Wind Integration Study Team

Dynamic Transfer Capability Task Force

Phase 3 Report

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1.0 Executive Summary

The Electric Power industry operating model in which scheduled power transfers between Balancing Authorities ("BAs") are generally fixed for the hour or variations are anticipated, is transitioning to one where there will be significantly increasing unanticipated variations in intra-hour power flow[1]. Drivers for this new operating model include installation of renewable generation and demand from transmission customers to have increased intra-hour scheduling flexibility. As these pressures increase across the WECC footprint, challenges associated with transfer variability will need to be managed and several questions will need to be addressed, including: Is there a limit on how much variability the system can handle, how often and at what cost? How much and how frequently can unanticipated changes in power transfers across the system occur without adverse impacts? Do variable transfers reduce a path's static transfer limit? These questions have been the focus of the Dynamic Transfer Capability (DTC) Task Force's work and a recommended methodology to address them is the core of this report.

Dynamic Transfers that are anticipated, namely schedules that change predictably (e.g. with an expected frequency and magnitude) within an hour, have been reliably used for decades, albeit on a relatively small scale relative to static hourly transfers. A notable example in the Northwest is some of the Mid-C generation that has been used for load following/AGC response in remote Balancing Authority Areas ("BAAs"). With increasing levels of wind penetration and requests for new Dynamic Transfer arrangements, many transmission planners and operators have expressed interest in objectively studying the need to limit new Dynamic Transfers that are unpredictable and associated with non-dispatchable or balancing resources in order to safeguard system reliability.

In October 2010 the Joint Initiative's Wind Integration Study Team ("WIST") assembled a Task Force of technical staff, primarily from Northwest, British Columbia and California transmission providers and sub-regional entities, to further explore the issues associated with increases in unpredictable Dynamic Transfers. Early in the process, of what amounted to more than 60 meetings in 14 months, the Task Force framed the fundamental question concerning limits on unpredictable Dynamic Transfers as: How much can power transfers vary unpredictably across the system within a defined time period (e.g. 15 minutes)[2] and how frequently before system adjustments are made by system operators, while still ensuring acceptable performance and reliable operation?

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[1]These within-hour variations can be either anticipated (e.g. intra-hour scheduling) or unanticipated (e.g. unforecasted variation in wind output).

[2]There are several proposals being considered to reduce the standard scheduling time period between operator initiated schedule adjustments, including 30 minutes as implemented in the Northwest in July 2011 and 15 minutes as proposed by FERC in 2010. Reducing the scheduling time period between operator adjustments, however, does not reduce the underlying power flow variations, but rather changes the way the systems dispatchable resources are operated to respond to variations in non-dispatchable resource and may imply acceptance of some higher operating costs (e.g. increased maintenance of voltage switching equipment). Furthermore, the need for balancing resources does not change, however, the BA responsibility for managing the variability may change.

The purpose of the Task Force is to propose solutions for determining limits and to facilitate increased Dynamic Transfers of non-dispatchable or balancing resources without compromising system reliability or imposing materially increased operating costs.[3] The Task Force named these limits Transfer Variability Limits (TVLs), and concluded that determining TVLs for flowgates was important to achieving its purpose. The Task Force's work was organized into three phases: Phase 1 defined the issues and framed the problem (report completed March 2011[4]); Phase 2 developed a proposed TVL methodology that could be applied by transmission providers to their system (report completed July 2011[5]); Phase 3 (this report) refines the TVL methodology, discusses some possible system improvements to increase TVLs and identifies some other Dynamic Transfer issues that were raised during the Task Force's work. While the Pacific Northwest transmission system is the focus of these three phases, the conclusions in this report have been presented to WECC, and it is anticipated that members of this Task Force will continue to provide information for any subsequent investigations by the larger WECC membership.

While providing greater operational flexibility to integrate variable, non-dispatchable resources across multiple BAAs, increases in TVLs may in some cases require system enhancements to improve the ability of the transmission system to respond automatically to variations in intra-hour transfers. Improvements may take the form of, but are not limited to, enhanced state-awareness, automation of controls, additional transmission lines or upgrading existing transmission facilities, additional voltage/var support equipment, increased maintenance for new and some existing equipment and added staff at the Balancing Authority/Transmission Operator Control Centers and/or WECC Reliability Centers.

In theory, all flowgates adversely impacted by varying, non-dispatchable sources and/or balancing resources should have limits established for unpredictable Dynamic Transfers that are scheduled across them. The Task Force recommends use of the proposed methodology to ensure that all Transmission Providers (TPs)[6] determine their need for TVLs for flowgates adversely impacted by Dynamic Transfers of non-dispatchable or balancing resources in a consistent manner using standard terminology. This consistency is needed for coordination as differences in systems or their operating characteristics may produce different TVL values for each side of a flowgate that is an intertie between adjacent TPs. Consequently, the Dynamic Transfers from the non-dispatchable and balancing sources would be limited by the most restrictive TVL limit in the path, just as is the normal practice for System Operating Limits (SOLs). These differences however point to the

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[3] The DTC Task Force built on studies carried out by CAISO, BPA and Powertech Labs. We are not aware of Transfer Variability Limits being the focus of any other studies. If readers are aware of related studies, please send a reference to Landauer@ColumbiaGrid.org or Gordon.Dobson-Mack@powerex.com. The original studies can be downloaded at:
CASIO (Jan 2011 – http://www.columbiagrid.org/download.cfm?DVID=2460),
BPA (Feb 2010 – http://www.columbiagrid.org/download.cfm?DVID=2461) and
Powertech Labs (June 2008 – http://www.columbiagrid.org/download.cfm?DVID=1933).

[4] Phase 1 Report: http://www.columbiagrid.org/download.cfm?DVID=2109

[5] Phase 2 Report: http://www.columbiagrid.org/download.cfm?DVID=2281

[6] NERC's FAC-014 indicates that the responsibility for establishing SOLs is shared by Transmission Operators, Planning Authorities and Transmission Planners. It is anticipated that the responsibility for establishing TVLs would be similarly shared. Transmission Providers is meant to cover these multiple entities.

need for each TP to develop their own TVLs based on their expert knowledge of their system, tolerance for risk, and quality of service standard(s). In addition, once a TVL is established for a flowgate, the affected TPs will need to determine how to allocate their Variable Transfer Capability to dynamically transferred non-dispatchable or balancing resources that would impact the flowgate. In addition, TPs will need to decide if real-time monitoring of variable transfer across the flowgate is necessary.

Much work remains to be done, most notably the development and coordination of commercial practices related to the use of those Dynamic Transfers that are unpredictable. It is hoped that this work will inform continued efforts to transition the power system toward the flexible operating model demanded by future uses, while maintaining the region's historic emphasis on reliability.

Conclusions of the DTC TF Phase 3 report are:

1. TVLs reflect an emerging issue that has reliability implications for some paths / flowgates.

2. A three part methodology for calculating TVLs has been developed. Its purpose is to determine when transfer variability across a path / flowgate may have an adverse impact on customers, equipment or reliable operating points.

3. There is an important distinction between variability that is anticipated and planned versus variability that cannot be anticipated. Where daily load or generation changes are anticipated and very predictable, system operators may follow a daily timetable for routinely adjusting voltage control equipment. Regular, anticipated adjustments and switching associated with load following (for example) is probably not feasible for non-dispatchable generation which is unpredictable.

4. There is a relationship between a path's static and variable transfers that defines the safe operating region. Characteristics of the relationship generally include:
    a. Maximum static transfer (equal to the SOL) occurs when variable transfer is zero;
    b. The maximum TVL will occur when the system is the least stressed;
    c. For any operating transfer level between 0 and SOL, a maximum variable transfer can be defined;
    d. Sum of the variable transfers plus the static transfers on a path must be less than or equal to the SOL;
    e. In between the end-points of the 0 MW of static transfers and 0 MW of variable transfers, a path will need to be managed to ensure that the combined operating point always stays within the perimeter of secure operating points.

5. TVL is less than or equal to the SOL. The reason for this relates the differences in methodology to determine TVLs and SOLs: for TVLs it is assumed that only automatic operations are available to adjust to changes in system flow, whereas for SOLs it is assumed that all the appropriate operator actions will take place to tune the system to maximize transfer levels. SOLs are higher because it is assumed that system operators are not time constrained, and can make as many adjustments as necessary to optimize the performance of the system. Systems which are already mostly under automatic control may have little or no reduction in the TVL versus the SOL.

6. Scheduling variable transfer on a path will restrict the amount of static transfer capacity available to be scheduled concurrently. Initial studies suggest that the exchange of static capability with variable capability will typically be less than one for one (i.e. less than one MW of variable transfer for one MW of static transfer) on paths with limited or no automatic voltage control.

7. The commercial issues associated with increased unpredictable Dynamic Transfers will need to be resolved in parallel with calculating TVLs for specific paths, including definition of the variable transmission service that could be scheduled and limited as needed.

8. The relationship between variable and static transfers on paths needs further study. In particular, it will be important to determine the impact of frequent and unanticipated variable transfers on different paths limited by different types of transmission constraints (e.g. voltage change, voltage stability, transient stability). In addition, further studies will be needed to assist some Path Operators/Owners in assessing how to manage trade-offs between variable and static transfers paths / flowgates on their system.

9. Determination of the TVL magnitude for a path is impacted by multiple effects, including:
    a. Actual operating point / scheduled operating point;
    b. Pre-outage conditions & stress of the study case;
    c. System topology (e.g. major lines out of service);
    d. Availability of automatic devices;
    e. Location of the variable resource and its balancing resource;
    f. Multiple simultaneous, unpredictable Dynamic Transfers flowing across the path;
    g. Policy Decisions (e.g. Risk tolerance, allowable voltage variation);
    h. Magnitude & frequency of the variation that is deemed acceptable over the defined time period;

10. Generally TVLs can be improved with more automated responses to variability (e.g. automated RAS arming & more automated voltage control) in conjunction with equipment designed to handle the associated duty cycles of automated voltage control.

11. All generators, and some dispatchable loads, could act as dynamic resources. Consequently, it is not just the variability from intermittent resources that needs to be accounted for, but rather all resources that cause frequent, unanticipated intra-hour variability in transfers across monitored paths / flowgates.

12. Prior to significant expansion of Dynamic Transfers in support of variable resources, it is recommended that Transmission Providers evaluate the need to implement TVLs on their systems, so that any potential impacts to customers, equipment and reliability are properly managed.[7]

[7] No NERC or WECC criteria refer to TVL, consequently there are no mandatory requirements to carry out TVL studies, however, as some Transmission Providers have identified transfer variability as an emerging issue it is hoped that others will consider whether this is also an issue for their system.

13. There are policy questions that need to be resolved in order to calculate TVLs for a system's paths / flowgates. They are related to risk tolerance and acceptable impacts to quality of service, and include but are not limited to:
    a. Acceptable magnitude/frequency of voltage deviations?
    b. Acceptable levels of incremental cost due to increased variability?
    c. Acceptable levels of incremental reactive switching due to increased variability?

14. There are Dynamic Transfer issues[8] related to implementation and commercialization, not directly related to the calculation of TVLs, that will also need to be resolved in order facilitate increased use of unpredictable Dynamic Transfers.

15. Where limitations in unpredictable Dynamic Transfers are deemed necessary, additional coordination may be necessary between operating entities. Examples include, but are not limited to, increased visibility, coordinating schedules of allowed voltage deviation over time, and coordination of automatic voltage control equipment.

[8] In the course of DTC Task Force discussions and through the interactions with WECC members numerous Dynamic Transfer issues were raised that did not fall within the Task Force's mandate of determining a method for calculating TVLs. As these issues are important and will need to be addressed by appropriate groups or entities, the Task Force has highlighted some of the issues in Section 7.0 Dynamic Transfer Issues and has provided a summary of all issues raised in Appendix E.

2.0 Introduction

Ensuring the reliable supply of electricity involves a complex series of tasks and multiple system adjustments so that the power system will be secure not only in the present moment, but also in the minutes that follow if the next worst outage that could possibly happen, did happen. At the center of this process are the system operators who ensure that the system operating points stay within acceptable limits verified by studies. Fundamental adjustments must be made to maintain load/generation balance while operating within system security limits and maintaining acceptable voltage levels.

Many of these adjustments interact with one another. For instance, as Figure 1 illustrates, light loading of a transmission line will cause the voltages on and around that line to rise. Conversely heavy loading of a transmission line will cause the voltages on and around the line to sag. To maintain the optimal voltage profile, that avoids the dangers of both under and over-voltage, requires that voltage control devices be switched to match the line loading. Similarly some RAS (Remedial Action Schemes) arming must be readjusted to match the current loading of the system to ensure system security.

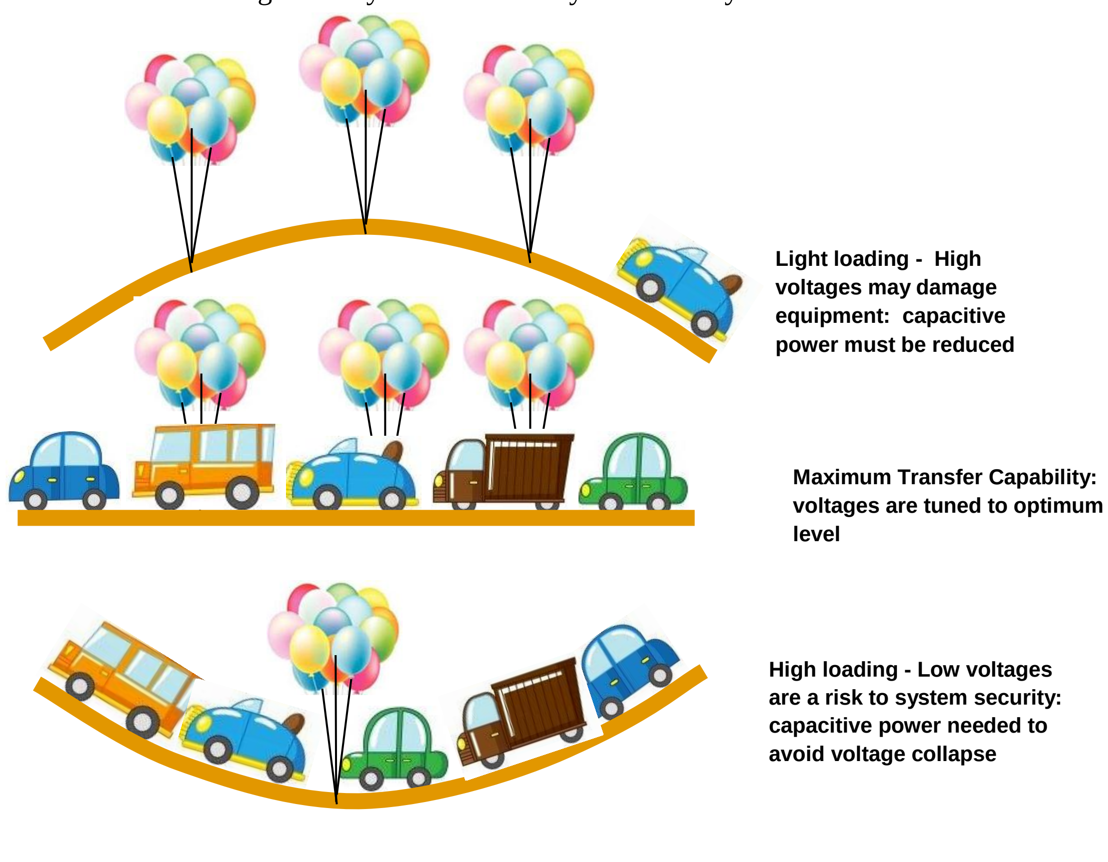

Figure 1: Voltage Profiles Associated with Different Transmission Loadings

For most Balancing Authority Areas in the WECC, energy schedules have generally only changed once per hour. There is movement in the Pacific Northwest towards implementing 30 minute scheduling as of July 2011, and there are discussions of possibly moving to 15 minute scheduling in the future. The assumption implicit with these changes to scheduling practices is that the System Operators will be able to actively monitor the ramps for these schedule adjustments and tune the power system accordingly.

A fundamental characteristic of Dynamic Transfers is that they will vary energy schedules across a path automatically, without any Operator initiated system adjustments. Consequently, the fundamental question that arises is: “How much can the transfer vary without jeopardizing system reliability or impacting system equipment and customers?” The DTC Task Force was convened in October 2010 to address this question.

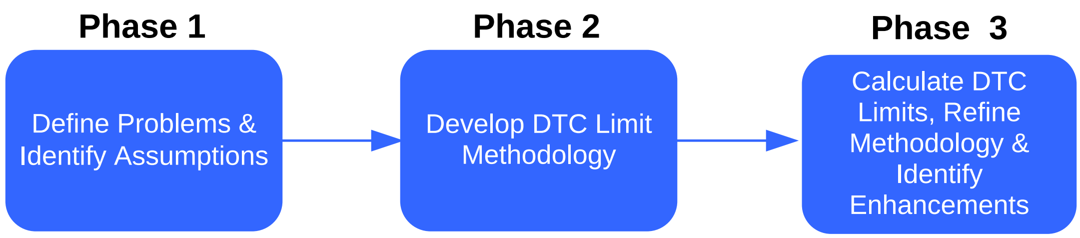

Figure 2: Phases of the DTC Task Force’s Work Plan

The Task Force organized its work into three phases with a primary goal of developing a commonly accepted methodology for calculating limits on unpredictable Dynamic Transfers. In the course of our discussions, five other insights emerged:

1. New terms related to unpredictable Dynamic Transfers are needed to help ensure a common understanding;
2. The characteristics of normal operation, specifically in relation to voltage control, equipment switching and frequency disturbances, need to be benchmarked in order to determine the level of acceptable variability with respect to the impact of unpredictable Dynamic Transfers on equipment and customers;
3. The interactions between static transfers, variable transfers and how SOLs and TVLs come into play in order to define a secure operating perimeter for a path;
4. The assumptions and approach adopted when applying the TVL methodology will impact the resulting limit;
5. Increased unpredictable Dynamic Transfers on a broad scale across the WECC will require a variety of issues to be resolved.

