Public Service Company of Colorado

10-YEAR TRANSMISSION PLAN

For the State of Colorado

To comply with

Rule 3627

of the

Colorado Public Utilities Commission

Rules Regulating Electric Utilities

DOCKET NO. 12M-102E

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Appendices – 10-Year Transmission Projects

ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
2012 Plan	2012 Ten-Year Transmission Plan
ARPA	Arkansas River Power Authority
ATCID	Available Transfer Capability Implementation Document
BES	Bulk Electric System
Black Hills	Black Hills/Colorado Electric Utility Company, L.P.
CBM	Capacity Benefit Margin
CBMID	Capacity Benefit Margin Implementation Document
CCPG	Colorado Coordinated Planning Group
CEII	Critical Energy Infrastructure Information
Commission	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CPCN	Certificate of Public Convenience and Necessity
DSM	Demand Side Management
EPAct	Energy Policy Act of 2005
ERP	Electric Resource Plan
ERP/APR	Electric Resource Plan Annual Progress Report
ERZ	Energy Resource Zone
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GIP	Generator Interconnection Process
HPX	High Plains Express
IRP/ERP	Integrated Resource Plan/Electric Resource Plan
Joint OATT	Joint Open Access Transmission Tariff
L&R	Load and Resource
L&R Study	Load and Resource Transmission Analysis
LTP	Local Transmission Plan
MEAN	Municipal Electric Agency of Nebraska
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
PA	Planning Authority
PNM	Public Service Company of New Mexico
Program	Public Participation Program
PRPA	Platte River Power Authority

Public Service	Public Service Company of Colorado
RES	Renewable Energy Standard
RTEP	Regional Transmission Expansion Project
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
SB07-100	Colorado Senate Bill 07-100
Sierra	Sierra Area Planning Group
SOL	System Operating Limits
SWAT	Southwest Area Transmission Group
TCPC	Transmission Planning and Coordination Committee
TEPPC	Transmission Expansion Planning Policy Committee
TOT	Total of Transfer
TP	Transmission Provider
Tri-State	Tri-State Generation and Transmission Association, Inc.
TRMID	Transmission Reliability Margin Implementation Document
TTC	Total Transfer Capability
WCSTP	WestConnect Project Agreement for Subregional Transmission Planning
WECC	Western Electricity Coordinating Council
Western	Western Area Power Administration

REGULATORY COMPLIANCE TABLE

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(g)	VI.A, VI.B, II.C

I. Introduction

On March 23, 2011, the Colorado Public Utilities Commission (the "Commission") issued its Order on Exceptions (Decision No. C11-0318) in Docket No. 10R-526E, "In the Matter of the Proposed Rules Related to Electric Transmission Facilities Planning, 4 Code of Colorado Regulations 723-3." Pursuant to this order, the Commission adopted Rules 3625 through 3627 governing the coordinated planning for additional electrical transmission facilities in Colorado. As stated in Rule 3626, the purpose of these rules is to establish a process to coordinate the planning for additional electric transmission in Colorado. This process is to be conducted on a state-wide basis in a comprehensive, transparent manner that takes into account the needs of all stakeholders. Further, the relevant utilities must provide government agencies and other stakeholders with opportunities for “meaningful participation” in their planning processes for the purpose of identifying “alternative solutions” to proposed electric transmission projects. Rule 3627 requires the preparation and biennial submission of ten-year transmission plans and conceptual long-range scenarios that consider a twenty (20)-year transmission planning horizon.[1] The plan must include all proposed facilities 100 kV or greater.

This 2012 Ten-Year Transmission Plan for the State of Colorado (“2012 Plan”) is the first such plan submitted following promulgation of Rule 3627. This plan has been jointly prepared and is being submitted by Black Hills/Colorado Electric Utility Company, L.P. d/b/a Black Hills Energy ("Black Hills"), Tri-State Generation and Transmission

[1] The first conceptual long-range plan is due to be submitted on or before February 1, 2014. See Rule 3627(e).

Association, Inc. ("Tri-State"), and Public Service Company of Colorado ("Public Service") (referred to individually as a "Company" and collectively as the "Companies").

The 2012 Plan includes transmission facilities that the Companies, individually or jointly, may construct or participate in over the next ten years in the state of Colorado. This 2012 Plan complements and builds upon the Companies' respective long-standing transmission planning policies and practices. Individual transmission projects included in the plan are the result of an open, transparent, meaningful, and coordinated stakeholder process that considers the needs of each Company, their Member-systems, customers, other transmission owners and operators, government agencies, and a wide variety of other stakeholders. Because the plan was developed through close coordination with other transmission providers in Colorado, the Companies are confident that individual transmission projects included in the plan meet all applicable reliability criteria and do not negatively impact the system of any other transmission provider or the overall transmission system in the near-term and long-term planning horizons. For the same reason, the Companies are equally confident that individual transmission projects included in the plan do not duplicate existing or planned transmission facilities of any other transmission provider in Colorado. Finally, the Companies' planning coordination and stakeholder outreach processes were designed to address their transmission needs as well as the needs of other stakeholders.

As a result, where possible, individual transmission projects included in the plan are designed to serve the mutual needs of more than one transmission provider and/or stakeholder. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation, or transmission expansions, economic issues, and other utilities' plans may impact this 2012 Plan and could result in changes to in-service dates or project scopes. Future federal and local mandates may also impact the 2012 Plan and the transmission planning process in general.

II. Overview of Colorado Transmission Planning Process

Historically, transmission system planning was performed to meet the basic reliability needs of the local customers under most foreseeable circumstances. Increasingly, planners must consider additional drivers such as increased access to markets, public policy initiatives, interconnection of remote renewable generation and other resources, local and regional transmission collaboration, environmental concerns, and mandatory reliability standards.

The Companies' transmission planning processes are intended to facilitate the development of electric infrastructure that both maintains reliability and meets load growth. At present there is no Regional Transmission Organization ("RTO") that covers the state of Colorado, so the Companies have the responsibility for planning their respective transmission systems. Each Company performs and participates in transmission planning at the localized transmission provider ("TP") level, as well as at the subregional and regional levels of the Western Electricity Coordinating Council ("WECC"). On a subregional level, there is active coordination among TPs and stakeholders in the state through study teams formed for specific projects, and through participation in the broader footprint of the Colorado Coordinated Planning Group ("CCPG")

The CCPG was formed in 1991 pursuant to the Joint Transmission Access Principles and Electric Transmission Policy Statement dated December 16, 1991, and filed with the Federal Energy Regulatory Commission ("FERC") in Docket No. EC92-8-000. The CCPG is a part of, and each Company is a member of, WestConnect, which is structured to support and manage the coordination of several subregional planning groups and their respective studies. WestConnect includes not only CCPG, but also the subregions of the Southwest Area Transmission Group ("SWAT") and the Sierra Area Planning Group ("Sierra"). WestConnect is comprised of fourteen (14) utility companies with transmission assets in eight states in the western United States. Through WestConnect, these utilities collaboratively assess stakeholder needs and develop cost-effective transmission and wholesale market enhancements. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the Western Interconnection. These responsibilities are detailed in the WestConnect Project Agreement for Subregional Transmission Planning ("WCSTP") to which Black Hills, Tri-State, and Public Service are signatories.

The WestConnect subregional planning groups coordinate with the other Western Interconnection TPs and their subregional planning groups on a WECC-wide basis through participation in committees such as the WECC Transmission Expansion Planning Policy Committee ("TEPPC") and the Regional Transmission Expansion Project ("RTEP"). 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.

Transmission plans are also developed consistent with the planning principles and requirements set forth in FERC Order No. 890, as well as through consideration of the cooperative principles of voluntary and open membership, member control, member economic participation, autonomy and independence, education and training, cooperation among cooperatives, and concern for the community. The Companies and the industry are presently evaluating how to comply with the requirements of FERC Order No. 1000, which was issued last year. Order No. 1000 is summarized in Section III. E of this report.

Finally, each Company considers applicable reliability standards and other reliability-related system improvements. Both internally, and through CCPG, the Companies perform annual system assessments that demonstrate adherence to the Standards and Criteria set forth by the North American Electric Reliability Corporation ("NERC") and WECC. Compliance with these standards and criteria is certified annually.

Throughout this coordinated planning process, a wide range of factors and interests are considered, including, but not limited to: the needs of network resource transmission service customers; transmission infrastructure upgrades for interconnections associated with both network and non-network resources in each Company's Large Generator Interconnection Process; the minimum reliability standards promulgated by NERC and WECC; bulk power system considerations above and beyond the NERC and WECC minimum reliability standards; transmission system operational flexibility which supports economic dispatch of interconnected generation resources; and regional and subregional transmission projects planned by other utilities and stakeholders. This comprehensive internal, regional, and subregional planning process ensures that transmission plans are carefully coordinated with all transmission providers in the state of Colorado.

In addition to these planning considerations, two of the Companies, Black Hills and Public Service, are subject to the requirements of Colorado Senate Bill 07-100 (“SB07-100”). This statute was passed by the Colorado State Legislature and signed into law in 2007. It requires that regulated electric utilities within the state of Colorado identify areas that have a high potential for beneficial resource development. These resources may include renewable, fossil fuel, and other generation types.

