Colorado Long Range Transmission Planning Study

2005 - 2015

Colorado Long Range Transmission Planning Group

Aquila Networks
Colorado Springs Utilities
Platte River Power Authority
Public Service Company of Colorado (Xcel Energy)
Tri-State Generation and Transmission
Western Area Power Administration

July 2006

Table of Contents

Appendices

I. Executive Summary

The purpose of the Colorado Long Range Transmission Planning Group (CLRTPG) is to provide a forum for electric load-serving entities (LSE's) in the State of Colorado to jointly explore the potential for the development of a coordinated transmission network. Current forecasts predict that over the next ten years, the demand for power will grow about 25% in Colorado's Front Range. To meet such a demand, approximately 4000 MW of new generation resources will have to be acquired and additional high-voltage transmission will be needed to deliver the power to the load. This report identifies potential transmission plans that can accommodate that generation using system models that represent the 2015 time frame.

In September 2005, Tri-State Generation and Transmission Association, Inc. (TSGT) announced its intention to pursue the development of a new 1200 MW coal-fired generation facility at the Holcomb Generating Station in Garden City, Kansas. In February 2005, PSCo released its "All-Source" Request for Proposals (RFP), seeking over 2500 MW of new resources through 2013[1]. TSGT and PSCo have the majority of the resource need for the state, but Platte River Power Authority (PRPA) and Colorado Springs Utilities (CSU) also have some long-term needs. Recently, the region near Lamar, Colorado has been an area of interest for new generation development. As a result, the CLRTPG also explored the potential for integrating an additional 600 MW in the vicinity of Lamar.

Due to the geographic dispersion of the projected resources, the transmission studies were divided into two areas: "Southern" and "Northern". The Southern studies developed alternative transmission plans to accommodate potential southern resources such as the TSGT plans for Holcomb, the PSCo Comanche Unit #3 Project, and recent interest in resource development in the vicinity of Lamar. The Northern studies developed plans to accommodate potential northern resources, including many of the PSCo RFP bids. Figures 1 through 6 show the transmission plans developed from this study. The alternatives are also highlighted on Colorado system maps in Appendix D.

Figures 1 through 4 are the transmission alternatives developed for the Southern resource scenarios. Figures 1 and 2 describe the two alternatives developed for a "Standard" Southern resource scenario, which modeled 1200 MW at Holcomb and some other anticipated southern Colorado resources. Figures 3 and 4 describe the transmission alternatives for an "Expanded" Southern resource scenario, which modeled an additional 600 MW of generation development near Lamar. Figures 5 and 6 describe the two transmission alternatives that were developed for the Northern resource scenario.

Estimated overall costs for each of the transmission plans are shown in Table 1. The costs are broken into "Primary Backbone", "Secondary Bulk" and "Regional" categories. The primary backbone transmission as defined in this report consists of the high-voltage facilities 230 kV and above, and in the area of study (Northern or

[1] The PSCo RFP window went to 2013, but this study evaluated resources through 2015.

Southern), required to provide a transmission path from new generation resources to the major load centers. Regional facilities are those that were required based primarily on regional load growth, and not necessarily influenced by the implementation of additional resources. The Secondary Bulk category includes higher voltage facilities (115 kV to 230 kV range), which are needed to deliver power from the primary backbone system to the load-serving systems[2]. All cost approximations are shown in Millions of 2006 dollars and are considered to be "scoping" type estimates, generally considered to have +/- 30% accuracy.

Table 1 Scenario Transmission Costs (in $Millions)

	Standard Southern 345 kV	Standard Southern 500 kV	Expanded Southern 345 kV	Expanded Southern 500 kV	Northern Alt 1	Northern Alt 2
Primary Backbone	$966	$1093	$1058	$1186	$177	$183
Secondary Bulk	$480	$487	$471	$475	$1,292	$1268
Regional	$253	$253	$254	$254	$253	$253
Total	**$1,699**	**$1,833**	**$1,783**	**$1,915**	**$1,722**	**$1,704**

Table 2 breaks down the costs for each alternative by entity.

Table 2 Transmission Costs by Entity (in $Millions)

Entity	Standard Southern 345 kV	Standard Southern 500 kV	Expanded Southern 345 kV	Expanded Southern 500 kV	Northern Alt 1	Northern Alt 2
PSCo	$471	$471	$473	$478	$521	$522
PRPA	$65	$65	$65	$65	$65	$65
CSU	$7	$13	$13	$13	$7	$7
TSGT	$965	$1,092	$1,040	$1,166	$938	$919
WAPA	$178	$178	$178	$179	$178	$178
Aquila	$14	$14	$14	$14	$14	$14
TOTAL	**$1,699**	**$1,833**	**$1,783**	**$1,915**	**$1,722**	**$1,704**

[2] The Secondary Bulk for the Southern alternatives includes some transmission that is considered Primary Backbone for the Northern alternatives. Also, the Secondary Bulk for the Northern alternatives includes transmission that is considered Primary Backbone for the Southern alternatives.

Figure 1: Standard Southern Resource Scenario - 345 kV Alternative

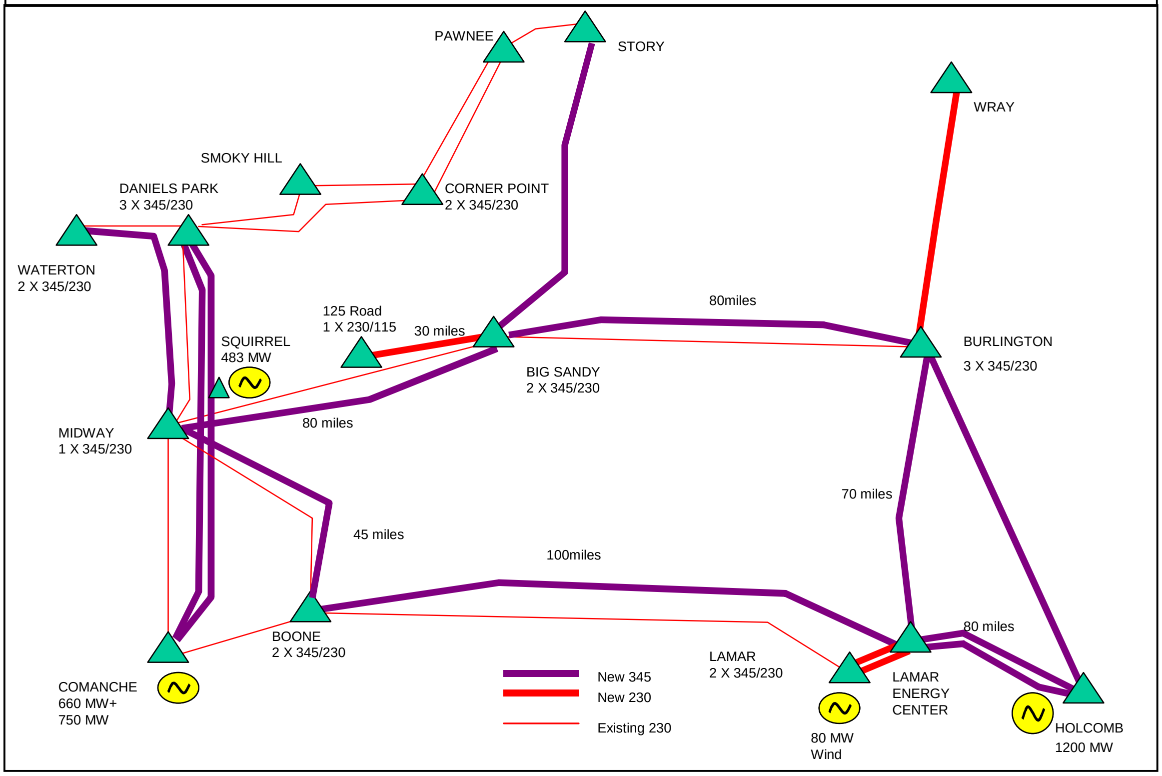


Figure 2: Standard Southern Resource Scenario - 500 kV Alternative

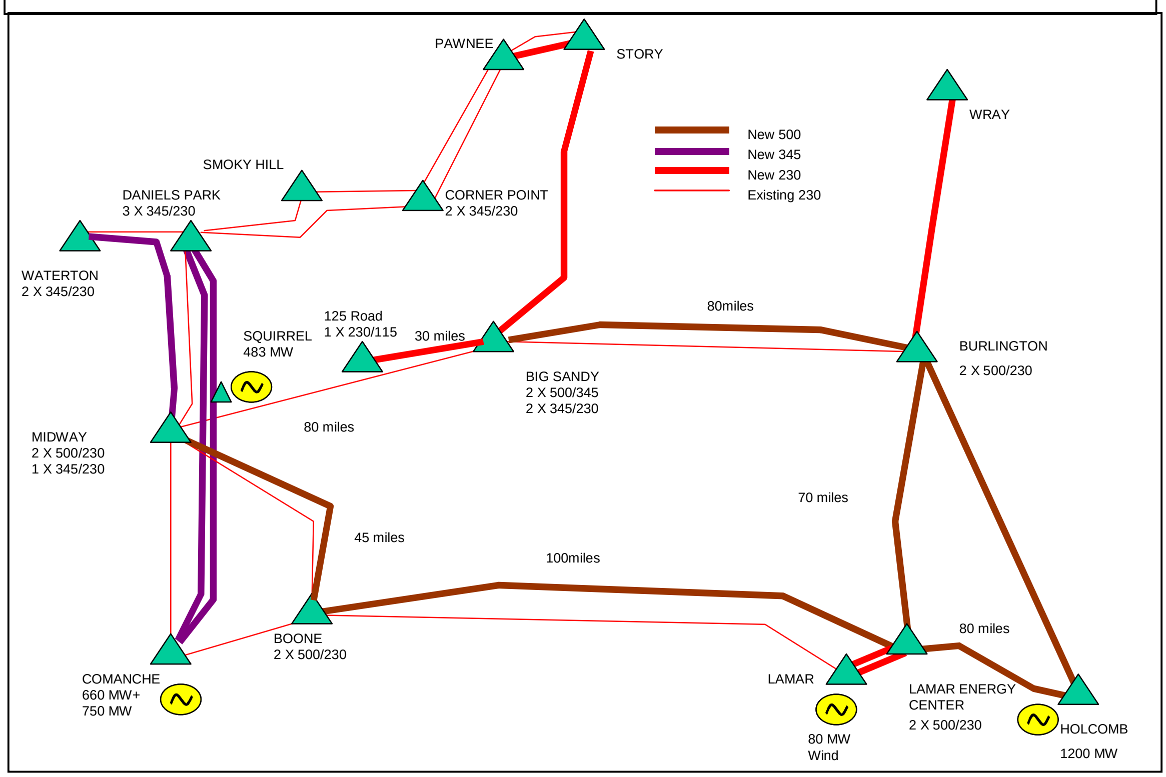


Figure 3: Expanded Southern Resource Scenario - 345 kV Alternative

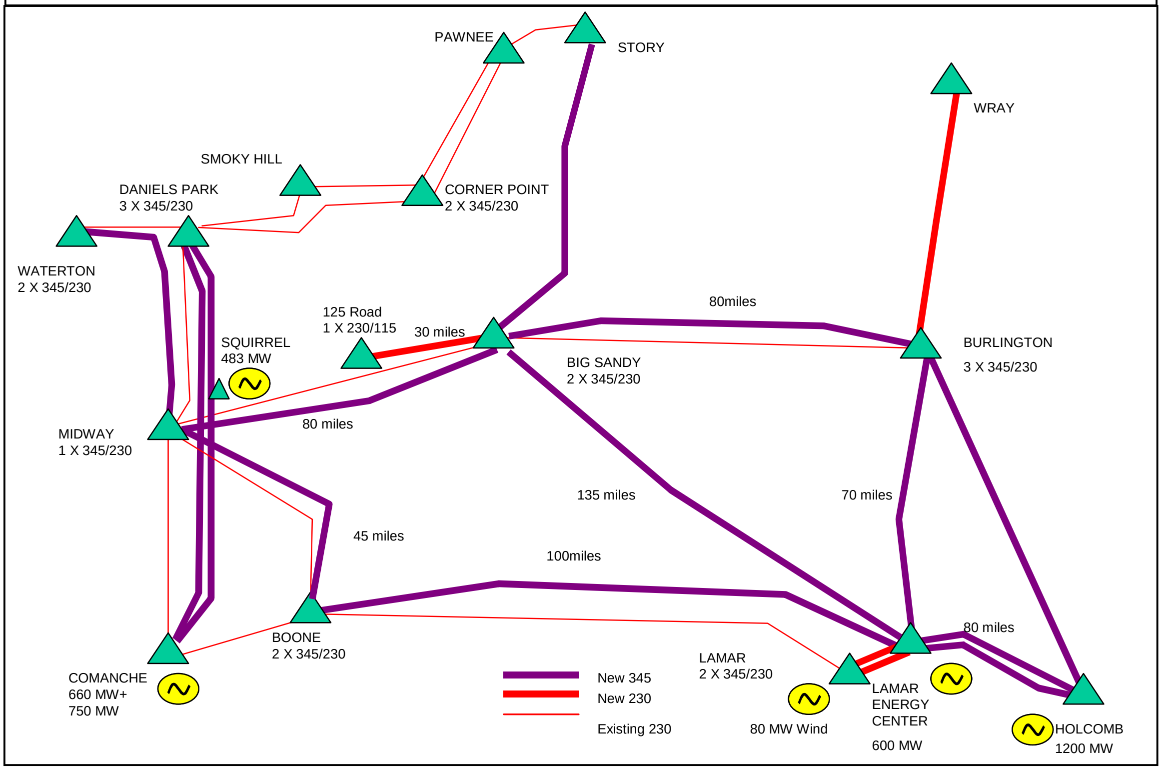


Figure 4: Expanded Southern Resource Scenario - 500 kV Alternative

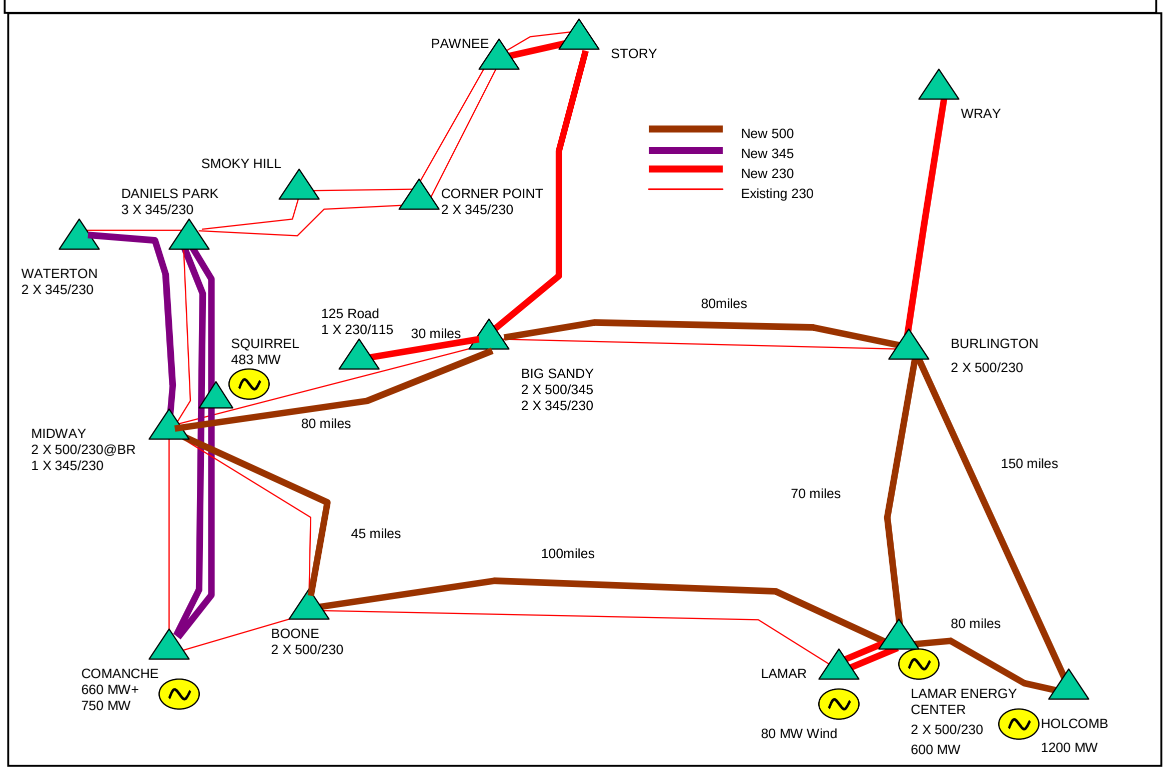


Figure 5 Northern Resource Scenario - Alternative 1

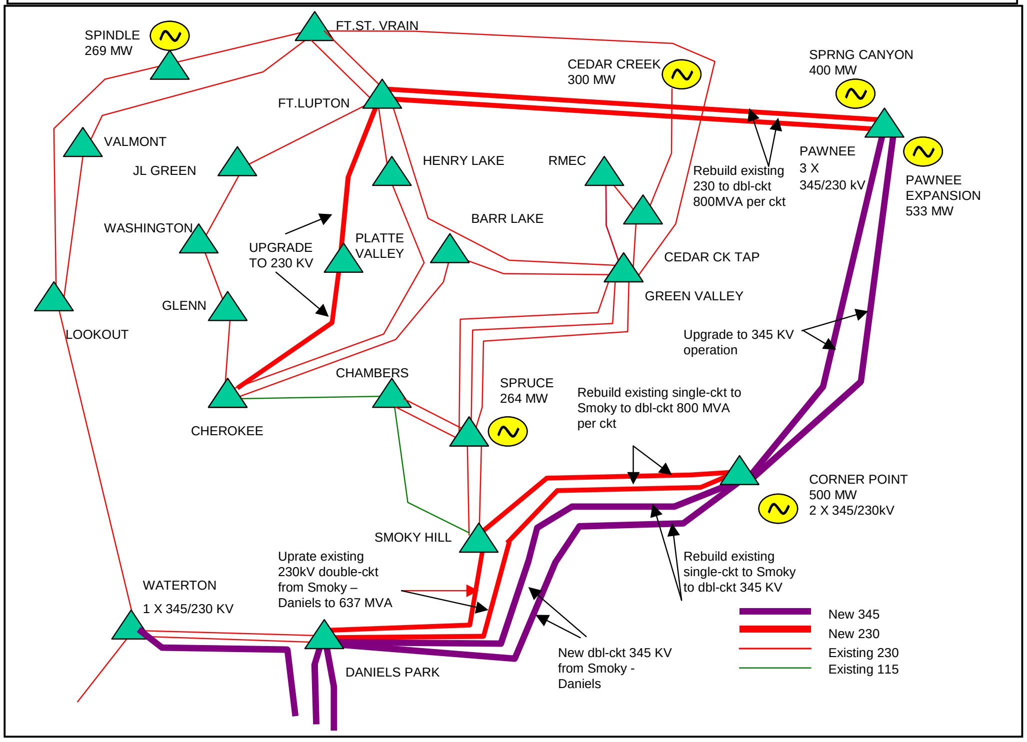
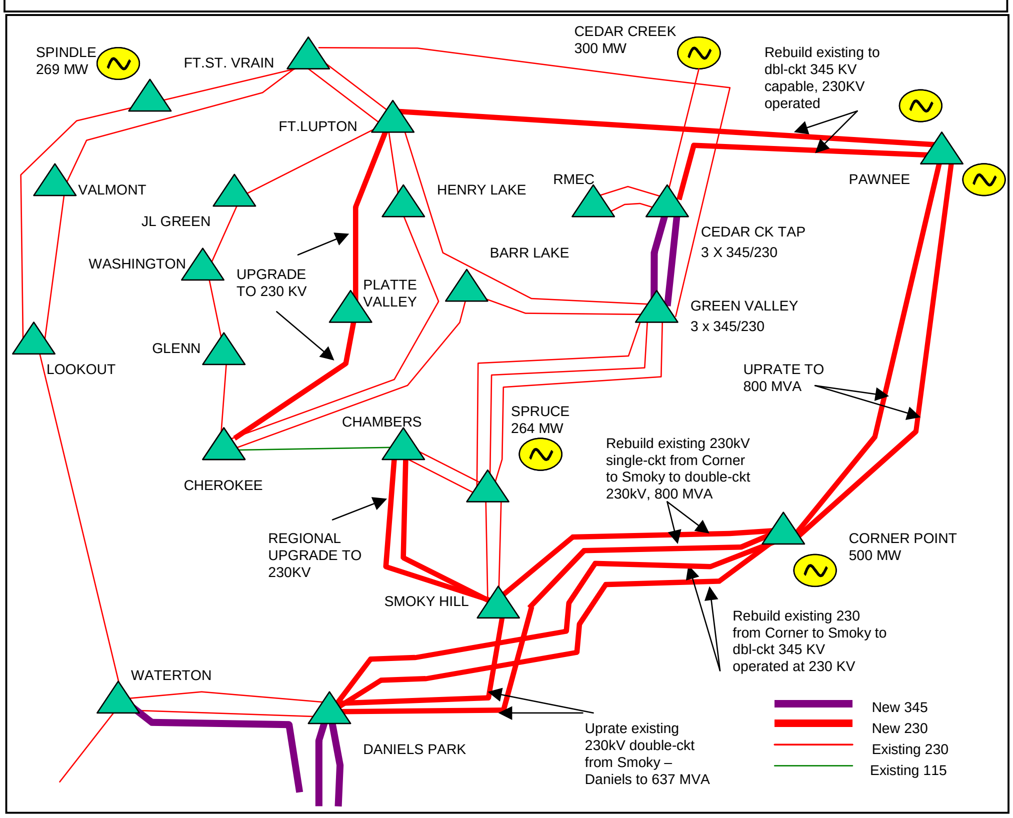


Figure 6 Northern Resource Scenario - Alternative 2



II. Scope

A. Purpose

The goal of the CLRTPG is to develop long-range transmission plans that fit the future needs of the state of Colorado given the anticipated load growth, collective knowledge of the transmission system planners, and potential sites for new generation resources. The transmission plans should result in robust, backbone transmission systems that eliminate the often piece-meal approach to transmission. Transmission Planners must formulate strategies to develop and improve the transmission system in the State of Colorado to support the anticipated load growth and resource requirements. To help assure that those transmission additions complement the needs of all LSE's and future generation resources throughout Colorado, the CLRTPG was formed to jointly develop ten-year regional plans for the implementation of high-voltage transmission in Colorado.

B. Background

The CLRTPG was initiated in January 2004 as a sub-committee of the Colorado Coordinated Planning Group (CCPG), whose purpose is to facilitate open discussion and joint planning efforts for the transmission in the Rocky Mountain Region (primarily Colorado and Wyoming). The first study report was issued in April 2004. In September 2005, TSGT announced its intention to pursue the development of a new 1200 MW coal-fired generation facility at the Holcomb Generating Station in Garden City, Kansas. TSGT recognized that to deliver this power to customer loads in the Western Interconnection would require hundreds of miles of high-voltage transmission into eastern Colorado. PSCo received approval from the Colorado Public Utilities Commission in January 2005 to construct an additional 750 MW coal-fired unit at the existing Comanche site near Pueblo. In February 2005, PSCo released an "All-Source" solicitation for new supply and demand-side resources. The solicitation included three Requests for Proposals (RFP's), totaling approximately 2500 MW of additional resources by the year 2013. With plans for 750 MW of that amount to be delivered from it's planned Comanche Unit #3 Project in 2010, the company would still need approximately 1750 MW by 2013.

Due to the future resource plans of TSGT and PSCo, it was determined that the CLRTPG should reconvene. An open invitation to all stakeholders desiring to participate in this effort was posted on the Rocky Mountain Area OASIS (RMAO)[3] in mid-September of 2005, and the Group met to kickoff a new round of studies on September 15, 2005[4]. The first half of the meeting was attended by all interested stakeholders. Many provided input regarding future generation scenarios to be considered for this study. The second half was limited to Transmission Providers (TP's) only. Studies were performed by those TP's that signed a non-disclosure

[3] www.rmao.com; OASIS is an acronym for Open Access Same-Time Information System
[4] Meeting invitation is included as Appendix A

agreement, in accordance with FERC rules. Updates were provided to all stakeholders at regularly scheduled CCPG meetings.

C. Principles

In addition to the system knowledge and expertise of the planners, the following basic planning philosophies were used as the transmission solutions were developed:

- Adhere to NERC/WECC Reliability Standards and Criteria
- Develop transmission that could accommodate a variety of generation placement (or options),
- Consider the needs and interests for Colorado load-serving entities by conducting joint planning,
- Manage issues associated with parallel low voltage networks,
- Maximize use of existing transmission corridors where prudent,
- Establish new transmission corridors,
- Establish high-voltage transmission corridors,
- Construct for higher voltage operation where appropriate,
- Plan corridors to allow for future circuits where appropriate,
- Acquire additional rights-of-way when possible for future transmission,
- Build new transmission adjacent to existing substations to allow for future sectionalizing.

D. Participants[5]

- Aquila Networks (Aquila)
- Arkansas River Power Authority (ARPA)
- Colorado Springs Utilities (CSU)
- Platte River Power Authority (PRPA)
- Tri-State Generation and Transmission (TSGT)
- Western Area Power Administration, Rocky Mountain Region (WAPA-RMR)
- Xcel Energy/ Public Service Company of Colorado (PSCo)

The preliminary transmission solutions developed for regional issues are not meant to imply any specific plans or commitments by participating entities, but are meant to gain an understanding of the relative magnitude in terms of quantity and cost of the localized load-serving solutions that might ultimately be implemented should the forecast load growth occur.

[5] Transmission Providers that signed a Non-Disclosure Agreement

III. Study Methodology and Development

A. Resource Needs

To assist with the modeling of resource needs for the study, each entity prepared a Load and Resource (L&R) spreadsheet to summarize forecasted loads, capacity resource plans, and reserve margins. Every L&R balance sheet shows a ten-year resource need. The individual resource requirements were added together to achieve the total resource requirement. Table 3 summarizes the resource needs for each entity. According to the L&R data, a total of approximately 4000 MW of additional generation resources will be needed by 2015, which includes a capacity reserve margin. The detailed L&R spreadsheets that were used for Table 3 are included in Appendix B.