The body of the report provides an overview of the recommended TVL methodology, discusses its application and other issues that were raised during discussions. The Appendices provide back-up details for the readers who want to dive deeper.

3.0 Path Variability – Magnitude & Frequency

Power flows vary around the WECC predominantly because of the inherent variability of load within and among the WECC sub-regions and due to the availability of and cost of resources dispatched to meet the load. Powerflow variability may increase significantly as a result of variable energy resources and dispatchable loads. The fundamental questions that the DTC Task Force explored were: *"How much and how frequently can transfer across a flowgate vary without causing any adverse impacts?"* To provide a context for discussing the need for TVLs, this section discusses the sources of variability; categorizes the variability as expected or unexpected; and provides some operation benchmarks from 2009 for transfer variability by path and for voltage change at critical busses in different systems.

Sources of Variability on a Path:

Variability in transfers across a path are attributable to a variety of expected and unexpected sources of variability. In general, the expected sources vary frequently such that their variability can be managed in advance, whereas the unexpected sources vary infrequently and must be managed after the event. Sources of path variability include:

1) Changes in scheduled interchange values, particularly at the morning and evening ramp periods (Expected).

2) Changes to path equipment {both expected (if planned) and unexpected (if unplanned)}:

    a. Phase Shifter angle adjustments;

    b. Series Capacitor insertions or bypassing;

    c. DC line adjustments;

    d. Planned Transmission line outages.

3) Unscheduled flow {(Both expected (for normal operations) and unexpected (during unusual operating conditions)}:

    a. The "shared" variation in sources of supply to meet time of day (i.e. real time) demand across interconnected regions in a parallel operated AC network, which may be mitigated by flow control equipment (i.e. phase shifters) and coordinated operating procedures;

    b. The distribution of frequency response across a parallel network, particularly for loss of a generating unit;

    c. Transmission Line Forced outages;

    d. RAS Operations (designed responses to certain generating and equipment outages);

    e. Uninstructed deviations from schedules across the path ;

    f. Over-generation or under-generation in adjacent BAs.

4) Dispatchable Dynamic Transfers across the path (Both predictable and unpredictable).

5) Non-dispatchable Dynamic Transfers across the path (Unpredictable).

Times of Variability on a Path:

In addition to having a variety of causes, transfer variability is also a function of time including: 1) time during hour (e.g. within a ramp period, or outside the ramp period); 2) time of day (e.g. HLH or LLH); 3) time of year (e.g. during a season when wind resources blow strongest).

Drivers of Increased Path Variability:

Transfers across some paths are expected to vary much more than they have in the past. Drivers of increased variability include:

- Increasing penetration levels of intermittent generation;
- Increased reliance on remote firming and balancing of intermittent resources;
- Increased Dynamic Transfers;
- Increased adoption of smart grid measures, particularly demand responsive loads;
- Application of FACTS (Flexible AC Transmission Solutions) devices that change the topology of the transmission system;
- Increased reliance on generation RAS to manage events on the transmission system;

Benchmarks of Variability:

To illustrate that variations across the power system have physical manifestations, two Figures are provided below and detailed tables are provided in Appendix D. Figure 3 shows the magnitude of transfer variability over 15 minutes as a function of how frequently this occurred in 2009 for four paths that were studied in Phase 3. Figure 4 shows the magnitude and frequency of voltage changes at a few critical busses from across the WECC in 2009.

These graphs illustrate that the power system accomodates variability in transfers today. For example, Figure 4 shows that typical (6x/day or greater) voltage variations are less than 1%. The question to consider is how much can the magnitude and frequency of transfer variability be increased before the system impacts are deemed unacceptable? The answer will help determine for a particular system whether transmission variability needs to be managed through the application of limits and/or reinforcing the grid to accommodate increased transfer variability.

The fact that the system has been able to accommodate a certain magnitude of variablilty in the past, should not be interpreted to mean that the system could accommodate that same magnitude of variability more frequently. The Phase 3 studies have highlighted that many variations in transfers require system adjustments to reset the system operating point within a safe operating perimeter – if large variations are repeated and frequent it is not realistic to assume operators will be able to make the necessary adjustments and as a result the transmission system may not be ready to withstand the next worst contingency.

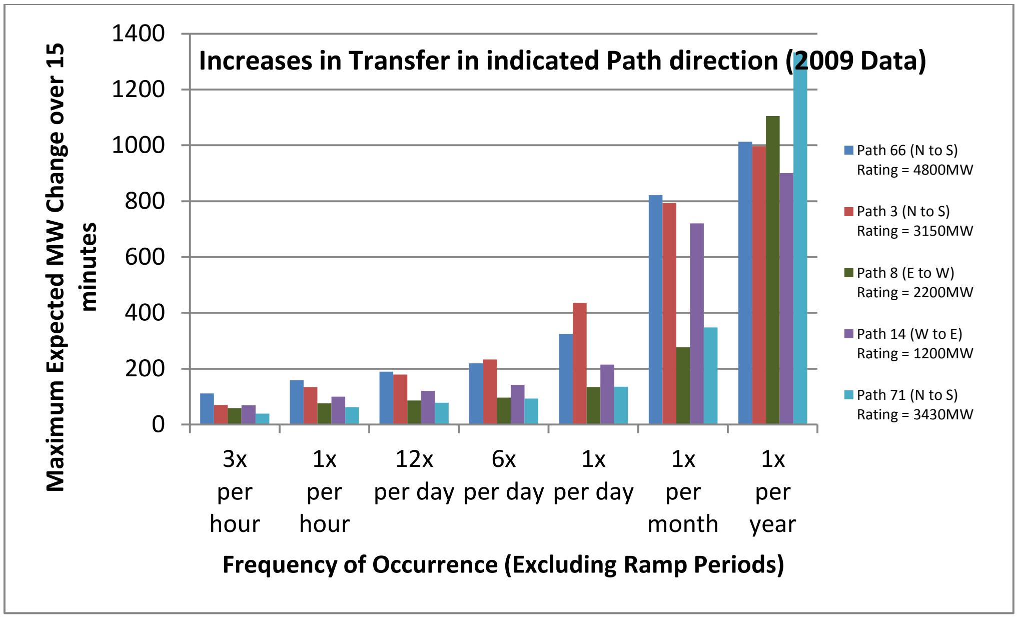

Figure 3: Magnitude vs Frequency of Transfer Variability by Path – Excluding Ramps (2009 Data)

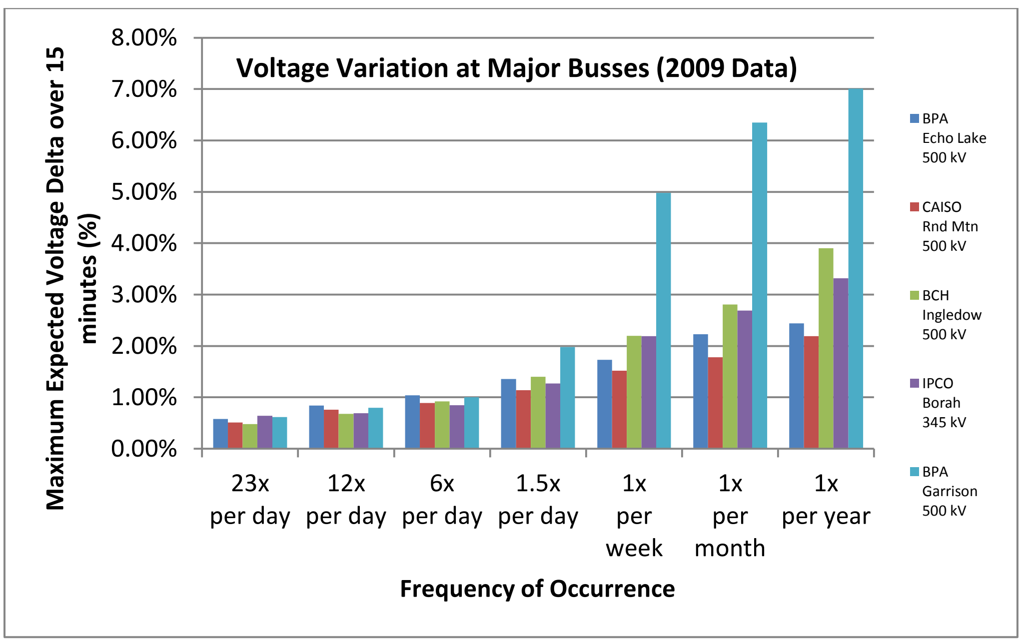

Figure 4: Magnitude vs Frequency of Voltage Variability at a Few Major Busses (2009 Data)[9]

[9] Daily voltage variation ranges between 1 to 2%. For less frequent intervals it is possible to see a wider range of voltage variation across the system. This points to the need for Transmission Providers to do path specific voltage analysis when determining the allowable voltage range to prevent customer impacts.

4.0 Recommended TVL Methodology

For a TVL methodology, the fundamental questions that need to be answered are: *"How much and how frequently can unanticipated changes in transfer across a flowgate vary without causing any adverse impacts?"* The ultimate goal of the DTC Task Force's work is the development of a methodology that Transmission Providers could apply to calculate TVLs for their system. This section provides an overview of the proposed methodology and introduces some new terms that the Task Force defined in order to ensure a commonly understood vocabulary when discussing limits on unpredictable Dynamic Transfers. A glossary of terms introduced throughout the report is included in Appendix A.

To begin the discussion of methodology, some key terminology needs to be defined:

> **Dynamic Transfer -** The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.
>
> **Variable Transfer:** Refers to the physical variations in actual power flows across a path / flowgate that are generally unpredictable and repetitive during a defined time period (e.g. 15 minutes). Sources of Variable Transfer include: unpredictable Dynamic Transfers, intermittent resources and inadvertent (when not accounted for with a TRM Transmission Reliability Margin).
>
> **Transfer Variability Limit (TVL) –** The maximum amount of frequent but unpredicted variability in the power transfer across a Flowgate that can be accommodated over a specified intra-hourly timeframe while ensuring the reliable operation of the system and the avoidance of unacceptable adverse impacts on equipment and customers. The TVL cannot be greater than the System Operating Limit (SOL). The TVL could be less than the SOL which has traditionally been calculated using constant, not variable flows.
>
> **Static Transfer:** Conventional transfers across a path / flowgate, usually made up of fixed hourly schedules between defined PORs (Points of Receipt) and PODs (Points of Delivery)
>
> **SOL (System Operating Limit):** The value that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

For unpredictable Dynamic Transfers across a given Flowgate, the Task Force proposed that the TVL could be calculated by quantifying adverse impacts from three perspectives:

1) Impact on Customers[10],
2) Impact on System Equipment, and
3) Reliability.

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[10] The Task Force uses the term Customer in the context of bulk transmission system users, rather than the more typical meaning of residential end user. For example, the Customer could be a generator, load serving entity (such as PUD), or describe the interface between sub-transmission and distribution.

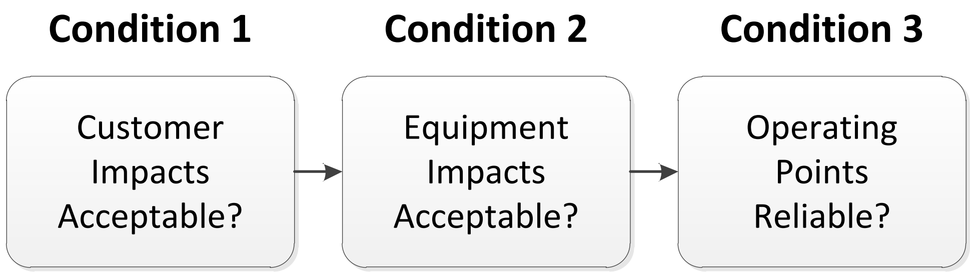

Figure 5: Proposed three part methodology for calculating TVLs

A working assumption for the DTC Task Force was that TVLs would need to be calculated seasonally, following a similar process used by NOPSG and WECC's other regional study groups. In the future, it is conceivable that Transmission Providers could have on-line system analysis tools that would allow for a near-real-time calculation of TVLs that reflect actual system operating conditions, however, it is expected that the first versions of such software would not be deployed for at least another 18 months.

<u>Condition 1: Customer Limit</u>:

Of the three limits this is the most difficult to quantify as it involves the most judgment. From an empirical perspective it would be possible to define the customer limit as a function of acceptable performance on criteria such as voltage sag. Analysis of voltage variation at key busses across the WECC shown in Appendix D reveals that the voltage performance normally experienced by the customer is much less variable than what can be experienced during infrequent events, or is allowed under existing criteria. Consequently, judgment needs to be exercised in determining the level at which the service and performance customers have traditionally received would be negatively impacted. Figure 6 below illustrates the TVL challenge as it relates to voltage variation.

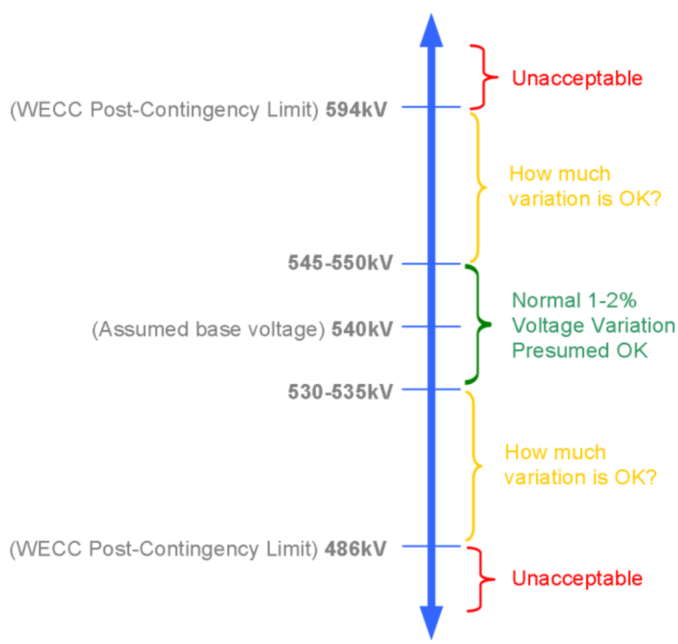

Figure 6: TVL and the relationship to acceptable voltage variation

Condition 2: Equipment Limit:

Variations in power transfer will cause voltage levels to vary. The power system needs to be operated within a defined range of acceptable voltages as both over-voltage and under-voltage conditions can cause reliability problems. In order to achieve a desired voltage profile, voltage control devices that raise or reduce voltages at specific busses are installed. Frequent and repeated changes in voltage levels resulting from increased variability in transfers could cause the voltage control devices to be switched more frequently than originally designed. For instance, most shunt capacitor (used to raise voltage) and shunt reactor (used to lower voltage) are switched with mechanical breakers. Many of these breakers were designed to have an expected lifetime of 40 years during which they could be operated up to 3000 times. Consequently, if increased variability in transfers resulted in increased reactive switching to maintain the desired voltage profiles, then there would be an impact on maintenance and lifespan for system equipment. Each Transmission Provider would need to decide what level of equipment impact was acceptable, but nonetheless, this would translate into a limit on transfer variability.

Condition 3: Reliability Limit:

The reliability of any operating point is measured by analyzing how the system performs when subjected to an unplanned loss of an element (contingency). It doesn't matter how that operating point is reached (whether by static transfers alone, or by a combination of static and Dynamic Transfers), the post-contingency response must be within the criteria defined by NERC standards.

The amount of change in variable transfers that can be accommodated across a flowgate before reaching a reliability limit depends on the assumed operating point. The Task Force felt that in order to calculate an appropriate seasonal TVL it would be important to assume stressed conditions, namely, assume that the path is being operated near its SOL so that the impact of transfer variations can be appropriately quantified. The reasons for assuming a high transfer initially include operating closer to system limits and the impact of change in transfers are magnified because the non-linear effects of the power system are more pronounced when paths are operated close to their SOL.

The general approach for calculating the reliability limit involved increasing the variability in steps until a violation of NERC planning criteria occurred. The basic steps are:

1) Assume that the system was tuned for an initial baseflow, such that voltage levels were set to a desired profile and RAS were armed to ensure appropriate post-contingency performance;

2) Increase the variable transfers and assume there will be no operator initiated system adjustments. Only automated RAS arming adjustments and automated voltage control adjustment would be modeled;

3) Perform contingency analysis to analyze post-contingency performance;

4) Repeat the process until a transmission limit is reached (i.e. without violating NERC planning performance criteria for transient instability, voltage instability, voltage dip or thermal limits).

The TVL for a flowgate would be the lowest of the Customer, Equipment and Reliability limits:

TVL = MINIMUM of (Customer Lim, Equipment Lim, Reliability Lim)

A detailed procedure for calculating a TVL, using Path 14 as an example, is shown in Appendix B.

