NORTHERN TIER TRANSMISSION GROUP

2010-2011 Biennial Transmission Plan

Final Report

December 1, 2011

Approved: 10.31.11 NTTG Planning Committee
Approved: 11.29.11 NTTG Steering Committee

This is the final report of the 2010-2011 Biennial Transmission Plan of the Northern Tier Transmission Group. It's our second biennial report, and we think it's our best work yet. The report represents the collective efforts of many people. Our thanks go out to the numerous Northern Tier transmission provider engineers and Comprehensive Power Solutions staff who did yeoman's work in soliciting and collecting the data, running the analyses, listening to and incorporating feedback, and preparing the studies. They did a commendable job, and we're proud of their product.

We'd also like to thank you, our stakeholders, for your interest and participation in NTTG public processes. You helped make this a better plan.

If you're familiar with our 2008-2009 report, you'll notice some differences. Right off, this report is bigger. We've included more data to support our findings, and we've included more background and appendices for those of you who want to dig deeper. More fundamentally, we eliminated the use of multi-season WECC base cases to do reliability testing, an approach that had created some hurdles in the 2008-2009 report. In a nutshell, the new method, which is described in detail in the report, pinpointed five critical hours of transmission congestion and peak loads. Studying the effects of load growth and new generation on the transmission system at these hours formed the core of the study.

The study confirms what many of you already suspect, that our region will need new transmission to connect electricity consumers with new sources of energy. The good news is that our transmission providers already are planning to build those transmission projects. However, the study also shows that any large new generation projects, such as the wind power resources simulated in the study, will require additional AC or DC transmission beyond what's planned. We hope this report bolsters that work, and adds to the larger job of building a more reliable grid throughout the West.

We invite you to read the report critically. Let us know if you have any comments or suggestions to improve our next report. Our contact information is on the back page.

Thanks again for your interest, not only in this report, but in the larger issue of energy system reliability. Through your participation, you've contributed to ensuring a more reliable transmission system for the nearly 3.5 million retail customers in the NTTG subregion who depend on us for safe, dependable and least-cost electricity.

We encourage you to stay involved as we begin work on the 2012-2013 biennium planning process.

Sincerely,

Kip Sikes, 2010 Chair and John Leland, 2011 Chair NTTG Planning Committee

Disclaimer

This report was prepared by the members of the Northern Tier Transmission Group (Northern Tier) and other stakeholders participating in the effort to provide coordinated, efficient and effective planning for expansion of transmission within the Northern Tier footprint. While Northern Tier cannot assure the plan will be implemented as designed, it represents the best information available during the current planning cycle. Changing needs or new information will be accommodated through appropriate data submittals during the next planning cycle.

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Northern Tier Transmission Group Mission: To ensure efficient, effective, coordinated use and expansion of the members' transmission systems in the Western Interconnection to best meet the needs of customers and stakeholders.

Map Illustrating Northern Tier Members' Principal Transmission Lines

The extensive high-voltage transmission network of the Northern Tier Transmission Group's transmission providers reaches to all states of the U.S. Western Interconnection.

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Abstract

The study plan sought to determine transmission system improvements needed for reliable operation in the year 2020 within the Northern Tier Transmission Group footprint in the western United States. First, the transmission study established the inadequacy of the existing transmission system to reliably handle forecasted 2020 load. Next, Core Cases examined five hours representing times of heavy load, import and export stress. Power flow reliability analysis on the five Core Cases demonstrated the adequacy of expected transmission upgrades to reliably integrate planned energy resources and serve forecasted NTTG system load. Finally, Scenario Cases applied four different wind generation configurations against the five Core Cases. The resource additions in these Scenario Cases exceeded the capability of the NTTG transmission system and its expected upgrades. Therefore, the study plan concluded, the NTTG system will require additional AC and/or DC transmission to serve forecasted load under these resource expansion scenarios.

Executive Summary

The Northern Tier Transmission Group (Northern Tier or NTTG) transmission plan establishes the baseline main grid transmission configuration for the Northern Tier footprint for the planning horizon ending in 2020. This planned transmission should be used as a "base plan" to inform other planning processes.

The transmission planning process had three goals: 1) identify transmission needs of transmission customers; 2) identify and evaluate transmission congestion that impedes efficient operation of electricity markets; and 3) consider the impacts on congestion of potential new generation facilities or new transmission projects. This year's NTTG planning process used a bottom-up approach, which rolled up the NTTG transmission providers' transmission plans, informed by other project developers' input, as the starting point for the planning studies described below.

The study plan sought to determine – given a limited number of load and resource scenarios – the general transmission improvements needed for feasible system operation at times of transmission stress 10 years in the future. It is the second biennial plan developed by NTTG.

Planning and preparation of the report took place over a two-year, eight-quarter span. Two planning cycles ran on parallel tracks. One track comprised the biennial transmission planning cycle. The other track included two annual economic congestion study cycles. Both planning cycles began in January 2010 and concluded with the final approval and publication of this report at the end of 2011. In completing these study cycles, a Technical Work Group developed the biennial transmission study and an Economic Studies Team planned and performed requested economic congestion studies. In January 2012, a third biennial planning cycle will begin, with data, models and processes enhanced by the experiences and results of the first two cycles.

The report begins with a review of the background and evolution of the Northern Tier Transmission Group, its current organization and the planning process. The relationship between the Northern Tier Transmission Group and other subregional and regional activities is outlined and their synchronized planning cycles described.

The report explains the study methodology, assumptions, data and analyses underlying the planning effort in the 2010-2011 cycle. The studies performed during the biennium are reviewed and their results summarized.

Over the biennium, NTTG received 45 economic study requests, most of which were regional in nature. But three were deemed relevant for study due to their subregional nature. The three subregional requests were clustered into one study to assess the impact of the transmission expansion on resource additions in Montana. In general, the economic analysis found that additional transmission is needed to accommodate increases in wind energy resources beyond those presently planned.

The biennial transmission study was comprised of three components: 1) a Null Case, 2) five Core Cases and 3) four resource development Scenario Cases.

The Null Case projected how the existing transmission system would perform 10 years in the future with assumed load growth (and an increase in the existing generation output) but without the addition of new transmission or energy resources. The Null Case concluded that the existing transmission system is inadequate to reliably serve estimated 2020 load and requires additional transmission capacity.

However, the power flow reliability analysis of the Core Cases demonstrated that the Foundational Transmission Projects, developed by the SPG Coordination Group[1] and adopted by the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee (TEPPC), increase the system capability to reliably integrate planned energy resources and serve the forecasted NTTG system load. These Core Cases were developed by exporting production cost simulation data to a power flow program for five hours representing: heavy load hours, maximum export hours and maximum import hour. The Core Cases contained the base system and resource and loading conditions for the Scenario Cases that followed.

Finally, the Scenario Cases applied four different wind generation configurations against the five Core Cases – 20 scenarios in all. Each study hour within a Scenario Case was evaluated using load flow analysis to identify the minimum amount of transmission improvements required to reduce transmission path flows to acceptable reliability levels. Single element (N-1) contingency analysis was performed on all five study hours for each scenario to evaluate the performance of the system. Each of these scenarios is examined in the report. The resource additions in these Scenario Cases exceeded the

[1] The SPG Coordination Group (SCG) is composed of representatives from each TEPPC-recognized Sub-regional Planning Group (SPG), including Canada. The purpose of the SCG is to develop the Foundational Transmission Projects List (List) for use in developing TEPPC's interconnection-wide plans.

capability of the NTTG transmission system and its Foundational Transmission Projects. Therefore, the NTTG system will require additional AC and/or DC transmission to accommodate these resources.

Chapter 1 - Background

The Northern Tier Transmission Group

One founding principle of the Northern Tier Transmission Group (Northern Tier or NTTG) is to fulfill Federal Energy Regulatory Commission (FERC) Order 890 requirements that local Transmission providers participate in regional and subregional planning. Northern Tier was created in fall 2006. The group began its work in 2007 as a forum where all interested stakeholders, including transmission providers, customers and state regulators, might participate in planning, coordinating and implementing a robust transmission system.

Additional detail on the history underlying the current organization is available in the 2007 Annual Planning Report published April 2, 2008 and accessible on the Northern Tier web site, http://www.nttg.biz.

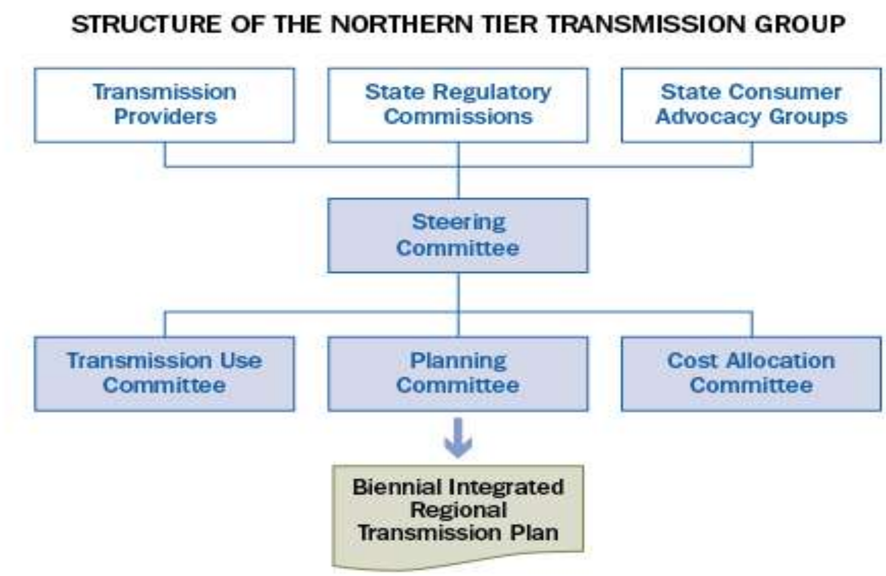


Figure 1-1 – Structure of the Northern Tier Transmission Group

NTTG focuses its efforts on the evaluation of transmission projects that move power across the subregional bulk electric transmission system, serving load in its footprint and delivering electricity to external markets. The transmission providers belonging to Northern Tier serve the nearly 3.5 million retail customers with nearly 3,000 miles of high voltage transmission lines. These members provide service across much of Utah, Wyoming, Montana, Idaho and Oregon, and parts of Washington and California.

NTTG works with the WECC Planning Coordination Committee for reliability planning, the WECC TEPPC for economic planning, and neighboring subregional planning entities.

Northern Tier Members

The Northern Tier Transmission Group's organizational structure has multiple levels, as shown in Figure 1.1 above. Overall planning direction is provided by the Steering Committee, whose membership at publication was as follows:

- Idaho Public Utilities Commission
- Oregon Public Utility Commission
- Montana Public Service Commission
- Montana Consumer Counsel
- Utah Public Service Commission
- Wyoming Public Service Commission
- Deseret Power Electric Cooperative
- Idaho Power Company
- NorthWestern Energy
- PacifiCorp
- Portland General Electric
- Utah Associated Municipal Power Systems

Transmission Planning Committee

The NTTG Planning Committee was formed to coordinate transmission planning for the Northern Tier footprint[2] and to coordinate with other subregional planning groups and the Western Electricity Coordinating Council's planning committees. Execution of the Transmission Planning Committee's charter occurs through the biennial planning process. Northern Tier's planning process is designed to be open, transparent and participatory. Transmission providers, regulators, customers and other stakeholders are encouraged to join the committee's activities and meetings, including semi-annual stakeholder meetings.

NTTG's 2010-2011 biennial plan was produced through its public processes in conjunction with related activities of the NTTG Cost Allocation Committee and NTTG Transmission Use Committee.

At publication, the Planning Committee had members from the following organizations:

[2] The Northern Tier footprint encompasses service territories of NTTG Funding Agreement signatories.

- Basin Electric
- Black Hills Power
- Deseret Power Electric Cooperative
- Gaelectric, LLC
- Grasslands Renewable Energy
- Idaho Power
- NextEra Energy Resources
- NorthWestern Energy
- PacifiCorp
- Portland General Electric
- Riverbank Power Corporation
- Sea Breeze Pacific
- TransCanada
- Utah Associated Municipal Power Systems
- Idaho Office of Energy Resources
- Montana Public Service Commission
- Wyoming Public Service Commission

Coordination Within the Northern Tier Footprint

Planning is an iterative process and must work in concert with local transmission plans and Integrated Resource Plans, where they exist. This Northern Tier transmission plan uses a bottom-up load service process, employing stakeholder data and input to ensure that the transmission planned for the Northern Tier footprint can reliably serve forecasted load growth and conditions. While this plan addresses transmission issues and solutions within the Northern Tier footprint, it is an informational plan that does not require construction and does not seek to accommodate broader regional needs.

Each of the Northern Tier transmission providers is also responsible for transmission planning and implementation for its own service area and for any Balancing Authority areas it administers. This local transmission planning process is designed to parallel and interact with the planning done at Northern Tier.

The local planning process digs deeper than the subregional process, in terms of its analysis both of finer detail (lower voltages and system dynamics) and more extensive construction detail. The transmission provider's responsibilities include path ratings, project financing, permitting and approvals, and construction.

The NTTG planning process provides a mechanism for coordinating stakeholder load and resource data, as well as for considering potential non-transmission provider transmission projects. Additionally, this process coordinates analysis of the existing subregional transmission system and the proposed projects that affect the transmission of electricity throughout the NTTG footprint.

Coordination with Others in the Western Interconnection

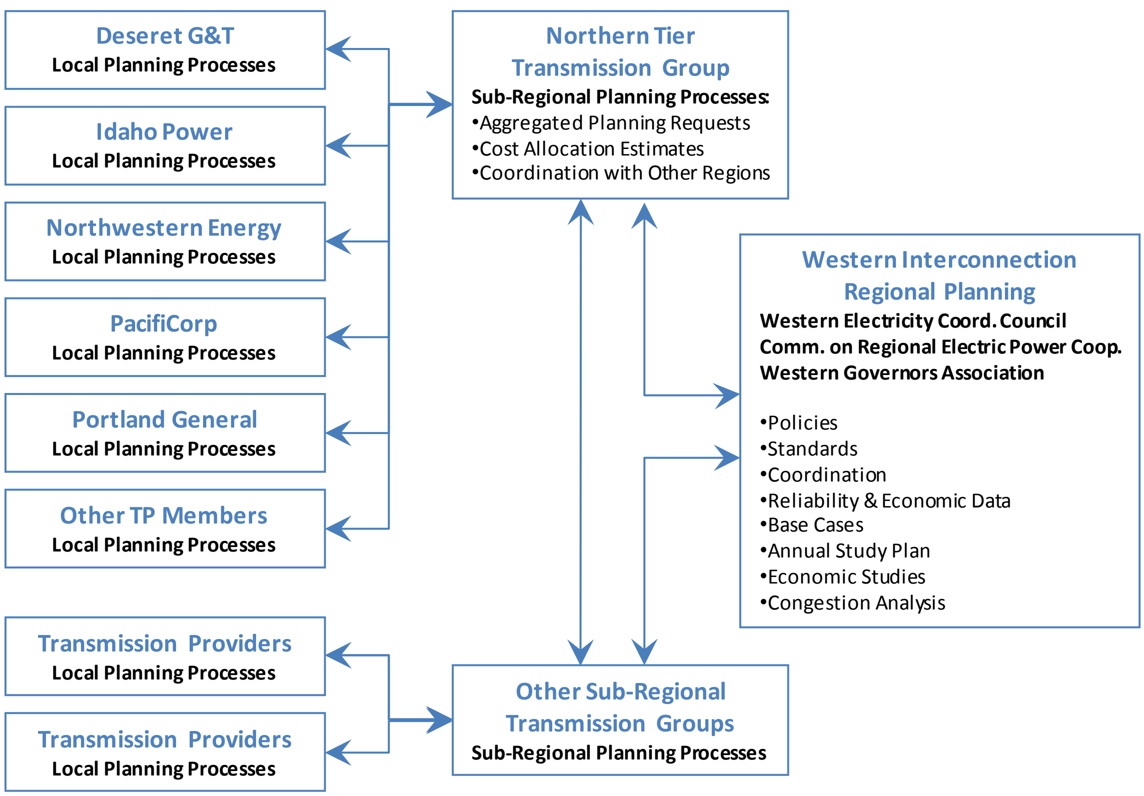
NTTG is committed to coordinating subregional planning efforts with adjacent subregional groups and other planning entities. In addition to working directly with the ColumbiaGrid and WestConnect subregional planning groups, Northern Tier relies on the data collection, validation and transmission modeling work done by WECC, the regional reliability organization. This Northern Tier transmission plan is consistent with the work of WECC.

WECC provides valuable services to transmission planners across the Western Interconnection. WECC's services include providing regional reliability planning and facility rating, and supplying economic planning data and analysis to its members through its Transmission Expansion Planning Policy Committee (TEPPC).

Relationships Among Planning Entities in the West

Transmission planning in the Western Interconnection has evolved to incorporate three distinct organizational levels: transmission providers, subregional transmission groups and regional planning entities. The relationships among regional, subregional and individual transmission entities are illustrated in Figure 1.2 below.

Figure 1-2 – Three-level Planning Process in the Western Interconnection

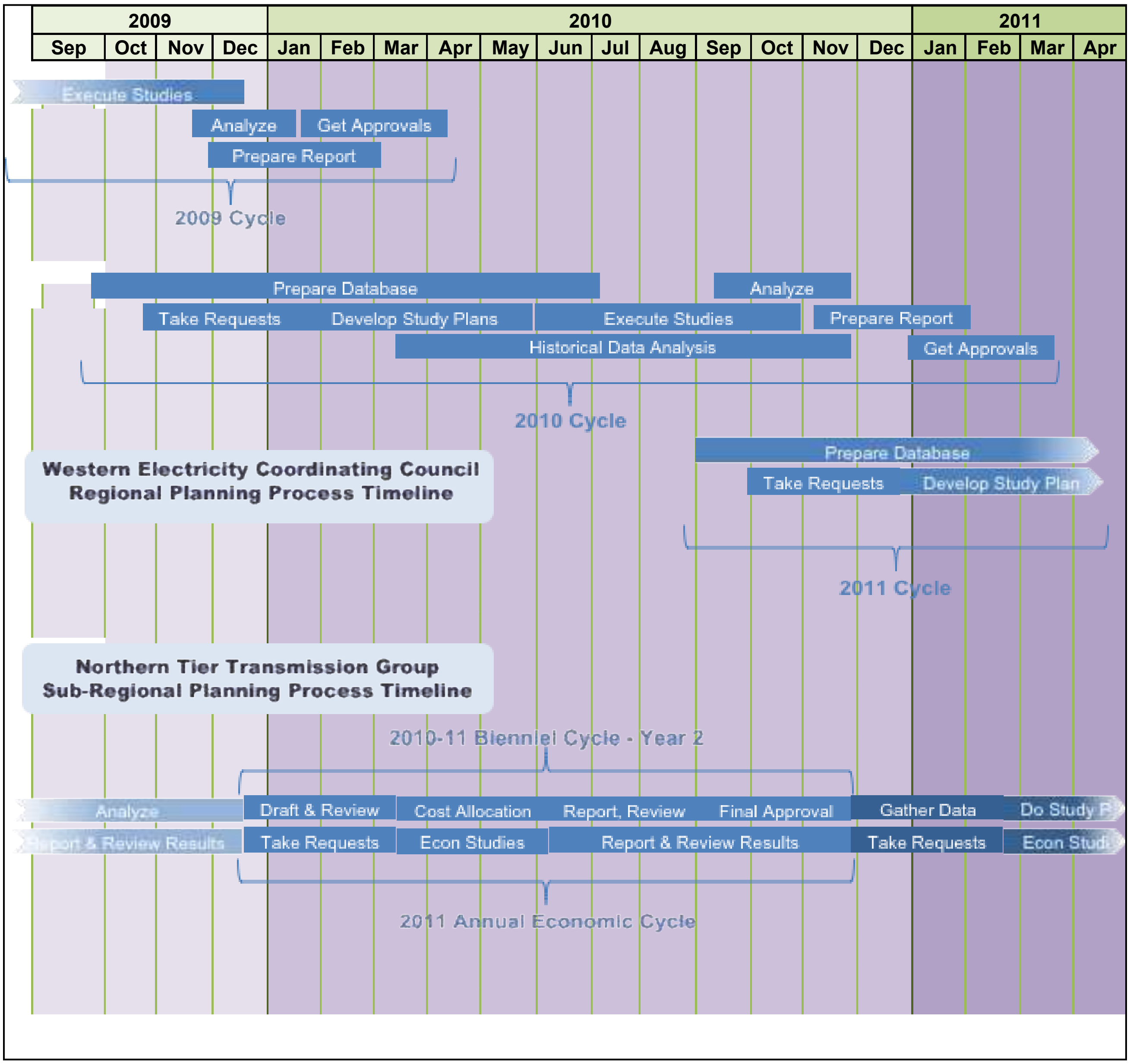


The transmission providers each develop and maintain an Open Access Transmission Tariff process, which receives and acts on requests for transmission service in accordance with a well-defined procedure. The transmission providers also assess future load and resource developments to plan the evolution of an efficient transmission system, and undertake reliability analysis and improvements.

Planning and analysis of improvements are coordinated at the subregional level when service requests and other identified needs call for the development of transmission that involves participation of multiple transmission providers within a subregional transmission group's footprint.

At the regional level, the WECC TEPPC provides a forum for coordination on regional issues and completes the three-level framework that addresses regional, subregional and local issues.

Figure 1-3 - Timelines for Regional & Subregional Planning



The Northern Tier Transmission Group's planning timelines are designed to coordinate with those of WECC. Those timelines include a two-year cycle for transmission expansion and reliability and a one-year economic study cycle. The economic study process examines preliminary plans during the first year of the biennial cycle and draft plans during the second year of the cycle.

NTTG – Review of 2010-2011 Planning Activities

Stakeholder participation is important to the processes of the Northern Tier Transmission Group. All interested parties are encouraged to attend and contribute to the many stakeholder meetings conducted by the Transmission Use, Planning and Cost Allocation committees, and to help in preparing, developing and analyzing planning studies. A chronology of activities in the 2010-2011 biennial planning cycle is provided in Table 1.1 below.

The Northern Tier Planning Committee conducted open conference calls on a frequent basis during the 2010-2011 biennium. The planning process was developed and managed in these conferences. Participants discussed and reached agreement on assumptions, data and methodologies.

The Planning Committee decided to perform studies using the staff of member transmission providers, taking advantage of their internal expertise and software tools. The committee formed a Technical Work Group ("TWG"), to separate detailed technical and model discussions from the policy-level Planning Committee and to provide proper control of confidential information.

An Economic Studies Team was similarly formed to plan and perform any needed economic studies resulting from NTTG's Economic Study Request solicitation during the biennium.

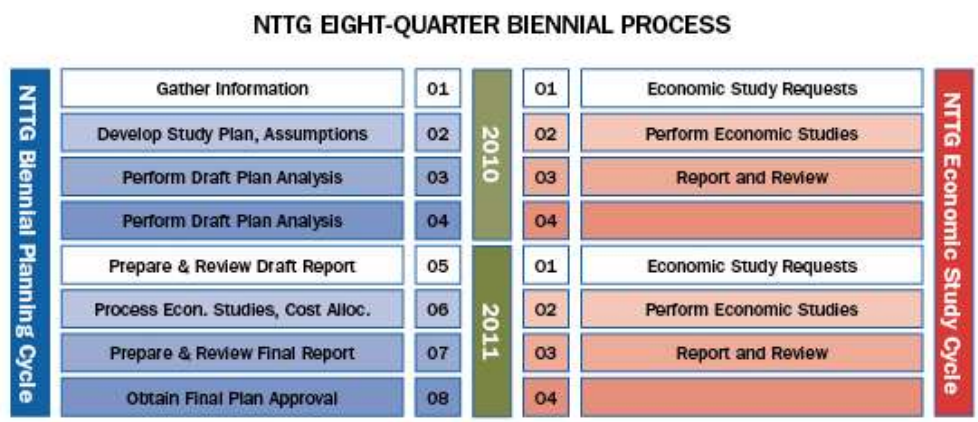
Table 1-1 – Chronology of Northern Tier Activities in 2010 and 2011

2010	Jan	28	2010 Public Semi-Annual Stakeholder Meeting
	Feb	2 24	2010-11 NTTG Planning Committee Data Request Form Posted Public Stakeholder Economic Study Request Webinar
	Apr	14	2010 Public Stakeholder Conference Call and Webinar
	May	5	2010 Public Stakeholder Conference Call and Webinar to review NTTG 2010-2011 Study Plan Development and Approach
	Jul	6	NTTG 2010-11 Study Plan Approved and Posted
	Aug	4	2010 Public Semi-Annual Stakeholder Meeting
2011	Jan	28 19 31	2010-11 NTTG Planning Committee Data Request Letter Posted 2011 Economic Study Request Webinar 2011 NTTG Stakeholder Conference Call
	Feb	2	2011 NTTG Semi-Annual Public Stakeholder Meeting
	Apr	6	NTTG Public Stakeholder Meeting
	Jul	28	2011 NTTG Semi-Annual Public Stakeholder Meeting
	Sep		Stakeholder input to the Biennial Plan
	Nov		Biennial Plan Approval by NTTG Steering Committee
	Dec		Biennial Plan publication

Details of the Eight-Quarter Northern Tier Planning Process

The overall biennial transmission planning process at Northern Tier is broken down into eight quarters and two tracks. Figure 1.4 diagrams this process for the current 2010-2011 cycle. The overall planning process runs across all eight quarters and is described in further detail in the Northern Tier Transmission Group's Planning Committee Charter.

Figure 1-4 – NTTG Eight-Quarter Biennial Process



The cycle began in January 2010 with a three-month window of opportunity for stakeholders to submit data for loads, resources and transmission projects to be studied, and to submit requests for economic congestion studies.

Based on the data collected, the second quarter was dedicated to developing a study plan and the appropriate study assumptions. Additionally, development of economic studies ensued during this quarter. The Planning Committee decided to approach the planning process by generating the study cases though production cost simulation. The technical work identified the hours of significance and exported the production cost data to the power flow simulation tool. These processes will be described in more detail later in this report.

The Economic Studies Team presented its economic congestion study results for the biennium in the third quarter of 2010.

The TWG devoted the third and fourth quarters of 2010 and the first quarter of 2011 to the export of the production cost cases to the power flow simulation program. There were significant modeling differences to overcome in order to generate acceptable power flow cases.

Work in 2011 (the second half of the biennial cycle) began with preparation and review of the draft transmission report and with conduct of the second economic study request. During the second quarter of 2011, the power flow cases were subjected to N-1 contingency analyses, with the N-1 contingency list provided by participating transmission engineers for their respective companies. Any resulting departures from NERC Standard and WECC Standard requirements were examined. All thermal overloads and voltage excursions were verified. The Planning Committee deemed the resulting power flow studies acceptable.

The biennial planning process concluded with the preparation, review and acceptance of this report. In January 2012, the third biennial planning cycle will begin, with data, models and processes enhanced by the experiences and results of the first two cycles. Additionally, FERC Order 1000, issued in July 2011, will have further implications for Northern Tier's planning and cost allocation practices. NTTG's 2012-2013 Biennial Report will reflect these modified practices in accordance with Order 1000.

Chapter 2 - NTTG Economic Studies

Objective of the Studies

NTTG transmission providers are obligated through their transmission tariffs, in compliance with FERC Order 890, to perform economic planning studies. The requirement for these studies is based on FERC's finding that transmission planning involves both reliability and economic considerations. In the transmission planning process, each transmission provider provides stakeholders with the right to request economic planning studies. These studies evaluate transmission upgrades to reduce congestion or integrate new resources and loads. One portion of this process provides for the transmission provider to determine whether the request is of a local, subregional or regional scope. Economic Study Requests that are found to be subregional or regional are forwarded to NTTG. NTTG performs up to two high-priority subregional studies, as determined by the Transmission Use Committee, each year of the two-year transmission planning process. Additional economic planning studies may be requested and funded by a stakeholder. Additionally, economic study requests may be merged if the requests are similar in scope. Studies deemed by NTTG to be regional in scope are forwarded to the regional transmission planning body.

Economic Study Requests

NTTG transmission providers forwarded subregional and regional study requests to NTTG in the first quarter of 2010 and again in 2011. The NTTG Planning Committee evaluated each request to determine the appropriate organization to perform the study, i.e., WECC TEPPC, NTTG or return to the local transmission provider. In 2010, NTTG received 21 regional, three subregional and one local economic study requests (the local request was returned to the transmission provider). In 2011, 24 requests were received, all regional in scope. There were no economic study requests that required production cost modeling or congestion analysis.

The following tables contain the dispensation of each economic study request received.

Table 2-1 - 2010 Economic Study Requests

Dispensation	2010 Economic Study Request
PPL Montana	
WECC Regional	Colstrip to SE Wyoming CCPG and/or Zephyr
WECC Regional	Colstrip to SE Wyoming CCPG w/o Chinook; hook up with Zephyr
WECC Regional	Broadview - Great Falls - Garrison
WECC Regional	Broadview - Great Falls - Ovando
WECC Regional	Great Falls - Helena - Townsend
WECC Regional	Determine the economic effects of the N-2 common corridor outage criteria
WECC Regional	Create an energy market hub in eastern Wyoming
Northwestern Energy	
NTTG Subregional	MSTI
NWE Local	1500 MW 230 kV radial collector lines into Townsend 500 kV & MSTI

NTTG Subregional	Amps 230 kV upgrade to 401 MW
NTTG Subregional	Colstrip 500 kV system upgrade
TransCanada	
WECC Regional	Northern Lights
WECC Regional	Zephyr
WECC Regional	Chinook
Sea Breeze	
WECC Regional	Juan de Fuca Cable
WECC Regional	West Coast Cable HVDC
WECC Regional	Triton Cable HVDC
WECC Regional	Juan de Fuca Cable II HVDC
Grasslands	
WECC Regional	Add 3000 MW wind in Montana, ND, AB, SK Western Renewable Energy Zones (WREZ); add transmission as needed
WECC Regional	Add 400 MW pumped storage between Broadview & Garrison to GRE1 Case
WECC Regional	Add 6000 MW wind in Montana, ND, AB, SK WREZs; add transmission as needed
WECC Regional	Add 400 MW pumped storage between Broadvu & Garrison to GRE2 Case
TransWest Express	
WECC Regional	600 kV HVDC
WECC Regional	Add 6000 MW of wind in Wyoming WREZs
WECC Regional	Add 12000 MW of wind in Wyoming WREZs

Table 2-2 - 2011 Economic Study Requests

Dispensation	2011 Economic Study Request
TransCanada	
WECC Regional	Zephyr HVDC
WECC Regional	Chinook HVDC 2020
WECC Regional	Chinook HVDC 2030
Wyoming Infrastructure Authority	
WECC Regional	9000 MW renewable and 1800 MW thermal generation in Wyoming
WECC Regional	12000 MW renewable and 2400 MW thermal generation in Wyoming
PacifiCorp	
WECC Regional	Hemingway – Capt. Jack 500 kV
WECC Regional	Sigurd – Las Vegas 500 kV
Grasslands	
WECC Regional	3000 MW in MT
WECC Regional	6000 MW in MT
WECC Regional	Wind Spirit
WECC Regional	Grasslands Northern Plains Intertie
TransWest Express, LLC	
WECC Regional	TransWest Express HVDC
WECC Regional	TransWest Express HVDC
WECC Regional	TransWest Express HVDC
WECC Regional	TransWest Express HVDC
Northwestern Energy	

WECC Regional	MSTI + SWIP
WECC Regional	MT-NW Upgrade (SerCap Upgrade)
WECC Regional	MSTI, MT-NW Upgrade, SWIP Cluster
Riverbank Symbiotics	
WECC Regional	Swan Lake pumped storage
WECC Regional	Parker Knoll
WECC Regional	Parker Knoll + transmission to Glen Canyon
WECC Regional	Parker Knoll + transmission to Intermountain Power Project DC
Tonbridge	
WECC Regional	Greenline
WECC Regional	MATL Upgrade

As shown in the 2010 Economic Study Request Table above, the only requests deemed to be subregional, and thus appropriate for the NTTG Economic Studies Team to take on, were three of the four NorthWestern Energy submissions. The three scenarios were:

1. MSTI 500 kV Line: MSTI is a proposed 500 kV line, approximately 420 miles long, extending from Townsend, MT, to Midpoint, ID. It is series-compensated, and power flow is controlled using a Phase Shifting Transformer. An existing model used by NTTG utilities already exists from the previous Biennial Planning Cycle. MSTI is nearing completion of Phase 2 of the WECC Path Rating Process. The new line would provide 1,500 MW transmission capacity north to south, about 950 MW south to north. The line could provide transmission service for up to 1,500 MW of new renewable resources.
2. Path 18 Upgrade: NorthWestern conducted a Montana to Idaho open season transmission subscription process in 2004. As a result of this subscription process, NorthWestern and the other Path 18 owners are contemplating increasing the capacity of the existing 230 kV AMPS line through the installation of series capacitors and voltage support devices on various Path 18 busses. This upgrade is not in the WECC Path Rating Process yet. The line runs between the Mill Creek 230 kV switchyard and the Antelope 230 kV station. The upgrade may increase path capacity to 401 MW.
3. 500 kV Upgrade: The owners of the Colstrip Transmission System and the Bonneville Power Administration (BPA) are considering increasing the capability of the existing twin 500 kV transmission lines that may start as far east as Colstrip, MT and end as far west as the Mid-Columbia area of Washington. Installation of series capacitors (up to 70% from the current 35%) and appropriate voltage control, and expanding the allowable current-carrying capacity (ampacity) of existing busses on the 500 kV line, may increase the transfer capability by as much as 500 MW to 700 MW. This upgrade is not yet in the WECC Path Rating Process.

The three subregional requests were clustered into one study to assess the impact of the transmission expansion on resource additions in Montana, as described below.

Economic Study Process

The NTTG Economic Studies Team applied Ventyx PROMOD and ABB GridView energy market simulation tools for the economic study, as both were available to the TWG and economic studies teams through

NTTG member companies. PROMOD is the program currently used by WECC staff and others in performing the TEPPC's analyses. GridView is used by a number of entities in the Western Interconnection to perform comparable studies.

Given the limited one-month timeline to run the studies, the team expedited the process by using an existing WECC TEPPC production cost simulation database, the TEPPC 2019 PC1A case. Minor edits were applied to align with NTTG assumptions. Common to all cases, 1,500 MW of wind-powered generation was added at the Townsend bus.

The general outline of the economic study process was to start with the WECC TEPPC 2019 PC1A cases, run three expansion cases and conclude with a sensitivity case. The following three expansion cases were developed:

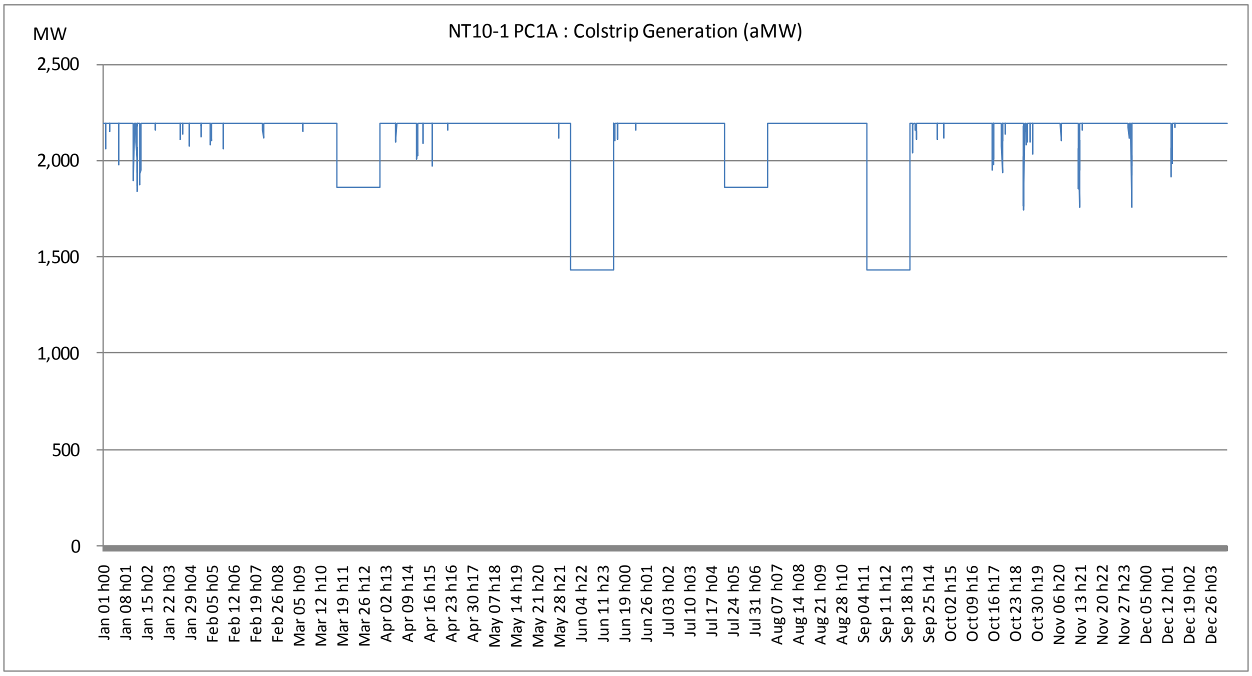
1. Increase capacity of the AMPS line (Path 18) from 337 to 401 MW
2. Increase rating of Montana-Northwest path (Path 8) by 600 MW
3. Add Mountain States Transmission Intertie (MSTI) project

A sensitivity case investigated methods to reduce any "excessive" cycling of coal-fired generators caused by wind-powered generator output variability.

