Rifle Cu-Colbran-Grand Junction 138 kV
ATC Evaluation Project
July 30, 2003

I. Executive Summary

The Applicant requested that Public Service Company of Colorado (PSCo) determine the Total Transfer Capability (TTC) and Available Transfer Capability (ATC) of the RifleCU-Colbran-Grand Junction 138 kV line. The RifleCU-Colbran 138 kV branch (Circuit #3014) is 41.2 miles long and the Colbran-Grand Junction 138 kV branch (Circuit #3015) is 22.9 miles long. The RifleCU-Colbran-Grand Junction 138 kV line is a load-serving line and is not a power transfer path recognized by the Western Electricity Coordinating Council (WECC). The TTC and ATC calculations in this study are based on the specific request from the Applicant and the TTC and ATC calculations are derived assuming that the extraction point is either east or west of the injection point (Highway 65, approximately 1.5 miles south of the town of Mesa, Colorado).

PSCo used the Managing and Utilization System Transmission (MUST) software created by Power Technologies, Inc. for the study. The power injection point for simulations was defined in the power flow models at a Mesa 138 kV bus located approximately 7.6 miles south of the Colbran Substation on the Colbran-Grand Junction 138 kV line. Two regions were defined for the study. Zone 801 was designated as the point of origin of incremental power schedules and included the new Mesa 138 kV bus (the power injection point), the Colbran 138 kV and 115 kV busses, the Mesa-Colbran 138 kV line, the Molina generation units (Pmax = 13.5 MW) at the Colbran 115 bus and the Grand Valley load at the Colbran 138 kV bus. Zone 800 was designated as the load-serving area and served as the point of delivery of incremental power schedules. Zone 800 contained the transmission south and west of Rifle and north of Grand Junction, but excluded the system contained in Zone 801 described previously. Figure No. 1 in Section V provides a diagram of the study area with Zone 801 indicated. Zone 800 is all of the system in Figure No. 1 outside Zone 801. The generators at Cameo and Atlas were the extraction points for incremental power schedules and were set to their Pmax values. The interface between Zone 801 and Zone 800 was defined as the Mesa-Grand Junction 138 kV line and the Colbran-RifleCU 138 kV line. The Mesa 138 kV injection point contained in Zone 801 was used to simulate generation into the system; however, PSCo has not received a specific generator interconnection request from the Applicant. Therefore, no attempt was made to model specific generator types or units.

The purpose of the MUST simulations was to inject increasing levels of power into the system at the Mesa 138 kV bus in Zone 801 and extract the power from Cameo and Atlas in Zone 800 thus creating a flow across the interface lines and within Zone 800 and Zone 801. At each incremental increase in power transfer, facility outages in the area were conducted to ensure that the power transfer could be accommodated under system intact and outage conditions. The study area is located within three WECC-accepted power transfer paths – TOT1A, TOT2A, and TOT5. The transmission facilities that make up these transfer paths are listed in Section VI of this report. Although the power transactions simulated in the MUST simulations did not negatively impact the existing TOT1A, TOT2A, and TOT5 power transfer limits, the flow across the TOT2A path does impact the reliability of the power transfers between Zone 801 and Zone 800. A graph that displays the non-firm ATC across the transfer path vs. the flow on TOT2A can be seen in Figure No. 3 in Section X. The study was not able to demonstrate a clear correlation between flows on the TOT1A and TOT5 paths and the non-firm ATC on the interface between Zone 800 and Zone 801. Graphs that display the non-firm ATC across the transfer path vs. the flow on TOT1A and TOT5 can be seen in Figure No. 2 and Figure No. 5 in Section X.

The study concluded the following:

1. The Total Transmission Capacity of the Mesa-Grand Junction 138 kV Colbran-RifleCU 138 kV path is 75 MVA. This limit is based on an overload of the Grand Junction 138-115 kV transformer for an outage of the Colbran-RifleCU 138 kV line.
2. The Existing Transmission Commitments (including Capacity Benefit Margin) varies between 8.9 MW and 11.0 MW and represents the amount of transmission transfer capability for load-serving entities to ensure access to the 13.5 MW of capability of the Molina generating units less the Grand Valley load connected to the Colbran 138 kV bus.
3. The Transmission Reliability Margin is the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The TRM varies from around zero MW up to 60.8 MW depending on the TOT2A flow and the Grand Valley demand in the case.
4. <u>There is no firm ATC available on the path</u>. The system must be able to accommodate TOT2A levels above 600 MW. The studies demonstrate that there is no ATC above 600 MW. Non-firm ATC may be available and the amount is described approximately by the following formula:

   Non-firm ATC = $-0.0001 * [TOT2A]^2 - 0.0352 * [TOT2A] + 67.91$ (in MW's)

5. No stability simulations were conducted for this study. The power transfer levels simulated in the study were well below known stability limitations in western Colorado.