Once TVLs are determined for particular flowgates, the question will arise on how dynamic resources will impact these variability limits. All generators, and even some loads[11], can be viewed as dynamic resources; however, not all dynamic resources will inject equal amounts of variability onto the transmission system. For instance, consider the variability associated with three types of generators:

1) A coal fired plant dynamically transferring base load energy to a remote BA via a pseudo-tie with a 5 MW/min ramp-rate;
2) A hydro plant supplying regulation to a remote BA via a dynamic schedule with a 100 MW/min ramp-rate[12]; and
3) A wind farm delivering its energy to a remote BA via a dynamic schedule with an average daily ramp rate of ~15 MW/min and a maximum recorded ramp rate of 110 MW/min.

Assuming plants of equal size then ramp-rate only represents half of the equation when calculating variability. The other half of the equation is the assumed length of time that the power system would be operating on auto-pilot because the system operators are busy.

Variability (MW) = Ramp Rate (MW/min) x Time (min)

You will see that in several of the definitions that follow that the "Time" component is referred to as the "TVL specified timeframe". In order to manage variability on the transmission system, the Transmission Providers must make an assumption on how many minutes variation in transfers could occur before system operators would readjust the system and restore the appropriate voltage profile and RAS arming. In the Pacific Northwest, parties believe that 15 minutes[13] is the appropriate timeframe to assume for TVL studies in 2011.

In order to calculate the Variability associated with a given dynamic resource it is necessary to analyze performance data for the Dynamic Resource and quantify its variability. The following terms describe the values that would be calculated during the resource analysis and would enable a BAA to aggregate the variability impacts on a specific flowgate from multiple Dynamic Resources:

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[11] Electric water heaters that can be switched on or off remotely depending on system conditions are an example of a demand responsive loads that could cause transfer variability across a flowgate.

[12] While these three examples all described Dynamic Transfers between BAs, it should be remembered that Transfer Variability issues can also arise within a single BA when resources in one region are used to balance resources in a different region of the same BA.

[13] For the California ISO Balancing Authority, it may be appropriate to assume a shorter "TVL specified timeframe" given its automated real-time dispatch and transmission control equipment.

Dynamic Percentile Limit (DPL) - Upper percentile (hours in the year) at which the DRVI for the Equipment and Customer Limits is determined. (Units %)

Dynamic Resource Variability Index (DRVI) – The expected percentage of its rated capacity that a Dynamic Resource varies during the TVL specified timeframe at the designated DPL. (Units: %)

Dynamic Resource Maximum (DRmax) – The rated generation capacity of a Dynamic Resource, also known as the Pmax. (Units: MW)

Dynamic Resource Variable Demand (DRVD) – The expected amount of variability that a Dynamic Resource injects into the transmission system at its interconnection point.
DRVD = DRVI x DRmax. (Units: MW)

Variable Transfer (VT): Refers to the physical variations in actual power flows across a path / flowgate that are generally unpredictable and repetitive during a defined time period (e.g. 15 minutes). Sources of Variable Transfer include: unpredictable Dynamic Transfers, intermittent resources and inadvertent (when not accounted for with a Transmission Reliability Margin {TRM}). (Units: MW)

Variable Transfer Limit (VTL): For a given static transfer, the amount of frequent but unpredicted variability in the power transfer across a flowgate that can be accommodated over a specified intra-hourly timeframe while ensuring the reliable operation of the system and avoiding unacceptable adverse impacts on equipment and customers.
(Units: MW)

Available Variable Transfer Capability (AVTC) – The amount of Variable Transfer that is still available to be scheduled across a flowgate for a given Variable Transfer Limit.
AVTC = VTL - ∑ DRVD * PTDF (Units: MW)

Power Transfer Distribution Factor (PTDF) – In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer (NERC Official definition). In the case of Variable Transfers, this definition becomes a measure of how the flow on transmission lines and flowgates change in response to a power transfer from a variable generator and its associated balancing resource[14]. (Units: %)

[14] PTDFs vary as a function of the path/flowgate in question and the Source/Sink pairs that are being examined.

5.0 Summary of Preliminary TVL Findings

The focus of Phase 3 was to apply the proposed TVL methodology with the objective of determining three things:

1) Is the proposed TVL methodology workable?
2) Which paths raise TVL concerns for some Transmission Operators?
3) What could be done to increase TVLs on constrained paths?

This section summarizes the Phase 3 findings. It is important to note that the studies run (using a Heavy Summer 2011 and a Light Spring 2011 operating cases) were scoped only to test the TVL methodology and validate the TVL concerns of some Transmission Providers. The actual limits that might be applied in 2012 will need to be determined by Transmission Providers who are responsible for maintaining reliability over their portion of the transmission grid. The DTC Task Force's role was to facilitate the calculation of TVLs through the development of a TVL methodology.

<u>Initial Operating Point & System Tuning Impacts TVL</u>:

The initial operating point is a key factor in determining how much transfer variability a path can withstand. When a power system is stressed, which is another way of saying that it is operating close to its reliability limits, there is less margin in the system to tolerate variations in power transfer. In addition, the tuning that system operators do are important factors in maximizing the transfer capacity of a path.

Two important system adjustments that are a key part of path operation are voltage regulation and RAS arming. Figure 7 illustrates how insertion of a shunt capacitor can boost system voltage and as a result increase the voltage stability limit for a path. One of the challenges of voltage regulation is that system operators must strike a balance between undervoltage conditions that increase the risk of voltage collapse following some contingencies, and overvoltage conditions that increase the risk of equipment damage (e.g. breakdown of insulation) in the event of some other contingencies.

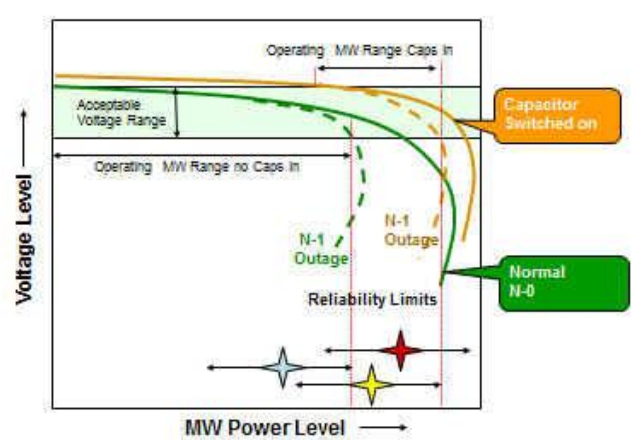

Figure 7: Voltage Stability Curve & Impact of a Capacitor on Path Transfer Capability

RAS (Remedial Action Schemes) play a very important role in maximizing transfer capacity as they ensure that when severe contingencies occur at higher transfer levels the power system will adjust, within fractions of a second, to ensure that loads will continue to be served and all equipment will continue to operate within ratings. However, as the power system is a very complex, non-linear system, the appropriate RAS actions at one transfer level can be inadequate at a different transfer level. With increasing levels of transfer variability, the challenge of managing RAS is more complex for companies who rely on system operators to arm / disarm RAS. Figure 8 illustrates how transfers on a path could move through the RAS arm / disarm threshold several times an hour and through the switching level for a capacitor bank.

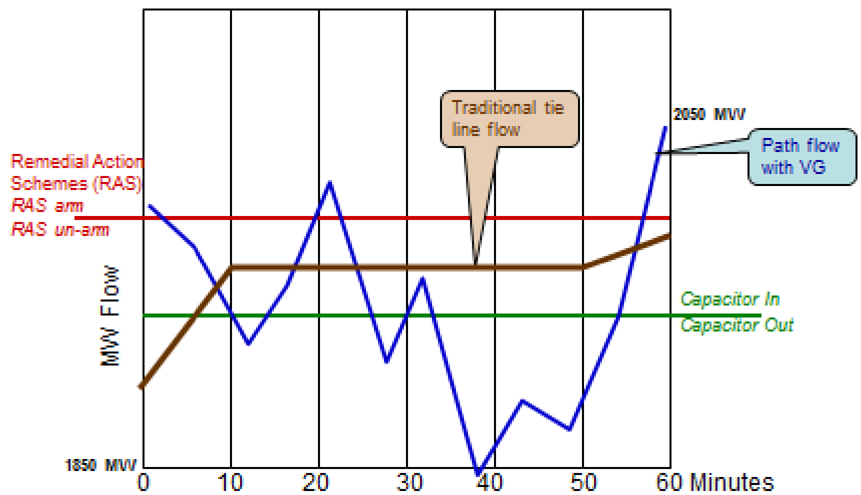

Figure 8: Path Variability, RAS arming and Voltage Regulation

<u>Relationship between Variable and Static Transfers on a Path</u> :

There is a relationship between a path's static and variable transfers that defines the safe operating region. The maximum Static Transfer equals the SOL when Variable Transfer is zero. Similarly the maximum Variable Transfer equals the TVL when Static Transfer is zero. In between these end-points, the static and variable transfers on a path will need to be managed to ensure that the combined operating point is always operate within the perimeter of secure operating points. Figure 9 illustrates a Variable vs. Static transfer nomogram for power flows in the same direction.

Some of the rules we expect to apply to a Variable vs. Static Transfer nomogram are:

1) Sum of Static Transfer (ST) and Variable Transfer (VT) will be less than the SOL:

ST + VT <= SOL

SOL = max ST when VT is zero

2) Variable transfers will be less than the TVL:

VT <= TVL

The amount of variable transfer scheduled would restrict the amount of static transfer capacity available. Initial studies suggest that the exchange of static transfer capability with variable transfer capability will typically be less than one for one (i.e. less than one MW of VT for one MW of ST) on some paths.

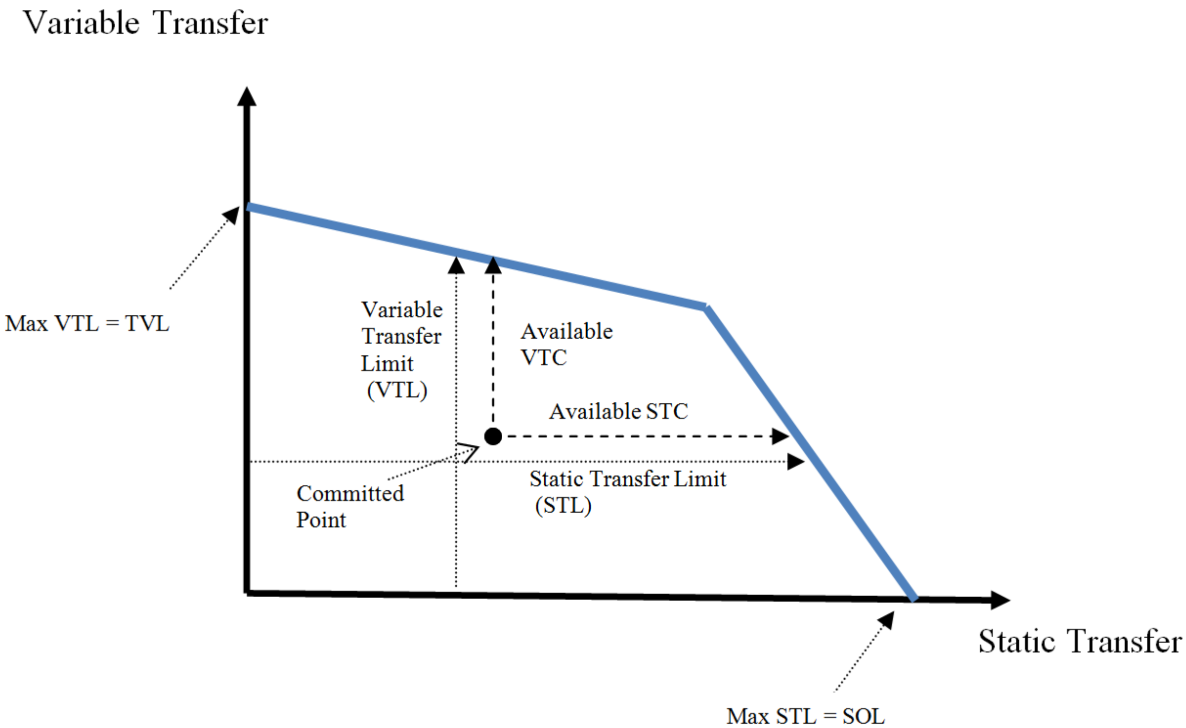

Figure 9: Nomogram relating Variable and Static Transfers on a Path

The relationship between variable and static transfers on paths needs further study. In particular, it will be important to determine the impact of variable transfers on different paths limited by different types of transmission constraints (e.g. voltage change, voltage stability, transient stability). In addition, further studies will be needed to assist some Path Operators/Owners in assessing how to manage trade-offs between variable and static transfers paths / flowgates on their system.

<u>TVL more restrictive than SOL</u>:

We observed on several paths that the TVL for 0 MW of static transfer was less than the SOL for 0 MW of variable transfer. The fundamental reason for this lies in how TVLs and SOLs are calculated: for TVLs it is assumed that only automatic operations are available to adjust to changes in system flow, whereas for SOLs it is assumed that all the appropriate operator actions will take place to tune the system to maximize transfer levels.

<u>Impacts on TVL</u>:

Numerous factors influence the magnitude of a path's TVL, these include:

a. Actual operating point / scheduled operating point:

b. Pre-outage conditions & stress of the study case;

c. System topology (e.g. major lines out of service);

d. Availability of automatic devices;

e. Location of the balancing reserves & the variable resource;

f. Multiple simultaneous, unpredictable Dynamic Transfers flowing across the path;

g. Policy Decisions (e.g. Risk tolerance, allowable voltage variation);

h. Magnitude & frequency of the variation that is deemed acceptable over the defined time period.

In Phase 3 the TVL methodology that is described in Section 4.0 was applied to four paths. The first objective of the Phase 3 studies was to determine if the TVL Methodology is workable. We conclude that the methodology is workable, however, it may need further refinements as experience is gained in its application, just as it has been refined from what was originally proposed in the July 2011 Phase 2 report.

The second Phase 3 objective, to identify some paths that raise TVL concerns for some Transmission Operators, is discussed in Section 6.0. The third Phase 3 Objective, to describe what could be done to increase TVLs on constrained paths, is discussed in Section 8.0.

6.0 Perceived Need for TVLs

The TVL methodology was tested on four paths. The paths were Path 66, Path 3, Path 8 & Path 14, namely paths that connect BPA's system in the Pacific Northwest to California, British Columbia, Montana and Idaho[15]. It may also be necessary to manage the variability of transfers across some internal flowgates with TVLs, however, due to limits on time and study resources, no internal flowgate studies were run. A map identifying the flowgates that were considered is shown below. Detailed summaries of the TVL findings by Path as shown in Appendix C.

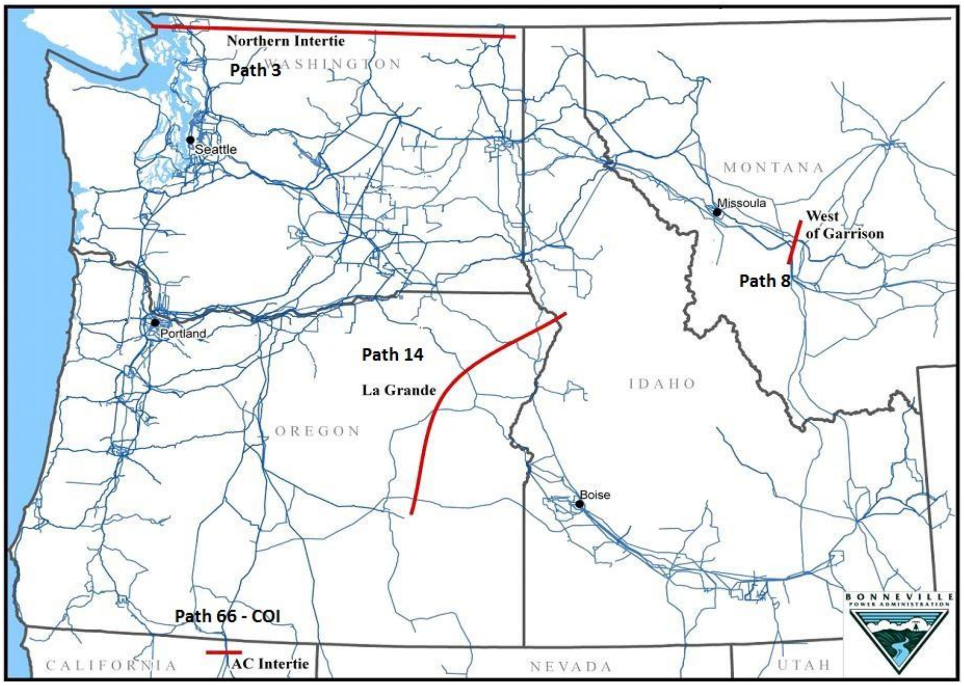

Figure 10: Major Paths / Flowgates in the Pacific Northwest

This section summarizes the path specific studies that were run in Phase 3 and lists the recommendations of DTC Task Force members who work for companies with reliability responsibilities for the paths in question. To make it easier for the reader to understand this analysis of the need for calculating path TVLs, the company perspectives were grouped into the three following highlighted categories shown below:

Plan to calculate TVLs (& associated nomograms):
Still considering need for TVLs:
Do not plan to calculate TVLs:

---

15 Study results are based on specific study assumptions (e.g. source & sink).

Path 66: COI

Plan to calculate TVLs (& associated nomograms):	BPA
Still considering need for TVLs:	TANC, WAPA, PAC, PGE
Do not plan to calculate TVLs:	CAISO, SMUD

BPA ran studies with high North-to-South transfers on COI (greater than 4000 MW) and found that for a Double Palo Verde contingency the system was more susceptible to voltage collapse with increasing amounts of transfer variability and no adjustments of RAS or voltage control. Additionally, interactions between COI and other BPA paths point to the need to consider how TVL across COI may interact with TVL on other paths. These results imply that the path SOL could be impacted, therefore these studies helped confirm the belief of BPA's DTC Task Force members that further TVL studies are needed and that TVLs should be calculated for the northern portion of Path 66.