Results and Observations

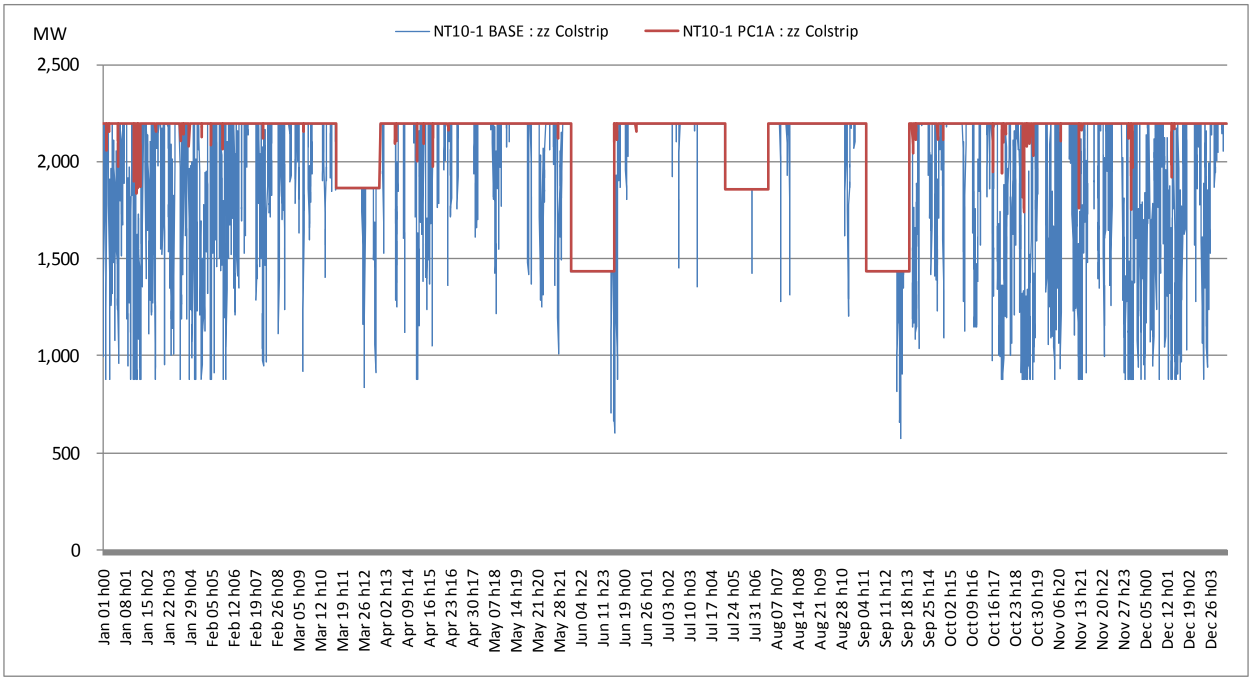
1. The 1,000 MW of new Montana wind resources already modeled in the TEPPC 2019 base case are accommodated with modest coal plant cycling and little wind curtailment as shown Figure 2.1 below.

Figure 2-1 – Colstrip Production in TEPPC 2019 Base Case



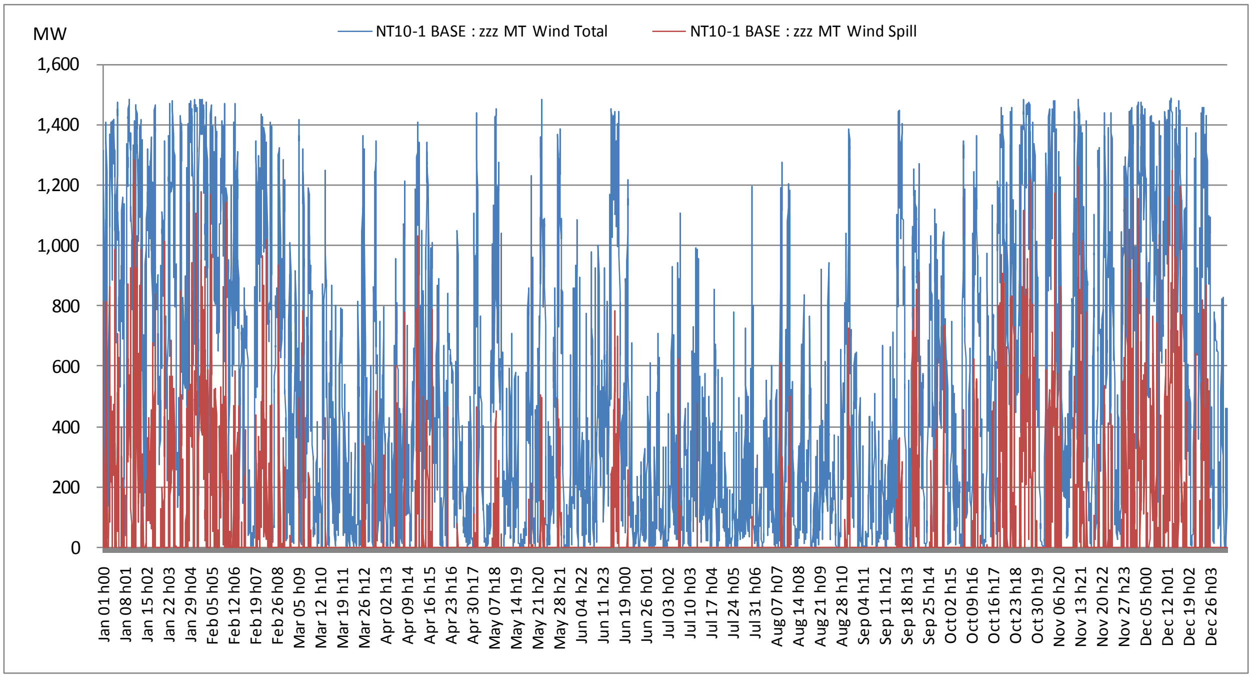
2. The addition of 1,500 MW of wind generation in Montana causes severe cycling of base load coal generation as shown in Figure 2.2 below.

Figure 2-2 – Colstrip Production Impacts from 1,500 MW of Wind Generation



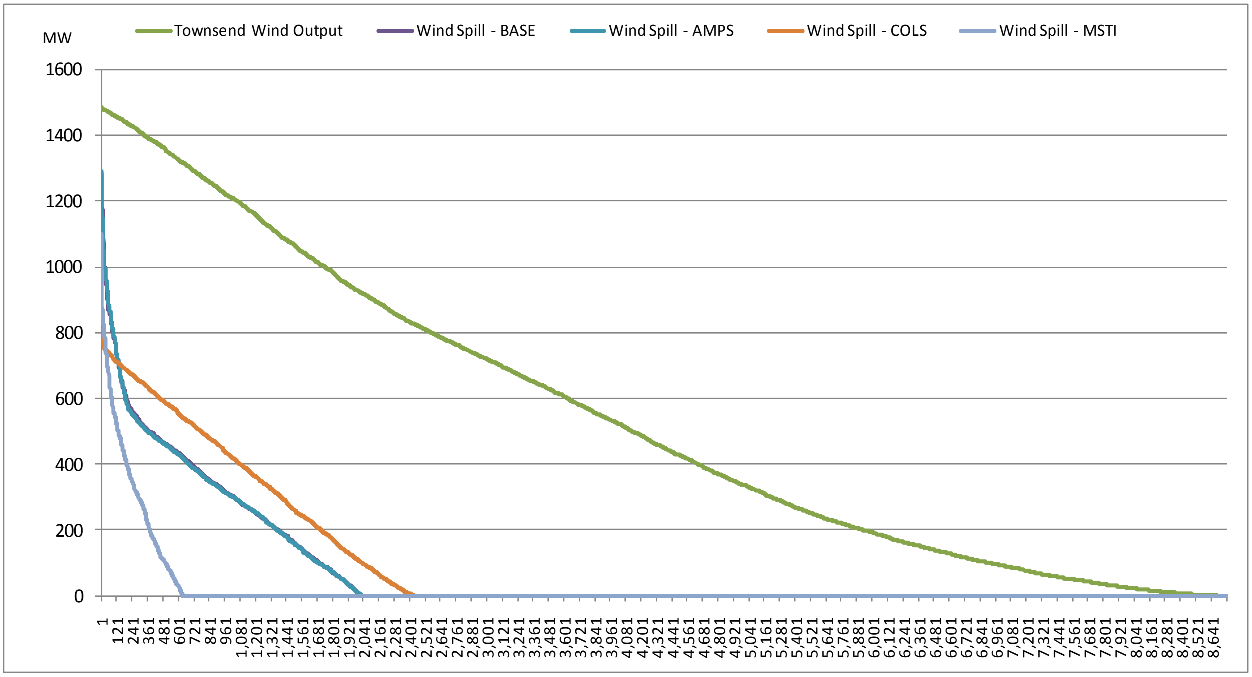
3. Without additional transmission, much of the additional wind energy cannot be accommodated by existing transmission and is curtailed as shown in Figure 2.3 below.

Figure 2-3 – Wind Generation Curtailments Due to Transmission Constraints



4. Upgrading the capacity of Paths 8 and 18 provides some benefit, but a large fraction of the additional wind energy remains unusable. However, the addition of the MSTI project provides the ability to transmit most of the added wind out of Montana to locations that are able to absorb the increased generation with modest re-dispatch of existing resource, as shown in Figure 2.4.

Figure 2-4 – Wind Generation Accommodated by Transmission Projects



5. The Path 8 upgrade and MSTI projects significantly decrease the hours of congestion for the south and west Montana transmission paths. The following table displays the hours of congestion on NTTG-relevant paths for the three expansion cases.

Table 2-3 - Transmission Impact on NTTG Path Congestion

Number of hours in 2019 that flows exceeded the indicated percent of the positive flowgate limit.	**NT10-1 PC1A with 1,500 MW Wind Added in MT**	NT10-1 Base, with Path 18 increased to 401 MW N-S	NT10-1 Base, with Path 8 increased by 600 MW	NT10-1 Base, with MSTI Project added
Monitored Interface	75%	75%	75%	75%
	NT10-1 BASE	**NT10-1 AMPS**	**NT10-1 COLS**	**NT10-1 MSTI**
Aeolus - Mona	-	-	-	-
Bonanza West	29	1	4	(12)
Borah West	-	-	-	-
Bridger West	-	-	-	-
Bridger - Populus	-	-	-	-
Brownlee East	19	(2)	(1)	(19)
COI (GridView), COB (Promod)	4,133	(9)	(203)	380
Idaho - Montana	960	(413)	(200)	(960)
Idaho - Northwest	-	-	-	-
Intermountain - Gonder 230 kV	114	-	64	25
IPP DC Line	3,407	(4)	(1,121)	(24)
Midpoint - Summer Lake	1,954	6	554	2,045
Mona - Oquirrh	-	-	-	-
Montana - Northwest	5,664	(53)	(1,601)	(1,020)
Montana - Southeast	1	-	(1)	(1)
Pacific DC Intertie (PDCI)	164	4	22	1
Pavant Intermountain - Gonder	3	(3)	(3)	(3)
TOT 2C	1,082	(18)	(141)	(145)
West of Colstrip	7,399	-	1	-
West of Hatwai	31	2	8	(30)

Chapter 3 - Transmission Study

Objective of the Study

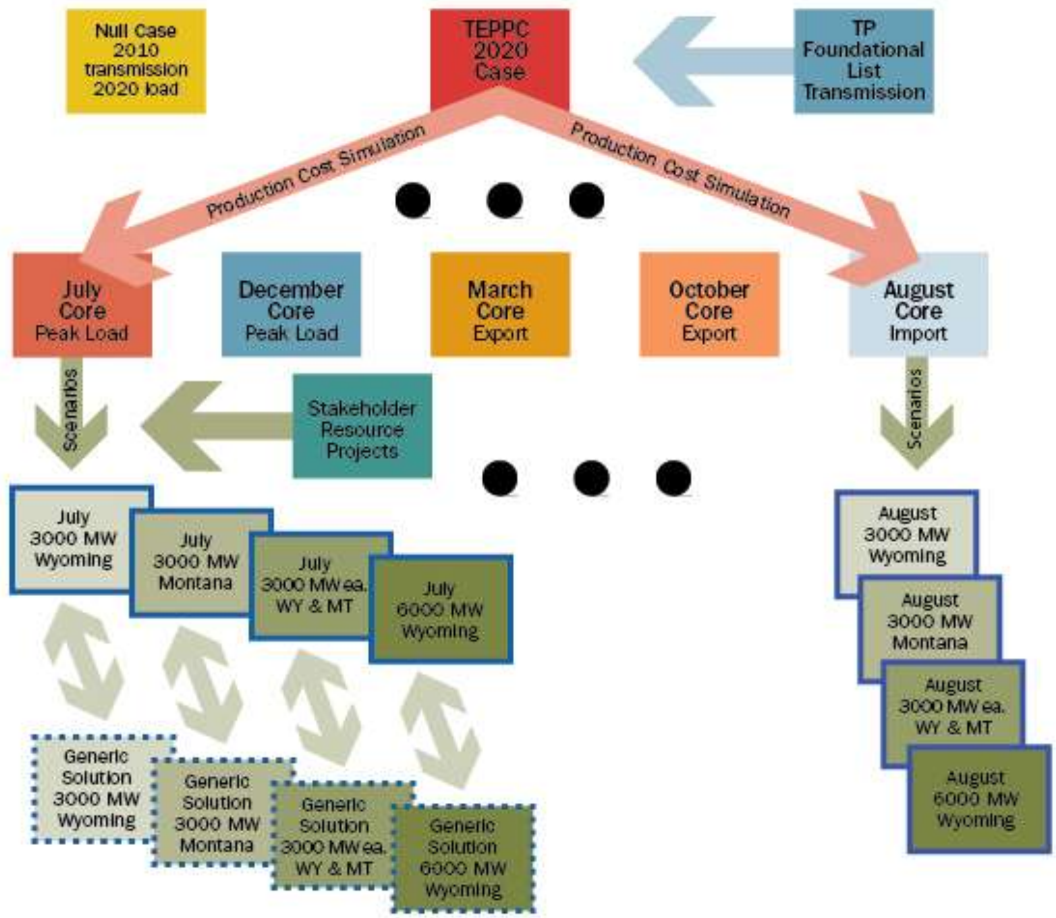
The objective of the 2010-2011 Northern Tier Transmission Plan is to determine what a reliable transmission system could look like in 2020. The plan involved a conceptual study to examine, given a limited number of forecasted and assumed load and resource portfolios, the generic transmission additions required to provide feasible system operation at forecasted stress times, 10 years in the future.

In 2011, high-level analyses were performed to determine the effectiveness of alternative sets of proposed transmission projects, suggested by the conceptual study. These analyses, or scenario cases, formed the basis for the NTTG Transmission Plan. Specifically, the transmission plan objectives were designed to:

1. Identify transmission needs of transmission customers (e.g., retail native load, network and point-to-point), as they are identified by and provided to the transmission provider. The transmission provider shall consolidate this information for their particular system to include in the subregional planning process.
    a. Native load needs will be incorporated by input from the various states' integrated resource planning (IRP) processes, where they exist.
    b. Network transmission customers will be asked to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format). The intent will be to plan for all end-use loads on a comparable basis.
    c. Each transmission provider's existing point-to-point customers will be asked to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points.
2. Identify transmission congestion that is an impediment to the efficient operation of electricity markets. Congestion on the existing and planned system will be reviewed and evaluated.
3. Consider the impacts on congestion of potential new generation facilities or new transmission projects. This will include production simulation studies on a subregional and regional level, and historical use analysis as provided by the Northern Tier Use Committee and TEPPC subcommittees.

To meet the above objectives, the Planning Committee devised a study plan with three major components. Figure 3.1, below, illustrates the framework of the study components comprising a Null Case, Core Cases and Scenario Cases.

Figure 3-1 – Transmission Study Framework



The Study Plan

The 2010-2011 biennial transmission study plan was developed during the second quarter of 2010 and approved by the Planning Committee on June 30, 2010. A copy of this plan is located in Appendix 1 and is available on the NTTG web site.

Null Case

The plan was formulated by the Planning Committee to meet the objective of performing a conceptual study that determines at a high level, given a limited number of load and resource scenarios, what general transmission improvements are required to provide a feasible system operation at times of transmission stress 10 years in the future. For a baseline, the load in the WECC 10hs3bp Base Case was modified to reflect the NTTG area 2019 load forecasts. This baseline, or Null Case, projected how the existing transmission system would perform without the addition of new transmission or energy resources.

Core Cases

In parallel with the development of the Null Case, the Planning Committee created a set of five Core Cases to analyze future system reliability during selected peak load hours and high import and export conditions. Reliability analysis has traditionally been performed on power flow base cases developed by WECC that simulate a specific load pattern, generation dispatch state and transmission topology in the WECC system (e.g., heavy summer peak load conditions or light autumn load conditions). These cases, however, may not adequately stress the NTTG transmission system in ways that may be present during other times of the year. Based on this assessment, the NTTG Planning Committee decided to undertake an alternative approach that combined both the production cost simulation and power flow analysis. The Planning Committee used an integrated one-hour loads and resources analysis to determine transmission system stress that could occur 10 years in the future due to increased load and energy resource additions. The committee chose to run security-constrained generator commitment and dispatch modeling across the 8,760 hours of 2019 to find specific hours when energy flow from resources to loads is most constrained within the NTTG transmission system. The selection of several hours of transmission constraint and peak load formed the basis, or core, of the study.

The TWG later decided to switch from the TEPPC 2019 PC1A to the TEPPC 2020 PC0 case in order to perform the analysis on the most up-to-date system model.

The plan conceived of a model of the 2020 network based on the existing system, with the addition of a minimal set of committed transmission projects. Only those transmission projects deemed to have a high probability of being in service before 2020 and to be primarily for firm load service and reliable system operation were included in this set (i.e., the Foundational Transmission Projects were included).

This transmission network was then tested. The assessment used a commitment and dispatch program and the TEPPC 2020 PC0 core base case. To determine where system stresses existed, the assessment then ran the load and resource scenarios under the hour-by-hour operating conditions across the year 2020 (8,784 hours). To determine times of stress, the TWG decided to use maximum NTTG summer and winter peak loads and times of aggregated maximum imports and exports on eastern NTTG paths. This approach was better able to ascertain congestion rather than the approach outlined in the original study plan. Then, for the most highly stressed hours, the load and resource states were exported to a power flow program for reliability analysis.

Scenario Cases

Finally, the Committee decided to augment the selected Core Cases with four energy resource expansion Scenario Cases. These scenarios were based on data submitted in response to Northern Tier's first quarter request for data. The data indicated that future energy needs will be met, at least in part, by development of renewable resources sited in areas with significant renewable energy potential, such as Wyoming and Montana.

Contingencies

Only N-1 contingencies were run on the core and scenario power flow cases, since this initiative is much closer to a high-level screening study than a rating study, where N-2 contingencies are more relevant. Also, only transmission lines with voltages of 230 kV or higher in the NTTG footprint and in the Northwest (Area 40) were monitored and included in contingency lists.

Generic Transmission Modifications

Both AC and DC generic transmission lines were simulated to resolve contingency violations for the resource addition scenarios.

Chapter 4 - The Null Case

Null Case Introduction

Power flow reliability analysis, as described in this section, was performed on the existing transmission system, the Null Case, to determine if the present system could meet the demands of the forecasted NTTG footprint load level expected in the year 2020.

Null Case Study Assumption and Parameters

The Null Case was developed from the WECC 2010 heavy summer (10hs3bp) base case. In the 2010 heavy summer base case, loads present in the NTTG footprint were increased to the 2020 heavy summer (20hs1ap) base case levels. A total of 3,170 MW (approximately 1.4% compounded annually) of load was increased in the NTTG footprint. Loads outside the NTTG footprint were kept at the 2010 levels. The list of the owners whose loads were increased, along with the area in which the load was present, is shown in Table 4.1. Details regarding the load increase are shown in Appendix 4.

Table 4-1 – Summary of Increased Area Loads

No.	Area (Owner Name)
1.	Area 40 (Portland General Electric)
2.	Area 65 (Pacificorp (East))
3.	Area 60 (Idaho Power Company)
4.	Area 62(NorthWestern Energy)
5.	Area 73 (Black Hill Power Company)
6.	Area 65 (Dixie Generation & Transmission)
7.	Area 63 (WAPA Upper Missouri)
8.	Area 73 (WAPA Lower Missouri)
9.	Area 65 (Utah Associated Municipal Power Systems)
10.	Area 65 (Deseret Power Electric Cooperative)

The transmission topology was not changed from the 10hs3bp base case. Transmission upgrades present in the 20hs1ap base case and new generation resources were not included in the Null Case study. NTTG footprint resources existing in the 10hs3bp base case and 10hs3bp base case resources in other areas were increased, if possible, to meet the load increase. No generation resource was increased beyond its maximum generating capability. Resources that were increased are shown in Table 4.2.

Table 4-2 - Null Case Generation Resources Adjustments

Generator Bus Number & Name	10HS Original Base Case	10 HS Base Case With Increased Load	Delta MW	% Change in Generation
40291 [COULEE19 15.000]	606.7	700	93.3	15.4
40293 [COULEE20 15.000]	0	700	700	999.9
40296 [COULEE22 15.000]	196.1	679.5	483.4	246.5
40298 [COULEE24 15.000]	0	600	600	999.9
60096 [BRWNL 1 13.800]	0	120	120	999.9
60097 [BRWNL 2 13.800]	100	120	20	20
60098 [BRWNL 3 13.800]	100	120	20	20
60099 [BRWNL 4 13.800]	100	120	20	20
60100 [BRWNL 5 13.800]	176.2	225.5	49.3	28
60151 [HELSCYN1 14.400]	130	145	15	11.5
60152 [HELSCYN2 14.400]	130	145	15	11.5
60153 [HELSCYN3 14.400]	0	145	145	999.9
60196 [L MALAD 6.9000]	12	14	2	16.7
60201 [L SAMN 1 13.800]	0	15	15	999.9
60203 [L SAMN 3 13.800]	0	15	15	999.9
60276 [OXBOW1-2 13.800]	80	100	20	25
60277 [OXBOW3-4 13.800]	80	100	20	25
60321 [STRIKE 1 13.800]	0	30	30	999.9
60322 [STRIKE 2 13.800]	20	30	10	50
60323 [STRIKE 3 13.800]	20	30	10	50
60352 [TWINFALS 6.9000]	0	8	8	999.9
60353 [TWINFALS 13.800]	20	40	20	100
60397 [BTMT CT1 18.000]	170	190	20	11.8
62048 [COLSTP 3 26.000]	606.5	815.5	209	34.5
63005 [FT PECK1 13.800]	54.8	34.9	-19	36.2
66055 [NAUGT G1 18.000]	129.2	222.3	93.1	72
73129 [MBPP-1 24.000]	586.9	719.7	132.8	22.6

Null Case Study Methodology

Power flow analysis was performed on the Null Case to determine if any voltage or thermal overload issues existed with all lines in service (i.e., N-0 condition) and with one transmission element out-of-service (i.e., N-1 condition), including auto transformer outages. All N-1 outages for transmission elements above 200 kV were studied for the NTTG footprint[3]. The N-1 power flow study was performed using the PSS/e "ACCC" function software. No N-2 (or higher) outages were taken. Special protection schemes were not implemented in this power flow analysis, which if implemented may have reduced the number of overload problems identified in this study. Also, the amount of regulating resources was not increased to accommodate the increased load. Neither transient stability analysis nor PVQV analysis was performed for this study.

Power Flow Analysis Results

The N-0 power flow analysis on the Null Case identified 24 (15 lines and nine auto transformers) thermal overloads on certain transmission elements with all transmission system elements in service. These overloads were not present in the 2010 heavy summer base case. A high-level summary of overloads and voltage issues on major transmission elements under N-0 conditions is shown in Table 4.3 below. The detailed results regarding thermal overloads under N-0 conditions are shown in Appendix 4. Busses with voltage below 0.90 per unit under N-0 conditions with the loads increased to the 20hs1ap base case level are shown in Appendix 4. There were several 500 kV busses and other busses with voltage above 1.05 per unit under N-0 conditions. They are also shown in Appendix 4.

Table 4-3 - Summary of Null Case N-0 violations

Area #	Number of transmission elements branches on which thermal overload(>100%) was observed due to increased load (Also includes overloads on autotransformers as well)	Highest overload observed (%)	Number of Busses with Voltage less than 0.90 p.u. due to increased load	Lowest Voltage observed (PU)
Area 40	17	131.7	9	0.8271
Area 60	2	115.4	0	N/A
Area 62	0	N/A	3 (Local Area Problem)	0.8674
Area 65	5**	118.1	4	0.826
**Over and above the 5 transmission overload, loading was increased on several 138/12.5 kV auto transformers that serves load in Area 65. This banks already had high loading and due to increase in the load the flows through the transformers had increased.				

Next, the Null Case was studied with single element outages. First, the N-1 contingencies were run with the taps on the auto transformers, switched shunts, phase-shifting transformers and tie lines enabled (allowed to move or adjust). Several contingencies reached maximum iterations without solving, and certain contingencies failed to solve, making the system unstable. The summary of results is shown in

[3] Area 40(Northwest), 60(Idaho), 62(Montana), 63(WAPA UW), 65(Pacificorp), 73 (WAPA RM)

Table 4.4 below. Then all the N-1 contingencies were run with the taps on the auto transformers, switched shunts, phase-shifting transformers and tie lines disabled (not allowed to move or adjust). This resulted in fewer contingencies reaching maximum iterations, as well as contingencies that failed to solve, making the system unstable. The summary of these results is shown in the second row of Table 4.4 below. Detailed results showing which contingency reached maximum iterations and which contingency failed to solve is shown in Appendix 4.

Table 4-4 - Summary of Null Case N-1 Contingency Solutions

	Number of contingencies that reached maximum iterations	Number of contingencies that failed to solve
Taps on auto-transformers, switched shunts, phase shifters, tie lines enabled (allowed to move or adjust)	72	12
Taps on auto-transformers, switched shunts, phase shifters, tie lines disabled or locked (not allowed to move or adjust)	5	5

The N-1 outage analysis showed overloads on several transmission elements. Summary of contingencies with overloads greater than 125% under outage conditions is shown in Table 4.5. The overloads were based on normal summer rating. Detailed results of transmission elements that observed overloads greater than 125% is shown in Appendix 4. Emergency ratings were not taken into account for this study. Fifty-five different thermal overloads (>100%) were observed in the Northwest area, nine different overloads (> 100%) were observed in Idaho area and two different overloads (>100%) were observed in the WAPA Rocky Mountain area. These overloads were based on normal summer rating. Voltage at some busses went below 0.90 per unit under certain outage conditions. The summary of these low voltages is also shown in Table 4.5 below.

Detailed description of the thermal overloads and voltage issues observed for different outage conditions are shown in Appendix 4.

Table 4-5 - Summary of Null Case N-1 Contingency Violations

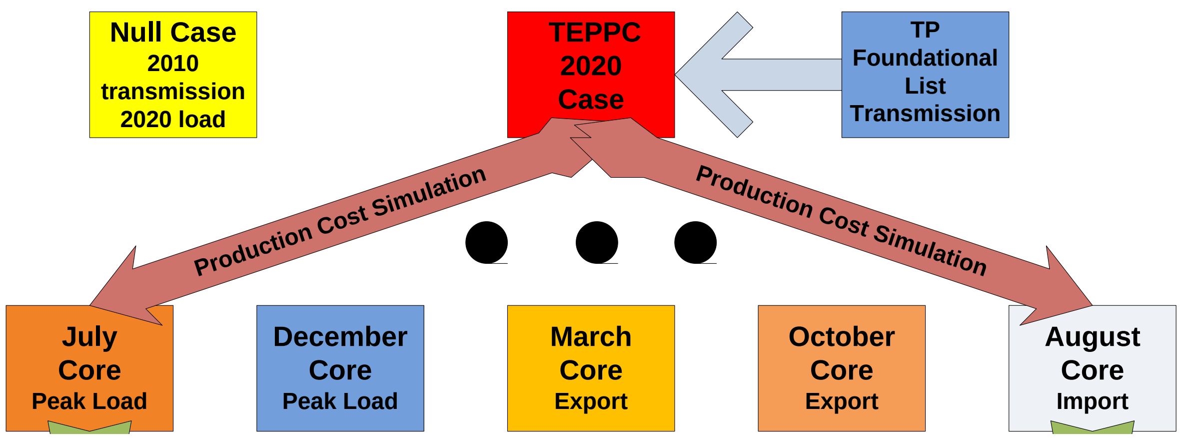
Area #	Number of transmission elements branches on which thermal overload(>100%) was observed due to increased load (Also includes overloads on autotransformers as well)	Highest overload observed (%)	Number of Busses with Voltage less than 0.90 p.u. due to increased load	Lowest Voltage observed (PU)
Area 40	18	163.1	1	0.89298
Area 60	0	N/A	1	0.89587
Area 65	0	N/A	5	0.80647

Conclusion

The Null Case power flow analysis discovered overloads on transmission elements under system normal operating and single element outage conditions. Voltage issues were also observed on several 500 kV busses and at other voltage levels under certain N-1 outage conditions. The results of the Null Case study found that the overloads on the transmission system increases beyond acceptable levels when compared to the NERC and WECC planning criteria.

The conclusion is that the existing transmission topology is not adequate in the year 2020 transmission to reliably serve the estimated 2020 load. Additional transmission capacity is necessary to meet NERC and WECC planning criteria. Additional transmission is necessary in order to reliably meet the future loads. These upgrades (the Foundational Transmission Projects) are defined by the transmission providers and used in the development of the Core and Scenario cases.

Chapter 5 - The Core Cases



Developing the System Model

During the NTTG 2008-09 planning cycle, NTTG used multiple WECC base cases to perform a reliability analysis within its footprint. Each base case had its own topology representation. This approach caused multiple issues for both the reliability studies and the economic studies. Project topology modifications and system contingency files had to be developed for each base case, and it was difficult to compare results between each base case.

Because of these overall inefficiencies, NTTG decided to discontinue using multi-season base cases after the 2008-09 planning cycle. Instead, NTTG chose to pursue exporting economic dispatch data from a production cost model (also called economic dispatch model or economic model) into the power flow programs for running reliability analysis. Using this method, a consistent network topology was assured, allowing network changes and system contingency files to be applied across all study cases.

But using economic dispatch models to develop reliability cases was a new concept. So NTTG judged it prudent to further develop the export capabilities for both PROMOD and GridView, the two economic dispatch models available to NTTG. This assured that at least one of the export methods would achieve the desired result. NTTG developed a Positive Sequence Load Flow (PSLF) macro to process PROMOD exports, while NTTG hired the ABB engineering and consulting group to automate the exporting of hourly data from GridView. At the conclusion of the study, NTTG was able to successfully export economic dispatch results into the GE PSLF power flow program.

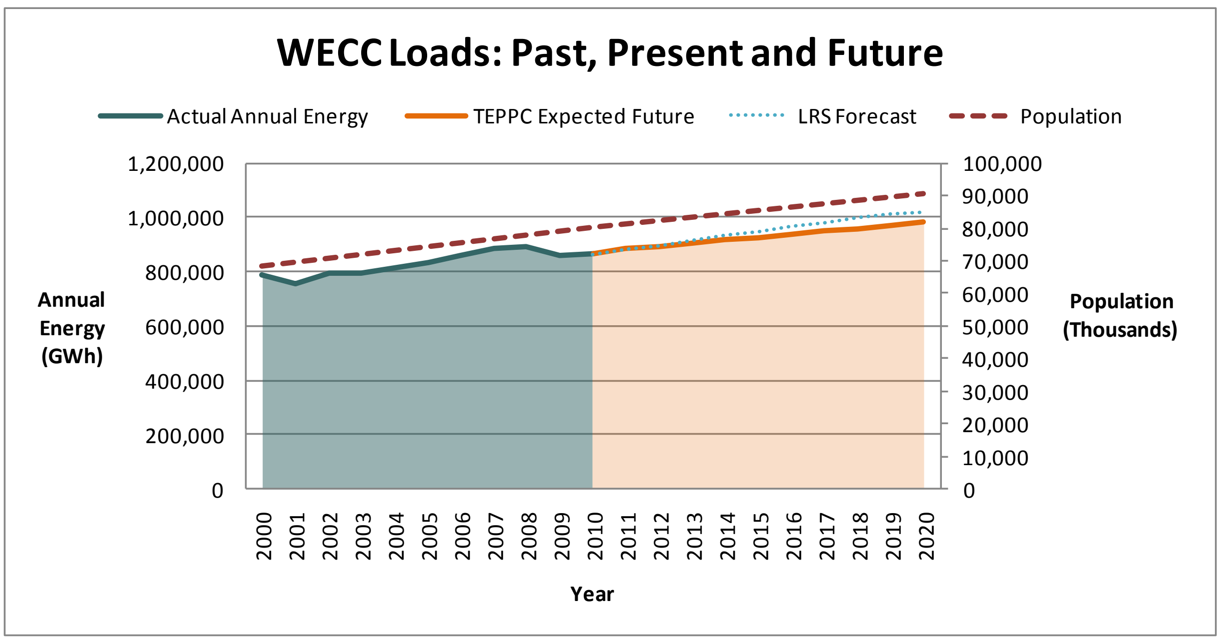
The TEPPC 2020 PC0 Base Case

NTTG turned to WECC for economic dispatch study input data, as the WECC TEPPC already provides this data. The WECC TEPPC develops an economic dataset that uses non-proprietary data. NTTG chose to use the most recent 2020 PC0 TEPPC production cost case for its studies. PC0, the reference case developed as a part of the 2010-11 TEPPC study program, offers expected future assumptions, including loads, generation, transmission and other study-related parameters.

Loads

The 2020 PC0 TEPPC production cost case shows that loads are forecasted to grow to 1 million GWh annually.

Figure 5-1 – WECC Loads: Past, Present and Future



Generation

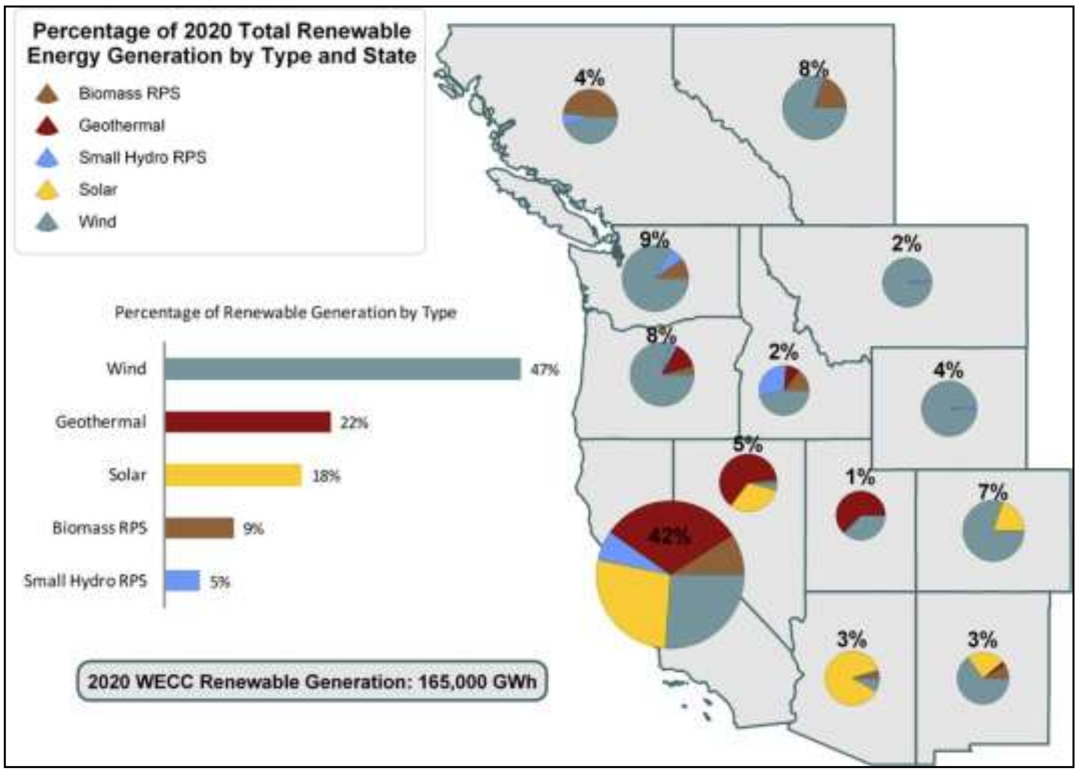
Incremental generation additions were designed to meet load growth through 2020 and the state Renewable Portfolio Standard targets listed below. Other Western states, Canadian provinces and regions with existing and planned renewable generation portfolios include Idaho, Wyoming, Alberta, British Columbia and portions of Mexico (CFE) .