II. Background and Study Objective

The Applicant requested a transmission study to determine the Total Transfer Capability and the Available Transfer Capability of PSCo's Rifle-Colbran-Grand Junction 138 kV transmission line. The Applicant requested the that TTC and ATC be derived assuming that the power extraction point is either east or west of the power injection point - Highway 65, approximately 1.5 miles south of the town of Mesa, Colorado.

The study defined two transmission system zones for the purpose of this evaluation. Zone 801 includes the Colbran 115 kV and 138 kV busses, the Mesa 138 kV bus (the point of power injection), the Molina Generating Station (Pmax = 13.5 MW) and the Grand Valley load both represented as connected to the Colbran 138 kV bus, and the Mesa-Colbran 138 kV line. Zone 800 includes the system south and west of Rifle and north of Grand Junction excluding the system contained within Zone 801 described previously. The interface between these two zones includes the Colbran-Rifle CU 138 kV line and the Mesa-Grand Junction 138 kV line. Please see Figure No. 1 in Section V for a description of the study area. For this study, the request from the Applicant has been interpreted as a request to determine the TTC and ATC of the interface between Zone 801 and Zone 800 with the interface defined as the Colbran-Rifle CU 138 kV line and the Mesa-Grand Junction 138 kV line. The injection point is at the Mesa 138 kV bus that is located in Zone 801 and the extraction points are the generation sites in Zone 800, namely Cameo and Atlas. The Molina, Cameo and Atlas generating units were all set to their Pmax levels in the study cases.

The Grand Junction-Mesa-Colbran-RifleCU 138 kV line is in the vicinity of existing WECC-recognized transfer paths; namely, TOT1A, TOT2A and TOT5. For example, TOT2A (that is comprised of jointly-owned transmission lines) defines the interface between southwest Colorado and northwest New Mexico. Because of this, simulations were conducted with high TOT1A, TOT2A and TOT5 flows. Power was injected at the Mesa 138 kV bus and the Cameo and Atlas units in the load-serving area were scaled down to accommodate the power injection. Facility outages were simulated at each injection incremental level until a criteria violation was encountered. Several load scenarios were studied and the results placed in a table for comparison.

III. ATC Principles

The following principles were taken from the North American Electric Reliability Council (NERC) document titled Available Transfer Capability Definitions and Determination dated June 1996. These Available Transfer Capability (ATC) Principles govern the development of the definition and determination of ATC. All transmission providers and users are expected to abide by these principles.

1. ATC calculations must produce commercially viable results. ATC's produced by calculations must give a reasonable and dependable indication of transfer capabilities available to the electric power market.
2. ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network. The effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint.
3. ATC calculations must recognize the dependency of ATC on the points of electric power injection, the direction of transfers across the interconnected transmission network, and the points of power extraction. All entities must provide sufficient information necessary for the calculation of ATC.
4. Region or wide-area coordination is necessary to develop and post information that reasonably reflects the ATC's of the interconnected transmission network.
5. ATC calculations must conform to NERC, Regional (WECC), sub-regional (CCPG), power pool, and individual system reliability planning and operating policies, criteria and guides.
6. The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.

IV. ATC Definitions

The following definitions were taken from the North American Electric Reliability Council (NERC) document titled Available Transfer Capability Definitions and Determination dated June 1996.

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. The Available Transmission Capacity (ATC) is defined by the following formula:

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ATC = TTC – TRM – Existing Transmission Commitments (including CBM)

Total Transfer Capability (TTC) is defined as the amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner while meeting all of a specific set of defined pre- and post-contingency system conditions.