Colorado Revised Statute § 40-2-126(2) requires rate-regulated electric utilities, such as Black Hills and Public Service, on or before October 31 of each odd-numbered year, to do the following:

(a) Designate Energy Resource Zones;

(b) Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones;

(c) Consider how transmission can be provided to encourage local ownership of renewable energy facilities, whether through renewable energy cooperatives as provided in §7-56-210, C.R.S., or otherwise; and

(d) Submit proposed plans, designations, and applications for certificates of public convenience and necessity (“CPCN”) to the Commission for simultaneous review.

The transmission planning activities that Black Hills and Public Service have performed to comply with the requirements of SB 07-100 have not been undertaken in isolation, but are part of the larger, coordinated planning effort described above.

The following sections provide additional information concerning each Company's own transmission planning process.

A. Black Hills

Black Hills' transmission planning process is performed on an annual basis in an open, transparent, coordinated and non-discriminatory fashion to ensure the opportunity for participation is offered to all stakeholders. Black Hills performs an annual transmission planning reliability study to meet the requirements of the NERC and WECC Standards and Criteria while implementing the planning principles laid out in FERC Order 890. Black Hills promotes participation in the planning process to all interested parties, and coordinates study efforts and results with other utilities as well as regional planning organizations such as West Connect, CCPG, and various groups within WECC. The transmission planning process and related discussions are subject to FERC's Critical Energy Infrastructure Information ("CEII") procedures. Additional studies are performed as necessary to address specific purposes including, but not limited to, transmission service requests, generator interconnections, transmission interconnections, load interconnections and transfer capability assessments.

The transmission planning process incorporates the most recent load and resource forecasts, transmission service commitments, expected local and regional transmission projects, valid contingency events, and reliability requirements. Network customers are required to provide their ten-year load and resource projections to the transmission provider annually pursuant to the Black Hills Open Access Transmission Tariff ("OATT"). Study models are created to provide an accurate depiction of a stressed transmission system for a given point in the future. Simulations of various relevant system disturbances are then conducted to detect any inability of the transmission system to meet all identified reliability and economic requirements within that time frame.

If a planning study identifies a deficiency in transmission system performance, various mitigation options are evaluated to determine an optimum solution that best meets the long-term needs of all affected parties. Consideration is given to reliability, flexibility, efficiency, cost, long-term adequacy, environmental impacts, and need, among other things, to ensure that the final solution is financially prudent, publicly acceptable and constructible. The identification and evaluation of a potential project is coordinated with interested stakeholders and neighboring transmission providers to avoid duplication and maximize the overall benefit of a project.

The transmission planning process is routinely performed for a wide range of scenarios to evaluate the adequacy of the transmission system over a ten (10) to twenty (20) - year period. In a given study year, the collection of identified system upgrades and transmission projects is compiled to create the Black Hills Ten-Year Transmission Plan. This Plan is evaluated annually and updated as necessary to reflect the continuing need for a project. Ongoing changes in reliability requirements, planned generation, transmission, load growth, and regulatory initiatives require the build out of a flexible, robust transmission system that meets the needs of all customers under a wide range of circumstances throughout the planning horizon. This 2012 Plan contains additional details on the Black Hills transmission planning process and confirms compliance with Rule 3627.

B. Tri-State

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that both maintains system reliability and meets customer needs, while continuing to provide reliable low cost electric power to its forty-four (44) member cooperatives. As Tri-State's member cooperatives are spread across four states (Colorado, Nebraska, New Mexico, and Wyoming), Tri-State is a regional power provider with only a portion of its planned transmission facilities located in Colorado and therefore included in this plan.

In this regard, the primary objectives of Tri-State's transmission planning process are to meet the needs of Network and Point-to-Point Customers, maintain reliability, accommodate load growth, and coordinate interconnections. The key elements of Tri-State's transmission planning process include:

- Maintaining safe, reliable electric service to its Members at the lowest possible cost;
- Improving efficiency of electric system operations;
- Providing open and non-discriminatory access to its transmission facilities; and
- Planning new transmission infrastructure in a coordinated, open, transparent and participatory manner.

The primary activities center on the preparation of the 10-year Capital Construction Plan for approval by the Tri-State Board and submittal to the Rural Utilities Service ("RUS"). All projects included in the 10-year Capital Construction Plan adhere to NERC and WECC Standards and Criteria; FERC Order No. 890 Planning Principles; coordinated regional planning principles, as well as the criteria outlined in Rule 3627.

Tri-State implements its transmission planning process through various studies, including:

- Reliability Studies (for both bulk system infrastructure and sub-transmission);
- Feasibility Studies;
- System Impact Studies;
- Transmission Service Requests;
- Generator Interconnection Studies;
- Facilities Studies; and
- Economic Studies.

Tri-State's Members create long-range plans and other work plans that they provide periodically to Tri-State's Transmission Planning Department. When Members' plans indicate the need for system upgrades or new construction, Members apply to Tri-State Transmission Planning for a new or modified delivery point to be served from the Tri-State transmission system. The application contains sufficient information for Tri-State Transmission Planning to identify and consider alternatives to meet the Member's requirements in a manner consistent with the immediate need and the long-term need in the context of the overall transmission system development.

The annual Load and Resource Transmission Analysis Report ("L&R Study") is a ten-year study plan informed by the Network Customers' requirements described above, coupled with submission of data by other Transmission Customers. This information and the resulting report are required to provide the most accurate planning models. The requirements of all transmission customers, including interconnection customers, are incorporated into the studies and result in the development of the 10-year Capital

Construction Plan prepared annually for consideration and approval by Tri-State's executives and the Board of Directors.

C. Public Service

The Public Service transmission planning process is intended to facilitate the development of electric infrastructure that both maintains reliability and meets load growth, and is based on the following objectives:

- Maintain reliable electric service;
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to the transmission facilities under its control; and
- Identify and support new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

The structure of transmission planning studies depends on the type and scope of the study. Local studies generally consist of developing reliable and economic transmission plans to:

- Provide transmission to allow Public Service's native load and network integration transmission service customers access to planned network generation resources under the Public Service FERC OATT;
- Support the Public Service local transmission and sub-transmission systems for both the near (0-5 year) and longer-term (5-10-year) time frames;
- Provide for new generation resource and load interconnections;
- Coordinate new transmission-to-transmission interconnections with neighboring transmission systems;

- Accommodate requests for long-term transmission access; and
- Meet requirements of Colorado state laws.

Public Service conducts most planning on a calendar year cycle. This includes a reliability assessment to determine transmission needs for the next five years. Every four years, Public Service performs transmission studies to coincide with its state-mandated integrated resource planning cycle. Electric Resource Plans are developed by the Xcel Energy Resource Planning group on behalf of Public Service and describe the Public Service resource requirements for an acquisition period not to exceed ten (10) years but including a planning horizon extending to a forty (40) year period.

Individual generator and load interconnection requests are handled on a sequential first-come, first served queue basis, and are completed according to FERC and Public Service rules, respectively. In April of each year, Public Service is required to submit a filing (Rule 3206) with the Commission in which all new transmission projects are identified. The Commission will determine normally within sixty (60) days which if any project requires a CPCN. Public Service also has obligations to file transmission plans based on Colorado statutes. An example of this is the requirements of SB07-100 under which the Company is required to have an open planning process and identify energy zones as well as transmission plans associated with those energy zones.

III. Transmission Plans

Three basic categories are used to define the projects included within the Companies' ten-year plans: Transmission, Substation, and Distribution. Each of these categories is described below. In addition, this 2012 Plan includes information provided by certain other utilities and transmission providers.

A. Transmission Plan Project Categories

1. Transmission

Transmission projects are those that consist of building new or rebuilding existing electric transmission of at least 100 kV. For Black Hills and Public Service, some transmission projects are listed as SB07-100 transmission projects. There are a variety of reasons for planning transmission projects including reliability, increased capacity, delivery for resources and, in some instances, to meet regulatory requirements.

2. Substation

Substation projects are those that consist of building a new switching station or substation, or upgrading an existing station by adding or replacing equipment. The substation projects may be part of a bigger transmission plan, but those listed in this report generally require little or no new transmission.

3. Distribution

Distribution projects are those that are meant to primarily serve customer loads at voltages less than 100 kV. They do not affect the overall transmission system, but are provided for information purposes.

B. Black Hills

The Colorado projects contained in Black Hills' 2012 10-year Plan are included in Appendix A and can also be found, along with supporting study reports at:

http://www.westconnect.com/documents_results.php?categoryid=177

C. Tri-State

Information concerning the specific Colorado projects included in Tri-State's 2012 10-year Plan is contained in Appendix B and can also be found at:

http://www.tristategt.org/transmissionPlanning/documents/10-Year-Transmission-Plan.pdf

Information concerning related studies and reports for Tri-State's transmission projects in the Colorado region, are located at the following link:

http://www.tristategt.org/transmissionPlanning/puc3627_TransmissionProjects.cfm

D. Public Service Company of Colorado

Information concerning the specific Colorado projects included in the Public Service 2012 10-year Plan is contained in Appendix C. Supporting documentation can be found by following the web links associated with each project. Transmission plans and project information for Public Service can also be found at the following sites:

http://www.xcelenergy.com/About_Us/Transmission

http://www.xcelenergy.com/About_Us/Transmission/Projects_Directory/SB100Transmission_Projects

http://www.rmao.com/wtpp/Public Service_studies.html

http://www.oatioasis.com/Public Service/index.html

E. Other Utilities and Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2012 Plan, a thorough understanding of all transmission projects planned in Colorado requires consideration of projects planned by other utilities and transmission providers. Information related to such projects is available through WestConnect and associated project summaries are contained in the following appendices:

1. Western Area Power Administration ("Western")

Information concerning the specific Colorado projects included in Western's 2012 Plan is contained in Appendix D.