Table 5-1 – Renewable Portfolio Standard by State (% of generation)

	AZ	CA	CO	MT	NV	NM	OR	TX	UT	WA
RPS % IOUs	10.0	33.0	30.0	15.0	22.0	20.0	20.0	5.0	13.3	15.0
RPS % Others	10.0	33.0	10.0	-	-	10.0	6.7	-	13.3	see[4]

The generation additions included almost 35,000 MW of renewable resources. The resulting renewable energy by type and state/province from the PC0 solution is shown below.

Figure 5-2 - Percentage of 2020 Total Renewable Energy Generation by Type and State



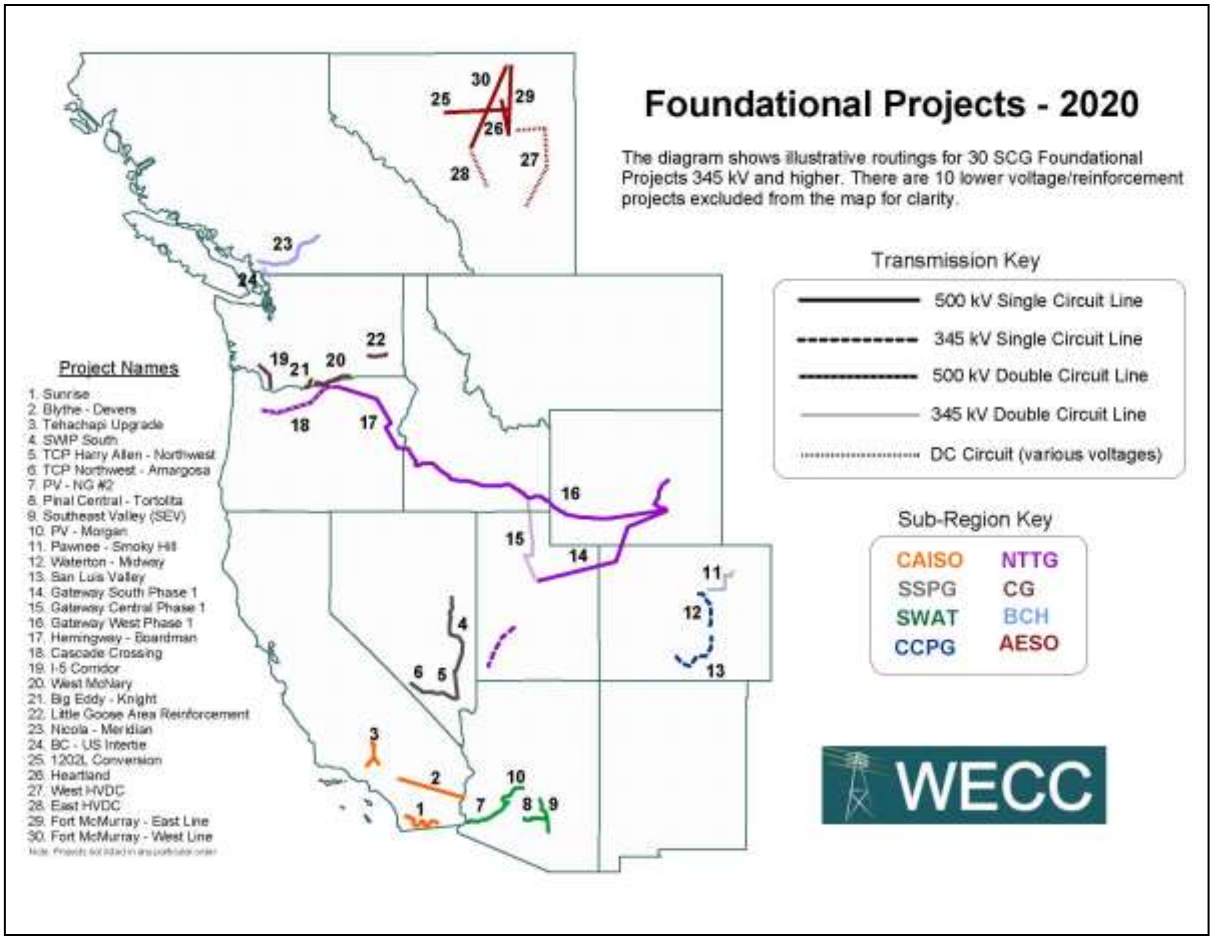
Matching Network Topologies

The 2020 PC0 TEPPC production cost case originated from the WECC 2020hs1a power flow base case. Since WECC staff had made some changes to the transmission topology after importing the power flow case into the production cost environment, NTTG confirmed and, as needed, modified the 2020hs1a case to assure alignment with the PC0 case.

4 In Washington state, the 15% standard applies to all "large" utilities having more than 25,000 customers, including PUDs and municipal utilities.

Changes applied to the WECC 2020hs1a powerflow case by TEPPC were taken from the Subregional Coordination Group's (SCG) Foundational Transmission Projects List Report.

Figure 5-3 – Foundational Transmission Projects - 2020



Aligning Generators

Significant differences in the number of generators exist between the production cost and the power flow models. More than 1,900 generators modeled in the power flow data do not appear in the production cost data. Conversely, there are generators in the production cost model that are not modeled in the power flow data. There can be good reasons for these discrepancies; prime examples include conceptual resources and modeling differences for combined cycle units.

NTTG used a Microsoft Excel spreadsheet to compare generator lists from the power flow and production cost datasets. A large number of generator unit identification numbers needed to be updated, as well as bus name changes. Additionally, many generators lack ID numbers in the production cost model. Those generators were added to the power flow representation. NTTG created a PROMOD database scenario change deck to improve the mapping between the two models. This change deck was shared with WECC and has been incorporated in ongoing WECC studies.

Using Production Cost Model to Simulate All Hours of 2020

NTTG used PROMOD and GridView to simulate an 8,784 hour/year (leap year) dispatch for 2020. Results from that run were exported to a Microsoft Excel spreadsheet to select hours of interest against the criteria of identifying the highest load, export and import hours. The results included line flows, as well as load and generation levels for each hour.

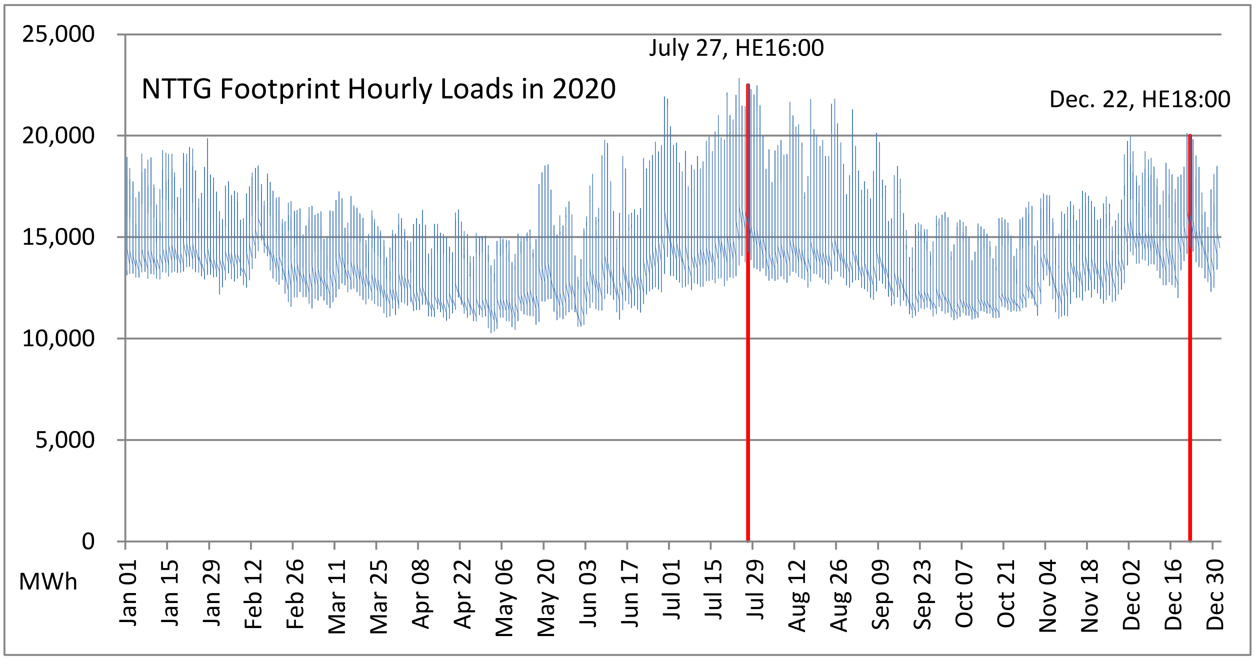
Selecting Hours for Power Flow Analysis

The NTTG TWG examined the hourly production-cost-model reference-case dispatch, for all monitored interfaces in the NTTG footprint, and considered flows at the periphery of the NTTG footprint. The group decided to focus on the eastern portion of the footprint. This approach was consistent with the transmission project study requests received during the second quarter stakeholder data submittal process. And it allowed looking at the total flow on export paths to the west, to the southwest and into Colorado.

Examining hourly flows on 12 WECC paths, the TWG reached consensus to study transmission congestion that would likely to occur during peak loads and high transfer hours. These hours represented times when local load serving transmission could be stressed and when transmission used to export out of or import into NTTG footprint could be stressed. High transfer hours were selected representing hours with maximum flows resulting in paths at or near their limits. Another reason to study high transfer times was that remote development of renewable resources that could meet renewable portfolio standards in the Southwest may lead to high flows to those loads. The peak and high transfer hours studied included:

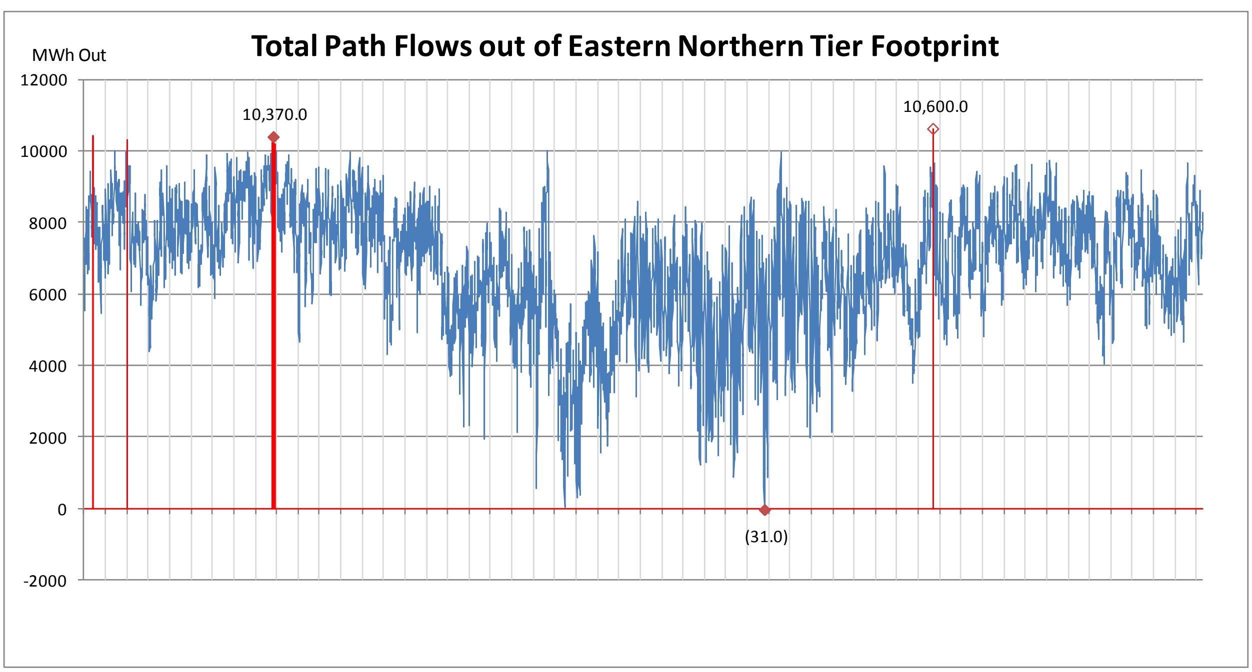
1. Peak load hours	Representing
a. July 27, Hour Ending 16:00	Summer peak
b. December 22, Hour Ending 18:00	Winter peak

Figure 5-4 – NTTG Peak Load Hours Selection



2. High transfer hours	<u>Representing</u>
a. March 2, Hour Ending 21:00	Highest spring exports
b. October 4, Hour Ending 21:00	Highest fall exports
c. August 10, Hour Ending 13:00	Highest annual import

Figure 5-5 – NTTG Export Hours Selection



These five selected hours as exported from the economic model are referred to as the "Core Cases." These contain the 2020 loads and generation as modeled in the TEPPC economic data, including the added generation resources, before any NTTG generation scenarios applied to them.

Transferring Load and Resource Data, and Solving Cases

Once these hours of interest were selected, the generation dispatch and NTTG load patterns were defined for each of the five hours selected by rerunning the economic model and exporting the data for those specific hours to the power flow program. Numerous data issues arose, resulting in specific network elements prohibiting a solution. Each issue was addressed until a successful solution was achieved.

With each additional study-hour simulation and conversion to the power flow case, resolving data modeling incompatibilities to obtain a solvable the power flow became easier. Due to high transfers in the Alberta area, the Alberta area was extracted and solved after first balancing the remaining system. In future studies collaboration between NTTG and the WECC TEPPC should reduce the production cost to power flow model conversion because WECC has adopted the same study process of exporting production cost simulations to power flows for reliability analysis. WECC's adoption of NTTG's process should result in improved alignment of the system model between production cost and power flow program databases.

The Core Cases

The following tabulation shows each Core Case path flow for select paths. Note that a path generally consists of several lines and not just a single line. Flows shown in red text indicate an overload on the path.

Table 5-2 – Core Cases N-0 Path Flows

CORE CASE	ID-NW (3800MW)[1]	MT-NW (2200MW)	COI (4800MW)	PDCI (3100MW)	NORTH OF JOHN DAY (7900MW)	BORAH WEST (4450MW)	BRIDGER WEST (3800MW)	TOT2[2] (A,B,C) (2070MW)	PATH C (1400MW)
JUL27H16	-123	635	3049	2600	5473	502	1593	316	-190
DEC22H18	649	1214	1122	2600	3848	722	1040	587	317
MAR02H21	961	1607	**4990**	2600	2737	778	1095	1416	215
OCT04H21	3208	1933	1640	2600	1318	3078	2713	1005	**1408**
AUG10H13	-754	166	-1146	2600	3577	-46	1683	695	-605

Notes:

(1) MW value shown below path name represents the transfer limit of the path.

(2) TOT2 values shown as the sum of the magnitude of the TOT2A, TOT2B and TOT2C flows. TOT2 overloads are identified as an overload on any one segment (A, B or C).

The Western Interconnection can be represented by balancing areas (e.g., areas where a transmission provider or several transmission providers balance the generation to the load) that are connected by paths. The flows across these paths (or interchange flows) between balancing areas for each Core Case are shown in Figures 5.4 through 5.8. MW values for the total area generation, total area load and total area interchange are shown on each diagram. Area losses can be determined from the diagram by taking the sum of the area total interchange and area total generation, then subtracting the total area load.

Figure 5-6 – Interface Flows for JUL27H16 Core Case

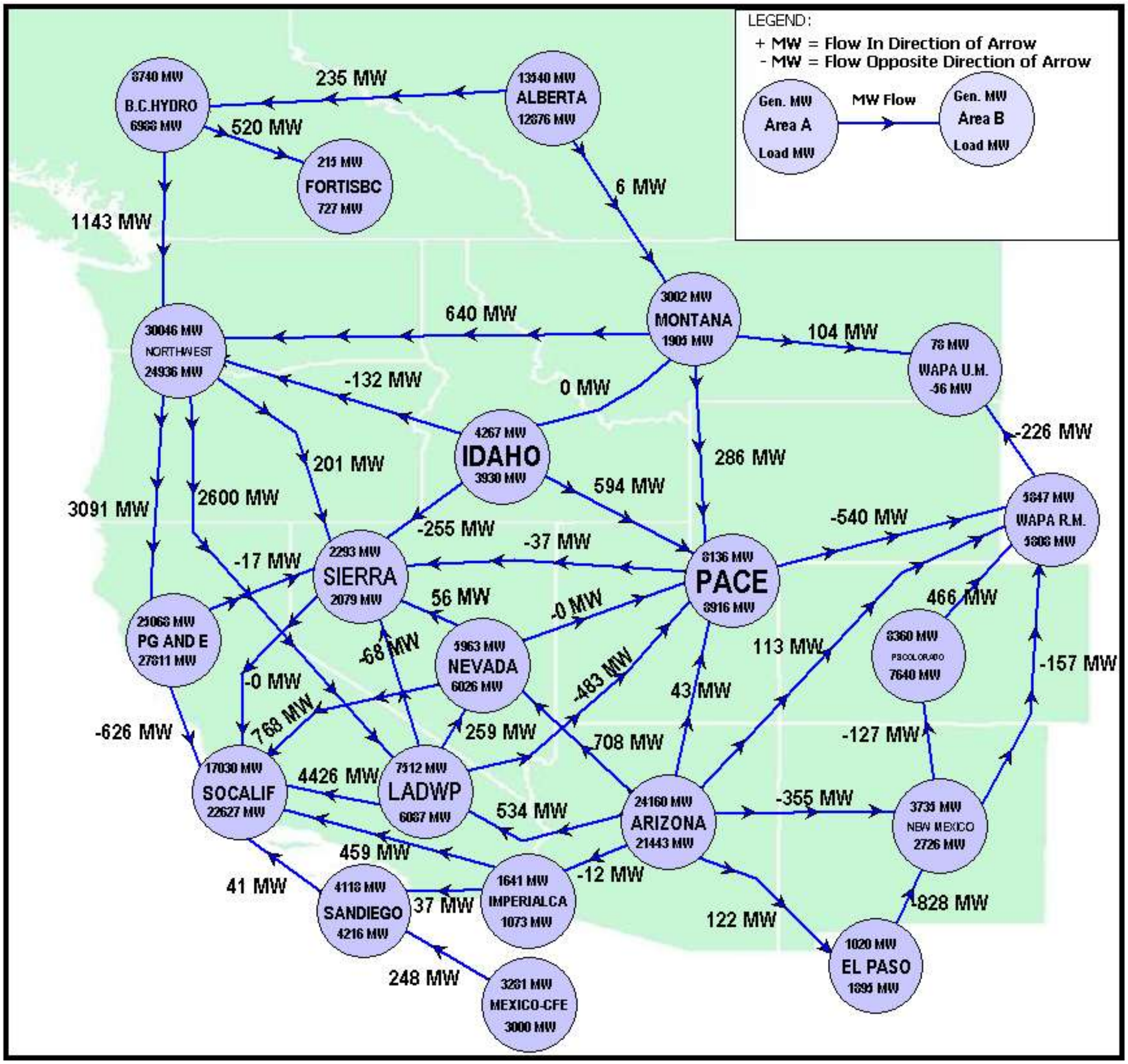


Figure 5-7 – Interface Flows for DEC22H18 Core Case

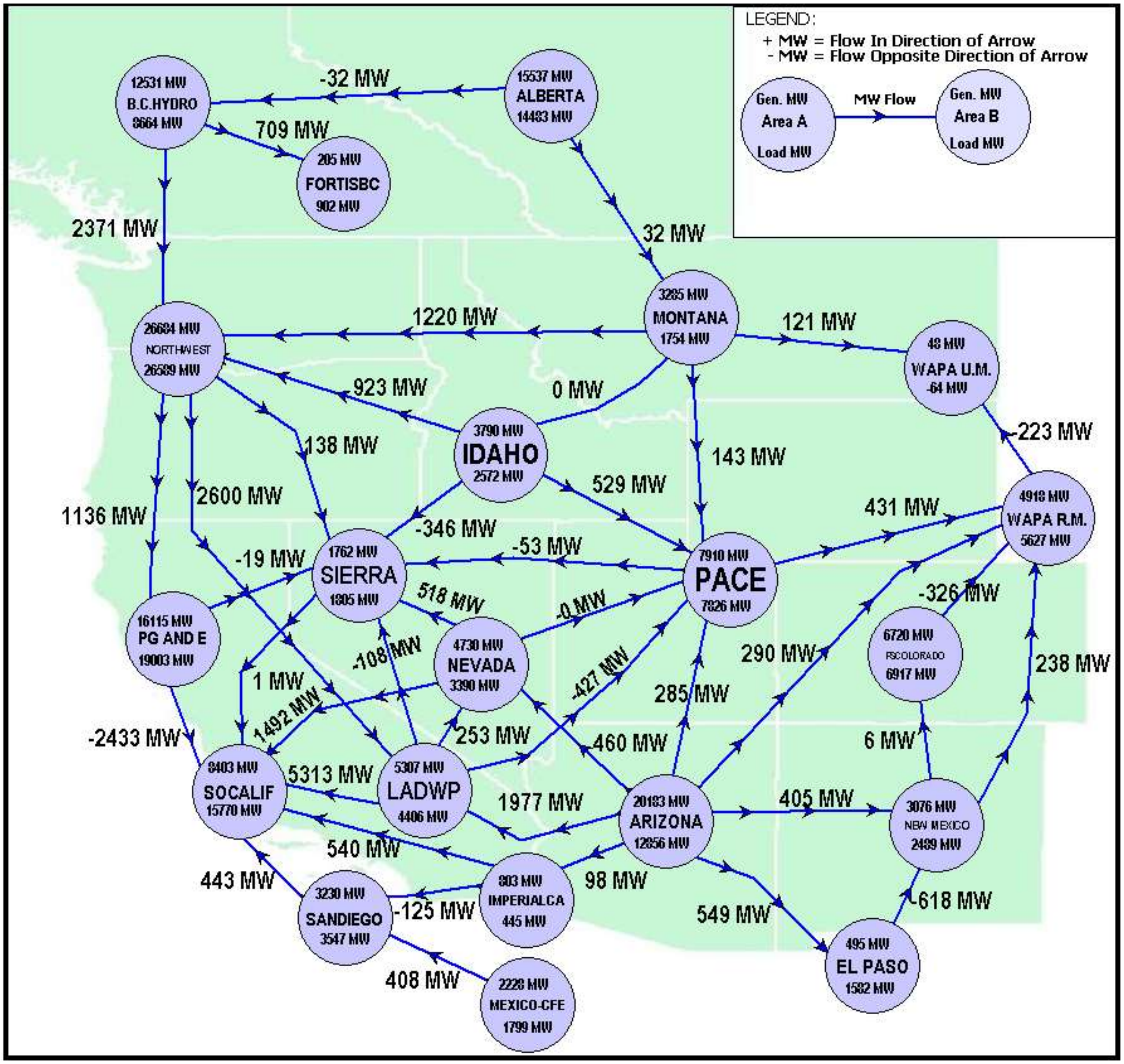


Figure 5-8 – Interface Flows for MAR02H21 Core Case

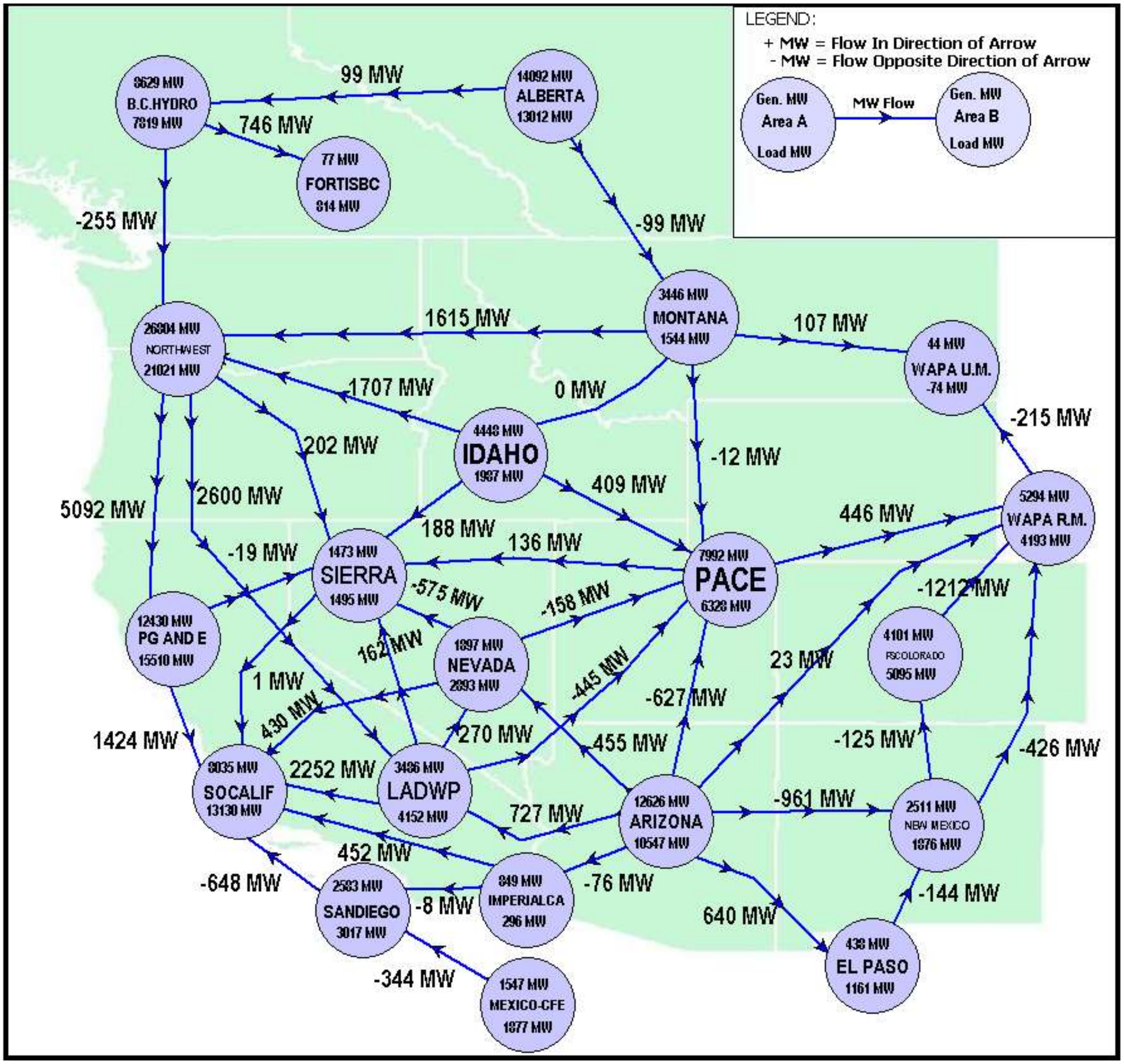


Figure 5-9 – Interface Flows for OCT04H21 Core Case

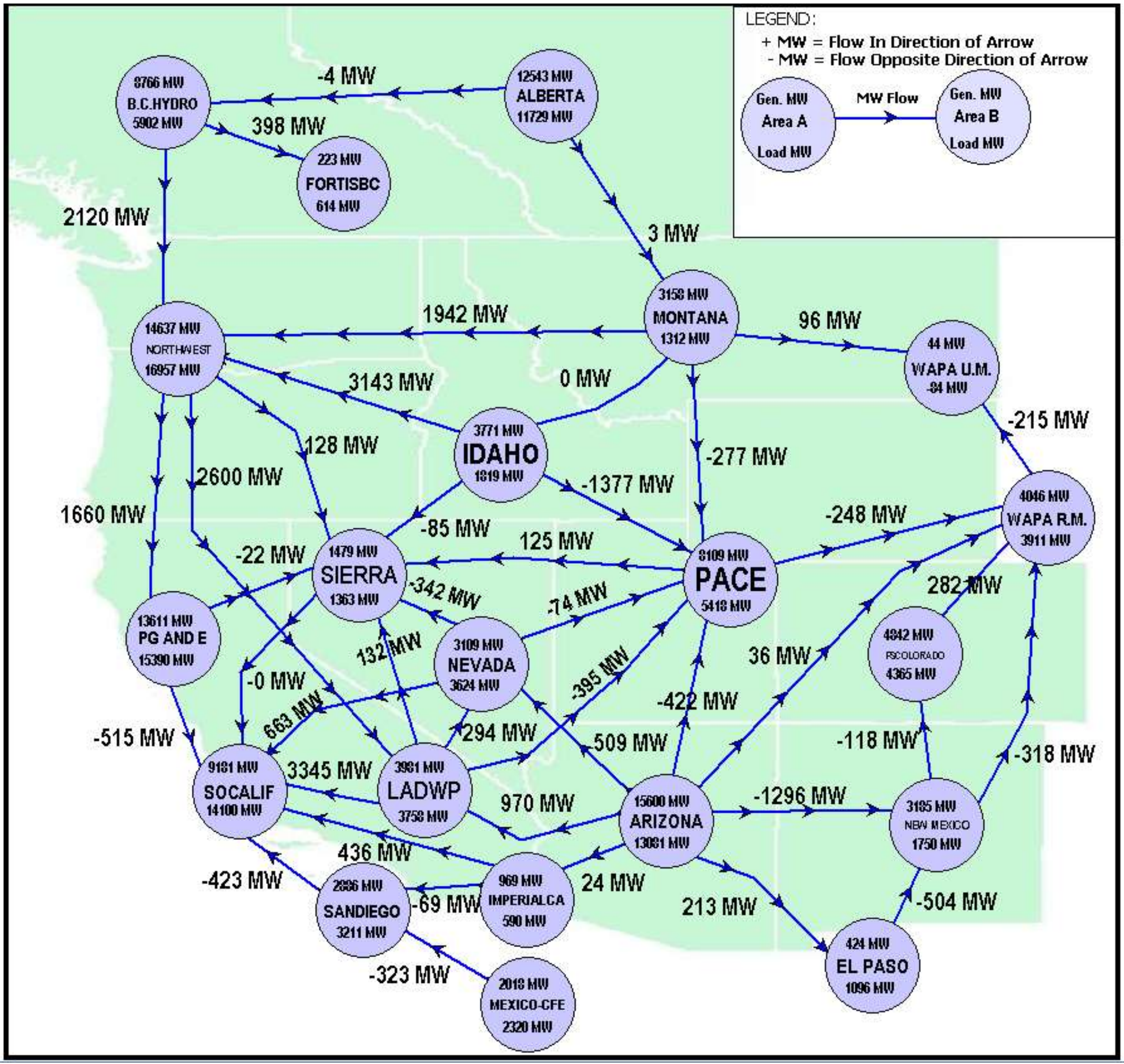
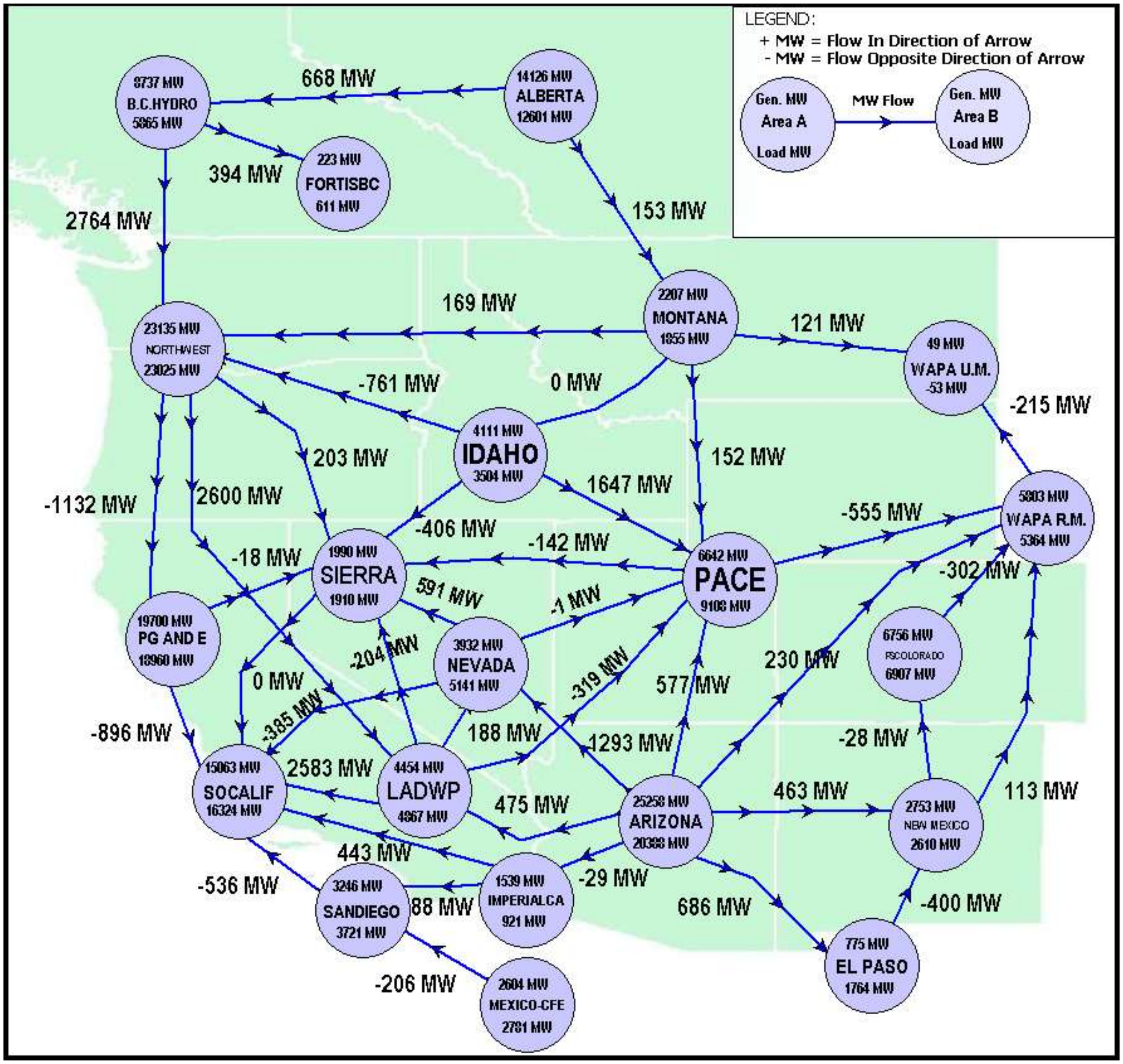


Figure 5-10– Interface Flows for AUG10H13 Core Case



Contingency Analysis

A power systems simulation application, PowerWorld Simulator, was used to analyze a comprehensive set of single element outages (N-1) on all 230 kV and greater lines and transformers, including NTTG and external Foundational Transmission Projects. This resulted in over 400 single-element outages that were simulated to determine the robustness of the proposed system and its ability to serve the projected loads and resources for year 2020.

Any overloads found in the pre-disturbance Core Cases (i.e., N-0) indicate three possible culprits. One explanation is a need to reinforce the Foundation Transmission Projects to reduce expected overloads. A second possibility is a lack of detailed network upgrades at the local transmission level that might not have been represented in the case. The third is a modeling error that is not related to actual system performance and can be corrected in the model. Overloads in the N-0 analysis would be exacerbated for particular outages and would again show either the need to strengthen a specific section of the transmission system (possibly through reinforcements to the Foundational Transmission Projects) or the need for new network upgrades to address specific issues brought about by the outages in question.

The Core Cases N-0 and N-1 violation tables for all five study hours are located Appendix 6.

Study Hour – July 27 H16

This hour represents a summer peak load condition for the NTTG footprint. The pre-disturbance (N-0) overload screening for this hour in the Core Case showed 14 overloaded elements, primarily transformers. This is most likely due to the projected load increase for the 2020 year and the stresses it places on the local system. A total of 21 voltage violations (outside the 0.9 – 1.1 per unit acceptable voltage range) were observed in the areas of interest. Other than a high voltage on the 230 kV busses, most of the other reported violations were either on “dummy” busses (e.g., on the line side of series capacitors, where these voltage levels would be acceptable) or slightly higher-than-normal voltages on some 500 kV busses. These could probably have been reduced by appropriate switching of reactive devices.

There were 10 N-1 thermal overload violations in addition to the 14 pre-disturbance overloads. One of the significant overloads (~137%) was due to the loss of the Dave Johnston – Windstar 230 kV circuit #2, which overloaded the corresponding parallel circuit. This element is one of the Foundational Transmission Projects and will likely be equipped with generation tripping to prevent this overload. The largest overload (143%) was seen on the Ben Lomond 345/138 transformer due to the loss of another source to the 138 kV load through the Syracuse 345/138 transformer.

A total of 28 voltage violations were identified for N-1 conditions – 27 violations for high bus voltage and one violation for low bus voltage. A large portion of the reported overvoltage violations related to 500 kV busses. Overvoltage in the 1.1 to 1.15 per unit (“p.u.”) range are not considered a severe violation, especially if the overvoltage occurs on a dummy buss. The listed under voltage on a 230 kV bus was related to a local area problem.