Transmission Reliability Margin (TRM) is the amount of transmission transfer capability needed to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

The Capacity Benefit Margin (CBM) is defined as the amount of transmission transfer capability reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Transfer Capability (TC) is the measure of the ability of interconnected electric systems to reliably move or transfer power from one area to another over all transmission lines or paths between those areas under specified conditions. Measured in MW, it is directional in nature and is different depending on the direction. Transfer Capability is highly dependant on generation, customer demand, and transmission system conditions assumed during the time period analyzed. The calculation of TC is generally based on computer simulations of the operation of the interconnected transmission network under a specified set of assumed operating conditions. The simulations are performed well before the systems approach that operational state. Each simulation represents a "snapshot" in time of the operation of the interconnected network based on the projections of many factors. Each simulation is viewed as a reasonable indicator of network performance and available transfer capability. Among the factors considered in simulations are:

- projected customer demands (on peak, off-peak, shoulder or "light" demand conditions
- generation dispatch (realistic dispatch)
- system configuration (expected generation and transmission outages, operating procedures in place, etc.)
- base scheduled transfers (scheduled electric power transfers)
- system contingencies (forced outages)

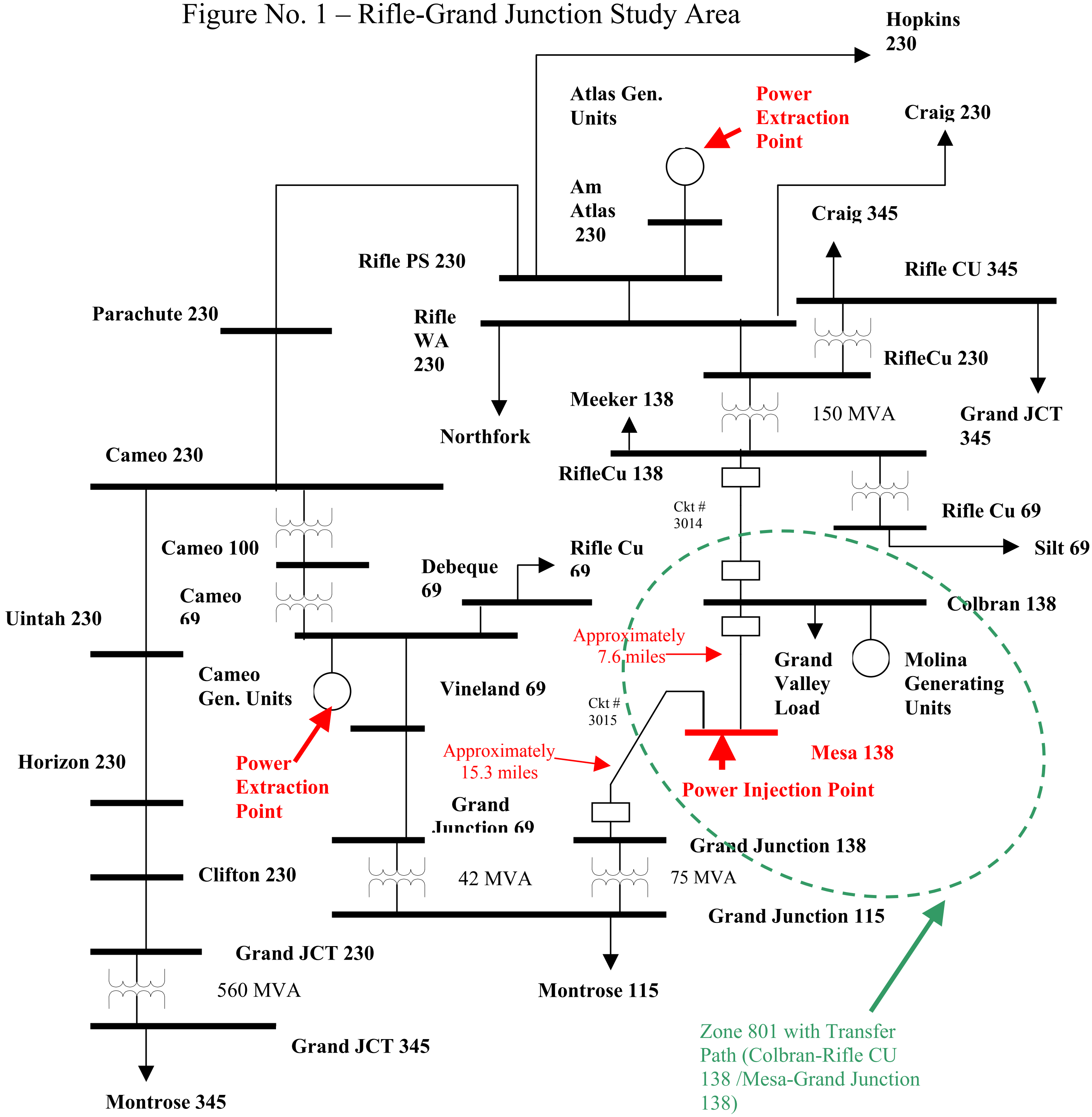
The conditions on the interconnected network vary continuously in real time. Therefore, the Transfer Capability of the network will vary from one instant to another. For this reason, transfer capability calculations may need to be updated periodically for application in the operation of the network (OTC Policy Group, operating studies). The farther in the future the system is modeled, the greater the uncertainty in the network capability.