Table 3 Front Range Resource Need for 2015

ENTITY	RESOURCE NEED (MW)
PSCo	2666
TSGT	1126
CSU	87
PRPA	134
Total	**4013**

The 2004 study showed a resource need of 2750 MW. The increase in resource need for this study is due primarily to a higher TSGT load forecast.

B. Resources

Table 4 describes the generation resources that were used for this study. As stated previously, the focus of the study was to evaluate transmission plans that could accommodate the planned Holcomb project, and potential PSCo RFP projects. At the time this study was initiated, the only specific planned resource for PSCo was the 750 MW Comanche Unit 3 Project, which is expected to be in service in 2010. Most of the other PSCo resources used for this study were based on RFP bids that were identified to proceed with system impact studies[6]. These included the Lamar Wind, Cedar Creek, Spindle, Spruce, and Squirrel projects. Finally, three sites were chosen based on historical interest from generator interconnection requests. These include the Spring Canyon, Pawnee, and Corner Point projects.

Platte River identified an additional unit at Rawhide as a potential location for additional generation.

[6] The proposed PSCo resources included in this study were based on information gathered from the Company's 2003 Least Cost Planning process. These resource studied were meant to represent interconnection sites that tend to be locations of interest and may not represent the final selection of resources.

Table 4 New Resources Modeled for the 2015 Studies

Studied Resources			Scenario Dispatch (MW)		
Project	**Interconnection**	**Utility**	**Standard Southern**	**Expanded Southern**	**Northern**
Holcomb		TS	1200	1200	700
Comanche Unit 3	Comanche	PSCo	750	750	600
Squirrel	Comanche – Daniels Park 345	PSCo	483	483	0
Lamar Wind	Lamar	PSCo	80	80	0
Cedar Creek	RMEC – Green Valley 230 kV	PSCo	30	30	300
Spruce	Blue Spruce Energy Center	PSCo	264	264	264
Spindle	St.Vrain – Valmont 230 kV	PSCo	269	269	269
Spring Canyon	Pawnee	PSCo	40	40	400
Corner Point	Pawnee – Smoky Hill 230 kV	PSCo	0	0	500
Pawnee Expansion	Pawnee	PSCo	533	533	533
Rawhide E	Rawhide	PRPA	80	80	80
Lamar Energy Center	Lamar	Indepen-dent	0	600	0
Total			**3729**	**4329**	**3646**

C. Scenarios

Based on the geographic locations of the resources listed in Table 4, the Group determined that studies should be divided into Northern and Southern scenarios. The Southern scenarios would model high generation in southern half of the state, with heavy power transfers to the north. These scenarios could be used to develop basic transmission plans to accommodate Holcomb and other southern resources. Two southern resource scenarios were modeled. One (Standard) scenario modeled the southern resources that would be required to meet the resource need described in Table 3. The other (Expanded) scenario modeled an additional 600 MW at the Lamar Energy Center to evaluate interests expressed by other parties to develop resources in that area.

A single Northern resource scenario was used to model potential generation resources in the northern half of the state and heavy power transfers to the south. This northern scenario was used to develop transmission plans to accommodate the majority of the PSCo RFP and Platte River resources. The last three columns of Table 4 show how the resource additions were dispatched for the three scenarios.

D. Base Case Development

1. Base Models

The study models were developed using an approved WECC 2014 heavy summer case. The case was modified to model the forecasted peak summer 2015 loads for the Rocky Mountain Region.

Significant elements of the case modeling are listed below.

a) The PSCo forecast used for these cases was an April 2005 Peak Demand Forecast at a 90% probability factor (7891 MW Native Load w/DSM).
b) To model a 16% planning reserve, power was imported from outside the Colorado area. Interchange from the Western control area to the PSCo control area was kept at around 1050 MW.
c) Transmission elements developed by the participants were implemented into the appropriate study models. Some minor modeling changes were also implemented into the cases.
d) Models of existing generators of similar size were used as a basis to represent the new scenario generators. For example, the two Holcomb 600 MW plants were modeled after the Laramie River Station units and Comanche 750 MW coal units were modeled using a Four Corners 750 MW coal unit as proxy. Most of the scenario generation was not fuel-type specific since the intent of the study was to focus on long-term transfer of power to the demand.

2. Load & Resource Modeling

a) TSGT

TSGT's load forecast is from the 2005 update of the TSGT 2004 Power Requirements Study (PRS) Forecast. It was used in TSGT's 2005 Least-Cost Resource Plan, and submitted to the Colorado Public Utilities Commission in October 2005. The "High Economic" scenario was used for this study. The forecast development process analyzes scenarios that account for various economic conditions and normal weather. The High Economic scenario forecast is the set of future loads that are one standard-deviation above Base forecast load levels. Loads were conservatively set at Member-coincident peak demand levels. Some adjustments to the loading in previous study models were made to reflect significant increases in some area loads reported after the forecast was published. This represents effects of high load growth in certain areas.

To maintain existing capacity margins in the 2015 timeframe, TSGT must add new resources to account for the load forecast, plus some generating capacity must be set-aside for reserves and additional growth. For the purposes of this study, operating reserve requirements were estimated to be 15%. This results in the need for about 175 MW of additional TSGT reserve capacity, making the total new resource requirement 1343 MW. Other resources also contribute to reserve capacity, and forecasts show the new resource requirement to be 1126 MW in 2015, as shown in the TSGT Load and Resource Table in Appendix B.

b) PSCO

The PSCo load models are based on a coincident peak demand value that is produced by the PSCo forecasting group. This peak demand value is based on weather, economics and resale probability factors. Native Load demand is then allocated to load buses based on historical (actual SCADA data) coincident peak demands at the individual PSCo load buses, and accounts for future substation additions.

c) CSU

The CSU summer peak demand forecasting methodology integrates weather, monthly electric sales and other variables. The forecasts are estimated for historical demands that occurred when the temperature was over 91 degrees on non-holiday weekdays from 1992-2005. The weather variables in the summer peak demand equations include maximum temperature and the sum of cooling degree-days for the peak day and the preceding two days. The first variable captures the impact of peak temperature while the second variable captures the heat build-up over several days. CSU monthly sales variables are used to explain the growth in peak and energy in the historical data and to translate the sales forecast into growing peak demand in the future. To account for billing cycles, both current month and the following month's sales are included (such as both July and August sales for a July peak demand).

d) PRPA

In September 2005 when the work began for this study, Platte River’s most recently approved forecast was the August 2004 Official Loads & Resources Forecast. Using the High Forecast, Platte River’s summer peak for native load is projected to increase 41% from 617 MW in 2005 to 867 MW in 2015 (without losses). The High Forecast is based on population and employment growth being 50% greater than projected in the Base Forecast. By comparison, the Base Forecast is 756 MW (without losses) in 2015. Platte River uses its High Forecast for transmission planning.

Platte River’s planning reserve requirement for generation consists of calculations that include the loss of its largest unit. Platte River projects the need for an additional peaking unit at its Rawhide Energy Station in 2010, and another new resource in 2013. The 2013 resource might be either purchased power or ownership in a new unit somewhere.

e) Aquila

Aquila Networks used their latest peak demand forecast for this study. As previously stated, Aquila loads are not shown as PSCo's responsibility for 2015 in the L&R sheet, as the current supply contract expires in 2011. Aquila loads were modeled as served from excess generation within the PSCo system.

E. Plan Verification

Sensitivity analyses were performed on the scenarios to determine the adequacy of the initially proposed transmission components and to evaluate alternatives to the proposed transmission. Single contingency (N-1) analyses were run on the cases to identify remaining facility overloading or voltage issues. Participants identified regional issues on their facilities and provided modeling updates and system enhancements to remedy the contingency violations. The scenario cases were revised to reflect the modifications and additions. These steps were repeated until the scenario cases showed no major load serving or power transfer issues in the Front Range.

Dynamic stability was found to be the limiting issue for the addition of the Holcomb plants. Numerous stability studies were run on these scenarios. All faults studied were 345 kV or 500 kV transmission line or bus faults with subsequent tripping of an associated transmission line. Faults modeled were 3 phase faults lasting 4 cycles with the subsequent tripping of the breakers at both ends of the faulted line.

F. Transmission Costs

The overall transmission investment estimates in this report represent a combination of budgeted and unbudgeted projects. Projects that have been contemplated through a study participant's normal budgeting process were included in the CLRTPG overall investment estimate as budgeted by the participant. However, additional projects for which a detailed cost estimate had not been prepared were estimated utilizing generic unit costs. The intent was to gain insight into the magnitude of transmission investment that could be expected in the ten-year timeframe to support the anticipated level of generation expansion.

The origin for most of the unit costs was the TSGT Cost Estimating guide developed and refined for the Holcomb Project Study. This set of unit costs represents 2006 dollars. The list of unit costs was also expanded to include some facilities that were not a part of the original Holcomb study. The list of unit costs estimates can be found in Appendix E. Again, all costs are in present year (2006) dollars and are considered to have +/- 30% accuracy. Estimated transmission line mileages shown in this report will change as actual preferred routes are developed.

IV. Results

A. Backbone vs. Regional Issues

Preliminary analysis of the primary backbone transmission additions revealed regional deficiencies that were due to local load growth as well as those due to the implementation of new generation. In most cases, those issues existed for all scenarios studied. To evaluate only the high-voltage requirements for the additional generation resources, the regional issues had to be alleviated. In some instances, participants evaluated and identified remedies for expected concerns on their systems. However, the models representing the system ten years into the future revealed other problems that had not been previously identified. Therefore, a great deal of effort was taken to develop potential solutions for those issues.

The transmission solutions developed for regional issues are not necessarily specific plans or commitments by associated entities. They are meant to gain an understanding of the relative magnitude in terms of quantity and cost of the localized load-serving solutions that might ultimately be implemented should the forecasted load growth and associated resource expansions occur.

B. Standard Southern 345 kV Alternative

1. Primary Backbone Transmission Description

The Primary Backbone transmission for this scenario is shown in Table 5. A detailed list of all regional changes for this scenario can be found in Appendix C in the Transmission Infrastructure Sheet.

Table 5 Primary Backbone Transmission for the Standard Southern 345 kV Alternative

Description	Entity	Miles	Cost
Big Sandy - Story 345 kV Line	TSGT	70	$50,230,000
Big Sandy 345/230 kV Transformers	TSGT	0	$26,227,000
Big Sandy-Burlington 345 KV Line	TSGT	80	$57,951,000
Big Sandy-Midway 345 KV Line	TSGT	85	$60,858,000
Boone 345/230 KV transformers	TSGT	0	$26,227,000
Boone-LEC 345 kV Line	TSGT	100	$72,109,000
Boone-Midway 345 KV Line	TSGT	45	$37,601,000
Burlington - Holcomb 345 kV Line	TSGT	150	$101,179,000
Burlington - LEC 345 kV Line	TSGT	70	$54,667,000
Burlington 345/230 kV Transformers	TSGT	0	$26,227,000
Holcomb - LEC #1 345 kV Line	TSGT	80	$63,011,000
Holcomb - LEC #2 345 kV Line	TSGT	80	$63,011,000
LEC 345/230 kV Transformers	TSGT	0	$31,288,000
Midway 345 kV Tie Line	TSGT	0	$7,378,000
Midway 345/230 KV Transformer	TSGT	0	$16,562,000
Burlington - Wray 230 kV Line	TSGT	60	$22,562,000
Lamar - LEC #1 230 kV Line	TSGT	20	$19,439,000
Lamar - LEC #2 230 kV Line	TSGT	20	$19,439,000
125Road 230/115 kV Substation	TSGT	0	$4,514,000
125 Road-Big Sandy 230 kV Line	TSGT	30	$22,430,000
Comanche-Daniels 345 kV line, subs, xfmrs	**PSCo**	115	$152,000,000
Midway-Waterton 345 kV line, subs, xfmrs	**PSCo**	9	$23,560,000
Waterton 230/115kV autos 1&2 Replacement	**PSCo**	0	$7,240,000
Total		**1014**	**$965,710,000**

2. Studies

Initial benchmark studies modeled potential southern resources including 1200 MW of generation at Holcomb. The preliminary 345 kV transmission plan is shown in Figure 7. Some performance inadequacies were found with this transmission configuration. Both powerflow and stability studies determined that the transmission would not be sufficient to reliably accommodate southern system generation. Stability analysis showed that a fault on the Lamar Energy Center (LEC) - Big Sandy 345 kV line with subsequent tripping of the line resulted in all Holcomb generation injected into Lamar and Burlington. This disturbance caused the Holcomb units to go unstable and trip off line. Therefore, subsequent alternatives evaluated the implementation of additional transmission.

Figure 7: Preliminary Southern 345 kV Transmission Configuration

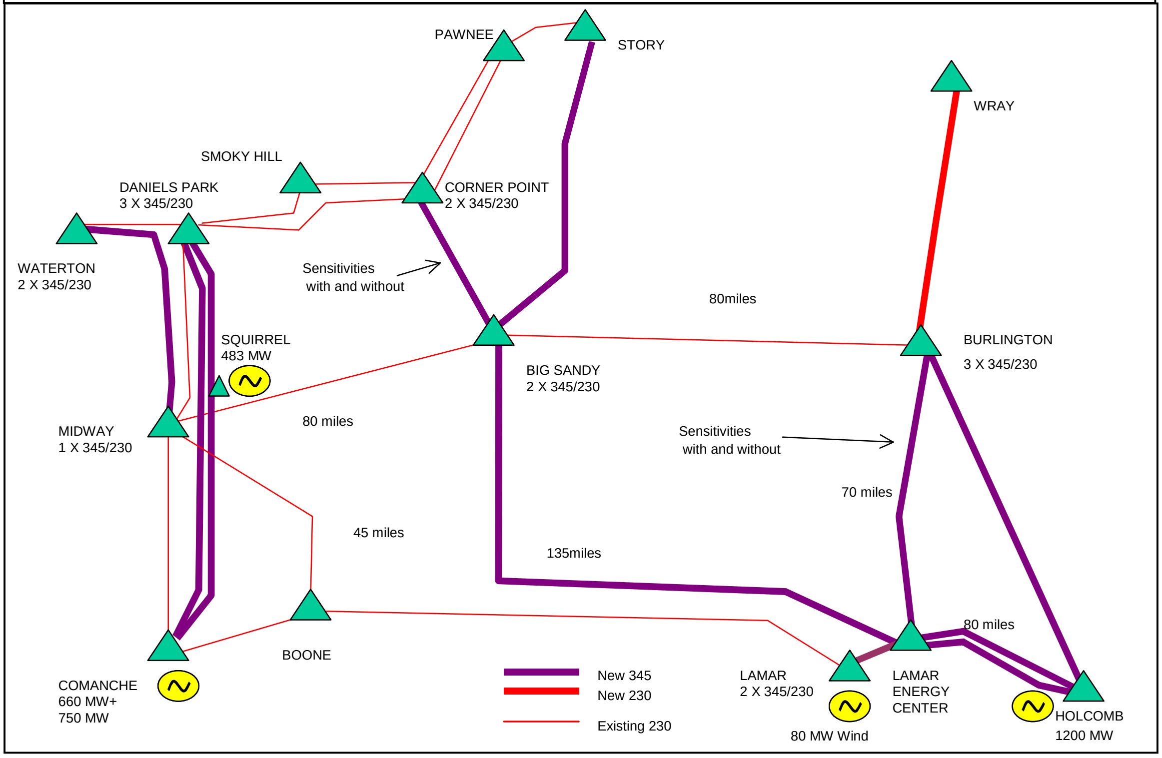


Figure 8 shows the next transmission configuration studied. This configuration modeled 345 kV line from LEC to Boone to Midway instead of from LEC to Big Sandy. This design also added two new 345 kV substations and 90 miles more transmission than the preliminary configuration in Figure 7. Powerflow analysis did not show any performance deficiencies with the configuration in Figure 8. However, stability studies showed problems with this configuration. A fault on the LEC - Boone 345 kV transmission line had the same instability problems as a fault on the LEC - Big Sandy line in the transmission configuration depicted in Figure 7.

To make the system transiently stable, a 345 kV transmission line was added from Burlington to Big Sandy as shown in Figure 9.

Stability analysis of the transmission configuration in Figure 9 indicated that the Holcomb units would be stable for a three-phase fault on any of the new transmission lines. Therefore, this transmission scheme appeared to be an adequate 345 kV transmission system to accommodate the modeled Standard Southern resource scenario.

Figure 8: Southern 345 kV;
Replace LEC – Big Sandy with LEC – Boone – Midway 345

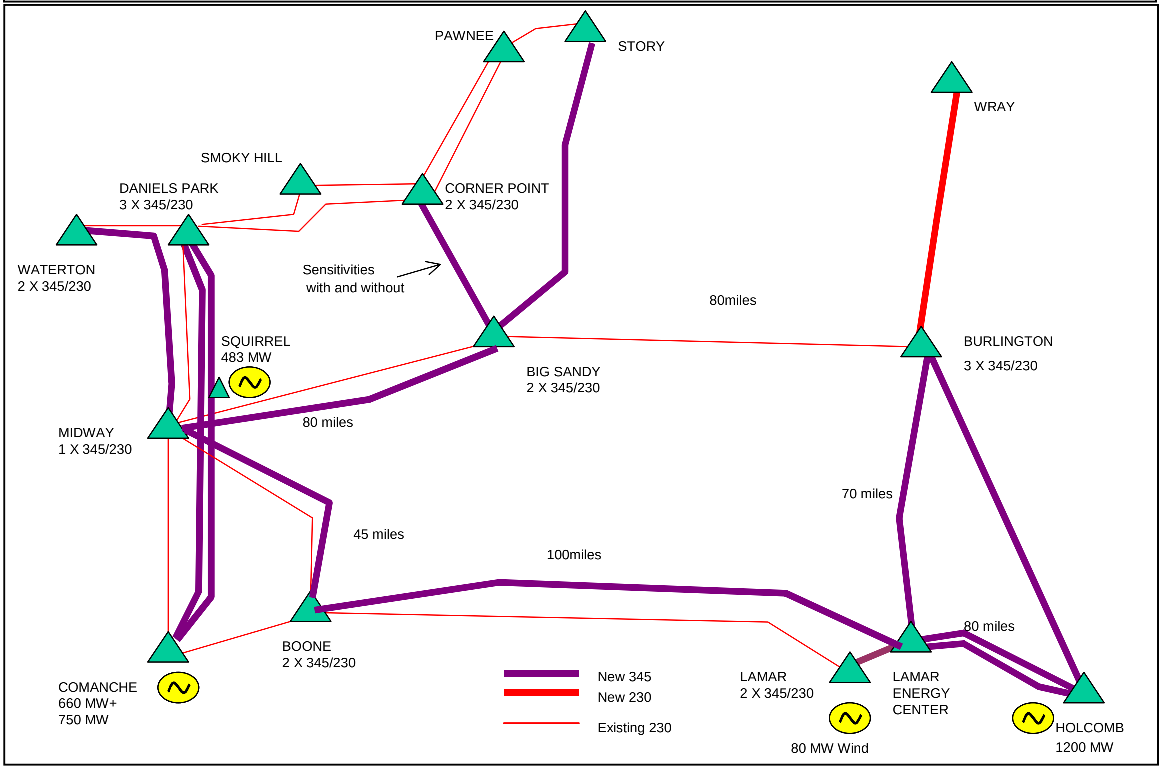
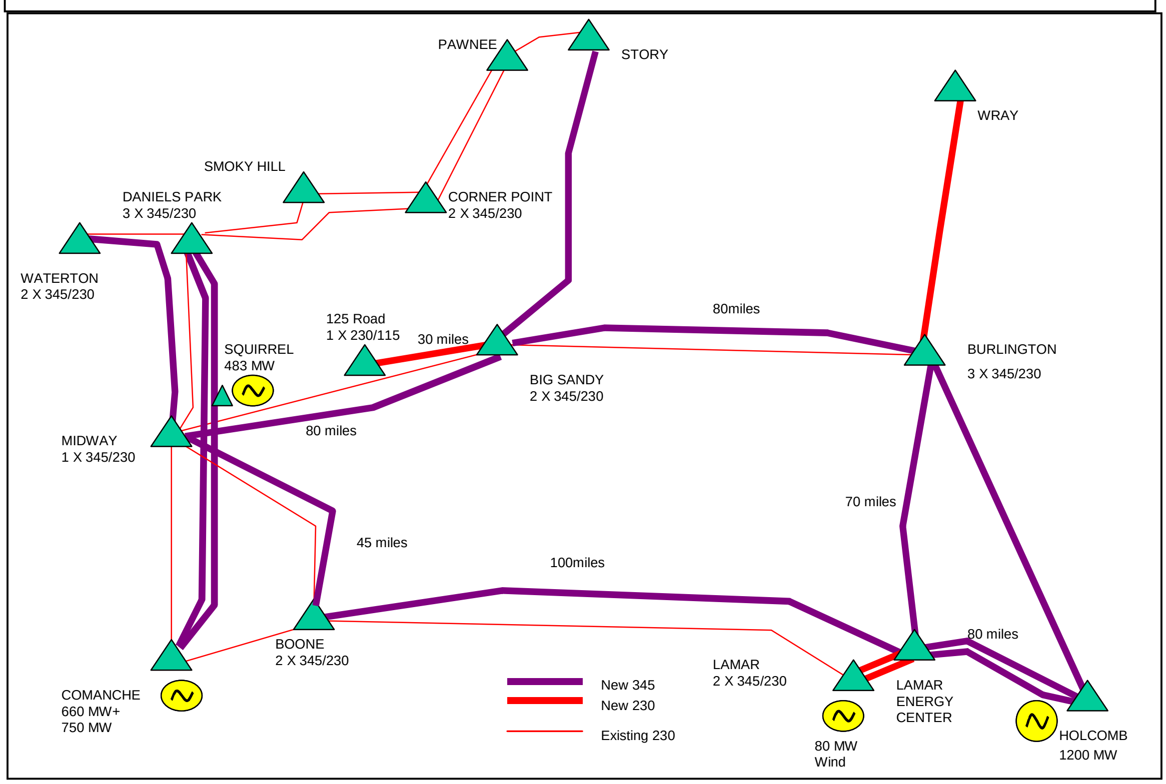


Figure 9: Add Burlington-Big Sandy 345 kV; Standard Southern 345 kV Alternative



Studies also showed that for this transmission configuration depicted in Figure 9, there were some contingency loading issues in the Denver-metro system. A new 230 kV transmission line from Waterton to Lookout in addition to a second Waterton 345/230 kV transformer reduced line and transformer contingency loadings in the region north of Daniels Park area. As a result, this transmission line and transformer were listed as Secondary Bulk elements for the Standard Southern alternatives.

Sensitivity studies showed that if a Big Sandy - Corner Point 345 kV transmission line is added to the configuration, it increased contingency loadings on the Denver system north of Daniels Park. However, it does not degrade performance in other locations. Therefore, it remains an option for subsequent studies of coordinated transmission expansion plans in the region. Results demonstrated that the configuration depicted in Figure 9 is an adequate 345 kV transmission configuration for the Standard Southern resource scenario.

C. Standard Southern 500 kV Alternative

1. Primary Backbone Transmission Description

The Primary Backbone transmission is shown in Table 6. A detailed list of all regional and secondary bulk changes for this scenario can be found in Appendix C in the Transmission Infrastructure Sheet.