The 14 transformer overloads reported for N-0 conditions were also reported as violations for N-1 conditions. These overloads were excluded from the N-1 violation tables.

Study Hour – December 22 H18

This hour represents a winter peak load condition for the NTTG footprint. The pre-disturbance overload screening for this hour in the Core Case showed 8 branch elements overloaded, primarily transformers. This is most likely due to the projected load increase for the 2020 year and the unresolved stresses it places on the local system.

A total of 57 high bus voltage violations (outside the 0.9 – 1.1 p.u. voltage range) were identified for N-0 conditions. Other than a high voltage on the 230 kV busses, most of the other reported violations were either on dummy busses or slightly higher-than-normal voltages on some 500 kV busses. The voltages were barely over the upper limit of the range. These probably could have been further reduced by appropriate switching of reactive devices.

For N-1 conditions, the results indicated three thermal overload violations, with all three voltages near or below the 115% emergency rating. These are considered minor overloads. One of the overloads barely exceeded the emergency limit of the Ben Lomond 345/138 kV transformer due to the loss of another source to the 138 kV load through the Syracuse 345/138 kV transformer.

N-1 contingency analysis indicated 28 voltage violations – 27 high voltage violations and one low voltage violation. Most of the reported overvoltage violations related to 500 kV busses. Overvoltage in the 1.1 to 1.15 p.u. range are not considered severe violations, in particular if these occur in dummy busses. The increase in voltage was minor and probably would not have resulted in reported violations had the initial voltages been tuned to fall inside the range. The listed under voltage on a 230 kV bus was related to a local area problem.

The transformer overloads reported on radial connected loads listed in the N-0 violation tables were excluded from the N-1 violation tables in order to reduce duplication of the report violations. These violations also occurred during N-1 system conditions.

Study Hour – March 02 H21

This hour represents a heavy spring export load condition for the NTTG footprint. A total of 12 thermal overload violations were identified for N-0 conditions. Most of these violations were overloads on transformers located in the neighborhood of new wind projects. It is very likely these overloads were related to failure to increase the associated transformer ratings when the new resources were added. These types of overloads are mainly a local issue as the majority of the transformers are rated for 34.5/230 kV operation. The Pavant, Intermount-Gonder 230 kV path was also overloaded in the case at 122% for N-0 conditions.

A total of 15 voltage violations were recorded for N-0 conditions – 14 high bus voltage violations and one low bus voltage violation. Other than a high voltage on the 230 kV busses, most of the other reported violations were either on dummy busses or slightly higher-than-normal voltages on some 500 kV busses. These probably could have been adjusted by appropriate switching of reactive devices. Notice also that the one reported low voltage, on the 500 kV level, occurred on a dummy bus on the line side of a series capacitor under light flow conditions.

A set of more than 400 N-1 contingencies were run on this March Core Case because as the study on the Core Cases was progressing it was determined that the March case represented the critical case for study. The study results indicated 10 thermal overload violations and 47 voltage violations. A large portion of the reported overvoltage violations related to 500 kV busses. Overvoltage in the 1.1 to 1.15 p.u. range are not considered a severe violation, in particular if these occur in dummy busses.

The transformer overloads reported on radial connected loads listed in the N-0 violation tables were excluded from the N-1 violation tables in order to reduce duplication of the report violations. These violations also occurred during N-1 system conditions.

Study Hour – October 04 H21

This hour represents a heavy autumn export load condition for the NTTG footprint. The pre-disturbance overload screening for this hour in the Core Case showed several transformers overloaded. Eight branch element overloads were recorded. These overloads appear to be data related, since they were associated with dedicated transformers for specific generation projects. There were three interface violations reported for N-0 conditions: Midpoint-Summer Lake at 107%, Pavant, Intermountain-Gonder at 105% and Path C at 101%.

A total of 53 bus voltage violations were recorded for N-0 conditions. Other than a high voltage on two 230 kV busses, most of the other reported violations were either on dummy busses or slightly higher-than-normal voltages on some 500 kV busses. The voltages were barely over their upper limit of the p.u. voltage range. These overvoltages could have been further reduced by appropriate switching of reactive devices.

The N-1 contingency results indicated 20 thermal overload violations. The most severe overloads (~140%) on the 500 kV system were related to the loss of the Hemingway to Boardman 500 kV line. This being a heavy export (from the NTTG footprint) case, loss of the Hemingway-Boardman 500 kV line resulted in overloading the parallel branch, the Hemingway-Summer Lake 500 kV line. Initiating unit tripping on the eastern side of the system, or increasing the rating of the limiting element (a series capacitor at Burns), are potential solutions to mitigate overloads for loss of the Hemingway to Boardman 500 kV line. Other overloads on the 230 kV system constituted a local area problem due to the projected increase in load/generation in the studied case.

A total of 63 voltage violations were recorded for N-1 conditions. Most of the reported overvoltage violations related to 500 kV busses. Overvoltages in the 1.1 to 1.15 p.u. range are not considered a severe violation. The increase in voltage was minor and probably would not have resulted in reported violations had the initial voltages been tuned to fall inside the range. The largest overvoltage (1.31 p.u.) on a 230 kV bus was related to large flow redistribution following the loss of a 230 kV tie near a source of wind generation. This was considered a local area problem.

The transformer overloads reported on radial connected loads listed in the N-0 violation tables were excluded from the N-1 violation tables in order to reduce duplication of the report violations. These violations also occurred during N-1 system conditions.

Study Hour – August 10 H13

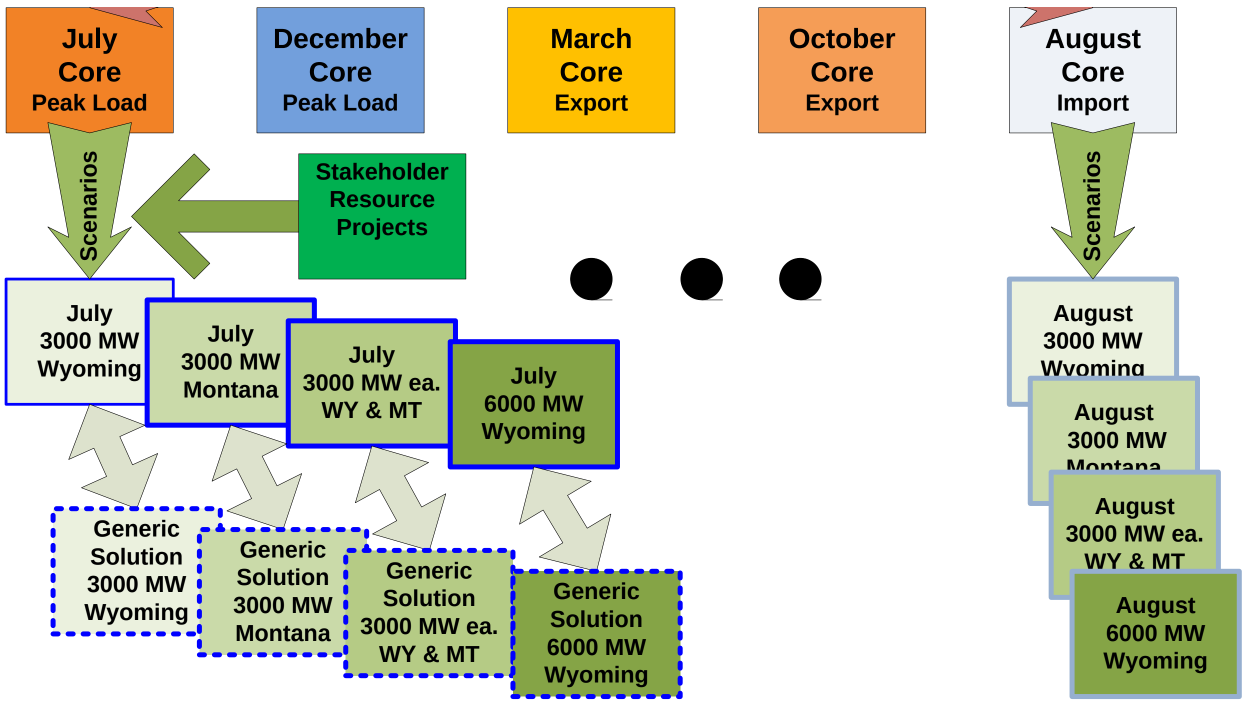
This hour represents a maximum import load condition for the NTTG footprint. The pre-disturbance overload screening for this hour in the Core Case shows 10 transformer overloads. The reported extreme thermal overload was 150% of the continuous rating. These overloads are most likely due to the projected load increase for the 2020 year and the unresolved stresses it places on the local system. For N-0 conditions, 68 bus voltage violations were recorded outside the 0.9 – 1.1 p.u. voltage range in the areas of interest. Other than a high voltage on the 230 kV busses, most of the other reported violations were either on dummy busses or slightly higher than normal voltages on some 500 kV busses. These overvoltages could probably have been reduced by appropriate switching of reactive devices. This study hour is an import (to the NTTG footprint) case with south-to-north flows on California-Oregon Intertie (COI). Most of the 500 kV voltage violations were along the COI system, highlighting the relatively light flows and the need for additional reactor switching.

A total of 12 overloaded elements were recorded for N-1 conditions. One significant overload (~134%) was due to loss of the Dave Johnston – Windstar 230 kV circuit #2. This line loss overloaded the corresponding parallel circuit. This element is one of the Foundational Transmission Projects and will likely be equipped with generation tripping to prevent this overload. The largest overload (140%) was seen on the Ben Lomond 345/138 transformer due to the loss of another source to the 138 kV load through the Syracuse 345/138 transformer. The Bridger-Rock Springs circuit 1 was overloaded just below the emergency rating (115%) for loss of the parallel circuit 230 kV #2.

A total of 28 bus voltage violations were recorded for N-1 conditions – 27 high bus voltage violations and one low bus voltage violation. A large portion of the reported overvoltage violations related to 500 kV busses. Overvoltages in the 1.1 to 1.15 p.u. range are not considered a severe violation, in particular if these occur in dummy busses (line side terminals of series capacitors). The number of elements that experienced overvoltages increased for outages that result in the loss of large generation in the NTTG footprint (i.e., Colstrip #4) or unloading the 500 kV system by impeding the flow (opening a 500/230 kV transformer) from the 500 kV system to the lower voltage (load serving) system. The listed undervoltage violation on a 230 kV bus was related to a local area problem.

The transformer overloads reported on radial connected loads listed in the N-0 violation tables were excluded from the N-1 violation tables in order to reduce duplication of the report violations. These violations also occurred during N-1 system conditions.

Chapter 6 - The Scenario Cases



The Scenario Cases

Four scenario cases were developed from the Core Cases to represent four different resource scenarios.

The four scenario cases are shown below:

1. 6,000 MW in Wyoming
2. 3,000 MW in Wyoming, 3,000 MW in Montana
3. 3,000 MW in Montana
4. 3,000 MW in Wyoming

Within each of the four scenarios, five study hours were selected. The five study hours are shown below:

1.	Summer Peak	July 27, Hour 16
2.	Winter Peak	December 22, Hour 18
3.	Heavy Spring Export	March 2, Hour 21
4.	Heavy Autumn Export	October 4, Hour 21
5.	Maximum Import	August 10, Hour 13

Each study hour within a scenario was evaluated using load flow analysis to identify the minimum amount of transmission improvements required to reduce path flows to acceptable levels on the overloaded path or on the path experiencing voltage problems. Single element (N-1) contingency analysis was performed on all five study hours for each scenario to evaluate the performance of the system.

The contingency analysis performance criterion is shown below:

- N-1 contingencies of 230 kV and above elements within the NTTG footprint (420 total)
- Report violations for elements at 230 kV and above
- Violation if the increase in flows on a monitored element was greater than 2% above the 100% rating of the element
- Violation if the voltage change on a monitored element was greater than 1%, outside a range of 90%-110%

1.0: Scenario 1 – 6,000 MW in Wyoming

This scenario intends to represent the effect of an additional 6,000 MW of alternative generation in Wyoming (assumed to be distributed among the Anticline, Dave Johnston, Windstar and Aeolus busses).

6,000 MW in Wyoming – Case Development

Case development for Scenario 1 began with the Core Case from each study hour. Generation resources were added to the Core Case for each study hour to develop five power flow cases for Scenario 1. Table 6.1 shows the generation resources added to the Core Case used to develop the five study hour cases for Scenario 1.

Table 6-1 – Scenario 1 Generation Resource Additions

Area Name	Bus Name	Generation Addition
PACE	DAVEJOHN	500 MW
	AEOLUS	2000 MW
	ANTICLINE	2000 MW
	WINDSTAR	1500 MW
	Total	**6000 MW**

A sink was created for each of the five study hours by removing generation resources in order to offset the 6,000 MW resource addition. Table 6.2 shows the generation resources removed from the Core Case used to develop the five study hour cases for Scenario 1. The values shown represent the total generation MW reduction in each of the areas listed. A more detailed table identifying the specific busses with generation reductions is provided in Appendix 7.

Table 6-2 - Scenario 1 Generation Resource Reductions

Area Name	Generation Reduction (MW) July 27 Hour 16	Generation Reduction (MW) December 22 Hour 18	Generation Reduction (MW) March 2 Hour 21	Generation Reduction (MW) October 4 Hour 21	Generation Reduction (MW) August 10 Hour 13
SOCALIF	2065	1000	2246	760	2954
SANDEIGO		178		70	272
NORTHWEST	8	12		107	
NEWMEXICO				270	
ARIZONA	1180	845	1947	1263	660
PG&E	2500	2240	2240	2463	436
SIERRA		47			
ALBERTA	129	1019		898	776
NEVADA	118				120
WAPA RM				60	
PACE		102		129	
	6000 MW	**5443 MW**	**6433 MW**	**6020 MW**	**5218 MW**

Once the generation additions and reductions were completed, the power flow case was solved. The study team identified overloads of transmission elements before the addition of generic transmission improvements. Table 6.3 shows the N-0 path flows for Scenario 1 before the addition of generic transmission improvements for each study hour analyzed in Scenario 1.

Items shown in red text indicate that path elements are overloaded above the existing rating due the addition of 6,000 MW of generation resources in Wyoming. The path ratings are shown in parentheses below the path name. TOT2 flows are shown as the sum of TOT2A, TOT2B and TOT2C. An overload on any element of TOT2 (A, B, C) is considered a path overload; so overloads on TOT2 could be listed at values less than the 2,070 MW value.

Table 6-3 - Scenario 1 N-0 Path Flows (Pre-Generic Transmission Improvements)

SCENARIO 1	ID-NW (3800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3800) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW
JUL27H16	2111	988	**5275**	2600	5815	3207	**4673**	**1963**	317
DEC22H18	3304	1486	2814	2600	3585	**5273**	**4704**	981	1191
MAR02H21	2135	**4018**	**7660**	1904	5181	1911	3088	**2705**	-96
OCT04H21	**5933**	2041	3358	2600	982	**6264**	**6049**	**2546**	**2174**
AUG10H13	1435	396	673	2600	3430	2447	**4242**	722	-10

Transmission improvements, in the form of new 500 kV transmission lines (AC solution option), were added to each of the five study hours to supplement the Foundational Transmission Projects. The locations of the 500 kV transmission improvements are shown in Figure 6.1.

Transmission improvements using DC transmission lines (DC solution option) were tested on the March study hour (maximum spring export). Figure 6.2 shows the location of the DC transmission improvements tested on the March study hour.

Both the AC solution option and DC solution option appeared as adequate solutions for relieving overloads.

Figure 6-1 – Scenario 1 Generic Transmission Improvements (AC Solution Option)

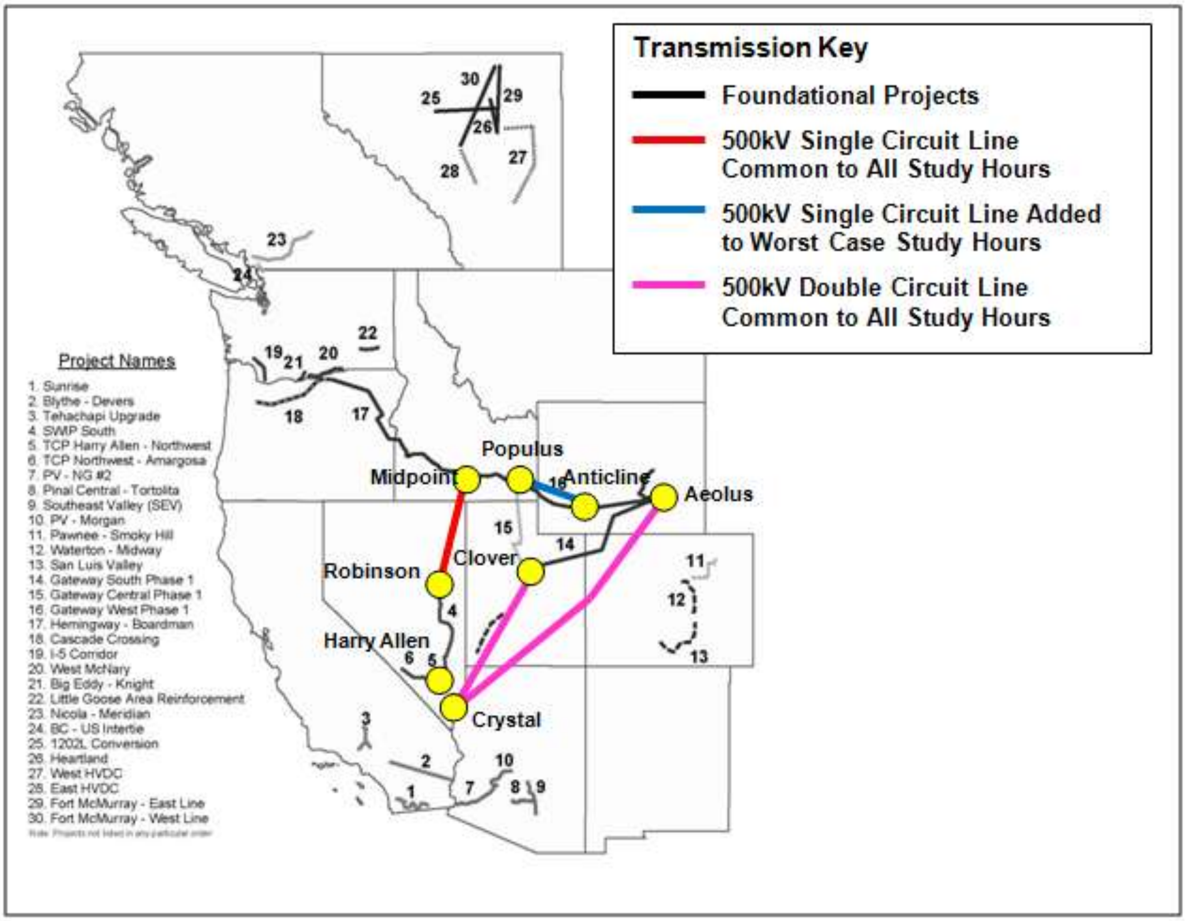
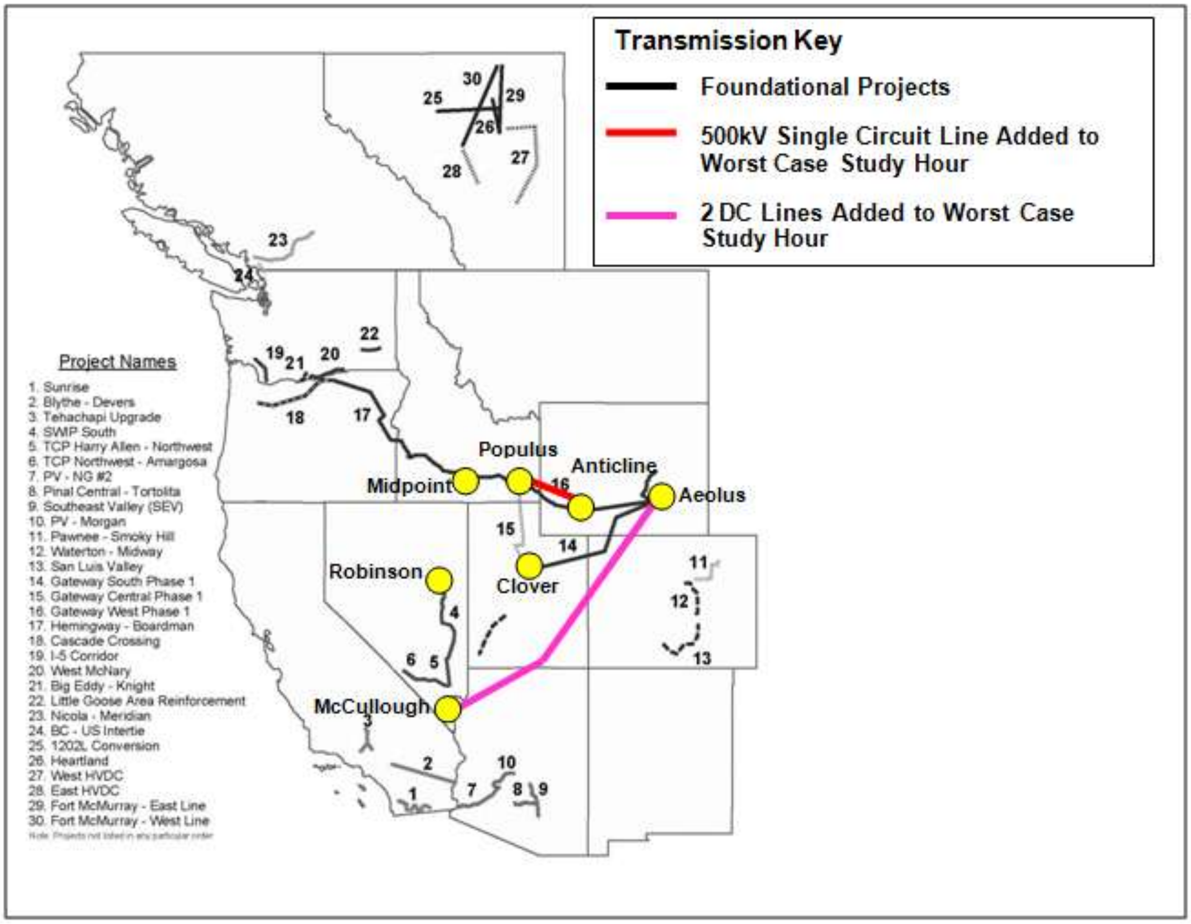


Figure 6-2 – Scenario 1 Generic Transmission Improvements (DC Solution Option)



6,000 MW in Wyoming – Study Results

The study results indicated that the addition of 6,000 MW of generation in Wyoming resulted in overloaded paths as shown in Table 6.3. Overloaded paths for Scenario 1 common between study hours were overloads on COI, Bridger West, Borah West and TOT2 (A,B,C). The overloaded elements identify the need for transmission improvements.

The transmission improvements common to all five study hours were: 1.) a double circuit 500 kV transmission line between the Aeolus and Crystal busses, 2.) a double circuit 500 kV transmission line between the Clover and Crystal busses, and 3.) a 500 kV transmission line between the Midpoint and Robinson busses. Load flow analysis was performed on each study to test if the proposed transmission improvements were adequate in reducing the overloads.

Post-improvement N-0 path flows are shown in Table 6.4. The study results indicate that the proposed transmission improvements relieved the majority of the overloads shown in Table 6.3.

For the March and August study hours, an additional 500 kV transmission line was added between Anticline and Populus to relieve overloads on the Bridger West Path. This transmission line was added in parallel with the Gateway West Phase 1 line, a Foundational Transmission Project.

One post-improvement N-0 overload common to the December and October study hours were overloads on Bridger West of 103.5% and 116.3% (respectively) on a 3,800 MW rating. The common overload on the Bridger West Path for the December and October study hours suggests than an additional transmission improvement between Anticline and Populus is one solution to resolve the identified overloads. The addition of a second 500 kV transmission element from Anticline to Populus in the March and August study hours relieved overloads on the Bridger West Path for Scenario 1.

A DC solution option was also tested on the March study hour. Two DC lines between Aeolus-McCullough were added to the case. The DC solution option also included a second 500 kV circuit between Anticline and Populus, however, this circuit is most likely not needed. The study results indicate that the DC solution option appears as an adequate solution alternative. One post-improvement overload on COI (105%) was identified with the DC solution option. This overload may be mitigated by adjusting the flow on the PDCI.

Even though this study did not include a combination of AC and DC transmission line improvements, several of the AC and DC improvements described above could be combined to create another solution option to resolve the transmission overloads identified in this Scenario.

N-1 contingency analysis for each study hour in Scenario 1 indicated that the majority of the 420 contingencies solved for each study hour. There were two study hours that had unsolved contingencies. The BOARDT2-DALREED contingency was unsolved in the March and October study hours.

N-0 and N-1 violations discussed in this report are violations on elements 200 kV and above within the NTTG footprint. N-0 and N-1 violation tables for each study hour within this scenario are provided in Appendix 8.

The sum of the N-1 violations for all the study hours in Scenario 1 was 371 violations. The majority of overloaded elements for all the study hours were transformer overloads for N-1 conditions. The most common N-1 violation for all study hours was high bus voltage. Most of the high bus voltage violations were reported at dummy busses near 500 kV series capacitors. The number of violations in the March study hour was similar for both the AC and DC solution options.

Table 6-4 – Scenario 1 N-0 Path Flows (Post-Generic Transmission Improvements)

SCENARIO 1	ID-NW (3800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3700) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW	DBL CKT 500kV Aeolus-Crystal (3000) MW	DBL CKT 500kV Clover-Crystal (3000) MW	SGL CKT 500kV Midpoint-Robinson (1500) MW	500kV CKT #2 Anticline-Populus (1500) MW	2 DC Lines Aeolus-McCullough (6000) MW
JUL27H16	695	881	3841	2599	5523	1952	3621	700	-199	1928	1148	437	NA	NA
DEC22H18	2817	1414	2331	2600	3482	3997	**3932**	239	764	1722	625	-366	NA	NA
MAR02H21 (AC Option)	1948	1680	4791	2769	2811	2693	4213	1459	-40	2912	1661	1496	1184	NA
MAR02H21 (DC Option)	2261	1688	**5060**	2760	2853	1690	2732	**1640**	145	NA	NA	NA	490	6000
OCT04H21	3480	1899	984	2600	622	3924	**4420**	888	984	2314	2163	315	NA	NA
AUG10H13	1310	378	529	2600	3384	2452	4674	646	-388	1000	207	117	1481	NA

Notes:

(1) Second 500 kV circuit between Anticline-Populus was added to the March and August study hours to relieve overloads on Bridger West. Interface rating was increased from 3,700 MW to 5,200 MW.

(2) Path rating shown in parentheses below the path name.

(3) Path overloads are identified in red text. TOT2 is reported as the sum on TOT2A, TOT2B and TOT2C. On overload on any TOT2 segment represents an overload on the path.

1.1: 6,000 MW in Wyoming – Summer Peak – July 27, Hour 16

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 21 overloaded branch elements – all transformers – ranging from 100.3% to 160% of the nominal rating. These transformer overloads were found to be located on radial-connected loads and are considered a local problem. There were 27 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency. The majority of the high bus voltage violations are on dummy busses located on the line side of series capacitors, where slightly higher-than-nominal voltage would be expected.

A set of 420 N-1 contingencies was run on this study hour, causing 53 violations with zero unsolved contingencies. Violations were observed on 11 elements overloaded above the 100% rating. Ten elements were overloaded at less than 115% of the 100% rating. One element produced an overload of 137% of the continuous rating. The remaining 42 violations resulted from elements with a bus voltage greater than 1.1 p.u.

Area interchange diagrams are provided in Figures 6.3-6.6. MW values shown on the difference diagram represent a MW change as referenced to the study hour Core Case.