The limits to Transfer Capability are the thermal limits. A thermal limit is the maximum electric current that a transmission line or electric facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Another limit to transfer capability are the voltage limits. The minimum voltage limits establishes the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in blackouts of portions of the network. Another limit to transfer capability are Stability Limits. All generators connected to the A.C. interconnected transmission system must operate in synchronism with each other at the same frequency (nominal 60 Hz). Immediately after a disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings and system voltages. For the system to be stable, oscillations must diminish as the electric system attains a new stable operating point. If a new stable operating point is not quickly established, the generators will likely lose synchronism with one another, and all or a portion of the interconnected electric system may become unstable causing uncontrolled widespread interruption of customers.

V. Study Area Description

Figure No. 1 illustrates the study area and indicates the Mesa 138 kV power injection point and the Cameo and Atlas extraction points. The system inside the ellipse that is shown on Figure No. 1 has been designated as Zone 801. The portion of the system shown in Figure No. 1 that is outside Zone 801 is designated as Zone 800.

Figure No. 1 – Rifle-Grand Junction Study Area



VI. Study Considerations

Three Western Electricity Coordinating Council (WECC) power transfer paths are located in the vicinity of the study area. The paths are comprised of transmission lines or transformers that operate in conjunction to allow power to be transferred between areas. The path descriptions are as follows:

A. TOT1A – This path defines the power transfers from northwest Colorado to northeast Utah and has a maximum east-to-west rating of 650 MW. The path owners include Platte River Power Authority, UAMPS, Western Area Power Administration, Tri-State G&T and Deseret G&T.

Line/Transformer	Metered End
-Bears Ears-Bonanza 345 kV	Bears Ears
-Hayden-Artesia 138 kV	Hayden
-Meeker-Rangely 138 kV	Rangely

B. TOT2A – This path defines the power transfers from southwest Colorado to northwest New Mexico and has a maximum north-to-south rating of 690 MW. The path owners include Western Area Power Administration, Tri-State G&T and Public Service Co. of Colorado.

Line/Transformer	Metered End
-Hesperus-San Juan 345 kV	San Juan
-Durango-Glade Tap 115 kV	Glade Tap
-Lost Canyon-Shiprock 230 kV	Shiprock

C. TOT5 – This path defines the power transfers from western Colorado to eastern Colorado and has a maximum west-to-east rating of 1675 MW. The path owners include Western Area Power Administration, Tri-State G&T, Platte River Power Authority, and Public Service Co. of Colorado.

Line/Transformer	Metered End
-Hayden-Archer 230 kV	Archer
-Craig-Ault 345 kV	Craig
-Gore Pass-Blue River 230 kV	Blue River
-Hayden-Gore Pass 138 kV	Gore Pass
-Gore Pass230/138-kV transformer	Gore Pass 230
-Gunnison-Poncha 230 kV	Poncha
-Curecanti-Poncha 230 kV	Curecanti
-Basalt-Malta 230 kV	Basalt
-Basalt-Hopkins 115 kV	Basalt
-Rifle-Hopkins 230 kV	Rifle

VII. Planning Criteria

For planning studies, PSCo adheres to the WECC Reliability Criteria. For system intact conditions, PSCo planning criteria is to maintain system bus voltages between 0.95 and 1.05 per unit. Operationally, PSCo tries to maintain a system voltage profile ranging from 1.02 at generators to 1.0 or higher at load buses in the Denver/Boulder area. Following a single contingency, voltages must be within 0.90 and 1.10 per unit. Facility loadings must remain within 100% of their nominal steady state ratings for system intact conditions. Under certain contingency conditions, PSCo will allow a 110% short-term (emergency) rating for transmission lines and 115% for large transformers if the transformer follows a daily load curve. Xcel Energy is continuing work towards the development of a standard rating methodology for both transformers and transmission lines.

VIII. Study Case Development

The determination of the ATC of a path must take into account variations in load forecasts, generation dispatches and parallel flows. To capture these uncertainties, several different power flow models were used to represent these variations. The include a 2004 heavy winter case, a 2006 heavy summer case, a 2010 heavy winter case, and a 2012 heavy summer case. In addition, high transfer flows were simulated in the cases to account for regional transfers possibilities.