Because CAISO completed a substantial Dynamic Transfer study in January 2011, and because there is automatic RAS arming and voltage control for all facilities that support the 500 kV system on the southern portion of COI, CAISO's and SMUD's (note: the TP is TANC; The BA is BANC-SMUD is the operator of the BANC BA the largest member of each, WAPA is the largest TOP within the BANC and the TOP of the 500-kV COTP) DTC Task Force members felt that the TVL for the southern portion of COI would be higher than the TVL that BPA would calculate for the northern portion of COI, and as a result are not recommending that CAISO or BANC calculate TVLs for the southern portion of Path 66 at this time.

Path 3: Northwest to Canada

Plan to calculate TVLs (& associated nomograms):	BPA, BCH, PSE
Still considering need for TVLs:	
Do not plan to calculate TVLs:	

BPA and BCH considered the impact on Path 3 North-to-South limits of remote BC generation responding to variations in Columbia Gorge wind. BPA examined contingencies in Washington State; BCH examined contingencies in BC, the effect of system conditions, as well as the impact of shifting the location of the balancing resources within BC (e.g. balancing with Columbia River generation vs. Peace River generation).

Upon review of the Phase 3 study results, the DTC TF members from the Path 3 owners (BPA, BCH & PSE) saw a need for further studies and are recommending that TVLs be calculated for Path 3.

Path 8: Montana to Northwest

Plan to calculate TVLs (& associated nomograms):	BPA
Still considering need for TVLs:	NWE, AVA, PSE, PGE, PAC
Do not plan to calculate TVLs:	

BPA and NWE considered the impact on Path 8 East-to-west limits of Upper Columbia, Mid Columbia, Lower Columbia hydro generation responding to variations in wind and other resources(Colstrip) in lieu of future wind projects in Montana. BPA and NWE both ran a subset of contingencies in BPA, Avista and NWE transmission system.

A key issue for further exploration is the allowable range of voltage fluctuation on 500 kV busses that can be permitted without impact to customers. While all DTC TF members from Path 8 owners see a need for further studies, some members (NWE, AVA, PSE, PGE, PAC) are still considering if TVLs will need to be managed on Path 8.

The DTC TF members from BPA see a need to calculate TVLs as the Path 8 studies demonstrate that dynamic capability may be limited on Path 8 when the path is subject to high flows and stressed conditions. As additional intermittent resources are developed in Montana, the need for Path 8 to accommodate higher levels of variability than historically experienced can be expected. Further studies should be performed, and the characteristic variability of intermittent generation using Path 8 evaluated, so that needed system improvements or operating procedures can be identified.

Path 14: Idaho to Northwest

Plan to calculate TVLs (& associated nomograms):	BPA
Still considering need for TVLs:	IPCO, AVA, PAC
Do not plan to calculate TVLs:	

IPC ran some studies to determine a preliminary relationship (nomogram) between Static flows on Idaho – Northwest (Path 14) in the West to East direction and Transfer Variable Limits at various operating levels. TVLs were calculated at different operating points under West to East transfers on Path 14. Both positive TVLs (same direction as Static flows) and negative TVLs (opposite direction to Static flows) were calculated. Only limits in voltage change (1% for 500kV & 345kV buses and 3% for remaining BES buses) in the Idaho BA were considered while increasing amounts of transfer variability and no adjustments of RAS or voltage control. A specific set of injection groups (source & sink) on either side of the flowgate were used in establishing these limits. Different injection groups will likely result in a different nomogram between static and variable flows on this Path. Future steps should consider limitations due to voltage constraints in the BPA area and need to meet reliability requirements (post-transient voltage & thermal limits, voltage and angular stability) under the limiting outages.

The DTC TF members from BPA see a need to calculate TVLs as the Path 14 study performed by IPC demonstrates that dynamic capability may be limited on Path 14 when the path is subject to high flows and stressed conditions. As additional uses of dynamic capability are developed in Idaho, the need for Path 14 to accommodate higher levels of variability than historically experienced can be expected. Further studies should be performed so that needed system improvements or operating procedures can be identified.

Internal Flowgates:

Plan to calculate TVLs (& associated nomograms): BPA
Still considering need for TVLs:
Do not plan to calculate TVLs:

Most wind generation in the Pacific Northwest has been developed in the Lower Columbia region, which is surrounded by multiple critical transmission paths. Variable transfers from this area to balancing resources or interties project the variability and uncertainty of intermittent resources to other areas of the transmission system. The close coupling of internal paths and their combined effect on voltage within the BPA system, requires an approach that takes the interrelationships into account while assessing the effect of variability on grid reliability as a whole. While time did not permit the inclusion of examples calculating internal path TVLs, a methodology for TVLs when multiple paths must be considered was discussed by the Task Force and is included in Appendix C.

7.0 Dynamic Transfer Issues & Questions

In the context of the DTC Task Force several Dynamic Transfer issues were raised that were not related to the calculation of TVLs, consequently they fell outside the mandate of the Task Force. For instance, consideration of possible market mechanisms for enforcing TVLs was out of scope. Nonetheless, Task Force members viewed many of the issues as important and felt it would be helpful to summarize the issues that had been raised to facilitate their resolution by other entities or groups. These issues are summarized in Appendix E and a few are highlighted in the section below.

How could dynamic capacity on a path be allocated?

The primary focus of the Task force has been on the physical (operational) impacts of unpredictable Dynamic Transfers. To this end the evaluations have been "path" based, rather than "transmission provider" based. However, given that there may be multiple transmission providers on a given path, it likely will be necessary to address the potential impact(s) one transmission provider may have on the others. Some of these "commercial" considerations are briefly discussed below.

Interaction of SOL and TVL

The initial work of the task force suggests that TVLs may have a non-linear impact on a path SOL. The issue is how to assign the impact(s) between the various transmission providers. The non-linear nature of the impact(s) could make a direct pro rata assignment more complex.

Different Treatment of Acceptable System Constraints on a Given Path

The task force has identified potential limits of TVLs for various system constraints. However, the determination of the appropriate TVL constraints on a given path is to be left to the individual transmission provider. If different providers select different constraints for the same path how will those differences be reflected in the respective scheduling rights of the various transmission providers on that path?

Treatment of Impacts on Parallel Paths

Preliminary analysis suggests that TVLs on one path may have impact(s) on parallel paths. To the extent the transmission providers are not the same on each of the paths, how are the impacts to be addressed?

Allocation of Capital, Operational, and Maintenance impacts Between Transmission Providers

To the extent that increasing levels of TVLs increase O&M costs or results in the need for additional capital improvements on a given path, how are these financial obligations to be allocated between the various transmission providers on a given path?

This brief list is not exhaustive but is representative of the commercial issues that will require resolution as TVLs become more common. The task force does not suggest where or how these issues should be addressed. However, it does want to emphasize that these commercial issues are important and complex. A forum should be established sooner rather than later to begin the dialogue.

<u>How would a generator get rights to dynamically schedule?</u>

Ultimately it will be the involved Transmission Providers who would determine how rights to dynamically schedule will be assigned. Nonetheless, it was suggested that a generic example could help illustrate one possible option for assigning Variable Transfer Capacity rights.

> <u>Step 1: Quantify variability of dynamic resource</u>: TVLs reflect the limit on variability that a path / flowgate can sustain over a defined period of time (e.g. 15 minutes in the Pacific Northwest). Consequently, the first step involves quantifying how much a dynamic resource would contribute the variability seen across a path / flowgate.
>
> <u>Step 2: Translate variability at the source into variability on the path</u>: Given that power flows from Points A to B via all parallel paths, a process is needed to determine how much of the variability that is expected at the Point of Receipt will manifest itself on the path / flowgate in question. VTC (Variable Transfer Capacity) is the quantity used to account for the variability that will show up on a particular path / flowgate and reflects the amount of dynamic transmission across a path / flowgate that would need to be allocated for a particular resource.
>
> <u>Step 3: Comparing VTC with the TVL</u>: A challenge of increased unpredictable Dynamic Transfers will be to ensure that the total VTC on a path / flowgate does not exceed its TVL.
>
> <u>More Discussion about Variability</u>: Quantifying the variability of a dynamic resource is a very important step and it involves judgment in at least two aspects:
>
> > a) The point of measurement influences the variability observed. To illustrate this point Figure 11 shows the historic variability for three wind conglomerations: it shows that the variability measured at the farm gate for a single 225 MW wind farm is greater in percentage terms than for four wind farms (with a combined output of 550 MW) that are integrated at substation, and greater still when viewed from a BA perspective (3372 MW). Aggregation of wind resources tends to reduce the net variability in percentage terms, although the magnitude of change expressed in MW will increase (e.g. 95^{th} percentile for One Wind Farm is 10% or 22.5 MW, whereas for Four Wind Farms it is 7% or 38.5 MW). Aggregation can be limited by transmission impacts, and prior to aggregating the Transmission Provider should determine that any path/ flowgates traversing the aggregated area are not themselves subject to TVLs.

b) Drawing the line to distinguish between normal events and exceptional events is important. For instance, if the line between normal and exceptional events was drawn at the 95th percentile, this would translate into an expected variability at source that was lower than it would have been if the 99th percentile had been chosen, and as a result would imply that a dynamic resource would require less VTC. In drawing a line between normal & exceptional, Transmission Providers will indicate what the allowed frequency of repetitive changes in Dynamic Transfer will be for their system.

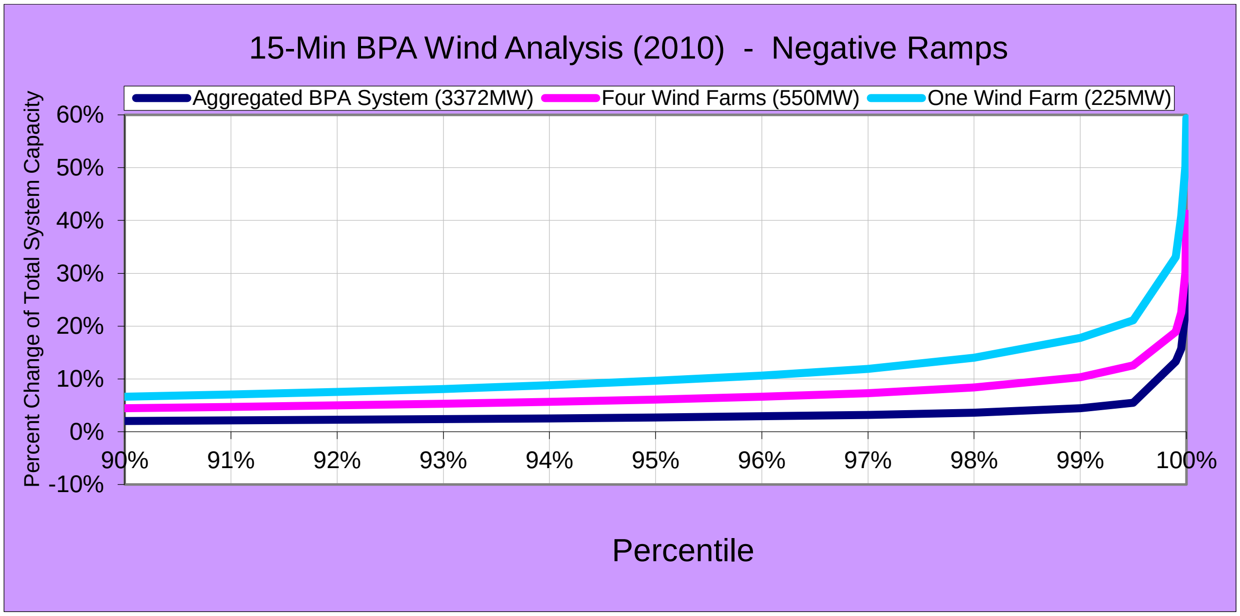

Figure 11: Wind Variability measured as percentage change for three conglomerations

<u>What happens when different TOPs calculate different TVLs for the same path?</u>

Given that the levels of automatic voltage control and RAS arming vary from one Transmission Provider to another, it follows that application of an identical TVL methodology could result in different TVLs for a shared path because the TVLs will reflect the differences in the flexibility of the transmission system on one side of the path versus the other as well as the system capability to withstand disturbances. In many ways this is merely the extension of what happens today when calculating SOLs for paths, as each Transmission Provider will base their calculation on the status of their system and how contingencies would affect their own and other systems. Ultimately, it is anticipated that differences in TVLs for a path will be reconciled by System Operators by agreement to operate to the most restrictive TVL.

<u>How much transmission should be reserved from a variable resource?</u>

A variable energy resource's hourly transmission reservations should never be more than the maximum installed capacity of the variable energy resource. The question is, 'Is this the appropriate level of transmission reservation or is there a lower level that would ensure an optimal balance between transmission usage and reliability for a given path?'

Generally speaking, it is expected that the transmission reservations from a variable energy resource will provide additional transmission capacity in case the resource's output exceeds its expected output. Reserving a relatively high amount additional transmission capacity would reduce the average transmission utilization for the path because transmission would be set aside to ensure that the generated energy rarely if ever, exceeded the reserved capacity. Reserving a low amount of additional transmission capacity could increase the risk of exceeding the path SOL, because any generation in excess of the expected value would flow on the path as unscheduled energy and in peak hours this could push the path above its limit. A challenge for Transmission Providers will be to establish policies regarding reserving additional transmission above a resource's expect output in order to ensure an appropriate balance between minimizing the unused transmission capacity on the path and minimizing the risk of exceeding the SOL.[16]

[16] One proposed method for determining an appropriate balance between the risk of unused transmission capacity during periods of demand and the risk of exceeding the path SOL involves a Transmission Provider conducting a statistical analysis of the flowgate under consideration for say a 5 year historical period prior to implementation of Dynamic Transfers. The purpose of this analysis would be to determine the historical frequency and magnitude of unexpected/unscheduled variation of flowgate flows. This would provide a benchmark for what has been acceptable in the past. This would be best illustrated by an example. Suppose a Transmission Provider decides to allocate Dynamic Transfers for a wind farm with a maximum installed capacity of P_{max}. The Transmission Provider would then conduct additional statistical analysis to determine the expected frequency and magnitude of the wind farm power output. The statistical analysis should provide information about the expected average (P_{avg}) and expected maximum output (P_{out}) of the wind farm say for a one hour period. The Transmission Provider then needs to decide the allowed transmission reservation which is a value between P_{out} and P_{max}. The value chosen will depend on how much risk the Transmission Provider wants to accept between underutilizing the path versus exceeding the SOL. If a value of P_{max} is chosen then maximum security is achieved by removing the risk of exceeding the SOL due to variation of the variable energy resource but at the expense of maximizing under-utilization of the flowgate. If P_{out} is chosen then security is reduced but the flowgate utilization improves. Using the results of the statistical analysis for the flowgate and wind farm and level of risk tolerance and the risk tolerance of the wind farm operators who will be subjected to curtailment when flows exceed the SOL, the Transmission Provider can determine the allowable amount of transmission reservations based on its risk tolerance. A defined TVL will reduce the risk of exceeding the SOL.

8.0 Comparison of Options to Increase TVLs

As a basic principle, the transmission system can be engineered to facilitate widespread use of unpredictable Dynamic Transfers. This requires some changes from what is currently done, as the system currently is managed and designed for operation in a static manner. Allowing transmission operation to be wholly dynamic up to the rating of the path – equivalent to making dynamic flexibility available to all schedules – is in theory possible, provided that:

- Adequate visibility and personnel at the RC, BA, and TOP for monitoring with respect to impact on reliability,
- Complete automation of controls whose settings are changed as a function of power flow,
- Adequate dynamic reactive available throughout the system to maintain voltage such that neither quality of service or reliability is compromised when power flow changes,
- Costs of installation and maintenance of this equipment is not prohibitive.

Based on the listing of critical elements and concerns developed in phase 1, the Task Force identified a number of enhancements to the system and its control mechanisms that would improve the ability to manage unpredictable Dynamic Transfers and thereby could lead to an increase in the total unpredictable Dynamic Transfer capability available for use.

The following chart itemizes the possible enhancements and tries to quantify the relative cost and implementation time of these enhancements. Any upgrade is dependent upon the Path it is being applied to along with many other factors. As systems are different, not all of these options would be available for all systems. Studies would have to be performed to determine which options are viable and how effective they are in increasing TVLs.

Upgrade Option to enhance TVL	Relative Cost: Low < $10M; High > $100M	Relative time to implement: Short < 2 years; Long >10 years
Revise Assumptions and/or criteria	Low	Short
Incorporate variable resource characteristics	Low	Short
Automate Reactive Voltage Control	Low	Short
Improved tools for system operations	Low	Short to Medium
Operational Procedures	Low	Short to Medium
Constrain ramp rates	Low	Short to Medium
Increase staffing Levels	Low-Medium	Short to Medium
Automate RAS	Medium	Medium-Long
Higher duty switching devices	Medium	Medium-Long
SVC	Medium	Medium-Long
STATCOMs	Medium	Medium-Long
Series Compensation	Medium	Medium-Long
FACTS	Medium-High	Medium-Long
Phase shifting Transformers	Medium-High	Medium-Long
Transmission Lines	High	Long

Table 1: Options to Increase Path TVL

9.0 Next Steps

Dynamic Transfers are a valuable tool for managing the variability of intermittent resources. As illustrated in Figure 12, Dynamic Transfers are viewed as an early and economic option to facilitate higher penetration rates of intermittent resources.