Figure 6-3 – Scenario 1 Core Case Flows: JUL27H16

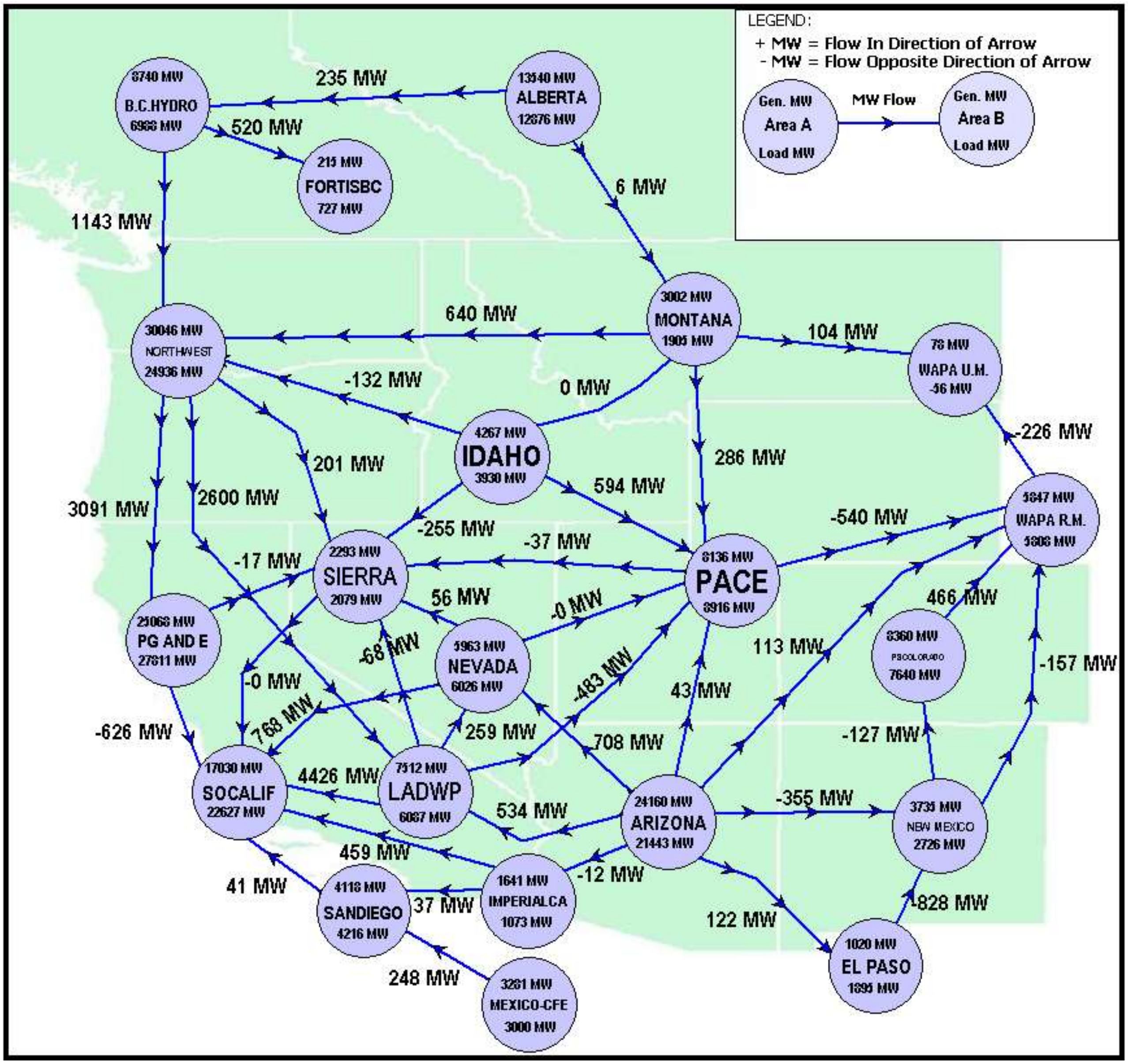


Figure 6-4 – Scenario 1 N-0 Flows (Pre-Transmission Improvements): JUL27H16

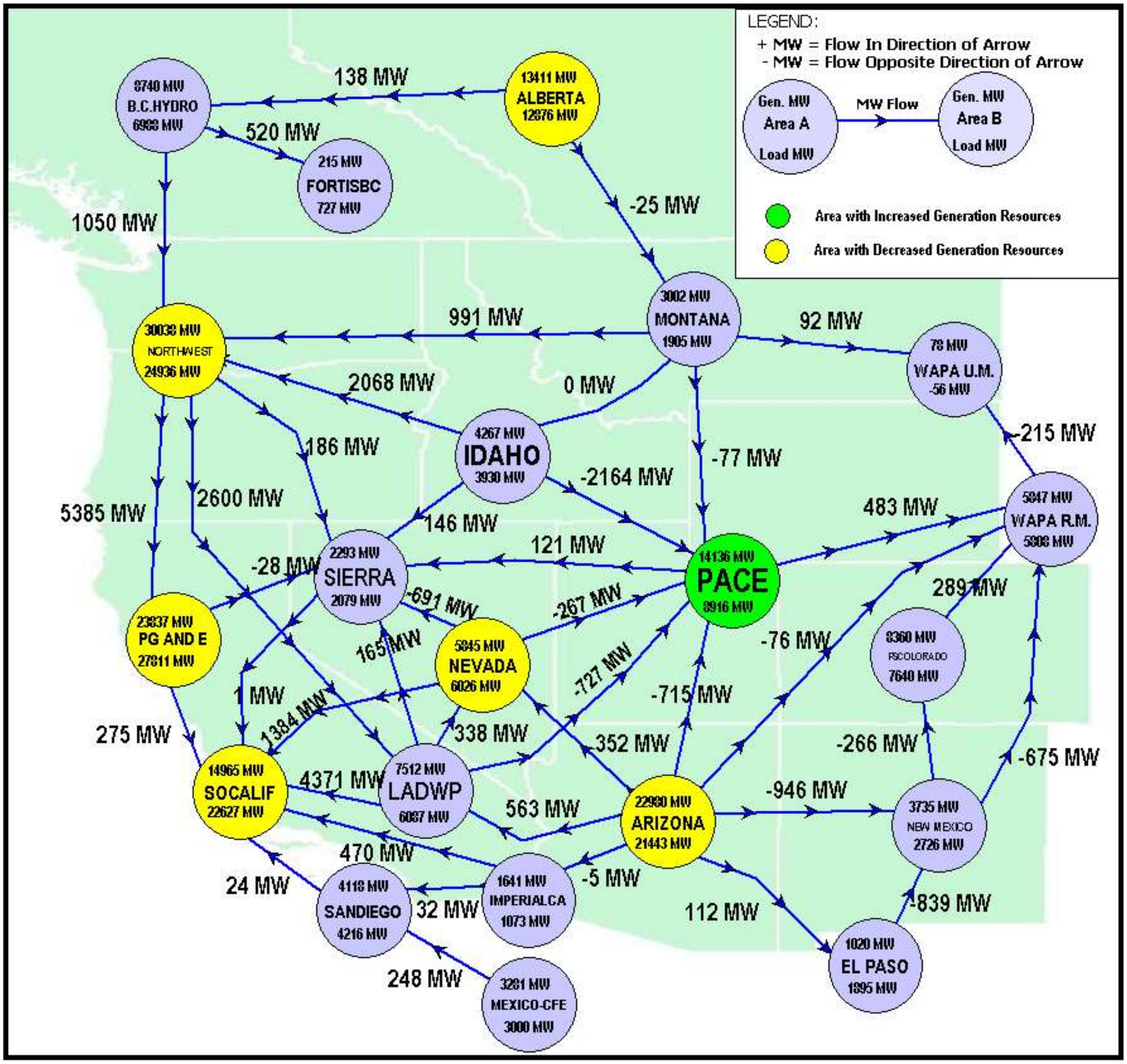


Figure 6-5 – Scenario 1 N-O Flows (Post-Transmission Improvements) JUL27H16

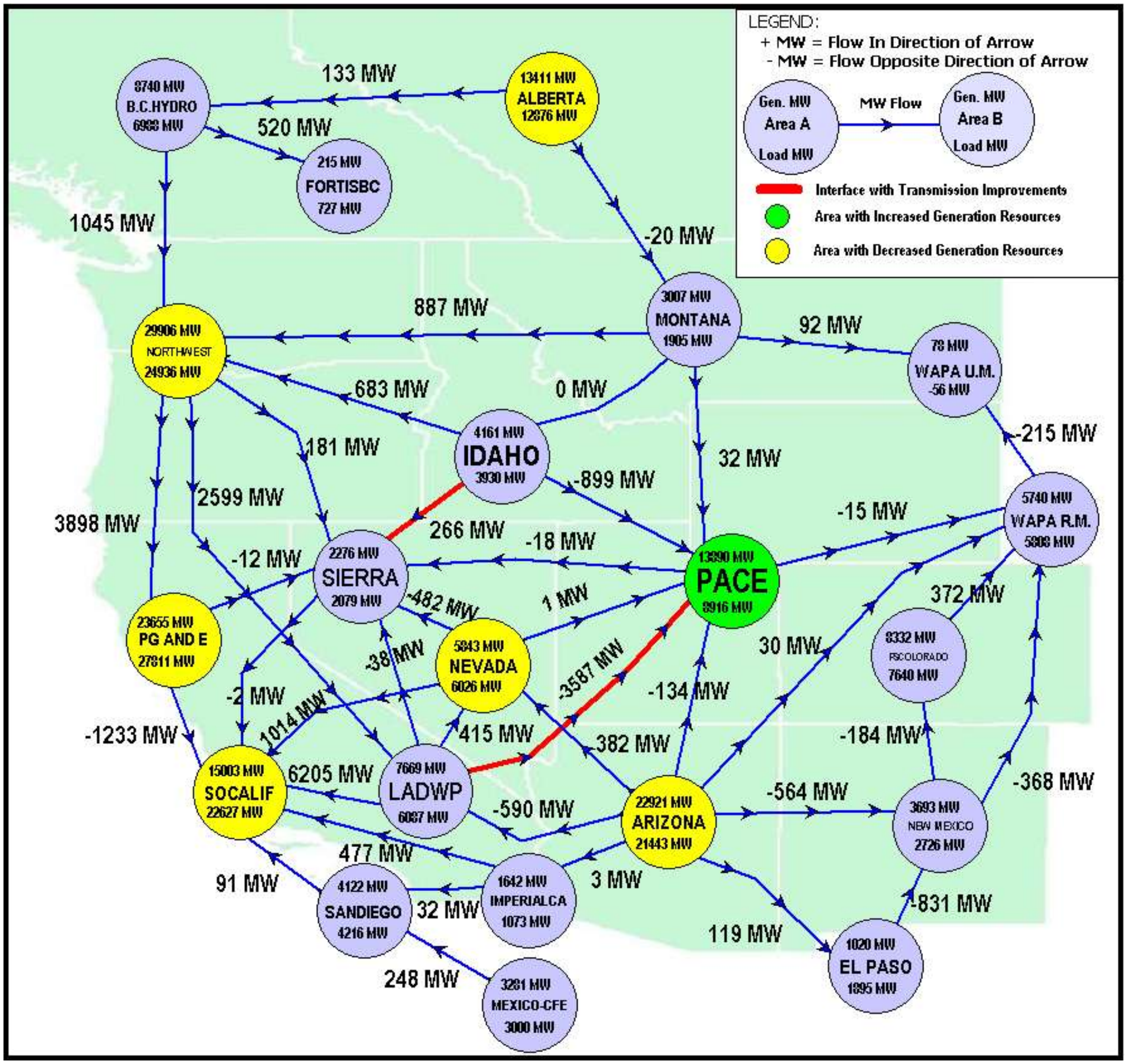
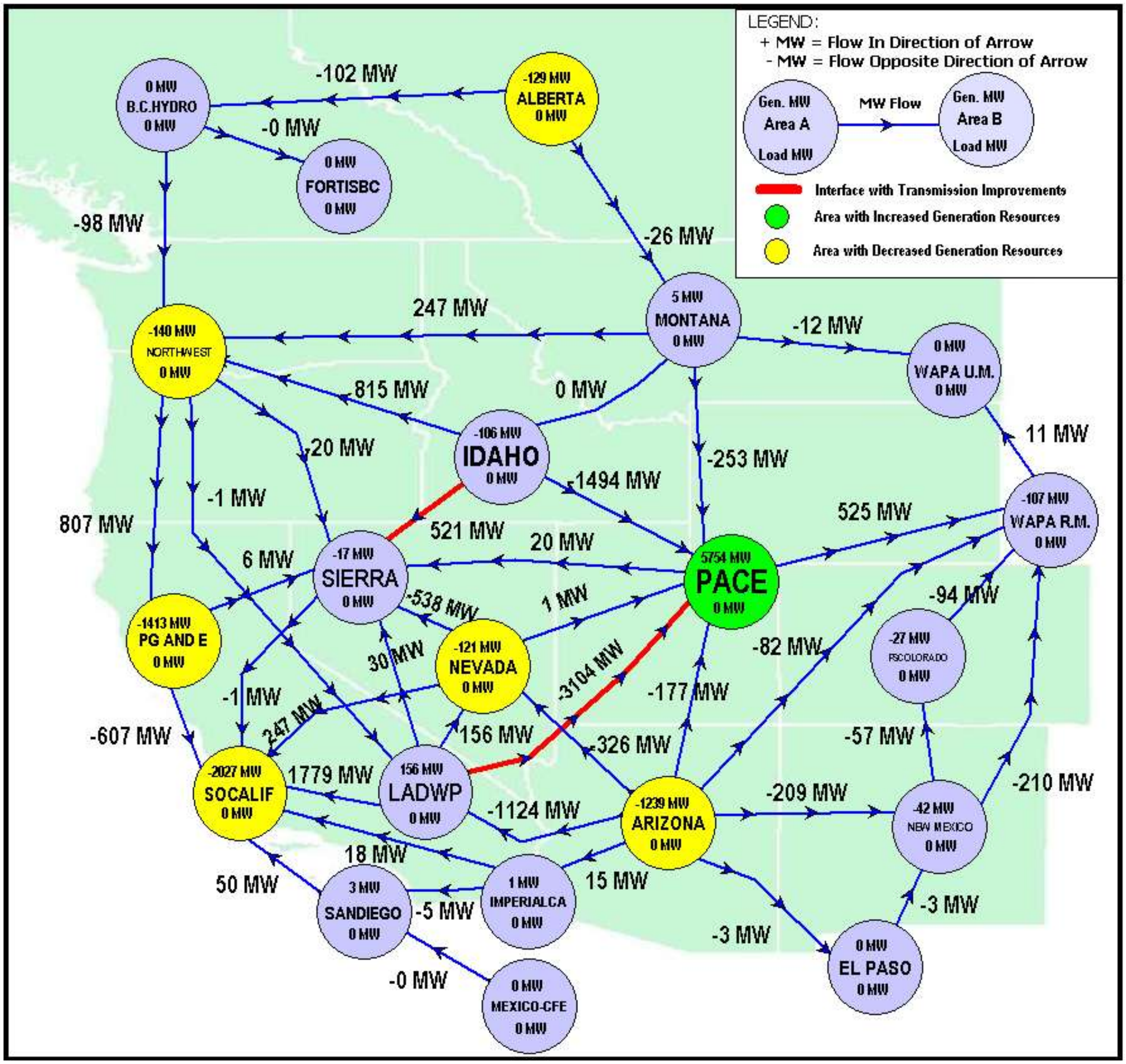


Figure 6-6 – Scenario 1 Difference Flows (Core Case vs. Post-Improvement Case) JUL27H16


LEGEND:
+ MW = Flow In Direction of Arrow
- MW = Flow Opposite Direction of Arrow
Gen. MW
Area A
Load MW
MW Flow
Gen. MW
Area B
Load MW
Interface with Transmission Improvements
Area with Increased Generation Resources
Area with Decreased Generation Resources
0 MW
B.C.HYDRO
0 MW
-102 MW
-129 MW
ALBERTA
0 MW
-0 MW
0 MW
FORTISBC
0 MW
-98 MW
-26 MW
5 MW
MONTANA
0 MW
247 MW
-12 MW
-140 MW
NORTHWEST
0 MW
0 MW
WAPA U.M.
0 MW
-815 MW
0 MW
11 MW
20 MW
-106 MW
IDAHO
0 MW
-253 MW
-1 MW
-1494 MW
807 MW
521 MW
525 MW
-107 MW
WAPA R.M.
0 MW
20 MW
6 MW
-17 MW
SIERRA
0 MW
5754 MW
PACE
0 MW
-538 MW
1 MW
-94 MW
-1413 MW
PG AND E
0 MW
-121 MW
NEVADA
0 MW
30 MW
3104 MW
-82 MW
-27 MW
PSCOLORADO
0 MW
-1 MW
-177 MW
247 MW
-607 MW
156 MW
-326 MW
-57 MW
-2027 MW
SOCALIF
0 MW
1779 MW
156 MW
LADWP
0 MW
-209 MW
-210 MW
-1124 MW
-1239 MW
ARIZONA
0 MW
-42 MW
NEW MEXICO
0 MW
18 MW
50 MW
3 MW
SANDIEGO
0 MW
-5 MW
1 MW
IMPERIALCA
0 MW
15 MW
-3 MW
-3 MW
0 MW
EL PASO
0 MW
-0 MW
0 MW
MEXICO-CFE
0 MW

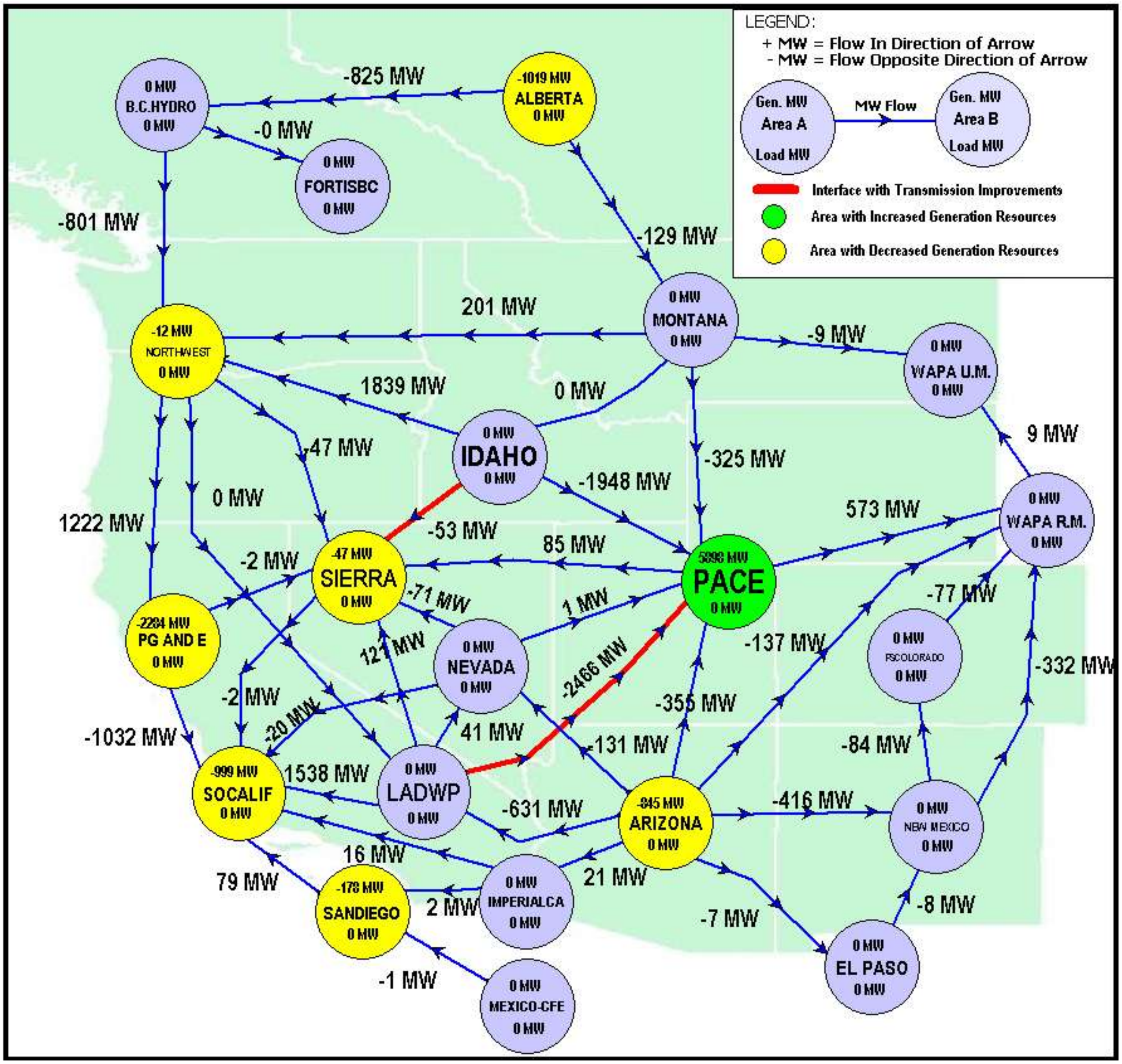
1.2: 6,000 MW in Wyoming – Winter Peak – December 22, Hour 18

After the addition of the generic transmission improvements, two N-0 interface violations were found within the NTTG footprint: Bridger West at 106% and Midpoint-Summer Lake at 104%. Pre-contingency, this study hour was found to have 17 overloaded branch elements ranging from 100.3% to 145% of the nominal rating. Most of these were transformers; two of the 17 elements were series capacitors. There were 25 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 87 violations with zero unsolved contingencies. Of the 87 violations, 18 violations were for overloaded elements. The range of overloads for the 18 violations was from 101% to 129%. There were four violations for low bus voltage and 65 violations for high bus voltage.

A difference flow diagram is shown in Figure 6.7. MW values shown on the difference diagram represent the MW change as referenced to the study hour Core Case. Additional area interchange diagrams are located in Appendix 5.

Figure 6-7 – Scenario 1 Difference Flows: DEC22H18



1.3: 6,000 MW in Wyoming – Heavy Spring Export –March 2, Hour 21

After the addition of the generic transmission improvements, one N-0 interface violation was found within the NTTG footprint: Bridger West at 114%. COI was operating at 99.8% capacity in the AC solution option case. Pre-contingency, this study hour was found to have 24 overloaded branch elements ranging from 101.2% to 182% of the nominal rating. The extreme overload of 181.6% was the result of a data error in the transformer rating assigned to the case. Of the 25 overloaded elements, there were five line elements, one series capacitor and 18 transformers. There were 24 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 119 violations with two unsolved contingencies on the AC solution option case. The two unsolved contingencies were BOARDT2-DALREED and JONESCYN-DALREED. Of the 119 violations, 40 violations were elements overloaded above the 100% rating. Of those, 32 were overloaded greater than 115%. The remaining 79 violations resulted from elements with a bus voltage greater than 1.1 p.u.

In the DC solution option case for this study hour, the study found 31 N-0 branch element overloads and three N-0 interface overloads. Overloaded interfaces were Midpoint-Summer Lake at 106%, COI at 105.4% and TOT 2C at 100.2%. Overloads on branch elements ranged from 100.1% to 217%. The majority of the overloaded branch elements were transformers on radial lines connected loads. There were 16 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

N-1 contingency analysis for the DC solution option reported 220 violations with two unsolved contingencies. The two unsolved contingencies were BOARDT2-DALREED and JONESCYN-DALREED. Of the 220 violations, 117 were elements overloaded above the 100% rating. The remaining 103 violations resulted from elements with a bus voltage greater than the 1.1 p.u. Of the 117 violations for overloads, 56 of the violations were overloaded greater than 115%.

A difference flow diagram for the AC solution option as referenced to the Core Case is shown in Figure 6.8. MW values shown on the difference diagram represent the MW change between the two power flow cases. The difference diagram for the DC solution as referenced to the Core Case is shown in Figure 6.9. Figure 6.10 is a comparison plot of the DC solution option referenced to the AC solution option. Additional area interchange diagrams are located in Appendix 5.

Figure 6-8 – Scenario 1 Difference Flows: MAR04H21 (AC Solution)

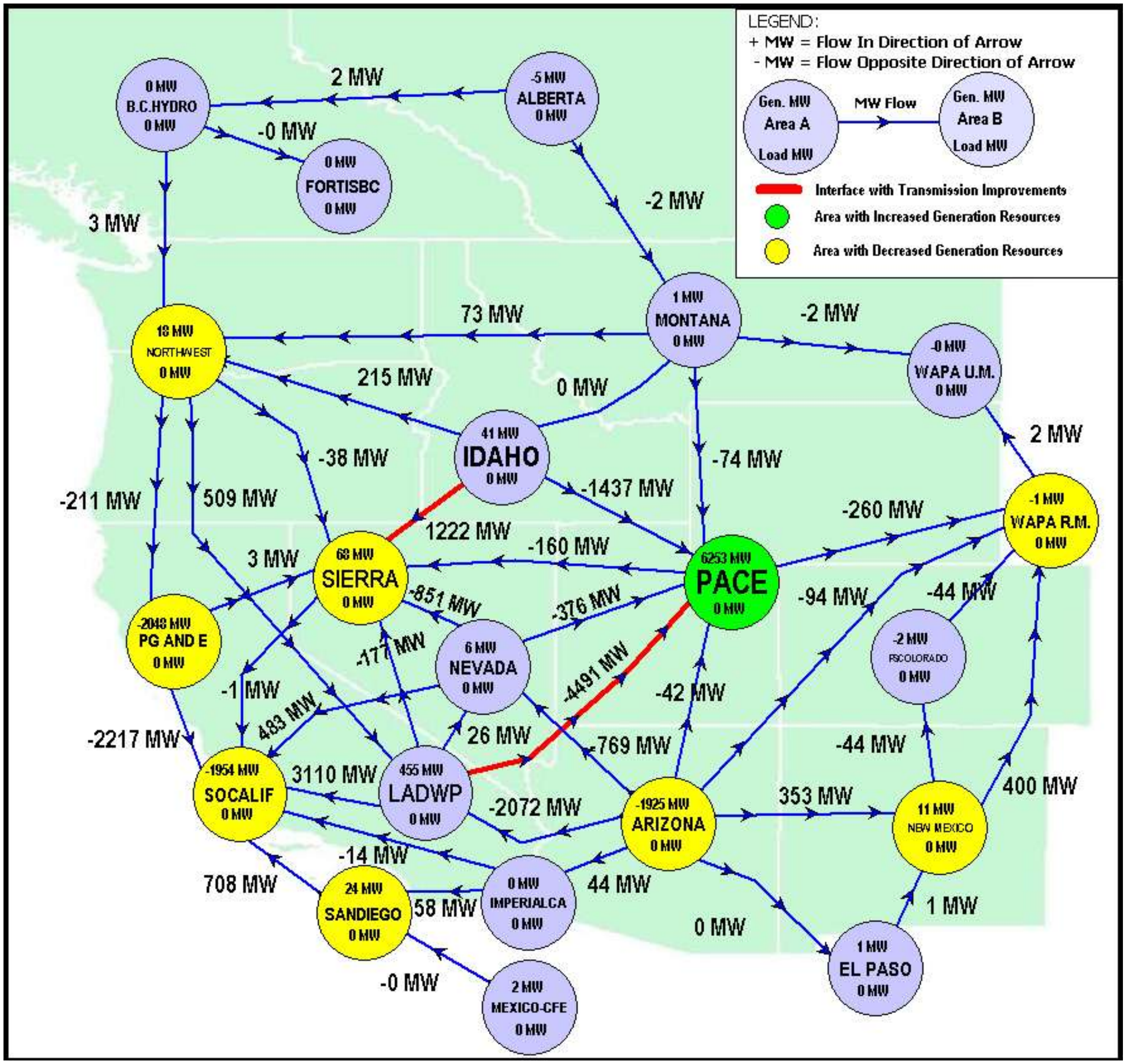


Figure 6-9 – Scenario 1 Difference Flows: MAR04H21 (DC Solution)

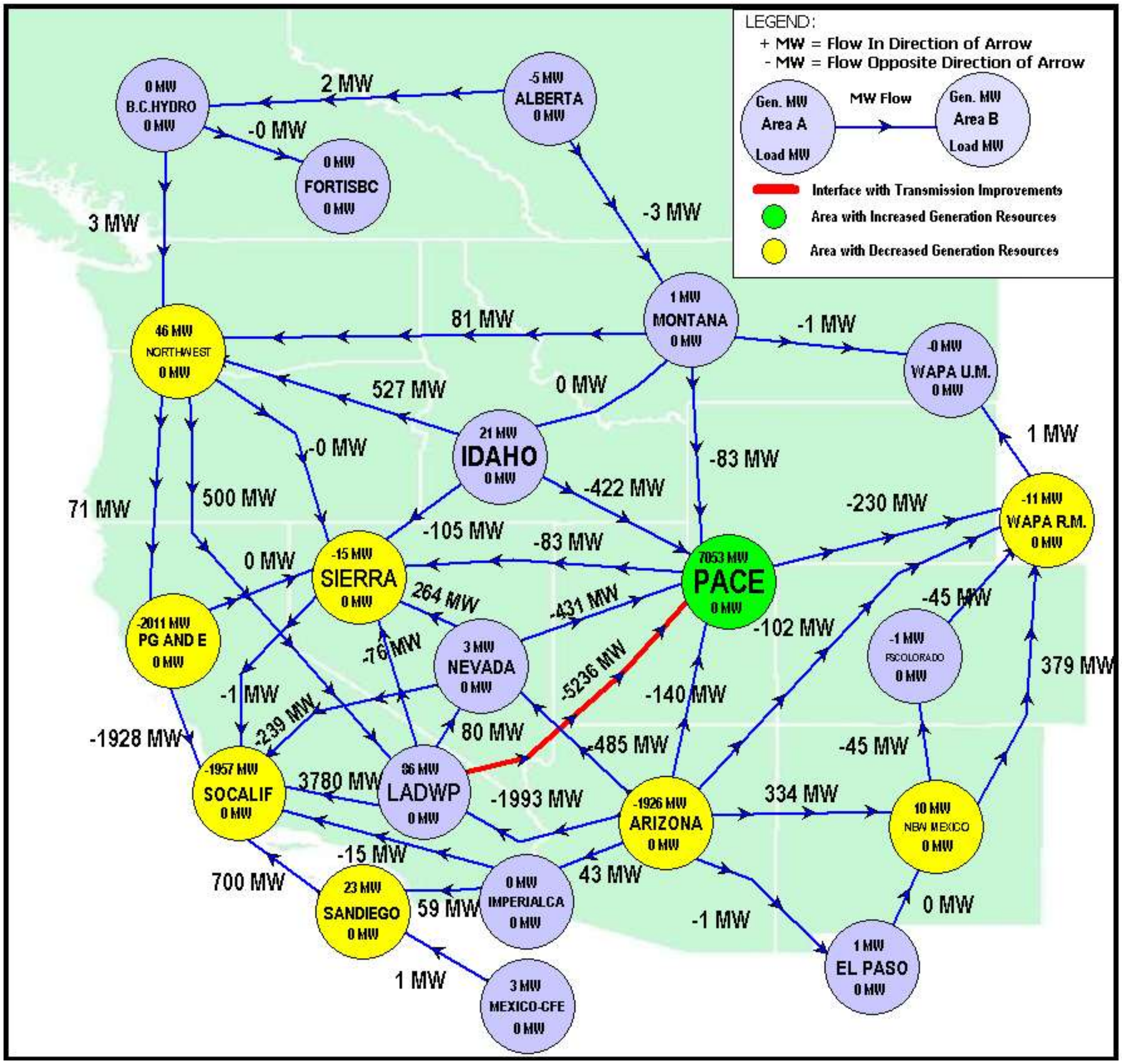
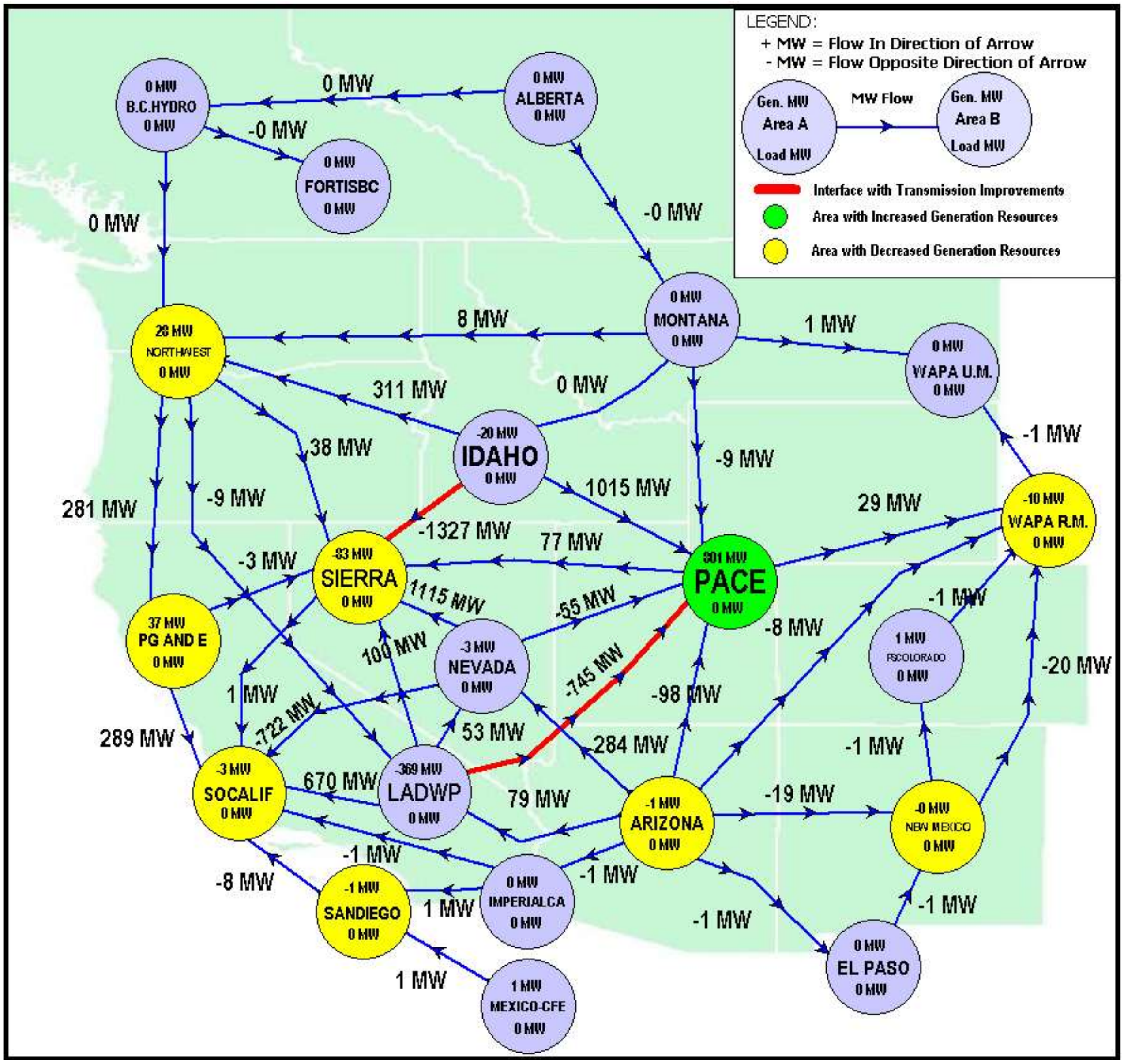


Figure 6-10 – Scenario 1 Difference Flows: MAR04H21 (AC Solution vs. DC Solution)



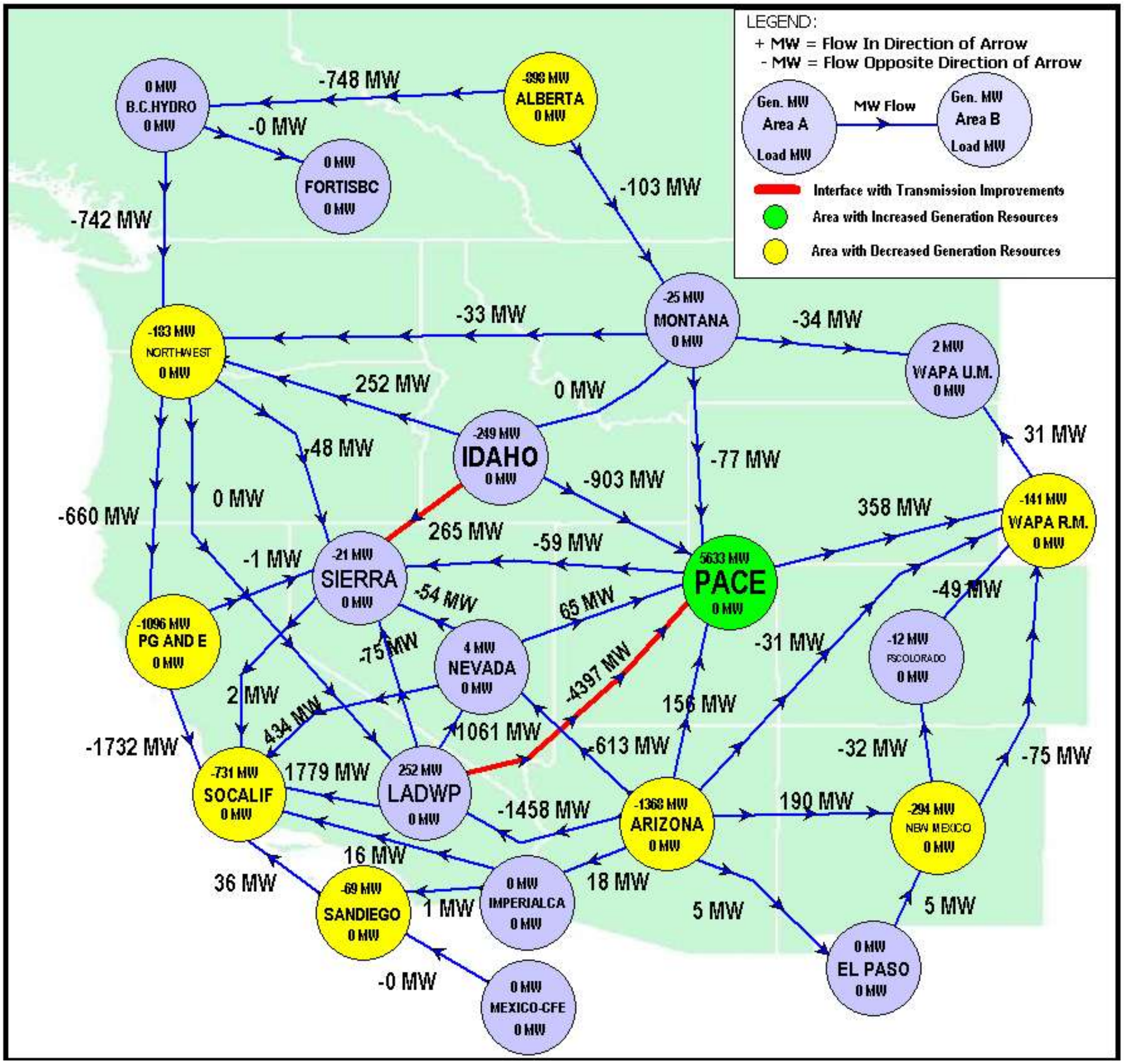
1.4: 6,000 MW in Wyoming – Heavy Autumn Export – October 4, Hour 21

After the addition of the generic transmission improvements, two N-0 interface violations were found within the NTTG footprint: Bridger West at 120% and Midpoint-Summer Lake at 111%. Pre-contingency, this study hour produced 20 overloaded branch elements ranging from 100.1% to 127% of the nominal rating. The N-0 overload elements consisted of one line, three series capacitors and 16 transformers. There were 10 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 64 violations with one unsolved contingency. The one unsolved contingency was BOARDT2-DALREED. Thirty of the 64 violations were overloaded elements. Fourteen of those overloaded elements were overloaded 115% above the continuous rating. The remaining 34 violations resulted from elements with a bus voltage greater than 1.1 p.u.

A difference flow diagram is shown in Figure 6.11. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-11 – Scenario 1 Difference Flows: OCT04H21



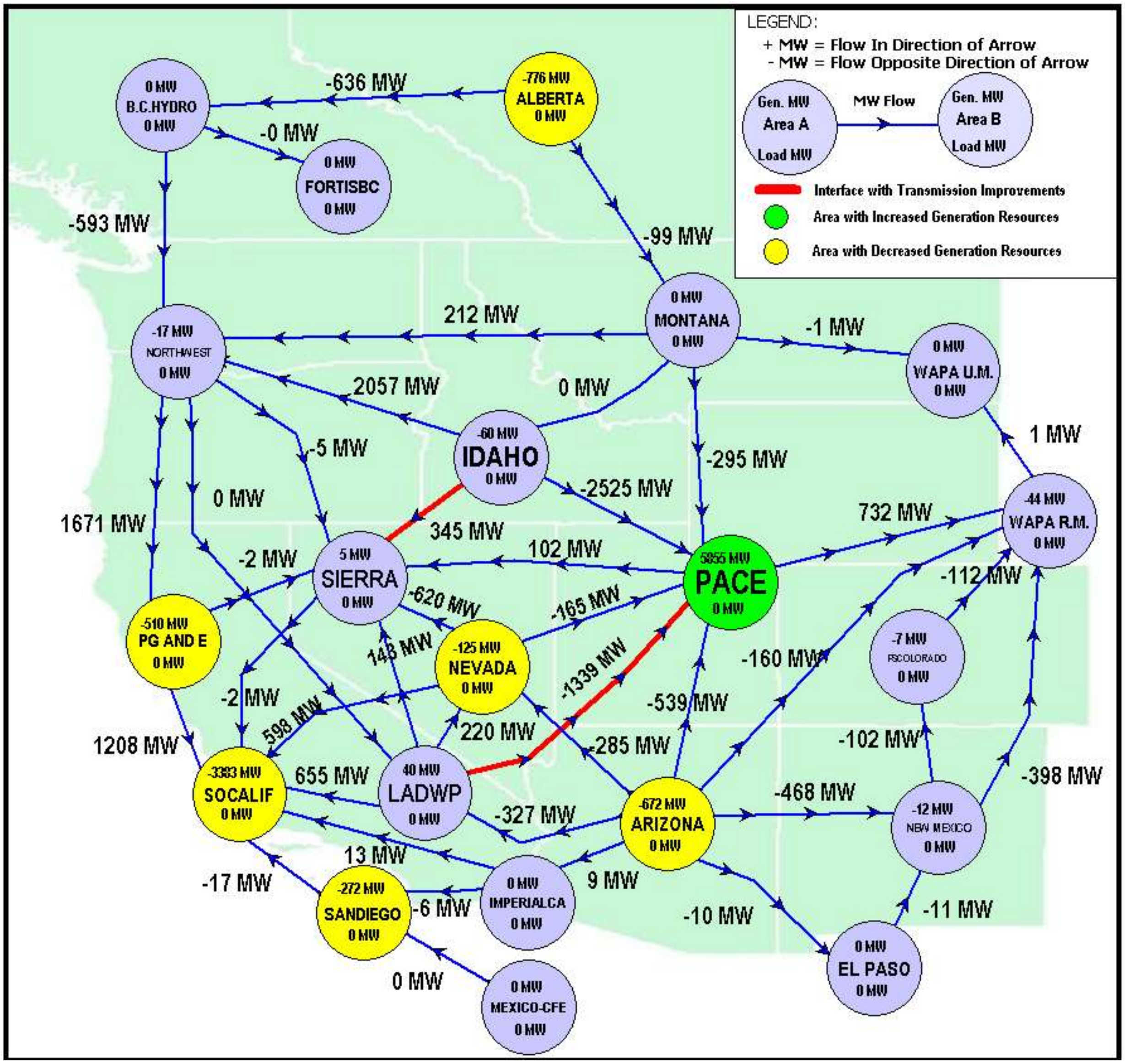
1.5: 6,000 MW in Wyoming – Maximum Import – August 10, Hour 13

After the addition of the generic transmission improvements, one N-0 interface violation was found within the NTTG footprint: Bridger West at 126%. Pre-contingency, this study hour was found to have 17 overloaded branch elements ranging from 100.4% to 149% of the nominal rating, all of which were transformers. There were 27 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 48 violations with zero unsolved contingencies. Of the 48 violations, 10 were overloaded elements, two of which were overloaded 115% above the continuous rating. Of the remaining 38 violations, 36 were elements with a bus voltage greater than 1.1 p.u., and two were elements with a bus voltage less than 0.9 p.u.

A difference flow diagram is shown in Figure 6.12. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-12 – Scenario 1 Difference Flows: AUG10H13



2.0: Scenario 2 – 3,000 MW in Wyoming, 3,000 MW in Montana

This scenario represents the effect of a combined additional 3,000 MW of alternative generation in Wyoming (equally distributed among the Anticline, Aeolus and Windstar busses) and 3,000 MW of alternative generation in Montana, located at the Townsend bus (between Broadview and Garrison busses).

3,000 MW in Wyoming, 3,000 MW in Montana – Case Development

Case development for Scenario 2 began with the Core Case from each study hour. Generation resources were added to the Core Case for each study hour to develop five power flow cases for Scenario 2. Table 6.5 shows the generation resources added to the Core Case used to develop the five study hour cases for Scenario 2.

Table 6-5 – Scenario 2 Generation Resource Additions

Area Name	Bus Name	Generation Addition
MONTANA	TOWNSEND	3000 MW
PACE	WINDSTAR	1000 MW
	AEOLUS	1000 MW
	ANTICLINE	1000 MW
	Total	**3000 MW WY** **3000 MW MT**

A sink was also created for each of the five study hours by removing generation resources in order to offset the total resource addition of 3,000 MW in Wyoming and 3,000 MW in Montana. Table 6.6 shows the generation resources removed from the Core Case used to develop the five study hour cases for Scenario 2. A more detailed table showing the bus locations with changes in generation is provided in Appendix 7.