The proposed Mesa injection point connects to the Grand Junction-Colbran 138 kV load-serving line. The line is not a recognized path for scheduling; however, the purpose of the study was to determine the maximum level of injection into the line. A load-serving area was defined for the study in order to evaluate the power transfer potential. The north boundary of the study area are the Meeker - Rangely 138 kV line, the Craig - Rifle WA 230 kV line and the Craig - Rifle CU 345 kV line. The south boundary of the study area are the GrandJct - Montrose 345 kV line, the GrandJct - Montrose 115 kV line and the Rifle WA - Northfrk 230 kV line. The east boundary of the study area is the Rifle PS - Hopkins 230 kV line and the Rifle CU - SiltUSBR 69 kV line. The system within this area was designated as Zone 800. The Mesa injection point was assigned to Zone 801 and transfers were simulated between Zone 801 and Zone 800. Outages of facilities in the area were simulated in order to determine the maximum plant output; and hence the capability of the Grand Junction-Colbran 138 kV line.

The following study cases were created for this study:

A. 2004HW-M

This case represents a 2004-2005 heavy winter scenario with the Mesa injection point modeled at a tap point on the Colbran-Grand Junction 138 kV line approximately 7.6 miles south of Colbran.

B. 2006HS-M

This case represents a 2006 heavy summer scenario with the Mesa injection point modeled at a tap point on the Colbran-Grand Junction 138 kV line approximately 7.6 miles south of Colbran.

C. 2010HW-M

This case represents a 2010-2011 heavy winter scenario with the Mesa injection point modeled at a tap point on the Colbran-Grand Junction 138 kV line approximately 7.6 miles south of Colbran.

D. 2010HW-MB1160

This case represents a 2010-2011 heavy winter scenario with the Mesa injection point modeled at a tap point on the Colbran-Grand Junction 138 kV line approximately 7.6 miles south of Colbran. The power output of generators in western Colorado was increased and scheduled to eastern Colorado to increase the power flow across TOT5. Because there were insufficient resources in western Colorado to stress TOT5, generation resources in Arizona/New Mexico were scheduled to eastern Colorado from south to north with the TOT2A, TOT2B1, and TOT2B1 phase-shifting transformers holding schedule.

E. 2012HS-M

This case represents a 2012 heavy summer scenario with the Mesa injection point modeled at a tap point on the Colbran-Grand Junction 138 kV line approximately 7.6 miles south of Colbran. The Craig/Hayden generation was re-dispatched using eastern Colorado generation in order to make available resources at Craig and Hayden to stress TOT2A.

F. 2012HS-MA250

This case represents a 2012 heavy summer scenario with the Mesa injection point modeled at a tap point on the Colbran-Grand Junction 138 kV line approximately 7.6 miles south of Colbran. A 250 MW schedule from Craig to Four Corners was modeled. The TOT2A phase-shifting transformers were holding schedule.

G. 2012HS-MA400

This case represents a 2012 heavy summer scenario with the Mesa injection point modeled at a tap point on the Colbran-Grand Junction 138 kV line approximately 7.6 miles south of Colbran. A 400 MW schedule from Craig to Four Corners was modeled. The TOT2A phase-shifting transformers were holding schedule.

IX. Outages

Outages were conducted for all facilities in Zones 708, 790, and 800.

X. Study Results

A software simulation tool developed by Power Technologies, Inc called Managing and Utilizing System Transmission (MUST) was used for the study. This software was developed to understand transaction patterns and effects, understand and justify transmission limits, provide a basis for transmission reliability margin, and calculate transfer limits rapidly.

The interface between Zone 801 and Zone 800 is comprised of the Colbran-RifleCU 138 kV line and the Mesa-Grand Junction 138 kV. The Total Transfer Capability from the Mesa injection point (in Zone 801) to the extraction points (Cameo and Atlas generators in Zone 800) is approximately 75 MW, the rating of the Grand Junction 138-115 kV transformer. The Grand Junction 138-115 kV transformer overloads for an outage of the Colbran-Rifle CU 138 kV line.

The Existing Transmission Commitments (including Capacity Benefit Margin or CBM) is defined as the amount of transmission transfer capability reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. For this project, the existing transmission commitments is the transmission capacity reserved for the Molina units to deliver their output to the loads in Zone 800 (less the Grand Valley load at the Colbran 138 kV bus). The amount of generation at Molina is 4.9 + 8.6 or 13.5 MW and is also connected to the Colbran 138 kV bus.