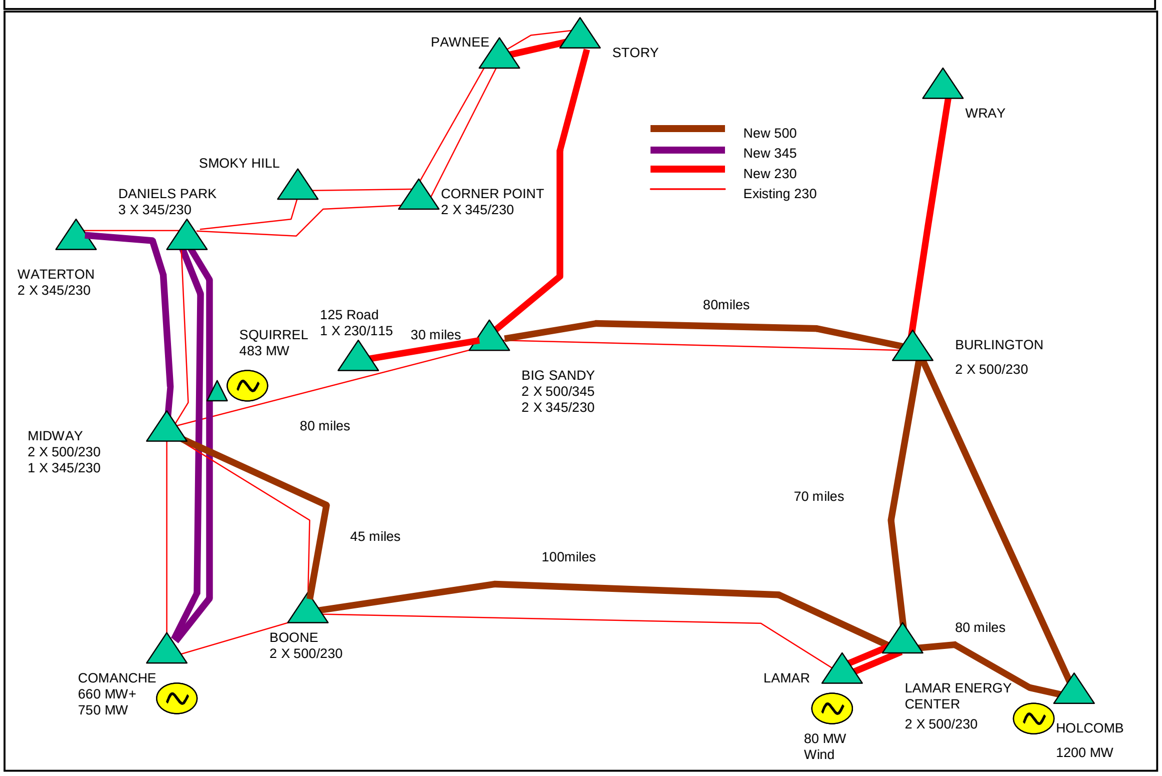
Table 6 Primary Backbone Transmission for the Standard Southern 500 kV Alternative

Description	Entity	Miles	Cost
Burlington - Wray 230 kV Line	TSGT	60	$22,562,000
Lamar - LEC #1 230 kV Line	TSGT	20	$19,439,000
Lamar - LEC #2 230 kV Line	TSGT	20	$19,439,000
Beaver Creek-Big Sandy 230 kV Line	TSGT	70	$39,872,000
Big Sandy 500/230 KV Transformers	TSGT	0	$38,808,000
Big Sandy-Burlington 500 KV Line	TSGT	80	$88,597,000
Boone 500/230 KV Transformers	TSGT	0	$35,975,000
Boone-LEC 500 KV Line	TSGT	100	$109,247,000
Boone-Midway 500 KV Line	TSGT	45	$57,702,000
Burlington 500/230 KV Transformers	TSGT	0	$38,808,000
Burlington-Holcomb 500 KV Line	TSGT	150	$154,457,000
Burlington-LEC 500 KV Line	TSGT	70	$82,767,000
Holcomb-LEC 500 KV Line	TSGT	80	$94,591,000
LEC 500/230 KV Transformers	TSGT	0	$41,969,000
Midway 500/230 KV Transformers	TSGT	0	$38,808,000
125Road 230/115 kV Substation	TSGT	0	$4,514,000
125 Road-Big Sandy 230 kV Line	TSGT	30	$22,430,000
Comanche - Daniels 345 kV line, subs, xfmrs	PSCo	115	$152,000,000
Midway - Waterton 345 kV line, subs, xfmrs	PSCo	9	$23,560,000
Waterton 230-115kV autos 1&2 Replacement	PSCo	0	$7,240,000
Total		**849**	**$1,092,785,000**

2. Studies

Initial studies of a 500 kV transmission plan utilized the same corridors as the 345 kV plan. However, studies showed that with a 500 kV configuration, only one line was needed between Holcomb and LEC. Figure 10 below shows the 500 kV configuration. Also, a Big Sandy – Midway line was not needed for the Standard resource scenario. Studies indicated that the line between Big Sandy and Story could be a 230 kV transmission line instead of 345 kV and terminate at Beaver Creek. This configuration eliminated the need for a 345 kV substation at Big Sandy and appeared to be adequate to accommodate the Standard Southern generation dispatch. This configuration was also studied with a line between Big Sandy and Corner Point. The Corner Point – Big Sandy line appeared to alleviate contingency overloads in the CSU system, but also contributed to contingency loading problems north of Daniels Park. Sensitivity studies showed that another Midway - RD Nixon 230 kV line could alleviate some of the CSU contingency loading issues. Therefore, a Corner Point - Big Sandy line was not pursued any further.

Figure 10: Standard Southern 500 kV Alternative Configuration



A Waterton-Lookout 230 kV transmission line and a second Waterton 345/230 transformer were shown to eliminate some contingency overload issues north of Daniels Park. The LEC-Boone fault was found to be the most severe disturbance for the configuration depicted in Figure 10, but the transmission system remained stable for the disturbance.

Transmission losses using the 500 kV configurations were found to be less than losses using 345 kV configurations. If loss savings can be realized in terms of operating cost savings, this would contribute to justification for a 500 kV alternative.

Results demonstrated that the configuration depicted in Figure 10 is an adequate 500 kV transmission configuration for the Standard Southern resource scenario.

D. Expanded Southern 345kV Alternative

The main purpose of studying the Expanded scenarios was to determine what additional upgrades to the bulk power system in eastern Colorado would be required to support additional generation in the region near Lamar.

1. Primary Backbone Transmission Description

The Primary Backbone transmission is shown in Table 7. A detailed list of all regional changes for this scenario can be found in Appendix C in the Transmission Infrastructure Sheet.

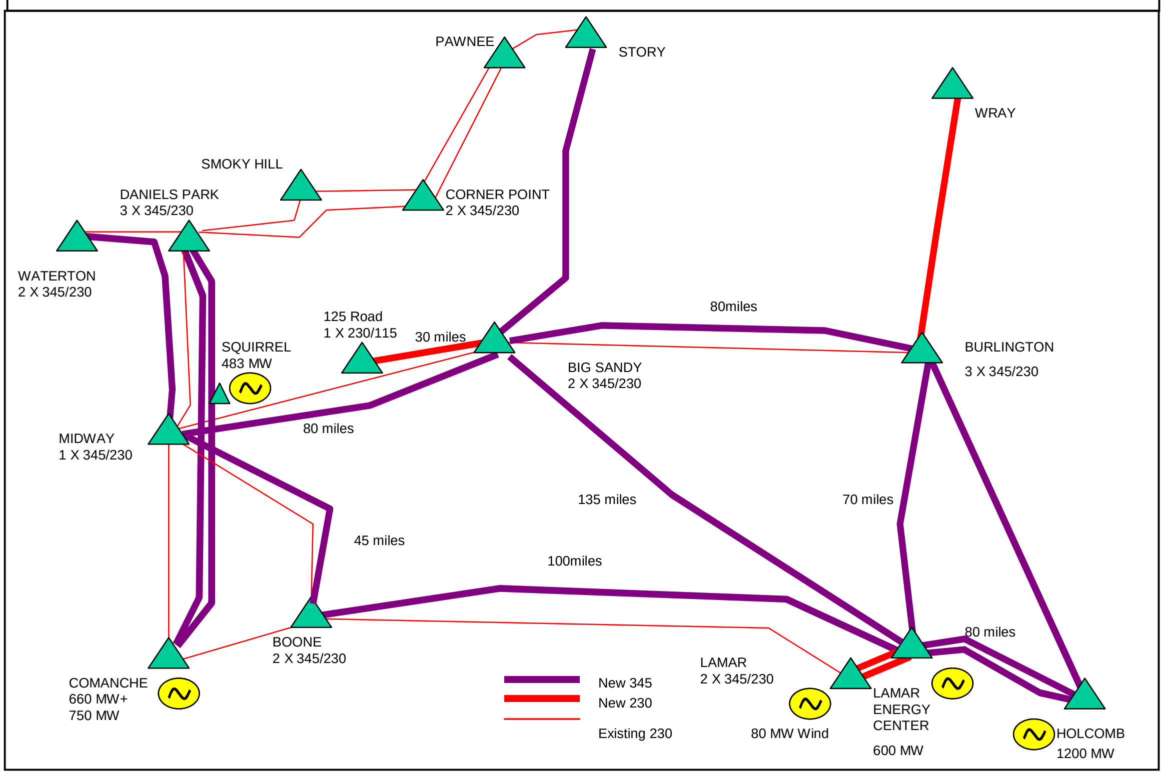
Table 7 Primary Backbone Transmission for the Expanded Southern 345 kV Alternative

Description	Entity	Miles	Cost
Big Sandy - LEC 345 kV Line	TSGT	135	$92,458,000
Big Sandy - Story 345 kV Line	TSGT	70	$50,230,000
Big Sandy 345/230 kV Transformers	TSGT	0	$26,227,000
Big Sandy-Burlington 345 KV Line	TSGT	80	$57,951,000
Big Sandy-Midway 345 KV Line	TSGT	85	$60,858,000
Boone 345/230 KV transformers	TSGT	0	$26,227,000
Boone-LEC 345 kV Line	TSGT	100	$72,109,000
Boone-Midway 345 KV Line	TSGT	45	$37,601,000
Burlington - Holcomb 345 kV Line	TSGT	150	$101,179,000
Burlington - LEC 345 kV Line	TSGT	70	$54,667,000
Burlington 345/230 kV Transformers	TSGT	0	$26,227,000
Holcomb - LEC #1 345 kV Line	TSGT	80	$63,011,000
Holcomb - LEC #2 345 kV Line	TSGT	80	$63,011,000
LEC 345/230 kV Transformers	TSGT	0	$31,288,000
Midway 345 kV Tie Line	TSGT	0	$7,378,000
Midway 345/230 KV Transformer	TSGT	0	$16,562,000
Burlington - Wray 230 kV Line	TSGT	60	$22,562,000
Lamar - LEC #1 230 kV Line	TSGT	20	$19,439,000
Lamar - LEC #2 230 kV Line	TSGT	20	$19,439,000
125Road 230/115 kV Substation	TSGT	0	$4,514,000
125 Road-Big Sandy 230 kV Line	TSGT	30	$22,430,000
Comanche-Daniels Park 345 kV line, subs, xfmrs	PSCo	115	$152,000,000
Midway-Waterton 345 kV line, subs and xfmrs	PSCo	9	$23,560,000
Waterton 230-115kV autos 1&2 Replacement	PSCo	0	$7,240,000
Total		**1149**	**$1,058,168,000**

2. Studies

The Expanded Southern scenarios included an additional 600 MW of generation at the LEC bus. Rather than increase loads in the study cases to model the additional generation, the power was scheduled outside the Front Range to generating units on the Western Slope of Colorado as well as to other control areas in the powerflow model. Studies were conducted to determine what additional Backbone transmission would be required to accommodate the additional power from LEC. From the Standard Southern 345 kV Alternative, an additional 345 kV transmission line from LEC to Big Sandy was required to maintain transient stability. A diagram of this configuration is shown in Figure 11.

Figure 11 Expanded Southern 345 kV System
Added LEC-Big Sandy 345 kV Line



Stability studies showed that a LEC - Boone disturbance was the most severe, but did not result in system instability. In the Standard Southern 345 kV case, overloads north of Daniels Park were resolved by adding a 230 kV transmission line from Waterton to Lookout and a second Waterton 345/230 kV transformer. For the Expanded resource models, even more system modifications would be required to eliminate contingency overloads in that region.

Some sensitivity studies attempted to divert power to northern Denver to better serve TSGT native load and alleviate overloading problems in south Denver. These sensitivity studies included adding a Big Sandy - Corner Point 230 kV transmission line. However, studies indicated that line could increase overloads in the southern Denver region. Therefore, a line into Corner Point was not pursued further. Other upgrades studied to mitigate overloads in south Denver included Waterton - Lookout and Greenwood - Arapahoe 230 kV transmission lines. The Waterton - Lookout transmission line appeared to show some benefits in the Standard resource case. However, additional contingency overloads north of Daniels Park reappeared with the Expanded case. A Greenwood - Arapahoe 230 kV transmission line appeared to reduce some of those overloads north of Daniels Park in the Expanded case, but caused other loading issues. Other regional overloads also remained.

Since the Expanded Southern resource scenarios are considered to be more representative of a time frame after 2015, further analysis should be pursued in subsequent studies with more appropriate models. The configuration shown in Figure 11 may show the Primary 345 kV Backbone system for an Expanded resource scenario. However due to regional contingency overloads resulting from the additional 600 MW of generation, studies should be performed to formulate a complete transmission plan.

E. Expanded Southern 500kV Alternative

1. Primary Backbone Transmission Description

The Primary Backbone transmission is shown in Table 8.

Table 8 Primary Backbone Transmission for the Expanded Southern 500 kV Alternative

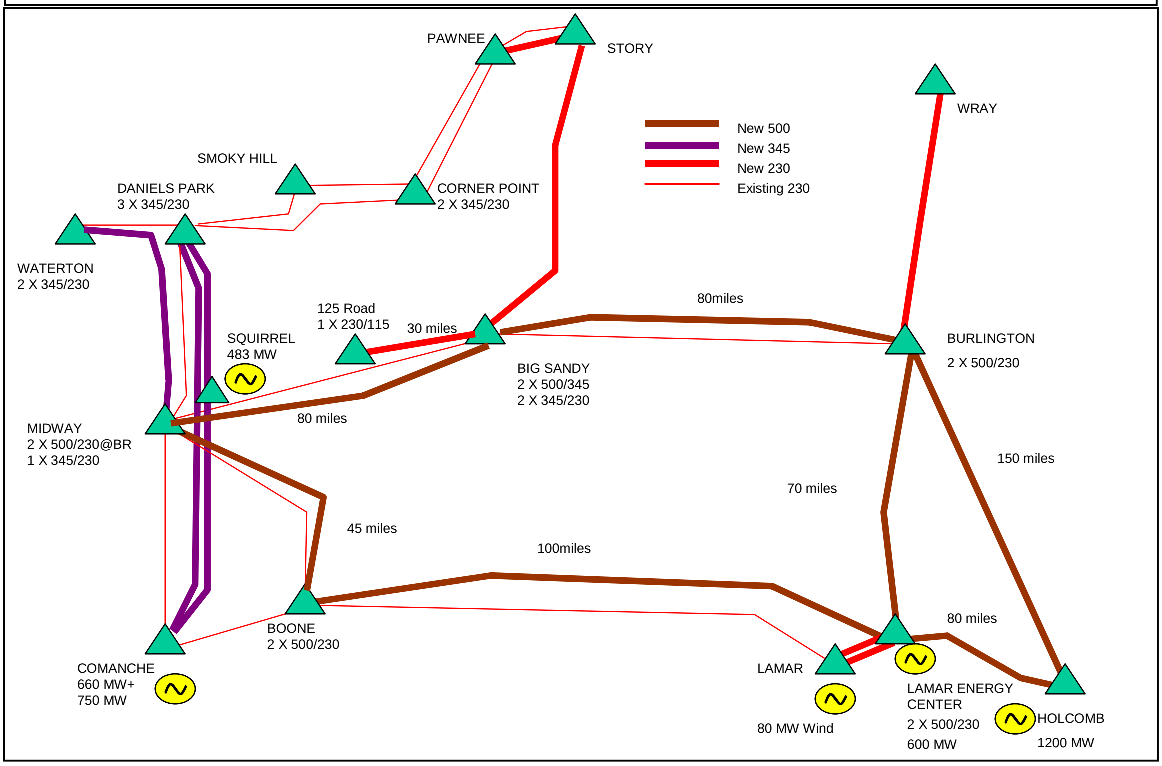
Description	Entity	Miles	Cost
Burlington - Wray 230 kV Line	TSGT	60	$22,562,000
Lamar - LEC #1 230 kV Line	TSGT	20	$19,439,000
Lamar - LEC #2 230 kV Line	TSGT	20	$19,439,000
Beaver Creek-Big Sandy 230 kV Line	TSGT	70	$39,872,000
Big Sandy 500/230 KV Transformers	TSGT	0	$38,808,000
Big Sandy-Burlington 500 KV Line	TSGT	80	$88,597,000
Big Sandy-Midway 500 KV Line	TSGT	85	$93,010,000
Boone 500/230 KV Transformers	TSGT	0	$35,975,000
Boone-LEC 500 KV Line	TSGT	100	$109,247,000
Boone-Midway 500 KV Line	TSGT	45	$57,702,000
Burlington 500/230 KV Transformers	TSGT	0	$38,808,000
Burlington-Holcomb 500 KV Line	TSGT	150	$154,457,000
Burlington-LEC 500 KV Line	TSGT	70	$82,767,000
Holcomb-LEC 500 KV Line	TSGT	80	$94,591,000
LEC 500/230 KV Transformers	TSGT	0	$41,969,000
Midway 500/230 KV Transformers	TSGT	0	$38,808,000
125Road 230/115 kV Substation	TSGT	0	$4,514,000
125 Road-Big Sandy 230 kV Line	TSGT	30	$22,430,000
Comanche - Daniels 345 kV line, subs, xfmrs	PSCo	115	$152,000,000
Midway - Waterton 345 kV line, subs, xfmrs	PSCo	9	$23,560,000
Waterton 230-115kV autos 1&2 Replacement	PSCo	0	$7,240,000
Total		**934**	**$1,185,795,000**

A detailed list of all regional changes for this scenario can be found in Appendix C in the Transmission Infrastructure Sheet.

2. Studies

Figure 12 shows the 500 kV transmission configuration developed for the Expanded Southern generation dispatch. Studies showed that a 500 kV transmission line between Big Sandy and Midway had to be added to the Standard Southern 500 kV configuration. Studies included a Greenwood - Arapahoe 230 kV transmission line, a Waterton - Lookout 230 kV transmission line, and two Waterton 345/230 kV transformers to help alleviate north of Daniels Park overloads. However, as was the case with the 345 kV configuration, some contingency overload remained in the region north of Daniels Park. A second Midway - RD Nixon 230 kV transmission line was also needed to mitigate some contingency loadings on the CSU system.

Figure 12: Expanded Southern 500 kV System



Transmission losses with the 500 kV configurations were found to be approximately 30 MW less than with the 345 kV configuration.

The configuration shown in Figure 12 may show the Primary 500 kV Backbone system for an Expanded resource scenario. However due to regional contingency overloads resulting from the additional 600 MW of generation, studies should be performed to formulate a complete transmission plan.

F. Northern Alternative 1

1. Primary Backbone Transmission Description

The Primary Backbone transmission is shown in Table 9. A detailed list of all regional changes for this scenario can be found in Appendix C in the Transmission Infrastructure Sheet.

Table 9 Primary Backbone Transmission for the Northern Alternative 1

Element	Entity	length (mi)	Cost
Pawnee-Ft. Lupton 230 kV rebuild to double-ckt 230	PSCo	64	$52,790,000
Uprate Pawnee-Quincy-Smoky Hill – Daniels Park	PSCo	0	$1,420,000
Pawnee - Corner Pt 345kV Double ckt Transmission	PSCo	55	$13,220,000
Pawnee 345 kV Sub & 3 345/230 kV Autos	PSCo	0	$11,500,000
Corner Point 345 kV Sub & 2 345/230 kV Autos	PSCo	0	$12,100,000
Corner Point – Smoky Hill double-ckt 345 kV	PSCo	40	$28,500,000
Smoky Hill – Daniels double-ckt 345 kV	PSCo	24	$17,100,000
Corner Pt – Smoky Hill 230 kV rebuilt double-ckt 230	PSCo	40	$26,880,000
Ft.Lupton – Cherokee Upgrade to 230 kV	PSCo	28	$13,685,000
TOTALS		**211**	**$177,195,000**

2. Studies

Initial studies benchmarked the performance of the northern system by adding resources to the region expected in 2010, which is when the last major planned transmission project will be in service. The benchmark Northern transmission system is shown in Figure 13. The figure shows the generation added to the Northern resource scenario. Some of the Standard Southern 345 kV transmission infrastructure was included in the North Scenario studies. The Holcomb generation was reduced to 700 MW to promote heavy north to south flows.

The performance of the system showed a large number of overloads in the Northern region. The 2004 CLTRPG Study exhibited similar results and a 345 kV transmission plan was developed in that study. That plan was used as a starting point for evaluating alternatives in this study and is shown in Figure 14 as Northern Alternative 1.

Studies showed that this alternative caused heavy power flows into the Ft. Lupton region and therefore, resulted in some high contingency loadings south of there. Also, the region south of the Rocky Mountain Energy Center and Green Valley exhibited high contingency loadings. Since this has been a region of interest for generation interconnection requests, another alternative was developed that could potentially accommodate additional future generation in that area.

Figure 13 Benchmark System for Northern Resource Scenario

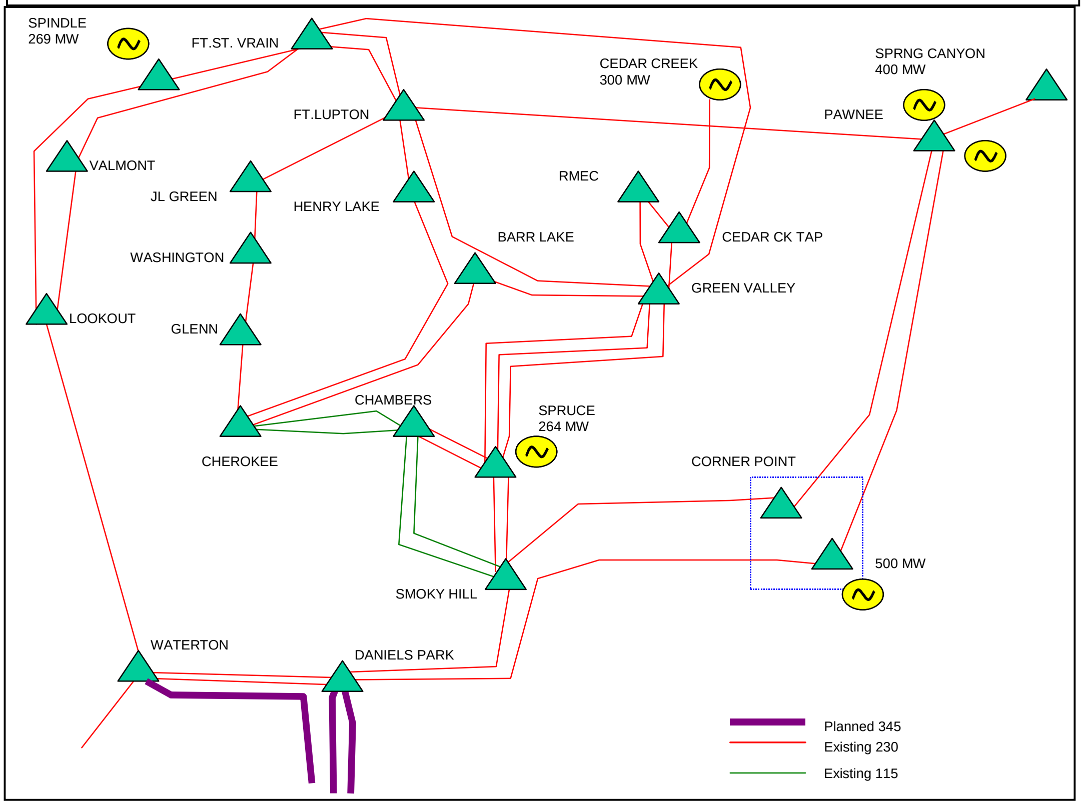
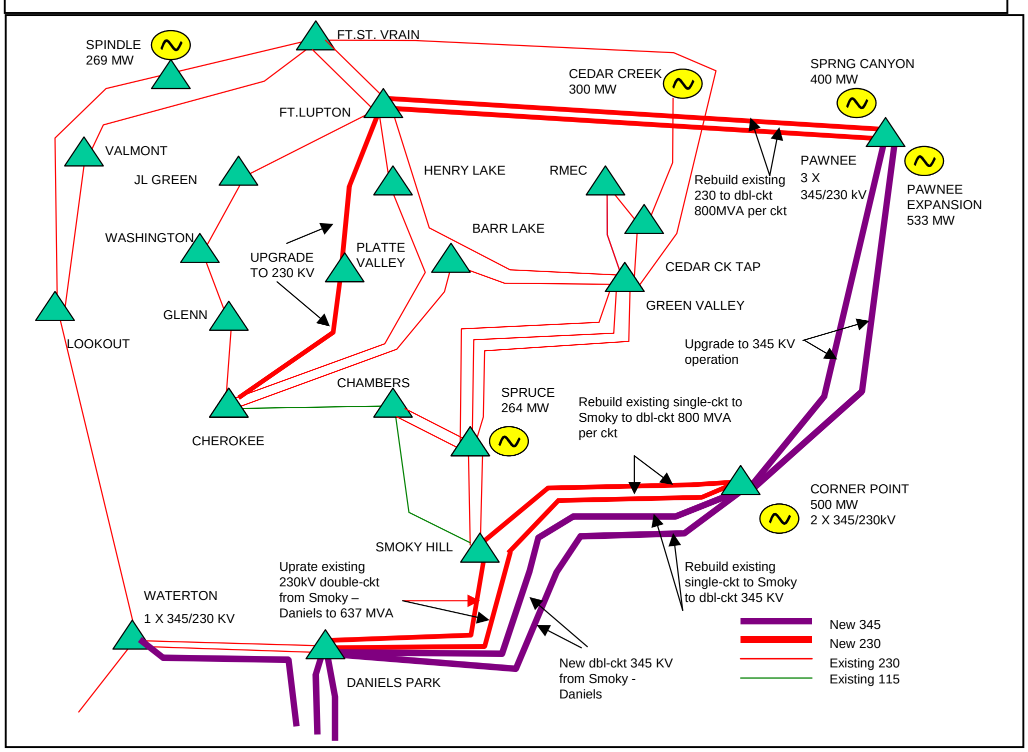


Figure 14 Northern Alternative 1



The analyses of the Northern resource scenario indicated the potential for contingency loading issues on the Denver-metro load serving transmission between Smoky Hills and Daniels Park. These impacts would have to be investigated further if this alternative were to be pursued.

G. Northern Alternative 2

1. Primary Backbone Transmission Description

The Primary Backbone transmission is shown in Table 10. A detailed list of all regional changes can be found in Appendix C in the Transmission Infrastructure Sheet.

