint planning between MAPP and its neighboring regions.

6.4 SPG Guidelines. The Subregional Planning Groups, to the extent possible, should:

(a) develop a coordinated Subregional Plan, the SPG Biennial Plan, including alternatives, for the ensuing ten years, for all transmission facilities in the subregion at a voltage of 115 kV or greater;

(b) review and comment on proposed Member Plans for additions and modifications to the subregional transmission system;

(c) incorporate proposed Member load-serving plans to the subregional transmission system into the SPG Biennial Plan;

(d) incorporate Member Plans for new generator connections and associated network upgrades into the SPG Biennial Plan as soon as practicable;

(e) coordinate the Subregional Plans of the SPG with the Subregional Plans of neighboring SPGs;

(f) update the SPG Biennial Plan as deemed necessary by the SPG or the TPSC;

(g) form technical study task forces as required to carry out the subregional planning responsibilities;

(h) encourage non-MAPP member participation to ensure that the TPSC and the SPGs learn of facility changes outside MAPP's system to ensure the impact of parallel path flows are considered in the planning studies;

(i) encourage participation by stakeholders so that the SPG can consider and incorporate the future transmission needs of the stakeholder into the Subregional Plan;

(j) ensure SPG studies meet NERC/MRO Planning Standards and requirements; and

(k) promote stakeholder and Regulatory Participant review and comment on the Subregional Plan and its development.

6.5 Submission of Member Plans to SPG. Each Transmitting Utility Member, as that term is defined in the MAPP Restated Agreement, shall submit its transmission plans to the SPG in which its system is geographically located, or SPGs in situations where its system crosses several SPG boundaries. The TPSC requires that all Members submit their individual Member Plans to the appropriate SPG. Each SPG member must be willing to participate in joint SPG studies to assess the adequacy of proposed Member Plans to best meet the needs of the subregion. The TPSC will not be in a position to support the transmission Member Plans of any Member who does not make such Member Plans available to the SPG.

6.6 Network Upgrades Out of Planning Cycle.

When planned transmission upgrades are identified by a Member outside the timing requirements of the Regional Plan (including any network upgrades needed for generation interconnection or transmission service):

- The Member will submit information about the upgrades at the next SPG meeting and the next TPSC meeting to make every reasonable effort to allow for stakeholder input on such upgrades before those upgrades go in-service.

- The Member will include those upgrades in their next Member Plan.

6.7 SPG Meetings. Each SPG should meet at least twice annually to review plans and determine what changes, if any, need to be made to coordinate Member Plans among Members. Participation in any SPG meeting is open to any interested party who has signed the MAPP NDA. Meeting notices are posted on the MAPP calendar at www.mapp.org. Recommendations carried forward to the TPSC by the SPG should reflect a consensus of the SPG members. However, a SPG member also has the right to reflect a minority opinion in any report to the TPSC.

The notice of SPG meetings are to be sent out by the SPG TPSC liaison person, the SPG Chair, or SPG Secretary to the SPG Membership via the SPG and TPSC exploder email list. Other stakeholders, such as interested parties, that request meeting notification shall also be sent a meeting notice. In addition, the meetings are posted on the MAPP website under the calendar of MAPP meetings. The notice shall state the time and place of the meeting, and shall include an agenda sufficient to notify Members of the substance of matters to be considered at the meeting. Additionally, the appropriate subregional Regulatory Participants, who are not SPG Members or may not be subscribed to the SPG and TPSC exploders list, are to be sent a meeting notice.

6.8 TPSC/SPG Communication. Each recognized SPG shall appoint a liaison to the TPSC to facilitate communication of the planning process. The liaison person can be any SPG member including an elected TPSC member. The form of communication the TPSC expects from the SPG includes: (a) SPG Meeting Agendas; (b) SPG final approved Meeting Minutes; and (c) SPG liaison status reports to the TPSC at the scheduled meetings. The SPG meeting agendas and approved minutes should be electronically sent to the TPSC Secretary for posting on the MAPP website in the RTC/TPSC area. The SPG status reports are given by the TPSC liaison at the scheduled TPSC meetings.

6.9 SPG Planning Responsibilities. The SPG shall develop a coordinated subregional transmission plan (the SPG Plan), including alternatives, for the ensuing ten years, for all transmission facilities in the subregion at a capacity of 115 kV or greater. This SPG Plan shall be submitted to the TPSC biennially, each even numbered or MAPP Regional Plan year. The SPG shall update and modify the SPG Plan, as required, between biennial planning year cycles and submit these modifications to the TPSC for approval. The Subregional Plan should:

(a) identify load serving problems in the subregion;

(b) identify constrained interface problems within the subregion and with neighboring subregions and regions;

(c) identify transmission needs for new generation;

(d) propose and study transmission expansion alternatives to address these problems and needs;

(e) recommend the preferred alternatives which best address the subregional requirements to the TPSC;

(f) forward alternative proposed solutions to the TPSC for the evaluation and determination of preferred plan options for inclusion in the MAPP

Regional Plan in the absence of consensus agreement by a SPG on the selection of preferred plan options;

(g) address subregional deficiencies identified in the MAPP Regional Plan; and

(h) provide feedback assessment of impacts of the published MAPP Regional Plan on the subregion.

6.10 Planning Criteria. The MAPP Restated Agreement states that each Member's plan shall conform to applicable reliability standards and requirements, and to applicable methods and assessment practices and other transmission planning standards and requirements established by the RTC. In this context, the Subregional Plan shall conform to the requirements of the MAPP Members Reliability Criteria and Study Procedures Manual and the NERC and MRO Planning Standards. In instances where these Standards are different, the more stringent Standard shall be adopted. Such criteria and standards are available at www.mapp.org.

6.11 SPG Study Models. Whenever possible, the SPGs shall adopt the most current approved regional model series to develop their base case study models. Each series provides near term, five-year and ten-year models representing summer peak, summer off-peak and winter peak system conditions. The SPG shall determine the appropriate load conditions (summer peak, summer off-peak, winter peak, etc.) and generation schedules for the SPG studies. The SPG shall verify that the load data, new generation data, and all existing firm transactions in the subregion are included and correct. In developing the base case load flow models to be used for the SPG studies, the SPG shall document all modifications required to load flow cases. The SPGs may add underlying transmission detail to these models as required. The SPG shall solicit input from stakeholders including additions or changes to transmission, generation, and demand resources, in developing base-line assumptions and models used in developing the SPG Plan. The SPG may, if appropriate, adopt other models to conduct its studies. However, the SPG shall develop and provide the TPSC with appropriate files to facilitate incorporation of the Subregional Plan study data into the next regional model series that will be used by the TPSC.

6.12 SPG Studies and Reports. A report summarizing the results of the Member and SPG Working Group studies shall be provided for review and consensus approval of the SPG, prior to adopting the plans of Members or the SPG study groups into the Subregional Plan. The SPG shall require its Members or its SPG Study Groups to perform system studies to demonstrate that the performance of the proposed Member and Subregional Plans meets the planning standards defined above. These studies may include, but not necessarily be limited to load flow (steady state, contingency and loss analysis), transient stability, voltage stability, small signal stability and economic analysis as deemed necessary by the SPG Members.

6.13 Subregional Plan Report to the TPSC. The Subregional Plan, or modifications to the SPG Plan, shall be provided to the TPSC each year. A report shall be provided describing the Subregional Plan. This report shall include the following information:

(a) an executive summary (to be incorporated into the MAPP Regional Plan report);

(b) a description of needs being addressed;

(c) a description of the alternatives considered;

(d) recommendations as to which alternatives should be included in the MAPP Regional Plan;

(e) a description of alternative plan options in the absence of consensus SPG agreement on preferred solutions;

(f) a brief description of the SPG studies, including costs, supporting the recommendations, with reference to the detailed SPG study report;

(g) a description of the new facilities; and

(h) a description of the Public Input/Review Process.

7.0 Public Input Process

7.1 Stakeholder Participation. The TPSC shall invite Members, interested parties, any actual or potential users of the relevant transmission facilities, and neighboring transmission owning utilities (referred to collectively as "stakeholders"), as well as Regulatory Participants, to be part of the planning process. The SPG shall invite such stakeholders to SPG meetings as part of the public input process into the Subregional Plan. The SPG shall:

(a) identify and maintain a list of stakeholders involved in the review and comment on additions to the Transmission System in their subregion;

(b) add stakeholders to the appropriate SPG email exploder lists following their requests to MAPPCOR planning staff to participate;

(c) verify that stakeholders have signed the MAPP NDA for attendance at the meetings where CEII material is discussed;

(d) identify comparable contacts from interconnected NERC regions;

(e) coordinate with stakeholders as to the process required, areas of needs, and possible solutions;

(f) review the solutions with stakeholders to identify the best options from a transmission and regulatory basis for that subregion to include in the Subregional Plan; and

(g) report to the TPSC and include in the Subregional Plan documentation of the public process completed for the Subregional Plan such as dates of meetings, number of stakeholders, highlights of key comments and SPG consideration of those comments. The SPG shall include in their Subregional Plan report to the TPSC a listing of the suggestions for economic planning studies that they received from their stakeholders during the year.

7.2 Regulatory Participation. The TPSC shall encourage and facilitate input from Regulatory Participants, in the development of the MAPP Regional Plan. The SPGs, as part of the formal process for regulatory participation, shall:

(a) Maintain a list of Regulatory Participants involved in the review and approval of additions to the Transmission System in their subregion.

(b) Maintain a list of comparable contacts from interconnected regions.

(c) Coordinate with the Regulatory Participants as to the process required, areas of needs, and possible solutions. Review the solutions with such participants to identify the best options from a transmission and regulatory basis for that subregion to include in the MAPP Regional Plan.

(d) Describe in the Subregional Plan how the proposed facilities address the needs, and identify the Regulatory Participants involved in the Subregional Plan development and what future regulatory approvals are required for development of facilities in the Subregional Plan.

The TPSC, as part of the formal process for the regulatory participation, shall:

(a) maintain a list of Regulatory Participants involved in the review and approval of additions to the Transmission System for each SPG;

(b) report in the MAPP Regional Plan the input of the Regulatory Participants obtained in developing the MAPP Regional Plan;

(c) present the results of the MAPP Regional Plan and the needed facilities to the RTC;

(d) work with the Members and SPGs on final approvals for needed projects as required and coordinate any regional information that needs to be disseminated;

(e) make the MAPP Regional Plan available to the public and regulatory community subject to applicable CEII restrictions; and

(f) as required, sponsor information seminars to facilitate regulatory and public acceptance of the MAPP Regional Plan.

8.0 Inter-regional Planning Coordination

The TPSC shall coordinate on planning issues with: (1) the subcommittees of the RTC; (2) the MRO; (3) relevant non-MAPP neighboring transmission owning utilities and Regional Transmission Organizations ("RTOs").

The TPSC will select a TPSC member who will be responsible for reporting on the relevant activities of the MAPP RTC, MRO and RTO subcommittees at each TPSC meeting. The TPSC liaison may attend the MAPP RTC, MRO and neighboring RTO subcommittee meetings or employ other effective means to obtain the required information.

8.1 Coordination Principles. The MAPP Regional Plan shall be developed in accordance with the principles of interregional coordination through collaboration with representatives from neighboring regions, or their applicable sub-regions, including adjacent transmission providers or regional transmission organizations, or their designated regional planning organization(s).

8.2 Joint Planning Committee. MAPP shall participate in a Joint Planning Committee ("JPC") with representatives of adjacent transmission providers or regional transmission organizations, or their designated regional planning organizations(s) ("Regional Planning Coordination Entities" or "RPCEs"). The JPC shall be comprised of representatives of MAPP and the RPCE(s) in numbers and functions to be identified from time to time. The JPC may combine with or participate in similarly established joint planning committees amongst multiple RPCEs or established under joint agreements to which MAPP is a signatory, for the purpose of providing for broader and more effective inter-regional planning coordination. The JPC shall have a Chairman. The Chairman shall be responsible for: the scheduling of meetings; the preparation of agendas for meetings; the production of minutes of meetings; and for chairing JPC meetings. The Chairmanship shall rotate amongst MAPP and the RPCEs on a mutually agreed to schedule, with each party responsible for the Chairmanship for no more than one planning study cycle in succession. The JPC shall coordinate planning of the systems of the Western

Area Power Administration's Upper Great Plains Customer Service Region and the RPCEs, including the following:

8.2.1 Coordinate the development of common power system analysis models to perform coordinated system planning studies including power flow analyses and stability analyses. For studies of interconnections in close electrical proximity at the boundaries among the systems of MAPP and the RPCEs, the JPC or its designated working group will coordinate the performance of a detailed review of the appropriateness of applicable power system models.

8.2.2 Conduct, on a regular basis, a Coordinated Regional Transmission Planning Study ("CRTPS"), which shall be reviewed by stakeholders, as set forth in Section 8.4.1.

8.2.3 Coordinate planning activities under this section 8, including the exchange of data and developing necessary report and study protocols.

8.2.4 Maintain an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process. Such sites and lists may be integrated with those existing for the purpose of communicating the open and transparent planning processes of MAPP.

8.2.5 Meet at least semi-annually to review and coordinate transmission planning activities.

8.2.6 Establish working groups as necessary to address specific issues, such as the review and development of the regional plans of the RPCE and MAPP, and localized seams issues.

8.2.7 Establish a schedule for the rotation of responsibility for data management, coordination of analysis activities, report preparation, and other activities.

8.3 Data and Information Exchange. MAPP shall make available to each RPCE the following planning data and information. Unless otherwise indicated, such data and information shall be provided annually. MAPP shall provide such data in accordance with the applicable CEII policy, and maintain data and information received from each RPCE in accordance with their applicable confidentiality policies.

8.3.1 Data required for the development of power flow cases, and stability cases, incorporating up to a ten year load forecasts as may be requested, including all critical assumptions that are used in the development of these cases.

8.3.2 Fully detailed planning models (up to the next ten (10) years as requested) on an annual basis and updates as necessary to perform coordinated studies that reflect system enhancement changes or other changes.

8.3.3 The regional plan documents, any long-term or short-term reliability assessment documents, and any operating assessment reports produced by MAPP and the RPCE.

8.3.4 The status of expansion studies, system impact studies and generation interconnection studies, such that MAPP and the RPCE have knowledge that a commitment has been made to a system enhancement as a result of any such studies.

8.3.5 Transmission system maps for MAPP and the RPCE bulk transmission systems and lower voltage transmission system maps that are relevant to the coordination of planning between or among the systems.

8.3.6 Contingency lists for use in load flow and stability analyses, including lists of all contingency events required by applicable NERC or Regional Entity planning standards, as well as breaker diagrams, as readily available, for the portions of the MAPP and the RPCE transmission systems that are relevant to the coordination of planning between or among the systems. Breaker diagrams to be provided on an as requested basis.

8.3.7 The timing of each planned enhancement, including estimated completion dates, and indications of the likelihood that a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and as requested the status of related applications for regulatory approval. This information shall be provided at the completion of each planning cycle of MAPP, and more frequently as necessary to indicate changes in status that may be important to the RPCE system.

8.3.8 Quarterly identification of interconnection requests that have been received and any long-term firm transmission services that have been approved, that may impact the operation of MAPP or the RPCE system.

8.3.9 Quarterly, the status of all interconnection requests that have been identified.

8.3.10 Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between or among the systems.

8.3.11 Load flow data initially will be exchanged in PSS/E format. To the extent practical, the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and breaker diagrams will be provided in an electronic format agreed upon by the Transmission Provider and the RPCE. Formats for the exchange of other data will be agreed upon by MAPP and the RPCE.

8.4 Coordinated System Planning. MAPP shall agree to coordinate with the RPCEs studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan. MAPP shall agree to conduct with the RPCEs such coordinated planning as set forth below.