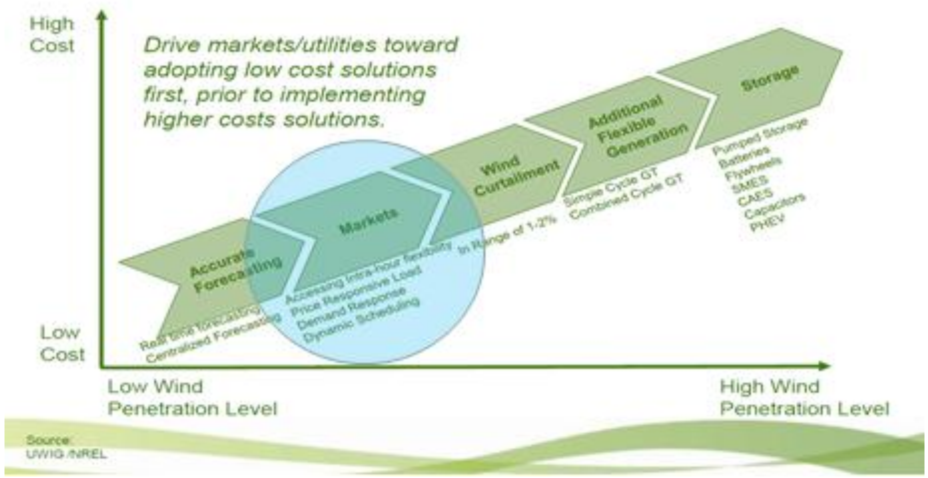

Figure 12: Options for managing variability of intermittent resources[17]

However, in order to significantly increase the number and characteristic of unpredictable Dynamic Transfers in the WECC, further work will be required by these distinct groups:

1) Transmission Providers will need to
   a. Identify commercial product for unpredictable Dynamic Transfers (for example, common business practice, common option time and schedule, common queue, tariff product, etc.);
   b. Develop common processes for unpredictable Dynamic Transfers;
   c. Develop rate methodology for unpredictable Dynamic Transfers;
   d. Quantify TVLs for their paths / flowgates and
   e. Identify options for increasing path TVL and their associated costs.

2) Transmission Customers will have different obligations and opportunities depending on where they connect to the transmission grid:
   a. TCs who are Generators: will need to quantify the variability of their dynamic resources and identify what they can do to help manage the variability (e.g. allow headroom, provide voltage support), to allow Transmission Providers to assess and manage the

[17] Source: http://www.westgov.org/EIMcr/meetings/07MAR11/present/panel5/l_beane.pdf see slide #3

impact on paths / flowgates. In addition, they will want to assess the transmission curtailment risks of different generation locations;

b. TCs who are Load Serving Entities / End Use: will need to identify their power quality needs so that the potential for adverse impacts can be properly assessed;

c. TCs who are Purchase Selling Entities: will need to know how firm their transmission service and understand when they could face transmission curtailment risks.

3) Regional Transmission Forums will need to come together to address the Dynamic Transfer issues that will arise when demand exceeds limits for Transfer Variability. In particular, a Joint Commercial/Operations Task Force needs to be formed to address marketing, policy, contract and other related issue in 2012.

Proposed Short Term Action Plan

1) DTC Task Force's Phase 3 report to be circulated to WECC & NWPCC members - 3 Jan. 2012;

2) CG & NT circulate Phase 3 report & action plan to Wind Integration Forum - 5 Jan 2012;

3) DTC Task Force members will provide internal briefings to their management - Jan 2012;

4) DTC Task Force to host a 2nd webinar to discuss the Phase 3 findings and WIST gather policy/trading and technical staff to prioritize commercial issues 24 Jan 2012;

5) WIST establish a Commercial/ Policy Task Force to address commercial issues - Feb 2012;

6) Explore how WECC will get involved in managing path TVLs - Mar 2012;

7) Transmission Providers present TVL results by path, as available, to WIST Throughout 2012;

8) TPs present approaches for resolving most significant commercial issues Throughout 2012.

Evaluating and quantifying the performance and reliability risks added to the transmission system by the widespread integration of intermittent resources and Dynamic Transfers is a complex issue, Transmission Providers have a considerable amount of work ahead in the effort to apply the methodology developed by this Task Force to their paths/flowgates. These studies will both inform, and be informed, by the efforts to resolve significant commercial issues, thus Transmission Providers are strongly encouraged to continue the efforts to examine the need for TVLs on their systems, and to perform these studies in a timely manner. It is anticipated that WIST will provide an ongoing forum for Transmission Providers to present results of TVL studies as they are performed, coordinate those results with adjacent TPs and define commercial/ policy issues.

10.0 Conclusions

Should unpredictable Dynamic Transfers be limited in order to safeguard system reliability and avoid equipment impacts (including generators) and load service power quality issues? To address this question, the Joint Initiative Wind Integration Study Team convened the DTC Task Force in October 2010. The third of three phases is now complete and the conclusions of this report are:

Conclusions of the DTC TF Phase 3 report are:

1. TVLs reflect an emerging issue that has reliability implications for some paths / flowgates.

2. A three part methodology for calculating TVLs has been developed. Its purpose is to determine when transfer variability across a path / flowgate may have an adverse impact on customers, equipment or reliable operating points.

3. There is an important distinction between variability that is anticipated and planned versus variability that cannot be anticipated. Where daily load or generation changes are anticipated and very predictable, system operators may follow a daily timetable for routinely adjusting voltage control equipment. Regular, anticipated adjustments and switching associated with load following (for example) is probably not feasible for non-dispatchable generation which is unpredictable.

4. There is a relationship between a path's static and variable transfers that defines the safe operating region. Characteristics of the relationship generally include:
    a. Maximum static transfer (equal to the SOL) occurs when variable transfer is zero;
    b. The maximum TVL will occur when the system is the least stressed;
    c. For any operating transfer level between 0 and SOL, a maximum variable transfer can be defined;
    d. Sum of the variable transfers plus the static transfers on a path must be less than or equal to the SOL;
    e. In between the end-points of the 0 MW of static transfers and 0 MW of variable transfers, a path will need to be managed to ensure that the combined operating point always stays within the perimeter of secure operating points.

5. TVL is less than or equal to the SOL. The reason for this relates the differences in methodology to determine TVLs and SOLs: for TVLs it is assumed that only automatic operations are available to adjust to changes in system flow, whereas for SOLs it is assumed that all the appropriate operator actions will take place to tune the system to maximize transfer levels. SOLs are higher because it is assumed that system operators are not time constrained, and can make as many adjustments as necessary to optimize the performance of the system. Systems which are already mostly under automatic control may have little or no reduction in the TVL versus the SOL.

6. Scheduling variable transfer on a path will restrict the amount of static transfer capacity available to be scheduled concurrently. Initial studies suggest that the exchange of static capability with variable capability will typically be less than one for one (i.e. less than one MW of variable transfer for one MW of static transfer) on paths with limited or no automatic voltage control.

7. The commercial issues associated with increased unpredictable Dynamic Transfers will need to be resolved in parallel with calculating TVLs for specific paths, including definition of the variable transmission service that could be scheduled and limited as needed.

8. The relationship between variable and static transfers on paths needs further study. In particular, it will be important to determine the impact of frequent and unanticipated variable transfers on different paths limited by different types of transmission constraints (e.g. voltage change, voltage stability, transient stability). In addition, further studies will be needed to assist some Path Operators/Owners in assessing how to manage trade-offs between variable and static transfers paths / flowgates on their system.

9. Determination of the TVL magnitude for a path is impacted by multiple effects, including:
    a. Actual operating point / scheduled operating point;
    b. Pre-outage conditions & stress of the study case;
    c. System topology (e.g. major lines out of service);
    d. Availability of automatic devices;
    e. Location of the variable resource and its balancing resource;
    f. Multiple simultaneous, unpredictable Dynamic Transfers flowing across the path;
    g. Policy Decisions (e.g. Risk tolerance, allowable voltage variation);
    h. Magnitude & frequency of the variation that is deemed acceptable over the defined time period;

10. Generally TVLs can be improved with more automated responses to variability (e.g. automated RAS arming & more automated voltage control) in conjunction with equipment designed to handle the associated duty cycles of automated voltage control.

11. All generators, and some dispatchable loads, could act as dynamic resources. Consequently, it is not just the variability from intermittent resources that needs to be accounted for, but rather all resources that cause frequent, unanticipated intra-hour variability in transfers across monitored paths / flowgates.

12. Prior to significant expansion of Dynamic Transfers in support of variable resources, it is recommended that Transmission Providers evaluate the need to implement TVLs on their systems, so that any potential impacts to customers, equipment and reliability are properly managed.[18]

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[18] No NERC or WECC criteria refer to TVL, consequently there are no mandatory requirements to carry out TVL studies, however, as some Transmission Providers have identified transfer variability as an emerging issue it is hoped that others will consider whether this is also an issue for their system.

13. There are policy questions that need to be resolved in order to calculate TVLs for a system's paths / flowgates. They are related to risk tolerance and acceptable impacts to quality of service, and include but are not limited to:
    a. Acceptable magnitude/frequency of voltage deviations?
    b. Acceptable levels of incremental cost due to increased variability?
    c. Acceptable levels of incremental reactive switching due to increased variability?

14. There are Dynamic Transfer issues[19] related to implementation and commercialization, not directly related to the calculation of TVLs, that will also need to be resolved in order facilitate increased use of unpredictable Dynamic Transfers.

15. Where limitations in unpredictable Dynamic Transfers are deemed necessary, additional coordination may be necessary between operating entities. Examples include, but are not limited to, increased visibility, coordinating schedules of allowed voltage deviation over time, and coordination of automatic voltage control equipment.

[19] In the course of DTC Task Force discussions and through the interactions with WECC members numerous Dynamic Transfer issues were raised that did not fall within the Task Force's mandate of determining a method for calculating TVLs. As these issues are important and will need to be addressed by appropriate groups or entities, the Task Force has highlighted some of the issues in Section 7.0 Dynamic Transfer Issues and has provided a summary of all issues raised in Appendix E.

Appendix A – Glossary of Dynamic Transfer Terms

To ensure consistent and reproducible results in a study methodology, it is imperative to have a common understanding of the basic terms. Consequently, the Task Force developed a glossary of terms to be used in describing the methodology and how its results could be applied. Some of these terms evolved during Phase 3; it is expected that they will continue to evolve as the methodology is further refined and that some of the terms will eventually be added to the NERC Glossary.

Dynamic Transfer - The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

Static Transfer (ST): Conventional transfers across a path / flowgate, usually made up of fixed hourly schedules between defined PORs (Points of Receipt) and PODs (Points of Delivery). (Units: MW)

System Operating Limit (SOL): The value that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. (Units: MW)

Static Transfer Limit (STL): For a given variable transfer, the maximum amount of Static Transfer that can be accommodated across a flowgate. (Units: MW)

Available Static Transfer Capability (ASTC) – The amount of Static Transfer that is still available to be scheduled across a flowgate for a given Static Transfer Limit. (Units: MW)

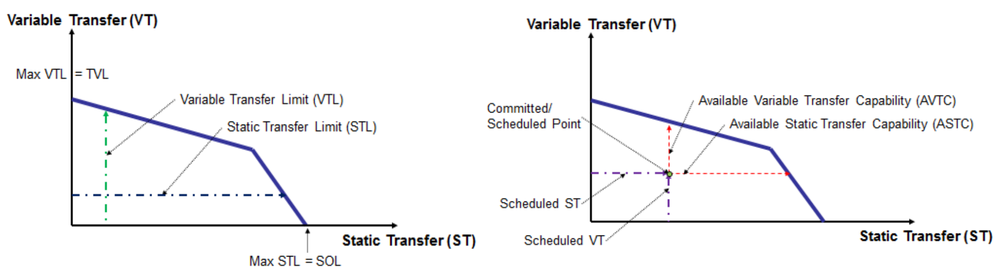


Figure A-1 and A-2: Variable and Static Transfer Nomogram and associated terms

Variable Transfer (VT): Refers to the physical variations in actual power flows across a path / flowgate that are generally unpredictable and repetitive during a defined time period (e.g. 15 minutes). Sources of Variable Transfer include: unpredictable Dynamic Transfers, intermittent resources and inadvertent (when not accounted for with a Transmission Reliability Margin {TRM}). (Units: MW)

Variable Transfer Limit (VTL): For a given static transfer, the amount of frequent but unpredicted variability in the power transfer across a flowgate that can be accommodated over a specified intra-hourly timeframe while ensuring the reliable operation of the system and avoiding unacceptable adverse impacts on equipment and customers.
(Units: MW)

Transfer Variability Limit (TVL) – The TVL is the maximum of the VTLs.
(Units: MW)

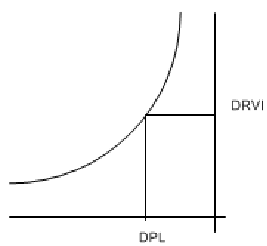
Available Variable Transfer Capability (AVTC) – The amount of Variable Transfer that is still available to be scheduled across a flowgate for a given Variable Transfer Limit.
AVTC = VTL - ∑ DRVD * PTDF (Units: MW)

Dynamic Percentile Limit (DPL) - Upper percentile (hours in the year) at which the DRVI for the Equipment and Customer Limits is determined. (Units %)

Dynamic Resource Variability Index (DRVI) – The expected percentage of its rated capacity that a Dynamic Resource varies during the TVL specified timeframe at the designated DPL. (Units: %)

Dynamic Resource Maximum (DRmax) – The maximum generation capacity of a Dynamic Resource, also known as the Pmax. (Units: MW)

Dynamic Resource Variable Demand (DRVD) – The expected amount of variability, measured in MW, that a Dynamic Resource injects into the transmission system at its interconnection point: DRVD = DRVI x DRmax. (Units: MW)



Cumulative Distribution Function Plot of Intermittent Generation Characteristic

Figure A-3: Graphical Illustration of DRVI as a function of DPL

Power Transfer Distribution Factor (PTDF) – In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer (NERC Official definition). In the case of Variable Transfers, this definition becomes a measure of how the flow on transmission lines and flowgates change in response to a power transfer from a variable generator and its associated balancing resource. (Units: %)

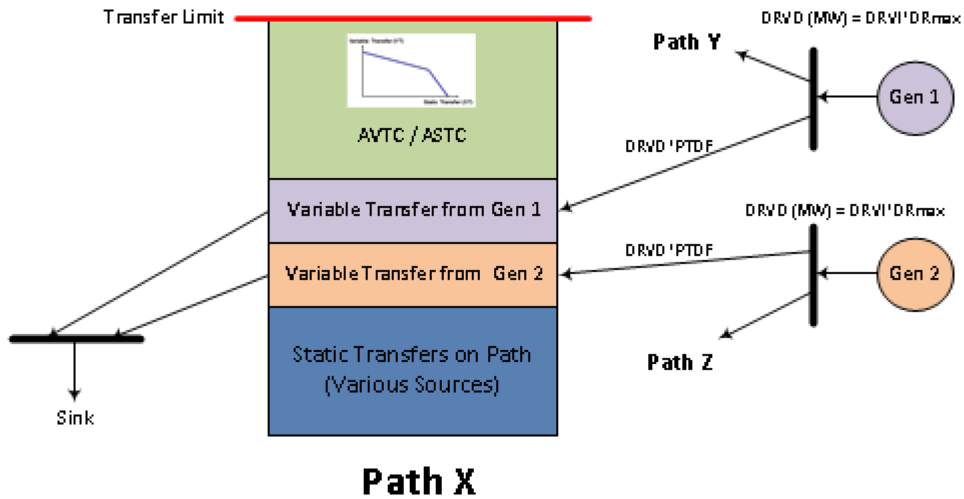


Figure A-4: Graphical Illustration of Variable and Static Transfers on a Path

In real-time operations it will be important to determine the correlation between the actual operating point and the actual scheduling point, as it is possible that there may be more or less Available Variable Transfer or Available Static Transfer for scheduling due to actual transfers being lesser or greater than the scheduled transfers. Further development may be needed to determine if additional terms are needed to track available transfers.

Available Variable Transfer is a function of both the actual operating point and the committed schedules point. Given that the actual operating point is not known in pre-schedule, it is hard to forecast what the Available Variable Transfer will be ahead of time. Consequently, this may require a conservative calculation during the pre-schedule timeframe; in the future with appropriate tools and procedures it may be possible to refine the preschedule numbers with more accurate real-time assumptions.

Appendix B – TVL Methodology Implementation Process – Single Path

Case 1 – Single Injection pair (source/sink) & Single Path

The following describes a procedure that can be used to implement the methodology proposed by BPA and other DTC members in determining the TVL (Transient Variability Limit) for a given Path and associated source/sink pair.

In the description that follows, Powerworld is assumed to be the tool of choice. Similar functions/features might be available in other power flow programs (PSLF/PSSE).

