Transmission Planning Study (Year 2022) for Cherokee 4 Replacement Alternatives

(Required per CPUC Decision No. C10-1328)

Final Report

(Submitted with Public Service's 2011 ERP)

Executive Summary

The objective of the study is to compare the Denver metro transmission system performance in the year 2022 for three Cherokee 4 replacement alternatives. The alternatives evaluated are: (a) new generation at Cherokee, (b) IPP generation at Arapahoe, Valmont and Fountain Valley, and (c) renewable resources outside the metro area. The steady-state contingency analysis results in the study indicate that transmission reinforcements and/or improvements are needed for all three alternatives in order to achieve adequate transmission system reliability. The reactive margin analysis results in the study indicate that all three alternatives satisfy the WECC system voltage stability criteria at all three monitored stations in the Denver metro area. However, the highest reactive margins occur with replacement generation located at Cherokee, which suggests that alternative (a) is more robust compared to alternatives (b) and (c) to minimize the risk of voltage collapse in the Denver metro area. The study also indicates that although there is value in retaining the existing generation at Arapahoe to provide operational flexibility by allowing utilization of generation dispatch (Arapahoe) to mitigate contingency thermal overloads, it is not essential to retain this generation for ensuring transmission system reliability.

In each of the three replacement generation alternatives, the thermal overloads occur in the system operating state involving the prior outage (G–1) of the 2x1 CC generating plant at Cherokee during summer peak load hours followed by a transmission element (N–1) forced out of service. All thermal overloads identified in the study can be mitigated by transmission

reinforcements – some by making changes to substation termination equipment (such as switches, jumpers, and breakers) and others by transmission facility upgrades. Per prudent transmission planning practice, Public Service will not normally initiate projects for upgrades to transmission facilities until there is more certainty in the 10 year planning horizon assumptions. The uncertainties in load forecasts and generation capacities and locations will become more defined in the 5-7 year time horizon. All transmission reinforcements identified in this study can be normally implemented within 3-5 years lead time.

Background

In Docket No. 10M-245E concerning Public Service Company of Colorado's ("PSCo" or "Public Service") Emissions Reduction Plan filed in compliance with House Bill 10-1365 (Clean Air-Clean Jobs Act), the Colorado Public Utilities Commission ("Commission")), in Decision No. C10-1328, Paragraph 135 required PSCo to "*…present alternatives to running Cherokee 4 on natural gas in its ERP fling due October 31, 2011…*" Potential alternatives suggested in Paragraph 135 were "*New or reconfigured transmission resources, IPP-provided generation, and new alternative proposals for replacement generation at Cherokee Station …*" The purpose of this transmission study is to fulfill these directives.

Study Scope

PSCo transmission planning developed three plausible scenarios representing Cherokee 4 replacement alternatives after seeking input from PSCo's Resource Planning staff.
PSCo conducted this transmission planning study for the projected system conditions in year 2022. This was accomplished by building a 2022 Heavy Summer power flow base case that modeled the following:

- Projected 2022 Summer Peak Load magnitudes using the PSCo 10-Year Demand Forecast dated April 2011,
- Projected 2022 PSCo Resources and Firm Purchases using the PSCo Loads & Resources Balance for Summer 2011-2022 dated April 2011,
- Normal Ratings (Rate A) consistent with the latest available PSCo FAC-009 Facility Ratings dated July, 2011.

The following comprised the analysis performed in this study using the PSS/E (Power Systems Simulation/Engineering) software tool by Siemens-PTI for system modeling:

I. Develop the 2022 Heavy Summer Case as the starting point (Benchmark Case 2022HS_BM) for the following three Cherokee 4 replacement resource scenarios (study scenarios). Note that the Cherokee 2x1 CC plant is assumed to be a prior outage in every study scenario.
   - Scenario 1 – Cherokee 4 output replaced by a new 1x1 CC plant of the same size (~350 MW net output) at Cherokee (2022HS_S1).
   - Scenario 2 – Cherokee 4 output replaced by IPP owned units (~313 MW aggregate net output) at Arapahoe, Valmont and Fountain Valley (2022HS_S2).
   - Scenario 3 – Cherokee 4 output replaced by renewable resources (~300 MW aggregate net output) located outside the Denver metro area (2022HS_S3).

II. Perform Steady State (Power Flow) Contingency Analysis

System performance is analyzed by simulating the forced outage of each transmission element (NERC Category B2 and B3) within the Denver-Boulder metro area (zone 700 in PSS/E model).