Table 6-6 - Scenario 2 Generation Resource Reductions

Area Name	Generation Reduction (MW) July 27 Hour 16	Generation Reduction (MW) December 22 Hour 18	Generation Reduction (MW) March 2 Hour 21	Generation Reduction (MW) October 4 Hour 21	Generation Reduction (MW) August 10 Hour 13
SOCALIF	2065	1000	2246	760	2954
SANDEIGO		178		70	272
NORTHWEST	8	12		107	
NEWMEXICO				270	
ARIZONA	1180	942	1947	1263	830
PG&E	2500	2240	2240	2463	436
SIERRA		47			
ALBERTA	129	1019		898	776
NEVADA	118				120
WAPA RM				60	
PACE		102		129	
	6000 MW	**5540 MW**	**6433 MW**	**6020 MW**	**5388 MW**

Once the generation additions and reductions were completed, the power flow case was solved. Additionally, overloads of transmission elements before the addition of generic transmission improvements were identified. Table 6.7 shows the N-0 path flows for Scenario 2 prior to the addition of generic transmission improvements for each study hour analyzed in Scenario 2.

Table 6-7 - Scenario 2 N-0 Path Flows (Pre-Generic Transmission Improvements)

SCENARIO 2	ID-NW (3800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3700) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW
JUL27H16	725	**3179**	**5804**	2600	7366	1737	3071	**1562**	-204
DEC22H18	2041	**3705**	3530	2084	5148	3322	121	578	588
MAR02H21	3351	**2880**	**7647**	2011	4332	1421	72	**2433**	-569
OCT04H21	3882	**4455**	3576	2600	2655	4122	**4028**	**2326**	1328
AUG10H13	-125	**2670**	1277	2600	5115	830	2568	422	-125

Generic transmission improvements that appeared to be adequate solutions to overloads and that were common to the five study hours for Scenario 2 are shown in Figure 6.13.

Transmission improvements in the form of new 500 kV transmission lines (AC solution option) were added to each of the five study hours. The location of the 500 kV transmission improvements are shown in Figure 6.13.

Transmission improvements using DC transmission lines (DC solution option) were tested on the March study hour (maximum spring export). Figure 6.14 shows the location of the DC transmission improvements tested on the March study hour.

Both the AC solution option and DC solution option proved to be adequate solutions for relieving overloads.

Figure 6-13 – Scenario 2 Generic Transmission Improvements (AC Solution Option)

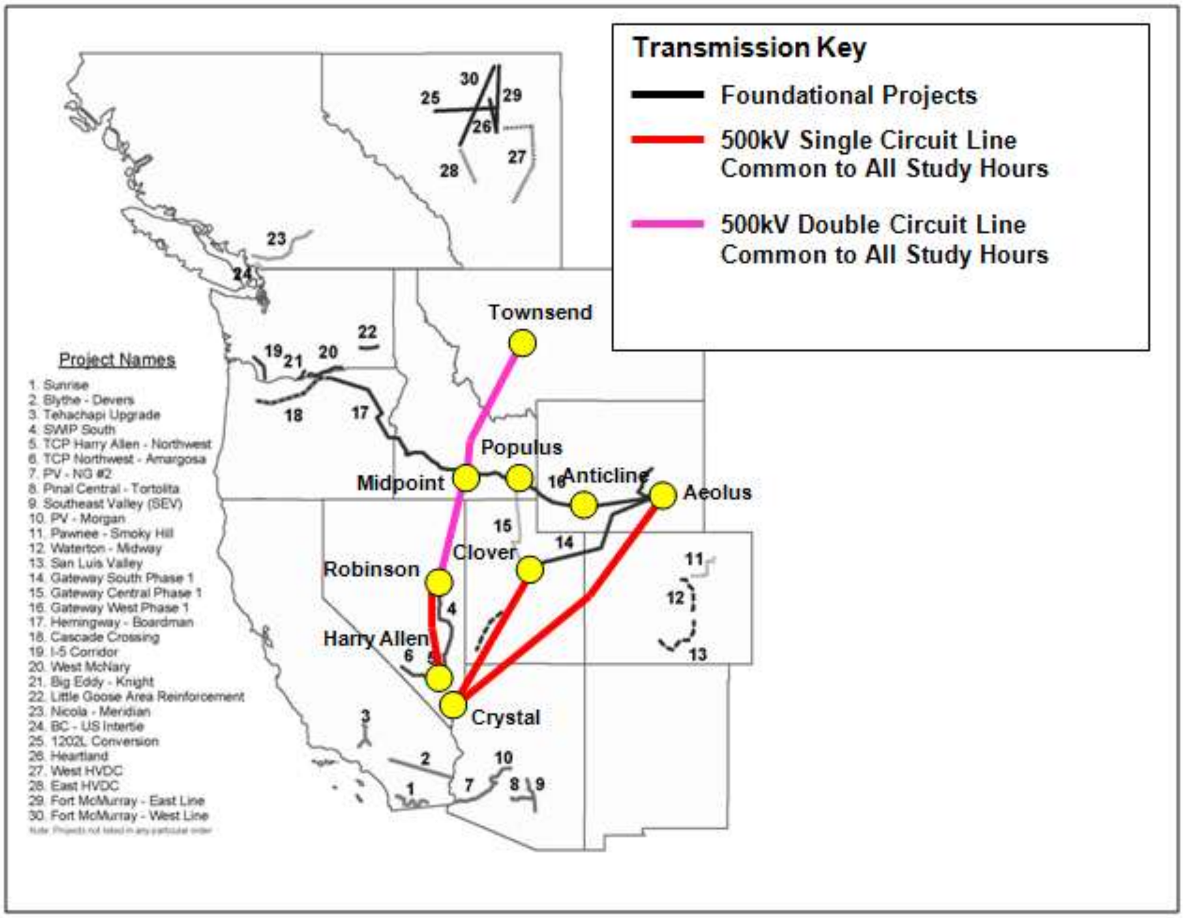
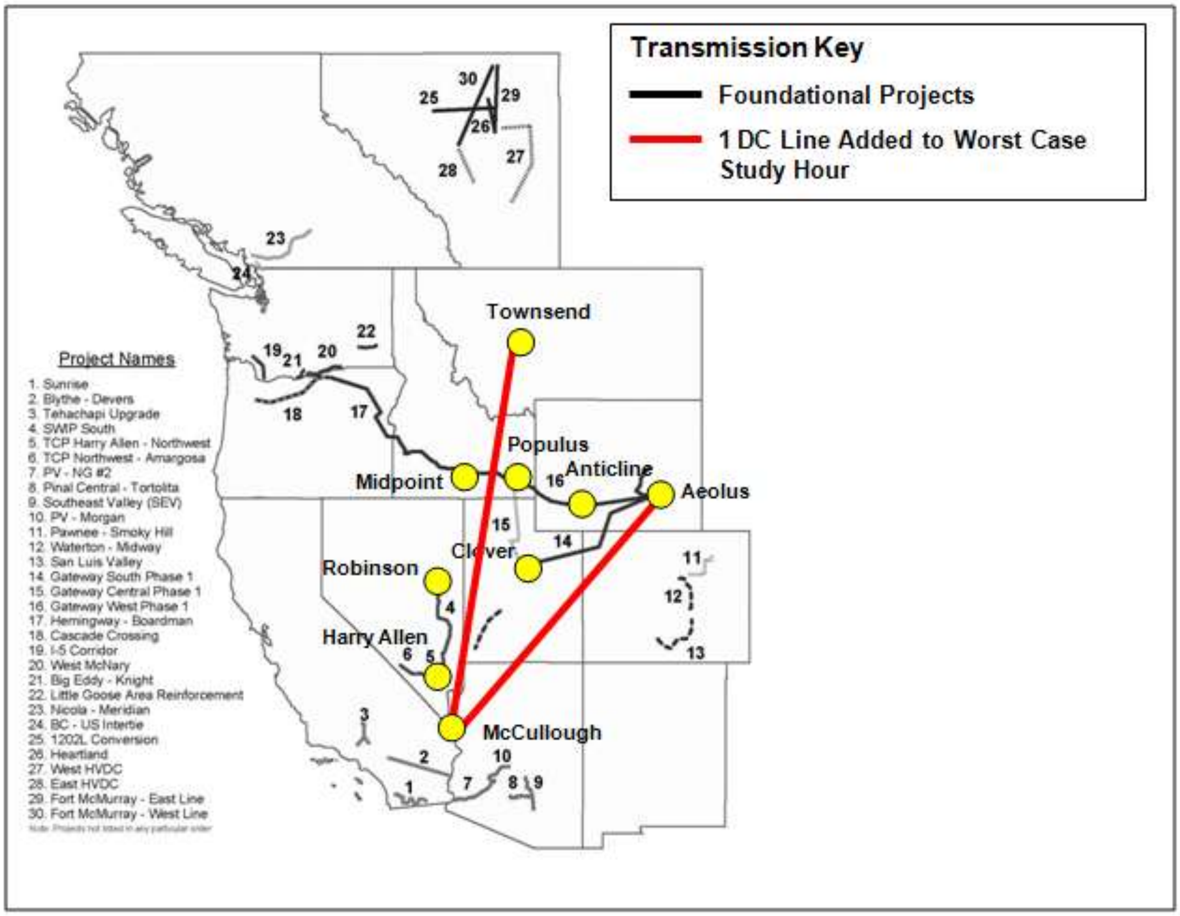


Figure 6-14 – Scenario 2 Generic Transmission Improvements (DC Solution Option)



3,000 MW in Wyoming, 3,000 MW in Montana – Study Results

The study results indicated that the addition of 3,000 MW of generation in Wyoming and 3,000 MW of generation in Montana caused overloaded paths as shown in Table 6.7. Overloaded paths for Scenario 2 that were common between study hours included overloads on Montana-Northwest, COI and TOT2. The overloaded elements identified the need for generic transmission improvements.

The transmission improvements common to all five study hours were: 1.) a double-circuit 500 kV transmission lines between the Townsend and Midpoint and Midpoint-Robinson busses, 2.)a second 500 kV circuit between the Robinson and Harry Allen busses. It should be noted that a 500 kV circuit between the Robinson-Harry Allen busses was already represented in each study hour (based on the

Core Case), 3.) a 500 kV transmission line between the Aeolus and Crystal, and 4.) a 500 kV transmission line between the Clover and Crystal busses.

Post-improvement N-0 path flows are shown in Table 6.8. The study results indicate that the proposed transmission improvements resolved the majority of the overloads shown in Table 6.7. Minor overloads were recorded in the Montana-Northwest path of 101% on a 2,200 MW rating for the December study hour. The March study hour also had a minor overload of 101.6% on a 4,800 MW rating for COI.

N-1 contingency analysis for each study hour in Scenario 2 indicated that the majority of the 420 contingencies solved for each study hour. There were two study hours that had unsolved contingencies: March with four and October with one.

A DC solution option was also tested on the March study hour. DC lines between Aeolus-McCullough and Townsend-McCullough were added to the case. The study results indicate that the DC solution option appears as an adequate solution alternative. One post-improvement overload on COI (105%) was identified with the DC solution option. This overload may be mitigated by adjusting the flow on the PDCI.

In this Scenario, the AC and DC transmission line improvements described above could be combined to create another solution option to resolve the transmission overloads identified. An example would be a DC transmission line from either Montana or Wyoming with the other state having an AC transmission line solution. Such cases were not contemplated during the creation of the study plan and not included during this study cycle.

There were 27 N-0 branch element overloads and one N-0 interface overload (COI at 103.6%) reported in the DC solution option case for the March study hour. Overloads on branch elements ranged from 100.1% to 192%. The majority of the overloaded branch elements were transformers on radial connected loads. There were 10 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

N-1 contingency analysis for the DC solution option reported 102 violations, with three unsolved contingencies. The three unsolved contingencies were BOARDT2-DALREED, JONESCYN-DALREED and HELLSCYN-BROWNLEEC1. Of the 102 violations, 69 were elements overloaded above the 100% rating, with 48 of those overloaded by more than 115%. The remaining 33 violations resulted from voltage violations, with one low bus voltage violation and 32 high bus voltage violations.

The sum of the N-1 violations for all the study hours in Scenario 2 was 275 violations. The majority of overloaded elements for all the study hours were transformer overloads for N-1 conditions. The most common N-1 violation for all study hours was high bus voltage, most commonly reported at dummy busses near 500 kV series capacitors.

N-0 and N-1 violations discussed in this report are violations on elements 200 kV and above within the NTTG footprint. N-0 and N-1 violation tables for each study hour within this scenario are provided in Appendix 8.

Table 6-8 – Scenario 2 N-0 Path Flows (Post-Generic Transmission Improvements)

SCENARIO 2	ID-NW (3800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3700) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW	DBL CKT 500kV Townsend-Midpoint (3000) MW	DBL CKT 500kV Midpoint-Robinson (3000) MW	DBL CKT 500kV Robinson-Harry Allen (3000) MW	SGL CKT 500kV Aeolus-Crystal (1500) MW	SGL CKT 500kV Clover-Crystal (1500) MW	2 DC Lines Townsend-McCullough & Aeolus-McCullough (6000) MW
JUL27H16	1382	727	4030	2600	5169	686	2390	704	-506	**3101**	1634	1676	907	825	NA
DEC22H18	1904	**2223**	2903	2251	3909	985	1127	241	308	1980	388	235	428	471	NA
MAR02H21 (AC Option)	1927	1730	**4876**	2760	2874	1365	534	1835	-291	2909	**3175**	2848	1453	1427	NA
MAR02H21 (DC Option)	2017	1877	**4975**	2788	2993	1364	832	1886	-40	NA	NA	54 SGL CKT	NA	NA	6000
OCT04H21	3798	2068	1328	2393	548	2922	3334	983	922	2740	1877	2009	1182	**1517**	NA
AUG10H13	1213	1028	881	2600	3765	641	2752	392	-702	2184	662	557	597	140	NA

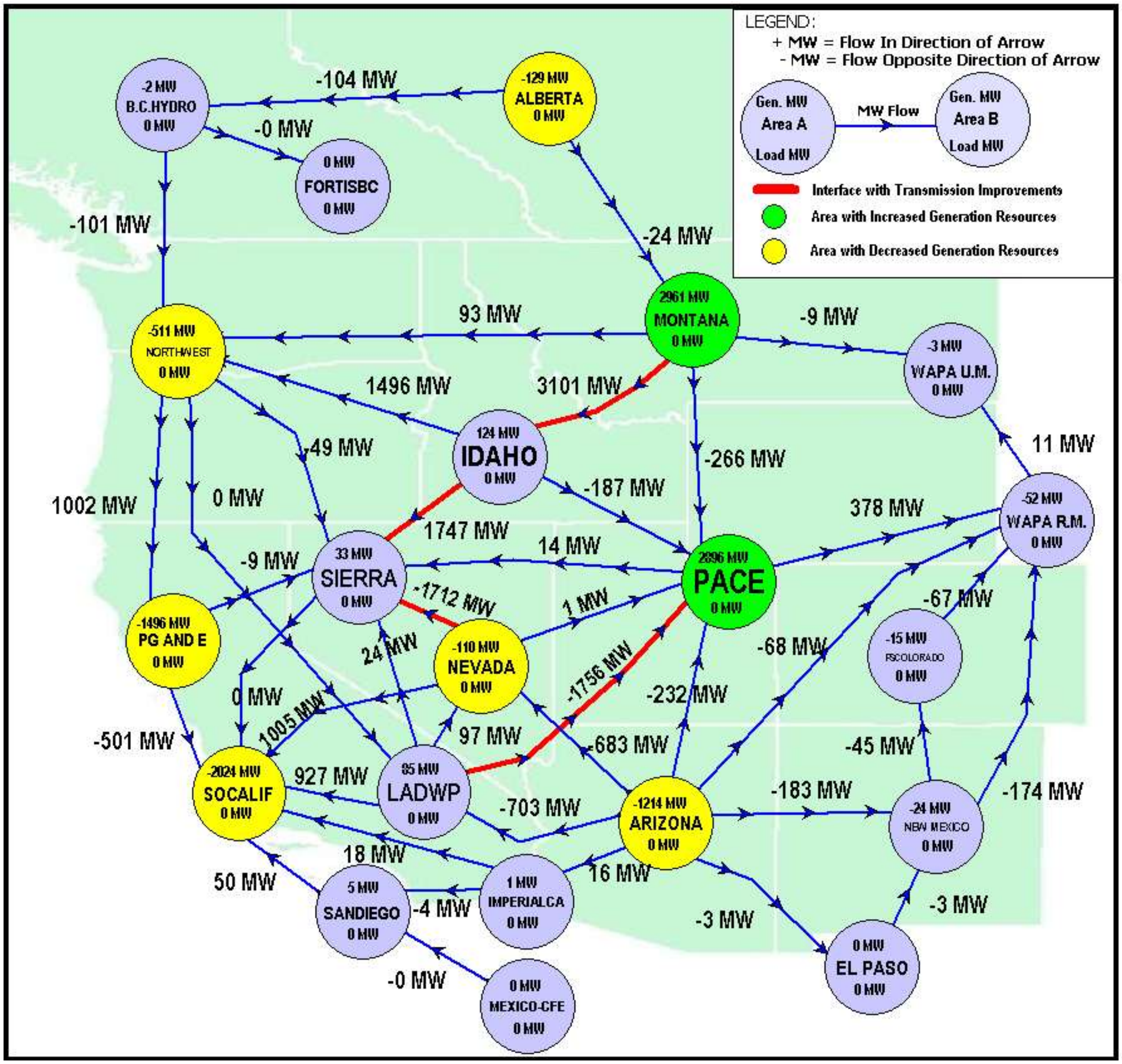
2.1: 3,000 MW in Wyoming, 3,000 MW in Montana – Summer Peak – July 27, Hour 16

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 21 overloaded branch elements, ranging from 102.3% to 160% of the nominal rating, all of which were transformers. There were 12 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 19 violations with zero unsolved contingencies. Of the 19 violations, five were for overloaded elements, with a maximum overload of 137%. There were two violations for low bus voltage and 12 violations for high bus voltage.

A difference flow diagram is shown in Figure 6.15. MW values shown on the difference diagram represent the MW change as referenced to the study hour Core Case. Additional area interchange diagrams are located in Appendix 5.

Figure 6-15 – Scenario 2 Difference Flows: JUL27H16



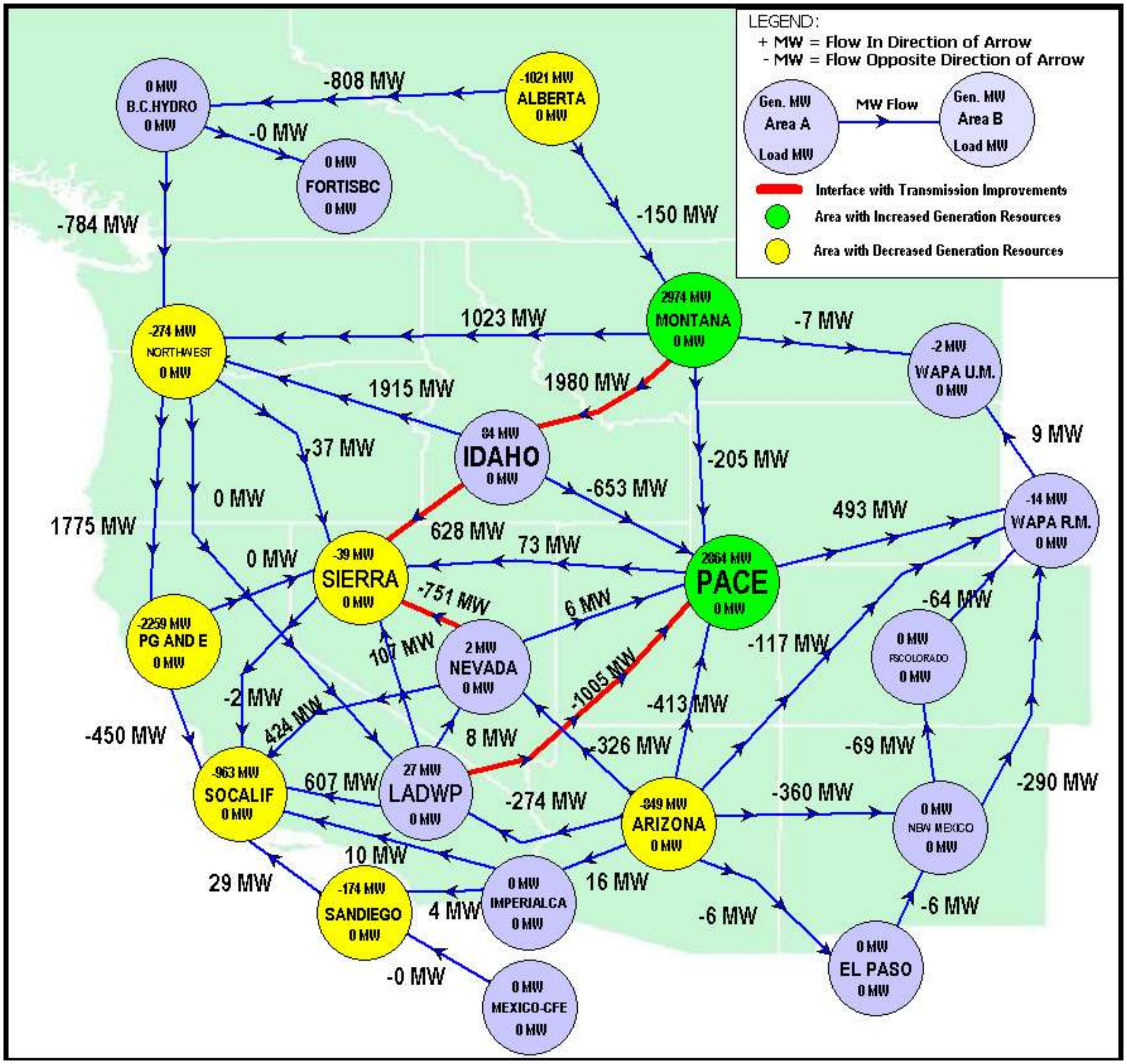
2.2: 3,000 MW in Wyoming, 3,000 MW in Montana – Winter Peak – December 22, Hour 18

After the addition of the generic transmission improvements, two N-0 interface violations were found within the NTTG footprint: Montana-Northwest at 101% and Midpoint-Summer Lake at 110.3%. Pre-contingency, this study hour uncovered 17 overloaded branch elements, ranging from 104.6% to 145% of the nominal rating. Of the 17 overloaded branch elements, 16 were transformers and one was an overloaded series capacitor. There were 18 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 45 violations, with zero unsolved contingencies. Of the 45 violations, 19 were overloaded elements with a range of 100.2% to 143%. There were two violations for low bus voltage and 24 violations for high bus voltage violations.

A difference flow diagram is shown in Figure 6.16. MW values shown on the difference diagram represent the MW change as referenced to the study hour Core Case. Additional area interchange diagrams are located in Appendix 5.

Figure 6-16 – Scenario 2 Difference Flows: DEC22H18



2.3: 3,000 MW in Wyoming, 3,000 MW in Montana – Heavy Spring Export – March 2, Hour 21

After the addition of the generic transmission improvements, one N-0 interface violation was found within the NTTG footprint: COI at 102%. Pre-contingency, this study hour revealed 26 overloaded branch elements ranging from 101.3% to 186% of the nominal rating for the AC solution option study case. The 26 overloaded elements comprised three series capacitors, five lines and 18 transformers. There were 12 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 102 violations with four unsolved contingencies. The four unsolved contingencies were BOARDT2-DALREED, JONESCYN-DALREED, WALAWALLA-WALLULA and HELLSCYN-BROWNLEE. Of the 102 violations, 50 violations were elements overloaded above the 100% rating. The extreme overload value for N-1 conditions was 224%. There were two low bus voltage violations and 50 high bus voltage violations.

For the DC solution option, one N-0 interface violation was found within the NTTG footprint: COI at 103.6%. Pre-contingency, this study hour was found to have 27 overloaded branch elements ranging from 101.3% to 192% of the nominal rating for the DC solution option study case. The extreme value was most likely a data error in the MVA rating of the overloaded element. The majority of the branch overloads were transformers, with a few series capacitors. There were 10 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A difference flow diagram for the AC solution option as referenced to the Core Case is shown in Figure 6.17. MW values shown on the difference diagram represent the MW change between the two power flow cases. The difference diagram for the DC solution as referenced to the Core Case is shown in Figure 6.18. Figure 6.19 is a comparison plot of the DC solution option referenced to the AC solution option. Additional area interchange diagrams are located in Appendix 5.

Figure 6-17 – Scenario 2 Difference Flows: MAR04H21 (AC Solution)

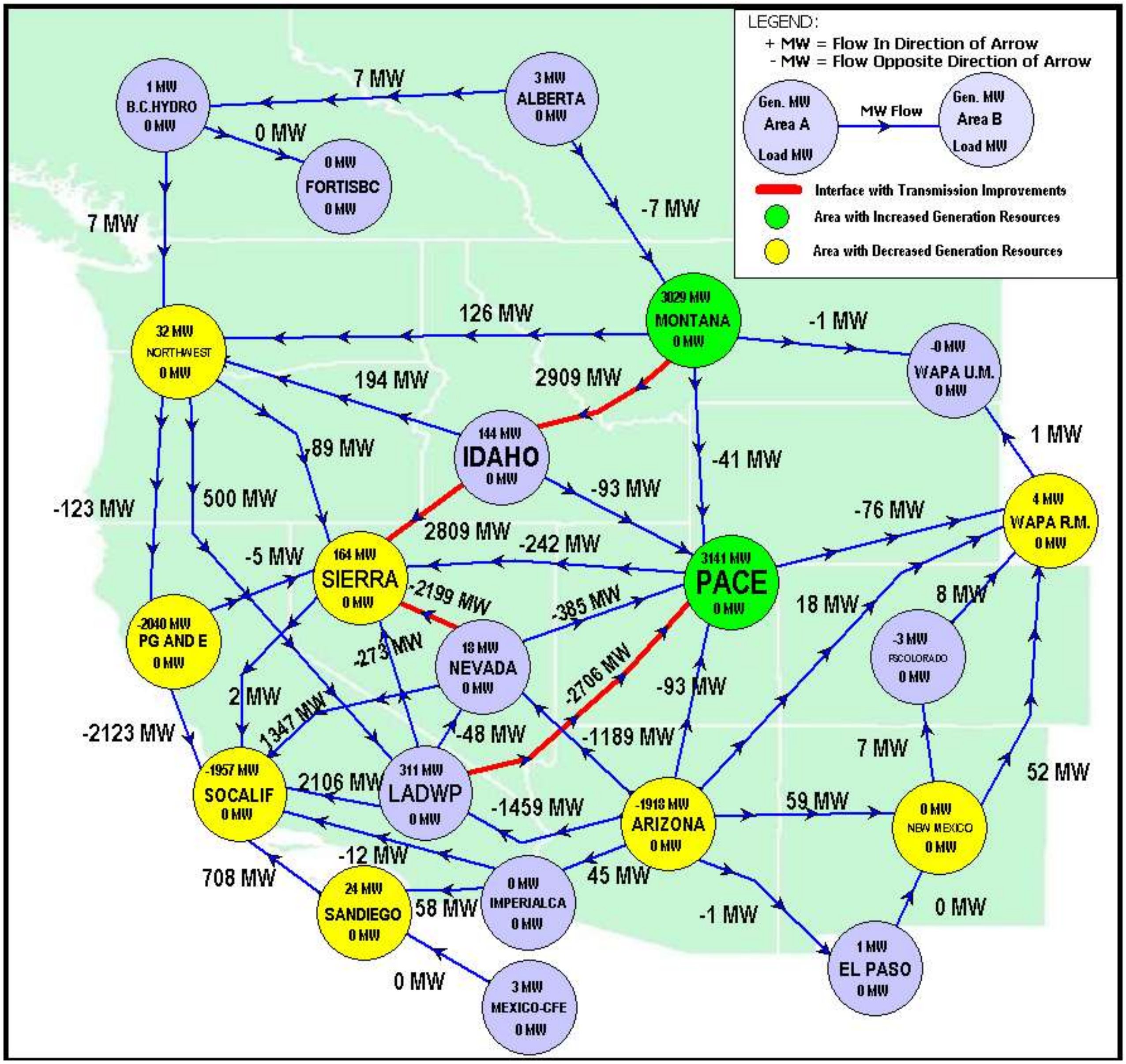

LEGEND:
+ MW = Flow In Direction of Arrow
- MW = Flow Opposite Direction of Arrow
Gen. MW Area A Load MW
MW Flow
Gen. MW Area B Load MW
Interface with Transmission Improvements
Area with Increased Generation Resources
Area with Decreased Generation Resources
1 MW B.C.HYDRO 0 MW
3 MW ALBERTA 0 MW
0 MW FORTISBC 0 MW
32 MW NORTHWEST 0 MW
3029 MW MONTANA 0 MW
-0 MW WAPA U.M. 0 MW
144 MW IDAHO 0 MW
4 MW WAPA R.M. 0 MW
164 MW SIERRA 0 MW
3141 MW PACE 0 MW
-2040 MW PG AND E 0 MW
18 MW NEVADA 0 MW
-3 MW PSCOLORADO 0 MW
-1957 MW SOCALIF 0 MW
311 MW LADWP 0 MW
-1918 MW ARIZONA 0 MW
0 MW NEW MEXICO 0 MW
24 MW SANDIEGO 0 MW
0 MW IMPERIALCA 0 MW
1 MW EL PASO 0 MW
3 MW MEXICO-CFE 0 MW
7 MW
0 MW
7 MW
-7 MW
126 MW
-1 MW
194 MW
2909 MW
89 MW
1 MW
-41 MW
-123 MW
500 MW
-93 MW
-76 MW
2809 MW
-242 MW
-5 MW
-2199 MW
-385 MW
18 MW
8 MW
-273 MW
2706 MW
2 MW
-93 MW
1347 MW
-2123 MW
-48 MW
-1189 MW
7 MW
52 MW
2106 MW
-1459 MW
59 MW
-12 MW
708 MW
45 MW
58 MW
-1 MW
0 MW
0 MW

Figure 6-18 – Scenario 2 Difference Flows: MAR04H21 (DC Solution)

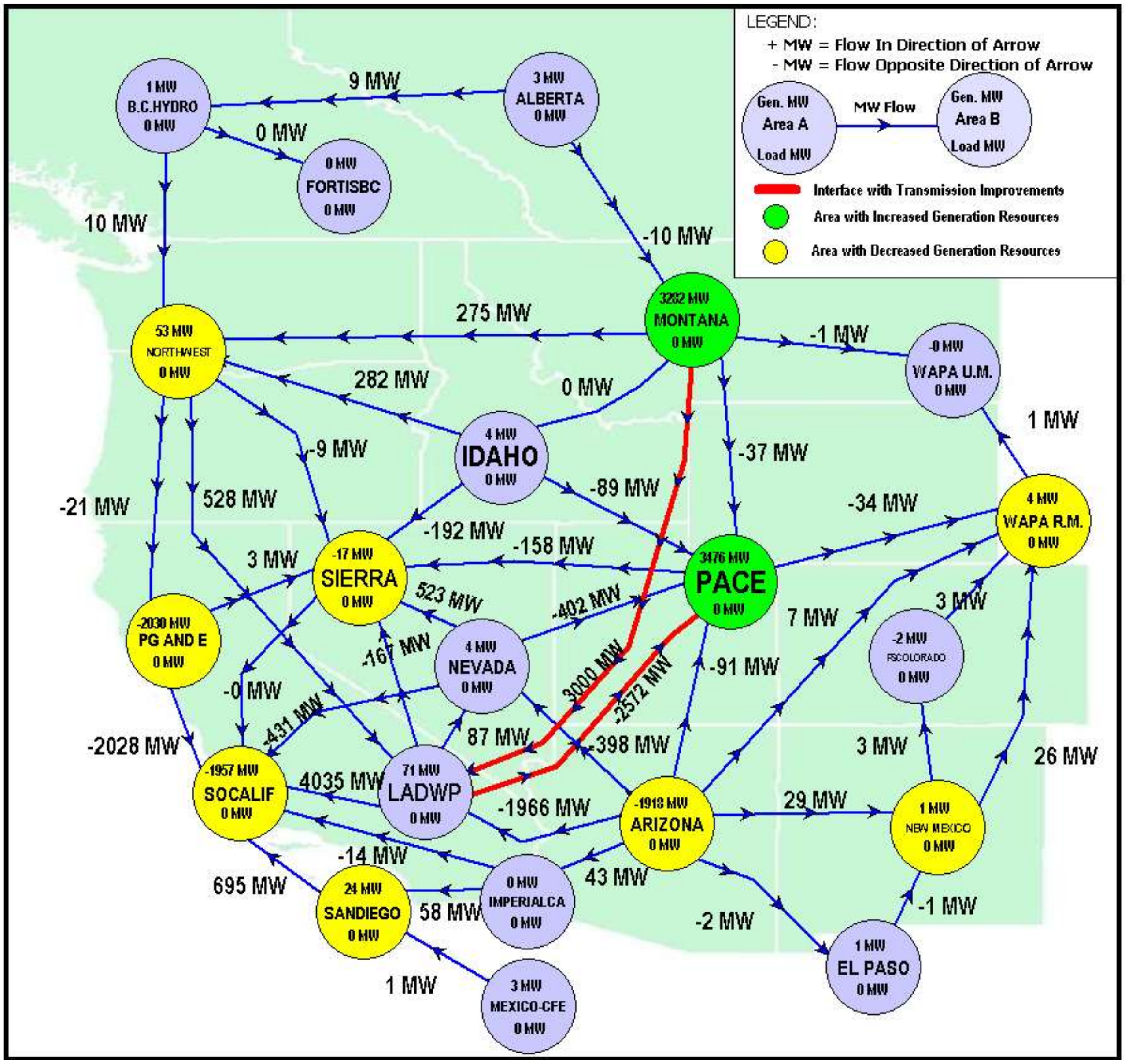
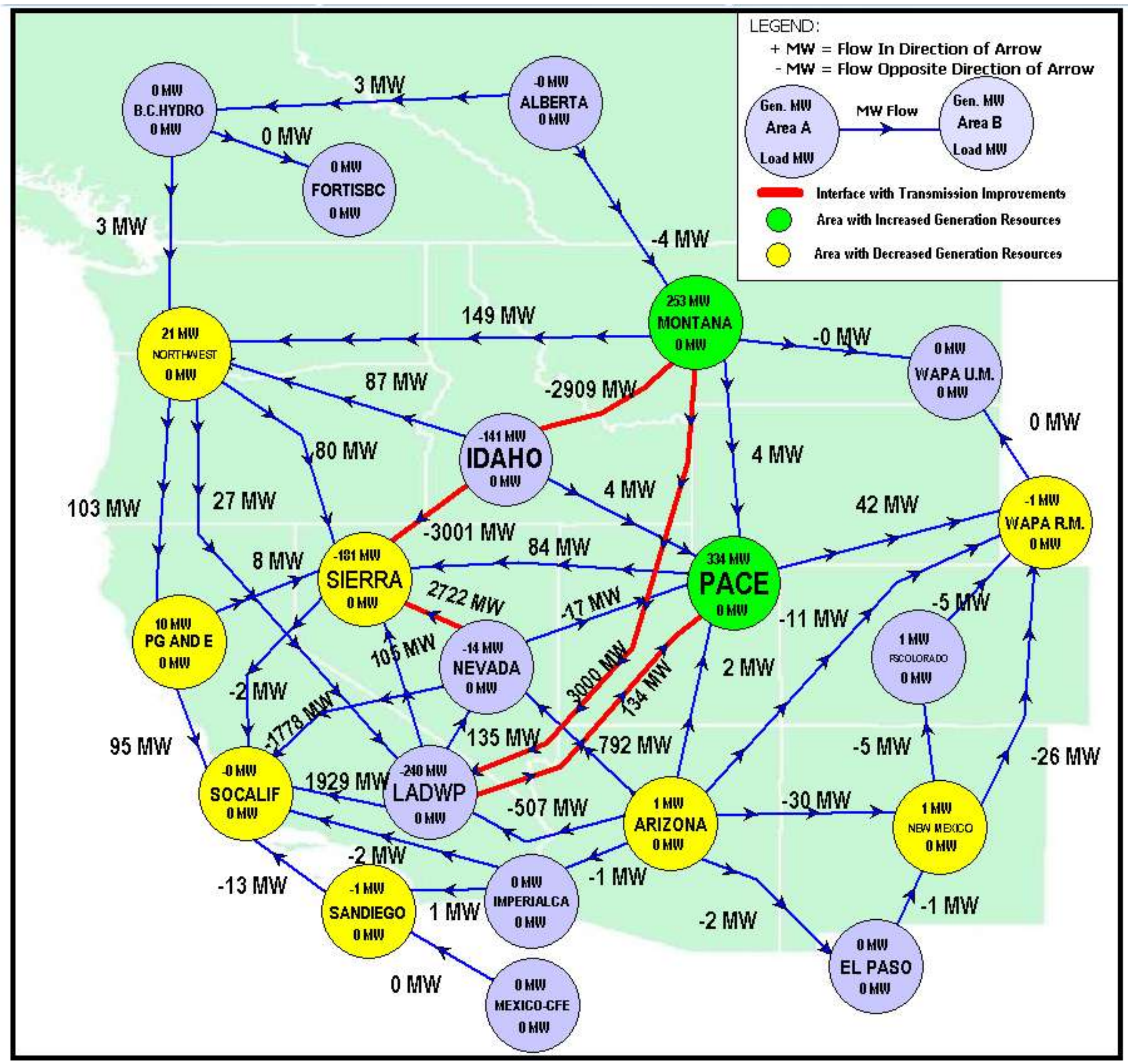


Figure 6-19 – Scenario 2 Difference Flows: MAR04H21 (AC Solution vs. DC Solution)



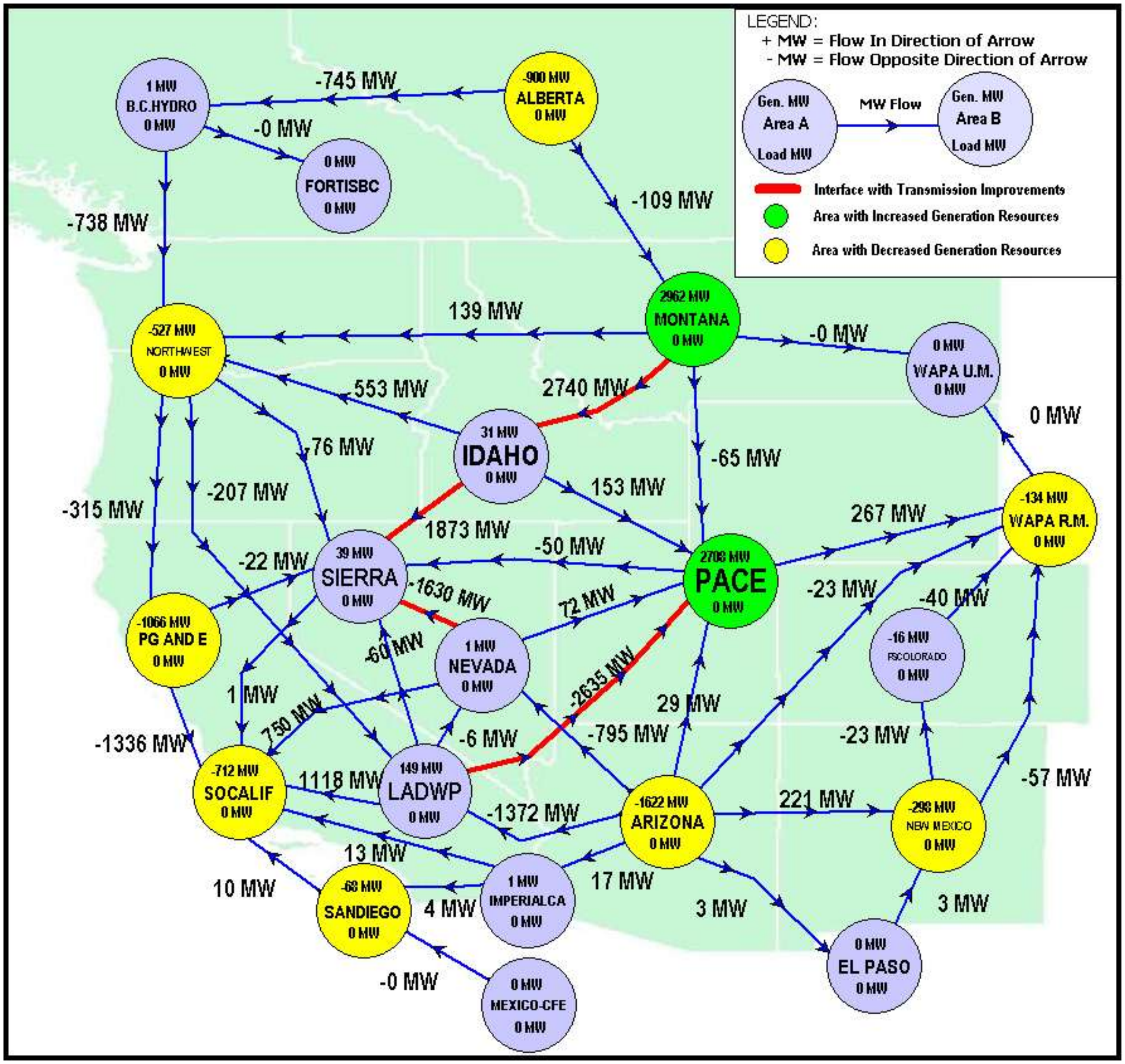
2.4: 3,000 MW in Wyoming, 3,000 MW in Montana – Heavy Autumn Export – October 4, Hour 21

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Idaho-Northwest was operating at 99.95% in the case, with Montana-Northwest at 94%. Pre-contingency, this study hour was found to have 20 overloaded branch elements ranging from 100.4% to 127% of the nominal rating. The 20 overloaded elements comprised one line, one series capacitor and 18 transformers. There were 26 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 80 violations, with one unsolved contingency. The unsolved contingency was BOARDT2-DALREED. Of the 80 violations, 23 resulted in elements overloaded above the 100% rating. The maximum overload was 165% of the continuous rating. The remaining 57 violations resulted from elements with a bus voltage greater than the 1.1 p.u.