2. Platte River Power Authority ("PRPA")

Information concerning the specific Colorado projects included in PRPA's 2012 Plan is contained in Appendix E.

3. LS Power

Information concerning the specific Colorado projects included in LS Power's 2012 Plan is contained in Appendix F.

IV. Compliance Requirements

A. Efficient Utilization on a Best-Cost Basis

Rule 3627(b)(I) defines "best-cost" as "balancing cost, risk and uncertainty and includes proper consideration of societal and environmental concerns, operational and maintenance requirements, consistency with short-term and long-term planning opportunities, and initial construction cost."

Each of the Companies endeavors to conduct its transmission planning so as to achieve best-cost solutions that balance the factors identified in Rule 3627 and result in optimal transmission projects. The Companies recognize that a project that is financially impractical will experience difficulty in gaining support from the Commission, customers, shareholders in the case of Black Hills and Public Service, and members in the case of Tri-State. However, cost is not the only consideration when selecting and developing transmission projects. The Companies take a number of factors into consideration when planning the long-term build out of the transmission system. These factors include, but are not limited to, load center projections, project partnership opportunities, regional congestion, transportation corridors, existing transmission corridors, environmentally sensitive areas, city and county zoning, geographic features, operational and maintenance requirements and flexibility, and cost. The primary method of identifying and addressing many of these concerns is through stakeholder participation in the planning process. In addition to stakeholder input, other resources are utilized as necessary, including any available maps, reports, and relevant study efforts. Since planning is one of the initial stages of transmission project development, a cursory evaluation of the aforementioned factors is typically performed as a screening process, with progressively more meaningful, in-depth evaluation occurring through the siting, permitting, and construction stages of development.

Adherence to best-cost principles is formally reflected by Tri-State in its internal policies. For example, Tri-State policy requires, in pertinent part, that Tri-State consider:

Cost comparison of alternatives for providing capacity to serve load.

a. The use of existing delivery points and sub-transmission system;

b. Early construction of other delivery points planned by the Member and/or neighboring utilities;

c. Alternate locations for the new delivery point; and

d. Possible augmentation of the distribution system in lieu of transmission facility construction.

An economic feasibility study of the best alternatives using the "single-entity concept," taking into consideration the total costs of Tri-State, the Member, and other affected utilities. The following criteria shall be evaluated:

a. Electrical performance of existing and proposed facilities, to include voltage drop, power-flow, and losses;

b. Estimated capital and annual costs;

c. Wheeling costs;

d. Reliability;

e. Environmental considerations; and

f. Coordination with Tri-State's and other transmission providers' long-range transmission plans.

In addition, the Companies incorporate "best cost" considerations through their interactions with various federal, state, and local regulatory bodies. For example, their OATTs require adherence to the principles in FERC Order No. 890 which requires Coordination, Openness, Transparency, Information Exchange, Comparability, Dispute Resolution, Regional Participation and Coordination, Economic Planning Studies, and Cost Allocation. All of the Companies participate in Commission dockets and initiatives, spending significant time and resources for Notices of Proposed Rulemaking, outreach efforts, meetings with Commission Staff, and actively participating in initiatives in which the Commission has expressed interest. In addition, the Companies participate with Commission Staff in the development of the Conceptual Long-Range plans for Colorado's electric transmission infrastructure. The Companies individually meet with representatives of the Governor's Energy Office and take into account the suggestions of the Office. The Companies also meet with local governmental officials. These meetings transcend simple permitting requests, taking into account factors such as the economic development aspirations of the communities, cultural concerns of communities, and the environmental aspects of transmission infrastructure expansion contemplated in various regions. Additionally, Tri-State's construction work plans are subject to the approval of the RUS.

B. Reliability Criteria

The Energy Policy Act of 2005 ("EPAct") amended the Federal Power Act ("FPA") to create mandatory electric reliability standards for the U.S. bulk power system. In compliance with these federal laws, the FERC certified the NERC as the electric reliability organization responsible for developing and enforcing the mandatory reliability standards authorized by the EPAct. NERC also utilizes certain Delegation Agreements with regional reliability organizations, such as the WECC. Various mandatory reliability standards relating to bulk power system planning, operations, and maintenance have been implemented by NERC and WECC as a result of the EPAct with the potential for fines of up to $1 million per day for serious violations that could impact the integrity of the bulk power system.

The NERC Reliability Standards can be found at:

http://www.nerc.com/page.php?cid=2|20

The WECC Criteria can be found at:

http://www.wecc.biz/library/Documentation%20Categorization%20Files/Forms/AllItems.aspx?RootFolder=%2flibrary%2fDocumentation%20Categorization%20Files%2fRegional%20Criteria&FolderCTID=&View=%7bAD6002B2%2d0E39%2d48DD%2dB4B5%2d9AFC9F8A8DB3%7d

Additional information concerning each Company's reliability compliance efforts is provided below.

1. Black Hills

As a WECC member, Black Hills adheres to NERC and WECC Standards and Criteria. In addition, the following additional guidelines are utilized in the planning process for determining acceptable levels of service for the Black Hills service territory:

- Transmission line loadings should not exceed 100 percent of continuous seasonal rating or the established equipment or operating limits.
- Transformer loading under system intact conditions should not exceed 100 percent of the normal rating.

- Transformer loading under contingency conditions should not exceed 100 percent of the emergency rating.
- Transmission bus voltage levels during normal conditions will be maintained between 0.95 p.u. and 1.05 p.u. of nominal system voltage.
- Transmission bus voltages during contingency conditions will be maintained between 0.90 p.u. and 1.1 p.u. of nominal system voltage.
- Following a disturbance, all generation units must remain in synchronism and voltage dips shall not drop below 0.70 p.u. at any load or non-load bus.

Additional details on the Reliability Criteria observed by Black Hills are provided on pages 15-18 of the Attachment K Methodology, Criteria, and Process Business Practices document, available at:

http://www.oatioasis.com/BHCT/BHCTdocs/BHCE_Method_Criteria_Process_Business_Practice_04082010.pdf

2. Tri-State

Tri-State adheres to NERC and WECC Standards and Criteria, as well as Tri-State's internal criteria for planning studies. Tri-State performs an annual assessment of its regional interconnected transmission system elements utilizing simulation modeling cases created by WECC members. This annual assessment takes into account Tri-State's members in four states, with associated projects located in Colorado included in this plan.

The modeling cases selected represent projected loads and transmission system topology for the year one through five horizon and the year six through ten horizon. These cases are selected to demonstrate system performance covering a range of forecasted demand levels and the most critical system conditions and study years. This analysis examines heavy and light loading scenarios, typically in cases modeling year one, year five, and year ten, unless other factors, such as known major system changes, dictate selection of another year. Cases created by WECC ensure that all projected firm transfers and established normal (pre-contingency) operating procedures are modeled, as well as existing and planned reactive power resources.

The transmission system is analyzed considering the planned projects for each utility in the study area. This assessment includes one or more current or past studies which together address the entire Tri-State area of operation.

Additional information concerning Tri-State's reliability criteria is available at the following site:

http://www.tristategt.org/transmissionPlanning/documents/PUC-3627_Reliability-Criteria.pdf

3. Public Service

Public Service adheres to NERC and WECC Standards and Criteria, as well as internal Company criteria for planning studies. Some of the internal criteria are as follows:

During system intact conditions, criteria are to maintain transmission system bus voltages between 0.95 and 1.05 per unit of nominal, and steady-state power flows below the thermal ratings of all facilities. Operationally, Public Service tries to maintain a transmission system voltage profile ranging from 1.02 per unit or higher at regulating (generation) buses to 1.0 per unit or higher at transmission load buses. Following a single contingency, transmission system steady state bus voltages must remain within 0.90 per unit to 1.05 per unit, and power flows within 100% of the facilities' continuous thermal ratings. Also, voltage deviations should not exceed 5%. Transient stability criteria require that all generating machines remain in synchronism and all power swings should be well damped. Also, transient voltage performance should meet the following criteria:

- Following fault clearing for single contingencies, voltage may not dip more than 25% of the pre-fault voltage at load buses, more than 30% at non-load buses, or more than 20% for more than twenty (20) cycles at load buses;
- Following fault clearing for multiple contingencies, voltage may not dip more than 30% of the pre-fault voltage at any bus or more than 20% for more than forty (40) cycles at load buses.

In addition, transient frequency performance should meet the following criteria:

- Following fault clearing for single contingencies, frequency should not dip below 59.6 Hz for six (6) cycles or more at a load bus; and
- Following fault clearing for multiple contingencies, frequency should not dip below 59.0 Hz for six (6) cycles or more at a load bus.

C. Legal and Regulatory Requirements

Per Rule 3627(b)(III), "Each ten year transmission plan shall demonstrate compliance with…[a]ll legal and regulatory requirements, including renewable energy portfolio standards and resource adequacy requirements." The following sections provide information concerning each Company's compliance with such legal and regulatory requirements.

1. Black Hills

Black Hills' 2012 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements. Black Hills is required to comply with the Colorado Renewable Energy Standard ("RES"). For additional information on resource adequacy requirements and resource requirements meeting the renewable energy portfolio standards, please refer to dockets and Commission decisions approving Black Hills' 2008 Electric Resource Plan (see http://www.blackhillscorp.com/pdf/BHE_RFP_2008ResourcePlan.pdf; and Decision No. C09-0184 in Docket No. 08A-346E), and confirming its RES Compliance Plans for 2008, 2009, and 2010 have complied with the RES standards (see Decision No. C09-1132 in Docket No. 07A-356E, Decision No. C10-1206 in Docket No, 08A-470E, and Decision No. C11-1709 in Docket No. 09A-494E).