8.4.1 Stakeholder Review Processes. MAPP, in coordination with coordinating RPCEs shall review the scope, key modeling assumptions, and preliminary and final results of the CRTPS with impacted stakeholders, and shall modify the study scope as deemed appropriate by MAPP in agreement with the coordinating RPCEs, after receiving stakeholder input. Such reviews will utilize the existing planning stakeholder forums of the coordinating parties including as applicable joint Sub Regional Planning Meetings.

8.4.2 Single Entity Planning. MAPP shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as necessary to fulfill its obligations under the MAPP Restated Agreement and any other MAPP transmission planning procedures. Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, and any successor organizations thereto. Such planning shall also conform to any and all applicable requirements of Federal or State regulatory authorities. MAPP will prepare a regional transmission planning report that documents the procedures, methodologies, and business rules utilized in preparing and completing the report. MAPP shall agree to share the transmission planning reports and assessments with each RPCE, as well as any information that arises in the performance of its individual planning activities as is necessary or appropriate for effective coordination among MAPP and the RPCEs on an ongoing basis. MAPP shall provide such information to the RPCEs in accordance with the applicable CEII policy and shall maintain such information received from the RPCEs in accordance with their applicable confidentiality policies.

8.4.3 Analysis of Interconnection Requests. In accordance with the procedures under which a MAPP Transmission Provider provides interconnection service, MAPP will agree to coordinate with each RPCE the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies shall include the following:

8.4.3.1 When the Transmission Provider receives a request under its interconnection procedures for interconnection, it will determine whether the interconnection potentially impacts the system of a RPCE. In that event, the Transmission Provider will notify the RPCE and convey the information provided in the interconnection queue posting. The Transmission Provider will provide the study agreement to the interconnection customer in accordance with applicable procedures.

8.4.3.2 If the RPCE determines that it may be materially impacted by an interconnection on the Transmission Provider's system, the RPCE may request participation in the applicable interconnection studies. The Transmission Provider will coordinate with the RPCE with respect to the nature of studies to be performed to test the impacts of the interconnection on the RPCE System, and who will perform the studies. The Transmission Provider will strive to minimize the costs associated with the coordinated study process undertaken by agreement with the RPCE.

8.4.3.3 Any coordinated studies associated with requests for interconnection to the Transmission Provider's system will be performed in accordance with the study timeline requirements and scope of the applicable generation interconnection procedures of Western.

8.4.3.4 The RPCE may participate in the coordinated study either by taking responsibility for performance of studies of its system, if deemed reasonable by the Transmission Provider, or by providing input to the studies to be performed by the Transmission Provider. The study cost estimates indicated in the study agreement between Transmission Provider and the interconnection customer, will reflect the costs, and the associated roles of the study participants including the RPCE. The Transmission Provider will review the cost estimates and scope submitted by all participants for reasonableness, based on expected levels of participation, and responsibilities in the study. If the RPCE agrees to perform any aspects of the study, the RPCE must comply with the timelines and schedule of Western's interconnection procedures.

8.4.3.5 The Transmission Provider will collect from the interconnection customer the costs incurred by the RPCE associated with the performance of such studies and forward collected amounts, no later than thirty (30) days after receipt thereof, to the RPCE. Upon the reasonable request of the RPCE, the Transmission Provider will make its books and records available to the requestor pertaining to such requests for collection and receipt of collected amounts.

8.4.3.6 The Transmission Provider will report the combined list of any transmission infrastructure improvements on either the RPCE and/or the Transmission Provider's system required as a result of the proposed interconnection.

8.4.3.7 Construction and cost responsibility associated with any transmission infrastructure improvements required as a result of the proposed interconnection shall be accomplished under the terms of Western's tariff under which the transmission service is provided, consistent with applicable Federal or State regulatory policy and applicable law.

8.4.3.8 Each transmission provider will maintain a separate interconnection queue. The JPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of MAPP and coordinating RPCEs. The JPC will post this listing on the Internet site maintained for the communication of information related to the coordinated system planning process.

8.4.4 Analysis of Long-Term Firm Transmission Service Requests. In accordance with applicable procedures under which the Transmission Provider provides long-term firm transmission service, Transmission Provider will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

8.4.4.1 The Transmission Provider will coordinate the calculation of ATC values, if any, associated with the service, based on contingencies on their systems that may be impacted by the granting of the service.

8.4.4.2 When Transmission Provider receives a request for long-term firm transmission service, it will determine whether the request potentially impacts the system of the RPCE. If Transmission Provider determines that the RPCE system is potentially impacted, and that the RPCE would not receive a transmission service request to complete the service path, Transmission Provider will notify the RPCE and convey the information provided in the posting.

8.4.4.3 If the RPCE determines that its system may be materially impacted by granting the service, it may contact Transmission Provider and request participation in the applicable studies. The Transmission Provider will coordinate with the RPCE with respect to the nature of studies to be performed to test the impacts of the requested service on the RPCE system, and will strive to minimize the costs associated with the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of the JPC members other than the Transmission Provider.

8.4.4.4 Any coordinated studies for request on Transmission Provider's system will be performed in accordance with the study timeline and scope requirements of the applicable transmission service procedures of the Transmission Provider.

8.4.4.5 The RPCE may participate in the coordinated study either by taking responsibility for performance of studies of its system, if deemed reasonable by the Transmission Provider or by providing input to the studies to be performed by Transmission Provider. The study cost estimates indicated in the study agreement between Transmission Provider and the transmission service customer will reflect the costs and the associated roles of the study participants. Transmission Provider will review the cost estimates and scope submitted by all participants for reasonableness, based on expected levels of participation and responsibilities in the study.

8.4.4.6 Transmission Provider will collect from the transmission service customer, and forward to the RPCE, the costs incurred by the RPCE with the performance of such studies.

8.4.4.7 Transmission Provider will identify any transmission infrastructure improvements required as a result of the transmission service request.

8.4.4.8 Construction and cost responsibility associated with any transmission infrastructure improvements required as a result of the transmission service request shall be accomplished under the terms of Western's Open Access Transmission Tariff

8.4.5 Coordinated Transmission Planning. MAPP agrees to participate in the conduct of a periodic Coordinated Regional Transmission Planning Study ("CRTPS"). The CRTPS shall have as input the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with sections 8.4.3 and 8.4.4. MAPP, in coordination with coordinating RPCEs, shall review the scope, preliminary results and final results of the CRTPS with impacted stakeholders, in accordance with section 8.4.1 and this section. The results of the CRTPS shall be an integral part of the expansion plans of each Party. Construction of upgrades on the Transmission System of the Transmission Provider identified as necessary in the CRTSP shall be under the terms of the applicable Western documentation applicable to the construction of upgrades identified in the expansion planning process. Coordination of studies required for the development of the Coordinated System Plan will include the following:

8.4.5.1 Every three years, MAPP shall participate in the performance of a CRTPS. Sensitivity analyses will be performed, as required, during the off years based on a review by the JPC of discrete reliability problems or operability issues that arise due to changing system conditions.

8.4.5.2 The CRTPS shall identify all reliability and expansion issues, and shall propose potential resolutions to be considered by MAPP and the coordinating RPCEs.

8.4.5.3 As a result of participation in the CRTPS, neither MAPP nor its members are obligated in any way to construct, finance, operate, or otherwise support any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS. Any decision to proceed with any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS shall be based on the applicable reliability, operational and economic planning criteria established for MAPP as applicable to the development of the MAPP Regional Plan and set forth in this Attachment P.

8.4.5.4 As a result of participation in the CRTPS, the RPCEs are not entitled to any rights to financial compensation due to the impact of the transmission plans of MAPP upon the RPCE system, including but not limited to its decisions whether or not to construct any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS.

8.4.5.5 The JPC will develop the scope and procedure for the CRTPS. The scope of the CRTPSs performed over time will include evaluations of the transmission systems against reliability criteria, operational performance criteria, and economic performance criteria applicable to MAPP and the RPCEs.

8.4.5.6 In the conduct of the CRTPS, MAPP and the coordinating RPCEs will use planning models that are developed in accordance with the procedures to be established by the JPC. Exchange of power flow models will be in a format that is acceptable to the coordinating parties.

9.0 Member Plans

The procedures, standards and requirements for making available Members' transmission plans ("Member Plans") and the information on which the Member Plans are based, as required by the MAPP Restated Agreement. Members may submit information to the TPSC individually, but submittals through the SPGs are preferred. The SPGs provide a forum for members to continue their long-term joint planning relationships with their neighbors, and involve regulatory staff. The Member Plans will be integrated into the SPG Subregional Plan.

The Subregional Plan reports, and subsequent updates, are submitted to the TPSC as part of the MAPP Regional Plan. Additionally, the MAPP Regional Plan will provide an executive summary report of the Member and SPG plans showing the anticipated transmission expansions in the region. Detailed Member planning reports are referenced in the Subregional Plan. Such reports typically provide details of economic evaluations, extensive alternative evaluations and supporting technical studies And minority opinions if consensus is not reached.

10.0 Dispute Resolution

All substantive and procedural disputes related to the MAPP Regional Planning Process shall be resolved in accordance with the dispute resolution procedures set forth in the MAPP Restated Agreement. Disputes related to local planning issues shall be resolved in accordance with the dispute resolution procedures set forth in this Tariff.

11.0 Economic Planning Studies

The TPSC shall evaluate limitations on MAPP transfer capability through historical Transmission Loading Relief ("TLR") analysis associated with the defined flowgates in the MAPP region. The TPSC shall utilize these comprehensive reviews to determine transmission constraints in the region. The TPSC shall also support economic studies necessary to review the integration of large proposed generation facilities to the regional grid and shall develop concept plans as part of regional study efforts.

The TPSC may also commission SPGs and joint SPGs to address highly constrained regional flowgates and to develop proposed plans for increasing inter-regional transfer capability. SPGs may also perform regional transfer capability analysis and develop exploratory transmission expansion plans to address the most limiting flowgates within their SPG region. The TPSC may also coordinate and support other joint exploratory economic planning efforts within and adjacent to the RTC Region.

In addition to these types of studies, stakeholders, through the TPSC, may request that the TPSC perform economic planning studies to evaluate potential upgrades or other investments that could reduce congestion or integrate new transmission, generation or demand resources and loads on an aggregated or regional basis. The TPSC shall review such proposals and select a certain number for study each year.

The TPSC may cluster or batch requests for economic planning studies so the TPSC can perform the studies in the most efficient manner. Requests for studies shall be submitted to the chairman of the TPSC. All such requests will be collected over a 12 month period ending January 1 of each year. The TPSC (with stakeholder input) will commit and engage to address up to five requests per year. The TPSC will attempt to combine the scope of such requests such that the scope of actual study work will adequately address multiple requests, so as not to exceed three studies. Requesting parties would be required to submit essential data for their requested study.

As part of this process, the TPSC may also consider economic studies of upgrades to MAPP flowgates. The flowgates studied will be selected among those determined to have recurring congestion, as evidenced by a high number of hours per year with no available firm Available Flowgate Capacity ("AFC") or a high number of historical hours per year under Transmission Loading Relief ("TLR"). Along with stakeholder input, the TPSC will use these or similar metrics to determine which MAPP flowgates are most congested and warrant study of the economic benefits of proposed flowgate upgrades. Any economic planning study, which identifies a new MAPP region transmission facility or the upgrade of an existing transmission facility as a proposed Economic Network Upgrade, shall identify the proposed upgrade subject to the cost allocation principles set forth in Section 12 of this Attachment P. Such economic study shall also include a benefit allocation analysis based on one or more of the following principles: (a) reductions in projected congestion costs; (b) reductions in projected energy costs; or (c) reductions in projected transmission losses.

The economic planning studies performed by the TPSC shall include sensitivity analyses representing various generation price scenarios; however, the TPSC shall study the cost of congestion only to the extent it has information to do so. If a stakeholder requests that a particular congested area be studied, it must supply relevant data within its possession to enable the TPSC to calculate the level of congestion costs that is occurring or is likely to occur in the near future.

12.0 Cost Allocation

12.1 Categories of Projects. The TPSC will identify cost responsibility on a regional and subregional basis for Network Upgrades identified in the MAPP Regional Plan for reliability and economic projects subject to any grandfathered project provisions from pre-existing agreements. There will be three categories of projects:

12.1.1 Baseline Reliability Projects (BRP). BRPs are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable NERC and MRO Reliability Standards.

12.1.2 New Transmission Access Projects. New Transmission Access Projects are defined as Network Upgrades identified in Facilities Studies and agreements pursuant to requests for transmission delivery service or transmission interconnection service under Western's Tariff. New Transmission Access Projects include projects that are needed to accommodate the incremental needs associated with requests for new transmission or interconnection service, as determined in Facilities Studies associated with such requests. New Transmission Access Projects are either Generation Interconnection Projects or Transmission Service Projects.

12.1.2.1 Generation Interconnection Projects. Generation Interconnection Projects are New Transmission Access Projects that are associated with either the interconnection of new generation, or an increase in the generating capacity of existing generation, under Western's Tariff.

12.1.2.2 Transmission Service Projects. Transmission Service Projects are New Transmission Access Projects that are needed to provide for requests for new Point-To-Point Transmission Service, or requests under Western's Tariff for Network Service or a new designation of a Network Resource(s).

12.1.3 Regionally Beneficial Projects (RBP). A RBP is a transmission network upgrade that shall be: (a) proposed in accordance with the MAPP Planning Process; (b) found to be eligible for inclusion in the MAPP Regional Plan; (c) determined not to be a New Transmission Access Project; and (d) found to have regional benefits. RBPs may include projects that expand the scope of a project that would otherwise qualify as a Baseline Reliability Project.

12.2 Cost Allocation. The allocation rules for these projects are as follows:

12.2.1 Allocation of Baseline Reliability Project Costs. Each transmission owner is obligated to construct and/or upgrade those BRP facilities required to meet NERC and MRO Reliability Standards associated with serving its native load customers and to meet its firm transmission commitments. Costs associated with a single Transmission Provider facility addition shall be recovered through Western's rate recovery method. Costs associated with BRP involving multiple transmission owners shall be shared among the affected transmission owners in accordance with this principle, subject to those transmission owners' respective interconnection agreements.

12.2.2 New Transmission Access Projects. New Transmission Access Projects may consist of a number of individual facilities that constitutes a single project for cost allocation purposes. Cost allocation methods applicable to specific requests for interconnection and transmission service under Western's Tariff shall be used for new Transmission Access Projects.

12.2.3 Allocation Rules for RBPs. The MAPP Regional Plan shall classify transmission projects as described above. Any economic planning study authorized by the MAPP RTC for a RBP and performed in compliance with Section 11 of this Attachment P, which identifies the need for a new MAPP region transmission facility or the upgrade of an existing transmission facility as a proposed Economic Network Upgrade, shall treat such proposed facility upgrade(s) as commercial transmission.

This procedure ("Auction Procedure") describes the process by which the MAPP transmission owner on whose transmission system the Economic Network Upgrade is located (Host TO) shall solicit participation for the proposed Economic Network Upgrade. The MAPP transmission owner shall have the right to elect to be an Affected System and not serve as the Host TO, provided that the MAPP RTC identifies another qualified transmission owner, including a consortium of transmission owners and/or independent transmission owners, as the Host TO. A transmission owner that has protested a project as causing undue burden, which has not been satisfactorily resolved, has the option to decline participation.

12.2.3.1 Applicability. This Auction Procedure is applicable to MAPP-Region transmission owners and Eligible Transmission Customers, including but not limited to Affected Generators and MAPP-Region Load-Serving Entities ("LSEs"), collectively referred to as "Eligible Participants."