A difference flow diagram is shown in Figure 6.20. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-20 – Scenario 2 Difference Flows: OCT04H21



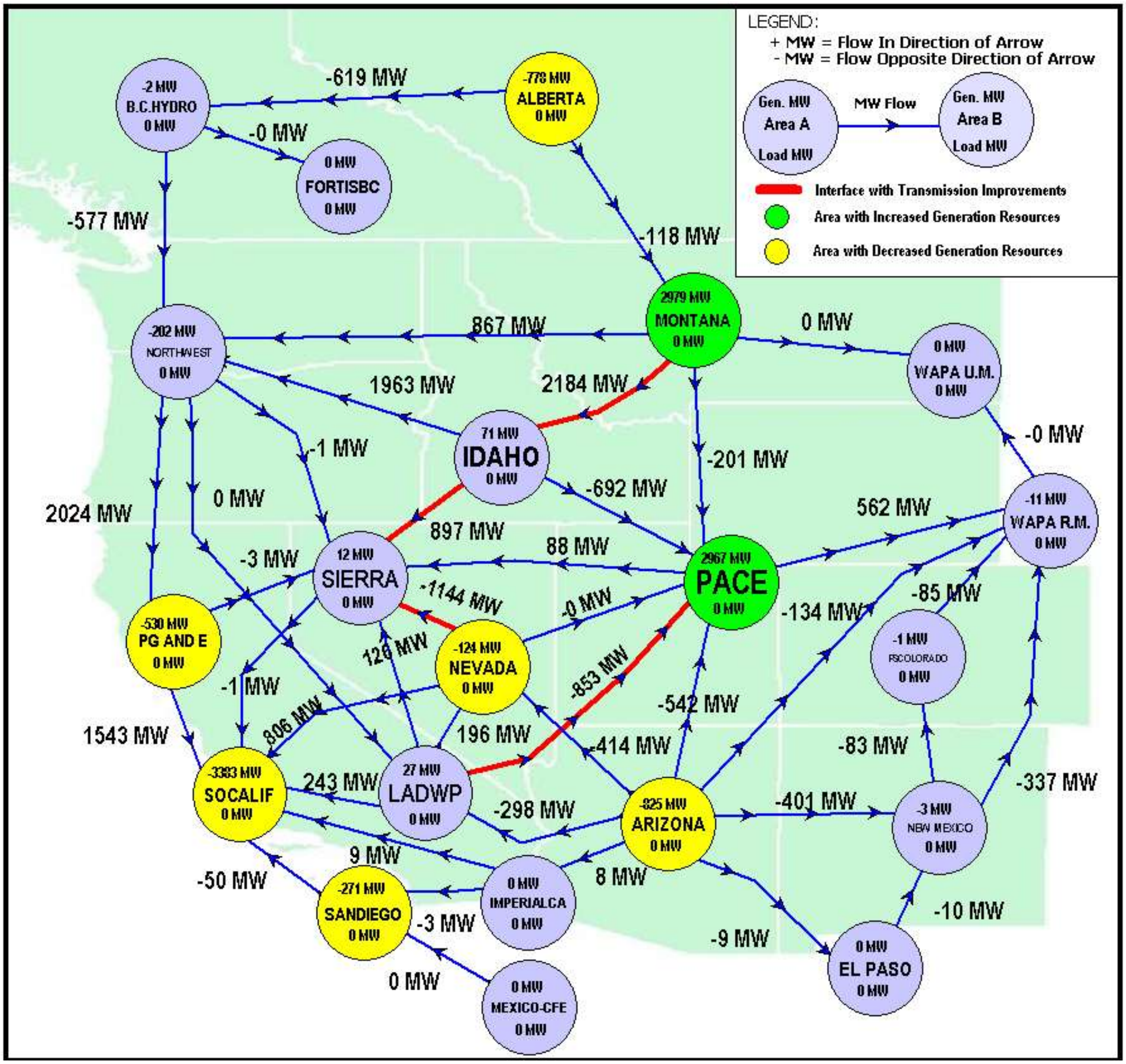
2.5: 3,000 MW in Wyoming, 3,000 MW in Montana – Maximum Import – August 10, Hour 13

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 16 overloaded branch elements ranging from 101.2% to 150% of the nominal rating. All N-0 overloaded elements were transformers. The extreme value of 362% appeared to be a data error in the transformer rating. There were 17 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 29 violations with zero unsolved contingencies. Of the 29 violations, seven were overloaded elements. The maximum overload was 135% of the continuous rating. The remaining violations were 21 high bus voltage violations and one low bus voltage violation.

A difference flow diagram is shown in Figure 6.21. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-21 – Scenario 2 Difference Flows: AUG13H13



3.0: Scenario 3 – 3,000 MW in Montana

The scenario intends to represent the effect of an additional 3,000 MW of alternative generation in Montana, equivalently located at the Townsend bus (between the Broadview and Garrison busses).

3,000 MW in Montana – Case Development

Case development for Scenario 3 began with the Core Case from each study hour. Generation resources were added to the Core Case for each study hour to develop five power flow cases for Scenario 3. Table 6.9 shows the generation resources added to the Core Case used to develop the five study hour cases for Scenario 3.

Table 6-9 – Scenario 3 Generation Resource Additions

Area Name	Bus Name	Generation Addition
MONTANA	TOWNSEND	3000 MW
	Total	**3000 MW**

A sink was also created for each of the five study hours by removing generation resources in order to offset the 3,000 MW resource addition. Table 6.10 shows the generation resources removed from the Core Case used to develop the five study hour cases for Scenario 3.

Table 6-10 – Scenario 3 Generation Resource Reductions

Area Name	Generation Reduction (MW) July 27 Hour 16	Generation Reduction (MW) December 22 Hour 18	Generation Reduction (MW) March 2 Hour 21	Generation Reduction (MW) October 4 Hour 21	Generation Reduction (MW) August 10 Hour 13
SOCALIF	1168	550	914	760	1695
SANDEIGO		178	451	70	
NORTHWEST	8	12	274	107	
NEWMEXICO			289	270	
ARIZONA	520		776	213	295
PG&E	1300	864	248	495	436
SIERRA		47	47		
ALBERTA		1019		898	776
WAPA RM			45	60	
PACE		102	182	129	
BC HYDRO			539		

	2996 MW	**2772 MW**	**3765 MW**	**3002 MW**	**3202 MW**

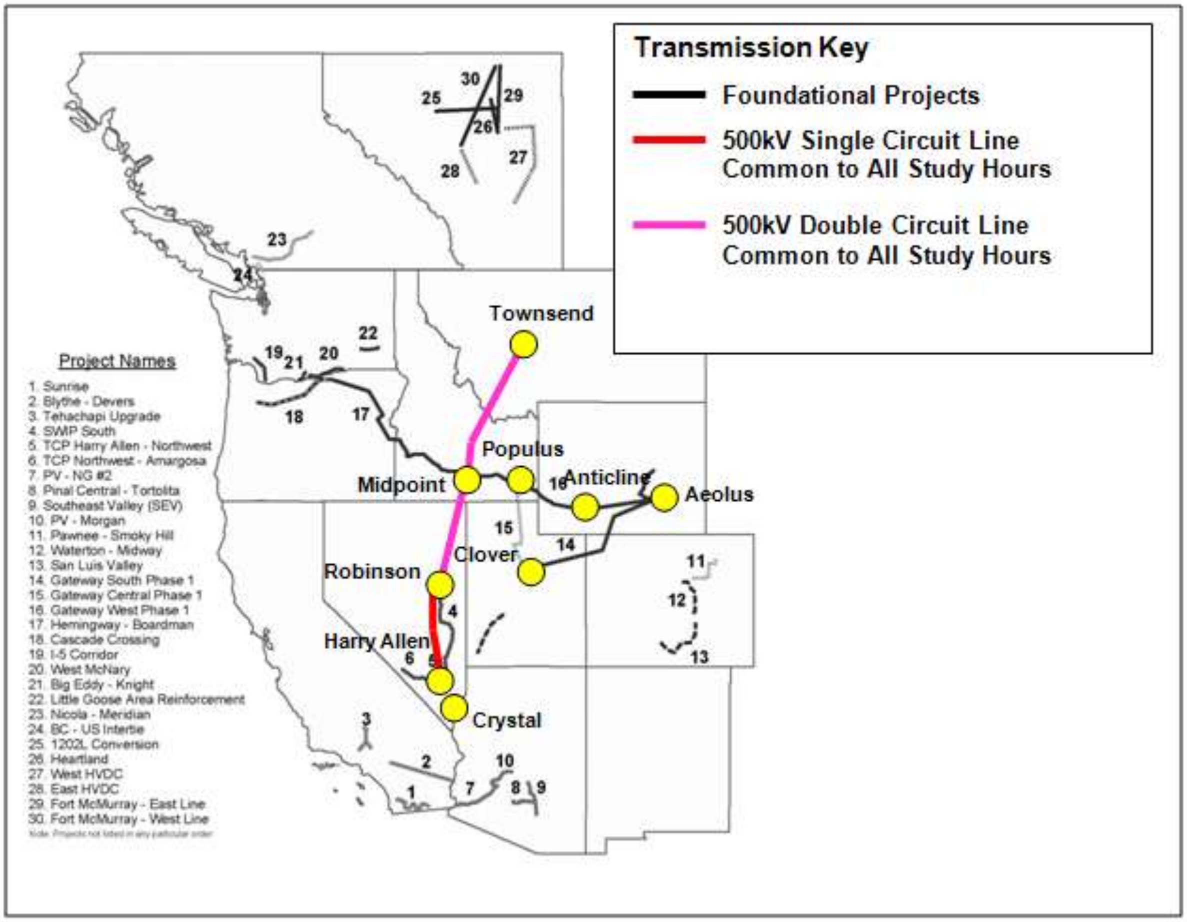
Once the generation additions and reductions were completed, the power flow case was solved. Additionally, the study identified overloads of transmission elements before the addition of generic transmission improvements. Table 6.11 shows the N-0 path flows for Scenario 3 prior to the addition of generic transmission improvements for each study hour analyzed in Scenario 3.

Table 6-11 – Scenario 3 N-0 Path Flows (Pre-Generic Transmission Improvements)

SCENARIO 3	ID-NW (3800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3700) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW
JUL27H16	-458	**2940**	4667	2600	7200	339	1551	691	-408
DEC22H18	824	**3431**	2179	2133	4877	1331	1196	289	322
MAR02H21	1442	**3862**	**6618**	2946	5053	1384	1102	**1981**	-160
OCT04H21	2953	**4300**	2652	2600	2477	2884	2537	1307	1137
AUG10H13	-919	**2458**	300	2600	4903	-86	1681	423	-756

Generic Transmission improvements that proved to be adequate solutions to overloads and that were common to the five study hours for Scenario 3 are shown in Figure 6.22.

Figure 6-22 – Scenario 3 Generic Transmission Improvements



3,000 MW in Montana – Study Results

The study results indicated that the addition of 3,000 MW of generation in Montana resulted in overloaded paths as shown in Table 6.11. Overloaded paths for Scenario 3 common between study hours were overloads on Montana-Northwest. The overloaded elements identified the need for generic transmission improvements.

Double-circuit 500 kV transmission lines were added between the Townsend-Midpoint and Midpoint-Robinson busses. A second 500 kV circuit was added in parallel to the Robinson-Harry Allen transmission line.

The N-0 path flows shown in Table 6.12 indicate that the proposed generic transmission improvements resolved the majority of the overloads shown in Table 6.11. One N-0 overload was recorded for the March study hour on COI, operating at 106.7% on a 4,800 MW rating.

N-1 contingency analysis for each study hour in Scenario 3 indicated that the majority of the 420 contingencies solved for each study hour. There were two study hours with unsolved contingencies; March with two and October with one.

The sum of the N-1 violations for all the study hours in Scenario 3 was 242 violations. The majority of overloaded elements for all the study hours were transformer overloads for N-1 conditions. The most common N-1 violation for all study hours was high bus voltage.

N-0 and N-1 violations discussed in this report are violations on elements 200 kV and above within the NTTG footprint. N-0 and N-1 violation tables for each study hour within this scenario are provided in Appendix 8.

A DC transmission solution originating in Montana as described in Scenarios 1 and 2 above would likely resolve the transmission overloads created by the increased Montana generation in this Scenario.

Table 6-12 – Scenario 3 N-0 Path Flows (Post-Generic Transmission Improvements)

SCENARIO 3	ID-NW (3800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3700) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW	DBL CKT 500kV Townsend-Midpoint (3000) MW	DBL CKT 500kV Midpoint-Robinson (3000) MW	DBL CKT 500kV Robinson-Harry Allen (3000) MW
JUL27H16	1089	522	3763	2600	5158	-66	1377	547	-480	**3178**	1290	1338
DEC22H18	2360	1907	2128	2288	3675	419	1296	169	-8	2102	-193	-417
MAR02H21 (AC Option)	2024	1684	**5125**	2946	3084	2311	989	1002	448	2956	**3606**	**3484**
OCT04H21	3759	2087	1470	2339	655	2787	2594	1097	1282	2722	1961	2176
AUG10H13	737	772	196	2600	3554	-793	1405	367	-1019	2272	179	419

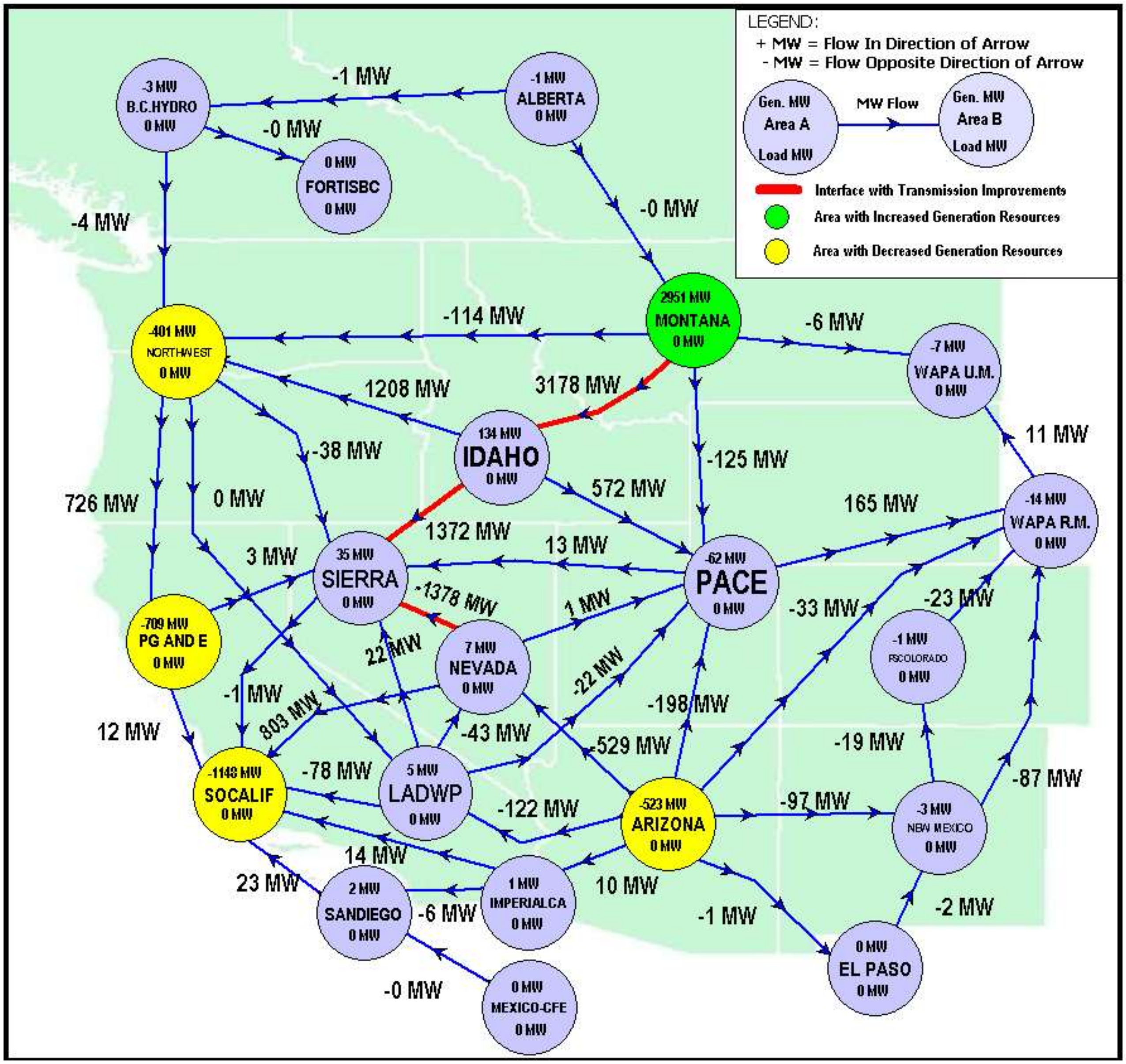
3.1: 3,000 MW in Montana – Summer Peak – July 27, Hour 16

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 18 overloaded branch elements, ranging from 104% to 166% of the nominal rating. All N-0 overloaded branch elements were transformers. There were 16 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 21 violations, with zero unsolved contingencies. Of the 21 violations, 10 were for overloaded elements. The extreme overload was 142% of the continuous rating. The remaining 11 violations resulted from elements with a bus voltage greater than 1.1 p.u.

A difference flow diagram is shown in Figure 6.23. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-23 – Scenario 3 Difference Flows: JUL27H16



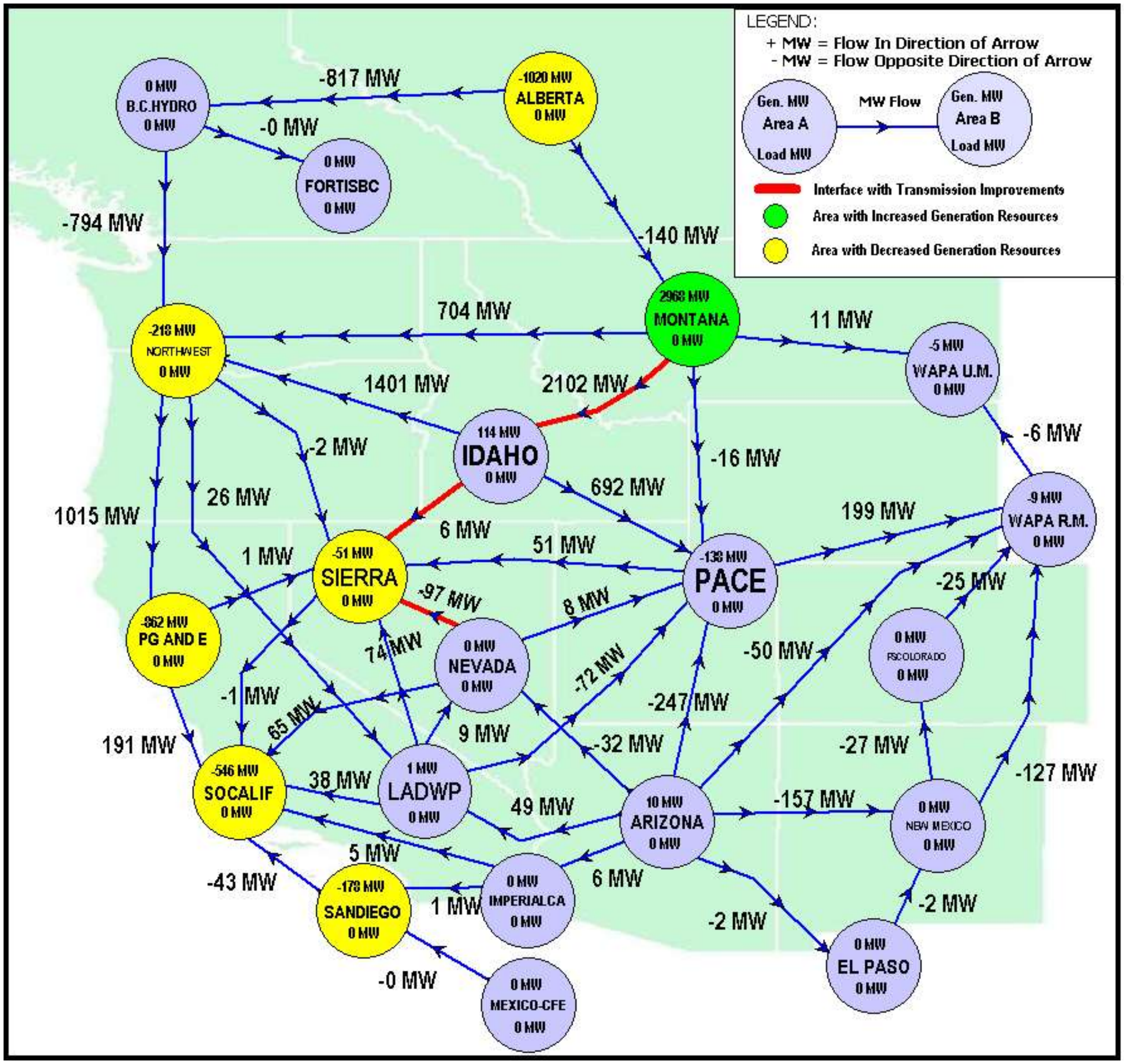
3.2: 3,000 MW in Montana – Winter Peak – December 22, Hour 18

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 15 overloaded branch elements – all transformers – ranging from 107.3% to 145% of the nominal rating. There were 41 busses in the case with a voltage magnitude greater than the 1.1pu pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 28 violations, with zero unsolved contingencies. Of the 28 violations, nine were overloaded elements. The maximum overload was 111% of path rating. There was one low bus voltage violation and 18 high bus voltage violations.

A difference flow diagram is shown in Figure 6.24. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-24 – Scenario 3 Difference Flows: DEC22H18



3.3: 3,000 MW in Montana – Heavy Spring Export – March 2, Hour 21

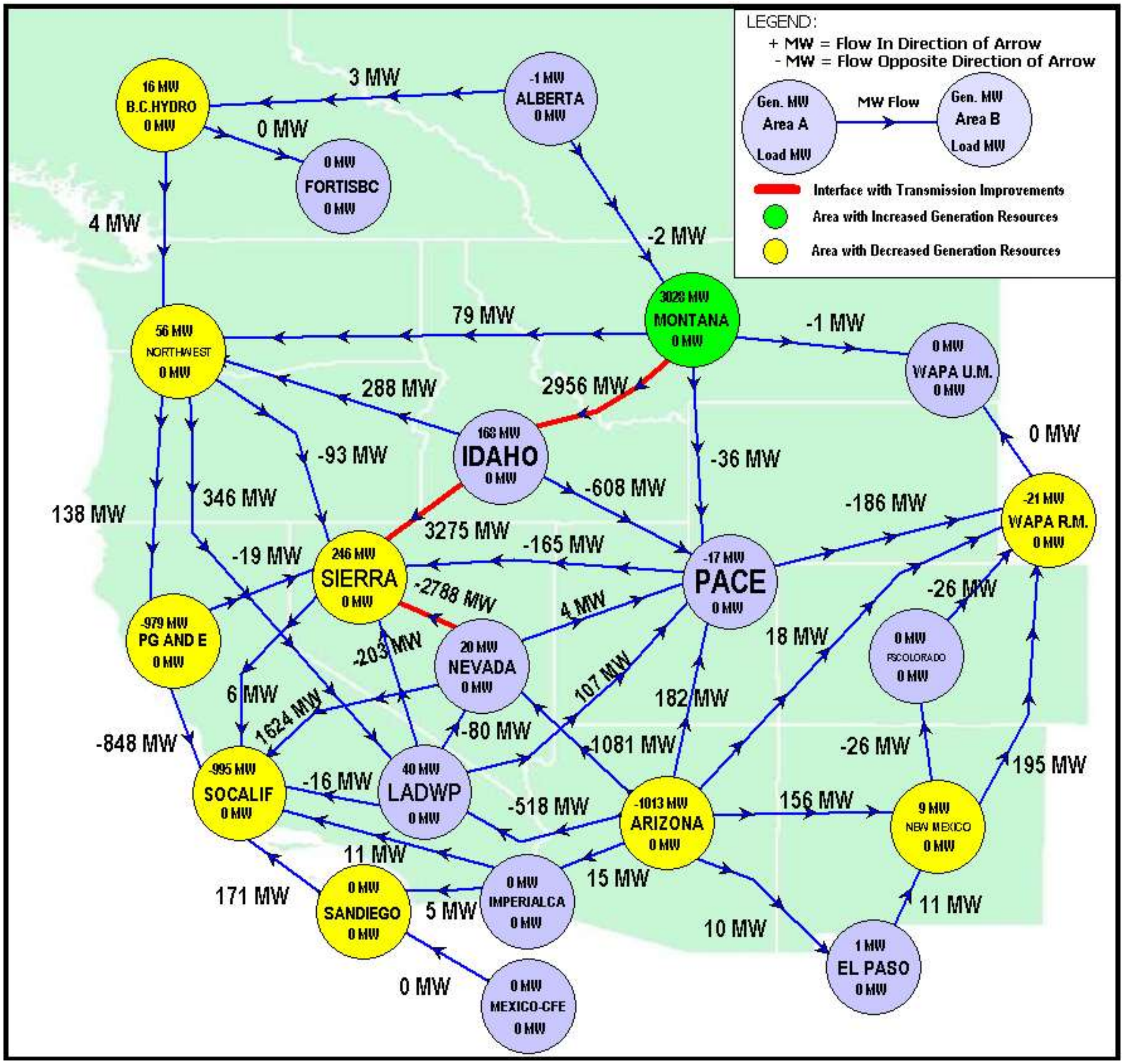
After the addition of the generic transmission improvements, one N-0 interface violations was found within the NTTG footprint: COI operating at 107%. Pre-contingency, this study hour was found to have

25 overloaded branch elements ranging from 103.5% to 174% of the nominal rating. The N-0 overloaded elements comprised three lines, three series capacitors and 19 transformers. There were 12 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 77 violations, with two unsolved contingencies. The two unsolved contingencies were BOARDT2-DALREED and JONESCYN-DALREED. Of the 77 violations, 11 were elements overloaded above the 100% rating. Of those 11, six were overloaded greater than 115%. The maximum overload was 224%. There were 65 violations for high bus voltage and one violation for low bus voltage.

A difference flow diagram is shown in Figure 6.25. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-25 – Scenario 3 Difference Flows: MAR02H21



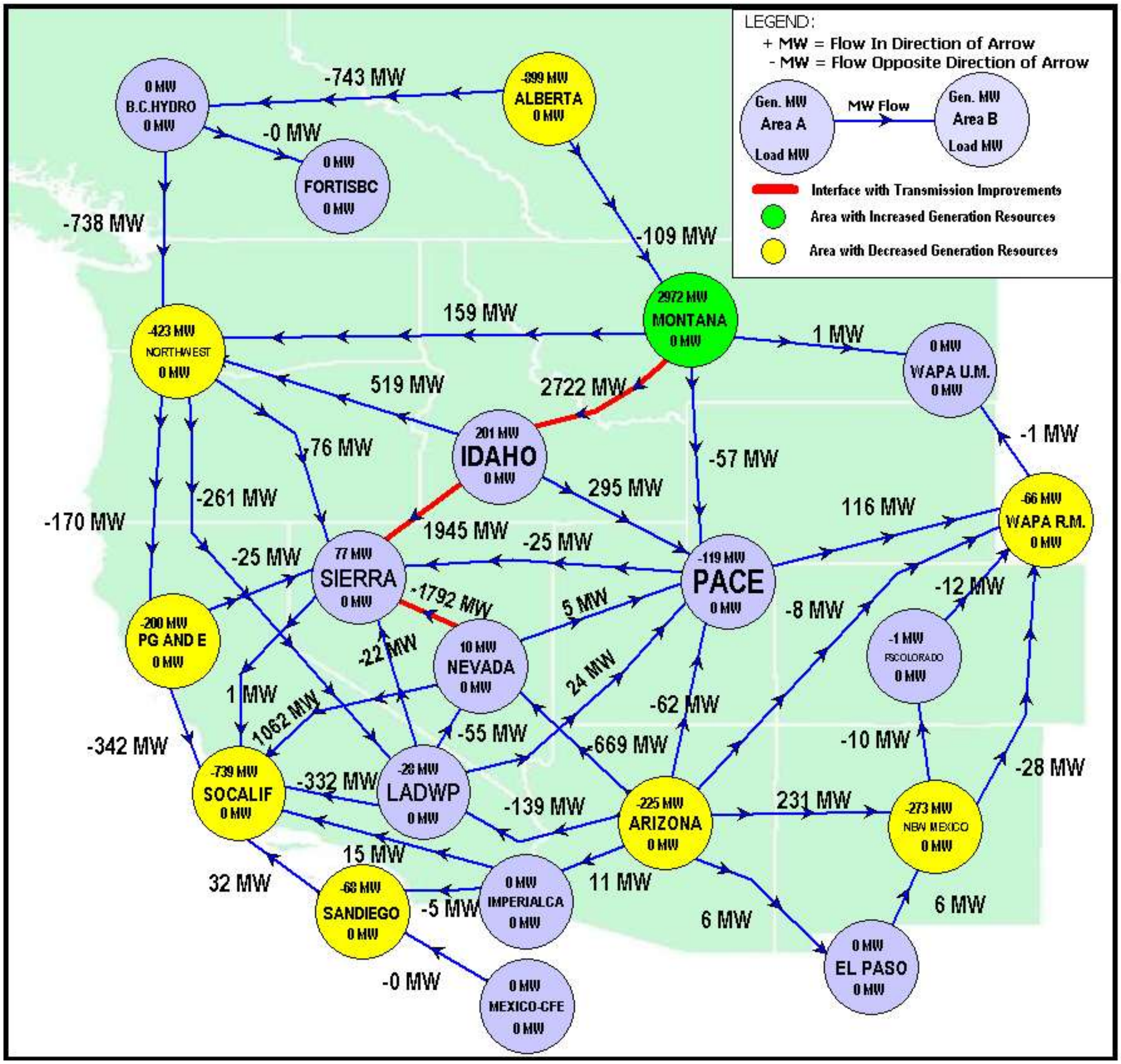
3.4: 3,000 MW in Montana – Heavy Autumn Export – October 4, Hour 21

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 16 overloaded branch elements ranging from 100.3% to 127% of the nominal rating. The N-0 overloaded elements comprised one line, one series capacitor and 14 transformers. There were 27 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 86 violations, with one unsolved contingency. The one unsolved contingency was BOARDT2-DALREED. Of the 86 violations, 28 were overloaded elements. The extreme overload was 165% of the continuous rating. The remaining 44 violations resulted from elements with a bus voltage greater than 1.1 p.u.