Table 10: Primary Backbone Transmission for the Northern Alternative 2

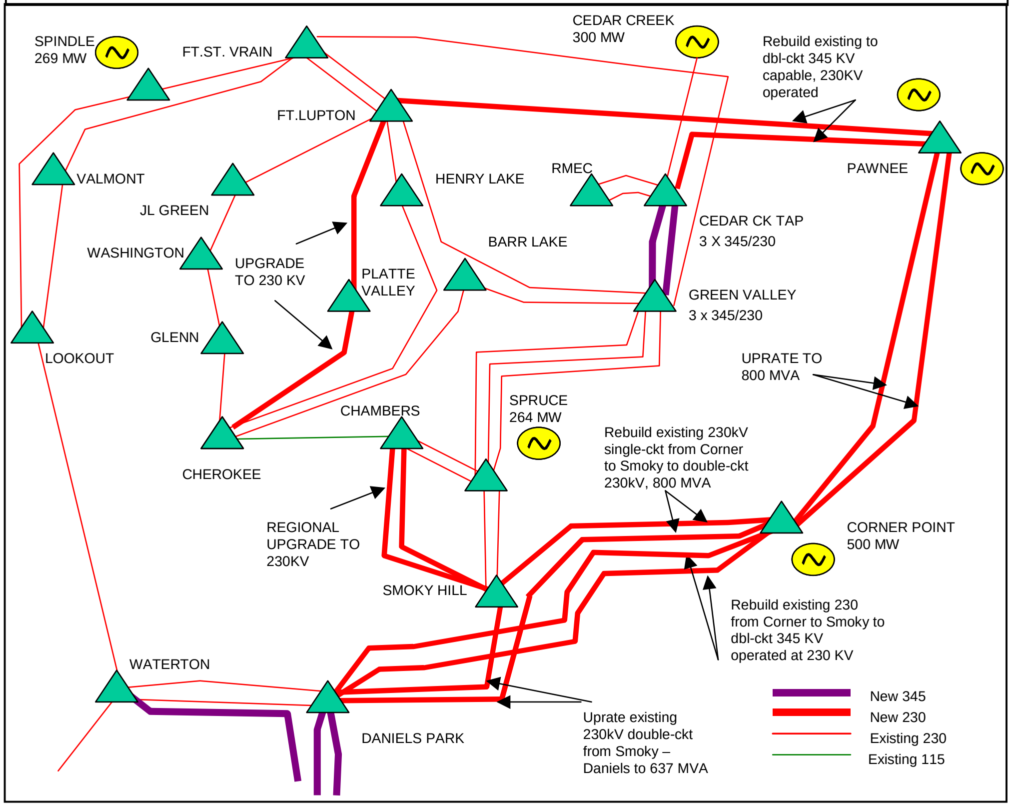
Element	Entity	length (mi)	Cost
Corner Point - Smoky Hill #1 rebuild to dbl-ckt	PSCo	40	$28,500,000
Corner Pt – Smoky Hill 230 kV rebuilt double-ckt 230	PSCo	40	$26,880,000
Smoky Hill - Daniels Park new 230kV Double ckt	PSCo	24	$17,100,000
Corner Point 230 kV Switching Station	PSCo	0	$8,525,000
Pawnee-Ft, Lupton and Pawnee-Cedar Tap	PSCo	119	$52,327,000
Uprate Pawnee-Quincy-Smoky Hill – Daniels Park	PSCo	0	$1,420,000
Cedar Tap 230/345 kV Switching Station	PSCo	0	$18,715,000
Green Valley 345 kV Switching	PSCo	0	$15,760,000
Ft.Lupton – Cherokee Upgrade to 230 kV	PSCo	28	$13,685,000
TOTALS		**183**	**$182,912,000**

2. Studies

Northern Alternative 2 has some similarities to Northern Alternative 1, but keeps the Pawnee-Daniels Park corridor at 230 kV. The Corner Point to Daniels Park transmission is constructed for 345 kV. The Pawnee-Ft. Lupton 230 kV line is reconstructed to double circuit 230 kV, but one circuit turns and heads to the Cedar Tap Switching Station near RMEC. This alternative alleviates the loading on the lines south of Ft. Lupton that existed with Northern Alternative 1 by moving power to the RMEC-Green Valley Corridor. The RMEC – Green Valley lines would be operated at 345 kV in order to avoid overloads of the parallel circuits. This alternative also reduced the loading issues from Daniels Park and Smoky Hill.

Figure 15 shows the Northern Alternative 2.

Figure 15 Northern Alternative 2



Northern Alternative 2 still exhibited the potential for some minor contingency overloads.

Additional studies are needed to evaluate the impacts of integrating the Northern Alternatives with the Southern Alternatives.

V. Final Conclusions

1. Two potential transmission alternatives were developed for the Standard Southern scenario. Either of these scenarios appear to accommodate the southern generation resources.

2. Two potential transmission alternatives were developed for the Expanded Southern scenarios. These alternatives did not fully alleviate potential system overloads. However, since the expanded generation is not anticipated until beyond the 2015 time frame, full system solutions were not developed. Post 2015 cases are needed to more accurately quantify required system upgrades for the Expanded Southern scenarios.

3. Two potential transmission alternatives were developed for the Northern scenario. Both of these alternatives appeared to accommodate the northern generation scenarios studied.

4. Additional studies will be required to determine the impacts of a composite case with the preferred south and north alternatives.

5. For future studies, the CLRTPG may need to follow up with additional investigations, including an evaluation of the TOTs and additional studies of a balanced generation scenario. The CLRTPG will continue on the path of studying the future of the transmission system with the results from this study as a foundation of that work. The Group plans to jointly review PSCo's Least Cost Planning efforts, including the transmission studies that will take place as part of the bid analysis for PSCo resource needs beyond the Comanche Unit #3. Due to anticipated load growth in Colorado over the next 10 years, implantation of new generation in the Front Range will continue. The results of this study provide the LSE's in the state with insight to the effects of added generation at various locations and what transmission might be necessary.

A. Future Studies

Subsequent studies are anticipated to refine the transmission proposals, including:

- Determination of the specific facilities to facilitate the Southern resource integration. Since both the 345 kV and the 500 kV options are viable transmission alternatives, additional studies will be required once a preferred alternative has been determined.
- Develop the appropriate network upgrades in the Denver-metro region to accommodate Southern resource scenarios. Preliminary studies indicated that the following facilities could help alleviate some of the loading issues:
    - Adding a second Waterton 345/230 kV autotransformer
    - Adding a Waterton – Lookout 230 kV line
    - Adding a Big Sandy – Green Valley 230 kV line.

- Refinements to the Northern alternatives to line up with the ultimate portfolio of future resource choices by PSCo. The future PSCo resources modeled in this study may not fully represent the final selection of future resources.
- Additional analyses of the Expanded Southern scenarios. These studies identified basic backbone transmission plans, but did not fully identify all of the transmission upgrades required to alleviate all of the contingency loading issues. Future studies should identify how the additional resources can be accommodated. It may be determined that models appropriate for these studies would be beyond the 2015 time frame.
- Integration of the Northern and Southern resource scenarios. Studies may likely show some synergies between the two scenarios. Preliminary sensitivities as a part of this study have identified potential ties between the two such as:
    - A Corner Point – Big Sandy transmission line
    - A Big Sandy - Green Valley transmission line
    - Additional transmission between Pawnee and Story

APPENDIX A

Invitation to Provide Input and Assist With Regional 10-Year Transmission Plan

September 8, 2005

To: Transmission and Resource Planners of the Colorado Coordinated Planning Group

Re: Meeting of the Colorado Long Range Transmission Planning Group

The Colorado Long Range Transmission Planning Group (CLRTPG) is meeting to review the long-range plan produced last year and explore potential changes. In order to help assure that transmission additions complement all the needs of utilities, customers, and load serving entities in our region, we have scheduled a meeting of the CLRTPG. The meeting will be held on September 15, 2005 from 1:00 PM – 5:00 PM, at the Tri-State Generation and Transmission (Tri-State) office, 1100 West 116th Street, Denver. We hope that your company will attend with both transmission planning and resource planning to represent your system needs and have the opportunity to provide input to these renewed study efforts.

Tri-State has recently announced plans to partner with Sunflower Electric in the development of a large coal-based generation facility near Holcomb, Kansas. Early estimates for the transmission to accommodate the generation indicate that 550 miles of new high-voltage transmission will be required into Colorado. In addition, Public Service Company of Colorado is presently in the process of a Least Cost Resource Plan, and evaluating proposals for approximately 2500 MW of generation resources to serve its needs for through 2013.

The goal of the CLRTPG continues to be the development of a long-range bulk transmission plan that will best fit the future needs of the State of Colorado given the anticipated load growth, collective knowledge of the transmission system, and potential sites for new generation resources. The transmission plan should result in a robust statewide view of a "back-bone" transmission system that eliminates the often "piece-meal" approach to transmission. This will be accomplished by developing a transmission system that will readily accommodate future generation development and optimize transmission additions.

Please be prepared to share any planned or speculative load and resource needs your company anticipates for the planning horizon through 2014. If you have any questions about the agenda for the meeting, please contact Thomas Green at 303-571-7223, or thomas.green@xcelenergy.com.

DRAFT AGENDA
Colorado Long Range Transmission Planning Group
September 15, 2005
TSGT Offices
1:00 to 5:00 p.m.

Open Meeting

1. Introductions

2. Purpose (Overview)

3. Changes to Agenda

4. Background
   4.1. Review Original Scope (Handout)
   4.2. Phase 2 Scope

5. Membership
   5.1. Open Group
   5.2. Transmission Provider Group
   5.3. Non-Disclosure Agreement (Handout)

6. Schedule (Possible Handout)
   6.1. Goal for January
   6.2. Other phases
   6.3. Meetings

Transmission Provider Meeting

7. Review Tri-State Plans (TS Handout)
   7.1. 2013/14
   7.2. 2020

8. Review status of PSCo RFP (Handout)

9. Studies
   9.1. Base Cases
   9.2. Load Modeling
   9.3. Philosophies

10. Next Meeting

APPENDIX B

Loads and Resources Balance Sheets

Table B- 1 PSCo Loads & Resources

PSCo Loads & Resources Balance for 2015 Summer			
	Base Case	**CLRTP**	**Notes**
Existing PSCo Dependable Capacity	**2014 HS1**	**2015 HS**	
Total	**3836**	**3846**	**Existing PSCo Owned Generation**
Firm Purchased Capacity			
Basin Electric Power Cooperative No.1	100	100	**From LRS**
Basin Electric Power Cooperative No.2	75	75	**From LRS**
Tri-State G&T No.2	100	100	**Available from LRS or Craig**
Tri-State G&T No.3	25	25	**Available from LRS or Craig**
Wheeling Losses	-9	-9	
Sub Total	291	**291**	
IPP Purchases (Assuming some contract extensions)			
ManChief Power Company	263	260	
Black Hills Valmont 7 & 8	81	81	
Black Hills Arapahoe 5, 6, 7	122	122	
Fountain Valley Midway	236	240	
Brush 4D	115	130	**These are the existing IPP's connected to the PSCo system**
Tri-State Limon	0	0	
Tri-State Brighton	0	128	
Calpine Blue Spruce	258	264	
Front Range Power	0	0	
PG&E Plains End	113	110	
Colorado Green Wind (a.k.a Lamar Wind)	49	16	**10% of Capacity for Summer Peak**
CPP Brush 1 & 3	75	0	
Calpine Rocky Mountain Energy Center	585	585	
Sub Total	1897	**1937**	
Qualifying Facilities (QF's)			
Brush Cogen Partners	68	68	
Thermo Greeley (Monfort)	32	32	
Thermo Power (UNC)	69	69	
Small QFs (21 facilities)	10	10	**Existing QF's connected to the PSCo system**
Thermo Fort Lupton	279	129	
Sub Total	458	**308**	
SPS Diversity Exchange	103	**105**	**Lamar HVDC Tie**
Projected Resources			
Comanche # 3 Generation		750	**Resource Approved by the CPUC**
Possible Projected Resources			
W22-Cedar Creek Wind		30	**10% of Capacity for Summer Peak**
W09 - Spring Canyon #2		40	**10% of Capacity for Summer Peak**
G14 - Morgan County Energy Center		533	
G25 - Blue Spruce Energy Center - 264 MW Expansion		264	
G29 - Spindle		269	**Potential Resources**
G31 - Squirrel Creek		483	
Corner Point Generation		500	
Possible Projected Resources Sub Total	0	**2869**	
Total Firm Purchases	2749	**2641**	**Sum**
PSCo Net Dependable Capacity	6585	**6487**	
PSCo Net Dependable Capacity with Projected Resources	6585	**9356**	
PSCO Native Load in 2014 Heavy Summer	7991		
March 2005 Base Demand Forecast 2015 Heavy Summer		**8082**	
Interruptible Load	126	127	
Existing Saver's Switch	64	64	
2003 LCP Settlement DSM (matches Strat)		320	
PSCo Firm Load Obligation 2015 HS1	7801	**7891**	
Reserve Margin IRP	0	0	
Reserve Requirement (Calc)	1014	**1263**	**MW (% of Load)**
Actual Reserve Capacity w/o Projected Resources	-1216	-1403	**MW (dependable less Load)**
Actual Reserve Capacity with Projected Resources	-1216	1466	**MW (dependable less load)**
Resource Need w/o Projected Resources		**2666**	
Resource Need with Projected Resources		**-203**	

Table B- 2 TSGT Loads & Resources

TSG&T Loads & Resources Balance			
	CLRTP	CLRTP-2	Notes
Existing TSG&T Capacity	2014 HS1	2015 HS	
Installed Net Dependable Capacity	1465	1595	Year 2006; CO+WY+w.NE only
			includes 41MW San Juan 3
Firm Purchased Capacity			
Loveland Area Project Co/Wy	270	270	excludes Tribal LAP
Loveland Area Project Nebraska		83	serves W.Nebraska load
CRSP - North (E)	159	146	
CRSP - North (W)	15	14	excluding Tribal CRSP
Basin - Nebraska		19	Supplemental for W.Nebraska
Basin	100	175	includes additional 25 MW above present purch
Tribal CRSP/LAP		3	
Sub Total	544	710	
TSG&T Firm Transactions			North area only
PACE F1	-25	-25	
Basin/PRECORP	-13	-10	
Sub Total	-38	-35	
TSG&T Non-Firm Transactions			North area only
PSCo #2	-100	-100	Unit contingent sale
PSCo #3	-25	-25	Unit contingent sale
Sub Total	-125	-125	
IPP Purchases			
Bio Gas			netted against load
Sub Total	0	0	
Qualifying Facilities (QF's)			
Vallecito hydro		5	
Other small hydro		0	Small IPP purchases netted against load
Sub Total	0	5	
DC TIES			
Sub Total	0	0	
Possible Projected/External Resources			
Holcomb (2) 600 MW units		1200	estimate as of January 2006
Off-system Transfers		0	
Springerville transfer into Colorado	100	60	
Sub Total	100	1260	
Total Purchased Firm Resources less Net Firm Sales	381	675	excluding QF's
Existing TSG&T Net Dependable Capacity	1846	2275	
TSG&T Net Dependable Capacity with Projected Resources		3535	
TSG&T Native Load / Heavy Summer	1879	2937	Wyo.+W.Nebr.+All Colo.+5% loss on net firm Lo
Interruptible Load			no interruptible load
Efficiency Program			
TSG&T Firm Load Obligation	1879	2937	includes losses
Reserve Margin	0	0	Total Operating Reserve
Reserve Requirement (Calc)	281	339	Reserve on Net Firm Load
Actual Reserve Capacity w/o Projected Resources	-33	-787	Resources less Firm and non-firm load
Actual Reserve Capacity with Projected Resources	67	473	
Resource Need w/o Projected Resources	314	1126	All Load +sales+reserve less resources
Resource Need with Projected Resources	214	-134	

Table B- 3 PRPA Loads & Resources

PRPA Loads & Resources Balance for 2015 Summer			
	Base Case	**CLRTP**	**Notes**
Existing PRPA Capacity	**2014 HS1**	**2015 HS1**	
Rawhide Unit 1		270	net
Rawhide Unit A		70	net
Rawhide Unit B		70	net
Rawhide Unit C		70	net
Rawhide Unit D		70	net
Craig Unit 1		77	net
Craig Unit 2		77	net
Installed Net Dependable Capacity		704	
Firm Purchased Capacity			
SLIP		74	net
LAP		30	net
Sub Total		104	
IPP Purchases			
Sub Total		0	
PRPA Exports			
Rawhide House Power		0	use net generation values
Sub Total		0	
Qualifying Facilities (QF's)			
Sub Total		0	
DC TIES			
Sub Total		0	
Possible Projected Resources			
Purchase Power or Build		60	net, 2013
Rawhide Unit E		80	net, 2010
Sub Total		140	
Total Firm Purchases		104	
PRPA Net Dependable Capacity		808	owned + contracted
PRPA Net Dependable Capacity with Projected Resources		948	owned + contracted + projected
PRPA Native Load in 2015 Heavy Summer		884	867 City Load + 17 Losses, High forecast 8-7-04, population & employment 50% greater than projected
Interruptible Load		7	
Effieciency Program			
PRPA Firm Load Obligation 2015 HS1		877	
Reserve Margin			
Reserve Requirement (Calc)		65	based on losing largest unit during summer peak with assistance from contracts & purchases
Actual Reserve Capacity w/o Projected Resources		-69	owned + contracted - firm load obligation
Actual Reserve Capacity with Projected Resources		71	owned + contracted + projected - firm load obligation
Resource Need w/o Projected Resources		**134**	**reserve requirement - (owned + contracted - firm load obligation)**
Resource Need with Projected Resources		**-6**	**reserve requirement - (owned + contracted + projected - firm load obligation)**

Table B- 4 CSU Loads & Resources

CSU (Colorado Springs) Loads & Resources Balance for 2015 Summer			
	CLRTPG	CLRTPG	Notes
Existing CSU Capacity	2014 HS1	2015 HS	
Installed Net Dependable Capacity	1073	1065	**From CSU Resource Supply projections**
Firm Purchased Capacity		75	**WAPA purchase**
Sub Total	0	75	
IPP Purchases		0	**none**
Sub Total	0	0	
Qualifying Facilities (QF's)			**none**
Sub Total	0	0	
DC TIES			**none**
Sub Total	0	0	
Resources Under Development		0	**No resources identified at this time**
Sub Total	0	0	
Possible Projected Resources		0	**No resources identified at this time**
Sub Total	0	0	
Total Firm Purchases	0	75	
CSU Net Dependable Capacity	1073	1065	
CSU Net Dependable Capacity with Projected Resources	1073	1140	
CSU Native Load in 2014 Heavy Summer	1163	1073	
Interruptible Load		0	
Effieciency Program		41	**Include 41MW of DSM**
ENTITY Firm Load Obligation 2014 HS1	1163	1032	
Reserve Margin	0	0	**12% less WAPA import**
Reserve Requirement (Calc)	124	120	
Actual Reserve Capacity w/o Projected Resources	-90	33	
Actual Reserve Capacity with Projected Resources	-90	33	
Resource Need w/o Projected Resources	**214**	**87**	
Resource Need with Projected Resources	**214**	**87**	

Table B- 5 Total CLRTPG Loads & Resources

CLRTPG Loads & Resources Balance for 2015 Summer			
	CLRTPG	**CLRTP**	**Notes**
Existing CLRTPG Capacity	**2014 HS**	**2015 HS**	
Installed Net Dependable Capacity	7058	**7210**	
Firm Purchased Capacity			
CLRTPG Total	959	**1181**	
IPP Purchases (Assuming some contract extensions)			
CLRTPG Total	1901	**1937**	
Qualifying Facilities (QF's)			
CLRTPG Total	458	313	
SPS Diversity Exchange	**103**	**105**	
Possible Projected Resources			
CLRTPG Total	100	4269	
Total Firm Purchases	**3421**	**3536**	
CLRTPG Net Dependable Capacity	**10479**	**10746**	
CLRTPG Net Dependable Capacity with Projected Resources	**10579**	**15015**	
CLRTPG Native Load in 2015 Heavy Summer	11858	12976	**Sum of CLRTPG Loads**
Interruptible Load	133	134	
Existing Saver's Switch	0	64	
Efficiency Programs	64	425	
ENITITY Firm Load Obligation 2015 HS1	**11661**	**12353**	
Total Resource Need For PSCO	2226	2666	MW
Total Resource Need For TSGT	297	1126	
Total Resource Need For PRPA	88	134	
Total Resource Need For CSU	214	87	
TOTAL CLRTPG RESOURCE NEED		**4013**	