The Transmission Reliability Margin (TRM) is the amount of transmission transfer capability needed to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The TRM varies based on the level of TOT2A.

For this study, it was assumed that the amount of power that can be reliably injected at the Mesa 138 kV bus in Zone 801 and extracted at Cameo and Atlas in Zone 800 provides a good approximation for the ATC provided the Molina generation was set to its maximum level and high levels of TOT flows were simulated. The various injections and extractions take into account the transmission that is needed to move the Molina generation out of Zone 801 and it takes into account the parallel flows through Zone 801 and Zone 800 for various high TOT flow conditions. The following formula defines the ATC.

ATC = TTC – TRM – Existing Transmission Commitments (including CBM)

The ATC of the path varies as the TOT2A flow increases. For example, at high TOT2A levels, the power that can be injected at the Mesa 138 kV bus and extracted at Cameo and Atlas is approximately 35 MW at a TOT2A level of 313 MW, and decreases to approximately 4 MW at a TOT2A level of 588 MW. The results of the power flow simulations to determine the TTC and ATC can be found in Table No. 1 below. The results of the ATC calculations can be seen in Table No. 2 shown below. The injection/extraction scenarios that were created by MUST provided the ATC numbers; therefore, the TRM was determined by subtracting the ATC and the existing transmission requirements (Molina generation less the Grand Valley load at Colbran) from the TTC of 75 MW. Since the ATC was derived from the amount of power injected at the Mesa 138 kV bus, the TRM was determined by subtracting the ATC (determined by the power injection) and the existing transmission commitments (including CBM) from the TTC. For example, Table No. 1 provides a summary of the study results. Case 2010HW-M has a Mesa 138 kV injection of 35.3 MW, a Molina generation level of 13.5 MW (the maximum output of all the units) and a Grand Valley demand at the Colbran 138 kV bus of 4.6 MW. Assuming the path ATC is the level of generation injected or 35.3 MW, the existing transmission commitments (less CBM) is 13.5 MW less 4.6 MW or 8.9 MW, and the TTC is 75 MW. The TRM would be 75 MW less 35.3 MW less 8.9 MW or 30.8 MW. The 30.8 MW represents the transmission capacity needed to support an injection of 35.3 MW at a TOT2A level of 313 MW. At that injection level or ATC level with TOT2A at 313 MW, an outage of the RifleCU-Grand Junction 345 kV line loads the Grand Junction 138-115 kV transformer to 100%. At very low TOT2A levels, the TRM was slightly negative due to line losses during the MUST simulations. For example, Case 2004HW-M has a Mesa 138 kV injection of 67.3 MW, a Molina generation level of 13.5 MW (the maximum output of all the units) and a Grand Valley demand at the Colbran 138 kV bus of 3.9 MW. Assuming the path ATC is the level of generation injected or 67.3 MW, the existing transmission commitments (less CBM) is 13.5 MW less 3.9 MW or 9.6 MW, and the TTC is 75 MW. The TRM would be 75 MW less 67.3 MW less 9.6 MW or –1.9 MW. Examining the power flow cases showed that the TRM is slightly less than zero in this case due to line losses in the MUST simulations.

The study found that the amount of power that can be injected at the Mesa 138 kV bus, transferred across the interface between Zone 801 and Zone 800, and extracted at the Cameo and Atlas busses is highly dependent on the flow on the TOT2A path. This relation ship can be seen in Figure No. 3. A curve-fitting algorithm was used to create an equation that describes the relationship of the non-firm ATC to TOT2A and is as follows:

$$\text{Non-firm ATC} = -0.0001 * [\text{TOT2A}]^2 - 0.0352 * [\text{TOT2A}] + 67.91 \quad \text{(in MW's)}$$

The system in western Colorado must be able to accommodate TOT2A flows above 600 MW. Therefore, there is no firm ATC on the path between Zone 801 and Zone 800. The non-firm ATC can be approximated by the above formula.