12.2.3.2 First Call Offer of Subscription Rights. The Contractor (*i.e.*, MAPPCOR acting on behalf of the Host TO) shall submit an offer to participate in the Economic Network Upgrade to all Eligible Participants and to any Affected System Operators participating on a reciprocal basis in accordance with the benefit allocation defined on a cost causation basis in the economic planning studies performed in compliance with Section 11 of this Attachment P, in exchange for Subscription Rights to the new transmission capacity.

The Contractor shall offer, on OASIS on a non-discriminatory, basis to all Eligible Participants the opportunity to participate in the Economic Network Upgrade by purchasing a portion of the Subscription Rights made available by such Auction Procedure. If an Eligible Participant accepts the subscription offer for participation in the Economic Network Upgrade, the subscription shall be granted to such Eligible Participant as a Subscription Rights buyer. If demand for the Subscription Rights offered exceeds the number of Subscription Rights available, the Contractor shall offer such Subscription Rights to the interested Eligible Participants on a pro rata basis, based on each Eligible Participant's designated level of transmission capacity megawatts requested in its submitted offer to participate to the total transmission capacity megawatts requested. Each participating interested Eligible Participant shall have 60 days to accept such an offer for pro rata Subscription Rights.

12.2.3.3 Second Round Offer of Subscription Rights. Within 30 days following the close of the above first call offer of Subscription Rights, the Contractor shall release any Subscription Rights that remain unsubscribed to all Eligible Participants. The Contractor shall allow thirty (30) days for recipients of the second round offer to indicate interest in acquiring the residual Subscription Rights. If the Subscription Rights offered are acquired by an Affected System Operator's transmission business unit, the revenue requirements will be rolled into the Affected System Operator's rate structure and the acquired transmission capacity shall be available under the Affected System Operator's open access transmission tariff ("OATT"). The Affected System Operator, including the Host TO, shall adjust the point-to-point and network service charges to reflect the addition of any revenue requirements to the Affected System Operator's OATT embedded cost rates, provided that any such Affected System Operator subject to the jurisdiction of the Commission shall obtain approval of the Commission prior to causing such rate adjustment to be effective.

Furthermore, any subscribing Eligible Participant may roll the revenue requirements associated with the acquired Subscription Rights into the Affected System Operator's rate structure, as approved by the Commission, if the subscribing Eligible Participant makes the acquired transmission capacity available under the Affected System Operator's OATT.

12.2.3.4 Resale and Reassignment of Subscription Rights. The MAPP transmission provider shall provide resale and reassignment provisions for Subscription Rights on the same basis as provided in the *pro forma* OATT for firm point-to-point transmission service.

12.2.3.5 Failure to Obtain Subscriptions. If, after the first and second rounds of the Auction Procedure have concluded, Subscription Rights sufficient to cover the total cost of the Economic Network Upgrade project have not been successfully subscribed, the Contractor shall notify subscribing Eligible Participants of the Subscription Rights shortfall. Such notice shall be in writing, include the amount of available Subscription Rights and provide thirty (30) days for such subscribing Eligible Participant to increase its Subscription Rights election. At the end of the expiration of the thirty (30) day notice period, the proposed project may be cancelled if it is still not fully subscribed. The Host TO or another Affected System Operator may choose to fund the remaining portion of the necessary subscription rights and roll those costs into their transmission revenue requirements. If a project is cancelled under such circumstances, the Contractor shall notify all of the subscribers in writing within thirty (30) days of its decision to terminate. If an Economic Network Upgrade is terminated for lack of subscriptions or for defaults on subscriptions, the project shall be deemed to have insufficient economic benefit to market participants, and the project shall not qualify for reconsideration as an Economic Network Upgrade until the latter of a) the next biennial MAPP Regional Plan planning cycle, or b) two years from the date of notice of cancellation.

12.2.3.6 Facilities Agreement. If the Economic Network Upgrade is fully subscribed, the Host TO shall offer the subscribers a Facilities Agreement within sixty (60) days of full subscription.

12.2.3.7 Defaulting Subscribers. If any of the subscribers fail to execute the Facilities Agreement within thirty (30) days of receipt of such agreement, the Contractor shall use its best efforts to award the non-signing subscriber's Subscription Rights to all Eligible Participants. If the Contractor is unable to secure an alternative subscriber, the Host TO shall pursue resolution with the non-signing/defaulting subscriber(s) pursuant to Article 9, Dispute Resolution, of the MAPP Restated Agreement. Any dispute that has not been resolved through the MAPP Article 9 Dispute Resolution process shall be resolved through the appropriate regulatory or jurisdictional dispute resolution proceedings. A party seeking to invoke FERC jurisdiction over a Dispute shall file with the Commission the Facilities Agreement unexecuted by the non-signing/defaulting subscriber. The Commission shall determine the obligations of the non-signing/defaulting subscriber. If, as a result of the dispute resolution process the non-signing/defaulting subscriber is relieved of its obligations, the Host TO may cancel the project with no further obligations to the remaining subscribers, except to notify all of the subscribers in writing within thirty (30) days of its decision to terminate.

12.2.3.8 Post-Auction Host Owner Option. In the event the defined Economic Network Upgrade is not fully subscribed after the Auction Procedure described in Sections 12.2.3.2-12.2.3.7 is exhausted, the Host TO may, of its own accord, elect to perform such **Economic** Network Upgrade, and roll the upgrade costs into the next update of its transmission revenue requirements.

12.2.3.9 Conversion of Subscription Rights to Physical Transmission Rights. The Facilities Agreement associated with an Economic Network Upgrade shall convert the Subscription Rights allocated pursuant to Sections 12.2.3.2, 12.2.3.3, 12.2.3.5 and 12.2.3.7 above, to Physical Transmission Rights. Subscription Rights and Physical Rights shall be the same transmission capability rights with the principal distinction merely being the stage of project commitment. Subscription Rights shall be associated with a good faith expression of intent, albeit still based on non-binding estimated planning costs, to invest in the Economic Network Upgrade. Upon signing a Facilities Agreement, the Eligible Participant's expression of intent to invest as a holder of Subscription Rights becomes a binding contractual commitment with the prescribed Physical Rights to the discrete transmission capability defined in the Facilities Agreement. The additional transmission capability achieved by the project shall be allocated to the Subscription Rights holders as Physical Transmission Rights in proportion to their respective payment for the network upgrade. The Physical Transmission Rights do not in themselves convey a form of transmission service under Part II or Part III of the Tariff. The holder of the Physical Transmission Rights may use those rights in conjunction with a specific application of transmission service under Part II or Part III of the Tariff of the Host TO, or the holder may sell or assign the Physical Transmission Rights to another party. Physical Transmission Rights may be used by a generator owner to secure firm transmission service and/or provide a hedge against potential congestion charges.

12.2.3.10 Completion of Economic Network Upgrades. Once an Economic Network Upgrade is fully subscribed and Facilities Agreements are in place for all subscribers, the Host TO shall apply good faith efforts to obtain approvals for, design, construct, own, operate and maintain the proposed Economic Network Upgrade facilities under the terms and conditions set forth in the Facilities Agreement(s).

12.2.3.11 Inter-Regional Coordination. This Procedure may be applied for inter-regional Economic Network Upgrades demonstrating inter-regional economic benefits. MAPP Transmission Owners may use this Procedure to fulfill any requirements of reciprocal obligations for inter-regional transmission upgrades identified by the planning processes of adjacent regional entities, including but not limited to the Midwest ISO Transmission Expansion Plan. This Procedure shall also be available to transmission owners in adjacent regions that may be invited to participate in a subscription rights offering from a MAPP Transmission Owner, based on demonstrations of benefits under Section 11 of this Attachment P.

12.2.3.12 Transmission Projects for Renewable Energy Zones. The Subscription Rights procedures of Sections 12.2.3.3 through 12.2.3.7 above may also be applied to a regional transmission project that is designed to develop deliverability from Renewable Energy Zones to a market in the same manner that the Subscription Rights procedures are applied for Economic Network Upgrades. However, this procedure shall not be an alternative for requirements of Transmission Access Projects under Parts II and III of the Tariff, or for the obligations of Attachment I, "Standard Large Generator Interconnection Procedures (LGIP)". The Renewable Energy Zone transmission project must be included in the MAPP Regional Plan or in the transmission plan of an adjacent region that has been coordinated with the MAPP Regional Plan.

12.3 Existing Cost Allocation Methodologies. The cost allocation methodology set forth in this Section 12.0 shall not modify or be inconsistent with (a) existing mechanisms to allocate costs for projects that are constructed by a single transmission owner and billed under existing rate structure, or (b) existing cost allocation methods applicable to specific requests for interconnection or transmission service under the pro forma OATT. Further, the cost allocation methodology set forth in this Section 12.0 shall not supersede cost-allocation, cost-sharing or joint-investment obligations to which an individual Host TO or Affected System may be subject.

13.0 Western's Upper Great Plains Region Local Planning Process

Western's UGPR Local Transmission Planning Process covers transmission facilities under Western's Tariff contained within both the Eastern and Western Interconnection of Western's Upper Great Plains Region. The Local Transmission Plan (LTP) is the transmission plan of the Transmission Provider that identifies the upgrades and other investments to the Western UGPR Transmission System necessary to reliably satisfy, over the planning horizon, Network Customers' resource and load growth expectations for Native Load Customers; Transmission Provider's obligations pursuant to grandfathered, non-OATT agreements; and Transmission Provider's Point-to-Point Transmission Service customers' projected service needs including obligations for rollover rights. In addition to this local process, Western UGPR participates in the regional planning efforts as described in Part I of this Attachment P and utilizes these forums also to coordinate new projects with Transmission Customers, Affected Generators, or other relevant stakeholders.

13.1 Scope.

The purpose of Western's UGPR Local Transmission Planning Process is to conduct local long-term planning for transmission facilities typically on a two year planning cycle with annual assessments to serve Western's network load and firm transmission commitments. The preparation of the LTP shall be done in accordance with the general policies, procedures, and principles set forth in this Attachment P.

13.1.1 Service Requests. Point-to-Point transmission service request must be made as a separate and distinct submission by an Eligible Customer in accordance with the procedures set forth in Transmission Provider's Tariff. Similarly, Network Customers must submit Network Resource and load additions/removals pursuant to the process set forth in Transmission Provider's Tariff.

13.1.2 Comparability between Customers. The process provides comparable long-term transmission system planning for similarly-situated wholesale customers. The process provides long-term reliability and economic planning of transmission facilities for Western's UGPR firm commitments (e.g., point-to-point service with rollover rights) and Network Customers served from the UGPR Transmission System that is comparable to the long-term planning of its own Native Load Customers from the UGPR System. In developing the LTP, Transmission Provider shall apply applicable reliability criteria, including criteria established by the Transmission Provider, the Midwest Reliability Organization, the WECC, the North American Electric Reliability Corporation, and the Federal Energy Regulatory Commission.

13.1.3 Comparability between Resources. Comparability between resources, including similarly situated customer-identified projects, will be accomplished by modeling from the generation to the Network Load on the UGPR Transmission System. Comparability between resources will be achieved in Western UGPR's LTP by including all valid data received from customers (including load forecast data, generation data and Demand Resource data) in the LTP development. Comparability will be achieved by allowing customer-defined projects sponsor participation throughout the transmission planning process and by considering customer-defined projects (transmission solutions and solutions utilizing Demand Resources load modeled as a load adjustment) in the LTP development. The Transmission Provider retains discretion as to which solutions to pursue and is not required to include all customer-identified projects in its plan.

13.2 Responsibilities.

Western will be responsible for the development of the transmission plans that result from Western's UGPR Local Transmission Planning Process. Western's UGPR Local Planning Process will allow timely and meaningful stakeholder input and participation in the development of the LTP. Western's UGPR Local Planning Process will follow regional planning procedures provided in Sections 1 through 12 and Sections 14 of this Attachment P. The transmission plans and studies on the eastern interconnect resulting from Western's UGPR Local Planning Process that are to be included in MAPP Regional Plans will be submitted to the applicable MAPP Committees and on the Western Interconnection resulting from Western's UGPR Local Planning Process that are to be included in WECC Regional Plans will be submitted to the applicable WECC Committees, to their successor regional or sub-regional committees, and/or to the successor regional transmission organization, independent transmission coordinator, or independent system operator, as appropriate.

In addition to developing transmission plans to be provided for regional coordinated planning, Western's UGPR Local Planning Process will develop plans to address local UGPR transmission issues, such as transmission facility uprates that do not significantly change network system flows. The plans will be provided in reports with executive summaries that are brief and designed to be understandable to stakeholders.

13.3 Open Planning Process.

13.3.1 Openness: Western's UGPR Local Planning Process will be open to all stakeholders during the development of the LTP. All meetings related to the LTP process shall be: (1) noticed by the Transmission Provider via the OASIS; and (2) provide for alternate means of participation, to the extent practical and economical, such as teleconference, videoconference or other similar means. The mode, method, schedule, process, and instructions for participation in Western's UGPR Local Planning Process shall be posted and maintained on the OASIS.

13.3.2 Limitations on Disclosure: While Western's UGPR Local Planning Process will be conducted in the most open manner possible, Transmission Provider has an obligation to protect sensitive information such as, but not limited to, Critical Energy Information and the proprietary materials of third parties. Nothing in this Attachment P shall be construed as compelling the Transmission Provider to disclose materials in contravention of any applicable regulation, contractual arrangement, or lawful order unless otherwise ordered by a governmental agency of competent jurisdiction. Transmission Provider may employ mechanisms such as confidentiality agreements, protective orders, or waivers to facilitate the exchange of sensitive information where appropriate and available.

13.3.3 Compliance: Transmission Provider will adhere to all applicable regulations in preparing the LTP, including but not limited to the Standards of Conduct for Transmission Providers and Critical Information Energy Information.

13.4 Study Process.

A local study group process will be instituted in addition to the open planning process described in Section 13.3. The purpose of the local study group process is to expand stakeholder participation in Western's UGPR Local Planning Process as provided in the following:

(a) A working group will be formed at the first semi-annual stakeholder meeting to receive information and provide comment on planning issues that are the subject of Western's UGPR Local Planning Process that arise between stakeholder meetings. Western UGPR will provide (subject to confidentiality, CEII, cyber security and Standards of Conduct requirements):

1. The initial assumptions used in developing the annual local process transmission assessment and will provide an opportunity for feedback.

2. The models used for local process transmission planning.

3. Information regarding the status of local process transmission upgrades and how such upgrades are reflected in future local process transmission plan development.

4. The draft study scope for those studies conducted by the working group as part of the local process, which will include or provide references to the basic assumptions for the study, the model or models used in the working group study including information regarding significant changes in the model.

5. The draft transmission report for those studies conducted by the working group as part of the local process, as prepared by Western UGPR or Western UGPR's designate. Stakeholders who do not participate on the working group will be given the opportunity to comment on the draft report after Western UGPR has considered the comments of the working group. The report will include an executive summary that is brief and is designed to be understandable to stakeholders.

6. Draft transmission plans that result from Western's UGPR Local Planning Process before they are distributed to stakeholders pursuant to the open planning process described in Section 13.3 above.

(b) The working group meetings will be established by Western UGPR on an as needed basis. Working group meetings will also be established if need is expressed by 10 members of the respective working group; however, Western UGPR will not be required to hold meetings of the working group more than on a semi-annual basis. Meetings will typically be conference calls and/or web casts, but face-to-face meetings may be called if necessary. Meeting notices will be distributed via email to the respective study group mailing list. Meeting materials may be distributed via email respecting email size limitations and CEII, cyber security, and Standards of Conduct requirements. A password protected FTP site or internet may be used to transmit study models or large amounts of data.

(c) Western UGPR will chair and provide leadership to the working group, including facilitating the group meetings.

(d) Input from the working group members will be considered in the local planning process. Comments will generally be expected via email or during working group meetings. Comments will be solicited within the defined comment periods of the study group process.