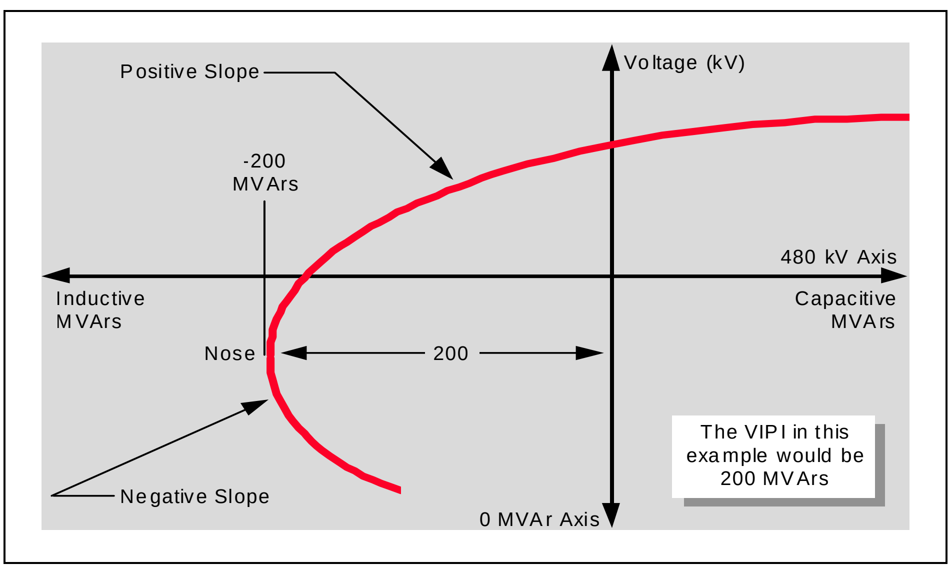
III. Identify significant thermal violations seen in each of the three study scenarios and identify potential transmission improvements needed to address them.

IV. Evaluate the reactive power margin ("Q-margin") at Cherokee, Arapahoe and Valmont buses in each of the three study scenarios and compare the system's robustness to voltage instability.

System Performance Criteria

Reactive Margin (Q-V Analysis) Criteria

Proximity to the point of voltage instability is measured by the amount of additional reactive demand at a bus necessary to change the slope ("dV/dQ") of the voltage vs. reactive requirement curve ("VQ curve") from positive to negative. The point at which the slope changes from positive to negative, or the nose of the VQ curve (illustrated below), is the point of voltage instability, or voltage collapse point. The *Reactive Margin ("Q-margin")*, also called the *Voltage Instability Proximity Indicator ("VIPI")*, is the additional reactive power to be provided at a bus to avoid voltage instability.



Negative Q-margin or VIPI ≡ measure of "distance" to voltage instability (higher is better)

Therefore, negative reactive margin (i.e. nose of VQ curve on left side of y-axis) illustrated above must be understood as the negative additional reactive power requirement at a bus to avoid voltage collapse – that is, negative reactive margin denotes reactive power available at a bus whereas positive reactive margin denotes reactive power deficiency at a bus.

Thermal Violation (Overload) Criteria

Use normal continuous facility ratings (not short-time or emergency) in PSS/E model for both system intact and contingency simulations. Elements/branches with thermal loading >100% are identified as facilities requiring overload mitigation solutions/projects.

2022 Heavy Summer Case Description

The 2022HS benchmark case was developed by starting from the WECC approved 2017HS1 base case by updating the peak load, generation dispatch, firm purchases and net interchange for the PSCo control area to reflect projected 2022 system conditions in accordance with the latest available (April, 2011) forecast of PSCo Loads & Resources Balance for Summer 2010-2022.

The Denver-Boulder metro area generation dispatch used in the 2022HS benchmark case and the three Cherokee 4 replacement generation study scenarios is tabulated below:

Table I   Metro Area Generation Dispatch for 2022HS Benchmark Case

Generation Plant	Unit Nos.	actual Pgen (MW)	Net Summer Pmax (MW)
Arapahoe	4	0	109
Arapahoe (SW Gen)	5, 6, 7	0	119
Valmont	6	0	43
Valmont (SW Gen)	7, 8	0	74
Cherokee	4	352	352
Cherokee	5,6,7 (2x1 CC)	570	570
Ft Lupton	1, 2	89.4	89.4
QF TC-TI	T1–T4	206	217
Blue Spruce EC	1, 2	270	278
Blue Spruce EC	3 (future)	135	139
Rocky Mountain EC	1, 2, 3	601	601
Rocky Mountain EC	4 (future)	135	139
Ft St Vrain	1	300	301
Ft St Vrain	2, 3, 4	300	379
Ft St Vrain	5, 6	290	290
Ft St Vrain	7 (future)	300	300
Spindle NUG	1, 2	2×100	2×134
Plains End NUG	G1, G2	2×48	2×55
Plains End NUG	G3, G4	2×50.4	2×58.8

Retired Units: Arapahoe #3, Valmont #5, Cherokee #1-3, Zuni #1-2

The Cherokee 4 replacement generation used in the three study scenarios differs from the benchmark scenario in the following respects:

Table II Cherokee 4 Replacement Generation Study Scenarios

Generation Dispatch	22-BM	22-S1	22-S2	22-S3
Cherokee 4	352 MW	Retired	Retired	Retired
Cherokee 5,6,7 (2x1 CC plant)	570 MW	0♦	0♦	0♦
Arapahoe 4	Off	Off	Off	Off
Valmont 6	Off	Off	Off	Off
Cherokee 1x1 CC plant	0	350 MW	0	0
IPP Generation: Arapahoe 5,6,7 (119 MW) Valmont 7,8 (74 MW) Fountain Valley (120 MW) Aggregate = 313 MW	0	0	313♠ MW	0
Renewable Resources outside Denver metro area: 250 MW Solar in San Luis Valley + 50 MW Wind at Calumet) Aggregate = 300 MW modeled as proxy generation at Comanche	0	0	0	300♣ MW
Total Generation at Cherokee	922 MW	350 MW	0	0
Total Generation at Arapahoe	0	0	119 MW	0
Total Generation at Valmont	0	0	74 MW	0

♦ Simulate prior outage of Cherokee 2x1 CC plant (G–1)
♠ Plus ~37 MW from Comanche swing bus generator
♣ Plus ~50 MW from Comanche swing bus generator

Steady-state Contingency Analysis Results

Results from the N–1 contingency analysis performed on each of the three scenario cases are tabulated in Table III (next page).

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Table III 2022 Contingency Analysis Thermal Overload Results

Facilities with Thermal Violations	Existing Facility Rating (MVA)	Thermal Overload (%)			Worst Contingency	Resolved by Upgrade to Conductor Rating ?	Transmission Reinforcement Solution (see Table IV)
		22-S1	22-S2	22-S3			
Cherokee – Federal Heights 115kV Line (9558)	144	130%	112%	120%	Valmont – Spindle 230kV Line	Yes (187 MVA)	**
Cherokee – Semper 115kV Line (9055)	120	109%	---	---	Cherokee – Federal Heights 115kV Line	Yes (159 MVA)	** (S1)
Denver Term – Capitol Hill 115kV UG Line (9007UG)	131	113%	127%	163%	Leetsdale 230/115kV Xfmr	**No** (131 MVA)	**TX2**
Denver Term – Capitol Hill 115kV UG Line (9007UG) **after TX2 project**	131	---	112%	108%	Leetsdale – Harrison 115kV Line	**No** (131 MVA)	**UG1 (S2, S3)**
Leetsdale – University 115kV Line (9338)	120	170%	124%	168%	Arapahoe 230/115kV Xfmr	**Yes (S2)** **No (S1, S3)** (191 MVA)	** (S2) **TX3 (S1, S3)**
Leetsdale – University 115kV Line (9338) **after termination upgrades**	191	107%	---	105.5%	Arapahoe 230/115kV Xfmr	**No (S1, S3)**	**TX3 (S1, S3)**
Leetsdale – Harrison 115kV UG Line (9955UG)	141	---	115%	114%	Denver Term 230/115kV Xfmr	**No** (141 MVA)	**UG2 (S2, S3)**
Ft Lupton – JL Green 230kV Line (5183)	452	114%	118%	121%	Riverdale – Henry Lake 230kV Line	Yes (574 MVA)	**
JL Green – Washington 230kV Line (5527)	480	102%	106%	109%	Riverdale – Henry Lake 230kV Line	Yes (579 MVA)	**
Valmont 230/115kV Xfmr T1 (T2)	280	122%	120%	131%	Valmont 230/115kV Xfmr T2 (T1)	N/A	**TX4**
Chambers 230/115kV Xfmr T1 (T2)	280	103%	111%	114%	Chambers 230/115kV Xfmr T2 (T1)	N/A	None (Loading within Emergency Rating)
Chambers – Havana 115kV Line section (9543/9544)	158	106%	114%	119%	Chambers – Havana 115kV Line section (9544/9543)	**No** (159 MVA)	**OH1**