Table No. 1 Summary of Study Results

Case Name	Description	TOT1A (E to W)	TOT2A (N to S)	TOT5 (W to E)	Craig/Hay Gen	Molina Gen	Colbran Demand	Mesa Injection	Critical Element	Rating	Critical Outage	Percent of Rating
2004HW-M	2004 Heavy Winter	427	-9	367	1290	13.5	3.9	67.3	GrdJct 138-115	75.0	Colbran-RifleCU 138	100.0
	w/ Mesa Injection											
2006HS-M	2006 Heavy Summer	355	54	531	1372	13.5	2.5	65.5	GrdJct 138-115	75.0	Colbran-RifleCU 138	100.0
	w/ Mesa Injection											
2010HW-M	2010 Heavy Winter	161	313	386	1545	13.5	4.6	35.3	GrdJct 138-115	75.0	RifleCU-GrdJct 345	100.0
	w/ Mesa Injection							42.7	GrdJct-Montrose 115	76.5	GrdJct-Montr 345	100.0
2010HW-	2010HW-M	-120	-120	1160	1545	13.5	4.6	69.6	GrdJct 138-115	75.0	Colbran-RifleCU 138	100.0
MB1160	w/ high TOT5 flow							96.8	Rifle 138-69	25.0	GrdJct-MesaCo 138	100.0
	See Note 1											
2012HS-M	2012 Heavy Summer	190	185	104	943	13.5	2.9	65.3	GndJct 138-115	75.0	Colbran-RifleCU 138	100.0
	w/ Mesa Injection											
2012HS-	2012HS-M w/250 MW	199	438	103	1193	13.5	2.9	29.2	GndJct 138-115	75.0	GndJct-RifleCU 345	100.0

MA250	Sched Crg to FC											
2012HS-	2012HS-M w/ 400 MW	196	588	53	1343	13.5	2.9	3.6	GrdJct-Montrs 115	76.5	GrdJct-RifleCU 345	100.0
MA400	Sched Crg to FC							17.0	GrdJct 138-115	76.0	GrdJct-RifleCU 345	100.0

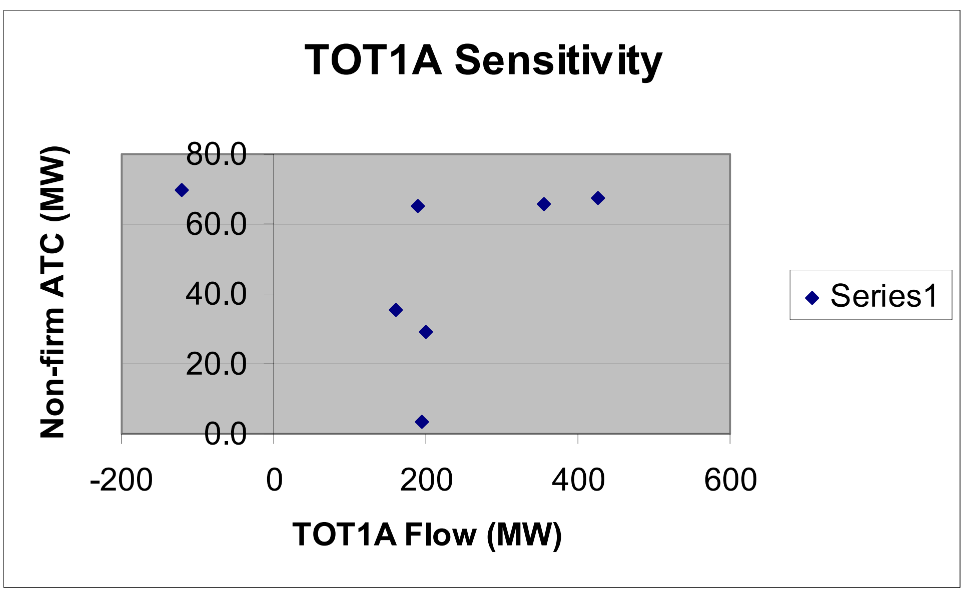
Note1: The Rifle 138-69 kV overload that occurs under high TOT5 conditions will be removed after the completion of the Shoshone-Rifle 69/115 kV Uprate Project.

Table No. 2 – TTC and Non-firm ATC Summary Table

	Case: 2004HW	Case: 2006HS	Case: 2010HW	Case: 2010HW MB1160	Case: 2012HS	Case: 2012HS-MA250	Case: 2012HS-MA400
TOT2A	-9	54	313	-120	185	438	588
TTC	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Existing Transmission Commitmnts	9.6	11.0	8.9	8.9	10.6	10.6	10.6
TRM	-1.9	-1.5	30.8	-3.5	-0.9	35.2	60.8
Non-firm ATC	67.3	65.5	35.3	69.6	65.3	29.2	3.6

The data from Table No. 1 is represented in Figure No. 2 below. No correlation between flows on TOT1A and the non-firm ATC on the path could be concluded.