2. Tri-State

Tri-State's 2012 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements. Tri-State's Members are required to comply with the Colorado RES. The Colorado RES requires that 1 percent of retail energy sales be served by renewable generation in 2010, growing to a 10 percent level in 2020 and beyond.

For additional information on resource adequacy requirements and resource requirements to meet the RES, please refer to Tri-State's 2010 Integrated Resource Plan/Electric Resource Plan and 2011 Electric Resource Plan Annual Progress Report available at:

> http://www.tristategt.org/ResourcePlanning/documents/Tri-State_IRP-ERP_Final.pdf

http://www.tristategt.org/ResourcePlanning/documents/Tri-State_2011-ERP-Progress-Report.pdf

3. Public Service

The Public Service 2012 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements. Information concerning the Company's compliance with the Colorado RES can be found at:

http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/2010RESComplianceReport_060111.pdf

http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Regulatory_Filings/CO_2012_Renewable_Energy_Standard_Compliance_Plan

The Company plans the adequacy of it system resources consistent with Commission rules:

http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Resource_Plans/Public Service_2011_Electric_Resource_Plan

D. FERC Order No. 890

The Companies' transmission plans, as well as those of other Colorado transmission providers, are developed under the guidance of the CCPG. As stated in its charter, the CCPG is a planning forum which operates to assure a high degree of reliability in joint planning, development, and operation of the high voltage transmission system in the Rocky Mountain Region of the WECC. The CCPG operates in accordance with FERC Order No. 890, which sets forth principles for transmission planning. All transmission planning must include an open stakeholder process. Any stakeholder interested in the planning of the transmission system in the CCPG footprint can participate and obtain information regarding base cases, plans, and projects. The planning forums allow stakeholders to provide input or express needs or concerns related to the transmission system.

In addition to the CCPG planning processes, each of the Companies has its own FERC Order No. 890 Stakeholder process. The following sections provide additional information concerning each Company's FERC Order No. 890 processes.

1. Black Hills

For Black Hills, the FERC Order No. 890 Stakeholder Process is included in its Attachment K to its Open Access Transmission Tariff, available at the following website:

http://www.oatioasis.com/BHCT/BHCTdocs/BHCE_Attachment_K_Compliance_6-15-2009.pdf

Additional information concerning Black Hills' FERC Order No. 890 processes can be found at:

i. Attachment K Business Practices; Methodology, Criteria, and Process; and Economic Study Request Form: http://www.oatioasis.com/bhct →Transmission Planning

ii. General Stakeholder Information: http://www.oatioasis.com/bhct →Transmission Planning →TCPC

2. Tri-State

Attachment L to Tri-State's OATT demonstrates Tri-State's Transmission Planning Process's consistency with the FERC Order No. 890 planning principles. As discussed previously in this 2012 Plan, all projects included herein have been identified and developed through Tri-State's Transmission Planning Process. Attachment L to Tri-State's OATT is available on Tri-State's OASIS, by clicking on "Tariff & GIP" and then "Tariff" at the following link:

http://www.oatioasis.com/tsgt/

Attachment L to Tri-State's OATT can be updated periodically. The present Attachment L at the time of this filing can be located directly at:

http://www.oatioasis.com/TSGT/TSGTdocs/Attachment_L_final_10-15-10.pdf

3. Public Service

For Public Service, the FERC Order No. 890 Stakeholder Process is included in the Xcel Energy Joint Open Access Transmission Tariff ("Joint OATT") Attachment R, available at the following website:

http://www.oatioasis.com/PUBLIC SERVICE/PUBLIC SERVICEdocs/Public Service_Attachment_R_101508.pdf

Additional information concerning the Public Service FERC Order No. 890 processes can be found at:

i. Economic Studies: http://www.oatioasis.com/Public Service/index.html -> FERC 890 Postings -> Customer Requests

ii. Stakeholder Meetings (General Info): http://www.oatioasis.com/Public Service/index.html -> FERC 890 Postings -> Stakeholder Meetings (This folder contains meetings agendas and presentations).

E. FERC Order No. 1000

In July of 2011, the FERC issued a final rule related to transmission planning and cost allocation, FERC Order No. 1000. This order builds on planning principles already established in FERC Order No. 890, as previously discussed. FERC Order No. 1000 requires that transmission owning and operating public utilities:

1) participate in a regional transmission planning process that produces a regional transmission plan;

2) amend their OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes;

3) remove from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities;

4) improve coordination between neighboring transmission planning regions for interregional transmission facilities;

5) participate in a regional transmission planning process that has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and

6) participate in a regional transmission planning process that has an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions.

The transmission owning and operating companies within the state of Colorado are reviewing FERC Order No. 1000 and evaluating options for complying with the Order. Currently, members of the CCPG are evaluating the concept of designating WestConnect as the FERC Order No. 1000 planning region. Because of the complexity of the Order, no final decisions have been made at this time.

V. Transmission Plan Supporting Information

A. Methodology, Criteria, & Assumptions

1. Facility Rating Methodology & Facility Ratings

a) FAC-008

NERC Reliability Standard FAC-008 requires that transmission and generation owners document their methodology used to develop ratings of their equipment. The standard requires that the transmission or generation owner supply its methodology to specific NERC registered entities upon request.

(1) Black Hills

Black Hills FAC-008 document is available at:

http://www.oatioasis.com/BHCT/BHCTdocs/BHCE_Facility_Rating Methodologyv1.1_072209.pdf

(2) Tri-State

Information concerning the transmission facility rating methodology, as defined by FERC standard FAC-008 and used by Tri-State is available at the following link:

http://www.tristategt.org/transmissionPlanning/documents/PUC-3627 Facility-Rating-Methodology.pdf

(3) Public Service

Information concerning the Public Service FAC-008 methodology is available upon request by contacting Mr. Gerry Stellern at Public Service.

b) FAC-009

NERC Reliability Standard FAC-009 requires transmission and generation owners to establish facility ratings per the methodology established through FAC-008.

Each transmission and generation owner has documented ratings for each of its facilities. The standard requires the transmission or generation owner to supply its facility ratings to specific NERC registered entities (i.e. associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s)) upon request. These documents are not publicly available and are not required to be per NERC standards. NERC Reliability Standard MOD-010-0 requires applicable entities to provide equipment characteristics, including established facility ratings, to NERC and WECC according to established reporting requirements. This is accomplished through the WECC Annual Study Program as prescribed by the Data Preparation Procedural Manual.

2. Transmission Base Case Data

a) Powerflow, Stability, Short Circuit

The Companies utilize transmission system power flow and transient dynamics modeling data prepared by WECC. Through its Annual Study Program, WECC facilitates the preparation of at least ten models per year. The models represent a variety of system conditions out to a ten-year horizon. WECC's 10-Year Regional Transmission Plan is an Interconnection-wide perspective on: 1) expected future transmission and generation in the Western Interconnection, 2) what transmission capacity may be needed under a variety of futures, and 3) other related insights.

WECC members participate in the data preparation process for the models and Public Service coordinates the data for the Rocky Mountain Region. Prior to being used for planning studies, the models are reviewed and adjusted to reflect the most current and accurate system elements, ratings, and operating conditions for the region to be studied. Short circuit data is coordinated between neighboring transmission providers as needed and periodically coordinated at the CCPG level.

Instructions for Obtaining Access to WECC Base Cases are as follows:

1. An organization requesting WECC base case(s) must either be a WECC member or they must execute the "Nonmember Confidentiality Agreement for WECC Data".

2. If the organization is not a WECC member, have them complete the "Nonmember Confidentiality Agreement for WECC Data" which can be found at: http://www.wecc.biz/library/Pages/Powerflow%20Base%20Cases.aspx The submission must include a statement from the organization explaining why they have a legitimate business need for the WECC base case(s).

B. Load Modeling

Pursuant to each Company's OATT, Network Customers are required to submit ten-year projected network loads and network resources by October 1st of each year. This information is then compiled with existing data and information to provide a basis for identification of the minimum transmission system enhancements required to ensure that a sufficiently robust transmission system is in place to meet Network Customers' requirements under all scenarios.

1. Forecasts

The Companies rely on the most recent and accurate load forecasts when developing system planning models. General load forecast assumptions are posted on each transmission provider's OASIS site.

a) Black Hills

In 2008, Black Hills filed with the Commission its Electric Resource Plan ("ERP"), which included details on expected customer growth.[2] Black Hills also receives updated load forecast information from its Network Customers on an annual basis. The ERP, in conjunction with the Network Customer forecast updates, is used in the development of Load and Resource ("L&R") reports submitted to WECC on an annual basis. Once the L&R report is developed, this forecast is disaggregated to the respective transmission system load buses. There are two types of load buses – (1) a load bus where the load does not change over time (e.g., a single large industrial load bus); and (2) a load bus where the load changes over time (e.g., residential load). Black Hills uses its knowledge of load characteristics along with historical loading observations to estimate the individual load bus data in time. The load bus forecasts are summed and compared to the WECC L&R report aggregate load forecast. If the two forecasts do not match, the variable bus load forecasts are adjusted until the two forecasts match. Through this procedure the WECC L&R reports, including the assumptions in the latest ERP, are reflected in the transmission planning models used within the WECC footprint.[3]

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[2] The Commission approved the ERP, as modified, in Decision No. C09-0184 in Docket No. 08A-346E. *See also* Decision No. C09-0337, granting Black Hills' application for reconsideration in part and modifying Decision No. C09-0184.