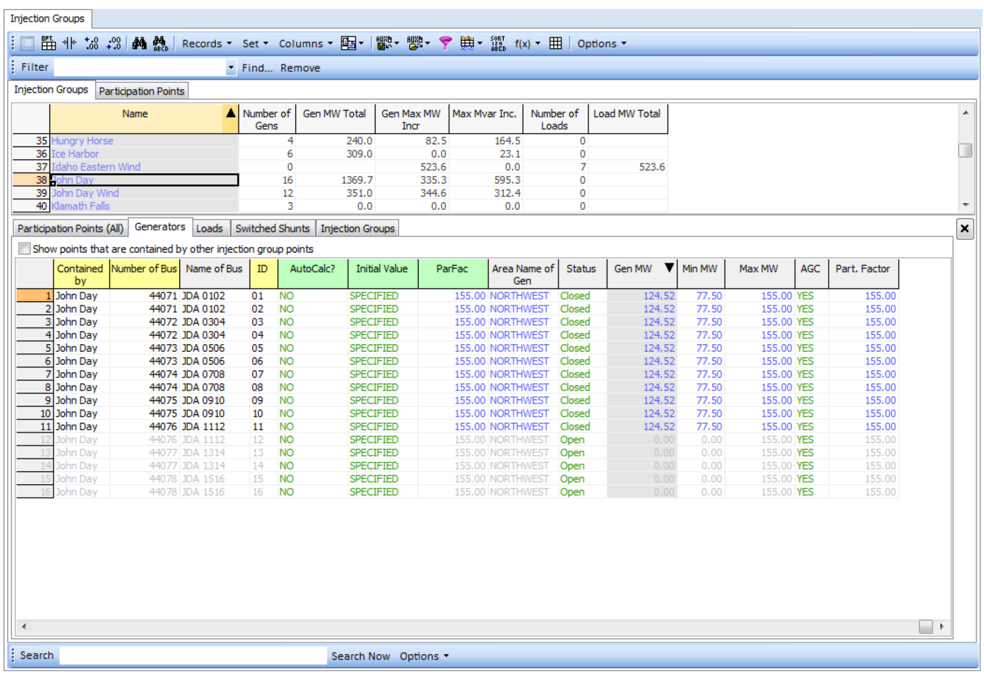
Step 1 –

Load in the case at a given initial transfer level across Path under study in the power flow program. Path flow should be less than SOL and voltage profiles and loading levels on BES elements should be within their normal/continuous range.

Step 2 -

Select a source/sink pair (injection groups) one each on opposite sides of the Path/flowgate over which a TVL is being determined. The source group is associated with the regulating element and the sink group with the variable source. For example a wind project (sink group) South of COI is being firmed up with resources (source injection group) North of COI. Note that the sink group can act as both a generator that ramps up as the wind increases or as a generator that ramps down (load increase) as the wind decreases.

To help with the description of the procedure used to implement the proposed methodology a practical example is presented in this write-up where the "John Day" plant is taken as an injection group in the Northwest (source).



Injection Groups

Records Set Columns Options

Filter Find... Remove

Injection Groups | Participation Points

	Name	Number of Gens	Gen MW Total	Gen Max MW Incr	Max Mvar Inc.	Number of Loads	Load MW Total
35	Hungry Horse	4	240.0	82.5	164.5	0	
36	Ice Harbor	6	309.0	0.0	23.1	0	
37	Idaho Eastern Wind	0		523.6	0.0	7	523.6
38	John Day	16	1369.7	335.3	595.3	0	
39	John Day Wind	12	351.0	344.6	312.4	0	
40	Klamath Falls	3	0.0	0.0	0.0	0	

Participation Points (All) | Generators | Loads | Switched Shunts | Injection Groups

Show points that are contained by other injection group points

	Contained by	Number of Bus	Name of Bus	ID	AutoCalc?	Initial Value	ParFac	Area Name of Gen	Status	Gen MW	Min MW	Max MW	AGC	Part. Factor
1	John Day	44071	JDA 0102	01	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
2	John Day	44071	JDA 0102	02	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
3	John Day	44072	JDA 0304	03	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
4	John Day	44072	JDA 0304	04	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
5	John Day	44073	JDA 0506	05	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
6	John Day	44073	JDA 0506	06	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
7	John Day	44074	JDA 0708	07	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
8	John Day	44074	JDA 0708	08	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
9	John Day	44075	JDA 0910	09	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
10	John Day	44075	JDA 0910	10	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
11	John Day	44076	JDA 1112	11	NO	SPECIFIED	155.00	NORTHWEST	Closed	124.52	77.50	155.00	YES	155.00
12	John Day	44076	JDA 1112	12	NO	SPECIFIED	155.00	NORTHWEST	Open	0.00	0.00	155.00	YES	155.00
13	John Day	44077	JDA 1314	13	NO	SPECIFIED	155.00	NORTHWEST	Open	0.00	0.00	155.00	YES	155.00
14	John Day	44077	JDA 1314	14	NO	SPECIFIED	155.00	NORTHWEST	Open	0.00	0.00	155.00	YES	155.00
15	John Day	44078	JDA 1516	15	NO	SPECIFIED	155.00	NORTHWEST	Open	0.00	0.00	155.00	YES	155.00
16	John Day	44078	JDA 1516	16	NO	SPECIFIED	155.00	NORTHWEST	Open	0.00	0.00	155.00	YES	155.00

Search Search Now Options

Figure B-1: Source Injection Group (in example)

And a set of load buses in eastern Idaho as the other injection group (sink). This group is made up of a collection of 138kV load buses to represent the general wind location in eastern Idaho. Note that sudden reductions in wind generation in Eastern Idaho are assumed compensated by balancing resources in the Northwest (source point) and add to the Eastbound stress across Path 14 (Idaho – Northwest). Sudden wind increases (in Eastern Idaho) are similarly assumed compensated by the source point in the Northwest and subtract from the eastbound stress across the Path.

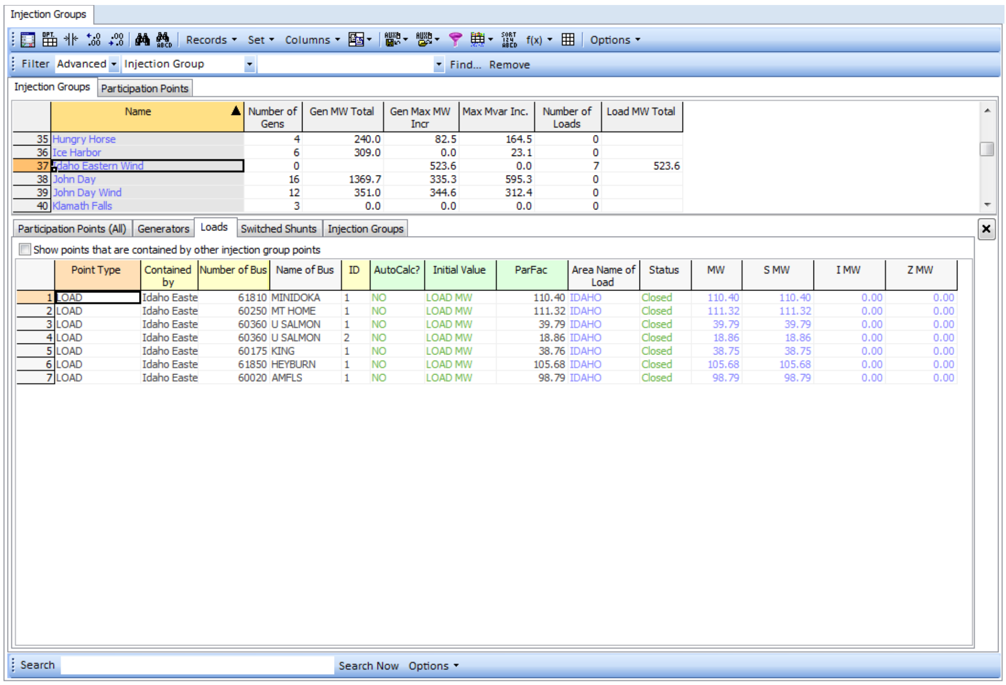


Figure B-2: Sink Injection Group (in example)

Step 3 –

Under the "Tools" tab go to Sensitivities < Flow & Voltage Sensitivities – Select the second tab "Single Transfer, Multiple Meters", Select "Inj. Group" for both Seller & Buyer Type. Select the desired Seller (source) and Buyer (sink) from the corresponding scroll down fields (need to have defined desired injection groups previously). Select Real Power (P) as the Transfer Type.

Click on the "Calculate Sensitivities" button.

Step 4 --

Group buses in areas where injection groups are located according to the following criteria:

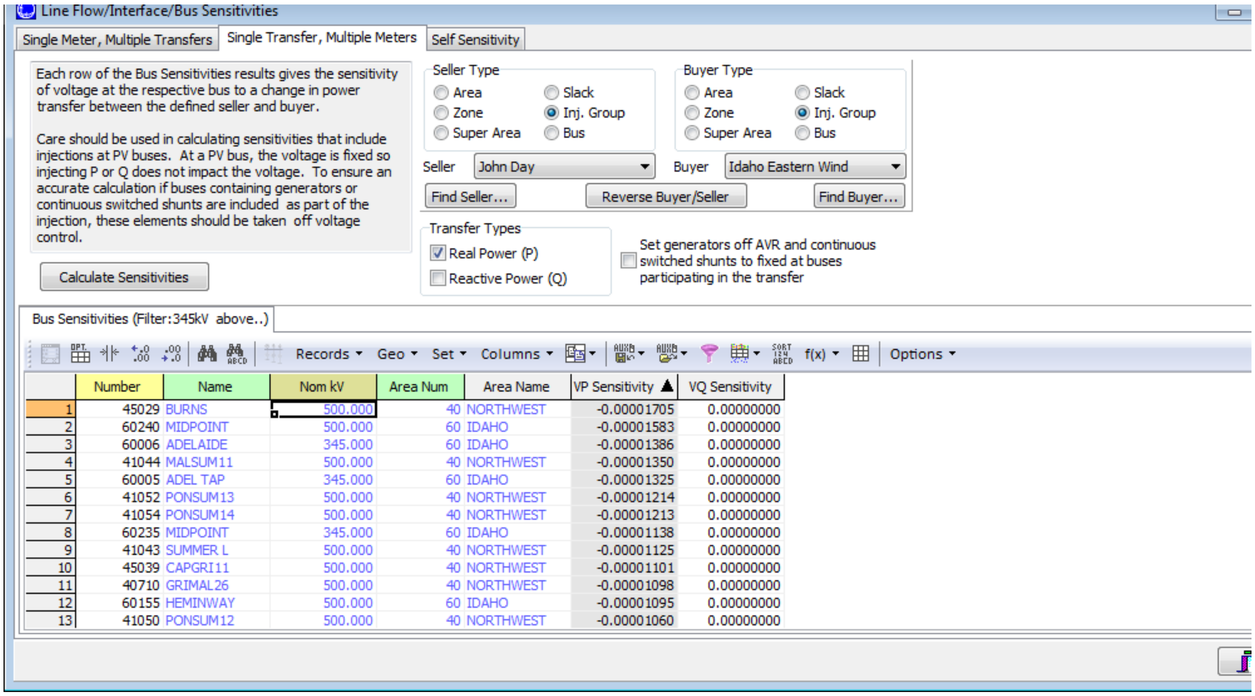
a- Nominal voltage greater than 345kV

b- Nominal voltage greater than 100kV < 300kV

The assumption is that buses in these areas would be the ones more significantly impacted by the source/sink injections. Alternatively one can monitor buses in all areas but still grouped according to above criteria.

Step 5 –

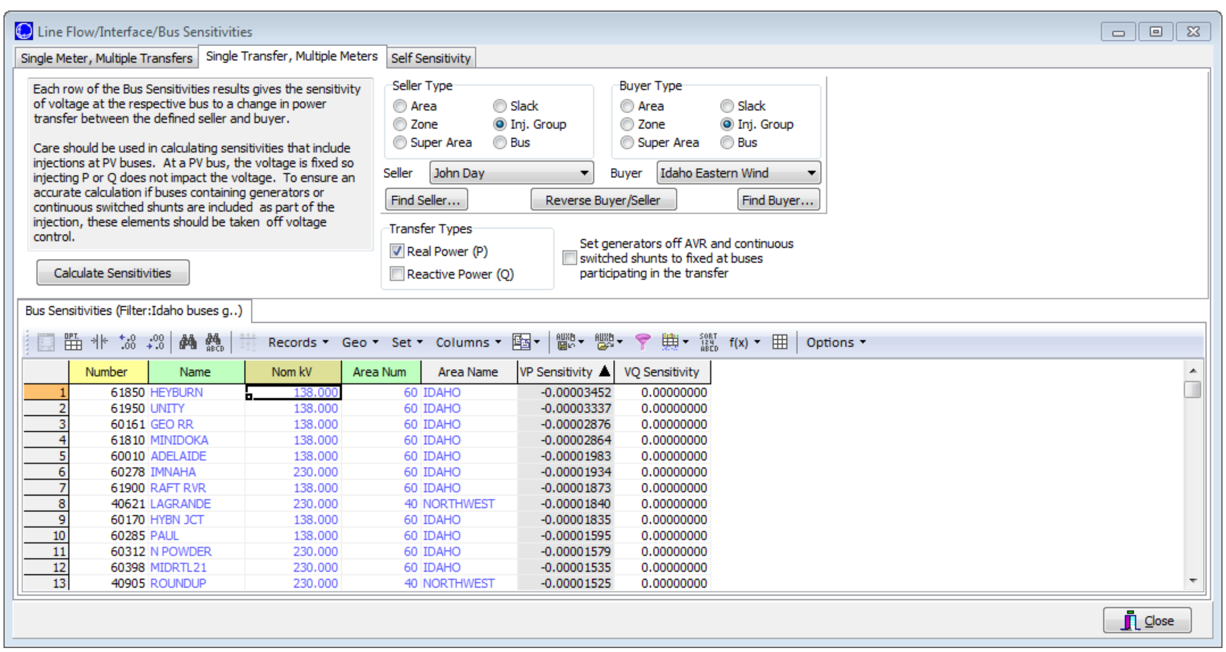
Determine which bus in each of the two groups above has the largest maximum absolute VP Sensitivity value of significance. In our example with a source at John Day (to simulate the compensating generator) and a sink in Eastern Idaho (to represent the Wind variation), the corresponding buses & max VP sensitivities are based on Table III below,



	Number	Name	Nom kV	Area Num	Area Name	VP Sensitivity	VQ Sensitivity
1	45029	BURNS	500.000	40	NORTHWEST	-0.00001705	0.00000000
2	60240	MIDPOINT	500.000	60	IDAHO	-0.00001583	0.00000000
3	60006	ADELAIDE	345.000	60	IDAHO	-0.00001386	0.00000000
4	41044	MALSUM11	500.000	40	NORTHWEST	-0.00001350	0.00000000
5	60005	ADEL TAP	345.000	60	IDAHO	-0.00001325	0.00000000
6	41052	PONSUM13	500.000	40	NORTHWEST	-0.00001214	0.00000000
7	41054	PONSUM14	500.000	40	NORTHWEST	-0.00001213	0.00000000
8	60235	MIDPOINT	345.000	60	IDAHO	-0.00001138	0.00000000
9	41043	SUMMER L	500.000	40	NORTHWEST	-0.00001125	0.00000000
10	45039	CAPGRI11	500.000	40	NORTHWEST	-0.00001101	0.00000000
11	40710	GRIMAL26	500.000	40	NORTHWEST	-0.00001098	0.00000000
12	60155	HEMINWAY	500.000	60	IDAHO	-0.00001095	0.00000000
13	41050	PONSUM12	500.000	40	NORTHWEST	-0.00001060	0.00000000

Figure B-3: Voltage Sensitivities Results (345kV & 500kV)

And filtering for 100kV to 300kV buses in Idaho & the Northwest,



	Number	Name	Nom kV	Area Num	Area Name	VP Sensitivity	VQ Sensitivity
1	61850	HEYBURN	138.000	60	IDAHO	-0.00003452	0.00000000
2	61950	UNITY	138.000	60	IDAHO	-0.00003337	0.00000000
3	60161	GEO RR	138.000	60	IDAHO	-0.00002876	0.00000000
4	61810	MINIDOKA	138.000	60	IDAHO	-0.00002864	0.00000000
5	60010	ADELAIDE	138.000	60	IDAHO	-0.00001983	0.00000000
6	60278	IMNAHA	230.000	60	IDAHO	-0.00001934	0.00000000
7	61900	RAFT RVR	138.000	60	IDAHO	-0.00001873	0.00000000
8	40621	LAGRANDE	230.000	40	NORTHWEST	-0.00001840	0.00000000
9	60170	HYBN JCT	138.000	60	IDAHO	-0.00001835	0.00000000
10	60285	PAUL	138.000	60	IDAHO	-0.00001595	0.00000000
11	60312	N POWDER	230.000	60	IDAHO	-0.00001579	0.00000000
12	60398	MIDRTL21	230.000	60	IDAHO	-0.00001535	0.00000000
13	40905	ROUNDUP	230.000	40	NORTHWEST	-0.00001525	0.00000000

Figure B-4: Voltage Sensitivity Results (100kV < buses < 300kV)

From which the following results are selected:

Number	Bus Name & kV	Area	VP Sensitivity
60240	Midpoint 500 kV	Idaho	-0.00001583
61850	Heyburn 138 kV	Idaho	-0.00003452

Table B-1: Initial Voltage Sensitivities – Limiting Buses

And assuming a maximum of 1% and 3% volt change as the acceptable customer limit, the estimated power transfer between the source and sink injection points would be:

Assumed Maximum Acceptable Voltage Deviation	Bus Name & kV	Corresponding Power Transfer between injection points.
1%	Midpoint 500 kV	631.2 MW
3%	Heyburn 138 kV	869.1 MW

Table B-2: Calculated Initial Transfers (between injection points) required for limiting voltage deviations

Where the Power Transfer between injection points that results in the maximum acceptable voltage deviation is determined by dividing the allowed deviation by the VP Sensitivity. Notice that in this particular example the voltage change criteria for 345kV & above buses of 1% is more limiting (it takes less of a transfer to achieve reach the limit) than for lower voltage buses (3%).