13.5 Transparency

In addition, Western's UGPR Local Planning Process will be open and transparent to facilitate comment and exchange of information, as described below:

(a) Western UGPR will make available the basic criteria that underlie its transmission system plans by posting Western UGPR's Transmission Planning Criteria for facilities covered by this Attachment P on the Western UGPR OASIS page.

(b) Western UGPR will make available to registered stakeholders (subject to CEII, cyber security, and Standards of Conduct requirements) the basic criteria, assumptions, and data that underlie its transmission system plans. For this purpose, Western UGPR will make the following documents available in a way that maintains confidentiality and complies with CEII and cyber security requirements: i. Western's FERC Form 714, ii. Western's FERC Form 715.

(c) Western UGPR will provide information on the location of applicable NERC/MAPP/Midwest Reliability Organization ("MRO")/WECC planning criteria, reliability standards, regional power flow models, or other pertinent information, as available.

(d) Western UGPR will provide its regional planning model submittal in accordance with Section 13.6 of this Attachment P.

(e) Western UGPR will set the planning study horizons and study frequencies considering NERC and or regional entity standards and the MAPP SPG planning cycle and the WECC Regional Planning Process.

(f) Western UGPR will simultaneously disclose transmission planning information where appropriate in order to alleviate concerns regarding the disclosure of information with respect to the FERC Standards of Conduct.

(g) Western UGPR will consider customer demand response resources in Western's UGPR Local Planning Process on a comparable basis with generation resources in developing transmission plans provided that

1. such resources are capable of providing measurable transmission system support needed to correct transmission system problems assessed in the Western's UGPR Local Planning Process,

2. such resources can be relied upon on a long-term basis,

3. such resources meet NERC Reliability Standards and applicable laws, rules, and regulations, and

4. the inclusion of such resources in corrective action plans are permitted by the NERC Reliability Standards.

13.6 Information Exchange

Certain information exchanges associated with the open planning process and the local study group process are described in Sections 13.3 and 13.4 in this Attachment P. In addition, information exchange for base regional model development will take place as follows:

(a) Western participates in the annual development of the regional base case power flow and stability models currently for the PSS™E computer application. These regional models provide the basis for studies of transmission service requests, generator interconnection requests, local planning studies and regional planning studies. To assist in the development of accurate base case regional models and thereby develop appropriate local transmission plans for the Western UGPR system, Western will request at a minimum the following data of its Transmission Customers:

1. Network Customers and other Load Serving Entities (LSE) within the Western UGPR Control Area will be requested annually to submit existing loads and future loads for the horizon of the regional base case models (typically 10 years) for each of its load points. Information for firm loads will be separated from information for interruptible loads.

2. Network Customers and other LSEs within the Western UGPR Control Area will be requested annually to provide a list of all existing and proposed new demand response resources including behind the meter generation or load curtailment; the MW impact on peak load; the historical and expected future operating practice of the demand response resources such as the conditions under which the customer intends to initiate each resource, and whether each resource is available for use in providing measurable transmission system support to correct problems assessed in Western's UGPR Local

Planning Process, as well as, other information required to consider such resources as provided in Section 13.5 (g). Network Customers and other LSEs will be requested to provide updates of this information when substantive changes occur.

3. Network Customers and other LSEs within the Western UGPR Control Area will be requested annually to provide a list of existing and proposed new generation resources and historical and expected future dispatch practices such as the load level at which the customer plans to start each generating unit and plant, and whether each generation resource is available for use in providing measurable transmission system support to correct problems assessed in Western's UGPR Local Planning Process, as well as, other information required to consider such resources as provided in Section 13.5 (g). Network Customers and other LSEs will be requested to provide updates of this information when substantive changes occur.

4. Registered point-to-point customers including Western UGPR's marketing and energy affiliates, as appropriate, will be requested annually to submit projections of their quantifiable transmission service needs over the planning horizon, including applicable receipt and delivery points and the transmission service reservations anticipated to be scheduled.

5. Network Customers and other LSEs within the Western UGPR Control Area will be requested annually to submit existing and expected future generation for the horizon of the regional base case models (typically 10 years).

6. Additional modeling data will be requested as necessary to conform to the requirements of the NERC MOD standards.

(b) The data submitted by Transmission Customers will be included to the extent appropriate in the base case model.

(c) The Western UGPR data request will be sent annually in coordination with the regional data request. Western UGRP will send a data request to its Transmission Customers typically prior to expected transmittal of the regional data request. Transmission Customers will be expected to respond to the Western UGPR data request in a timely fashion.

(d) Responses to the data request will be accepted in forms such as PSS™E raw data format or in spreadsheet format with appropriately labeled headings.

(e) Each Transmission Customer and LSE within the Western UGPR control area will be responsible for providing Western with an email address of its data modeling contact. Western will send the annual data request to these contacts via email.

(f) The Western data response will be made available subject to CEII, cyber security and Standards of Conduct restrictions upon request to registered stakeholders.

13.7 Western's UGPR Local Economic Planning Studies

Local economic planning studies are performed to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and loads. Such studies may analyze any, or all, of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, in whole or in part, including transmission solutions, generation solutions and solutions utilizing demand response resources, (iii) the associated costs of congestion (iv) the costs associated with relieving congestion through system enhancements (or other means), and, as appropriate, (v) the economic impacts of integrating new resources and loads. All local economic planning studies will be performed through Western UGPR's participation in the regional economic planning studies as described in this Attachment P.

(a) Any Transmission Customers, Affected Generators, or other relevant stakeholders ("Requester") may submit a study request for an economic planning study directly to Western, the MAPP TPSC, or the WECC TEPPC. All requests must be electronically submitted to Western's Regional Office Contact e-mail Address as posted on the Transmission Providers OASIS. Western will not perform local economic planning studies but will coordinate the performance of such studies with the MAPP TPSC or the WECC TEPPC. The economic planning study cycle will be that of the MAPP TPSC or WECC TEPPC process as outlined in this Attachment P.

(b) Western shall ensure that any economic planning study requests submitted to Western are properly handled by forwarding the Requestor to MAPP TPSC or WECC TEPPC for inclusion in the regional economic planning studies as outlined in this Attachment P.

(c) If the MAPP TPSC or WECC TEPPC determines, after reviewing through an open stakeholder process, that the requested economic planning study as forwarded by Western is not a high priority study, the Requester may perform the economic planning analysis at the Requester's expense. Western will support the Requester in ensuring that the study is coordinated as necessary through local, subregional or regional planning groups.

(d) Western cannot fund any high priority and other local economic planning studies due to its spending authorization being contingent upon Congressional Appropriations. In the event that Western is requested to perform a local economic planning study, Western will, at the Requester's expense, provide its assistance in having a third party perform the local economic planning study. Western will support the Requester in ensuring that the study is coordinated as necessary through local, subregional or regional planning groups.

14.0 Introduction to the WECC Regional Planning Process for Western's UGPR

Western UGPR will coordinate its Western Interconnection LTP through the WECC SPGs. The WECC SPGs will coordinate their subregional plans with the other subregional plans in the Western Interconnection and at the TEPPC level.

14.1 WECC Procedures for Regional Planning Project Review

(a) WECC develops the Western Interconnection-wide coordinated base cases for transmission planning analysis such as power flow, stability and dynamic voltage stability studies. The WECC approved base cases are used for study purposes by transmission planners, subregional planning groups, and other entities that have signed confidentiality agreements with WECC.

(b) WECC also maintains a data base for reporting the status of all planned projects throughout the Western Interconnection.

(c) WECC provides for coordination of planned projects through its Procedures for Regional Planning Project Review.

(d) WECC's Path Rating Process ensures that a new project will have no adverse effect on existing projects or facilities.

14.2 WECC Open Stakeholder Meetings

Western Interconnection-wide economic planning studies are conducted by the WECC TEPPC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC-TEPPC Transmission Planning Protocol, including the TEPPC procedures for prioritizing and completing regional economic studies, is posted on the WECC website. Western participates in the region-wide planning processes, as appropriate, to ensure that data and assumptions are coordinated.

14.3 Role of WECC TEPPC.

WECC TEPPC provides two main functions in relation to Western's planning process:

(a) Development and maintenance of the west-wide economic planning study database. TEPPC uses publicly available data to compile a database that can be used by a number of economic congestion study tools. Also, TEPPC's database is publicly available for use in running economic congestion studies. For an interested transmission customer or stakeholder to utilize WECC's Pro-Mod planning model, it must comply with WECC confidentiality requirements.

(b) TEPPC has an annual study cycle described in the WECC-TEPPC Transmission Planning Protocol, during which it will update databases, develop and approve a study plan that includes studying transmission customer high priority economic study requests as determined by the open TEPPC stakeholder process, perform the approved studies and document the results in a report.

PART II – Western Interconnection of Western's Rocky Mountain, Desert Southwest and Sierra Nevada Regional Offices

Western coordinates its transmission planning with other transmission providers and stakeholders in the Rocky Mountain – located in Loveland, CO, Desert Southwest - located in Phoenix, AZ, and Sierra Nevada - located in Folsom, CA, Regional Offices, and the Western Interconnection as a whole, through its active participation in the Southwest Area Transmission Planning (SWAT) group, the Colorado Coordinated Planning Group (CCPG), the Sierra Subregional Planning Group (SSPG), membership in WestConnect[1], membership in the Western Electricity Coordinating Council (WECC), and participation in the WECC Transmission Expansion Planning Policy Committee (TEPPC) and its Technical Advisory Subcommittee (TAS).

Three subregional planning groups (SPG) operate within the WestConnect footprint: SWAT, CCPG and SSPG. WestConnect's planning effort, which includes funding and provision of planning management, analysis, report writing and communication services, supports and

[1] WestConnect was formed under a memorandum of understanding (MOU) that has been entered into by 13 transmission providing electric utilities in the Western Interconnection. The purposes of WestConnect are to investigate the feasibility of wholesale market enhancements, work cooperatively with other Western Interconnection organizations and market stakeholders, and address seams issues in the appropriate forums. WestConnect has initiated an effort to facilitate and coordinate regional transmission planning across the WestConnect footprint. Current parties to the WestConnect MOU are: Arizona Public Service Company, El Paso Electric Company, Imperial Irrigation District, Nevada Power Company Sierra Pacific Power Company, Public Service Company of Colorado, Public Service Company of New Mexico, Sacramento Municipal Utility District, Salt River Project, Southwest Transmission Cooperative, Transmission Agency of Northern California, Tri-State Generation and Transmission Association, Tucson Electric Power Company, and Western Area Power Administration.

manages the coordination of the subregional planning groups and their respective studies. Such responsibilities are detailed in the WestConnect Project Agreement for Subregional Transmission Planning (WestConnect STP Project Agreement), dated May 23, 2007 (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)). Western is a signatory to this Agreement.

The subregional planning groups within the WestConnect footprint, assisted by the WestConnect planning manager, coordinate with other Western Interconnection transmission providers and their subregional planning groups through TEPPC. TEPPC provides for the development and maintenance of an economic transmission study database for the entire Western Interconnection and performs annual congestion studies at the Western Interconnection region level.

1.0 Western Transmission Planning

1.1 Western Planning Process

Participation in Western's planning process is open to all affected parties, including but not limited to all transmission and interconnection customers, state authorities, sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, and other stakeholders.

1.1.1 Confidential or Proprietary Information

Western's transmission planning studies may include base case data that are WECC proprietary data or classified as Critical Energy Infrastructure Information (CEII) by the Federal Energy Regulatory Commission (FERC). A stakeholder must hold membership in or execute a confidentiality agreement with WECC (see Western Attachment P Hyperlinks List) www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm in order to obtain requested base case data from Western. A stakeholder may obtain transmission planning information classified as CEII from Western upon execution of a confidentiality agreement with Western.

1.1.2 Overview

Western's transmission planning process consists of an assessment of the following needs:

(a) Provide adequate transmission to serve Firm Electric Service (FES) customers.

(b) Where feasible, identify alternatives such as demand response resources that could meet or mitigate the need for transmission additions or upgrades.

(c) Access adequate resources in order to reliably and economically serve FES and network loads.

(d) Provide for interconnection for new generation resources.

(e) Coordinate new interconnections with other transmission systems.

(f) Accommodate requests for long-term transmission access.

1.1.3 Western's Transmission Planning Cycle

(a) Calendar Year Planning Cycle. Western conducts its transmission planning on a calendar year cycle for a ten year planning horizon.

(b) Annually Updated Ten Year Plan. Western updates its ten year plan annually and publishes an annual Ten Year Transmission Plan document typically in November.

1.1.4 Transmission Customer's Responsibility for Providing Data

(a) Use of Customer Data. Western uses information provided by its transmission customers to, among other things; assess network load and resource projections (including demand response resources), transmission needs, in-service dates to update regional models used to conduct planning studies.

(b) Submission of Data by Network Transmission Customers. Network transmission customers shall supply information on their ten year projected network load and network resources (including demand response resources) to Western on an annual basis. Western requires that this information be submitted electronically to Western Regional Office Contact e-mail address (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm) by March 15 each year.

(c) Submission of Data by Other Transmission Customers. To maximize the effectiveness of the Western planning process, it is essential that all other transmission customers provide their ten year needs in the form of relevant data for inclusion in the Western transmission planning process. Western requires that this information be submitted electronically to Western Regional Office Contact e-mail address (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm) by March 15 each year. This will facilitate inclusion of transmission customer data in the planning process for the annual transmission plan.

(d) Transmission Customer Data to be Submitted. To the maximum extent practical and consistent with protection of proprietary information, data submitted by network transmission customers and other transmission customers should include for the ten year planning horizon:

i. Generators – planned additions or upgrades (including status and expected in-service dates) and planned retirements.

ii. Demand response resources – existing and planned demand resources and their impacts on peak demand.

iii. Network customers – forecast information for load and resource requirements over the planning horizon and identification of demand response reductions.

iv. Point-to-point transmission customers – projections of need for service over the planning horizon, including transmission capacity, duration, and receipt and delivery points.

(e) Notification of Material Changes to Transmission Customer Data. Each transmission customer is responsible for timely submittal of written notice to Western of material changes in any of the information previously provided related to the transmission customer's load, resources (including demand response resources), or other aspects of its facilities or operations which may, directly or indirectly, affect Western's ability to provide service.

1.1.5 Types of Planning Studies

(a) Economic Planning Studies. Economic planning studies are performed to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and loads. Such studies may analyze any, or all, of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, in whole or in part, including transmission solutions, generation solutions and solutions utilizing demand response resources, (iii) the associated costs of congestion (iv) the costs associated with relieving congestion through system enhancements (or other means), and, as appropriate, (v) the economic impacts of integrating new resources and loads. All economic planning studies will be performed either by a sub-regional planning group or TEPPC, and will utilize the TEPPC public data base.

(b) Reliability Studies. Western will conduct reliability planning studies to ensure that all transmission customers' requirements for planned loads and resources are met for each year of the ten year planning horizon, and that all NERC, WECC, and local reliability standards are met. These reliability planning studies will be coordinated with the other regional transmission planning organizations through the SWAT, CCPG, and SSPG studies.