[3] Additional details related to Black Hills' forecast can be found beginning on page 37 of the 2008 Black Hills ERP: http://www.blackhillscorp.com/pdf/BHE_RFP_2008ResourcePlan.pdf

b) Tri-State

General load forecast information is available on Tri-State's OASIS, by clicking on "ATC Information" and then "Load Forecast Descriptive Statement" at the following link:

http://www.oatioasis.com/tsgt/

The general load forecast information may be updated periodically. The present general load forecast assumptions at the time of this filing can be located directly at:http://www.oatioasis.com/TSGT/TSGTdocs/Load_Forecast_Information_ATC_Info_4-1-2011.pdf.

Tri-State prepares load forecasts on a system-wide and regional basis with regional forecasts used for resource planning purposes. Tri-State receives load forecasts from its Network Customers by October 1st of each year. These loads are modeled as required for inclusion in the planning models developed in conjunction with neighboring entities.

More information can be found in Section II of Tri-State's Integrated Resource Plan/Electric Resource Plan ("IRP/ERP"), Existing System and Forecasts, part 2 – Electric Demand and Energy Forecasts. The IRP/ERP includes Tri-State's 2009 load forecast data and is posted at the following site:

http://www.tristategt.org/ResourcePlanning/documents/Tri-State_IRP-ERP_Final.pdf

Tri-State's most recent transmission plans utilize 2011 load forecast data. Base forecast data for these plans is available in Appendix A of Tri-State's 2011 Electric Resource Plan Annual Progress Report ("ERP/APR") posted at:

http://www.tristategt.org/ResourcePlanning/documents/Tri-State_2011-ERP-Progress-Report.pdf

c) **Public Service**

Public Service prepares two load forecasts a year. In addition to native load forecasts, Public Service receives forecasts from its wholesale customers, which it incorporates into the overall forecast. Transmission Planners allocate the loads on a substation by substation basis, based on historical trends. More information can be found on page 2-98 of the 2011 Electric Resource Plan Vol. 2 – Technical Appendix:

http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PublicService-ERP-2011/Exhibit-No-KJH-1-Volume-2.pdf

2. Demand Side Management

The effects of Demand Side Management ("DSM") program savings are typically taken into account within the load forecasts described previously. Within the context of power system modeling, DSM is simply reflected in the power flow model as reduced load and therefore included in planning studies.

a) **Black Hills**

Details related to the effects of DSM savings estimates on Black Hills' load forecast can be found in Section 7.1 at pages 37-41 of the 2008 Black Hills ERP:

http://www.blackhillscorp.com/pdf/BHE_RFP_2008ResourcePlan.pdf.

b) **Tri-State**

Load forecasts provided for bulk electric transmission planning typically include existing DSM and other load reducing programs including member energy efficiency programs and local distributed generation. These programs are reflected in the power flow model as reduced load and are inherently included in studies. For transmission planning, load forecasts that contain load reducing factors may be used for specific projects or for individual Tri-State members with DSM, local distributed generation, or other energy efficiency programs. For such cases, please refer to individual project planning studies. For Tri-State's system load forecast, these are described in Tri-State's 2010 IRP/ERP and in Tri-State's 2011 ERP/APR.

For the 2010 IRP/ERP, see Section II, Existing System and Forecasts, part 2 – Electric Demand and Energy Forecasts, which can be found at the following link:

http://www.tristategt.org/ResourcePlanning/documents/Tri-State_IRP-ERP_Final.pdf

Tri-State's 2011 ERP/APR posted at:

http://www.tristategt.org/ResourcePlanning/documents/Tri-State_2011-ERP-Progress-Report.pdf

c) Public Service

Public Service accounts for DSM through reduction in its load forecast based, in part, on the goals established by the Commission. In regards to how DSM impacts the Company's load and resources, see the Company's ERP found on page 2-66 of the 2011 Electric Resource Plan Vol. 2 – Technical Appendix:

http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PublicService-ERP-2011/Exhibit-No-KJH-1-Volume-2.pdf

C. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Study Program base cases as required by the Data Preparation Procedural Manual. The detail of generation models utilized within planning studies can vary depending on the nature of the study. For example, a Large Generator Interconnection study for a wind facility may explicitly model each individual wind turbine and the associated collector system to properly assess the low voltage ride through capabilities of the facility. That same facility may be modeled as a single equivalent wind turbine with an equivalence collector system within a long-range planning study where the performance of individual wind turbines is not a concern. The scope of the technical study will influence the level of detail that is modeled.

a) Black Hills

Refer to Sections 3 and 8 of the Black Hills 2008 ERP for a listing of existing and planned resources to be included in planning studies: http://www.blackhillscorp.com/pdf/BHE_RFP_2008ResourcePlan.pdf.

Black Hills typically utilizes an economic-based dispatch philosophy similar to the one found in Section 8 of the 2008 ERP, beginning on page 45. Depending on the objective of the study being performed, the generation profile may deviate from an economic-based dispatch to a 'high-renewables' scenario or a high energy import/export scenario to evaluate the impacts of that particular set of assumptions. The selected generation dispatch assumptions are identified in each transmission planning study report.

b) Tri-State

Tri-State's transmission planning function receives generation assumptions from its Network Customers (Tri-State Power Marketing, Arkansas River Power Authority ("ARPA"), Municipal Electric Agency of Nebraska ("MEAN"), and Public Service Company of New Mexico ("PNM")) annually by October 1st. These generation assumptions are utilized to develop the L&R Study to ensure a sufficiently robust transmission system to meet Network Customers' needs over a ten (10) year planning horizon. The most recent L&R Study is available at:

http://www.oatioasis.com/TSGT/TSGTdocs/LR_Report_2011_final_JGC_IK_MSBT_RS_7_7_11.pdf

Generation assumptions, including dispatch assumptions, and corresponding data for other transmission plans are project specific. Therefore, the individual transmission studies should be referenced for generation assumptions relative to each such project.

c) Public Service

Public Service follows the WECC established requirements and guidelines specific to modeling. Base Cases reflect generation dispatch based on Public Service's internal procedures that take into account production costs, maintenance schedules and other factors. Some of these are:

- If a generator will be modeled out of service, the Pgen & the generator status values should be set to zero. This is necessary to achieve correct reserve calculations;
- Model generator planned outages with outage period of 6 months or more;
- In general, high production cost generation plants are typically modeled out of service. If resources are needed, these units should be modeled in service;
- Typically, all Public Service combustion turbine generators are operated at full or near output to minimize the production costs;
- Typically, the Public Service large coal fired plants are base loaded (always operating at high output, 24/7). If generation adjustments are necessary, these generators should be adjusted last;

- Hydro generation has net dependable seasonal ratings. Each seasonal rating reflects the average generation that can be continuously maintained over the duration of the daily peak period for the respective season. In winter, the daily period is approximately five (5) hours long. All generators on-line should be producing MVARs. Generator bus voltage scheduling may be necessary if the generating unit is acting in a condensing mode (consuming MVARs);
- Wind generation is typically modeled at 12-75% of nameplate, depending on the study; and
- Solar generation is typically modeled at 65%.

System changes, load transfers and other topology changes are also coordinated through CCPG.

D. Methodologies

1. System Operating Limits

"System Operating Limits" ("SOL") is defined in NERC Reliability Standard FAC-010-2.1 as the responsibility of the Planning Authority ("PA") to ensure reliable planning of the Bulk Electric System. SOL is required to be established per FERC standards but is not required to be publicly available.

a) Black Hills

Black Hills has defined both Operational Criteria, which are limits for typical every day/normal operations, and SOL, which are limits that are of an emergency nature and must be acted upon promptly to insure facility ratings are not exceeded. Black Hills' SOLs are communicated to the LRCC Reliability Coordinator so that when an SOL is exceeded, the Reliability Coordinator will be aware of the concern and be able to provide assistance in ensuring the SOL violation is removed. Black Hills' SOLs are summarized below:

- Bulk Electric System ("BES") Transmission Line SOLs are exceeded when the line thermal limit summer rating is exceeded for 30 minutes.
- BES Voltages SOLs are exceeded when they exceed the “Emergency Voltage” rating for more than 30 minutes. The “Emergency Voltage” is plus/minus 10% of the nominal voltage.
- BES Transformer SOLs are exceeded when their loaded MVA exceeds the ½ hour overload limit (of 153%) for more than 30 minutes.

b) Tri-State

Tri-State is not a PA and, therefore, uses the SOL as defined by the PA in R1 and R2 of NERC standard FAC-010-2.1, available at the following link:

http://www.nerc.com/files/FAC-010_2.pdf

c) Public Service

Public Service has one SOL for the Total of Transfer (“TOT”) 7 located north of the Denver metro area. The TOT 7 studies are conducted annually. The results of those studies for 2011 summer can be viewed at the following link:

http://www.oatioasis.com/PSCO/PSCOdocs/TOT_7_Limits_Summer_2011.pdf

SOLs are required to be established per FERC standards, but are not required to be publicly available.