APPENDIX C

Transmission Infrastructure Data Sheets

	A	B	D	E	F	G	H	I	J	K	L	M	N	Q	R	S	U	V	W	X	Y	Z	AA
1		**CLRTP Master Transmission Infrastructure (Revised 6/30/06)**																					
2	**Entity**	**Element**	**South 345 kV 1200 MW**	**South 500 kV 1200 MW**	**North Alt. 1**	**North Alt. 2**	**South 345 kV 1800 MW**	**South 500 kV 1800 MW**	**r**	**x**	**b**	**MVA Rating**	**length (mi)**	**ISD**	**Esitmated Facility Cost ($)**	**Notes**	**Reason**	**South 345 kV 1200 MW Costs**	**South 500 kV 1200 MW Costs**	**North Alt. 1 Costs**	**North Alt. 2 Costs**	**South 345 kV 1800 MW Costs**	**South 500 kV 1800 MW Costs**
3	**psco**	**Comanche - Daniels Park 345 kV including subs & Xfmrs**	x	x	x	x	x	x	0.00150	0.01275	0.25031	1200	115.00	2009	$152,000,000	PSCo Proxy	Deliver COMA G3	$152,000,000	$152,000,000	$152,000,000	$152,000,000	$152,000,000	$152,000,000
4	**psco**	**Midway - Waterton 345 kV including subs and Xfmrs**	x	x	x	x	x	x	0.00670	0.04900	0.80800	1200	9.00	2010	$23,560,000	RFP Est.	Relieve Overloads on the CSU for loss of the 345 kV from Squirrel Creek Gen	$23,560,000	$23,560,000	$23,560,000	$23,560,000	$23,560,000	$23,560,000
5	**psco**	**Waterton 230-115kV autos 1&2 Replacement**	x	x	x	x	x	x	0.00600	0.03239	0.00000	280	0.00	2010	$7,240,000	RFP Est.	Loass of Parallel XFMR	$7,240,000	$7,240,000	$7,240,000	$7,240,000	$7,240,000	$7,240,000
6	**psco**	**Waterton 230/345 kV 560 MVA auto #2**	x	x			x	x	n/a	n/a	n/a	560	0.00	2015	$6,400,000	PSCo Proxy	Multiple Outages Near Midway	$6,400,000	$6,400,000	$0	$0	$6,400,000	$6,400,000
7	**psco**	**Corner Point - Smoky Hill 345kV Double ckt**	x	x	x	x	x	x	0.00161	0.01841	0.34267	1200	40.00	2015	$28,500,000	*Pawnee Feas. Study Estimate(Jul 03')*	Loss of Pawnee-DP or Pawnee Smoky	$28,500,000	$28,500,000	$28,500,000	$28,500,000	$28,500,000	$28,500,000
8	**psco**	**Corner Point to Smoky Hill 230 kV double ckt**			x	x			0.00578	0.06627	0.24373	800	40.00	2015	$26,880,000	Comanche SIS Study, Estimated 3/04	Relieve Overloads for loss on CP-DP#1	$0	$0	$26,880,000	$26,880,000	$0	0
9	**psco**	**Smoky Hill - Daniels Park 345kV Double ckt**	x	x	x	x	x	x	0.00964	0.01105	0.20560	1200	24.00	2015	$17,100,000	*Pawnee Feas. Study Estimate(Jul 03')*	Loss of Pawnee-DP or Pawnee Smoky	$17,100,000	$17,100,000	$17,100,000	$17,100,000	$17,100,000	$17,100,000
10	**psco**	**Pawnee-Ft, Lupton and Pawnee-Cedar Tap**				x			n/a	n/a	n/a	800/1200	63.9/55	2015	$52,327,000			$0	$0	$0	$52,327,000	$0	$0
11	**psco**	**Pawnee-Story #2 345 kV Construction**	x	x			x	x	n/a	n/a	n/a	800/1200	10.00	2015	$3,110,000	PSCo Proxy	Loss of Pawnee-Story #1	$3,110,000	$3,110,000	$0	$0	$3,110,000	$3,110,000
12	**psco**	**Cedar Tap 230/345 kV Switching Station w 3 autos**				x			n/a	n/a	n/a	n/a	0.00	2015	$18,715,000	PSCo Proxy	GI-2004-5 SIS (5/05)	$0	$0	$0	$18,715,000	$0	$0
13	**psco**	**Green Valley 345 kV Switching**				x			n/a	n/a	n/a	n/a	0.00	2015	$15,760,000	PSCo Proxy	GI-2004-5 SIS (5/05)	$0	$0	$0	$15,760,000	$0	$0
14	**psco**	**Pawnee 345 kV Substation (includes Autos & Line Terminations)**			x				0.00010	0.01500	0.00000	560	0.00	2015	$11,500,000	*Pawnee Feas. Study Estimate(Jul 03')*	Loss of Pawnee-DP or Pawnee Smoky	$0	$0	$11,500,000	$0	$0	$0
15	**psco**	**Pawnee - Ft.Lupton double-ckt 230kV**	x	x	x		x	x	0.00597	0.06320	0.27954	800	63.90	2015	$52,790,000	RFP Est. - Includes Substation Equipment	Loss od Pawnee-Smoky or Pawnee-Daniels Pk	$52,790,000	$52,790,000	$52,790,000	$0	$52,790,000	$52,790,000
16	**psco**	**Pawnee - Corner Pt 345kV Double ckt**			x				0.00228	0.02655	0.48254	1200	54.58	2015	$13,220,000	*Pawnee Feas. Study Estimate(Jul 03')*	Loss of Pawnee-DP or Pawnee Smoky	$0	$0	$13,220,000	$0	$0	
17	**psco**	**Corner Point 345/230kV Substation (includes Autos & Line Terminations) Including Corner Gen Interconnectin**			x				0.00010	0.01500	0.00000	560	0.00	2015	$12,100,000	*Pawnee Feas. Study Estimate(Jul 03')*	Loss of Pawnee-DP or Pawnee Smoky	$0	$0	$12,100,000	$0	$0	
18	**psco**	**Ft. Lupton to Cherokee (Platte Valley Conversion)**	x	x	x	x	x	x	n/a	n/a	n/a	800	28.30	2015	$13,685,000	GI-2004-1 SIS	Loss of Other Ft. Lupton-Cherokee Parallel Ckt.	$13,685,000	$13,685,000	$13,685,000	$13,685,000	$13,685,000	$13,685,000
19																							
20																							
21	psco	Chambers 230/115 kV switching Station and associated transmission lines	x	x	x	x	x	x	n/a	n/a	n/a	495	10.00	2007	$14,720,000	PSCo Proxy	1999 IRP Required for RMEC and BSEC	$14,720,000	$14,720,000	$14,720,000	$14,720,000	$14,720,000	$14,720,000
22	psco	Uprate Spruce - SmokY Hill	x	x	x	x	x	x	n/a	n/a	n/a	800	0.00	2007	$1,840,000	RFP Est.	Loss of parallel circuit	$1,840,000	$1,840,000	$1,840,000	$1,840,000	$1,840,000	$1,840,000
23	psco	Uprate St. Vrain to Valmont Dbl Ckt	x	x	x	x	x	x	n/a	n/a	n/a	600	0.00	2007	$1,580,000	RFP Est.	Loss of parallel circuit	$1,580,000	$1,580,000	$1,580,000	$1,580,000	$1,580,000	$1,580,000
24	psco	Chambers 2nd 230-115kV auto							0.00060	0.03000	0.00000	280	0.00	2007	$3,470,000	RFP Est.	Loss of Spuce-Smoky #1 or #2 230 KV Line	$0	$0	$0	$0	$0	$0
25	psco	B. Creek PSCo 230-115kV auto Upgrade/Uprate to 250 MVA	x	x	x	x	x	x	0.00450	0.04960	0.00000	250	0.00	2015	$3,300,000	RFP Est./TSGT Holcomb Study	Loss of Beaver Creek PSCo -BC WAPA 115 kV Line	$3,300,000	$3,300,000	$3,300,000	$3,300,000	$3,300,000	$3,300,000
26	psco	Valmont 230-115kV 280 MVA 2nd Auto	x	x	x	x	x	x	0.00085	0.03619	0.00000	280	0.00	2007	$3,740,000	RFP Est.	Loss of Plains End-Look Out 230 kVline	$3,740,000	$3,740,000	$3,740,000	$3,740,000	$3,740,000	$3,740,000
27	psco	Daniels Park 230-115kV 280 MVA auto Replacement	x	x	x	x	x	x	0.00600	0.03239	0.00000	280	0.00	2009	$2,740,000	RFP Est.	Loss of Parker-Bayou 115 kV Line	$2,740,000	$2,740,000	$2,740,000	$2,740,000	$2,740,000	$2,740,000
28	psco	Cedar Tap 230 kV Switching Including W022 Interconnection	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2007	$5,010,000	PSCo Proxy	GI-2004-5 SIS (5/05)	$5,010,000	$5,010,000	$5,010,000	$5,010,000	$5,010,000	$5,010,000
29	psco	Comanche #1 & #2 Auto Replacements	x	x	x	x	x	x	0.00600	0.03239	0.00000	350	0.00	2008	$4,940,000	RFP Est.	Loass of Parallel XFMR	$4,940,000	$4,940,000	$4,940,000	$4,940,000	$4,940,000	$4,940,000
30	psco	Uprate Pawnee-Quincy-Smoky Hill from 478 MVA to 800 MVA & Uprate Smoky Hill to Daniels DBL Ckt . Towers from 328 to 637 MVA	x	x	x	x	x	x	n/a	n/a	n/a	800	121.00	2007	$1,420,000	PSCo Proxy (2007 Budget)	Required for loss of Pawnee-CP or Pawnee-Ft. Lupton	$1,420,000	$1,420,000	$1,420,000	$1,420,000	$1,420,000	$1,420,000
31	psco	Corner Point 230 kV Switchng North Alt. 3 Including Corner Gen Interconnectin				x			n/a	n/a	n/a	n/a	0.00	2015	$8,525,000	TSGT Est. Guide	Interconnection of Corner Gen and Delivery Corner and Pawnee Gen	$0	$0	$0	$8,525,000	$0	$0
32	psco	Corner Point 230 kV Switchng North Alt. 1 Including Corner Gen Interconnectin	x	x			x	x	n/a	n/a	n/a	n/a	0.00	2015	$4,374,000	*GI-2003-2 Facilties Study (Jun '05)*	Interconnection and Delivery of Corner Gen	$4,374,000	$4,374,000	$0	$0	$0	$4,374,000
33	psco	Tie in Corner-Daniels Park into Smoky Hill	x	x	x		x	x	n/a	n/a	n/a	800	1.00	2015	$500,000	PSCo Proxy	Loss of Daniels Park-Prairie/Greenwood	$500,000	$500,000	$500,000	$0	$500,000	$500,000
34	psco	Interconnect W009 at Pawnee	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2007	$1,150,000	PSCo Proxy	GI-2006-1 Cluster	$1,150,000	$1,150,000	$1,150,000	$1,150,000	$1,150,000	$1,150,000
35	psco	Interconnect G014 at Pawnee	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2015	$1,150,000	PSCo Proxy	RFP Est.	$1,150,000	$1,150,000	$1,150,000	$1,150,000	$1,150,000	$1,150,000
36	psco	Interconnect Spindle	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2007	$3,990,000	PSCo Proxy	GI-2006-1 Cluster	$3,990,000	$3,990,000	$3,990,000	$3,990,000	$3,990,000	$3,990,000
37	psco	Interconnect BSEC #2	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2008	$1,230,000	PSCo Proxy	GI-2006-1 Cluster	$1,230,000	$1,230,000	$1,230,000	$1,230,000	$1,230,000	$1,230,000
38	psco	Interconnect Squirrel	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2010	$8,240,000	PSCo Proxy	GI-2006-1 Cluster	$8,240,000	$8,240,000	$8,240,000	$8,240,000	$8,240,000	$8,240,000
39	psco	Arapahoe-Greenwood 230 kV					x	x	0.00129	0.14549	0.02817	495	8.94	2015	$6,970,000	PSCo Proxy	Loss of Smoky Hill to Buckley #1	$0	$0	$0	$0	$6,970,000	$6,970,000
40	psco	Weld 230/115 kV Auto Replacement	x	x	x	x	x	x	n/a	n/a	n/a	350	0.00	2015	$3,470,000	PSCo Proxy	Loss of WAPA Auto	$3,470,000	$3,470,000	$3,470,000	$3,470,000	$3,470,000	$3,470,000
41	psco	Waterton-Lookout 230 kV line	x	x	x		x	x	n/a	n/a	n/a	495	22.00	2015	$3,850,000	PSCo Proxy	Loss of Smoky Hill to Buckley #1	$3,850,000	$3,850,000	$3,850,000	$0	$3,850,000	$3,850,000
42																							
43																							
44	psco	Sulphur 2nd 230/115 kV 168 MVA auto	x	x	x	x	x	x	0.00100	0.00543	0.00100	268	0.00	2006	$1,445,000	PSCo Proxy	Loss of Smoky-Peakview 115 kV	$1,445,000	$1,445,000	$1,445,000	$1,445,000	$1,445,000	$1,445,000
45	psco	Ft. Lupton 2nd 230/115 kV auto	x	x	x	x	x	x	n/a	n/a	n/a	280	0.00	2015	$3,470,000	PSCo Proxy	Open Ended from Valmont on Ft. Lupton-Valmont Line	$3,470,000	$3,470,000	$3,470,000	$3,470,000	$3,470,000	$3,470,000
46	psco	3rd 115/46 kV transformer at Weld PS	x	x	x	x	x	x	n/a	n/a	n/a	48	0.00	2015	$1,500,000	PSCo Proxy	Loass of Parallel XFMR	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000
47	psco	Ridge 230/115 kV auto Replacements from 100 MVA to 168 MVA	x	x	x	x	x	x	n/a	n/a	n/a	168	0.00	2015	$1,083,750	PSCo Proxy	Loss of Parallel XFMR	$1,083,750	$1,083,750	$1,083,750	$1,083,750	$1,083,750	$1,083,750
48	psco	San Luis Valley-Walsenburg 230 kVline	x	x	x	x	x	x	0.01103	0.10105	0.20852	416.7	80.00	2010	$10,240,974	TSGT Proxy	Loss of Poncha - San Luis Valey 230 kV	$10,240,974	$10,240,974	$10,240,974	$10,240,974	$10,240,974	$10,240,974
49	psco	Englewood to Littleton 115 kV line uprate to 162 MVA	x	x	x	x	x	x	n/a	n/a	n/a	162	11.55	2015	$50,000	open ended from waterton	Open ended from Waterton	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
50	psco	Littleton-Waterton 115 kV Uprate	x	x	x	x	x	x	n/a	n/a	n/a	217	10.89	2010	$100,000	GI-2006-1 Cluster	Open Ended from Arapahoe	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
51	psco	Smoky Hill -East-Fitzsimmons-Chambers 230 kV Conversion	x	x	x	x	x	x	n/a	n/a	n/a	495	15.50	2015	$18,737,500	PSCo Proxy/TSGT EST. Guide Includes Substation Const.	load growth/reduce the size of Chambers Auto and number	$18,737,500	$18,737,500	$18,737,500	$18,737,500	$18,737,500	$18,737,500
52	psco	Smoky Hill-Meadows-Jordan Uprate	x	x	x	x	x	x	n/a	n/a	n/a	558	7.52	2007	$920,000		Loss Smoky Hill-Buckley @30 kV	$920,000	$920,000	$920,000	$920,000	$920,000	$920,000
53	psco	Capitol Hill-North 547 115 kV upgrade	x	x	x	x	x	x	0.00180	0.00593	0.13078	182	3.64	2006	$3,714,000	PSCo Proxy	Loss of Cherokee-Mapelton 115 kV	$3,714,000	$3,714,000	$3,714,000	$3,714,000	$3,714,000	$3,714,000
54	psco	Comanche-Reader Upgrade/Place Underground	x	x	x	x	x	x	n/a	n/a	n/a	239	0.21	2005	$1,003,342	PSCo Proxy	Loss of Coma-Walsburg/ComancheG3 Installation	$1,003,342	$1,003,342	$1,003,342	$1,003,342	$1,003,342	$1,003,342
55	psco	IREA Brick Center Switching Station (includes 230/115 kV auto)	x	x	x	x	x	x	n/a	n/a	n/a	n/a	n/a	2007	$6,482,243	PSCo Proxy	Load Serving	$6,482,243	$6,482,243	$6,482,243	$6,482,243	$6,482,243	$6,482,243
56	psco	IREA Brick Center-Bennet 115 kV Line	x	x	x	x	x	x	0.00620	0.03740	0.07000	188	7.00	2007	$1,540,000	TSGT Est. Guide	IREA Load Serving Line	$1,540,000	$1,540,000	$1,540,000	$1,540,000	$1,540,000	$1,540,000
57	psco	IREA Brick Center - Elizabeth 115 kV line	x	x	x	x	x	x	0.01947	0.11447	0.01811	179	22.00	2010	$4,840,000	TSGT Est. Guide	IREA Load Serving Line	$4,840,000	$4,840,000	$4,840,000	$4,840,000	$4,840,000	$4,840,000
58	psco	IREA Bennett-Strasburg 115 kV Line	x	x	x	x	x	x	0.00420	0.02510	0.05000	188	5.70	2007	$1,254,000	TSGT Est. Guide	IREA Load Serving Line	$1,254,000	$1,254,000	$1,254,000	$1,254,000	$1,254,000	$1,254,000
59	psco	2nd Comanche - Reader 115kV line	x	x	x	x	x	x	0.00016	0.00150	0.00016	239	0.21	2009	$995,000	PSCo Proxy	Loss of #1 Ckt	$995,000	$995,000	$995,000	$995,000	$995,000	$995,000
60	psco	Bancroft - Gray St. 115kV line Upgrade	x	x	x	x	x	x	0.00192	0.01907	0.04281	247	3.43	2015	$1,200,500	PSCo Proxy	Open Ended Allison to Soda Lakes	$1,200,500	$1,200,500	$1,200,500	$1,200,500	$1,200,500	$1,200,500
61	psco	Denver Terminal-Dakota-Arapohoe 230 kV	x	x	x	x	x	x	n/a	n/a	n/a	495	??	2006	$10,710,000	PSCo Proxy	Relieves Varioues Downtoewn UG OL's	$10,710,000	$10,710,000	$10,710,000	$10,710,000	$10,710,000	$10,710,000
62	psco	Cherokee - Federal Heights 115kV line upgrade ckts 1&2	x	x	x	x	x	x	0.00280	0.02691	0.03794	239	4.84	2015	$2,420,000	TSGT Est. Guide	Loss of Parallel Ckt	$2,420,000	$2,420,000	$2,420,000	$2,420,000	$2,420,000	$2,420,000
63	psco	Federal Heights - Broomfield 115kV line upgrade ckts 1&2	x	x	x	x	x	x	0.00287	0.02576	0.03886	239	4.95	2015	$2,475,000	TSGT Est. Guide	Loss of Parallel Ckt	$2,475,000	$2,475,000	$2,475,000	$2,475,000	$2,475,000	$2,475,000
64	psco	Uprate Lafayette to Valmont 115 kV line	x	x	x	x	x	x	0.00194	0.08785	0.04762	239	7.61	2015	$2,967,900	PSCo Proxy	Open Ended From Ft. Lupton	$2,967,900	$2,967,900	$2,967,900	$2,967,900	$2,967,900	$2,967,900
65	psco	Sandown-Leetsdale 115 kV	x	x	x	x	x	x	0.00035	0.00315	0.31590	251	5.00	2009	$11,127,000	Loss of various 115 kV lines from Cherokee	Relieves Varioues Downtoewn UG OL's	$11,127,000	$11,127,000	$11,127,000	$11,127,000	$11,127,000	$11,127,000
66	psco	Kendrick - Bancroft 115kV Upgrade	x	x	x	x	x	x	0.00164	0.01445	0.01254	319	3.70	2015	$1,295,000	Bundeled 795 kCMIL ACSR	Open Ended Allison to Soda Lakes	$1,295,000	$1,295,000	$1,295,000	$1,295,000	$1,295,000	$1,295,000
67	psco	Soda Laker 230 KV 90 MVAR capacitor bank	x	x	x	x	x	x	n/a	n/a	n/a	n/a	n/a	2015	$1,200,000	PSCo Proxy	VAR/Voltage Support	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$1,200,000
68	psco	Marcy 230 kV 180 MVAR Capacitor Bank	x	x	x	x	x	x	n/a	n/a	n/a	n/a	n/a	2015	$2,000,000	PSCo Proxy	VAR/Voltage Support	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
69	psco	Sulphur 230 kV 180 MVAR Capacitor Bank	x	x	x	x	x	x	n/a	n/a	n/a	n/a	n/a	2015	$2,000,000	PSCo Proxy	VAR/Voltage Support	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
70	psco	Broomfield 45 MVAR Capacitor bank	x	x	x	x	x	x	n/a	n/a	n/a	n/a	n/a	2015	$750,000	PSCo Proxy	VAR/Voltage Support	$750,000	$750,000	$750,000	$750,000	$750,000	$750,000
71	psco	Ridge 90 MVAR Capacitor bank	x	x	x	x	x	x	n/a	n/a	n/a	n/a	n/a	2015	$2,000,000		VAR/Voltage Support	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
72	psco	Cherokee-Conoco Uprate to 162 MVA	x	x	x	x	x	x	n/a	n/a	n/a	162	0.00	2015	$50,000	Simple Rerate / PSCo Proxy	Loss of Cherokee-Mapelton 115 kV	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
73	psco	Soda Lakes - Allison 115 kV upgrade	x	x	x	x	x	x	0.00187	0.01764	0.04540	319	4.19	2015	$1,466,500	Bundeled 795 kCMIL ACSR	Open end from Bancroft	$1,466,500	$1,466,500	$1,466,500	$1,466,500	$1,466,500	$1,466,500
74	psco	Broomfield-Semper 115 kV Dbl Ckt. Uprate	x	x	x	x	x	x	n/a	n/a	n/a	162	0.00	2015	$50,000	Simple Rerate / PSCo Proxy	Loss of Parallel Ckt #1 or #2	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
75																	**PSCo TOTAL**	**$470,716,709**	**$470,716,709**	**$520,532,709**	**$521,899,709**	**$473,312,709**	**$477,686,709**
76		**South 345 kV 1200 PSCo Total Infrastructure Costs (Millions) ------>**															**PSCo BACKBONE**	**$304,385,000**	**$304,385,000**	**$358,575,000**	**$355,767,000**	**$304,385,000**	**$304,385,000**
77		**South 500 kV 120) MW PSCo Total Infrastructure Costs (Millions) ------>**															**PSCo Regional**	**$99,087,709**	**$99,087,709**	**$99,087,709**	**$99,087,709**	**$99,087,709**	**$99,087,709**
78		**North PSCo Total Infrastructure Costs (Millions) ------>**															**PSCo SECONDARY BULK**	**$67,244,000**	**$67,244,000**	**$62,870,000**	**$67,045,000**	**$69,840,000**	**$74,214,000**
79		**South 345 kV 1800 MW PSCo Total Infrastructure Costs (Millions) ------>**															**SECONDARY BULK and Regional Total**	**$166,331,709**	**$166,331,709**	**$161,957,709**	**$166,132,709**	**$168,927,709**	**$173,301,709**
80																							
81																			**South Pri in North Pri**	**$175,560,000**	**$175,560,000**		
82																			**Total North less North Pri**	**$337,517,709**	**$341,692,709**		
83		**South 500 kV 1800 MW PSCo Total Infrastructure Costs (Millions) ------>**																	**North Pri Less South Pri**	**$183,015,000**	**$180,207,000**		
84																		**South 345 kV 1200 MW Costs**	**South 500 kV 1200 MW Costs**		**North Alt. 2 Costs**	**South 345 kV 1800 MW Costs**	**South 500 kV 1800 MW Costs**
85	**prpa**	**(DEL) Rawhide - Timberline 230kV WEST line Ckt 2**	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	n/a 2006			change system configuration	$65,000,000	$65,000,000	$65,000,000	$65,000,000	$65,000,000	$65,000,000
86	**prpa**	**Rawhide - Dixon 230kV line**	x	x	x	x	x	x	0.00566	0.04421	0.08762	378	30.00	2006			load growth	$0	$0	$0	$0	$0	$0
87	**prpa**	**St. Vrain - Fordham 230kV line**	x	x	x	x	x	x	0.00232	0.01864	0.70020	339	19.60	2007			load growth	$0	$0	$0	$0	$0	$0
88	**prpa**	**Dixon-Horseshoe 230kV line**	x	x	x	x	x	x	0.00181	0.01310	0.02775	472	9.40	2008			load growth	$0	$0	$0	$0	$0	$0
89	**prpa**	**Dixon 230-115kV autos T1 & T2**	x	x	x	x	x	x	0.00110	0.05870	0.00000	184	0.00	2006			load growth	$0	$0	$0	$0	$0	$0
90	**prpa**	**Fordham 230-115kV autos T1 & T2**	x	x	x	x	x	x	0.00110	0.05870	0.00000	184	0.00	2007			load growth	$0	$0	$0	$0	$0	$0
91	**prpa**	**Horseshoe 230-115kV autos T1 & T2**	x	x	x	x	x	x	0.00110	0.05870	0.00000	184	0.00	2008			load growth	$0	$0	$0	$0	$0	$0
92	**prpa**	**2nd Boyd 230-115kV auto**	x	x	x	x	x	x	0.00110	0.05870	0.00000	184	0.00	2009			load growth	$0	$0	$0	$0	$0	$0
93	**prpa**	**3rd Longs Peak 230-115kV auto**	x	x	x	x	x	x	0.00150	0.04700	0.00000	184	0.00	2010			load growth	$0	$0	$0	$0	$0	$0
94	**prpa**	**2nd Timberline 230-115kV auto**	x	x	x	x	x	x	0.00434	0.08393	0.00000	184	0.00	2011	$65,000,000	Cost total is in PRPA proxy estimations	load growth	$0	$0	$0	$0	$0	$0
95	**prpa**	**60 (1x60) MVAR shunt reactor, Fordham end of St.Vrain 230 kV line**	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2007			protect 230 kV cable from overvoltage	$0	$0	$0	$0	$0	$0
96	prpa	Laporte Tap - Overland 115kV line rebuild	x	x	x	x	x	x	0.00169	0.01239	0.00169	236	2.20	2006			load growth	$0	$0	$0	$0	$0	$0
97	prpa	Overland - Dixon 115kV line rebuild	x	x	x	x	x	x	0.00154	0.01127	0.00155	236	2.00	2006			load growth	$0	$0	$0	$0	$0	$0
98	prpa	(DEL) Terry - Fordham 115kV line	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	n/a 2007			change system configuration	$0	$0	$0	$0	$0	$0
99	prpa	35 (1x35) MVAR cap at Terry 115 kV, C1	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2006			meet reactive demand/voltage support	$0	$0	$0	$0	$0	$0
100	prpa	70 (2x35) MVAR caps at Dixon 115 kV, C1 & C2	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2006			meet reactive demand/voltage support	$0	$0	$0	$0	$0	$0
101	prpa	70 (2x35) MVAR caps at Horseshoe 115 kV (C1 in 2008, C2 in 2012)	x	x	x	x	x	x	n/a	n/a	n/a	n/a	0.00	2012			meet reactive demand/voltage support	$0	$0	$0	$0	$0	$0
102																		$0	$0	$0	$0	$0	$0
103															**$65,000,000**	**PRPA Total**	Total PRPA	**$65,000,000**	**$65,000,000**	**$65,000,000**	**$65,000,000**	**$65,000,000**	**$65,000,000**
104																							
105																		**South 345 kV 1200 MW Costs**	**South 500 kV 1200 MW Costs**	**North Alt. 1 Costs**	**North Alt. 2 Costs**	**South 345 kV 1800 MW Costs**	**South 500 kV 1800 MW Costs**
106																							