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Recommended Transmission Reinforcements

Following transmission system reinforcements are necessary to ensure that the Denver-Boulder metro area transmission facilities have adequate thermal capability to achieve reliable operation. Note that TX1 is an existing budgeted project and was assumed in service for all three scenarios, whereas projects TX2, TX4 and OH1 are the reinforcements needed for all three scenarios. Further, project TX3 is not required for scenario S2 (the IPP generation alternative), whereas projects UG1 and UG2 are not required for scenario S1 (the Cherokee 1×1 CC alternative).

Table IV Recommended Transmission Reinforcement Projects

	Reinforcement Project Description	Applicable Scenarios	High level Cost Estimates $ Million
TX1	Add Chambers 230/115 Auto-transformer – Budgeted project	**All**	**5.0**
TX2	Add Leetsdale 230/115 Auto-transformer – Planned project	**All**	**5.0**
TX3	Add Arapahoe 230/115 Auto-transformer	**S1, S3**	**5.0**
TX4	Add Valmont 230/115 Auto-transformer	**All**	**5.0**
UG1	Replace 9007UG (2.17 mi) Denver Term – Capitol Hill 115kV Cable	**S2, S3**	**4.3**
UG2	Replace 9955UG (3.27 mi) Leetsdale – Harrison 115kV Cable	**S2, S3**	**6.5**
OH1	Rebuild 9543/9544 (4.64 miles)OH Chambers – Havana 115kV dbl-ckt line	**All**	**3.7**
**	Upgrade termination equipment limiters to achieve line conductor ratings	**Per Table III**	**1.0 -- 1.5**

Note that all the transmission reinforcement projects identified in Table IV consist of upgrades to existing PSCo transmission facilities and substations. Following are the high level cost estimates for each category of transmission reinforcement solution identified in the above.

Category TX – Add auto-transformer in existing station = $5.0 Million
Category UG – Replace 115kV underground cable = $2.0 Million per mile[1]
Category OH – Rebuild 115kV overhead line = $0.4 Million per circuit per mile
Category ** -- Upgrades to termination equipment = $1.0 - $1.5 Million for all

[1] Can vary significantly due to volatile copper prices.

Equivalent generation dispatch solutions can be used as alternatives for some of these transmission reinforcement solutions – in particular, the installation of additional 230/115kV auto-transformer at Arapahoe can be deferred or avoided by dispatching approximately 110 MW from any of the two generation options available (see below) at Arapahoe.

Generating Units	Cumulative MW Rating
Arapahoe #4	109
Arapahoe #5, #6, #7	119

Reactive Margin Analysis Results

A reactive margin evaluation (i.e. QV analysis) using constant MVA load modeling was conducted for the 2022 summer peak load conditions. The objective was to perform a comparative evaluation of reactive margins at specific Denver metro area transmission buses for the three Cherokee 4 replacement generation scenarios listed in Table II. For each study case (22-S1, 22-S2 and 22-S3), the QV analysis was performed for the post-transient system state existing after the generation governor response resulting due to the prior outage of 570 MW Cherokee 2×1 CC generating plant has occurred. The assumptions used in the three study cases are summarized in Table V below.

Table V Scenario Descriptions for Reactive Margin Evaluation (QV Analysis)

Assumption	Study Case 22-S1	Study Case 22-S2	Study Case 22-S3
Cherokee unit 4	Retired	Retired	Retired
Cherokee 2x1 CC (units 5, 6, 7)	**Outage**	**Outage**	**Outage**
Arapahoe unit 4	Off	Off	Off
Cherokee 1x1 CC (units 8, 9)	350.6 MW Net	Off	Off
SouthWest Gen Total: **Arapahoe Units 5, 6 & 7** **Valmont Units 7 & 8** **Fountain Valley Units 1 & 2**	0 MW (Off)	313.0 MW[2] Net 119 MW 74 MW 120 MW	0 MW (Off)
Renewable Import into Denver Metro (modeled at Comanche)	0 MW (Off)	0 MW (Off)	350.6 MW[3] Net
Cherokee Synchronous Condenser (Unit 2)	On	On	On
Q-Margin evaluation at Buses	Cherokee 115 Arapahoe 115 Valmont 115	Cherokee 115 Arapahoe 115 Valmont 115	Cherokee 115 Arapahoe 115 Valmont 115