2. Transfer Capabilities

Available Transmission System Capability Methodology is available and posted per NERC Standard MOD-001:

http://www.nerc.com/files/MOD-001-1a.pdf

Additional information concerning each Company's transfer capabilities is presented below.

a) Black Hills

Black Hills utilizes the Rated System Path Methodology for determining Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") for all Posted Paths and in all ATC time horizons. The determination of TTC is based on the maximum flow of a path while meeting all reliability criteria for Category B events. In the event that the path is flow-limited and a reliability limit cannot be reached, the transfer capability of the path is set to the thermal rating of the path. For further details on the calculation of transfer capability, refer to Black Hills' ATC Implementation Document on the Black Hills OASIS at:

http://www.oatioasis.com/BHCT/BHCTdocs/1_Current_Available_Transfer_Capability_Implementation_Document_-_ATCID_(MOD-001-1).pdf

b) Tri-State

Tri-State's TTC path values for jointly owned paths that are interfaces identified and rated through WECC processes and OTC determinations are based upon the Rated System Path Methodology (NERC MOD-29-1). Tri-State has TTC allocations on WECC rated Paths 30 (TOT1A), 31 (TOT2A), 36 (TOT3), 39 (TOT5), 47 (SNMI), and 48 (NNMI). These paths are studied by the path operator with actual flow levels at the combined path ratings under simulated N-1 scenarios to ensure that the planning reliability criteria are being met. The path participants have previously used studies and negotiations to determine the manner in which the TTC will be allocated to each of the participants.

For jointly owned paths that are not WECC rated paths, the TPs determine the appropriate combined TTC and the allocation of it is based upon contractual capacity entitlements. This allocation is done outside of any WECC approval process since these are Tri-State TTC/Available Transfer Capability Implementation Document ("ATCID") minor paths that are not part of an interface and do not impact any major recognized WECC paths.

Tri-State utilizes TTC values based upon thermal facility ratings for all flow limited paths that are owned solely by Tri-State. If the NERC MOD-029-1 requirement R2.1 simulation studies result in sufficient flow ability on a path segment to determine a reliability limit, then the TTC on the ATC Path segment is set to the simulated flow corresponding to the reliability limit while at the same time satisfying all planning criteria.

In addition, Tri-State has created many extended ATC paths that are defined by a serial concatenation of rated path segments. The resulting TTC and ATC for each extended ATC path is based upon the lowest TTC and ATC of all the serial path segments included in each path definition.

The ATCID provides for the documentation of required information as specified in the NERC MOD Standards and the NAESB OASIS Standards regarding the calculation methodology and information sharing of ATC specific to this TP. The

ATCID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "ATCID Document" at the following link:

http://www.oatioasis.com/tsgt/

The ATCID can be updated periodically. The ATCID at the time of this filing can be located directly at:

http://www.oatioasis.com/TSGT/TSGTdocs/ATCID_Combined_Posting_10-14-2011.pdf

c) Public Service

Public Service's Available Transfer Capabilities Implementation Documents (MOD-001) is posted at the following link:

http://www.oatioasis.com/PUBLIC SERVICE/PUBLIC SERVICEdocs/Public Service_ATCID.pdf

3. Capacity Benefit Margin

Capacity Benefit Margin ("CBM") methodology is available and posted per NERC Standard MOD-004. Additional information concerning each Company's CBM methodology is provided below.

a) Black Hills

Black Hills does not implement CBM in the assessment of ATC. The Capacity Benefit Margin Implementation Document ("CBMID") for Black Hills is located at the following link:

http://www.oatioasis.com/BHCT/BHCTdocs/2_Current_CBM_Implementation_Document_-_CBMID_(MOD-008-1).pdf

b) Tri-State

Based on FERC's allowance for TPs to not use CBM, Tri-State does not allow for the use of CBM and as such, its value is set to zero (0) in the ATC equations for all paths posted by Tri-State. Furthermore, Tri-State's practice is to not maintain CBM. Tri-State will review its CBM practice, at least annually, and will post any changes to the OASIS as needed. The CBMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "Capacity Benefit Margin Statement (CBMID)" at the following link:

http://www.oatioasis.com/tsgt/

The CBMID can be updated periodically. The CBMID at the time of this filing can be located directly at:

http://www.oatioasis.com/TSGT/TSGTdocs/Capacity_Benefit_Margin_v1-0_2011.pdf

c) Public Service

Public Service's CBMID is located at the following link:

http://www.oatioasis.com/PUBLIC SERVICE/PUBLIC SERVICEdocs/Public Service_CBMID.pdf

4. Transmission Reliability Margin

NERC Standard MOD-008-1, Transmission Reliability Margin Calculation Methodology, requires that each Transmission Operator prepare and keep current a Transmission Reliability Margin Implementation Document ("TRMID"). Additional information concerning each Company's Transmission Reliability Margin is provided below.

a) Black Hills

The TRMID for Black Hills is located at the following link:

http://www.oatioasis.com/BHCT/BHCTdocs/3_Current_TRM_Implementation_Document_-_TRMID_(MOD-008-1).pdf

b) Tri-State

The TRMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "TRMID Document" at the following link:

http://www.oatioasis.com/tsgt/

The TRMID can be updated periodically. The TRMID at the time of this filing can be located directly at:

http://www.oatioasis.com/TSGT/TSGTdocs/TRMID_6-23-11_v1-1.pdf

c) Public Service

The TRMID for Public Service is located at the following links:

http://www.oatioasis.com/PUBLIC SERVICE/PUBLIC SERVICEdocs/Public Service_TRMID.pdf

http://www.oatioasis.com/PUBLIC SERVICE/PUBLIC SERVICEdocs/CBM-TRM_postings_11-01-2011.pdf

E. Status of Upgrades

Projects that constitute upgrades to existing transmission facilities are discussed in Section II of this Plan and the associated appendices. Since this is the first Ten-Year Plan submitted under Rule 3627, there are no changes, additions, or deletions in the current plan when compared with the prior plan.

F. Studies and Reports

Most of the Companies' documentation can be found by starting at the sections of the WestConnect website that are dedicated to the CCPG:

http://www.westconnect.com/planning_ccpg.php

1. Black Hills

Public access to transmission market information, generator interconnection and transmission service requests, business practices, and other topics related to the Black Hills transmission system is provided on Black Hills' OASIS at http://www.oatioasis.com/bhct. Information on Black Hills' 2011 SB07-100 study process, including the final 2011 SB07-100 study report, was filed with the Commission in Docket No. 11M-872E and can be found in the Commission's E-filing system under that docket number, and is also located at http://www.blackhillscorp.com/transmission.htm. Information on prior SB07-100 studies can be found on Black Hills' OASIS. Study reports supporting the projects in Black Hills' Ten Year Transmission Plan are located at

http://www.westconnect.com/documents_results.php?categoryid=177.

2. Tri-State

Planning studies and related reports for Tri-State transmission projects in the Colorado region are located at the following link:

http://www.tristategt.org/transmissionPlanning/puc3627_TransmissionProjects.cfm

3. Public Service

http://www.rmao.com/wtpp/Public Service_studies.html

http://www.oatioasis.com/Public Service/index.html

http://www.xcelenergy.com/About_Us/Transmission/About_Transmission/Planning_for_the_PSCo_Transmission_System

SB07-100 2007, 2009, and 2011 reports are available at:

http://www.sb100transmission.com/pdf/sb100/2011-Senate-Bill-100-Biennial-Report.pdf

G. In Service Dates

Information concerning the expected in-service date for each utility's facilities identified in this Plan and the entities responsible for constructing and financing each facility is contained in Section II of this Plan and the associated appendices.

H. Economic Studies

The purpose of economic planning studies is to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and/or 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, (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/or loads. Economic studies are generally described as being either "local" or "regional" in nature.

1. Black Hills

Through the procedures outlined in its OATT Attachment K, which can be found at

http://www.oatioasis.com/BHCT/BHCTdocs/BHCE_Attachment_K_Compliance_6-15-2009.pdf

Black Hills will accept requests for economic studies on an annual basis. Upon receiving a valid request for an economic study, Black Hills, with input from its stakeholder committee, will classify the request as local, subregional or regional. Black Hills will study up to one economic study request that has been classified as local on a bi-annual basis. All economic study requests that have been classified as subregional or regional will be forwarded to the WECC TEPPC for inclusion in the WECC TEPPC

Economic Planning Study Master List. Refer to Section D of this report for the link to the Economic Study Request Form.

2. Tri-State

Western Interconnection-wide congestion and economic planning studies are conducted by WECC-TEPPC in an open stakeholder process that holds region wide stakeholder meetings on a regular basis. The WECC-TEPPC planning process is posted on its website (see www.wecc.biz). Tri-State participates in the regional planning processes, as appropriate, to ensure data and assumptions are coordinated. The following link shows Economic Studies requested and responded to since February, 2010.

http://www.tristategt.org/transmissionPlanning/documents/Economic-Study-for-CO-PUC.pdf

3. Public Service

Public Service shall facilitate priority local economic planning studies for the Public Service transmission system, pursuant to the procedures in its OATT Attachment R. Regional economic planning studies shall be performed by the WECC TEPPC, pursuant to procedures posted on the TEPPC page of the WECC website.

Economic studies can be found at the following link: http://www.oatioasis.com/Public Service/index.html -> FERC 890 Postings -> Customer Requests.

VI. Stakeholder Participation

Per Rule 3627(g)(I), “Government agencies include affected federal, state, municipal and county agencies. Other stakeholders include organizations and individuals representing various interests that have indicated a desire to participate in the planning process.” The following sections summarize each Company's approach to stakeholder outreach and participation.