	A	B	D	E	F	G	H	I	J	K	L	M	N	Q	R	S	U	V	W	X	Y	Z	AA
1	**CLRTP Master Transmission Infrastructure (Revised 6/30/06)**																						
2	**Entity**	**Element**	**South 345 kV 1200 MW**	**South 500 kV 1200 MW**	**North Alt. 1**	**North Alt. 2**	**South 345 kV 1800 MW**	**South 500 kV 1800 MW**	**r**	**x**	**b**	**MVA Rating**	**length (mi)**	**ISD**	**Esitmated Facility Cost ($)**	**Notes**	**Reason**	**South 345 kV 1200 MW Costs**	**South 500 kV 1200 MW Costs**	**North Alt. 1 Costs**	**North Alt. 2 Costs**	**South 345 kV 1800 MW Costs**	**South 500 kV 1800 MW Costs**
107																		**South 345 kV 1200 MW Costs**	**South 500 kV 1200 MW Costs**	**North Alt. 1 Costs**	**North Alt. 2 Costs**	**South 345 kV 1800 MW Costs**	**South 500 kV 1800 MW Costs**
108	**csu**	**Nixon-Kelker double circuit reconductor**	x	x	x	x	x	x				482/ckt	20.00	2009	$2,500,000	CSU estimated cost	Load Growth	*$2,500,000*	$2,500,000	$2,500,000	*$2,500,000*	$2,500,000	$2,500,000
109	**csu**	**2nd Nixon - Kelker 230kV line**	x	x	x	x	x	x	0.00250	0.01980	0.03840	300	7.00	2006	$2,750,000	Total line length 13.5 - project to complete circuit	Load Growth	$2,750,000	$2,750,000	$2,750,000	*$2,750,000*	$2,750,000	$2,750,000
110	**csu**	**2nd Midway-Nixon 230kV line**		x			x	x	0.00090	0.00810	0.01440	483	5.40	2010-2012	$5,956,800	TSGT Est. Guide	Holocomb Delivery	$0	$5,956,800	$0	*$0*	$5,956,800	$5,956,800
111	csu	Kelker W - Rock Island 115kV line Upgrade (re-cond)	x	x	x	x	x	x	0.00550	0.02590	0.00350	159	4.59	2008-10	$465,000	CSU estimated cost	Load Growth	$465,000	$465,000	$465,000	*$465,000*	$465,000	$465,000
112	csu	Rock Island - Templeton 115kV line Upgrade (re-cond)	x	x	x	x	x	x	0.00340	0.01580	0.00220	159	2.80	2008-10	$285,000	CSU estimated cost	Load Growth	$285,000	$285,000	$285,000	*$285,000*	$285,000	$285,000
114	csu	Kelker E - Templeton 115kV line Upgrade (re-cond)	x	x	x	x	x	x	0.00890	0.04170	0.00570	159	7.39	2008-10	$750,000	CSU estimated cost	Load Growth	$750,000	$750,000	$750,000	*$750,000*	$750,000	$750,000
115	csu	Kelker W - Drake 115kV Upgrade (re-cond)	x	x	x	x	x	x				159	5.47	2007	$500,000	CSU estimated cost	Load Growth	$500,000	$500,000	$500,000	*$500,000*	$500,000	$500,000
116																**CSU Total**	CSU TOTAL	**$7,250,000**	**$13,206,800**	**$7,250,000**	**$7,250,000**	**$13,206,800**	**$13,206,800**
117																	CSU SECONDARY BULK	$5,250,000	$11,206,800	$5,250,000	$5,250,000	$11,206,800	$11,206,800
118																	CSU REGIONAL	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
119																		$0	$0		$0	$0	$0
120																		$0	$0		$0	$0	$0
121	Tri-State	Big Sandy - LEC 345 kV Line					x		0.00486	0.0683	1.14839	1619	135.00	2020	$92,458,000	need for 345/1800 stability	Holcomb Power Delivery	$0	$0	$0	$0	$92,458,000	$0
122	Tri-State	Big Sandy - Story 345 kV Line	x		x	x	x		0.00252	0.03542	0.59546	1619	70.00	2011	$50,230,000		Holcomb Power Delivery	$50,230,000	$0	$50,230,000	$50,230,000	$50,230,000	$0
123	Tri-State	Big Sandy 345/230 kV Transformers	x		x	x	x		0.0002	0.0129	N/A	(2) 500	N/A	2011	$26,227,000	(2) 400 MVA minimum recommended; (2) 500 MVA + new sub used for cost estimation	Holcomb Power Delivery	$26,227,000	$0	$26,227,000	$26,227,000	$26,227,000	$0
124	Tri-State	Big Sandy-Burlington 345 KV Line	x		x	x	x		0.00254	0.04146	0.66049	1619	80.00	2011	$57,951,000	needed for stability	Holcomb Power Delivery	$57,951,000	$0	$57,951,000	$57,951,000	$57,951,000	$0
125	Tri-State	Big Sandy-Midway 345 KV Line	x		x	x	x		0.00254	0.04146	0.59546	1619	85.00	2011	$60,858,000		Holcomb Power Delivery	$60,858,000	$0	$60,858,000	$60,858,000	$60,858,000	$0
126	Tri-State	Boone 345/230 KV transformers	x		x	x	x		0.0002	0.0129	N/A	(2) 500	N/A	2011	$26,227,000	(2) 350 MVA minimum recommended; (2) 500 MVA + new sub used for cost estimation	Holcomb Power Delivery	$26,227,000	$0	$26,227,000	$26,227,000	$26,227,000	$0
127	Tri-State	Boone-LEC 345 kV Line	x		x	x	x		0.00315	0.0517	0.82667	1619	100.00	2011	$72,109,000		Holcomb Power Delivery	$72,109,000	$0	$72,109,000	$72,109,000	$72,109,000	$0
128	Tri-State	Boone-Midway 345 KV Line	x		x	x	x		0.00144	0.0234	0.37094	1619	45.00	2011	$37,601,000		Holcomb Power Delivery	$37,601,000	$0	$37,601,000	$37,601,000	$37,601,000	$0
129	Tri-State	Burlington - Holcomb 345 kV Line	x		x	x	x		0.00612	0.08601	1.44612	1619	150.00	2011	$101,179,000	Includes new transmission sub costs	Holcomb Power Delivery	$101,179,000	$0	$101,179,000	$101,179,000	$101,179,000	$0
130	Tri-State	Burlington - LEC 345 kV Line	x		x	x	x		0.00252	0.03542	0.59546	1619	70.00	2011	$54,667,000		Holcomb Power Delivery	$54,667,000	$0	$54,667,000	$54,667,000	$54,667,000	$0
131	Tri-State	Burlington 345/230 kV Transformers	x		x	x	x		0.0002	0.0129	N/A	(2) 500	N/A	2011	$26,227,000	(2) 575 MVA minimum recommended; (2) 500 MVA + new sub used for cost estimation	Holcomb Power Delivery	$26,227,000	$0	$26,227,000	$26,227,000	$26,227,000	$0
132	Tri-State	Holcomb - LEC #1 345 kV Line	x		x	x	x		0.00342	0.04806	0.80812	1619	80.00	2011	$63,011,000		Holcomb Power Delivery	$63,011,000	$0	$63,011,000	$63,011,000	$63,011,000	$0
133	Tri-State	Holcomb - LEC #2 345 kV Line	x		x	x	x		0.00342	0.04806	0.80812	1619	80.00	2011	$63,011,000		Holcomb Power Delivery	$63,011,000	$0	$63,011,000	$63,011,000	$63,011,000	$0
134	Tri-State	LEC 345/230 kV Transformers	x		x	x	x		0.0002	0.0129	N/A	(2) 500	N/A	2011	$31,288,000	(2) 175 MVA minimum recommended; (2) 500 MVA + new sub used for cost estimation	Holcomb Power Delivery	$31,288,000	$0	$31,288,000	$31,288,000	$31,288,000	$0
135	Tri-State	Midway 345 kV Tie Line	x		x	x	x		0	0.001	0	1619	0.10	2011	$7,378,000		Holcomb Power Delivery	$7,378,000	$0	$7,378,000	$7,378,000	$7,378,000	$0
136	Tri-State	Midway 345/230 KV Transformer	x		x	x	x		0.0002	0.0123	N/A	560	N/A	2011	$16,562,000	(2) 400 MVA minimum recommended; (1) 560 MVA, single-phase used for cost estimation	Holcomb Power Delivery	$16,562,000	$0	$16,562,000	$16,562,000	$16,562,000	$0
137	Tri-State	Burlington - Wray 230 kV Line	x	x	x	x	x	x	0.00486	0.0683	0.22684	1080	60.00	2011	$22,562,000		Holcomb Power Delivery	$22,562,000	$22,562,000	$22,562,000	$22,562,000	$22,562,000	$22,562,000
138	Tri-State	Lamar - LEC #1 230 kV Line	x	x	x	x	x	x	0.00162	0.02277	0.3828	1080	20.00	2011	$19,439,000		Holcomb Power Delivery	$19,439,000	$19,439,000	$19,439,000	$19,439,000	$19,439,000	$19,439,000
139	Tri-State	Lamar - LEC #2 230 kV Line	x	x	x	x	x	x	0.00162	0.02277	0.3828	1080	20.00	2011	$19,439,000		Holcomb Power Delivery	$19,439,000	$19,439,000	$19,439,000			
140	Tri-State	Beaver Creek-Big Sandy 230 kV Line		x				x	0.0152	0.1156	0.23412	1080	70.00	2011	$39,872,000	constructed for 345 kV	Holcomb Power Delivery	$0	$39,872,000	$0	$0	$0	$39,872,000
141	Tri-State	Big Sandy 500/230 KV Transformers		x				x	0.00026	0.02277	N/A	(2) 600	N/A	2011	$38,808,000	(2) 450 MVA minimum recommended; (2) 600 MVA used for cost estimation	Holcomb Power Delivery	$0	$38,808,000	$0	$0	$0	$38,808,000
142	Tri-State	Big Sandy-Burlington 500 KV Line		x				x	0.001	0.02117	1.79865	3001	80.00	2011	$88,597,000	needed for stability	Holcomb Power Delivery	$0	$88,597,000	$0	$0	$0	$88,597,000
143	Tri-State	Big Sandy-Midway 500 KV Line						x	0.001	0.02117	1.79865	3001	85.00	2020	$93,010,000	needed for 500/1800 stability	Holcomb Power Delivery	$0	$0	$0	$0	$0	$93,010,000
144	Tri-State	Boone 500/230 KV Transformers		x				x	0	0.0289	N/A	(2) 450	N/A	2011	$35,975,000	(2) 400 MVA minimum recommended; (2) 450 MVA used for cost estimation	Holcomb Power Delivery	$0	$35,975,000	$0	$0	$0	$35,975,000
145	Tri-State	Boone-LEC 500 KV Line		x				x	0.00105	0.02227	1.89397	2400	100.00	2011	$109,247,000		Holcomb Power Delivery	$0	$109,247,000	$0	$0	$0	$109,247,000
146	Tri-State	Boone-Midway 500 KV Line		x				x	0.00048	0.01008	0.84989	2400	45.00	2011	$57,702,000		Holcomb Power Delivery	$0	$57,702,000	$0	$0	$0	$57,702,000
147	Tri-State	Burlington 500/230 KV Transformers		x				x	0.00026	0.02277	N/A	(2) 600	N/A	2011	$38,808,000	(2) 525 MVA minimum recommended; (2) 600 MVA used for cost estimation	Holcomb Power Delivery	$0	$38,808,000	$0	$0	$0	$38,808,000
148	Tri-State	Burlington-Holcomb 500 KV Line		x				x	0.00167	0.03286	2.89832	3001	150.00	2011	$154,457,000	Includes new transmission sub costs	Holcomb Power Delivery	$0	$154,457,000	$0	$0	$0	$154,457,000
149	Tri-State	Burlington-LEC 500 KV Line		x				x	0.00074	0.01565	1.32339	2400	70.00	2011	$82,767,000		Holcomb Power Delivery	$0	$82,767,000	$0	$0	$0	$82,767,000
150	Tri-State	Holcomb-LEC 500 KV Line		x				x	0.001	0.02117	1.79865	3001	80.00	2011	$94,591,000		Holcomb Power Delivery	$0	$94,591,000	$0	$0	$0	$94,591,000
151	Tri-State	LEC 500/230 KV Transformers		x				x	0	0.0289	N/A	(2) 450	N/A	2011	$41,969,000	(2) 150 MVA minimum recommended; (2) 450 MVA used for cost estimation	Holcomb Power Delivery	$0	$41,969,000	$0	$0	$0	$41,969,000
152	Tri-State	Midway 500/230 KV Transformers		x				x	0.0026	0.02277	N/A	(2) 600	N/A	2011	$38,808,000	(3) 400 MVA minimum recommended; (2) 600 MVA used for cost estimation	Holcomb Power Delivery	$0	$38,808,000	$0	$0	$0	$38,808,000
153	Tri-State	125Road 230/115 kV Substation	x	x			x	x	0.0012	0.053	N/A	200	N/A	2010	$4,514,000		Holcomb Power Delivery and Future load serving	$4,514,000	$4,514,000	$0	$0	$4,514,000	$4,514,000
154	Tri-State	125 Road-Big Sandy 230 kV Line	x	x			x	x	0.00235	0.03301	0.10964	1080	30.00	2010	$22,430,000	constructed for 345 kV	Holcomb Power Delivery and Future load serving	$22,430,000	$22,430,000	$0	$0	$22,430,000	$22,430,000
155																							
156																							
157	Tri-State	125 Road - Elbert 115 kV line	x	x	x	x	x	x	0.04541	0.1564	0.0206	146	28.00	2010	$8,031,000		Holcomb Power Delivery and Future load serving	$8,031,000	$8,031,000	$8,031,000	$8,031,000	$8,031,000	$8,031,000
158	Tri-State	125 Road - Peyton 115 kV line	x	x	x	x	x	x	0.05029	0.1732	0.0228	146	31.00	2010	$8,278,000		Holcomb Power Delivery and Future load serving	$8,278,000	$8,278,000	$8,278,000	$8,278,000	$8,278,000	$8,278,000
159	Tri-State	Black Squirrel - Peyton 115 kV line	x	x	x	x	x	x	0.01470	0.05141	0.00650	146	9	2008	$2,378,000	Build Meridian Ranch substation as load serving tap on this line	TSGT 10 Year Construction Budget	$2,378,000	$2,378,000	$2,378,000	$2,378,000	$2,378,000	$2,378,000
160	Tri-State	Bromley - Prairie Center 115 kV line	x	x	x	x	x	x	0.00846	0.03254	0.25036	166	4.1	2006	$5,307,000	operated normally open	TSGT 10 Year Construction Budget	$5,307,000	$5,307,000	$5,307,000	$5,307,000	$5,307,000	$5,307,000
161	T/S / ARPA	City of Lamar-Willow Creek Second 69 KV line	x	x	x	x	x	x	0.0145	0.0335	0.0003	45.7	2.5	2013	$488,000	needed prior to City of Lamar generator ISD	CTY LAM 14.4-CTY LAM 25.0 CIRCUIT 1 OUTAGE	$488,000	$488,000	$488,000	$488,000	$488,000	$488,000
162	TS/IREA	Elbert - Kiowa 115 kV Line	x	x	x	x	x	x	0.01461	0.0578	0.00739	146	10.00	2012	$5,092,000		TS/IREA Interconnetion Option	$5,092,000	$5,092,000	$5,092,000	$5,092,000	$5,092,000	$5,092,000
163	Tri-State	Elbert 115/12.5 kV Transformer	x	x	x	x	x	x	N/A	N/A	N/A	N/A	N/A	2010	$878,000		Holcomb Power Delivery and Future load serving	$878,000	$878,000	$878,000	$878,000	$878,000	$878,000
164	Tri-State	Elbert-Monument 115 kV line	x	x	x	x	x	x	0.03696	0.14623	0.0187	146	25.30	2011	$2,459,000	Rebuild Palmer Divide and Russelville substations	Holcomb Power Delivery and Future load serving	$2,459,000	$2,459,000	$2,459,000	$2,459,000	$2,459,000	$2,459,000
165	Tri-State	Emil Anderson 115 kV, 2-15 MVAr Caps	x	x	x	x	x	x	N/A	N/A	N/A	N/A	N/A	2013	$2,500,000	Required for voltage support; not modeled	TSGT 10 Year Construction Budget	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000
166	Tri-State	Farr - Windy Gap 138 kV Line	x	x	x	x	x	x	0.00680	0.02490	0.00620	209	12	2007	$7,940,000	Double Circuit with 69 kV Line	TSGT 10 Year Construction Budget	$7,940,000	$7,940,000	$7,940,000	$7,940,000	$7,940,000	$7,940,000
167	Tri-State	Granby 138/69 kV Transformer	x	x	x	x	x	x	0.00570	0.14720	N/A	56	N/A	2007	$0	Included in cost for Farr - Windy Gap 138 kV Line	TSGT 10 Year Construction Budget	$0	$0	$0	$0	$0	$0
168	T/S / ARPA	Lamar Replacement 25/14.4 kV Generation Transformer (City)	x	x	x	x	x	x	0.01000	0.10000	N/A	40	N/A	2013	$350,000	needed prior to City of Lamar generator ISD	Accommodate increase in local generation	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000
169	Tri-State	Lincoln Hills - Plainview 115 kV Line	x	x	x	x	x	x	0.01828	0.06639	0.01651	166	16	2011	$5,472,000		TSGT 10 Year Construction Budget	$5,472,000	$5,472,000	$5,472,000	$5,472,000	$5,472,000	$5,472,000
170	Tri-State	Meridian Ranch 115/12.5 kV Transformer	x	x	x	x	x	x	N/A	N/A	N/A	N/A	N/A	2008	$74,000	TS share	Holcomb Power Delivery and Future load serving	$74,000	$74,000	$74,000	$74,000	$74,000	$74,000
171	Tri-State	Palmer Divide 115/12.5 kV Transformer	x	x	x	x	x	x	N/A	N/A	N/A	N/A	N/A	2010	$1,024,000		Holcomb Power Delivery and Future load serving	$1,024,000	$1,024,000	$1,024,000	$1,024,000	$1,024,000	$1,024,000
172	Tri-State	Prairie Center-Reunion 115 kV line	x	x	x	x	x	x	0.00970	0.03730	0.28700	166	4.7	2006	$7,193,000		TSGT 10 Year Construction Budget	$7,193,000	$7,193,000	$7,193,000	$7,193,000	$7,193,000	$7,193,000
173	Tri-State	Red Willow - Wages 115 kV Line Reconductor	x	x	x	x	x	x	0.01942	0.07054	0.01754	166	17.02	2006	$2,232,000	Reconductor required and estimated; uprate modeled	TSGT 10 Year Construction Budget	$2,232,000	$2,232,000	$2,232,000	$2,232,000	$2,232,000	$2,232,000
174	Tri-State	Reunion 230/115 kV autotransformer	x	x	x	x	x	x	0.00099	0.05377	N/A	100	N/A	2006	$2,733,000		TSGT 10 Year Construction Budget	$2,733,000	$2,733,000	$2,733,000	$2,733,000	$2,733,000	$2,733,000
175	Tri-State	Richard Lake - Waverly 115 kV Line	x	x	x	x	x	x	0.01020	0.03940	0.00530	166	7	2007	$7,612,000		TSGT 10 Year Construction Budget	$7,612,000	$7,612,000	$7,612,000	$7,612,000	$7,612,000	$7,612,000
176	Tri-State	Russelville 115/12.5 kV Transformer	x	x	x	x	x	x	N/A	N/A	N/A	N/A	N/A	2010	$830,000		Holcomb Power Delivery and Future load serving	$830,000	$830,000	$830,000	$830,000	$830,000	$830,000
177	Tri-State	Stem Beach-Walsenburg 115 kV Line Uprate	x	x	x	x	x	x	N/A	N/A	N/A	166	37.98	2010	$1,709,000		TSGT 10 Year Construction Budget	$1,709,000	$1,709,000	$1,709,000	$1,709,000	$1,709,000	$1,709,000
178	Tri-State	Willow Creek Second 115/69 kV Transformer	x	x	x	x	x	x	0.00690	0.13245	N/A	42	N/A	2006	$3,423,000		TSGT 10 Year Construction Budget	$3,423,000	$3,423,000	$3,423,000	$3,423,000	$3,423,000	$3,423,000
179																							
180																				$0			
181	T/S / Wester	Beaver Creek - Story 230 kV Tie Line	x	x	x	x	x	x	0.00030	0.00200	0.00180	413.5	0.1	2009	$6,384,000		TSGT 10 Year Construction Budget	$6,384,000	$6,384,000	$6,384,000	$6,384,000	$6,384,000	$6,384,000
182	Tri-State	Burlington 230/115 kV Replacement Xfmr #2	x	x	x	x	x	x	0.0045	0.0496	N/A	167	N/A	2012	$1,625,000		BURLNGTN 115-BURLNGTN 230 CIRCUIT 1 OUTAGE	$1,625,000	$1,625,000	$1,625,000	$1,625,000	$1,625,000	$1,625,000
183	Tri-State	Colorado - New Mexico 230 kV Intertie Line	x	x	x	x	x	x	0.01487	0.16042	0.34823	558	113	2006	$45,726,000		TSGT 10 Year Construction Budget	$45,726,000	$45,726,000	$45,726,000	$45,726,000	$45,726,000	$45,726,000
184	Tri-State	Comanche - Stem Beach 115 KV Line	x	x	x	x	x	x	0.0164	0.0598	0.0036	255	12	2008	$4,956,000	TSGT 10 Year Construction Budget; 954 ACSR conductor	COMANCHE 230-WALSENBG 230 CIRCUIT 1 OUTAGE	$4,956,000	$4,956,000	$4,956,000	$4,956,000	$4,956,000	$4,956,000
185	Tri-State	La Junta (TS) Replacement 115/69 kV Transformer	x	x	x	x	x	x	N/A	N/A	N/A	67	N/A	2009	$687,000		The outage of one transformer overloads the other	$687,000	$687,000	$687,000	$687,000	$687,000	$687,000
186	Tri-State	La Junta (TS) Second 115/69 kV Transformer	x	x	x	x	x	x	0.00404	0.08516	N/A	67	N/A	2016	$1,587,000		Solve Regional Problems	$1,587,000	$1,587,000	$1,587,000	$1,587,000	$1,587,000	$1,587,000
187	TS/Aquila	La Junta 69 kV Tie Line	x	x	x	x	x	x	0.00312	0.00783	0.00013	83.2	1.00	2009	$1,100,000		Solve Regional Problems	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,100,000
188	T/S / Xcel	Lamar 230/115 kV Replacement Xfmr					x		0.00187	0.06927	N/A	167	N/A	2020	$1,625,000	needed for 1800 MW at 345 kV	LAMAR CO 115-LAMAR CO 230 CIRCUIT 2 OUTAGE	$0	$0	$0	$0	$1,625,000	$0
189	T/S / Xcel	Lamar Second 230/115 kV Transformer	x	x	x	x	x	x	0.00187	0.06927	N/A	167	N/A	2011	$5,551,000	167 MVA is needed for 1800 MW at 345 kV; otherwise, match existing 100 MVA transformer	LAMAR CO 115-LAMAR CO 230 CIRCUIT 1 OUTAGE	$5,551,000	$5,551,000	$5,551,000	$5,551,000	$5,551,000	$5,551,000
190	Tri-State	Pueblo Tap - West Station 115 kV line uprate	x	x	x	x	x	x	N/A	N/A	N/A	166	13.00	2009	$585,000		COMANCHE 115-STEM BCH 115 CIRCUIT 1 Line Outage	$585,000	$585,000	$585,000	$585,000	$585,000	$585,000
191	T/S / Xcel	San Luis Valley - Walsenburg 230 kV Line	x	x	x	x	x	x	0.01103	0.10105	0.20852	416.7	75	2009	$27,879,000		TSGT 10 Year Construction Budget	$27,879,000	$27,879,000	$27,879,000	$27,879,000	$27,879,000	$27,879,000
192	Tri-State	Stem Beach - Walsenburg Second 115 kV Line	x	x	x	x	x	x	0.0434	0.1576	0.0392	166	37.98	2010	$7,108,000	477 ACSR conductor	TSGT 10 Year Construction Budget	$7,108,000	$7,108,000	$7,108,000	$7,108,000	$7,108,000	$7,108,000
193	Tri-State	Walsenburg Second 230/115 kV Transformer	x	x	x	x	x	x	0.00036	0.00994	N/A	100	N/A	2006	$2,915,000		TSGT 10 Year Construction Budget	$2,915,000	$2,915,000	$2,915,000	$2,915,000	$2,915,000	$2,915,000
194																				$0			
195																		$0	$0	$0	$0	$0	$0
196																		$0	$0	$0	$0	$0	$0
197																		$0	$0	$0	$0	$0	$0
198																	**TSG&T Total**	**$965,016,000**	**$1,092,091,000**	**$938,072,000**	**$918,633,000**	**$1,039,660,000**	**$1,165,662,000**
199																	TSGT Primary Backbone	**$782,910,000**	**$909,985,000**	**$755,966,000**	**$736,527,000**	**$855,929,000**	**$983,556,000**
200																	TSGT SECONDARY BULK	**$76,003,000**	**$76,003,000**	**$76,003,000**	**$76,003,000**	**$76,003,000**	**$76,003,000**
201																	TSGT REGIONAL	**$106,103,000**	**$106,103,000**	**$106,103,000**	**$106,103,000**	**$107,728,000**	**$106,103,000**
202																		$182,106,000	$182,106,000	$182,106,000	$182,106,000	$183,731,000	$182,106,000

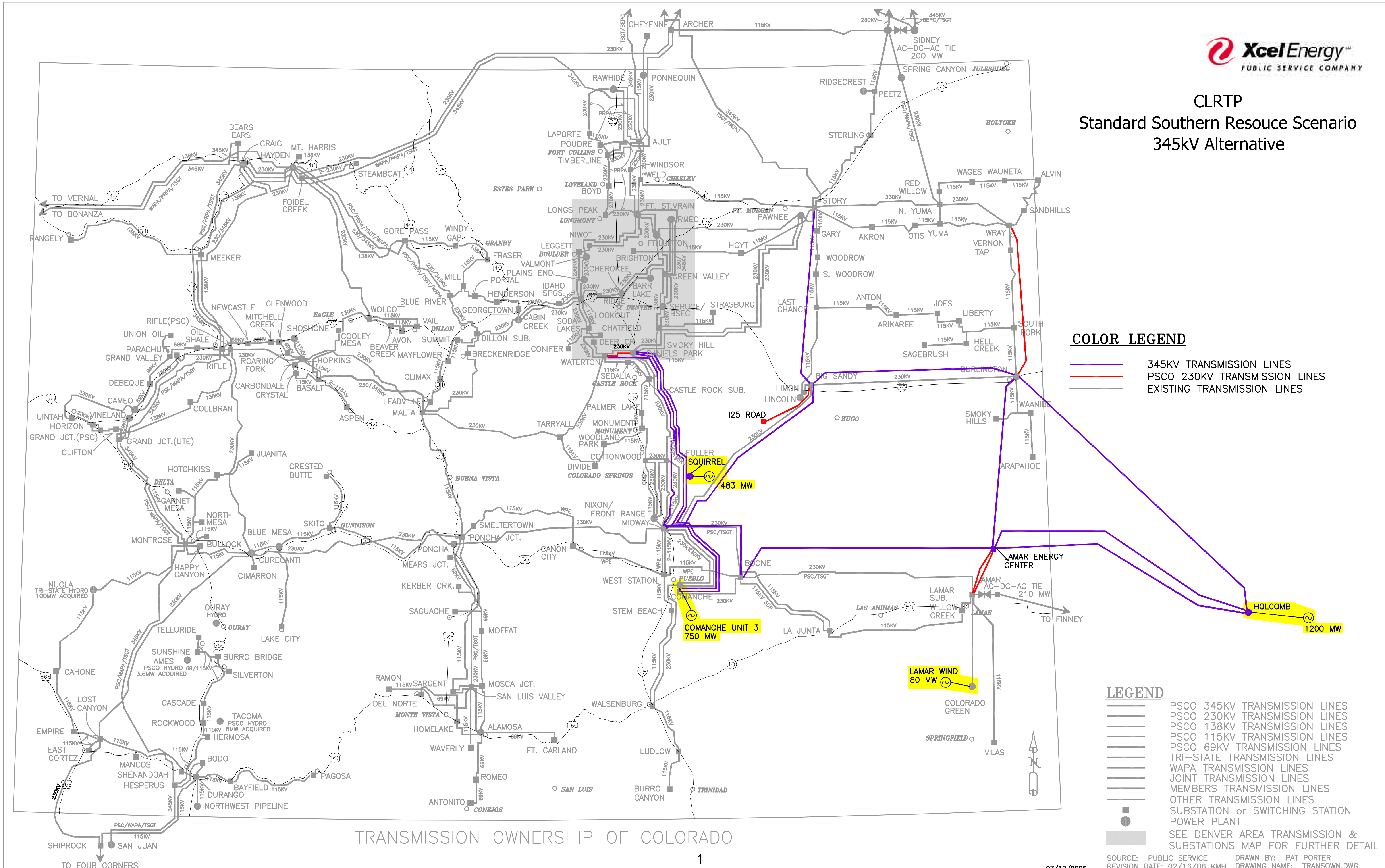
CLRTP Master Transmission Infrastructure (Revised 6/30/06)