1.1.6 Economic Planning Study Requests (*See* Flow Chart Attached as Exhibit 1)

Requesting Economic Planning Studies. Any Western transmission customer or other stakeholder, including transmission solutions, generation solutions and solutions utilizing demand response resources ("Requester") may submit a study request for an economic planning study directly to Western or TEPPC. All requests must be electronically submitted to Western at Western Regional Office Contact e-mail address (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm). Western will not perform economic planning studies but will coordinate the performance of such studies with TEPPC. The economic planning study cycle will be that of the TEPPC process

(a) Process for Handling Economic Transmission Planning Study Requests by Western. Western shall ensure that any economic planning study requests are properly handled under this Attachment P by:

i. TEPPC Master List. Forwarding the Requestor to TEPPC for inclusion in the TEPPC Master List of economic planning studies for the Western Interconnection and for consideration by TEPPC as a priority request. (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

(b) Process for Handling Economic Study Requests Received by TEPPC. TEPPC will review economic planning study requests received from Requesters directly or from Western. TEPPC shall review such study requests during its open stakeholder meeting and, together with its stakeholders, prioritize requests for economic planning studies. Western will participate in the TEPPC prioritization process and provide input as to whether a study request should be included in the TEPPC study plan. The Requester is also encouraged to participate and provide input in the TEPPC prioritization process. For more detail regarding the TEPPC economic planning study process, see the executive summary overview of the TEPPC Transmission Planning Protocol. (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

(c) Low Priority Economic Study Requests. If TEPPC determines, after reviewing through an open stakeholder process, that the requested economic planning study is not a priority study, the Requester may have a third party perform the economic planning analysis at the Requester's expense. The Requester will have use of the TEPPC economic study data base and Western will support the Requester in ensuring that the study is coordinated as necessary through local, subregional or regional planning groups.

(d) Clustering Local Priority Economic Planning Studies. TEPPC may determine that any number of Requesters' economic planning study requests should be studied together with other requests.

(e) Cost Responsibility for Economic Planning Studies

i. Priority and Non-Priority Local Economic Planning Studies. Western cannot fund any Priority and Non-Priority local economic planning studies due to its spending authorization being contingent upon Congressional Appropriations. In the event that Western is requested to perform an economic planning study, Western will, at the Requesters expense, provide its assistance in having a third party perform the economic planning study. The Requester will have use of the TEPPC economic study data base and Western will support the Requester in ensuring that the study is coordinated as necessary through local, subregional or regional planning groups.

ii. Priority Regional Economic Planning Studies. Regional economic studies are performed by TEPPC and funded by WECC.

(f) Exchange of Data Unique to Economic Planning Studies

i. All data used for its economic planning studies from the TEPPC data base.

ii. Requester's request for detailed base case data must be submitted to WECC in accordance with the WECC procedures.

iii. All requests made to Western for economic planning studies and responses to such requests shall be posted on the Western OASIS and the WestConnect website (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)), subject to confidentiality requirements.

(g) Western Point of Contact for Study Requests. Western will identify a Point of Contact on its OASIS to respond to customer/stakeholder questions regarding modeling, criteria, assumptions, and data underlying economic planning studies. (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

1.1.7 Stakeholder Participation in Western Study Plans and Planning Results. Western will hold a public planning meeting to review and discuss its transmission study plans and planning results (*see* Part II Section 1.2.2 below).

1.1.8 Western Study Criteria and Guidelines. Requesters should refer to the Western Planning Criteria document for Western planning criteria, guidelines, assumptions and data. The Western Planning Criteria are posted on the OASIS. (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

1.1.9 Western and Stakeholder Alternative Solutions Evaluation Basis. Western's planning process is an objective process that evaluates use of the transmission system on a comparable basis for all customers. All solution alternatives that have been presented on a timely basis (per Part II Section 1.1.4 of this Attachment P), including transmission solutions, generation solutions and solutions utilizing demand response resources, whether presented by Western or another Stakeholder, will be evaluated on a comparable basis. The same criteria and evaluation process will be applied to competing solutions and/or projects, regardless of type or class of Stakeholder. Solution alternatives will be evaluated against one another on the basis of the following criteria to select the preferred solution or combination of solutions: (1) ability to practically fulfill the identified need; (2) ability to meet applicable reliability criteria or NERC Planning Standards issues; (3) technical, operational and financial feasibility; (4) operational benefits/constraints or issues; (5) cost-effectiveness over the time frame of the study or the life of the facilities, as appropriate (including adjustments, as necessary, for operational benefits/constraints or issues, including dependability); and (6) where applicable, consistency with State or local integrated resource planning requirements, or regulatory requirements, including cost recovery through regulated rates.

1.2 Open Public Planning Meetings

Western will conduct at least two open public planning meetings each year, in coordination with four SWAT open public transmission planning meetings, including one joint meeting with CCPG and SSPG that will allow and encourage customers, interconnected neighbors, sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, and other stakeholders to participate in a coordinated, nondiscriminatory process for development of Western's transmission plan.

1.2.1 Purpose and Scope. Western's open public transmission planning meetings will provide an open transparent forum whereby electric transmission stakeholders can comment and provide advice to Western during all stages of its transmission planning. These public transmission planning meetings will serve to:

(a) Provide a forum for open and transparent communications among area transmission providers, customers, sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, and other interested stakeholders;

(b) Promote discussion of all aspects of Western's transmission planning activities, including, but not limited to, methodology, study inputs and study results; and

(c) Provide a forum for Western to understand better the specific electric transmission interests of all stakeholders.

1.2.2 Public Planning Meeting Process.

(a) Open Stakeholder Meetings. All public transmission planning meetings will be open to all stakeholders.

(b) Planning Meeting Schedule. Western will establish its public planning meeting schedule as needed, but no less than twice annually.

(c) Meeting Purpose. Meetings will be conducted to (i) allow Western to maximize its understanding of its customers' forecast needs for Western's transmission system; (ii) offer customers, sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, and other stakeholders an opportunity to be informed about, offer input and advice into, Western's transmission system and planning process, as well as to propose alternatives for any upgrades identified by Western; (iii) review study results; and (iv) review transmission plans.

(d) Coordination with SWAT, CCPG and SSPG. Western's local transmission planning process will be coordinated with the SPGs through quarterly planning meetings described in more detail below (*see* Part II Section 2.2.7).

(e) Posting of Meeting Notices. All meeting notices, including date, time, place and draft meeting agenda, will be posted on Western's OASIS and the WestConnect website (see Western Attachment P Hyperlinks List(www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)), and distributed to Western customer 30 days prior to the public planning meeting.

(f) Posting of Study Plans and Planning Results. Study plans and planning results will be posted on Western's OASIS and the

WestConnect website (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)), and distributed to Western's customers two weeks prior to the public planning meeting.

(g) Meeting Process. At the public planning meetings, Western will (i) review its transmission planning process and current study plan with stakeholders; (ii) request stakeholder review of the current study plan; (iii) provide an opportunity for comment on any aspect of its transmission planning process; (iv) invite the submittal of transmission study requests from stakeholders for review and discussion; and (v) provide updates on its planned projects. During the meeting, and for fifteen (15) calendar days following the meeting, all stakeholders and interested parties will be encouraged to provide Western with any comments on the study results presented in the public meeting. The final local study results and study plan will be posted on Western's OASIS and the WestConnect website (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

(h) Electronic Input and Comments. Stakeholders and interested parties are also encouraged to provide input, comments, advice and questions on Western's transmission planning process at any time by sending e-mails to Western Regional Office Contact e-mail address (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm).

(i) Public Planning Meeting Agenda.

i. It is anticipated that in the 2nd Quarter meetings, Western will review information on loads, resources (including demand response resources) and other needs received by March15 from its transmission customers pursuant to Part II Sections 1.1.4(b) and (c) for inclusion in a draft study plan.

ii. It is anticipated that in the 4th Quarter meetings, Western will review planning study requests received by each Regional Office pursuant to Part II Section 1.1.6 and present a draft of its ten year plan for stakeholder review and comment.

iii. This schedule may be modified to coordinate with the subregional and regional transmission planning processes, subject to posting on Western's OASIS and the WestConnect website (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

(j) Western Customer Distribution List. All existing Western customers, network and point-to-point, will be included on the distribution list and actively notified *via* e-mail of all upcoming public planning meetings. Any other stakeholder, including but not limited to, sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, wanting to be included on Western's e-mail distribution list should submit its information to Western's Point of Contact at Western Regional Office Contact e-mail address (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm).

(k) Posting of Meeting Documents. Western will post all meeting-related notes, documents and draft or final reports on its OASIS and the WestConnect website (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

(l) Posting of Public Documents. In order to permit all stakeholders access to the information posted on the OASIS and WestConnect websites, only public information will be shared, and public business conducted, in the open public planning meetings.

1.3 Ten Year Transmission System Plan

Each year Western uses the planning process described in Part II Section 1.1 above to update its Ten Year Transmission System Plan. The Ten Year Transmission System Plan identifies all of its new transmission facilities, 115 kV and above, and all facility replacements/upgrades required over the next ten years to reliably and economically serve its loads.

2.0 Subregional and Regional Coordination

Regional Planning and Coordination at the WestConnect-SWAT,-CCPG and-SSPG subregional level.

2.1 Overview

Western is a party to the WestConnect STP Project Agreement (see Western Attachment P Hyperlinks List) www.wapa.gov/Transmission/Planning.htm, and is actively engaged in the SWAT, CCPG and SSPG planning groups. The WestConnect footprint, which includes the regions covered by SWAT, CCPG and SSPG, encompasses the states of Arizona, Colorado, New Mexico, Nevada, and parts of California, Texas, and Wyoming. Western submits its transmission plans to its relevant subregional transmission planning group as required for inclusion in and coordination with the SPG's transmission plan. Western actively participates in the SPG transmission planning process to ensure that Western's data and assumptions are coordinated with the subregional plan. The WestConnect planning manager will ensure that the subregional transmission plan is coordinated to produce the WestConnect Transmission Plan.

2.2 The Subregional Transmission Planning Process

2.2.1 SWAT,-CCPG and SSPG's Role. Each SPG tasked with bringing transmission planning information together and sharing updates on active projects within the various subregions. The SPG's provide an open forum where any stakeholder interested in the planning of the transmission system in each footprint including sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, can participate and obtain information regarding base cases, plans, and projects and to provide input or express its needs as they relate to the transmission system. SWAT, CCPG and SSPG do not conduct economic planning studies.

2.2.2 Membership. The subregional transmission planning groups are comprised of transmission providers, transmission users, transmission operators, state regulatory entities and environmental entities. Membership is voluntary and open to all interested stakeholders including sponsors of transmission solutions, generation solutions and solutions utilizing demand resources. Western will participate in SWAT, CCPG and SSPG and relevant SPG subcommittees and work groups and will submit its Ten Year Transmission Plans to the relevant work groups. Western's Ten Year Transmission Plans will then be incorporated with the SWAT, CCPG and SSPG subregional transmission plans in accordance with the WestConnect STP Project Agreement. (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)). Western will incorporate any applicable information, data or study results from SWAT, CCPG or SSPG into its planning process.

2.2.3 Subregional Coordination. The SPG's role is to promote subregional transmission planning and development and to ensure that all of the individual transmission plans are coordinated in order to maximize use of the existing transmission system and identify the transmission expansion alternatives that most effectively meet future needs.

2.2.4 Open Subcommittee Forum. All SPG subcommittee planning groups provide a forum for entities including sponsors of transmission solutions, generation solutions and solutions utilizing demand resources, within each respective region, and any other interested parties, to determine and study the needs of the region as a whole.

2.2.5 Forum for Project Sponsors. The SPGs also provide a forum for transmission project sponsors to introduce their specific projects to interested stakeholders and potential partners and allows for joint study of these projects, coordination with other projects, and project participation, including ownership from other interested parties.

2.2.6 Subregional Open Planning Meetings. All SPG transmission planning process for the high voltage and extra high voltage system is open to all transmission customers and stakeholders wishing to participate. Western will assist transmission customers and stakeholders interested in becoming involved in the subregional transmission planning process including sponsor of transmission solutions, generation solutions, and solutions utilizing demand resources, by directing them to appropriate contact persons and websites. All transmission customers and stakeholders are encouraged to bring their plans for future generators, demand resources, loads or transmission services to the SPG planning meetings.

2.2.7 Meeting Agendas. The meeting agendas for the SPG's, WestConnect, Western and any other planning meetings scheduled in conjunction with the SPG meetings will be sufficiently detailed, posted on the WestConnect website (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)) and circulated in advance of the meetings in order to allow customers and stakeholders the ability to choose their meeting attendance most efficiently.

2.3 WestConnect's Role in the Subregional Transmission Planning Process

2.3.1 WestConnect STP Project Agreement. Each WestConnect party is a signatory to the West Connect STP Project Agreement (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm) which formalizes the parties' relationships and establishes obligations among the signatory transmission providers to coordinate subregional transmission planning among the WestConnect participants and the subregional planning groups (SWAT, CCPG, and SSPG), participate in the SWAT, CCPG and SSPG subregional transmission planning groups, as appropriate, and produce a WestConnect Transmission Plan. The WestConnect STP Project Agreement is also open for participation by other non-WestConnect transmission providers that participate in the transmission planning activities of SWAT, CCPG and SSPG or any other subregional transmission planning group that may form within the WestConnect footprint.

2.3.2. WestConnect Objectives and Procedures for Regional Transmission Planning. Under the WestConnect Objectives and Procedures for Regional Transmission Planning, Western, along with the other WestConnect STP Project Agreement participants, agrees to work through the SWAT, CCPG and SSPG planning processes to integrate its Ten Year Transmission Plans with the other WestConnect participant transmission plans into one ten year regional transmission plan for the WestConnect footprint by:

(a) Actively participating in the subregional transmission planning processes, including submitting its respective expansion plan, associated study work and pertinent financial, technical and engineering data to support the validity of Western's plan;

(b) Coordinating, developing and updating common base cases to be used for all study efforts within the SWAT, CCPG and SSPG planning groups and ensuring that each plan adheres to the common methodology and format developed jointly by WestConnect subregional planning groups for this planning purpose;

(c) Providing funding for the WestConnect STP Project Agreement planning management functions pursuant to the WestConnect STP Project Agreement;

(d) Retaining an independent facilitator to oversee the WestConnect STP Project Agreement process, ensure comparability among the subregional processes and perform the study work required to pull all the plans together;

(e) Maintaining a regional planning section on the WestConnect website where all WestConnect planning information, including meeting notices, meeting minutes, reports, presentations, and other pertinent information is posted; and

(f) Posting detailed notices on all SWAT, CCPG and SSPG meeting agendas on the WestConnect website. (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

2.3.3. WestConnect Planning Meetings. WestConnect hosts two open public stakeholder meetings for transmission planning per year, one in the 1st Quarter and one in the 4th Quarter.

2.3.4. WestConnect Role in Economic Planning. WestConnect will provide advice, on an as needed basis, to TEPPC regarding prioritizing regional economic planning study requests and potential clustering of requested regional economic planning studies, if those studies involve facilities in the WestConnect footprint. WestConnect will not conduct economic planning studies.

2.4. Quarterly Schedule of Subregional and Local Transmission Planning Meetings

Western will coordinate with SWAT, CCPG and SSPG in order to assure that quarterly meetings are times in order to allow projects to escalate from local to subregional to regional councils in a timely fashion.

The proposed focus of the SPG meetings, WestConnect transmission planning meetings and Western public planning meetings will be:

2.4.1. 1st Quarter Meetings

SPG Meetings.

- Approve the final SPG reports for the previous year's study work.
- Approve the SPG study plans for the new year.

WestConnect Planning Annual Meeting (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)).

- Present the WestConnect Ten Year Transmission Plan and WestConnect Transmission Planning Study Report to the Planning Management Committee.

- Recommend approval of the WestConnect Ten Year Transmission Plan by the WestConnect Steering Committee.

- Recommend approval of the WestConnect Transmission Planning Study Report by the WestConnect Steering Committee.

- Approve WestConnect study plans for the new year.

- Propose adjustments to the planning process or budget for the current year as necessary or appropriate.

2.4.2. 2nd Quarter Meeting

SPG Meetings.

- Present preliminary SPG study results.
- Determine additional SPG study sensitivities

Western Planning Stakeholder Meetings:

- Western reviews its transmission planning process and current study plan with transmission customers and stakeholders, and requests their review, comment and advice on any aspect of its transmission planning process. Additionally, Western reviews information on loads, resources and other needs received by March 31 from its transmission customers.