A. Black Hills

Black Hills recognizes the importance of stakeholder involvement throughout the transmission planning process. Black Hills considers a transmission planning stakeholder as a person, group, or entity that has an expressed interest in participating in the planning process, is affected by the transmission plan, or can provide meaningful input to the process that may affect the development of the final plan.

Historically, the primary method of involving stakeholders in Black Hills' planning activities has been performed through the annual Transmission Planning and Coordination Committee (“TCPC”) study process. The TCPC is an advisory committee consisting of stakeholders interested in providing input to the transmission plan. The TCPC study process consists of a comprehensive evaluation of the Black Hills and surrounding transmission systems for critical scenarios throughout the ten-year planning horizon. Stakeholders are notified of the initial meeting at the start of the study cycle, and invited to participate. An opportunity is provided to comment on the scope of the study at this point in the process. Relevant system modeling data is requested from the stakeholders, as well as any economic study or alternative scenario requests. Once the study cases are compiled, another open stakeholder meeting is held to review and finalize the data and study scope. Following initial study work, a stakeholder meeting is held to review the results and recommended solutions, as well as identify any additional solutions for evaluation. This allows the TCPC to develop a comprehensive transmission plan to meet the needs of all interested parties. A final stakeholder meeting is held to approve the study report and Local Transmission Plan ("LTP"). Meaningful stakeholder involvement is allowed and encouraged throughout this study process.

A list of potential stakeholders was created during the initial TCPC study cycle and has continued to evolve through active invitations, recommendations from existing participants and outreach at CCPG meetings.

Meeting notices are posted in advance on the Black Hills OASIS as well as the CCPG section of the West Connect web site. Participants are invited to attend either in person or via web conference. Following each meeting, contact information for the transmission planner performing the study is provided to allow for questions or comments regarding the study process.

The TCPC process for stakeholder participation is also employed when performing the biennial study as required by SB 07-100.

Stakeholders are offered the opportunity to participate in the Black Hills transmission planning process through the CCPG as well. The CCPG is a forum recognized by a broad group of potential stakeholders and offers participation to anyone who is interested.

Black Hills is currently in the process of developing an expanded stakeholder list in order to invite a more comprehensive group of participants into the transmission planning process. This stakeholder outreach concept will build on the existing process used for the annual TCPC study. The initial meeting was educational in nature and provided the attendees with the general concepts of transmission planning in Colorado and how it affects them. The meeting also provided information on the annual Black Hills TCPC study process and extended an invitation to attend the quarterly meetings under the existing study process. The stakeholder communication plan is designed to meet the requirements of Colorado Rule 3627 and FERC Order No. 890, as well as to foster a closer working relationship with anyone desiring to participate in the transmission planning process.

Additional communication methods will be utilized as part of the stakeholder communication plan. These methods, including an updated web page, emails, and printed mailings will allow Black Hills to reach a larger group of potential participants with the intent of enhancing the overall quality of the transmission plan.

For more information regarding the stakeholder process utilized in the 2011 Black Hills TCPC planning process, including meeting notices, notes, presentations, and contact information, refer to the Stakeholder Outreach folder on the West Connect web site at:

http://www.westconnect.com/documents_results.php?categoryid=180

or the Transmission Planning folder on the Black Hills OASIS at

http://www.oatioasis.com/bhct.

B. Tri-State

Tri-State performs outreach with stakeholders as a standard part of its day-to-day business, consistent with its policy of planning in a coordinated, open, transparent, and participatory manner. As described in Rule 3627(g)(I), the stakeholders included fall into one of two categories, government agencies (including federal, state, county, and municipal agencies), and other stakeholders. To attempt to capture the potentially affected federal, state, county, and municipal agencies, Tri-State utilized existing contact lists developed for individual projects and developed new contact lists for projects where such lists did not already exist. For purposes of identifying the relevant agencies with respect to new projects that did not have an existing contact list, Tri-State employed generally a "buffer" of five miles surrounding the proposed facilities.

Federal agencies in the areas of the transmission projects included in Tri-State's 2012 Plan include: Bureau of Land Management, U.S. Forest Service, National Park Service, and Department of Defense. State agencies in the areas of the identified transmission projects include: Colorado State Land Board and associated Stewardship Trust Lands, and Colorado Division of Wildlife. For municipalities identified in the project areas, Tri-State included outreach to local officials and administrative staff such as the mayor, clerk, managers, planners, and economic development staff of each municipality. Similar to municipalities, county outreach included local officials and staff such as commissioners, administrators, attorneys, and various other staff such as planning and zoning director and managerial positions. In some instances, Tri-State also included certain county and municipal agencies such as parks and school districts.

Contacts for "other stakeholders" include lists developed through various transmission planning forums such as CCPG, other WestConnect planning groups, and those gathered for annual stakeholder meetings conducted by Tri-State. The "Other stakeholders" identified include a wide range of groups such as other utilities and Tri-

State Member-systems, energy and transmission project developers, environmental groups, non-governmental organizations, economic development organizations, advocacy groups, elected officials not included in the government agency list, and other stakeholders that have indicated a desire to participate in the planning process.

Consistent with Rule 3627(g), Tri-State has processes in place to allow stakeholders the opportunity to meaningfully participate in the planning process. The opportunity to participate can occur in a variety of forums, including participation in CCPG and other WestConnect transmission planning forums, meetings on individual projects, via available standard communication methods (i.e., e-mail, website, phone), and through Tri-State hosted planning meetings. Tri-State conducts at least one open public meeting each calendar year to gather stakeholder input to consider in its transmission plans, including alternative solutions to proposed projects.

In 2011, there were two separate meetings conducted at Tri-State's offices and made available through a webinar to discuss Tri-State's present Ten-Year transmission plans and allow for stakeholder input. On October 17, 2011, Tri-State held an open stakeholder meeting as part of its annual transmission planning process. This meeting included presentations on: Tri-State's Transmission Planning Process, Tri-State's 2011-2020 L&R Assumptions, Tri-State's Transmission Capital Construction Plan, Tri-State's Generator Interconnection Process ("GIP"), and an update on Tri-State's OATT. The meeting allowed for stakeholder participation and provided an opportunity for stakeholder questions and comments, consistent with the planning principles of FERC Order No. 890, Commission Rule 3627, and Tri-State's OATT and GIP.

A second stakeholder outreach meeting was held on December 2, 2011. This meeting focused primarily on Colorado transmission projects to be included in the 2012 Plan, consistent with the requirements of Commission Rule 3627. More than 400 e-mail invitations and 570 mailed invitations were sent to identified stakeholders as described previously. The individual mailings were directed generally to the governmental agencies that were in the vicinity of the project, and included copies of the relevant two page project description and map from the WestConnect and Tri-State websites. All invitations included information concerning how to access Tri-State's transmission planning website, which provides descriptions of all of the projects planned to be included in the 2012 Plan as well as a comment form and public meeting information.

Details of the October 17, 2011 and December 2, 2011 meetings, including the invitation list, attendees, questions and comments with Tri-State's responses, and presentation can be found at:

http://www.tristategt.org/transmissionPlanning/Stakeholder-outreach.cfm

These two meetings provided opportunities for stakeholders to ask questions, make comments, provide feedback on identified projects, and present information concerning proposed alternatives to such projects. Stakeholders were also able to submit written comments and questions via a dedicated e-mail address (TransmissionPlanning@tristategt.org), or via a public comment form available on Tri-State's website. For items that required follow up after the two meetings or after other written stakeholder input was received, Tri-State provided a written response. To facilitate preparation of the 2012 Plan report, submissions following the December 2, 2011 meeting were due by December 31, 2011. Responses to such submissions were provided by January 15, 2012.

In addition to these larger group stakeholder meetings addressing system-wide and Colorado-specific transmission plans, there have also been a number of meetings with specific government agencies in connection with individual proposed projects. The nature and timing of these individual outreach efforts was generally dependent upon the development status of the relevant project.

For example, Tri-State and Public Service conducted stakeholder outreach for the Lamar-Front Range Transmission Project which included numerous meetings with individual counties and economic development boards to inform them of the utilities' present plans and provide them an opportunity to provide feedback, including potential alternatives.

Tri-State also posted transmission planning information on its website, at: http://www.tristategt.org/TransmissionPlanning/

This website provided access to project descriptions and maps, project studies, public comment forms for feedback, and information regarding open stakeholder meetings with the public.

As required by Rule 3627(g)(III), on January 16, 2012 Tri-State provided notice to government agencies and other stakeholders via electronic mail concerning Tri-State's evaluation of alternative solutions identified during the stakeholder outreach process for Tri-State's 2012 Plan. While there were numerous comments received, including questions that Tri-State responded to, no government agency or other stakeholder proposed an alternative solution in connection with any of the transmission projects presented during the stakeholder outreach process. Accordingly, no stakeholder-identified alternative solutions are evaluated or included in Tri-State's 2012 Plan.