	A	B	D	E	F	G	H	I	J	K	L	M	N	Q	R
2	Entity	Element	South 345 kV 1200 MW	South 500 kV 1200 MW	North Alt. 1	North Alt. 2	South 345 kV 1800 MW	South 500 kV 1800 MW	r	x	b	MVA Rating	length (mi)	ISD	Esitmated Facility Cost ($)
203															
204	**wapa**	Beaver Ck - Hoyt Upgrade to 230 construction, operate at 115 (BCK-ADN)	x	x	x	x	x	x	0.00997	0.09433	0.01325	220	17.01	2008	$17,880,000
205	**wapa**	(ADN-HYT)	x	x	x	x	x	x	0.00857	0.08767	0.01089	220	14.95		
206	**wapa**	Hoyt-Erie Upgrade to 230 construction, operate at 115 (HYT-SND)	x	x	x	x	x	x	0.00917	0.09382	0.01166	220	16.00	2010	$27,300,000
207	**wapa**	(SND-BRN)	x	x	x	x	x	x	0.00917	0.14656	0.01821	220	25.00		
208	**wapa**	(BRN-ERIE)	x	x	x	x	x	x	0.00275	0.02815	0.00350	220	4.80		
209	**wapa**	Erie-Terry Street	x	x	x	x	x	x	0.00900	0.09206	0.01144	220	15.70		$4,365,000
210	**wapa**	Beaver Ck-Erie 230 kV Transmission Line	x	x	x	x	x	x	0.01114	0.11446	0.22892	442	93.46		
211	**wapa**	Erie SW 230/115 transformer	x	x	x	x	x	x	0.00060	0.03239		250	N/A		$4,000,000
212	**wapa**	Beaver Ck 230/115 substation	x	x	x	x	x	x	0.00450	0.04960		200	N/A	2010	$5,600,000
213	**wapa**	Wiloby - Prospect 230/115 substation	x	x	x	x	x	x	0.00100	0.06100		167	N/A	2014	$3,135,000
214	**wapa**	Wiloby - Ault 230	x	x	x	x	x	x	0.00453	0.04639	0.09227	442	32.00	2014	$10,100,000
215	**wapa**	Ault - Cheyenne 230	x	x	x	x	x	x	0.00503	0.04813	0.10824	442	35.15	2010	$15,975,000
216	**wapa**	Cheyenne 230/115 substation	x	x	x	x	x	x	0.00450	0.04960		200	N/A	2010	$5,150,000
217	**wapa**	Cheyenne - Snowy Range 230	x	x	x	x	x	x	0.00759	0.06584	0.14889	442	47.00	2009	$32,533,000
218	**wapa**	Snowy Range 230/115 substation	x	x	x	x	x	x	0.00450	0.04960		200	N/A	2009	$9,951,000
219	**wapa**	Miracle Mile - Snowy Range 230	x	x	x	x	x	x	0.01562	0.14107	0.02964	442	98.50	2009	
220	**wapa**	Miracle Mile 230/115 substation	x	x	x	x	x	x	0.00450	0.04960		200	N/A	2009	$5,000,000
221	**wapa**	Midway (USBR) 230/115 kV 167 MVA Replacement Autotransformer	x	x	x	x	x	x	0	0.0633	N/A	167	N/A	2010	$3,000,000
222	**wapa**	Ault substation additions	x	x	x	x	x	x	All new conductor is 1272 ACSR				N/A	2010	$2,100,000
223															
224	**wapa**	Weld transformer replaccement	x	x	x	x	x	x	0.00058	0.02950		350	N/A	2014	$4,000,000
225	**wapa**	Weld - Flatiron 230-kV upgrade (operated at 115 kV)	x	x	x	x	x	x	*0.00370*	*0.01650*	*0.00233*	*133*	30.72	2015	$13,800,000
226	**wapa**	Yellowtail 230/115 transformer	x	x	x	x	x	x	0.00190	0.05599		130	N/A	2006	$2,971,000
227	**wapa**	Flaming Gorge 230/138 transformer	x	x	x	x	x	x	0.00076	0.02668		250	N/A	2007	$3,225,000
229	**wapa**	Eckley-Wray Tap 115 kV Line Reconductor						x	0.0413	0.0848	0.01	160	14.10	2015	$1,509,000
230	ALL	Miscellaneous Capacitor additions	x	x	x	x	x	x					N/A	2014	$7,750,000
231															
232															
233															
234															
235															
236															
237															
238															
239															
240															
241	aquila	Freemary - Reader 115kV line	x	x	x	x	x	x	0.012845	0.03108	0.003771	99	3.32	2008	$727,080
242	aquila	West Station - Burnt Mill 115kV line	x	x	x	x	x	x	0.02202	0.05328	0.00647	99	7.60	2007	$1,664,400
243	aquila	Burnt Mill - Freemary 115kV line	x	x	x	x	x	x	0.012845	0.03108	0.003771	99	3.75	2007	$821,250
244	aquila	New W. Canon - Arequa Gulch 115kV line	x	x	x	x	x	x	0.0548	0.1534	0.0172	107	18.90	2008-2009	$4,139,100
245	aquila	New Arequa Gulch - P.P. Mine 115/69kV Xformer	x	x	x	x	x	x	0.0114	0.2968		50	?	2008-2009	$200,000
246	aquila	New Reader - St. Charles 115kV line	x	x	x	x	x	x	0.01275	0.03344	0.00405	162	6.00	2012	$1,314,000
247	aquila	New St. Charles - Airport Memorial 115kV line	x	x	x	x	x	x	0.00521	0.01366	0.00165	162	2.00	2012	$438,000
248	aquila	Rebuild West Station - Hyde Park 115kV line	x	x	x	x	x	x	0.00219	0.01242	0.00168	162	2.21	2007?	$483,990
249	aquila	Rebuild Hyde Park - Pueblo 115kV line	x	x	x	x	x	x	0.00251	0.01422	0.00192	162	2.53	2007?	$554,070
250	aquila	Rebuild Boone to DOT Tap 115kV line	x	x	x	x	x	x	0.0073	0.0177	0.00216	162	3.01	2010?	$659,190
251	aquila	Rebuild DOT Tap to Airprot Tap 2 115kV line	x	x	x	x	x	x	0.028	0.0679	0.0081	162	7.86	2010?	$1,721,340
252	aquila	New line from Belmont to Airprot Industrial 115kV	x	x	x	x	x	x	0.0044	0.0123	0.0014	99	1.60	2010?	$350,400
254	aquila	Replace West Station CT's - W.Station - Portland 115kV	x	x	x	x	x	x	0.0485	0.118	0.01432	99	20.02	2008?	$150,000
255	aquila	Manzanola 15 MVAR Capacitor (3 by 5 MVAR)	x	x	x	x	x	x	n	n	n	3x5	0.00	2015	$300,000
256															
258															
260															
261															
262															
263		**South 345 kV 1200 Total Infrastructure Costs (Millions) ------>**													**$1,699,490,529**
264		**South 500 kV 1200 Total Infrastructure Costs (Millions) ------>**													**$1,832,522,329**
265		**North Alt. 1 Total Infrastructure Costs (Millions) ------>**													**$1,722,362,529**
266		**North Alt. 2 Total Infrastructure Costs (Millions) ------>**													**$1,704,290,529**
267		**South 345 kV 1800 Total Infrastructure Costs (Millions) ------>**													**$1,782,687,329**
268		**South 500 kV 1800 Total Infrastructure Costs (Millions) ------>**													**$1,914,572,329**
269															
270	**Bold** Indicative of "Backbone" infrastructure for the 10-year plan.**Bold Red** indicative of Infrastructure that may not be needed for the 10-year plan.														
271	Proxy costs are derived from a TSG&T cost estimation guide for the Holcomb Project Project, unless otherwise noted. All costs are in 2006 dollars.														
272															
273	S1, S2 & S3 = Scenarios 1, 2 &3 (X's indicate if these facilities should be in the respective cases)														
274	345/230 Autos are 560 MVA														
275															

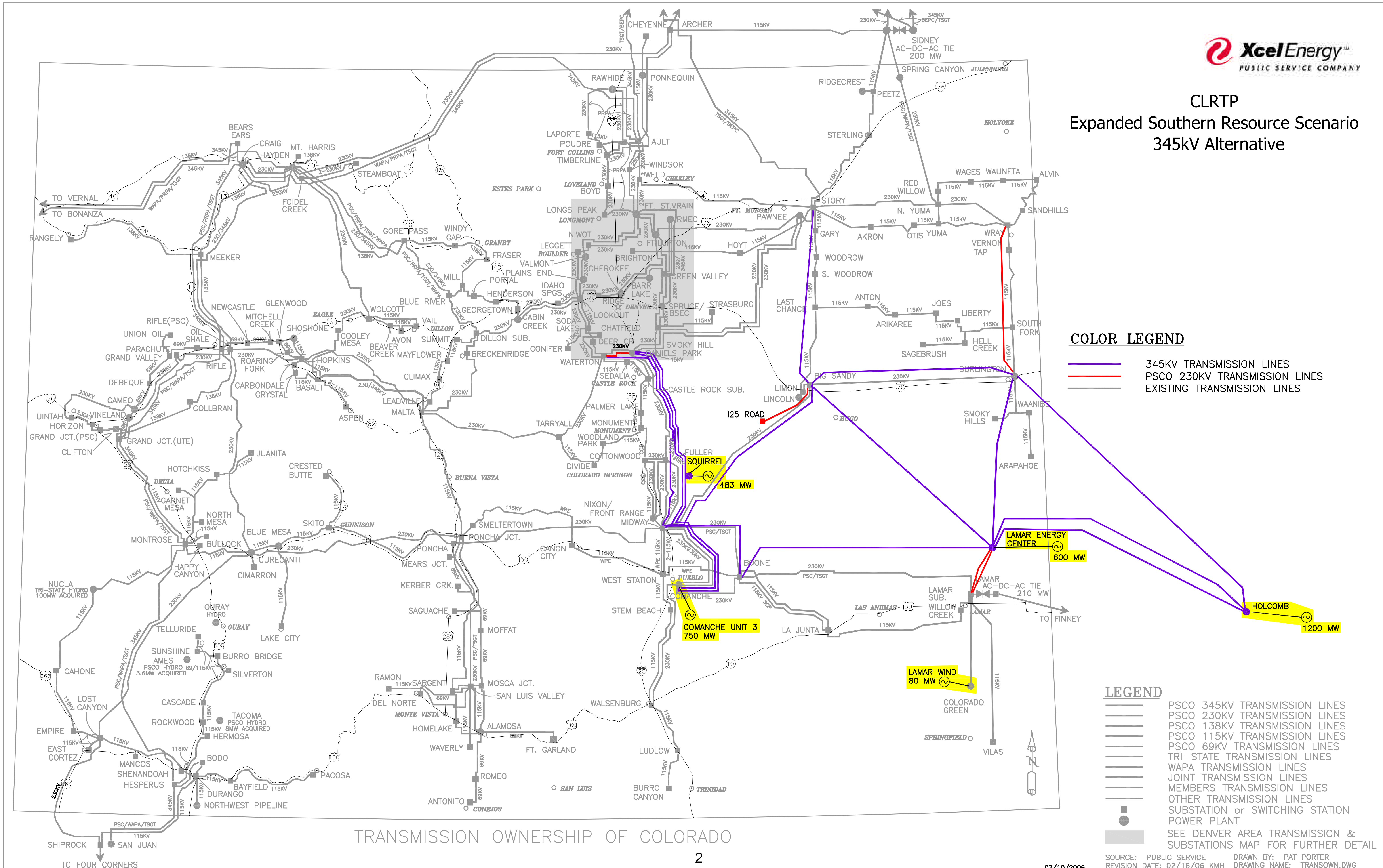
	S	U	V	W	X	Y	Z	AA
2	Notes	Reason	South 345 kV 1200 MW Costs	South 500 kV 1200 MW Costs	North Alt. 1 Costs	North Alt. 2 Costs	South 345 kV 1800 MW Costs	South 500 kV 1800 MW Costs
203			South 345 kV 1200 MW Costs	South 500 kV 1200 MW Costs	North Alt. 1 Costs	North Alt. 2 Costs	South 345 kV 1800 MW Costs	South 500 kV 1800 MW Costs
204	Result of WAPA 10 YR Planning Study	BCK-Brush 115 kV outage	$17,880,000	$17,880,000	$17,880,000	$17,880,000	$17,880,000	$17,880,000
205	Result of WAPA 10 YR Planning Study	BCK-Brush 115 kV outage	$0	$0	$0	$0	$0	$0
206	Result of WAPA 10 YR Planning Study		$27,300,000	$27,300,000	$27,300,000	$27,300,000	$27,300,000	$27,300,000
207	Result of WAPA 10 YR Planning Study		$0	$0	$0	$0	$0	$0
208	Result of WAPA 10 YR Planning Study		$0	$0	$0	$0	$0	$0
209	Result of WAPA 10 YR Planning Study		$4,365,000	$4,365,000	$4,365,000	$4,365,000	$4,365,000	$4,365,000
210	Result of WAPA 10 YR Planning Study		$0	$0	$0	$0	$0	$0
211	Result of WAPA 10 YR Planning Study	BCK-Erie 230 kV termination	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000
212	Result of WAPA 10 YR Planning Study	BCK-Erie 230 kV termination	$5,600,000	$5,600,000	$5,600,000	$5,600,000	$5,600,000	$5,600,000
213	Result of WAPA 10 YR Planning Study	Voltage Support for WLD area loads	$3,135,000	$3,135,000	$3,135,000	$3,135,000	$3,135,000	$3,135,000
214	Result of WAPA 10 YR Planning Study	Voltage Support for WLD area loads	$10,100,000	$10,100,000	$10,100,000	$10,100,000	$10,100,000	$10,100,000
215	MM-AU 230 kV-TOT3 TTC Increase to 1680MW	Replace Aging T-Line and Increase TOT 3 TTC	$15,975,000	$15,975,000	$15,975,000	$15,975,000	$15,975,000	$15,975,000
216	MM-AU 230 kV-TOT3 TTC Increase to 1680MW	Improve Transient Voltage Dips in Cheyenne	$5,150,000	$5,150,000	$5,150,000	$5,150,000	$5,150,000	$5,150,000
217	MM-AU 230 kV-TOT3 TTC Increase to 1680MW	Replace Aging T-Line and Increase TOT 3 TTC	$32,533,000	$32,533,000	$32,533,000	$32,533,000	$32,533,000	$32,533,000
218	MM-AU 230 kV-TOT3 TTC Increase to 1680MW	Improve Transient Voltage Dips in Laramie Area	$9,951,000	$9,951,000	$9,951,000	$9,951,000	$9,951,000	$9,951,000
219	MM-AU 230 kV-TOT3 TTC Increase to 1680MW	Replace Aging T-Line and Increase TOT 3 TTC	$0	$0	$0	$0	$0	$0
220	MM-AU 230 kV-TOT3 TTC Increase to 1680MW	Replace Aging T-Line and Increase TOT 3 TTC	$5,000,000	$5,000,000	$5,000,000	$5,000,000	$5,000,000	$5,000,000
221		Midway-RD Nixon 230 kV Outage	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000
222	MM-AU 230 kV-TOT3 TTC Increase to 1680MW	Replace Aging T-Line and Increase TOT 3 TTC	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000
223					$0			
224	Result of WAPA 10 YR Planning Study	Parallel Transformer Outage	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000
225	Result of WAPA 10 YR Planning Study	Boyd Transformer Outage	$13,800,000	$13,800,000	$13,800,000	$13,800,000	$13,800,000	$13,800,000
226		Increase of YT South TTC	$2,971,000	$2,971,000	$2,971,000	$2,971,000	$2,971,000	$2,971,000
227	TOT 1A Issue	Replace Aging / Overloaded Transformer	$3,225,000	$3,225,000	$3,225,000	$3,225,000	$3,225,000	$3,225,000
229		N.Yuma-Wray 230 kV Outage	$0	$0	$0	$0	$0	$1,509,000
230	Miscellaneous Local Voltage Issues	Miscellaneous Local Voltage Issues	$7,750,000	$7,750,000	$7,750,000	$7,750,000	$7,750,000	$7,750,000
231			$0	$0	$0	$0	$0	$0
232			$0	$0	$0	$0	$0	$0
233	**Western Total**	**WAPA TOTAL**	**$177,835,000**	**$177,835,000**	**$177,835,000**	**$177,835,000**	**$177,835,000**	**$179,344,000**
234		SECONDARY BULK	**$146,089,000**	**$146,089,000**	**$146,089,000**	**$146,089,000**	**$146,089,000**	**$146,089,000**
235		Regional	**$31,746,000**	**$31,746,000**	**$31,746,000**	**$31,746,000**	**$31,746,000**	**$33,255,000**
236								
237		TSGT & WAPA TOTAL 2nd and Regional	**$359,941,000**	**$359,941,000**	**$359,941,000**	**$359,941,000**	**$361,566,000**	**$361,450,000**
238			**South 345 kV 1200 MW Costs**	**South 500 kV 1200 MW Costs**	**North Alt. 1 Costs**	**North Alt. 2 Costs**	**South 345 kV 1800 MW Costs**	**South 500 kV 1800 MW Costs**
239			$0	$0	$0	$0	$0	$0
240			$0	$0	$0	$0	$0	$0
241		Relieves overload of the 69kV and Reader Transformers	$727,080	$727,080	$727,080	$727,080	$727,080	$727,080
242		Relieves overload of the 69kV and Reader Transformers	$1,664,400	$1,664,400	$1,664,400	$1,664,400	$1,664,400	$1,664,400
243		Relieves overload of the 69kV and Reader Transformers	$821,250	$821,250	$821,250	$821,250	$821,250	$821,250
244		Voltage support for load growth	$4,139,100	$4,139,100	$4,139,100	$4,139,100	$4,139,100	$4,139,100
245		Voltage support for load growth	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
246		Relieves overload of the 69kV and Reader Transformers	$1,314,000	$1,314,000	$1,314,000	$1,314,000	$1,314,000	$1,314,000
247		Relieves overload of the 69kV and Reader Transformers	$438,000	$438,000	$438,000	$438,000	$438,000	$438,000
248		Loss of Reader-W. Station 115kV	$483,990	$483,990	$483,990	$483,990	$483,990	$483,990
249		Loss of Reader-W. Station 115kV	$554,070	$554,070	$554,070	$554,070	$554,070	$554,070
250		Loss of Reader-W. Station 115kV	$659,190	$659,190	$659,190	$659,190	$659,190	$659,190
251		Loss of Reader-W. Station 115kV	$1,721,340	$1,721,340	$1,721,340	$1,721,340	$1,721,340	$1,721,340
252		Relieves overload of the 69kV and Reader Transformers	$350,400	$350,400	$350,400	$350,400	$350,400	$350,400
254		Load growth	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000
255	PSCo Proxy	Voltage support for load growth	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
256			$0	$0	$0	$0	$0	$0
258			$0	$0		$0	$0	$0
260	**Aquila Total**		**$13,672,820**	**$13,672,820**	**$13,672,820**	**$13,672,820**	**$13,672,820**	**$13,672,820**
261			**South 345 kV 1200 MW Costs**	**South 500 kV 1200 MW Costs**	**North Alt. 1 Costs**	**North Alt. 2 Costs**	**South 345 kV 1800 MW Costs**	**South 500 kV 1800 MW Costs**
262								
263			**$1,699,490,529**				South 345 kv 1200 less PSCO & TSGT	$263,757,820
264			**$1,832,522,329**				South 500 kv 1200 less PSCO & TSGT	$269,714,620
265			**$1,722,362,529**				North less PSCO & TSGT	$784,240,529
266			**$1,704,290,529**				North less PSCO & TSGT	$263,757,820
267			**$1,782,687,329**				South 345 kv 1800 less PSCO & TSGT	$269,714,620
268			**$1,914,572,329**				South 500 kv 1800 less PSCO & TSGT	$271,223,620
269			**BACKBONE**	**REGIONAL**	**SECONDARY BULK**	**Check**		
270		**South 345 kV 1200 MW Costs**	**$1,087,295,000**	**$252,609,529**	**$359,586,000**	**$1,699,490,529**	$0	
271		**South 500 kV 1200 MW Costs**	**$1,214,370,000**	**$252,609,529**	**$365,542,800**	**$1,832,522,329**	$0	
272		**North Alt. 1 Costs**	**$1,114,541,000**	**$252,609,529**	**$355,212,000**	**$1,722,362,529**	$0	
273		**North Alt. 2 Costs**	**$1,092,294,000**	**$252,609,529**	**$359,387,000**	**$1,704,290,529**	$0	
274		**South 345 kV 1800 MW Costs**	**$1,160,314,000**	**$254,234,529**	**$368,138,800**	**$1,782,687,329**	$0	
275		**South 500 kV 1800 MW Costs**	**$1,287,941,000**	**$254,118,529**	**$372,512,800**	**$1,914,572,329**	$0	

APPENDIX D

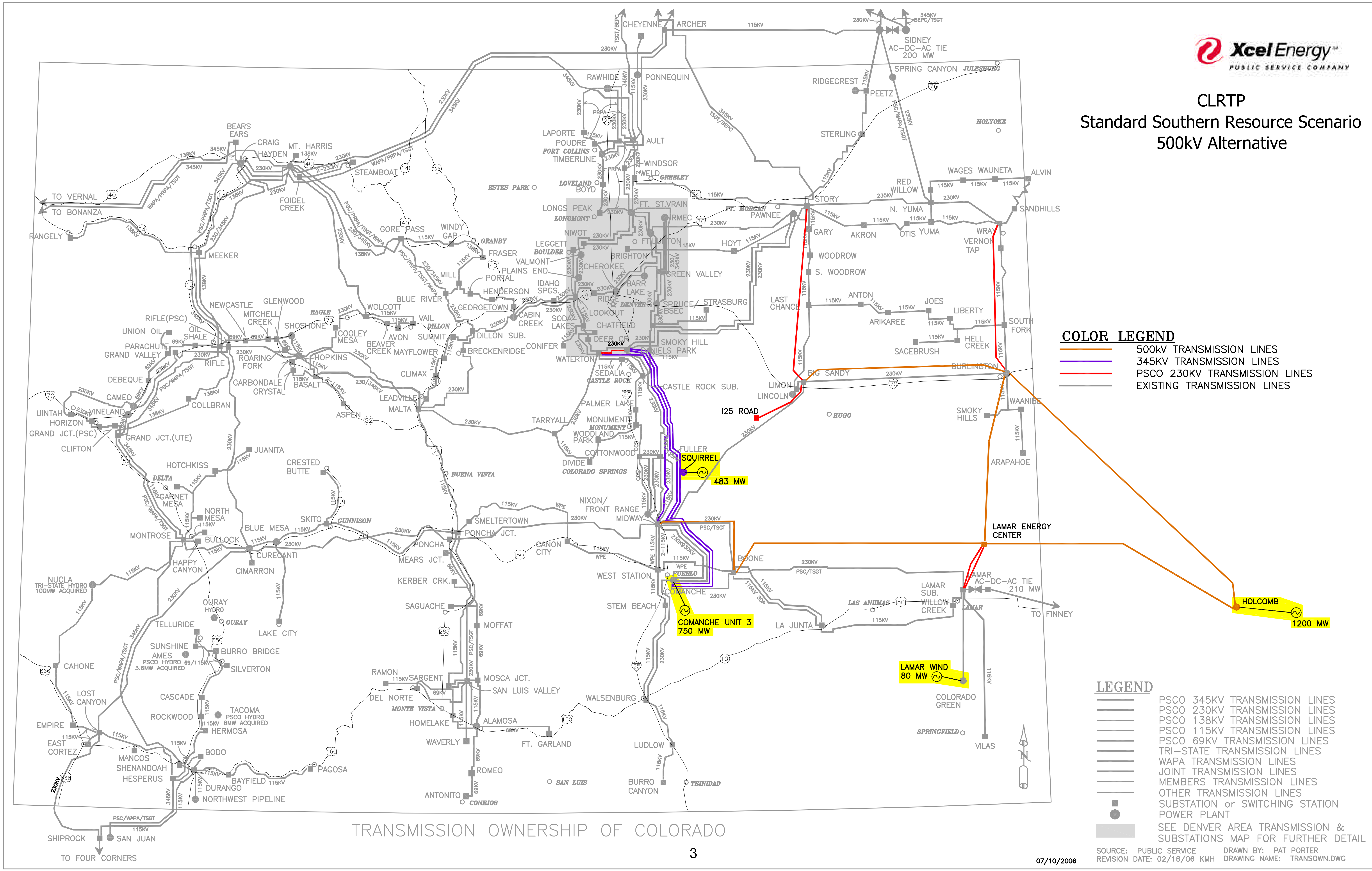
Scenario Generation and Primary Bulk Transmission Maps