A difference flow diagram is shown in Figure 6.26. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-26 – Scenario 3 Difference Flows: OCT04H21



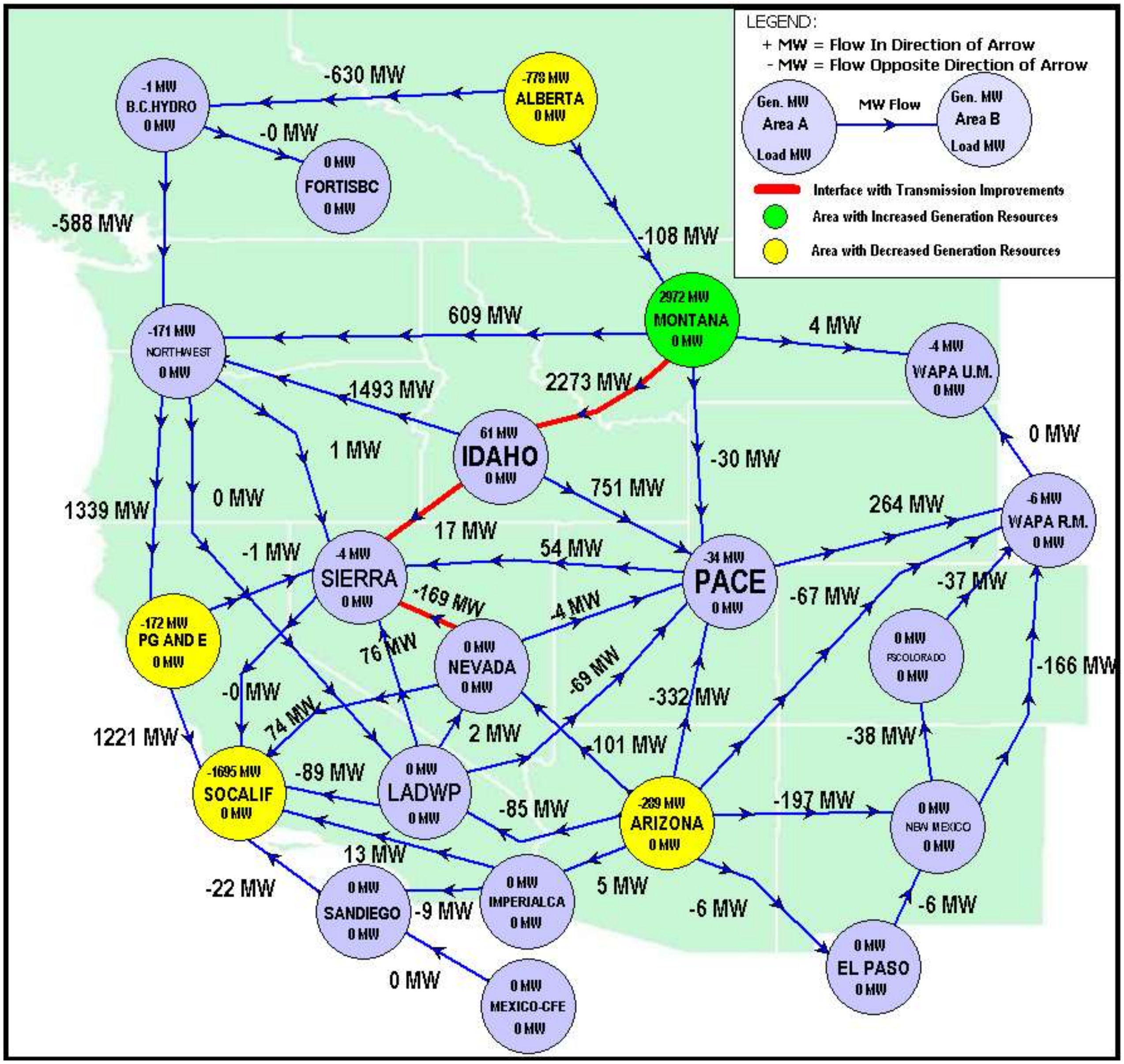
3.5: 3,000 MW in Montana – Maximum Import – August 10, Hour 13

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 17 overloaded branch elements – all transformers – ranging from 101.1% to 150% of the nominal rating. There were 70 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 30 violations, with zero unsolved contingencies. Of the 30 violations, 10 were overloaded elements ranging from 101% to 136%. There were 19 violations for high bus voltages and one violation for low bus voltage.

A difference flow diagram is shown in Figure 6.27. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-27 – Scenario 3 Difference Flows: AUG10H13



4.0: Scenario 4 – 3,000 MW in Wyoming

This scenario represents the effect of an additional 3,000 MW of alternative generation in Wyoming, equally distributed amongst the Anticline, Aeolus and Windstar busses. These busses are part of the

Gateway West project, one of the Foundational Transmission Projects, expected to be in place to help move energy from alternative generation resources in Wyoming.

3,000 MW in Wyoming – Case Development

Case development for Scenario 4 began with the Core Case from each study hour. Generation resources were added to the Core Case for each study hour to develop five power flow cases for Scenario 4. Table 6.13 shows the generation resources added to the Core Case used to develop the five study hour cases for Scenario 4.

Table 6-13 – Scenario 4 Generation Resource Additions

Area Name	Bus Name	Generation Addition
PACE	AEOLUS	1000 MW
	ANTICLIN	1000 MW
	WINDSTAR	1000 MW
	Total	**3000 MW**

A sink was also created for each of the five study hours by removing generation resources in order to offset the 3,000 MW resource addition. Table 6.14 shows the generation resources removed from the Core Case used to develop the five study hour cases for Scenario 4.

Table 6-14 – Scenario 4 Generation Resource Reductions

Area Name	Generation Reduction (MW) July 27 Hour 16	Generation Reduction (MW) December 22 Hour 18	Generation Reduction (MW) March 2 Hour 21	Generation Reduction (MW) October 4 Hour 21	Generation Reduction (MW) August 10 Hour 13
SOCALIF	1168	550	914	760	1695
SANDEIGO		178	451	70	
NORTHWEST	8		274	107	
NEWMEXICO			289	270	
ARIZONA	520		776	213	295

PG&E	1300	1122	248	495	436
SIERRA		47	47		
ALBERTA		1019		898	776
WAPA RM			45	60	
PACE			182	129	
BC HYDRO			539		
	2996 MW	**2916 MW**	**3765 MW**	**3002 MW**	**3202 MW**

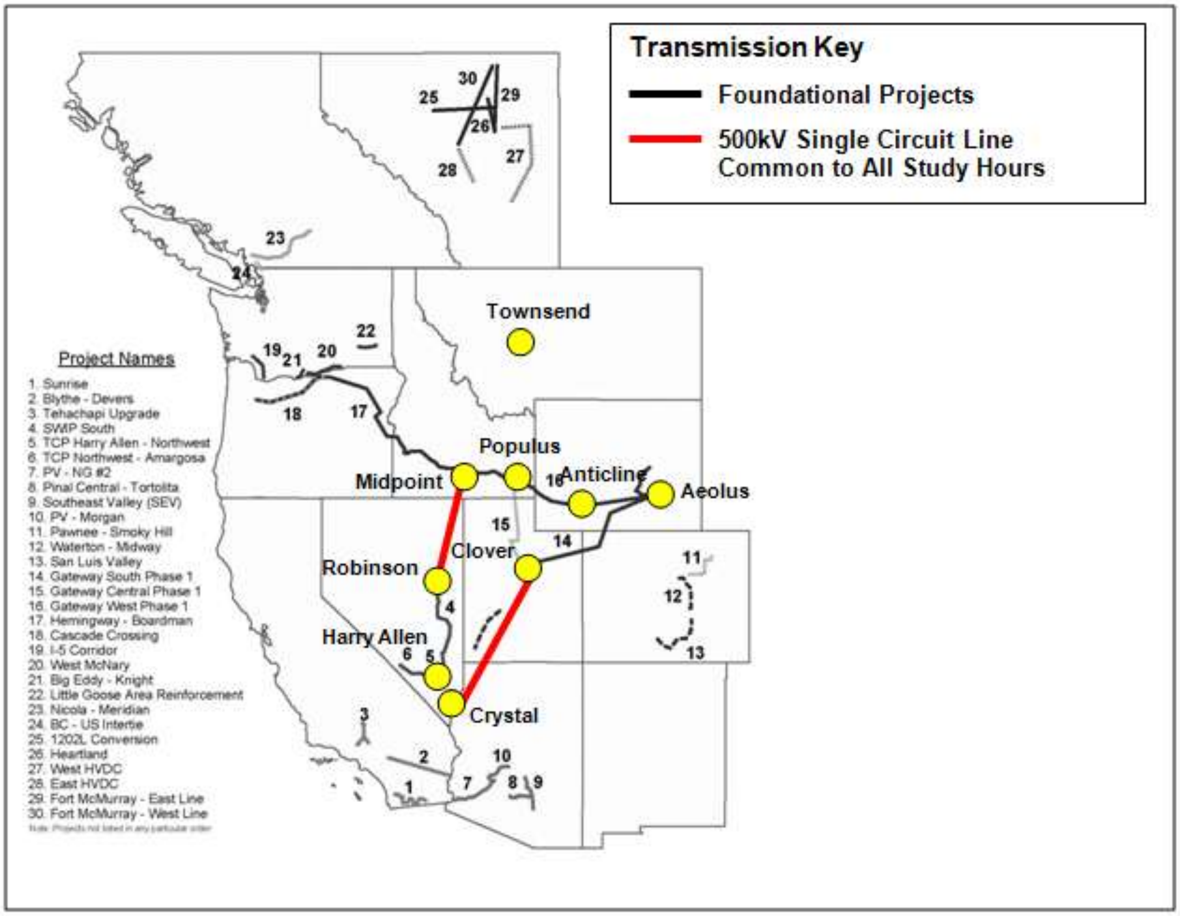
Once the generation additions and reductions were completed, the power flow case was solved and overloads of transmission elements prior to the addition of generic transmission improvements were identified. Table 6.15 shows the N-0 path flows for Scenario 4 prior to the addition of generic transmission improvements for each study hour analyzed in Scenario 4.

Table 6-15 – Scenario 4 N-0 Path Flows (Pre-Generic Transmission Improvements)

SCENARIO 4	ID-NW (3800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3700) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW
JUL27H16	1093	906	4417	2600	5767	1932	3119	1061	66
DEC22H18	2296	1387	1809	2600	3426	3490	3326	109	836
MAR02H21	3122	1752	**6084**	2946	3323	2761	**3790**	**2421**	398
OCT04H21	**4139**	2037	2491	2600	1591	**5404**	**4096**	**1943**	**1620**
AUG10H13	692	342	-97	2600	3340	1556	3312	460	-245

Generic Transmission improvements that appeared as adequate solutions to overloads that were common to the five study hours for Scenario 4 are shown in Figure 6.28.

Figure 6-28 – Scenario 4Generic Transmission Improvements


Transmission Key
Foundational Projects
500kV Single Circuit Line Common to All Study Hours
Project Names
1. Sunrise
2. Blythe - Devers
3. Tehachapi Upgrade
4. SWIP South
5. TCP Harry Allen - Northwest
6. TCP Northwest - Amargosa
7. PV - NG #2
8. Pinal Central - Tortolita
9. Southeast Valley (SEV)
10. PV - Morgan
11. Pawnee - Smoky Hill
12. Waterton - Midway
13. San Luis Valley
14. Gateway South Phase 1
15. Gateway Central Phase 1
16. Gateway West Phase 1
17. Hemingway - Boardman
18. Cascade Crossing
19. I-5 Corridor
20. West McNary
21. Big Eddy - Knight
22. Little Goose Area Reinforcement
23. Nicola - Meridian
24. BC - US Intertie
25. 1202L Conversion
26. Heartland
27. West HVDC
28. East HVDC
29. Fort McMurray - East Line
30. Fort McMurray - West Line
Townsend
Populus
Midpoint
Anticline
Aeolus
Clover
Robinson
Harry Allen
Crystal

3,000 MW in Wyoming – Study Results

The study results indicated that the addition of 3,000 MW of generation in Wyoming resulted in overloaded paths as shown in Table 6.15. Overloaded paths for Scenario 4 common between study hours were overloads on Bridger West.

The transmission improvements for all hours were: 1.) a 500kV transmission line from the Midpoint and Robinson busses and 2.) a 500 kV transmission line from the Clover to Crystal busses.

The N-0 path flows shown in Table 6.16 indicate that the proposed generic transmission improvements resolved the majority of the overloads shown in Table 6.15. Study hours with overloads after the generic transmission improvements were added to the study case were March and October. The March study hour recorded a slight overload on COI: 101.8% on a 4,800 MW rating. The October study hour recorded overloads on Bridger West (113% on 3,700 MW rating) and Path C (108% on 1,400 MW rating).

N-1 contingency analysis for each study hour in Scenario 4 indicated that the majority of the 420 contingencies solved for each study hour. The March study hour showed two unsolved contingencies.

The sum of the N-1 violations for all the study hours in Scenario 4 was 457 violations. The majority of overloaded elements for all the study hours were transformer overloads for N-1 conditions. The most common N-1 violation for all study hours was high bus voltage.

N-0 and N-1 violations discussed in this report are violations on elements 200 kV and above within the NTTG footprint. N-0 and N-1 violation tables for each study hour within this scenario are provided in Appendix 8.

A DC transmission solution originating in Wyoming as described in Scenarios 1 and 2 above would likely resolve the transmission overloads created by the increased Wyoming generation in this Scenario.

Table 6-16 – Scenario 4 N-0 Path Flows (Post-Generic Transmission Improvements)

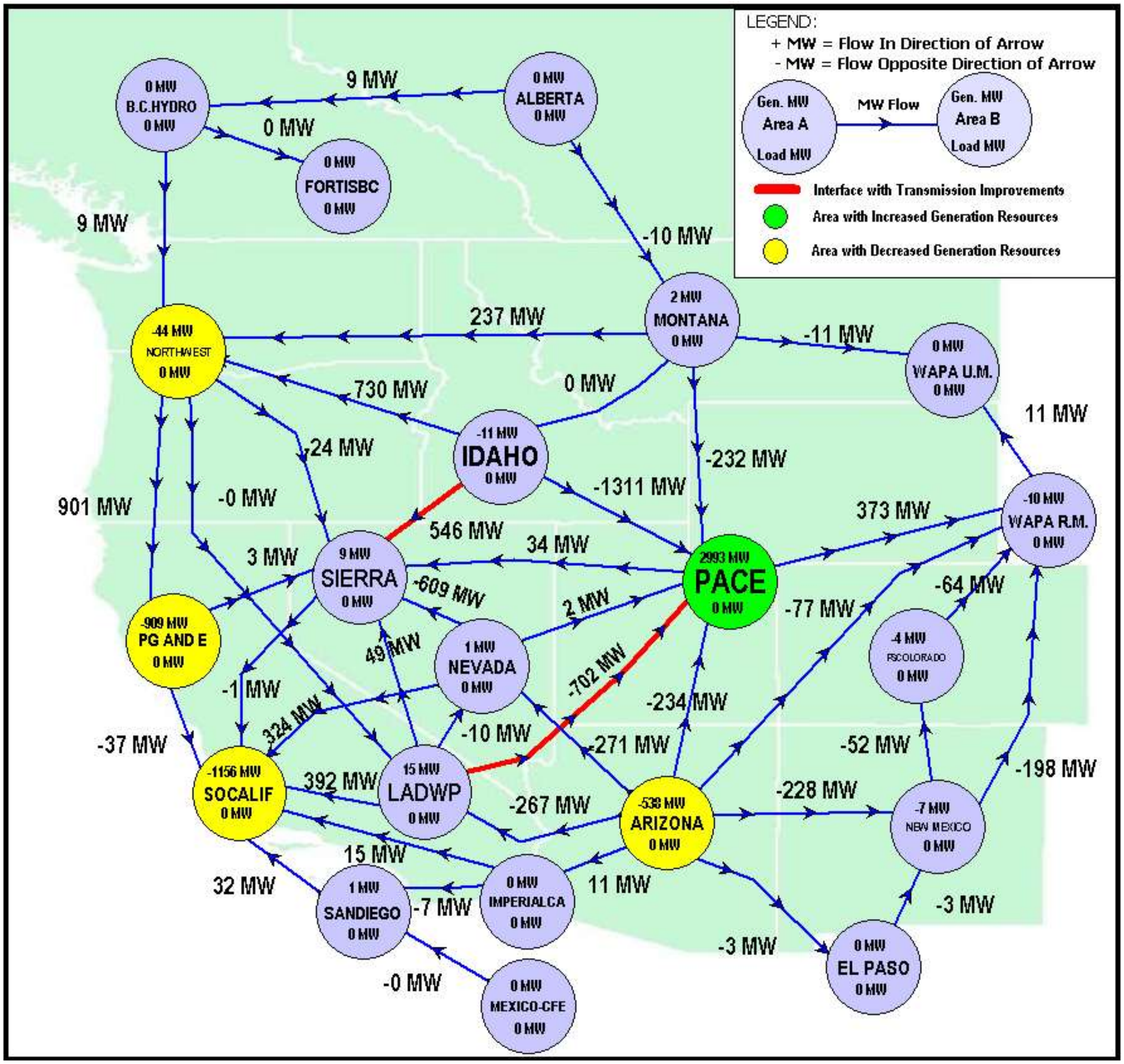
SCENARIO 4	ID-NW (4800) MW	MT-NW (2200) MW	COI (4800) MW	PDCI (3100) MW	N. OF JOHN DAY (7900) MW	BORAH WEST (4450) MW	BRIDGER WEST (3700) MW	TOT2 (A,B,C) (2070) MW	PATH C (1400) MW	SGL CKT 500kV Clover-Crystal (1500) MW	SGL CKT 500kV Midpoint-Robinson (1500) MW
JUL27H16	610	871	3931	2600	5678	1800	3081	739	-41	654	463
DEC22H18	2382	1376	1889	2600	3425	3122	119	50	651	256	-405
MAR02H21 (AC Option)	1827	1673	**4884**	2946	3025	2752	3672	1760	445	1277	**1707**
OCT04H21	3717	1870	1250	2600	816	4269	**4179**	1162	**1512**	1236	623
AUG10H13	831	348	44	2600	3355	1479	3281	445	-286	-32	-255

4.1: 3,000 MW in Wyoming – Summer Peak – July 27, Hour 16

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 17 overloaded branch elements – all transformers – ranging from 102% to 167% of the nominal rating. There were 19 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 37 violations, with zero unsolved contingencies. Of the 37 violations, five were overloaded elements ranging from 101% to 138%. The remaining 37 violations resulted from elements with a bus voltage greater than 1.1 p.u. A difference flow diagram is shown in Figure 6.29. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-29 – Scenario 4 Difference Flows: JUL27H16



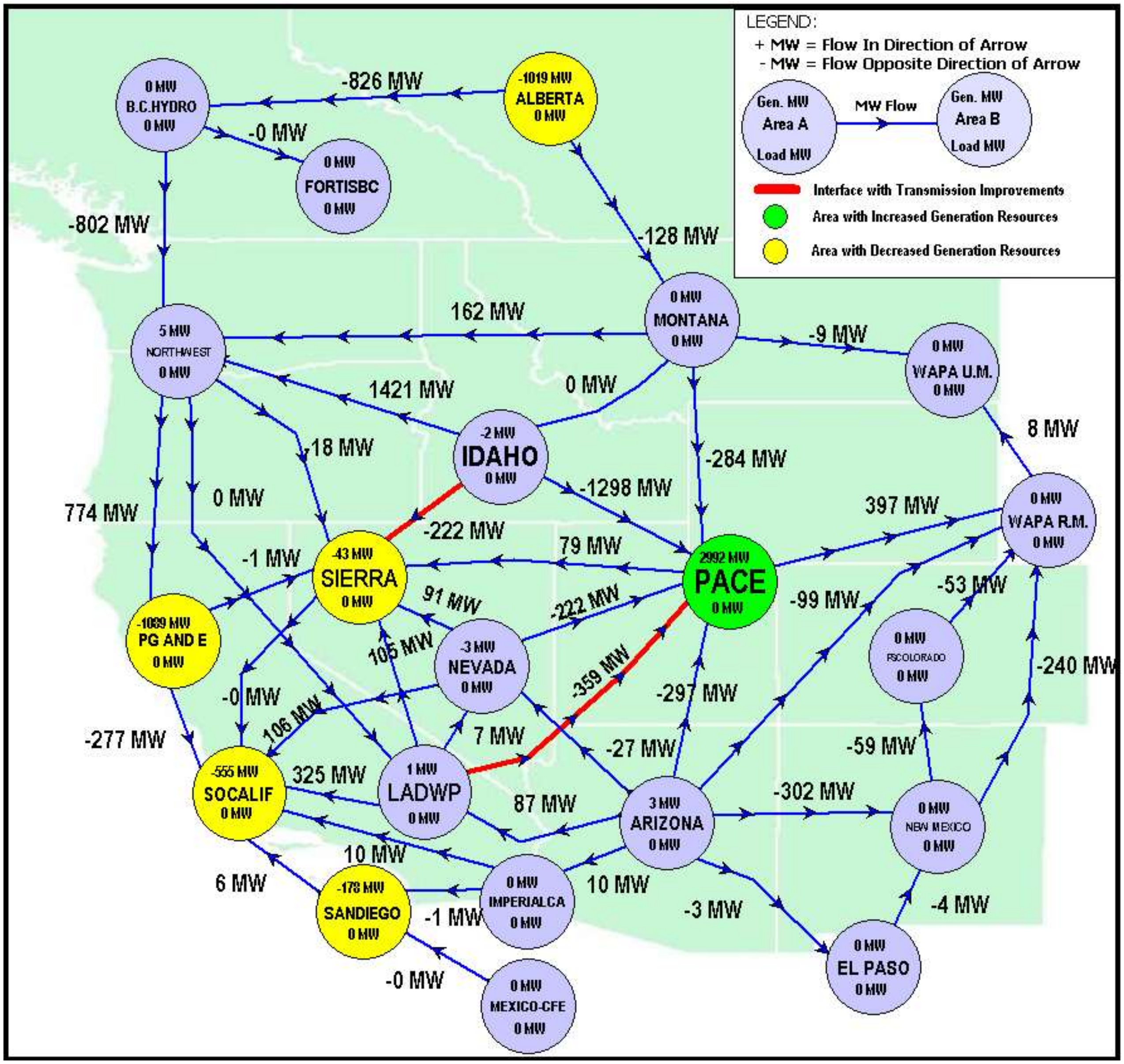
4.2: 3,000 MW in Wyoming – Winter Peak – December 22, Hour 18

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 11 overloaded branch elements – all transformers – ranging from 102% to 145% of the nominal rating. There were 36 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 56 violations, with zero unsolved contingencies. Of the 56 violations, there were eight violations for overloaded elements. The maximum overload was 112% of the continuous rating. There were two violations for low bus voltage and 46 violations for high bus voltage.

A difference flow diagram is shown in Figure 6.30. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-30 – Scenario 4 Difference Flows: DEC22H18



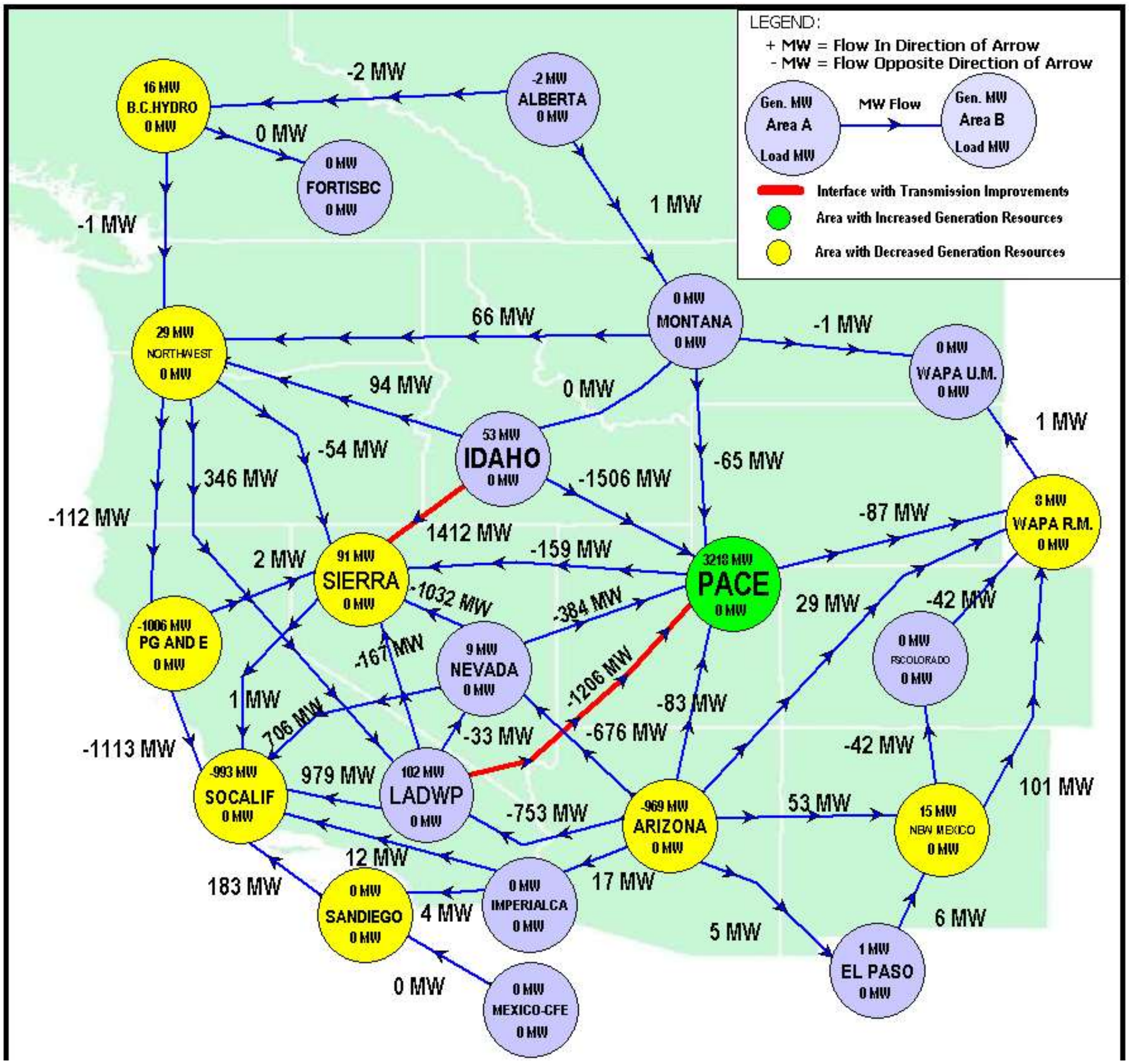
4.3: 3,000 MW in Wyoming – Heavy Spring Export – March 2, Hour 21

After the addition of the generic transmission improvements, one N-0 interface violation was found within the NTTG footprint: COI operating at 102%. Pre-contingency, this study hour was found to have 24 overloaded branch elements ranging from 101% to 188% of the nominal rating. There were five overloaded lines, one overloaded series capacitor and 18 overloaded transformers. Twenty-one busses in the case showed a voltage magnitude greater than 1.1 p.u. All these result were pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 200 violations, with two unsolved contingencies. The two unsolved contingencies were BOARDT2-DALREED and JONESCYN-DALREED. Of the 200 violations, 91 were elements overloaded above the 100% rating. There were two violations for bus voltage less than 0.9 p.u. and 107 violations for bus voltage greater than 1.1 p.u.

A difference flow diagram is shown in Figure 6.31. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-31 – Scenario 4 Difference Flows: MAR02H21



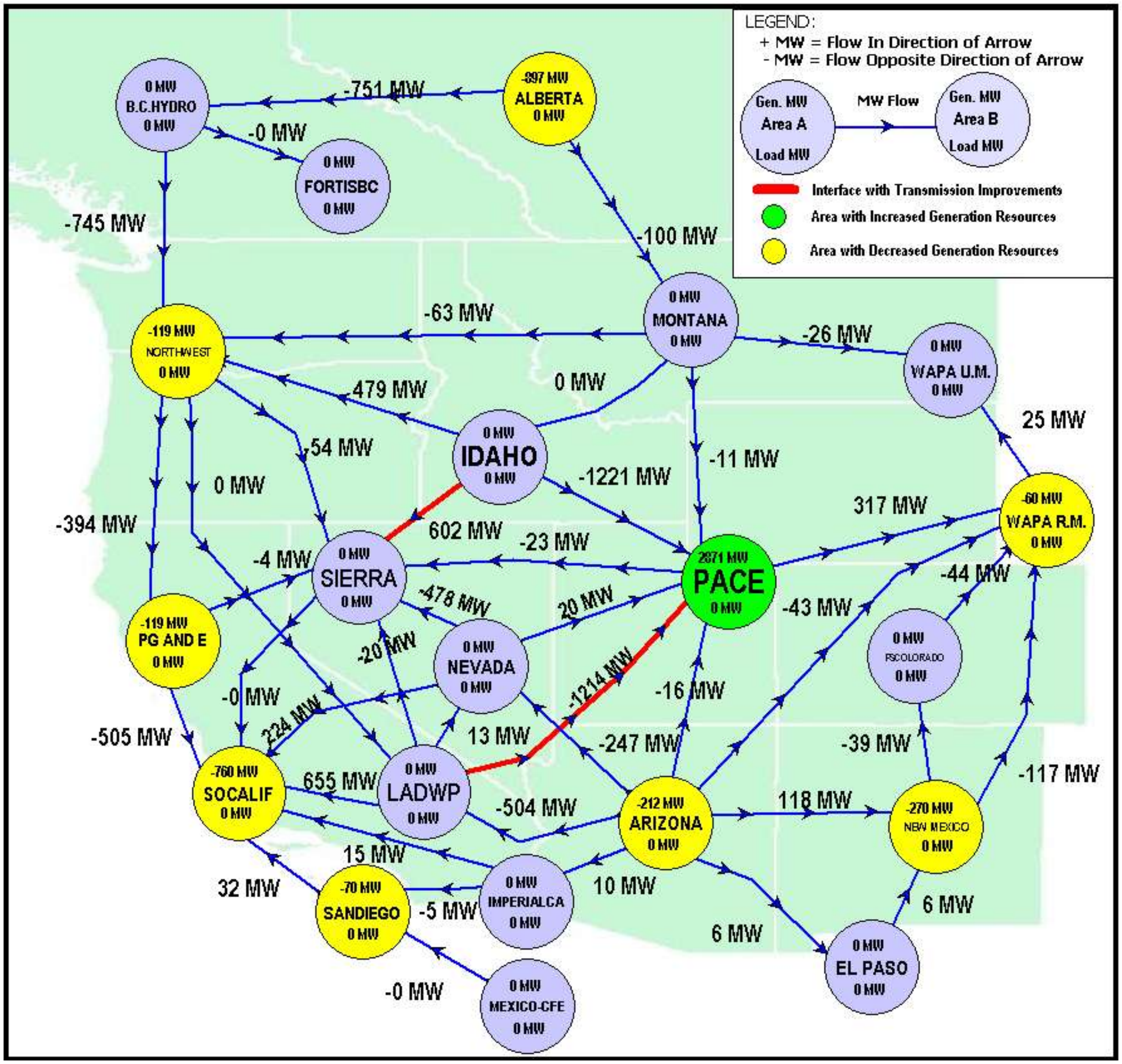
4.4: 3,000 MW in Wyoming – Heavy Autumn Export – October 4, Hour 21

After the addition of the generic transmission improvements, three N-0 interface violations were found within the NTTG footprint: Midpoint-Summer Lake at 118%, Bridger West at 113% and Path C at 108%. Pre-contingency, this study hour was found to have 16 overloaded branch elements ranging from 100.5% to 128% of the nominal rating. The pre-contingency overloaded elements consisted of three series capacitor elements and 13 transformers. Pre-contingency, there were 41 busses in the case with a voltage magnitude greater than 1.1 p.u.

A set of 420 N-1 contingencies was run on this study hour, resulting in 122 violations, with zero unsolved contingencies. Of the 122 violations, 25 resulted in overloaded elements above the 100% rating. The maximum overload was 1147% [correct?] of the continuous rating. The remaining 97 violations were either high or low bus voltages. Four violations were for bus voltages less than 0.90 p.u., and 93 violations were for bus voltages greater than 1.10 p.u.

A difference flow diagram is shown in Figure 6.32. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-32 – Scenario 4 Difference Flows: OCT04H21



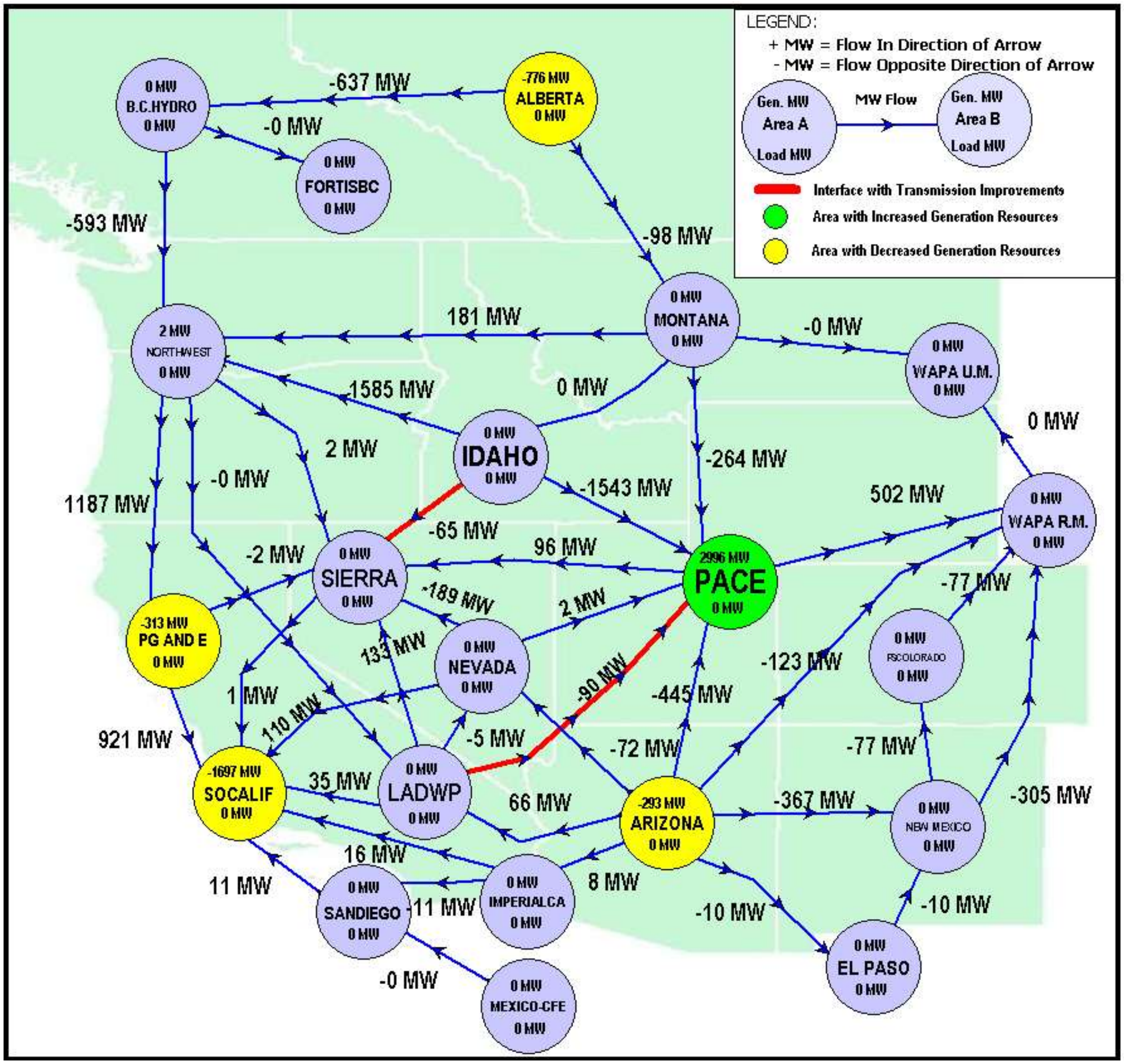
4.5: 3,000 MW in Wyoming – Maximum Import – August 10, Hour 13

After the addition of the generic transmission improvements, zero N-0 interface violations were found within the NTTG footprint. Pre-contingency, this study hour was found to have 13 overloaded branch elements – all transformers – ranging from 101.2% to 150% of the nominal rating. There were 71 busses in the case with a voltage magnitude greater than the 1.1 p.u., pre-contingency.

A set of 420 N-1 contingencies was run on this study hour, resulting in 42 violations, with zero unsolved contingencies. Of the 42 violations, eight resulted in elements overloaded above the 100% rating. The eight overloaded elements contained seven near or below 115% of the 100% rating and one at the maximum overload of 139% of the continuous rating. The remaining 32 violations were mostly bus voltages greater than 1.1 p.u. Two of these had bus voltage violations less than 0.90 p.u. voltage.

A difference flow diagram is shown in Figure 6.33. MW values shown on the difference diagram represent the MW change between the study hour and the Core Case. Additional area interchange diagrams for this study hour are located in Appendix 5.

Figure 6-33 – Scenario 4 Difference Flows: AUG10H13



Chapter 7 - Conclusions

The NTTG TWG performed reliability analysis in the traditional method using the Null Case to analyze the performance of the existing NTTG transmission system to serve the increased loads forecasted for the year 2020. The method of exporting production cost simulation to power flow cases was successfully developed and allowed the simulation of five NTTG transmission system loading conditions representing heavy load, maximum export and maximum import conditions. These production cost simulation-generated cases were further analyzed for performance under the addition of 3,000 MW of wind generation in Montana or Wyoming, or both; and 6,000 MW in Wyoming. In conclusion:

1. The NTTG TWG, through the Null Case analysis, has determined that the existing NTTG transmission system is not adequate to serve the projected NTTG system load in the year 2020.

2. The NTTG TWG has demonstrated the ability to develop hourly power flow cases from production cost simulation exports. This provides the ability to identify and perform reliability analysis on an appropriate set of transmission system loading conditions for future system dispatch configurations.

3. The Core Cases power flow reliability analysis has demonstrated that the Foundational Transmission Projects increase the system capability to reliably integrate planned energy resources and serve the forecasted NTTG system load.

4. The development of large amounts of Montana or Wyoming wind generation, as studied in the Scenario Cases, will exceed the capability of the NTTG transmission system and its Foundational Transmission Projects. Therefore, additional AC, DC, or a combination of AC and DC transmission lines, such as the projects listed in Appendix 3, from the NTTG system to forecasted RPS driven load are required under these resource expansion scenarios.