Tri-State confirms that, as required by Commission Rule 3627(g)(V), Tri-State has made its Ten Year Transmission Plan available to all government agencies and other stakeholders by posting it on Tri-State's Transmission Planning website and by notifying all such stakeholders of its availability. The final report is available on Tri-State's website at the following address:

http://www.tristategt.org/transmissionPlanning/puc3627_TransmissionProjects.cfm

C. Public Service

Public Service engages in public outreach on transmission projects in a variety of ways on an ongoing basis including through participation in transparent, open forum meetings with CCPG, in regular FERC Order No. 890 public meetings, and at project specific meetings held about planned infrastructure development. In addition, Public Service developed and implemented a comprehensive and robust Public Participation Program ("Program") to meet the requirements of Rule 3627. The primary methods for engaging stakeholders and soliciting their input were to hold transmission planning workshops and develop a website. The website was used to provide information to people who were unable to attend any of the workshops by providing online all the information that was available at those workshops. The link to the website is:

http://www.xcelenergy.com/About_Us/Transmission/About_Transmission/CPUC Rule_3627

Public Service decided to cast a wide net to ensure that all government agencies and other stakeholders both within its service territory and in proximity to its planned electric transmission projects were identified. The comprehensive list included approximately 1,500 stakeholders (including large commercial customers) from the following categories: elected officials (federal, state, county, city); affected government agencies (federal, state, county, city); planning organizations; economic development agencies; chambers of commerce; investor-, municipal- and consumer-owned utilities; renewable energy developers; large commercial customers; non-government organizations/associations; environmental non-government organizations; customer advocacy groups; interveners on past Public Service filings with the Commission; federal facilities; other stakeholders who desire to participate in the planning process; and the public.

A postcard was followed by a letter of invitation that contained more detailed information about transmission planning and Rule 3627. Public Service also sent email notices to members of various organizations such as the CCPG and state legislators. A media alert was sent to media markets to announce the workshops and provide information for attendance and participation. And finally, advertisements were run for two consecutive weeks in targeted newspapers for the transmission planning workshops, newspapers of record in county seats and other large daily newspapers including the *Denver Post*.

After the workshops, a follow up letter was sent inviting stakeholders to visit the company's website to view the virtual workshop and complete the online survey. This was followed by an email to those email addresses that were included in the stakeholder contact list. Later, a final email was sent encouraging participation in the virtual workshop and online survey before the survey was removed from the website in early October.

Two two-hour workshops were held in each location, with one conducted in the afternoon and the other in the evening. The workshops included registration, information material packets, open house and interactive feedback session with four display stations that were staffed by subject matter experts from Public Service. Recognizing that participants in the workshops may not be familiar with electric utility operations and systems, Public Service provided an overview of how the electric system operates from generator to customer meter as the opening section of the presentation. The emphasis was on the transmission system and how it functions. More time was spent on the transmission planning process and its drivers including collaboration with regional transmission entities, compliance requirements, and others.

This was followed by a presentation and a question and answer period. The presentation was designed to inform participants about Rule 3627, transmission planning, Public Service's planned electric transmission projects and the Program, and to help participants understand how they play a role in the transmission planning process and to illicit their input. This was followed by another interactive, open house session.

August 23, 2011 Workshops

Greeley – Clarion Hotel & Conference Center

The stakeholders in attendance included local elected officials, the public, a regional industry organization, renewable energy companies, industrial customers, a state agency, a land rights company, a non-profit environmental group, other electric utilities and a planning organization. The feedback received is summarized in the following categories:

- *Outreach*: Was outreach extended to all levels of elected officials? Does Public Service think there is a lack of interest in transmission planning as noted by the small number of stakeholders attending the workshop?
- *Regulatory Timing*: Local land use approvals generally are sought later in the permitting process and early feedback opportunities such as the workshop are appreciated. In addition, timing needs to be better coordinated with developers and permitting processes.
- *Ownership*: Clarification is needed to define developers and owners of wind generators and developers and owners of electric transmission lines.
- *Workshop/Outreach Feedback*: There could be greater coordination with the PUC approach process and the local land use/siting process so that local jurisdictions and/or property owners can provide input before a project is approved.
- *Rule-Making Process*: One attendee had participated in the rule-making process for Rule 3627 and recommended all planning efforts, regional and subregional, be included in this process so that projects within and outside the state that could affect Colorado be considered. Examples of other efforts include: CCPG process, WECC process and subregional planning influenced by FERC Order No. 1000.

- *Environmental Concerns*: Environmental and cultural considerations are closely aligned with the siting process and should be included in project budgets so that they are transparent. Adding these costs to the budget helps plan for avoidance and mitigation measures. These concerns are of great interest to environmental groups, who will always be a stakeholder in the process and should be included early on.
- *General Outreach*: Recommendation engaging Farm Bureau's and Cattlemen's Associations in outreach and planning efforts.
- *Landowner Compensation*: Other states have different compensation methods for landowners (annual annuity versus one-time payment) and some groups may advocate for a change in Colorado.

August 24, 2011 Workshops

Aurora -– Crowne Plaza Convention Center

Stakeholders in attendance at the afternoon and evening workshops represented state agencies, non-profit organizations, city and county offices, other energy companies, state elected officials, federal agencies, renewable energy companies, an energy consulting firm and an energy-focused law firm. The feedback received is summarized in the following categories:

- *Renewable Energy*: What are the various energy sources for the most recent projects completed by Public Service and has the company found economic ways to better integrate higher amounts of renewable energy in the system? What is the current percentage of energy created by solar and wind?

- *Renewable Energy Standard*: Colorado has a RES of 30 percent for investor-owned utilities by the year 2020 and it is understood that Public Service will meet that goal in advance of the deadline. Does Public Service view the deadline as a floor or a ceiling?
- *Storage*: One issue with renewable energy is the ability to store and transmit. There are viable and effective storage mechanisms for natural gas but renewable energy storage solutions are still in the infancy stage. What is the timeframe for finding a solution?
- *Capacity*: What is the interconnection capacity for each of the new projects? What is the power generation output for the new projects? The forecasted capacity looks to be greater than forecasted load so is Public Service planning to export energy? How many years of capacity will the new projects provide until additional capacity is needed?
- *Population Growth*: What are the population projections for the next 20 years and how will that affect electric transmission load?
- *Integration of Generation and Transmission*: Does Public Service integrate its generation and transmission project planning efforts?
- *Planning Life-Cycle*: Transmission planning for projects can take eight to ten years before an in-service date is realized which affects how developers can predict certainty for their projects.

- *Joint Ownership*: What percentage of transmission lines are jointly owned with other energy utilities in Colorado?
- *Exports and Emergency Back Up*: Some of these projects are close to state borders. Is Public Service planning to export energy or is the intent to provide emergency back-up both within and outside of the state?
- *Tower Design*: Will the Pawnee-Daniels Park project replace the lattice towers with tubular steel towers?
- *Workshop/Outreach Feedback*: The workshop was helpful, informative and Public Service staff was available and provided a better understanding of transmission planning. Public Service should keep trying to gather local input.

August 31, 2011 Workshops

Rifle - Garfield School District Administrative Offices

Stakeholders represented a federal agency, a city office, a private landowner, an oil field service company, an electric co-operative and the local school district. The evening workshop was canceled for lack of participation. The feedback received is summarized in the following categories:

- *Existing Corridors*: Public Service should co-locate transmission lines whenever feasible.
- *Visual Resources*: Minimizing the impact to visual resources should be considered in transmission planning criteria.
- *Underground*: Is it possible to install the transmission lines underground?
- *Health Effects*: Do transmission lines have a negative effect on the ozone and will the people living near transmission lines contract leukemia?

- *Eminent Domain*: Private landowners have the right to use and develop their own natural resources and Public Service should not pre-empt that right by installing their projects on private land.
- *Electric and Magnetic Fields*: EMF can affect the health of those who reside near transmission lines and most of the impact is to agricultural and undisturbed areas but perhaps the lines should be located in more populated areas since that is where the demand is located.
- *Airport*: Any installation of a transmission line near the Garfield County Airport should be done in cooperation with the FAA to ensure avoidance with airplane approaches and aviation instruments.
- *Workshop/Outreach Feedback*: It is recommended that Public Service hold public meetings when proposed locations and alternatives are selected. In general, attendees were appreciative of the opportunity to provide input for transmission planning.

At the request of a representative from City of Aurora government who attended one of these workshops, Public Service representatives attended an Aurora City Council subcommittee meeting on planning to present them with information on the proposed Pawnee Daniels Park and Harvest Mile Projects. The subcommittee has requested that Public Service return to a working session when more detailed project information is available.

One stakeholder requested that information about the High Plains Express ("HPX") Project be included in this filing. The HPX concept consists of new high-voltage transmission connecting Wyoming, Colorado, New Mexico and Arizona. The first stage assessment indicated that the project was feasible. A second stage assessment was completed in early 2011 and was performed by participants including seven utilities, two transmission development companies and two state infrastructure authorities (Wyoming and Colorado). This stage evaluated five transmission alternatives ranging in length from 1,450 to 2,250 miles, with capacity ranges from 1600 to 8000 MW and with cost ranges from \$3.4 to \$8.3B. HPX would support renewable energy development, enhance system reliability, and coordinate with other high-voltage transmission projects in the HPX footprint. Stage 3 is focusing on evaluating relevant regulatory developments, monitoring economic drivers and forming strategies for moving the HPX initiative forward.

In addition, Public Service has been working on outreach with Tri-State on the Lamar Front Range Transmission Project. Outreach efforts on this specific project began in the second quarter of 2011 and have included meetings with numerous stakeholders. Representatives from both companies have met with government representatives from eleven (11) counties in the project area to provide project overviews and garner feedback. The Lamar Front Range Project would coordinate with portions of the HPX Project within Colorado. Public Service and Tri-State are continuing work on finalizing the scope for this project. Studies are in progress and proposed modifications to the termination points are being evaluated in an open and transparent stakeholder process through CCPG.

2012 CPUC Rule 3627

Appendices