2.4.3. 3nd Quarter Meeting

SPG Meetings.

- Annual Joint SWAT-CCPG-SSPG meeting. SWAT, CCPG and SSPG present current study results and approve key results, findings, and conclusions.

- SWAT specifically invites customer and stakeholder review, comment, advice and transmission study requests for the SWAT transmission planning process.

2.4.4. 4th Quarter Meeting

SWAT Meeting:

- Present draft SPG reports for approval with modifications.

- Specifically invite the submittal of transmission study requests from stakeholders for inclusion in their respective study plans.

WestConnect Planning Workshop:

- Present each current year study supported by (i) final report or (ii) status summary report.

- Present each WestConnect transmission provider's draft ten year transmission plan. Present proposed study plans from SWAT, CCPG and SSPG.

- Discuss future study needs with input from

    - Study groups
    - TEPPC
    - Other subregional planning groups
    - Stakeholders at large

- Draft the WestConnect Ten Year Transmission Plan.

- Draft the WestConnect Transmission Planning Study Report.

Western Planning Stakeholder Meeting:

- Western reviews its transmission planning process and current study plan with stakeholders, and requests stakeholder review, comment and advice on any aspect of its transmission planning process. Additionally, Western reviews planning study requests received and presents a draft of its ten year plan for stakeholder review and comment per each Regional Office calendar.

3.0. Coordination at the Western Interconnection Level

Western will coordinate its plan on a west-wide regional basis through the SPGs and WestConnect. WestConnect will coordinate its subregional plan with the other subregional plans in the Western Interconnection and at the TEPPC level.

3.1. Procedures for Regional Planning Project Review

3.1.1. WECC coordination of reliability planning.

(a) WECC develops the Western Interconnection-wide coordinated base cases for transmission planning analysis such as power flow, stability and dynamic voltage stability studies. The WECC approved base cases are used for study purposes by transmission planners, subregional planning groups, and other entities that have signed confidentiality agreements with WECC.

(b) WECC also maintains a data base for reporting the status of all planned projects throughout the Western Interconnection.

(c) WECC provides for coordination of planned projects through its Procedures for Regional Planning Project Review.

(d) WECC's Path Rating Process ensures that a new project will have no adverse effect on existing projects or facilities.

3.1.2. WECC Open Stakeholder Meetings. Western Interconnection-wide economic planning studies are conducted by the WECC TEPPC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC-TEPPC Transmission Planning Protocol, including the TEPPC procedures for prioritizing and completing regional economic studies, is posted on the WECC website (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)). Western participates in the region-wide planning processes, as appropriate, to ensure that data and assumptions are coordinated.

3.1.3. Role of WECC TEPPC. WECC TEPPC provides two main functions in relation to Western's planning process:

(a) Development and maintenance of the west-wide economic planning study database.

i. TEPPC uses publicly available data to compile a database that can be used by a number of economic congestion study tools.

ii. TEPPC's database is publicly available for use in running economic congestion studies. For an interested transmission customer or stakeholder to utilize WECC's Pro-Mod planning model, it must comply with WECC confidentiality requirements.

(b) Performance of economic planning studies. TEPPC has an annual study cycle described in the WECC-TEPPC Transmission Planning Protocol (see Western Attachment P Hyperlinks List (www.oatioasis.com/WAPA/WAPAdocs/Planning-Process.htm)), during which it will update databases, develop and approve a study plan that includes studying transmission customer high priority economic study requests as determined by the open TEPPC stakeholder process, perform the approved studies and document the results in a report.

4.0. Dispute Resolution

Western Interconnection Western Regional Offices adhere to the WECC Dispute Resolution process.

5.0. Cost Allocation for New Transmission Projects

5.1. Western will utilize a case-by-case approach to allocate costs for new transmission projects. This approach will be based on the following principles:

5.1.1. Open Season Solicitation of Interest. Project sponsor announces project and actively or verbally solicits interest in the project through informational meetings, information posted on the project sponsor's website, and industry press releases. For any transmission project identified in a Western reliability study in which Western is the project sponsor, Western may elect to hold an "open season" solicitation of interest to secure additional project participants. Upon a determination by Western to hold an open season solicitation of interest for a transmission project, Western will:

(a) Announce and solicit interest in the project through informational meetings, its website and/or other means of dissemination as appropriate.

(b) Hold meetings with interested parties and meetings with public utility staffs from potentially affected states.

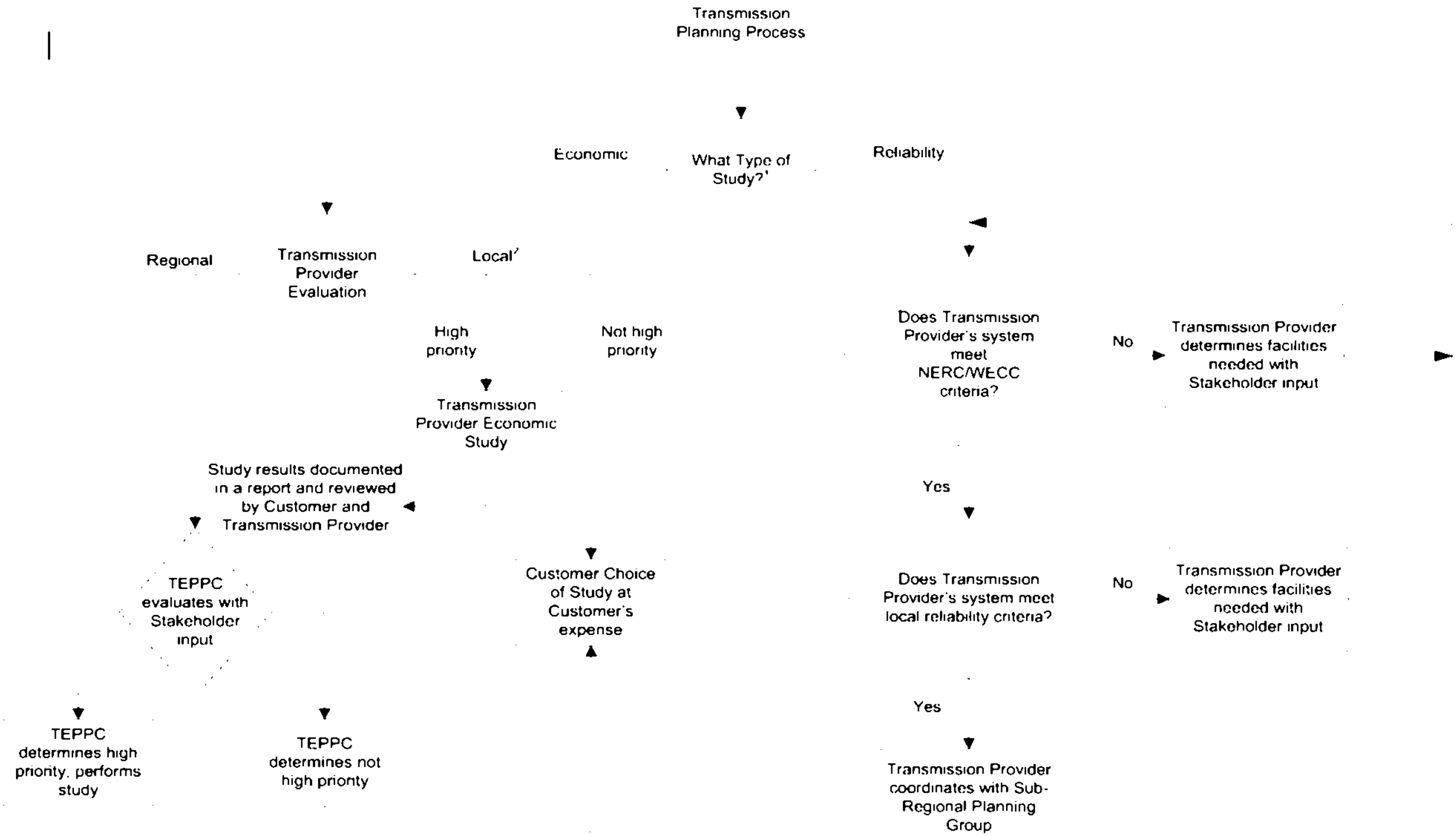
(c) Post information via WECC's planning project review reports

(d) Develop the initial transmission project specifications, the initial cost estimates and potential transmission line routes; guide negotiations and assist interested parties to determine cost responsibility for initial studies; guide the project through the applicable line siting processes; develop final project specifications and costs; obtain commitments from participants for final project cost shares; and secure execution of construction and operating agreements.

It is possible that the cost allocation principles for economic studies may be different from the cost allocation methods for projects involving multiple owners. Western, together with WestConnect and WECC, will seek input from stakeholders in proposing cost allocation method.

Exhibit 1

Attachment P



1. Generator Interconnection Request studies are performed pursuant to the Large Generator Interconnection Procedure contained in the Transmission Provider's Open Access Transmission Tariff (OATT). Transmission Service Requests are also performed pursuant to OATT procedures.

2. All requests for economic planning studies received by the Transmission Provider are forwarded to TEPPC for inclusion in the TEPPC Master List. TEPPC will evaluate only those requests that have regional impacts.

ATTACHMENT Q

Creditworthiness Procedures

~~For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit.~~

~~The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.~~

~~Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:~~

~~(1) a summary of the procedure for determining the level of secured and unsecured credit;~~

~~(2) a list of the acceptable types of collateral/security;~~

~~(3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;~~

~~(4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;~~

~~(5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and~~

~~(6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.~~

1.0 OVERVIEW OF CREDITWORTHINESS POLICY

1.1 Introduction

1.1.1 Application of Policy. For the purpose of determining the ability of the Transmission Customer to meet its obligations, the Transmission Provider will consistently apply credit review procedures to evaluate the

Transmission Customer's credit risk in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement financial assurance(s) to meet its responsibilities and obligations.

1.1.2 Creditworthiness Process. The creditworthiness procedures consist of data collection (quantitative, qualitative information), credit evaluation, credit score determination, and overall determination of the Transmission Customer's creditworthiness. The Transmission Customer shall provide information to the Transmission Provider as part of its data collection process and as part of the Transmission Customer's Credit Application, or as part of the periodic review to continue receiving services. For credit qualification purposes, prior to the Transmission Customer receiving service, there must be a completed Credit Application and a creditworthiness evaluation.

1.2 Overview of Procedures

1.2.1 Entity Definition. In order to differentiate Transmission Customers and clarify determination of a Transmission Customer's credit requirements, the Transmission Customer shall be defined as either a new or existing Public Power Entity or Non-Public Power Entity for calculating credit scores. A Public Power Entity shall be defined as a Transmission Customer that is a not-for-profit organization such as but not limited to municipalities, cooperatives, joint action agencies, Native American Tribes, or any other governmental entity. A Non-Public Power Entity shall be defined as any Transmission Customer that is not a Public Power Entity.

1.2.2 Review. The Transmission Provider shall conduct a creditworthiness review, outlined in Section 3.1 below, of the Transmission Customer using information provided by the Transmission Customer from the data collection process (Section 2.0) and upon its initial request for services and thereafter pursuant to Section 4.1 or at the request of the Transmission Customer. Existing Transmission Customers with a timely payment history at the date of implementation of this policy will be deemed to have satisfied the creditworthiness requirements at that time and be subject to re-evaluation pursuant to Section 4.1. The Transmission Provider can require the Transmission Customer to provide or increase its provided financial assurances before service will be initiated or continued (Section 4.2)

1.2.3 Credit Score. The Transmission Provider shall use the creditworthiness procedures in Section 3.1.1 to establish a credit score for Non-Public

Power Transmission Customers. Credit scores will not be calculated for existing Non-Public Power Transmission Customers with a timely payment history at the date of implementation of this policy. Credit scores for such Transmission Customers will be calculated if and when a re-evaluation is required pursuant to Section 4.1. Public Power Transmission Customers will not receive a credit score. Such Transmission Customers will instead be evaluated based on criteria outlined in Section 3.1.2.

2.0 DATA COLLECTION

2.1 Non-Public Power Entity

A non-public power entity shall provide the following information to the Transmission Provider as part of the Transmission Provider's creditworthiness evaluation:

2.1.1 Agency Ratings. If available to the Transmission Customer, the senior unsecured long-term debt ratings assigned to the Transmission Customer by Standard & Poor's and/or Moody's Investor Service or any other similar bond rating agency, and the long-term issuer rating if the senior unsecured long-term rating is not available.

2.1.2 Financial Statements. The two (2) most recent quarters of financial statements signed by the company controller or other authorized company officer AND the two (2) most recent audited annual financial statements [including, but not limited to the balance sheet, income statement, statement of cash flows, management's discussion and analysis, report of independent auditor (audit opinion), and accompanying notes] of the Transmission Customer's Annual Report, 10K, 10Q, or 8K, as applicable.

2.1.3 Material Issues/Changes. Any pending information not incorporated in the financial reports that could materially impact the viability of the Transmission Customer including, but not limited to litigation, investigations, arbitrations, contingencies, liabilities, and affiliate relationships.

2.1.4 Additional Information. The Transmission Provider may request additional information as it determines is necessary and appropriate for the credit evaluation, and the Transmission Customer shall provide such additional information in a timely manner. At any time, the Transmission Customer may provide the Transmission Provider with additional information that the Transmission Customer considers relevant to the credit evaluation.

2.2 Public Power Entity

A public power entity will answer questions specific to its financial viability on the Credit Application and be evaluated on the criteria set forth in Section 3.1.2.

2.3 Information Concerning Material Changes/Issues

2.3.1 The Transmission Customer, public or non-public, must give the Transmission Provider notice of any material change in its financial condition within five (5) business days of the occurrence of the material change. A material change in financial condition includes but is not limited to the following:

(a) For entities that initially met the creditworthiness requirements under the policy and are not required to post financial assurance to the Transmission Provider, a change in financial condition that results in a downgrade of long or short-term debt rating by a major bond rating agency or being placed on a credit watch with negative implications by a major credit rating agency; or

(b) The resignation of key officer(s); or

(c) The issuance of a regulatory order or the filing of a lawsuit that could materially adversely impact current or future results; or

(d) A default in payment obligations; or

(e) Any new investigations, arbitrations, contingencies or changes in affiliate relationships; or

(f) The filing of a voluntary or involuntary petition to institute bankruptcy proceedings under the United States Bankruptcy Code or any successor statute, or the filing to institute any proceedings under state law concerning actual or potential insolvency.

2.4 Format

All data must be submitted in the English language. Financial data must be denominated in U.S. currency and conform to U.S. Generally Accepted Accounting Principles (GAAP). The Transmission Provider will maintain any non-public data included in such information on a confidential basis.

2.5 Consolidated Entity

If the Transmission Customer's financial information is consolidated with other entities, the Transmission Customer must extract and submit as separate documents all data and information related solely to the Transmission Customer. This must include all financial information, associated notes, and all other information that would comprise a full financial report conforming to GAAP.

3.0 CREDIT EVALUATION

3.1 Determining Creditworthiness

3.1.1 Non-Public Power Entities

In order to be found creditworthy, the Transmission Customer must meet the following standards:

(a) The Transmission Customer is not in default of its payment obligations under the Tariff and has not been in persistent default under the provisions of the Tariff; and

(b) The Transmission Customer is not on Western's subscribed rating service watch list; and

(c) The Transmission Customer is not in default of any payment obligation to the Transmission Provider; and

(d) The Transmission Customer is not in bankruptcy proceedings; and

(e) The Transmission Customer meets credit score requirements consisting of the following quantitative and qualitative factors. The Transmission Customer shall receive a score for meeting or exceeding each qualitative or quantitative factor. A Non-Public Power Entity may receive a minimum score of zero (0) and a maximum score of six (6), six being best. One point will be awarded for each of the following items.

i. Total Debt/Total Capital less than 70%.

ii. EBIT coverage (Earnings Before Interest and Income Taxes/Interest Expense) greater than 1.5 times.

iii. Current Ratio greater than 1.0.

iv. Have Cash Flow from Operations to Total Debt (includes short-term debt, long-term debt, current portion of long-term debt, and off-balance sheet operating lease obligations) greater than 10%.

v. Agency Ratings of investor grade or higher (e.g., S&P of BBB- and/or Moody's Baa3). Transmission provider will use the lower of the ratings if rated by multiple agencies.

vi. Positive Payment Record with the Transmission Provider (if previous or existing Transmission Customer).