[2] The difference of 37.6 MW (350.6 MW – 313.0 MW) is picked up by the area swing bus generator at Comanche.
[3] This proxy generation representing renewable gen from the south is represented as MW only (0 MVAR capability)

All studies used post-transient governor power flow solution technique to model the period of time after the power and voltage transient oscillations have damped out, but before system operators have had time to readjust intertie schedules, etc. following the outage of the Cherokee 2×1 CC generating plant (units 5, 6 & 7). The simulated time frame is approximately 30 seconds to 3 minutes subsequent to a disturbance. Results for the QV analyses performed are tabulated in Table VI.

Table VI 2022 QV Analysis Results

Study Case	Cherokee 115kV Bus			Arapahoe 115kV Bus			Valmont 115kV Bus		
	Qmargin (Mvar)	Vnose (kV)	Vinitial (kV)	Qmargin (Mvar)	Vnose (kV)	Vinitial (kV)	Qmargin (Mvar)	Vnose (kV)	Vinitial (kV)
22-S1	–944.7	88.6	115.2	–800.9	77.5	114.8	–708.4	76.7	114.7
22-S2	–810.6	87.5	113.3	–728.2	80.7	114.5	–645.6	78.7	114.4
22-S3	–618.3	89.3	111.2	–564.8	82.8	111.6	–509.1	82.0	111.9

Sensitivity analysis was conducted to determine the reduction in Q-margin due to the unavailability (prior outage) of key static/dynamic reactive resources at each of the three buses. The resulting Q-margin is therefore a measure of the inherent reactive robustness (or reactive deficiency) of the system to voltage instability/ collapse under extreme system operating conditions, i.e. prior outage of Cherokee 2×1 CC generating plant and outage of key reactive resources located at Denver metro area 115kV buses occurring at summer peak load hours.

Following are the sensitivity analysis results:

- *Loss of Cherokee Unit 2 Synchronous Condenser*: Loss of this 118 MVAr resource results in the loss of 100-104 MVAr of reactive margin at the Cherokee 115kV bus.
- *Loss of Cherokee 115kV Capacitors*: Loss of this 90 MVAr resource results in the loss of about 53 MVAr of reactive margin at the Cherokee 115kV bus.
- *Loss of Arapahoe 115kV Capacitor*: Loss of this 135 MVAr resource results in the loss of 60-70 MVAr of reactive margin at the Arapahoe 115kV buses.
- *Loss of Valmont 115kV Capacitors*: Loss of this 90 MVAr resource results in the loss of 39-45 MVAr of reactive margin at the Valmont 115kV bus.

The following conclusions can be drawn from the above QV analysis results[4]:

1) All reactive margin results are acceptable, with no studied scenarios causing a reactive deficiency in the Denver metro area transmission system that could lead to voltage collapse. The lowest reactive margin is more than 450 MVAr.
2) Case 22-S1 yields the best reactive margin results for every bus, followed by Case 22-S2 and Case 22-S3. The reactive margin reduction between generation scenario 22-S1 (most dynamic reactive resources in metro area) and generation scenario 22-S3 (least dynamic reactive resources in metro area) is ~326 MVAr at Cherokee, ~236 MVAr at Arapahoe, and ~200 MVAr at Valmont. Going from Case 22-S1 to Case 22-S3, the nose voltages (Vnose) rise modestly at every bus, indicating reactive robustness of the Denver metro area transmission system.
3) The highest nose voltage of ~90 kV is sufficiently below the lowest acceptable voltage of 103.5 kV (90% of nominal voltage) – thus allowing automatic control devices sufficient time to respond and providing operators adequate situational awareness to initiate corrective actions based on monitoring the bus voltage decline.

[4] QV analysis is a voltage stability study methodology utilized to determine how close a system is to voltage collapse by modeling a fictitious synchronous condenser at a specific bus and recording the reactive requirements associated with variations in bus voltage. QV curves should be interpreted as *indicators* of a shortage or surplus of reactive power in the localized area around a particular bus. There are many variables which can affect the derived results including load modeling, reactive capability of generators, modeling errors, solution methodologies, etc. Accordingly, any margin-deficient results should not be construed as an absolute criteria violation and should trigger additional studies to more completely understand the potential for voltage instability.