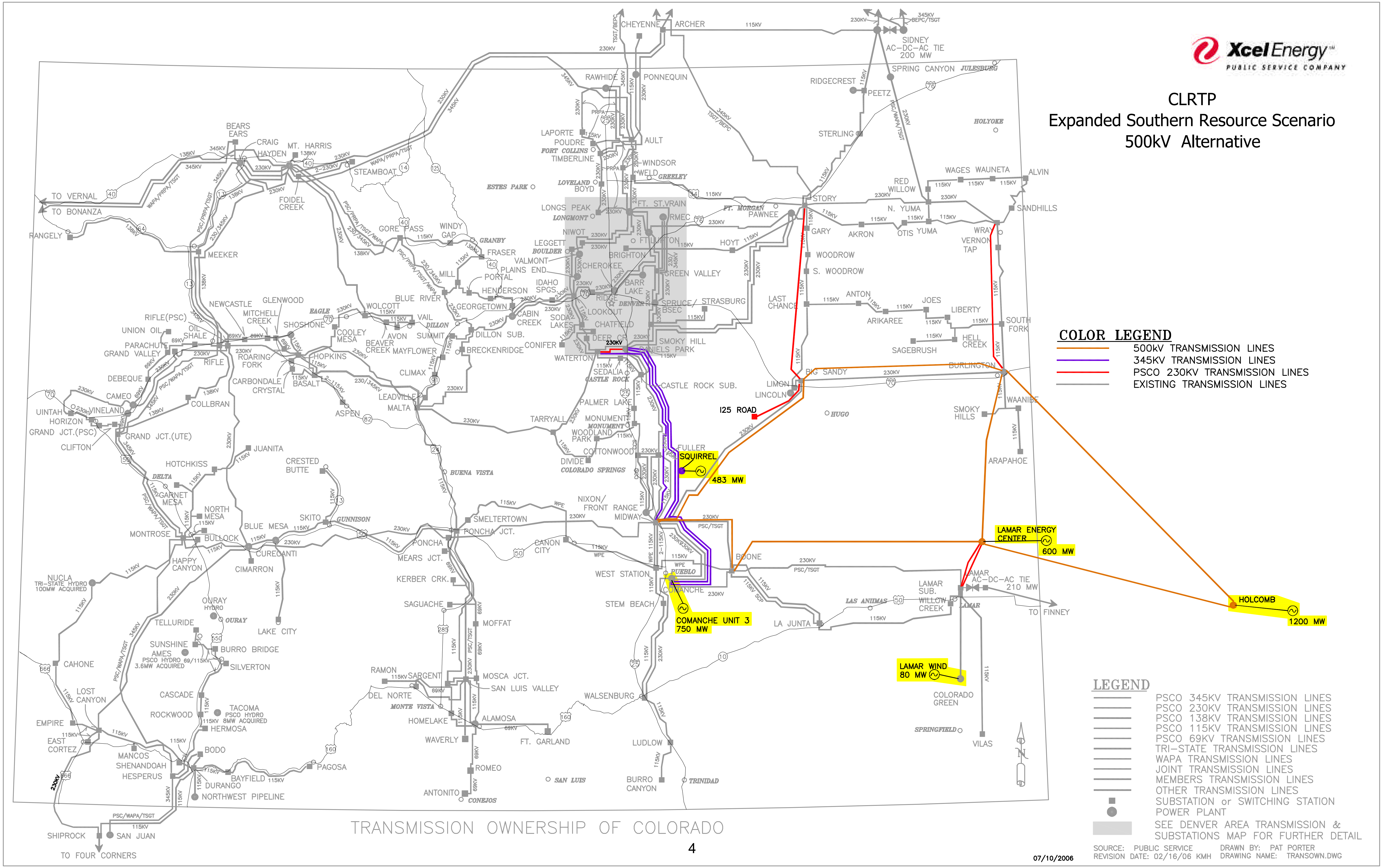


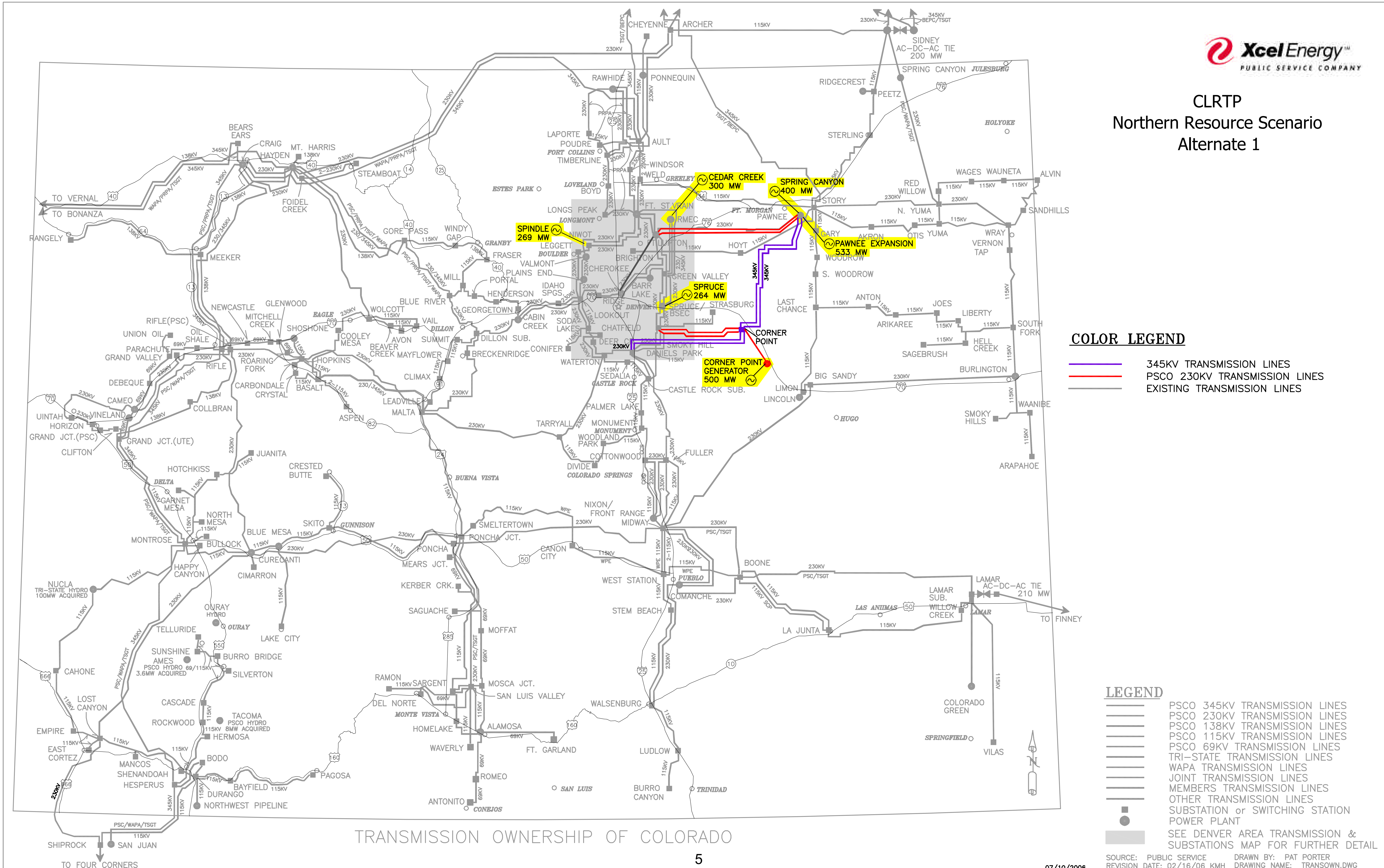
Xcel Energy
PUBLIC SERVICE COMPANY
CLRTP
Standard Southern Resouce Scenario
345kV Alternative
COLOR LEGEND
345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
EXISTING TRANSMISSION LINES
SQUIRREL
483 MW
COMANCHE UNIT 3
750 MW
HOLCOMB
1200 MW
LAMAR WIND
80 MW
LAMAR ENERGY CENTER
I25 ROAD
SIDNEY AC-DC-AC TIE 200 MW
LAMAR AC-DC-AC TIE 210 MW
TO FINNEY
TO VERNAL
TO BONANZA
TO FOUR CORNERS
LEGEND
PSCO 345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
PSCO 138KV TRANSMISSION LINES
PSCO 115KV TRANSMISSION LINES
PSCO 69KV TRANSMISSION LINES
TRI-STATE TRANSMISSION LINES
WAPA TRANSMISSION LINES
JOINT TRANSMISSION LINES
MEMBERS TRANSMISSION LINES
OTHER TRANSMISSION LINES
SUBSTATION or SWITCHING STATION
POWER PLANT
SEE DENVER AREA TRANSMISSION & SUBSTATIONS MAP FOR FURTHER DETAIL
TRANSMISSION OWNERSHIP OF COLORADO
SOURCE: PUBLIC SERVICE
REVISION DATE: 02/16/06 KMH
DRAWN BY: PAT PORTER
DRAWING NAME: TRANSOWN.DWG
07/10/2006
1

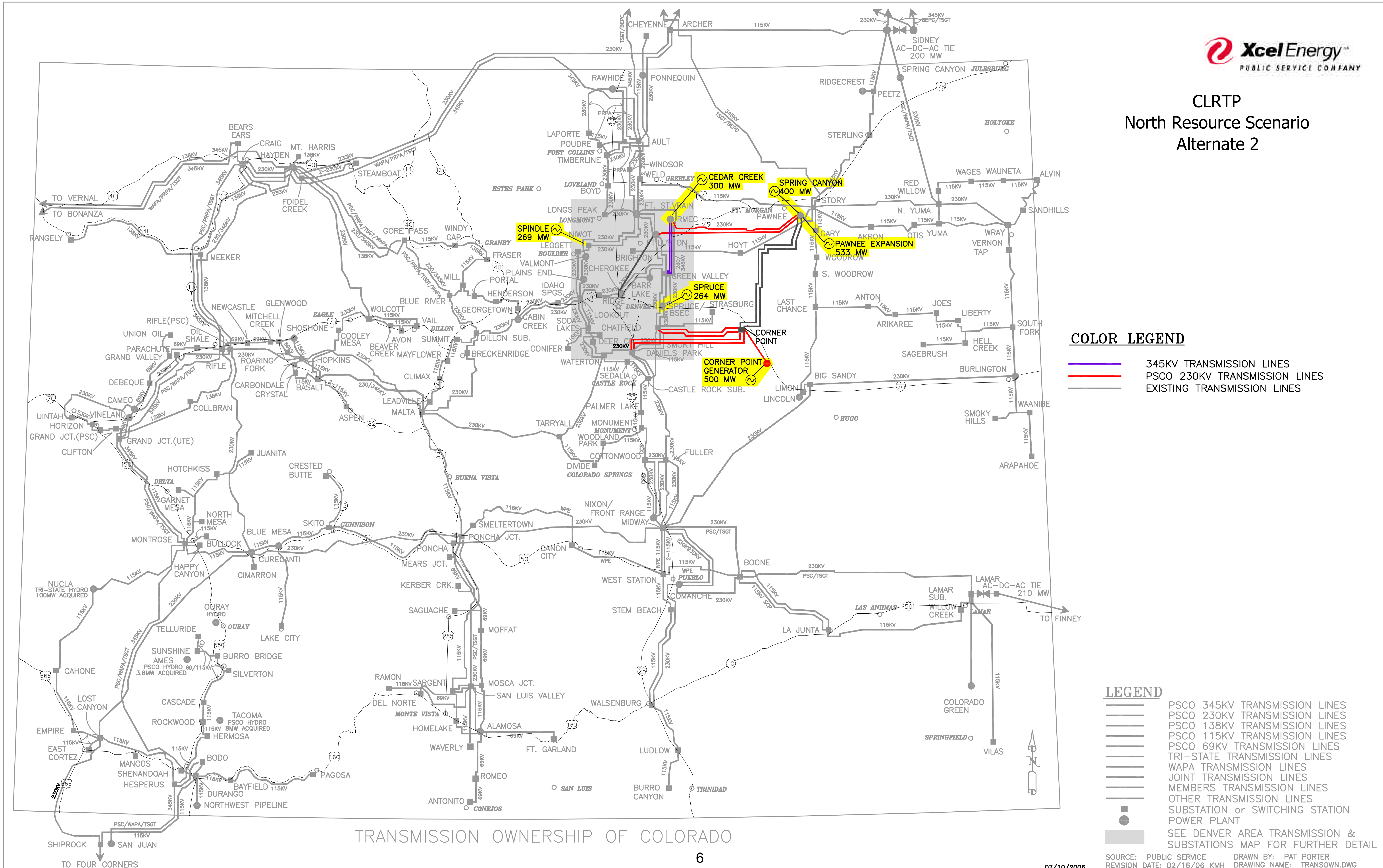


Xcel Energy
PUBLIC SERVICE COMPANY
CLRTP
Expanded Southern Resource Scenario
345kV Alternative
COLOR LEGEND
345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
EXISTING TRANSMISSION LINES
SQUIRREL
483 MW
LAMAR ENERGY CENTER
600 MW
HOLCOMB
1200 MW
COMANCHE UNIT 3
750 MW
LAMAR WIND
80 MW
I25 ROAD
SIDNEY AC-DC-AC TIE 200 MW
LAMAR AC-DC-AC TIE 210 MW
TO FINNEY
TO VERNAL
TO BONANZA
TO FOUR CORNERS
CHEYENNE
ARCHER
RAWHIDE
PONNEQUIN
STERLING
FORT COLLINS
LONGMONT
BOULDER
DENVER
GREELEY
FT. MORGAN
PAWNEE
BIG SANDY
LIMON
BURLINGTON
COLORADO SPRINGS
MIDWAY
PUEBLO
COMANCHE
BOONE
LA JUNTA
WALSENBURG
ALAMOSA
DURANGO
MONTROSE
GRAND JCT.(PSC)
CRAIG
HAYDEN
RIFLE
GLENWOOD
LEADVILLE
TRANSMISSION OWNERSHIP OF COLORADO
LEGEND
PSCO 345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
PSCO 138KV TRANSMISSION LINES
PSCO 115KV TRANSMISSION LINES
PSCO 69KV TRANSMISSION LINES
TRI-STATE TRANSMISSION LINES
WAPA TRANSMISSION LINES
JOINT TRANSMISSION LINES
MEMBERS TRANSMISSION LINES
OTHER TRANSMISSION LINES
SUBSTATION or SWITCHING STATION
POWER PLANT
SEE DENVER AREA TRANSMISSION & SUBSTATIONS MAP FOR FURTHER DETAIL
SOURCE: PUBLIC SERVICE
REVISION DATE: 02/16/06 KMH
DRAWN BY: PAT PORTER
DRAWING NAME: TRANSOWN.DWG
07/10/2006
2


Xcel Energy
PUBLIC SERVICE COMPANY
CLRTP
Standard Southern Resource Scenario
500kV Alternative
COLOR LEGEND
500kV TRANSMISSION LINES
345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
EXISTING TRANSMISSION LINES
SQUIRREL
483 MW
COMANCHE UNIT 3
750 MW
LAMAR ENERGY CENTER
HOLCOMB
1200 MW
LAMAR WIND
80 MW
I25 ROAD
TO FINNEY
LEGEND
PSCO 345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
PSCO 138KV TRANSMISSION LINES
PSCO 115KV TRANSMISSION LINES
PSCO 69KV TRANSMISSION LINES
TRI-STATE TRANSMISSION LINES
WAPA TRANSMISSION LINES
JOINT TRANSMISSION LINES
MEMBERS TRANSMISSION LINES
OTHER TRANSMISSION LINES
SUBSTATION or SWITCHING STATION
POWER PLANT
SEE DENVER AREA TRANSMISSION & SUBSTATIONS MAP FOR FURTHER DETAIL
SOURCE: PUBLIC SERVICE
REVISION DATE: 02/16/06 KMH
DRAWN BY: PAT PORTER
DRAWING NAME: TRANSOWN.DWG
07/10/2006
TRANSMISSION OWNERSHIP OF COLORADO


Xcel Energy
PUBLIC SERVICE COMPANY
CLRTP
Expanded Southern Resource Scenario
500kV Alternative
COLOR LEGEND
500kV TRANSMISSION LINES
345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
EXISTING TRANSMISSION LINES
SQUIRREL
483 MW
LAMAR ENERGY CENTER
600 MW
HOLCOMB
1200 MW
COMANCHE UNIT 3
750 MW
LAMAR WIND
80 MW
I25 ROAD
LEGEND
PSCO 345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
PSCO 138KV TRANSMISSION LINES
PSCO 115KV TRANSMISSION LINES
PSCO 69KV TRANSMISSION LINES
TRI-STATE TRANSMISSION LINES
WAPA TRANSMISSION LINES
JOINT TRANSMISSION LINES
MEMBERS TRANSMISSION LINES
OTHER TRANSMISSION LINES
SUBSTATION or SWITCHING STATION
POWER PLANT
SEE DENVER AREA TRANSMISSION & SUBSTATIONS MAP FOR FURTHER DETAIL
SOURCE: PUBLIC SERVICE
REVISION DATE: 02/16/06 KMH
DRAWN BY: PAT PORTER
DRAWING NAME: TRANSOWN.DWG
07/10/2006
TRANSMISSION OWNERSHIP OF COLORADO


Xcel Energy
PUBLIC SERVICE COMPANY
CLRTP
Northern Resource Scenario
Alternate 1
CEDAR CREEK 300 MW
SPRING CANYON 400 MW
SPINDLE 269 MW
PAWNEE EXPANSION 533 MW
SPRUCE 264 MW
CORNER POINT
CORNER POINT GENERATOR 500 MW
COLOR LEGEND
345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
EXISTING TRANSMISSION LINES
LEGEND
PSCO 345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
PSCO 138KV TRANSMISSION LINES
PSCO 115KV TRANSMISSION LINES
PSCO 69KV TRANSMISSION LINES
TRI-STATE TRANSMISSION LINES
WAPA TRANSMISSION LINES
JOINT TRANSMISSION LINES
MEMBERS TRANSMISSION LINES
OTHER TRANSMISSION LINES
SUBSTATION or SWITCHING STATION
POWER PLANT
SEE DENVER AREA TRANSMISSION & SUBSTATIONS MAP FOR FURTHER DETAIL
SOURCE: PUBLIC SERVICE
REVISION DATE: 02/16/06 KMH
DRAWN BY: PAT PORTER
DRAWING NAME: TRANSOWN.DWG
TRANSMISSION OWNERSHIP OF COLORADO
07/10/2006
CHEYENNE
ARCHER
SIDNEY AC-DC-AC TIE 200 MW
LAMAR AC-DC-AC TIE 210 MW
TO VERNAL
TO BONANZA
TO FOUR CORNERS
TO FINNEY


Xcel Energy
PUBLIC SERVICE COMPANY
CLRTP
North Resource Scenario
Alternate 2
CEDAR CREEK 300 MW
SPRING CANYON 400 MW
SPINDLE 269 MW
PAWNEE EXPANSION 533 MW
SPRUCE 264 MW
CORNER POINT
CORNER POINT GENERATOR 500 MW
COLOR LEGEND
345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
EXISTING TRANSMISSION LINES
LEGEND
PSCO 345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
PSCO 138KV TRANSMISSION LINES
PSCO 115KV TRANSMISSION LINES
PSCO 69KV TRANSMISSION LINES
TRI-STATE TRANSMISSION LINES
WAPA TRANSMISSION LINES
JOINT TRANSMISSION LINES
MEMBERS TRANSMISSION LINES
OTHER TRANSMISSION LINES
SUBSTATION or SWITCHING STATION
POWER PLANT
SEE DENVER AREA TRANSMISSION & SUBSTATIONS MAP FOR FURTHER DETAIL
SOURCE: PUBLIC SERVICE
REVISION DATE: 02/16/06 KMH
DRAWN BY: PAT PORTER
DRAWING NAME: TRANSOWN.DWG
TRANSMISSION OWNERSHIP OF COLORADO
07/10/2006

APPENDIX E

TSGT Cost Estimation Guide

Figure 16: TSGT Estimating Guide Page 1 of 2

EASTERN PLAINS TRANSMISSION PROJECT					
CLRTPG-II SIS-Holcomb/CPP(LEC) Line Facilities (New construction, OPGW lines, unless otherwise indicated)	**Unit Cost**-Installed **($1000)**		**Unit**	**Reference for Unit Cost**	**Reason for Change from Previous Revisions**
500 kV Aerial Line, 3x1272 ACSR TWD, steel lattice	$	883	mile	TSGT Planning Cost Guide	New, then Revised cost
345 kV Aerial Line, 2x1272 ACSR, steel lattice	$	582	mile	"	Escalated cost
345 kV Aerial Line, 2x1272 ACSR, steel lattice, double-circuit	$	952	mile	"	New, then Revised cost
230 kV Aerial Line, 1272 ACSR, steel pole	$	422	mile	"	Escalated cost
230 kV Aerial Line, 1272 ACSR, wood H-frame	$	298	mile	"	New, then Revised cost
230 kV Aerial Line, 954 ACSR, steel pole	$	394	mile	"	"
230 kV Aerial Line, 954 ACSR, wood H-frame	$	287	mile	"	"
345 kV UG Line, 2x1750 Cu, solid dielectric	$	6,000	mile	Manufacturer, 11/16/05 email	New cost
230 kV UG Line, 2x1750 Cu, solid dielectric	$	4,000	mile	Manufacturer, 11/16/05 email	"
115 kV Aerial Line, 795 ACSR, steel pole	$	300	mile	TSGT Planning Cost Guide	New cost
115 kV Aerial Line, 795 ACSR, wood H-frame	$	235	mile	"	New, then Revised cost
115 kV Aerial Line, 795 ACSR, wood pole	$	223	mile	"	New cost
115 kV Aerial Line, 477 ACSR, steel pole	$	275	mile	"	"
115 kV Aerial Line, 477 ACSR, wood H-frame	$	209	mile	"	New, then Revised cost
115 kV Aerial Line, 477 ACSR, wood pole	$	192	mile	"	New cost
Reconductor 115 kV Transmission Line, 4/0-477 ACSR, 25+ years old	$	107	mile	CPP SIS Unit Cost	Escalated cost
Uprate 115 kV Transmission Line, 4/0-477 ACSR, 25+ years old	$	45	mile	"	"
125 MVAr (for 100-mile line), 500 kV Line Reactor, OLTC, with MOAB	$	2,000	each	Industry Consultant, 02/22/06 email	New cost
125 MVAr (for 100-mile line), 500 kV Line Reactor, NLTC, with MOAB	$	1,750	each	Industry Consultant, 02/22/06 email	"
60 MVAr (for 100-mile line), 345 kV Line Reactor, OLTC, with MOAB	$	1,900	each	Industry Consultant, 11/18/05 email	New, then Revised cost
150 MVAr (50% comp example), 500kV Series Capacitor, with MOAB	$	3,229	each	TSGT EPTP Planning Cost Estimate	New cost
200 MVAr (60% comp example), 345kV Series Capacitor, with MOAB	$	3,210	each	"	"

Figure 17: TSGT Estimating Guide Page 2 of 2

CLRTPG-II SIS-Holcomb/CPP(LEC) Substation Facilities (New equipment, 3-phase transformers, unless otherwise indicated)	Unit Cost-Installed ($1000)		Unit	Reference for Unit Cost	Reason for Change from Previous Revisions
600 MVA, 500/345 kV Autotransformer, (4) Single-Phase	$	7,716	each	TSGT Planning Cost Guide	Revised cost
600 MVA, 500/345 kV Autotransformer	$	4,570	each	"	New cost
500 MVA, 500/345 kV Autotransformer, (4) Single-Phase	$	6,423	each	Industry Consultant, 3/16/06 email	Revised cost
500 MVA, 500/345 kV Autotransformer	$	4,174	each	"	New cost
400 MVA, 500/345 kV Autotransformer, (4) Single-Phase	$	6,904	each	TSGT Planning Cost Guide	"
400 MVA, 500/345 kV Autotransformer	$	3,808	each	"	"
600 MVA, 500/230 kV Autotransformer, (4) Single-Phase	$	8,509	each	"	"
600 MVA, 500/230 kV Autotransformer	$	5,941	each	"	"
500 MVA, 500/230 kV Autotransformer, (4) Single-Phase	$	6,874	each	Industry Consultant, 3/16/06 email	Revised cost
500 MVA, 500/230 kV Autotransformer	$	4,525	each	"	New cost
400 MVA, 500/230 kV Autotransformer, (4) Single-Phase	$	8,123	each	TSGT Planning Cost Guide	"
400 MVA, 500/230 kV Autotransformer	$	4,570	each	"	"
600 MVA, 345/230 kV Autotransformer, (4) Single-Phase	$	6,803	each	TSGT Planning Cost Guide	New cost
600 MVA, 345/230 kV Autotransformer	$	3,699	each	"	Escalated cost
500 MVA, 345/230 kV Autotransformer, (4) Single-Phase	$	4,375	each	Industry Consultant, 3/16/06 email	New cost
500 MVA, 345/230 kV Autotransformer	$	2,922	each	"	Escalated cost
400 MVA, 345/230 kV Autotransformer	$	2,748	each	TSGT Planning Cost Guide	New cost
350 MVA, 345/230 kV Autotransformer	$	2,529	each	"	"
300 MVA, 345/230 kV Autotransformer, (4) Single-Phase	$	4,671	each	"	"
300 MVA, 345/230 kV Autotransformer	$	2,308	each	"	"
250 MVA, 345/230 kV Autotransformer	$	2,000	each	"	"
200 MVA, 345/230 kV Autotransformer	$	1,705	each	"	"
150 MVA, 345/230 kV Autotransformer	$	1,496	each	"	"
100 MVA, 345/230 kV Autotransformer, (4) Single-Phase	$	2,234	each	"	"
100 MVA, 345/230 kV Autotransformer	$	1,289	each	"	"
400 MVA, 230/115 kV Autotransformer	$	2,780	each	"	"
350 MVA, 230/115 kV Autotransformer	$	2,518	each	"	Escalated cost
300 MVA, 230/115 kV Autotransformer, (4) Single-Phase	$	4,671	each	"	"
300 MVA, 230/115 kV Autotransformer	$	2,295	each	"	"
280 MVA, 230/115 kV Autotransformer	$	2,150	each	CPP SIS Unit Cost	"
250 MVA, 230/115 kV Autotransformer	$	2,013	each	TSGT Planning Cost Guide	De-escalated cost
224 MVA, 230/115 kV Autotransformer	$	2,075	each	CPP SIS Unit Cost	Escalated cost
200 MVA, 230/115 kV Autotransformer	$	1,780	each	TSGT Planning Cost Guide	New cost
167 MVA, 230/115 kV Autotransformer	$	1,625	each	CPP SIS Unit Cost	Escalated cost
150 MVA, 230/115 kV Autotransformer	$	1,412	each	TSGT Planning Cost Guide	"
100 MVA, 230/115 kV Autotransformer	$	1,179	each	"	De-escalated cost
224 MVA, 230/115 kV Autotransformer, used, move	$	540	each	"	Escalated cost
167 MVA, 230/115 kV Autotransformer, used, move	$	485	each	"	"
100 MVA, 230/115 kV Autotransformer, used, move	$	430	each	"	"
500 kV Circuit Breaker, 3000 A, 1.5 or Double CB design	$	5,994	each	"	New cost
345 kV Circuit Breaker, 3000 A, 1.5 or Double CB design	$	4,125	each	"	New; then Revised cost
345 kV Circuit Breaker, 2000 A, 1.5 CB design	$	3,813	each	"	New cost
345 kV Circuit Breaker, 2000 A, M&T or Ring CB design	$	1,543	each	"	New cost
230 kV Circuit Breaker, 2000 A, 1.5 CB design	$	2,624	each	"	Escalated cost
230 kV Circuit Breaker, 2000 A, M&T or Ring CB design	$	1,054	each	"	New cost
115 kV Circuit Breaker, 1200 A, M&T or Ring CB design	$	606	each	CPP SIS Unit Cost	Escalated cost
Sub, new (Fixed Cost)	$	1,075	each	"	"