The Transmission Customer will be determined to be creditworthy and granted unsecured credit if it complies with the criteria above and receives a credit score of four (4) or higher.

3.1.2 Public Power Entities

Public Power Entities are considered creditworthy and granted unsecured credit if the following exist:

(a) The Transmission Customer is not in default of its payment obligations under the Tariff and has not been in persistent default under the provisions of the Tariff; and

(b) The Transmission Customer is not on Western's subscribed rating service watch list; and

(c) The Transmission Customer is not in default of any payment obligation to the Transmission Provider; and

(d) The Transmission Customer is not in bankruptcy proceedings; and

(e) If the Transmission Customer or its guarantor is a federal, state or other governmental agency/entity and its financial obligations are backed by the full faith and credit of the United States, state or other governmental entity as applicable; and/or

(f) The Transmission Customer has the ability to raise rates to cover outstanding obligations.

3.2 Notification

The Transmission Provider shall notify the Transmission Customer whether it has been found to be creditworthy or whether relevant financial assurance is required within five (5) business days after: (a) receiving the Transmission Customer's applicant with all required information; (b) receiving the Transmission Customer's written request for re-evaluation of creditworthiness with all required information; or (c) determining that a change in creditworthiness status or change in financial assurance is required as determined by the rotational review or other reviews performed pursuant to Section 4.1.

The Transmission Provider shall, upon the Transmission Customer's written request, provide a written explanation of the basis for the Transmission Provider's determination via e-mail within five (5) business days for any: (a) non-creditworthy determination; (b) changes in creditworthiness status; or (c) changes in requirements for financial assurances.

3.3 Establishing Credit Limits

If an entity is determined to be creditworthy no credit limit will be established. For non-creditworthy entities, the credit limit will equal five (5) months of total estimated service charges as determined by the Transmission Provider from time to time. If at any time the Transmission Provider determines according to these creditworthiness standards that the Transmission Customer is not able to fully support its credit exposure based solely on its financial viability, the Transmission Provider may require collateral be provided.

3.4 Secured Credit

3.4.1 Posting Collateral

If collateral is required by the Transmission Provider, the Transmission Customer will be asked to provide an acceptable form of collateral as defined in Section 3.4.3 below within 30 days of the Transmission Provider's request. No service to the Transmission Customer shall commence until this requirement is satisfied.

If service to the Transmission Customer already has commenced (existing Transmission Customer) and the Transmission Customer fails to provide the collateral as defined in Section 3.4.3 below and required by the Transmission Provider within five (5) business days of notification, the Transmission Customer will be deemed in default of its Service Agreement.

3.4.2 Required Amount of Collateral

Given the Transmission Provider's current billing practices and payment terms, the required amount of security will be based on the maximum total estimated service charge for five (5) months. This represents the potential value of services rendered prior to termination of service in the event of a default arising from a failure of nonpayment.

3.4.3 Acceptable Collateral

Acceptable collateral, totaling five (5) months of estimated service charges, includes:

(a) Prepayment for service; or

(b) An unconditional and irrevocable letter of credit as security to meet the Transmission Customer's responsibilities and obligations. If this form of collateral is used, it will comply with the requirements as stated in the Uniform Customs and Practice for Documentary Credits; or

(c) A cash deposit; or

(d) An irrevocable and unconditional corporate guaranty from an entity that satisfies the creditworthiness requirements.

4.0 RE-EVALUATION

4.1 Timeframe

The Transmission Provider will review its credit evaluation for each Transmission Customer annually. Timely payments will be sufficient evidence for re-affirming the current credit arrangements, barring the reporting of any of the material changes outlined in Section 2.3. The Transmission Provider, at its sole discretion, may conduct additional reviews and updates of its credit evaluation in response to new facts or occurrences that may bear upon the Transmission Customer's creditworthiness due to material changes in financial condition of the Transmission Customer, or if the Transmission Customer fails to pay invoices from the Transmission Provider on time. These updates will follow the procedures set forth in Section 3.1 of this Attachment.

4.2 Change in Limit/Collateral

As a result of the Transmission Provider's creditworthiness review or in response to the Transmission Customer's request for re-evaluation or the Transmission Customer's notice of any material change in its financial condition, the Transmission Provider may adjust the Transmission Customer's credit limit and collateral requirements in accordance with Section 3.3 and Section 3.4, respectively. If required, additional collateral must be posted in accordance with Section 3.4.1.

The Transmission Customer may make reasonable requests for the Transmission Provider to re-evaluate the Transmission Customer's creditworthiness pursuant to the criteria detailed in Section 3.1.

5.0 RIGHT TO DRAW UPON FINANCIAL ASSURANCES UPON DEFAULT

The Transmission Provider shall have the right to liquidate, or draw upon, all or a portion of the Transmission Customer's form of financial assurance(s) in order to satisfy the Transmission Customer's total net obligation to the Transmission Provider upon a default. The Transmission Customer shall within five (5) business days replace any liquidated or drawn-upon financial assurances.

6.0 SUSPENSION OF SERVICE

6.1 Notification

Notwithstanding any other provision of this Tariff, if the Transmission Customer fails to provide the entirety of required financial assurances when due under this Attachment, the Transmission Provider may suspend service to such Transmission Customer thirty (30) days after the Transmission Provider's notification to such Transmission Customer. The Transmission Provider will provide at least thirty (30) days written notice to the Commission before suspending service pursuant to this provision.

Any notices sent to the Transmission Customer and to the Commission pursuant to the Attachment may be sent concurrently.

6.2 Length of Suspension

The suspension of service shall continue only for as long as the circumstances that entitle the Transmission Provider to suspend service continue.

6.3 Obligation to Pay

A Transmission Customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

WESTERN AREA POWER ADMINISTRATION
CREDIT APPLICATION

Complete all sections of this form and submit to:
Western Area Power Administration
ATTN:
P.O. Box 281213
Lakewood, CO 80228-8213

Date: ______________________________

Applicant Name (Customer): ______________________________
Address: ______________________________
____
____

Type of Service Requested: ______________________________

Expected Monthly Business: ______________________________

DUNS Number: ______________________________
Credit Rating (if applicable): ______________________________

Credit Manager or Point of Contact: ______________________________

Phone: ______________ Fax: ______________ Email: ______________

Is your company a subsidiary or affiliate of another company? Yes ____ No ____
If Yes, please provide information on the related company:

Company Name: ______________________________
Address: ______________________________
____
DUNS Number: ______________________________

Does your company plan to establish credit with a guarantee from the related company listed above? Yes _____ No _____

If Yes, all required information necessary for credit qualification is needed from the company guaranteeing credit.

Public Power Entities (not-for-profit):
Is your company a not-for-profit entity (governmental entity)? Yes ____ No ____

If your company is a not-for-profit entity, is it backed by the full faith and credit of a governmental entity (United States, state government or other government, as applicable)? Yes ____ No ____ If Yes, state type of governmental entity and provide evidence.

____

If your company is a not-for-profit entity, do you have the ability to raise rates to cover outstanding obligations? Yes ____ No ____

Provide any material issues/changes that could impact the viability of the Transmission Customer and/or the credit decision including, but not limited to, litigation, investigations, arbitrations, contingencies, liabilities and affiliate relationships which have occurred within the past year.

Non-Public Power Entities:
To enable the Transmission Provider to conduct the proper analysis required to determine creditworthiness, the information below must be submitted with the Credit Application.

1. Rating agency reports (if applicable).

~~1.~~2. The most recent two quarters of financial statements signed by the company controller or other authorized company officer and the most recent two years of audited financial statements. Financial statements should include, but not be limited to:

   a. Annual report;
   b. Balance sheet;
   c. Income statement;
   d. Statement of cash flows;
   e. Management's discussion and analysis;
   f. Report of independent auditor and accompanying notes for the Annual report, 10K, 10Q or 8K, as applicable.

3. Material issues that could impact the viability of the Transmission Customer and/or the credit decision including, but not limited to, litigation, investigations, arbitrations, contingencies, liabilities and affiliate relationships which have occurred since the last audited financial statements.

Note: The Transmission Provider may request additional information as it determines is necessary and appropriate for the credit evaluation.

ATTACHMENT L

STANDARD LARGE GENERATOR

INTERCONNECTION PROCEDURES (LGIP)

including

STANDARD LARGE GENERATOR

INTERCONNECTION AGREEMENT (LGIA)

Standard Large Generator

Interconnection Procedures (LGIP)

(Applicable to Generating Facilities that exceed 20 MW)

TABLE OF CONTENTS

Page No.

Section 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by an Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date *shall mean the date upon which the Generating Facility is initially* synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's

Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network 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 Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or

ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection ~~Agreement~~Procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Transmission Provider from the Point of Change of

Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Section 2. Scope and Application

2.1 Application of Standard Large Generator Interconnection Procedures.
Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Large Generating Facility.

2.2 Comparability.
Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data.
Transmission Provider shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to confidentiality provisions in LGIP Section 13.1. Transmission Provider is permitted to require that Interconnection Customer sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (i) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service.
Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

Section 3. Interconnection Requests

3.1 General.
An Interconnection Customer shall submit to Transmission Provider an Interconnection Request in the form of Appendix 1 to this LGIP and a refundable deposit of $10,000. Transmission Provider shall apply the deposit toward the cost of the Scoping Meeting and an Interconnection Feasibility Study. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

3.2 Identification of Types of Interconnection Services.
At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service, as described; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

3.2.1 Energy Resource Interconnection Service.

3.2.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.

3.2.1.2 The Study. The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Large Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Large Generating Facility without requiring additional Network Upgrades.

3.2.2 Network Resource Interconnection Service.

3.2.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service allows Interconnection Customer 's Large Generating Facility to be designated as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

3.2.2.2 **The Study**. The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Large Generating Facility's interconnection is also studied with Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider's Transmission System, consistent with Transmission Provider's reliability criteria and procedures. This approach assumes that some portion of existing Network Resources are displaced by the output of Interconnection Customer's Large Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.3 Valid Interconnection Request.

3.3.1 Initiating an Interconnection Request.

To initiate an Interconnection Request, Interconnection Customer must submit all of the following: (i) a $10,000 deposit, (ii) a completed application in the form of Appendix 1, and (iii) demonstration of Site Control or a posting of an additional deposit of $10,000. Such deposits shall be applied toward the Scoping Meeting and any Interconnection Studies pursuant to the Interconnection Request. If Interconnection Customer demonstrates Site Control within the cure period specified in Section 3.3.3 after submitting its Interconnection Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for Transmission Provider's expansion planning period) not to exceed seven years from the date the

Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

3.3.2 **Acknowledgment of Interconnection Request.**
Transmission Provider shall use Reasonable Efforts to acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.3.3 **Deficiencies in Interconnection Request.**
An Interconnection Request will not be considered to be a valid request until all items in Section 3.3.1 have been received by Transmission Provider. If an Interconnection Request fails to meet the requirements set forth in Section 3.3.1, Transmission Provider shall use Reasonable Efforts to notify Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.3.3 shall be treated in accordance with Section 3.6.

3.3.4 **Scoping Meeting.**
Transmission Provider shall use Reasonable Efforts to establish within ten (10) Business Days after receipt of a valid Interconnection Request a date agreeable to Interconnection Customer for the Scoping Meeting.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. Transmission Provider and Interconnection Customer will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider and Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 6.1, and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

3.3.5 Environmental Review Agreement.
Unless otherwise agreed, Transmission Provider shall use Reasonable Efforts to tender, within 15 Calendar Days of providing an Interconnection System Impact Study report to Interconnection Customer, an environmental review agreement authorizing Transmission Provider, at Interconnection Customer's expense, to perform environmental review of the proposed interconnection, including review under the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, et seq., as amended, and setting forth Interconnection Customer's responsibilities in connection with such environmental review. Interconnection Customer shall execute the environmental review agreement and return it, along with the required funds set forth in the agreement, to the Transmission Provider within 30 Calendar Days of receipt of the final version offered for execution. If an executed environmental review agreement and the required funds are not provided in the manner set forth above, the Interconnection Request shall be deemed withdrawn. If the costs incurred by Transmission Provider are less than the deposit submitted by Interconnection Customer, Transmission Provider shall refund the difference, without interest, as soon as the necessary vouchers may be prepared. In addition, if at any time prior to the issuance of Transmission Providers final NEPA decisional document the Interconnection Customer fails to comply with the terms of the environmental review agreement, Transmission Provider reserves the right to deem the Interconnection Request withdrawn.

3.4 OASIS Posting.
Transmission Provider will maintain on its OASIS a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the type of Interconnection Service being requested; and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of Interconnection Customer until Interconnection Customer executes an LGIA. Before holding a Scoping Meeting with its Affiliate, Transmission Provider shall post on OASIS an advance notice of its intent to do so. Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to Transmission Provider's OASIS site subsequent to the meeting between Interconnection Customer and Transmission Provider to discuss the applicable study results. Transmission Provider shall also post any known deviations in the Large Generating Facility's In-Service Date.

3.5 Coordination with Affected Systems..

Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in this LGIP. Transmission Provider will include such Affected System Operators in all meetings held with Interconnection Customer as required by this LGIP. Interconnection Customer will cooperate with Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

3.6 Withdrawal.

Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider. In addition, if Interconnection Customer fails to adhere to all requirements of this LGIP, except as provided in Section 13.5 (Disputes), Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to Transmission Provider all costs that Transmission Provider prudently incurs with respect to that Interconnection Request prior to Transmission Provider's receipt of notice described above. Interconnection Customer must pay all monies due to Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

Transmission Provider shall (i) update the OASIS Queue Position posting and (ii) refund to Interconnection Customer any portion of Interconnection Customer's deposit or study payments that exceeds the costs that Transmission Provider has incurred. In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 13.1, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

Section 4. Queue Position

4.1 General.

Transmission Provider shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 3.3.3, then Transmission Provider shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 4.4.3.

The Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

Transmission Provider may allocate the cost of the common upgrades for clustered Interconnection Requests without regard to Queue Position.

4.2 Clustering.

At Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

Clustering shall be implemented on the basis of Queue Position. If Transmission Provider elects to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service. The deadline for completing all Interconnection System Impact Studies for which an Interconnection System Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

Clustering Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on Transmission Provider's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

4.3 Transferability of Queue Position.
With Transmission Provider's approval, an Interconnection Customer may transfer its Queue Position to another entity, but only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications.
Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1, 4.4.2 or 4.4.5, or are determined not to be Material Modifications pursuant to Section 4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable and Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the return of the executed Interconnection System Impact Study Agreement to Transmission Provider, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2 Prior to the return of the executed Interconnection Facility Study Agreement to Transmission Provider, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease of electrical output (MW), and (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer.

4.4.3 Prior to making any modification other than those specifically permitted by Sections 4.4.1, 4.4.2, and 4.4.5, Interconnection Customer may first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1, 6.1, 7.2 or so allowed elsewhere or otherwise initiated under mutual agreement between Transmission Provider and Interconnection Customer, shall constitute a Material Modification. Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.4 Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4, Transmission Provider shall use Reasonable Efforts to commence and perform any necessary additional studies within thirty (30) Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost.