Figure No. 2 – TOT1A Sensitivity



The data from Table No. 1 is represented in Figure No. 3 below. The data demonstrates the impact of TOT2A flows on the amount of power that can be reliably transferred from the injection point at the Mesa 138 kV bus and the extraction points at Cameo and Atlas. At TOT2A levels above 600 MW, there is no non-firm ATC on the path. The rating of the path according to the WECC Path Rating Manual is 690 MW. A curve-fitting algorithm was used to determine a polynomial that most closely fits the data points, and this can be seen in Figure No. 4.

Figure No. 3 – TOT2A Sensitivity

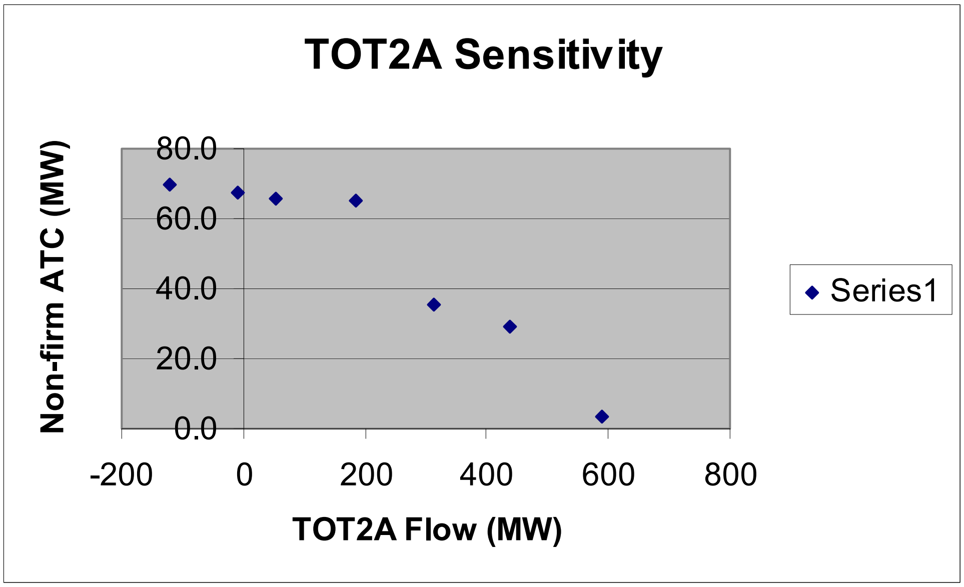
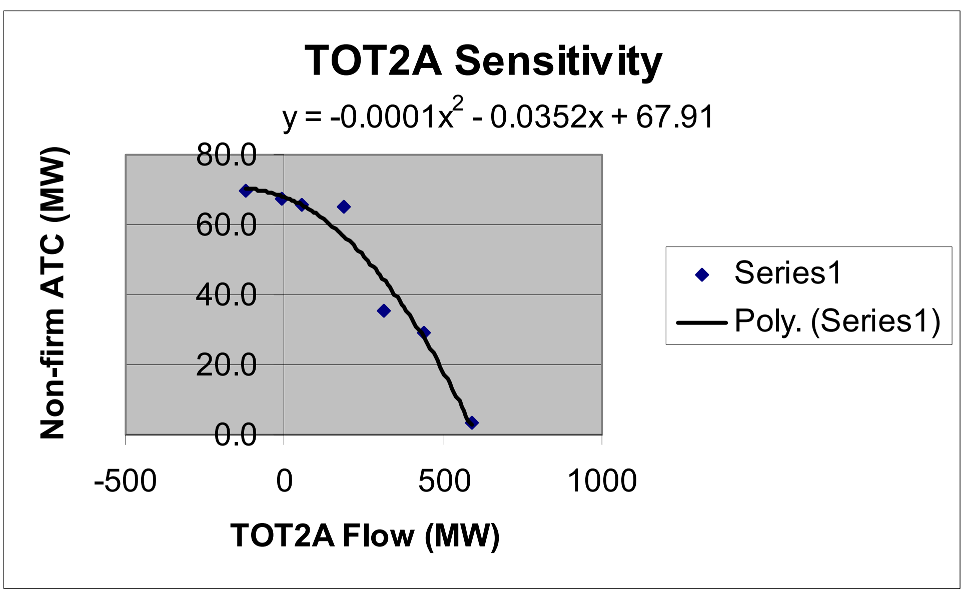


Figure No. 4 - TOT2A Sensitivity (with curve-fitting to the data points)



The data from Table No. 1 is represented in Figure No. 5 below. No correlation between flows on TOT5 and the non-firm ATC on the path could be concluded.

Figure No. 5 – TOT5 Sensitivity