Because of the large transfer level required to achieve the maximum acceptable voltage deviations and the non-linearities associated with this approach, half of the calculated transfer is applied in the power flow and the sensitivities re-calculated as an intermediate step in estimating the required transfer between injection points.

The power flow solution should block/disable phase shifters and other regulating transformers that are operated manually. All manually switched devices are assumed fixed in the initial state they are found in the original case. Additionally the ACE/Area Control option is also turned off in the solution.

Expected Voltage Deviation (based on applied transfer)	Actual Voltage Deviation from power flow	Bus Name & kV	Corresponding Power Transfer between injection points.
0.5%	0.66%	Midpoint 500 kV	315 MW

Table B-3: Power flow results at half the calculated transfer level

Notice that the voltage deviation as determined from the power flow simulation was 0.66% rather than the 0.5% initially estimated.

And the new voltage sensitivities under the applied transfers are now:

Number	Bus Name & kV	Area	VP Sensitivity
60240	Midpoint 500 kV	Idaho	-0.00002285
61850	Heyburn 138 kV	Idaho	-0.00004337

Table B-4: Voltage Sensitivities – Limiting Buses (intermediate results)

Note that at this intermediate level, the voltage sensitivities will not necessarily remained as found originally. Not just the magnitude but their associated buses might also be different. One way to account for this is to continue monitoring, in addition to the new worst offenders, the original ones when verifying the results (actual voltage change) in the power flow. Transfers can then be adjusted accordingly.

Additional Voltage Deviation	Bus Name & kV	Corresponding Power Transfer between injection points.
0.34% 1)	Midpoint 500 kV	149 MW
1) Additional voltage deviation allowed before reaching maximum total acceptable voltage deviation of 1% with respect to initial case.		

Table B-5 Calculated additional transfer (between injection points) required to achieve additional ΔV

And the power flow results,

Expected Voltage Deviation (based on applied transfer)	Actual Voltage Deviation from power flow	Bus Name & kV	Additional Power Transfer between injection points.
0.34%	0.4%	Midpoint 500kV	149 MW
0.34%	0.34%	Midpoint 500kV	129 MW 2)
2) Power transfer adjusted by trial and error to satisfy desired voltage deviation.			

Table B-6: Power flow results at the new estimated transfer level

Even though the sensitivity calculation estimated that only additional 149 MW of transfer between the specified injection points were needed, because of non-linearities, the required additional transfer level was found to be 129 MW. The maximum total MW transfer between the injection points before the assumed voltage change criteria is exceeded (1% for a 500 kV bus, in this case Midpoint 500), was found to be 315 MW + 129 MW = 444 MW.

The corresponding flows/transfers of interest are summarized in the table below,

Case Name	Transfer between injection points (John Day & Idaho Wind)	Idaho – NW (Path 14)	Midpoint 500kV (Voltage, pu)
Initial Case	0	-750 MW	1.0651
Stressed Case	444 MW	-1075 MW	1.0551

Table B-7 Voltage at limiting bus, transfers between injection points and across Path under study

At this point it is necessary to verify that reliability performance requirements are met at the estimated TVL (1075 MW -750 MW = 325 MW) associated with the static operating level of 750 MW import into Idaho; mainly that the case solves for an additional 2.5% stress level across the Path for the limiting N-2 outage, and an additional 5% stress level across the Path for the limiting N-1 outage. More detailed studies should verify transient stability and post-disturbance performance at the proposed TVL level.

If the reliability performance is acceptable, then the available TVL at the 750 MW import level into Idaho from the NW would be 325 MW. Unacceptable system performance implies that the TVL should be reduced systematically until acceptable performance is achieved.

At this point the available TVL across a Path, associated with a pre-specified power transfer between injection points (source & sink each at opposite side of the Path) would have been determined for a given initial operating static transfer level across the same Path.

Repeating this process for different values of initial transfers across the Path, for the same set of injection points, will prescribe the Nomogram relationship between the initial static Path flow and its associated TVL. Notice that different injection points (at opposite sides of the Path/flowgate) can result in a different Nomogram.

Appendix C – Recommended TVL Methodology for Multiple Paths

Dynamic Transfer Customer Impact

A method to compute the customer impact is presented using a simple 5 bus example. The method is presented first with single injection pair that is a single source and sink. The same 5 bus example is extended to two sources and sinks to show the impact of multiple transfers. Then a generalized approach is presented for multiple transfers.

Single Injection Pair (Source/Sink)

The following section describes a methodology to compute the customer impact due to single injection pair combination. The methodology is presented using a simple 5 bus model as shown below

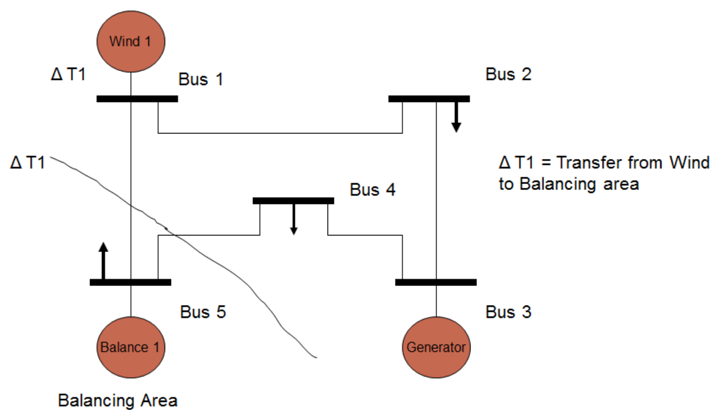


Figure C-1: Sample 5 bus system in this example as shown in Figure C-2, a wind plant is balanced by an injection group (Balance). Then the bus voltage change at any bus "i" can be computed using the voltage to transfer sensitivity.

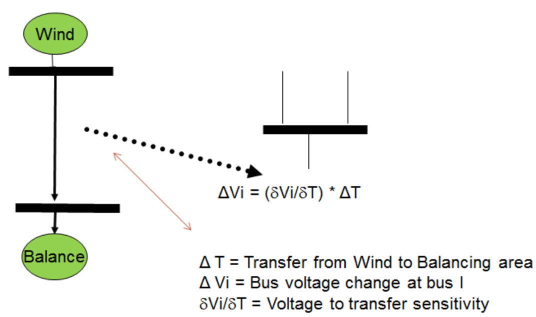


Figure C-2: Bus voltage change due to single transfer

Let as assume a 1% maximum allowable voltage change at any bus for customer impact. Then the bus voltage change for a transfer ΔT at all the 5 buses in the above system can be calculated as follows:

$\Delta V1 = \delta V1/\delta T * \Delta T <= 0.01$

$\Delta V2 = \delta V2/\delta T * \Delta T <= 0.01$

$\Delta V3 = \delta V3/\delta T * \Delta T <= 0.01$

$\Delta V4 = \delta V4/\delta T * \Delta T <= 0.01$

$\Delta V5 = \delta V5/\delta T * \Delta T <= 0.01$

In general terms it can be stated as

$[\delta V/\delta T] * [\Delta T] <=$ [Allowable bus voltage change due to customer impact]

For the 5 bus example assume the following sensitivity and the above equation can be written as

Bus	dV/dT	Allowable Voltage change (PU)
1	**0.0000250**	**0.01**
2	**0.0000500**	**0.01**
3	**0.0000150**	**0.01**
4	**0.0000100**	**0.01**
5	**0.0000010**	**0.01**

All the 5 buses in this example should meet the voltage change constraint. So the [ΔT] can be calculated by solving the above equation and finding the minimum value. For the example shown [ΔT] is 200 MW and is due to bus 2. The sensitivities are not constant and change based on the operating conditions. So it is necessary to recalculate sensitivities. Figure 3 presents a flow chart to calculate the customer impact on single transfer.

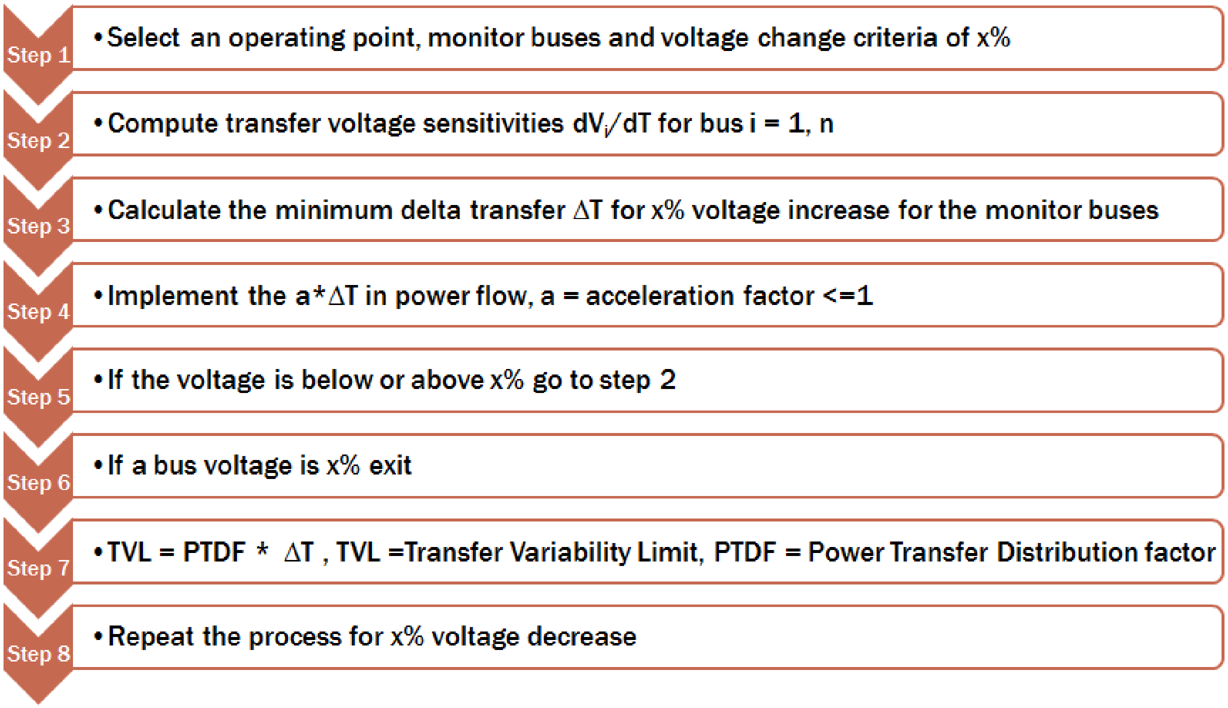


Figure C-3: Flow chart to compute customer impact due to single transfer

Multiple Sources and Multiple Sinks

The 5 Bus model presented for single injection pair is expanded to include an additional set of injection pair as shown below in figure 4.

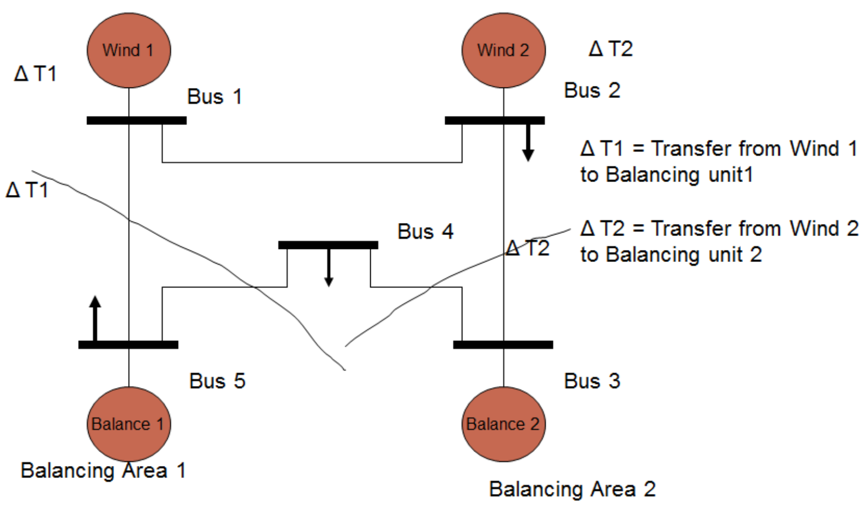


Figure C-4: Sample 5 bus system

In this illustration, wind 1 plant is balanced by units in balancing area 1 and wind 2 is balanced by units in balancing area 2. Then bus voltage change at any bus "i" can be computed using the voltage to transfer sensitivities. When additional transfers are added bus voltage is impacted by the amount of transfers as well as location of the injection groups. The impact can be calculated using superposition as shown in figure 5.

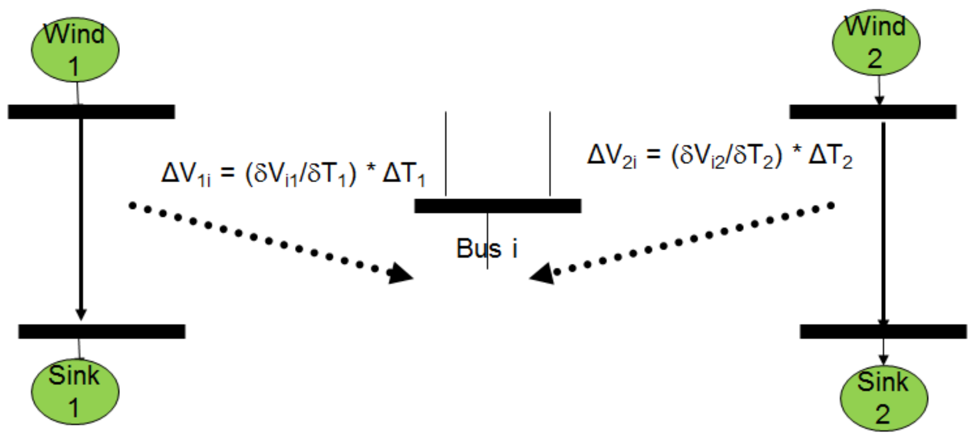


Figure C-5: Bus voltage using superposition

In this example there are two pairs of source/sink. So bus voltage change at any bus i will be impacted by the first pair of source/sink by $\Delta V1i$ and by the second pair by $\Delta V2i$. So bus voltage change at any bus "i" will be sum $\Delta V1i$ and $\Delta V2i$.

During Dynamic Transfer, the source and sink can shift their role based on the balancing need. So for two pairs of source and sink, there are 4 bus voltage equations as shown below:

$\Delta V1i + \Delta V2i = \Delta Vi$

$-\Delta V1i + \Delta V2i = \Delta Vi$

$\Delta V1i - \Delta V2i = \Delta Vi$

$-\Delta V1i - \Delta V2i = \Delta Vi$

As the wind changes, the balancing amount and direction can change. So bus voltage will increase or decrease based on the flow.

Let us assume 1% voltage change allowed due to customer impact. The bus voltage change at all the 5 buses in the above system for a transfer $\Delta T1$ and $\Delta T2$ can be calculated as follows:

$\Delta V1 = \delta V1/\delta T1 * \Delta T1 + \delta V1/\delta T2 * \Delta T2 <= 0.01$

$\Delta V2 = \delta V2/\delta T1 * \Delta T1 + \delta V2/\delta T2 * \Delta T2 <= 0.01$

$\Delta V3 = \delta V3/\delta T1 * \Delta T1 + \delta V3/\delta T2 * \Delta T2 <= 0.01$

$\Delta V4 = \delta V4/\delta T1 * \Delta T1 + \delta V4/\delta T2 * \Delta T2 <= 0.01$

$\Delta V5 = \delta V5/\delta T1*\Delta T1 + \delta V5/\delta T2*\Delta T2 <= 0.01$

In general terms it can be stated as

$[\delta V/\delta T] * [\Delta T] <=$ [Allowable Bus Voltage Change due to customer impact]

For the 5 bus example assume the following sensitivity and the above equation can be written as:

Bus	|dV/dT1| (kV/MW)	|dV/dT2| (kV/MW)	Allowable Voltage change Per Unit
1	**0.0000250**	**0.0000500**	**<=0.01**
2	**0.0000500**	**0.0000250**	**<=0.01**
3	**0.0000150**	**0.0000250**	**<=0.01**
4	**0.0000100**	**0.0000320**	**<=0.01**
5	**0.0000010**	**0.0000425**	**<=0.01**

The above equations are represented in figure 6. Each line represents the bus voltage constraint based on the transfer levels. Below the line the bus voltage constraints will be satisfied. For example for any bus if the transfer 1 and 2 are below the bus voltage will be less than 0.01PU.