4.4.5 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

Section 5. Procedures for Interconnection Requests Submitted Prior to Effective Date of Standard Large Generator Interconnection Procedures

5.1 Queue Position for Pending Requests.

5.1.1 Any Interconnection Customer assigned a Queue Position prior to the effective date of this LGIP shall retain that Queue Position.

5.1.1.1 If an Interconnection Study Agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.

5.1.1.2 If an Interconnection Study Agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which an Interconnection Customer has not signed an Interconnection Study Agreement prior to the effective date of the LGIP, Transmission Provider must offer Interconnection Customer the option of either continuing under Transmission Provider's existing interconnection study process or going forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Studies Agreement) in accordance with this LGIP.

5.1.2 Transition Period.
To the extent necessary, Transmission Provider and Interconnection Customers with an outstanding request shall transition to this LGIP within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding request" herein shall mean any Interconnection Request, on the effective date of this LGIP: (i) that has been submitted but not yet accepted by Transmission Provider; (ii) where the relevant Interconnection Study Agreements have not yet been executed; or (iii) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding request as of the effective date of this LGIP may request a reasonable extension of any deadline, otherwise applicable, if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by Transmission Provider to the extent consistent with the intent and process provided for under this LGIP.

5.2 New Transmission Provider.
If Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this LGIP shall be paid by or refunded to Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If Transmission Provider has tendered a draft LGIA to Interconnection Customer but Interconnection Customer has not executed the LGIA, unless otherwise provided, Interconnection Customer must complete negotiations with the successor Transmission Provider.

Section 6. Interconnection Feasibility Study

6.1 Interconnection Feasibility Study Agreement.
Simultaneously with the acknowledgement of a valid Interconnection Request Transmission Provider shall provide to Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 2. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. Transmission Provider shall use Reasonable Efforts to tender to Interconnection Customer the

Interconnection Feasibility Study Agreement signed by Transmission Provider within five (5) Business Days following Transmission Provider's receipt of such designation, including a good faith estimate of the cost for completing the Interconnection Feasibility Study. Interconnection Customer shall execute and deliver to Transmission Provider the Interconnection Feasibility Study Agreement along with a $10,000 deposit no later than thirty (30) Calendar Days after its receipt.

On or before the return of the executed Interconnection Feasibility Study Agreement to Transmission Provider, Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and Re-studies shall be completed pursuant to Section 6.4 as applicable. For the purpose of this Section 6.1, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

If Interconnection Customer and Transmission Provider agree to forgo the Interconnection Feasibility Study, Transmission Provider will initiate an Interconnection System Impact Study under Section 7 of this LGIP and apply the $10,000 deposit towards the Interconnection System Impact Study.

6.2 Scope of Interconnection Feasibility Study.
The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Transmission System.

The Interconnection Feasibility Study will consider the Base Case as well as all generating facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

6.3 Interconnection Feasibility Study Procedures.
Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the

Interconnection Feasibility Study no later than forty-five (45) Calendar Days after Transmission Provider receives the fully executed Interconnection Feasibility Study Agreement. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If Transmission Provider is unable to complete the Interconnection Feasibility Study within that time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, work papers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 13.1.

6.3.1 Meeting with Transmission Provider.
Transmission Provider shall use Reasonable Efforts to meet with Interconnection Customer within ten (10) Business Days of providing an Interconnection Feasibility Study report to Interconnection Customer to discuss the results of the Interconnection Feasibility Study.

6.4 Re-Study.
If Re-Study of the Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4, or re-designation of the Point of Interconnection pursuant to Section 6.1, Transmission Provider shall notify Interconnection Customer in writing. Transmission Provider shall use Reasonable Efforts to complete such Re-Study within forty-five (45) Calendar Days from the date of the notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 7. Interconnection System Impact Study

7.1 Interconnection System Impact Study Agreement.
Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 3.3.4, simultaneously with the delivery of the Interconnection Feasibility Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection System Impact Study Agreement in the form of Appendix 3 to this LGIP. The Interconnection System Impact Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection System Impact Study. Transmission Provider shall use Reasonable Efforts to provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study within three (3) Business Days following the Interconnection Feasibility Study results meeting.

7.2 Execution of Interconnection System Impact Study Agreement.
Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to

Transmission Provider no later than thirty (30) Calendar Days after its receipt along with demonstration of Site Control, and a $50,000 deposit.

If Interconnection Customer does not provide all such technical data when it delivers the Interconnection System Impact Study Agreement, Transmission Provider shall use Reasonable Efforts to notify Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement, and Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

7.3 Scope of Interconnection System Impact Study.

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Interconnection System Impact Study will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

7.4 Interconnection System Impact Study Procedures.
Transmission Provider shall coordinate the Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.5 above. Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the Interconnection System Impact Study Agreement or notification to proceed, study payment, and technical data. If Transmission Provider uses Clustering, Transmission Provider shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within ninety (90) Calendar Days after the close of the Queue Cluster Window.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection System Impact Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If Transmission Provider is unable to complete the Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, work papers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1.

7.5 Meeting with Transmission Provider.
Transmission Provider shall use Reasonable Efforts to meet with Interconnection Customer within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer to discuss the results of the Interconnection System Impact Study.

7.6 Re-Study.
If Re-Study of the Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4, or re-designation of the Point of Interconnection pursuant to Section 7.2, Transmission Provider shall notify Interconnection Customer in writing. Transmission Provider shall use Reasonable Efforts to complete such Re-Study within sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 8. Interconnection Facilities Study

8.1 Interconnection Facilities Study Agreement.
Simultaneously with the delivery of the Interconnection System Impact Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix 4 to

this LGIP. The Interconnection Facilities Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study. Transmission Provider shall use Reasonable Efforts to provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study within three (3) Business Days following the Interconnection System Impact Study results meeting. Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to Transmission Provider within thirty (30) Calendar Days after its receipt, together with the required technical data and ~~the greater~~a deposit of $100,000 ~~or Interconnection Customer's portion of the estimated monthly cost of conducting~~for the performance of the Interconnection Facilities Study and other work, including, but not limited to, environmental review activities and development of an E&P Agreement and the LGIA.

8.1.1 If Transmission Provider's cost of conducting the Interconnection Facilities Study and other work does not exceed the amount of the deposit, Transmission Provider shall continue to hold the remaining amount on deposit until settlement of the final invoice.

8.1.~~1~~2 If Transmission Provider's cost of conducting the Interconnection Facilities Study and other work exceeds the amount of the deposit, Transmission Provider shall invoice Interconnection Customer for any such additional costs on a monthly basis in advance ~~of the work to be conducted on the Interconnection Facilities Study~~. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.

8.2 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

8.3 Interconnection Facilities Study Procedures.

Transmission Provider shall coordinate the Interconnection Facilities Study with any Affected System pursuant to Section 3.5 above. Transmission Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after receipt of an executed Interconnection Facilities Study

Agreement: ninety (90) Calendar Days, with no more than a +/- 20 percent cost estimate contained in the report; or one hundred eighty (180) Calendar Days, if Interconnection Customer requests a +/- 10 percent cost estimate. Regardless of the amount of such estimates, Interconnection Customer shall be invoiced by Transmission Provider and shall pay all actual costs associated with the equipment, environmental, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Transmission System, with such invoicing and payment to be made as set forth in Article 11.5 of the LGIA.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Facilities Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If Transmission Provider is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

Interconnection Customer may, within thirty (30) Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall use Reasonable Efforts to issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, work papers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 13.1.

8.4 Meeting with Transmission Provider.
Transmission Provider shall use Reasonable Efforts to meet with Interconnection Customer within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer to discuss the results of the Interconnection Facilities Study.

8.5 Re-Study.
If Re-Study of the Interconnection Facilities Study is required due to a higher queued project dropping out of the queue or a modification of a higher queued project pursuant to Section 4.4, Transmission Provider shall so notify Interconnection Customer in writing. Transmission Provider shall use Reasonable Efforts to complete such Re-Study within

sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 9. Engineering & Procurement ('E&P') Agreement

Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request an E&P Agreement that authorizes Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. If Transmission Provider determines that it may offer an E&P Agreement before completing an environmental analysis under ~~the National Environmental Policy Act of 1969~~NEPA~~, 42 U.S.C. § 4321, et seq., as amended (NEPA)~~, concerning the interconnection of the Large Generating Facility, Transmission Provider shall offer the Interconnection Customer such Agreement; provided, that Transmission Provider's determination shall not be subject to dispute resolution. However, Transmission Provider shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments for such costs.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Provider may elect: (i) to take title to the equipment, in which event Transmission Provider shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment; or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

Section 10. Optional Interconnection Study

10.1 Optional Interconnection Study Agreement.

On or after the date when Interconnection Customer receives Interconnection System Impact Study results, Interconnection Customer may request, and Transmission Provider shall perform a reasonable number of Optional Studies. The request shall describe the assumptions that Interconnection Customer wishes Transmission Provider to study within the scope described in Section 10.2. Transmission Provider shall use Reasonable Efforts to provide to Interconnection Customer an Optional Interconnection Study Agreement in the form of Appendix 5 within five (5) Business Days after receipt of a request for an Optional Interconnection Study.

The Optional Interconnection Study Agreement shall: (i) specify the technical data that Interconnection Customer must provide for each phase of the Optional Interconnection Study, (ii) specify Interconnection Customer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection service for Interconnection Requests remaining in the Optional Interconnection Study case, and (iii) Transmission Provider's estimate of the cost of the Optional Interconnection Study. To the extent known by Transmission Provider, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, Transmission Provider shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

Interconnection Customer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to Transmission Provider.

10.2 Scope of Optional Interconnection Study.
The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. Transmission Provider shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. Transmission Provider shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

10.3 Optional Interconnection Study Procedures.
The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to Transmission Provider within ten (10) Business Days of Interconnection Customer receipt of the Optional Interconnection Study Agreement. Transmission Provider shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement. If Transmission Provider is unable to complete the Optional Interconnection Study within such time period, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid in advance to Transmission Provider or refunded to Interconnection Customer, as appropriate. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation and work papers and databases or data developed in the preparation of the Optional

Interconnection Study, subject to confidentiality arrangements consistent with Section 13.1.

Section 11. Standard Large Generator Interconnection Agreement (LGIA)

11.1 Tender.

Interconnection Customer shall tender comments on the draft Interconnection Facilities Study Report within thirty (30) Calendar Days of receipt of the report. Transmission Provider shall use Reasonable Efforts to tender a draft LGIA, together with draft appendices, within thirty (30) Calendar Days after the comments are ~~submitted~~received. The draft LGIA shall be in the form of Transmission Provider's standard form LGIA currently on file with FERC, which is in Appendix 6. If Interconnection Customer ~~shall execute~~ does not request negotiation pursuant to 11.2, the draft LGIA shall be considered the final LGIA and the Interconnection Customer shall execute and return it to the ~~completed draft appendices~~ Transmission Provider within thirty (30) Calendar Days after receipt. If the Interconnection Customer does not return a signed copy of the final LGIA within thirty (30) days or request negotiation pursuant to section 11.2, the Interconnection Customer's request shall be deemed withdrawn. Interconnection Customer understands that Transmission Provider's decision to execute the LGIA is dependent on conclusions reached in the record of decision under NEPA, or other such appropriate NEPA document, concerning the interconnection of the Large Generating Facility and that Transmission Provider's NEPA review could result in a decision not to execute the LGIA, or to delay LGIA execution. Transmission Provider's decision shall not be subject to dispute resolution.

11.2 Negotiation.

Notwithstanding Section 11.1, at the request of Interconnection Customer, Transmission Provider shall begin negotiations with Interconnection Customer concerning the appendices to the LGIA at any time after Interconnection Customer executes the Interconnection Facilities Study Agreement. Interconnection Customer shall be responsible for Transmission Provider's actual costs incurred as a result of negotiations under this LGIP, including legal, consulting, administrative and general costs; provided, that any Transmission Provider invoices shall include a detailed and itemized accounting of such costs. Transmission Provider and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft LGIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study Report. ~~Interconnection Customer shall be responsible for Transmission Provider's actual costs incurred as a result of negotiations under this LGIA, including legal, consulting, administrative and general costs; provided, that any Transmission Provider invoices shall include a detailed and itemized accounting of such costs.~~ If Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft LGIA pursuant to Section 11.1 and initiate Dispute Resolution procedures pursuant to Section 13.5. If Interconnection Customer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if Interconnection

Customer has not executed the draft LGIA or initiated Dispute Resolution procedures pursuant to Section 13.5 within sixty (60) Calendar Days of tender of draft LGIA, it shall be deemed to have withdrawn its Interconnection Request. Transmission Provider shall decide whether to offer to Interconnection Customer a final LGIA ~~after~~ based on the conclusions the Transmission Provider ~~completes~~reaches in a record of decision under NEPA, or other such appropriate NEPA document, concerning the interconnection of the Large Generating Facility; provided, that this decision shall not be subject to dispute resolution. If Transmission Provider decides to offer Interconnection Customer a final LGIA, Transmission Provider shall use Reasonable Efforts to do so within fifteen (15) Business Days after the ~~date on which (i) the Transmission Provider has decided to make such offer or (ii) the Parties have completed the~~ end of the negotiation process~~, whichever is later~~. Interconnection Customer shall execute and return the final LGIA within fifteen (15) Business Days after receipt or it shall be deemed to have withdrawn its Interconnection Request.

11.3 Execution~~and Filing~~.

Interconnection Customer understands that Transmission Provider's decision to execute the LGIA is dependent on conclusions reached in the record of decision under NEPA, or other such appropriate NEPA document, concerning the interconnection of the Large Generating Facility and that Transmission Provider's NEPA review could result in a decision to not execute the LGIA, or to delay LGIA execution. Transmission Provider's decision shall not be subject to dispute resolution. Transmission Provider shall use Reasonable Efforts to execute and return the final LGIA to the Interconnection Customer within fifteen (15) Business Days after receipt. Within fifteen (15) Business Days after receipt of the final LGIA, Interconnection Customer shall provide Transmission Provider (A) reasonable evidence ~~that~~ of continued Site Control or (B) posting of a non-refundable deposit of $250,000, which shall be applied toward future construction costs. At the same time, Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit. If the Interconnection Customer does not provide the above items within (15) Business Days after receipt of the final LGIA that has been executed by the Transmission Provider, it shall be deemed to have withdrawn its Interconnection Request. ~~Interconnection Customer shall execute two originals of the tendered LGIA and return them to Transmission Provider~~.

11.4 Commencement of Interconnection Activities.

If Interconnection Customer executes the final LGIA, Transmission Provider and Interconnection Customer shall perform their respective obligations in accordance with the terms of the LGIA.

Section 12. Construction of Transmission Provider's Interconnection Facilities and Network Upgrades

12.1 Schedule.
Transmission Provider and Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing.

12.2.1 General.
In general, the In-Service Date of an Interconnection Customers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades.

12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than Interconnection Customer.
An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider: (i) any associated expediting costs; and (ii) the cost of such Network Upgrades.

Transmission Provider will refund to Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. Transmission Provider shall forward to Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to Interconnection Customer. Transmission Provider then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the LGIA.

12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Transmission Provider.

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of Transmission Provider, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider: (i) any associated expediting costs; and (ii) the cost of such Network Upgrades. Transmission Provider shall refund to Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA.

12.2.4 Amended Interconnection System Impact Study.

An Interconnection System Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Large Generating Facilities that are expected to be in service on or before the requested In-Service Date.

Section 13. Miscellaneous.

13.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of an LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the LGIA; or (6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

13.1.2 Release of Confidential Information.
Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 13.1.

13.1.3 Rights.
Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties.
By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care.
Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure.
If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies.
The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

13.1.8 Disclosure to FERC or its Staff.
Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the LGIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when its is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112.

13.1.9 Subject to the exception in Section 13.1.8, any information that a Party claims is competitively sensitive, commercial or financial information ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

13.1.11 Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.