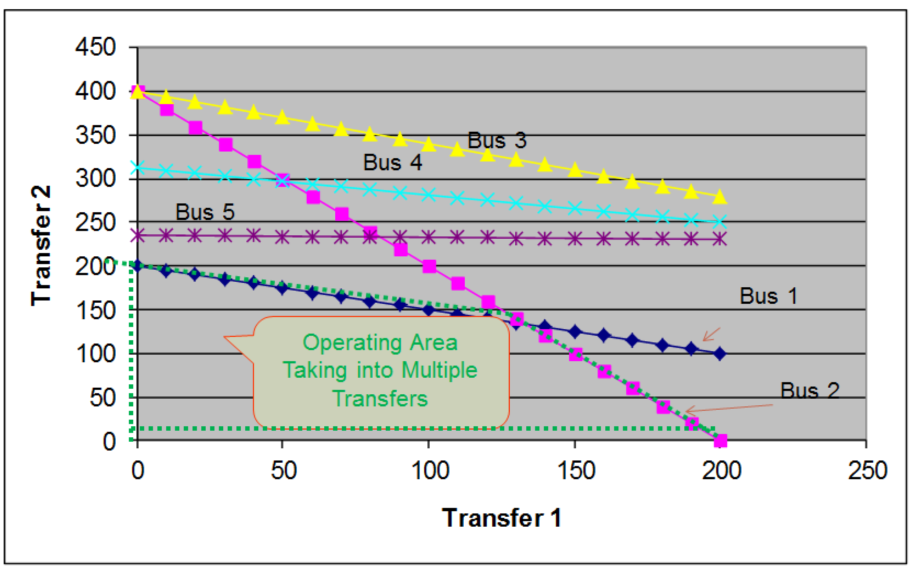
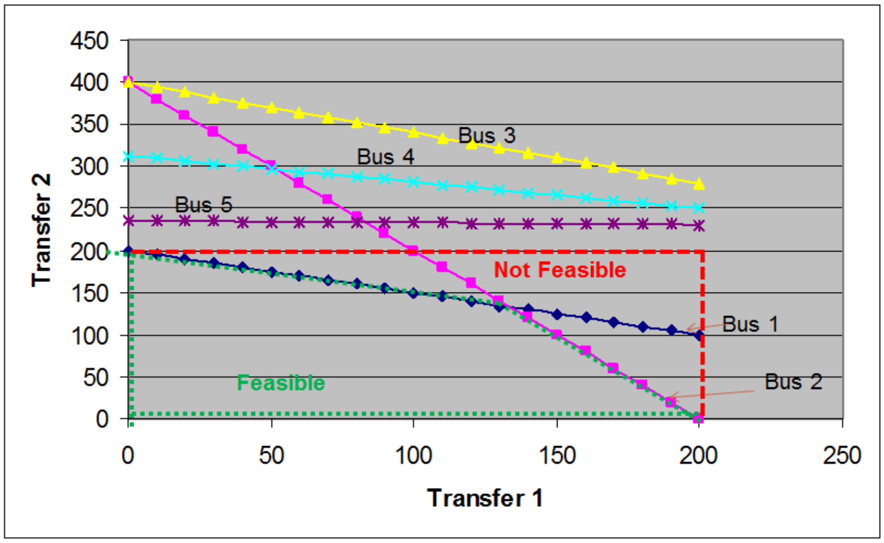


Figure C-6: Change in bus voltage constraints

In this plot (Figure. 6) it is clear that bus voltages 3, 4 and 5 voltage changes do not impact the transfer limit. Only bus 1 and bus 2 voltage changes impact the transfer. The green area provides the region one can operate the system without exceeding the change in bus voltage constraint.

If there are no interactions between transfer 1 and transfer 2 on the bus voltages 1 and 2 the transfer limit for a 1% voltage change will be 200 MW for transfer 1 and 2. Because of the interaction as transfer 1 increases, we can see maximum transfer 2 decreases. Figure 7 shows the feasible and non-feasible areas. Hence it is critical to consider the interactions when multiple transfers impact the same bus voltage and those buses are critical buses.



FigureC-7: Feasible and not feasible areas

Our goal is to maximize the unpredictable Dynamic Transfer across the system to integrate maximum amount of wind. In this case the maximum unpredictable Dynamic Transfer can be obtained when Transfer 1 and Transfer 2 are 133.3 MW as shown in the table below.

DT1	DT2	DT1 + DT2
0	0	0
200	0	200
0	200	200
133.3	133.3	**266.6**

If the transfer 1 and 2 or below 133.3 MW no voltage change constraints will be violated. Customer impact will be satisfied. The results are plotted in the figure 8.

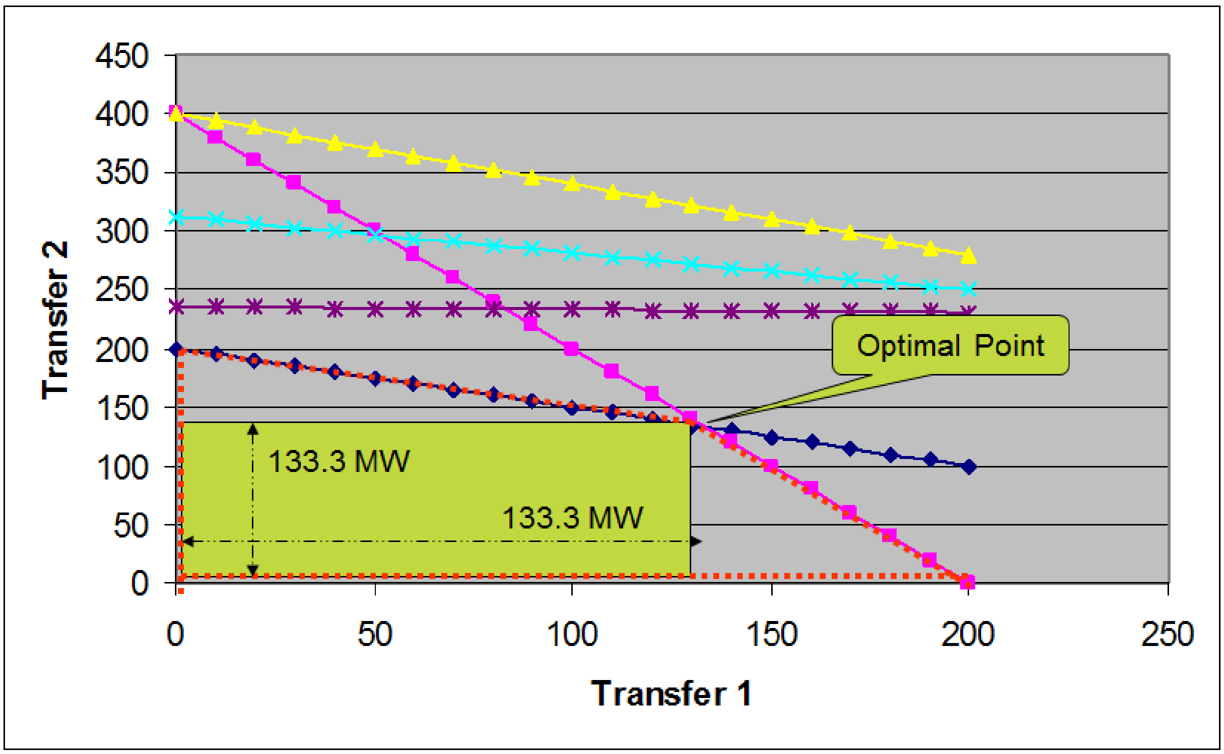


Figure 8: Optimal operating point

When the transfer 1 exceeds 133.3 MW one needs to decrease transfer 2 below 133.3 MW. If Dynamic Transfer 1 is 175 MW then Dynamic Transfer two cannot exceed 50 MW for this case and it is shown in Figure 9.

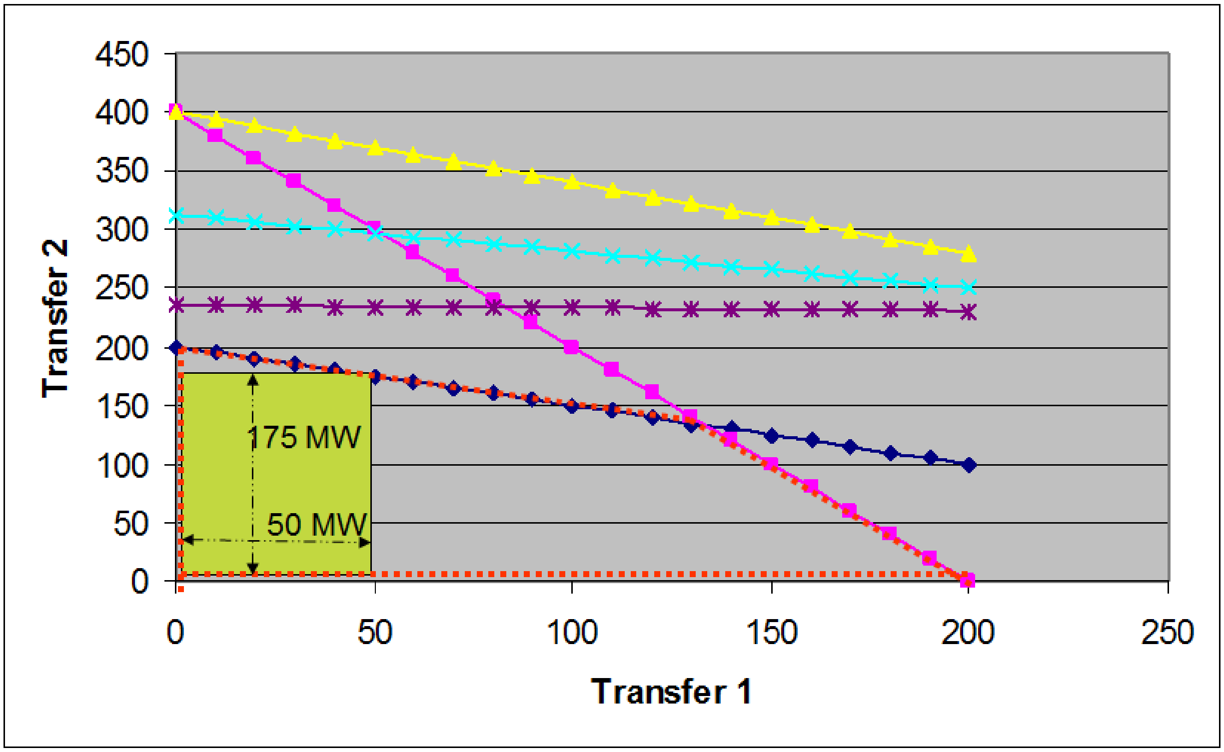


Figure 9: Changes in Dynamic Transfer limits based on other Dynamic Transfers

Optimization Formulation

If there are "n" buses monitored in the system and "m" source/sink pairs then the total number of equations will be m x m x n. Then the problem becomes very complicated when multiple source/sink are present in the system. The goal is to maximize the total unpredictable Dynamic Transfer through a system so we can allow a large quantity of intermittent energy sources (wind) at the same time, without violating system operating limits.

Objective:

Max ∑ Abs(Transfer (Z))

for i = 1 to n Dynamic Transfers

- Subject to
  - H(z) <= 0
- Where
  - Z = is the vector of decision variables that includes both control and state variables
  - H(z) = is vector of operating conditions that cannot be violated

Transfer flows are function of the voltages and angles at its terminal buses and can be written as:

$$\Delta Tkm = [\partial Pkm/\partial Vk]\Delta Vk + [\partial Pkm/\partial Vm]\Delta Vm + [\partial Pkm/\partial øk]\Delta øk + [\partial Pkm/\partial øm]\Delta øm$$

Where

ΔT_{km} = Change in Transfer flow from bus k to m

$[\partial Pkm/\partial Vk]$ = Partial derivative of flow change from bus k to bus m by voltage change at bus k

ΔVk = Change in voltage at bus k

$[\partial Pkm/\partial øk]$ = Partial derivative of flow change from bus k to bus m by angle change at bus k

$\Delta øk$ = Change in bus angle at bus k

In this formulation voltage change and angle change at any bus can be calculated using the injection changes and control variable changes using the Jacobin matrix. Figure 10 below presents the optimization problem.

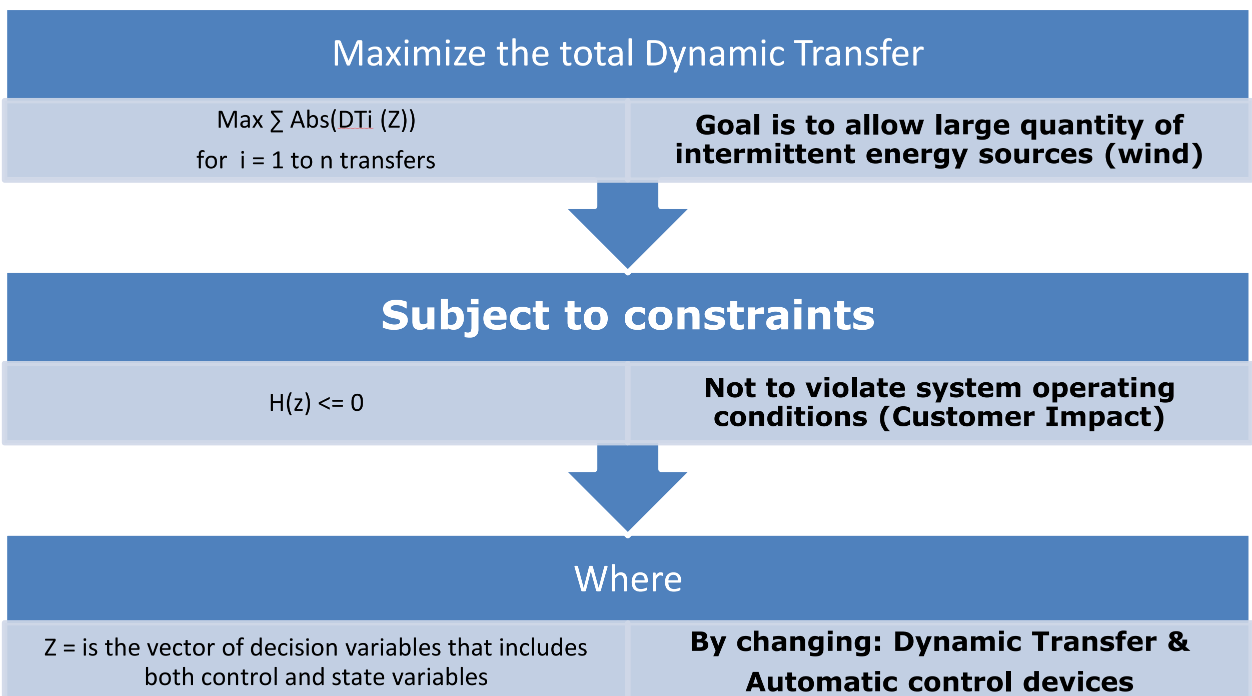


Figure 10: Optimization formulation

The optimization problem can be solved using different optimization techniques. Figure 11 presents a technique to solve the optimization problem using successive linearization. Similar to single transfer voltage transfer sensitivities are calculated. Using optimization approach delta transfers are calculated such that voltage constraints are satisfied. They are applied to power flow and the voltage change constraints are verified. The process is repeated till all constraints are satisfied. Once the transfers are known TVLs are calculated using power transfer distribution factors (PTDF) or by power flow. Additional steps or modifications from single transfers are highlighted in red in figure 11.

Step 1 • Select an operating point, monitor buses and voltage change criteria of x%

Step 2 • Calculate transfer voltage sensitivities dV_i/dT_j for bus i = 1 to n and for transfer j = 1 to m

Step 3 • Maximize the transfer using optimization

Step 4 • Calculate the delta transfers ΔT's for x% voltage change

Step 5 • Implement the a*ΔT's in power flow, a <=1

Step 6 • If the voltages are below or above x% go to step 2

Step 7 • If a voltage is x% exit

Step 8 • Calculate TVL_k = sum ($PTDF_{kj}$ * ΔT_j) For k = 1 to s, j = 1 to m

Figure 11: Flow chart to compute TVLs – multiple transfer case

Observations

- It is important to consider the impact of multiple transfers
- Within the feasible region, customer impact will be satisfied
- Feasible area will be maximum when there are no interaction between transfers
- Feasible area will be reduced when there are interactions between transfers
- When transfers have interactions
    - Maximum ΔT1 happens when ΔT2 is zero
    - Maximum ΔT2 happens when ΔT1 is zero
- To have maximum transfer ΔT1opt + ΔT2opt will be maximum (Optimal point)
    - ΔT1opt = ΔT1 is the value at the optimal point
    - ΔT2opt = ΔT2 is the value at the optimal point
- Choice of transfer scenarios will impacts the results

Appendix D – Magnitude & Frequency of Path Variability in 2009

This Appendix summarizes some of the data that the DTC Task Force reviewed to understand how transfer variability currently manifests itself. The first analysis quantified the frequency and magnitude of path variability for a few paths located around the WECC. The second analysis examines voltage variations measured at some critical busses across the WECC for 15 minute increments.

Path / Flowgate	Path 66	Path 3	Path 8	Path 14	Path 71
	CAISO & BPA	BC Hydro & BPA	NWE & BPA	IPCO & BPA	S of Allston BPA
Path Rating	S>N 3675 N>S 4800	N>S 3150 S>N 2000	E>W 2200 W>E 1350	E>W 2400 W>E 1200	N>S 3430
3 times an hour	110 -111	71 -61	59 -58	62 -62	39 -39
once an hour	157 -158	134 -98	76 -75	82 -83	62 -61
12 times a day	187 -189	179 -124	86 -87	94 -95	78 -77
6 times a day	217 -219	233 -151	97 -100	105 -107	94 -93
once a day	327 -325	436 -218	134 -155	144 -153	135 -132
once a month	822 -821	793 -367	276 -605	709 -870	348 -471
once a year	1178 -1013	997 -529	1105 -988	924 -976	1333 -1721

Table D-1: **Magnitude & Frequency of Path Variabilityfor 15 minute intervals excluding Ramp Periods - 2009 Calendar Year**

Path / Flowgate	Path 66 CAISO & BPA	Path 3 BC Hydro & BPA	Path 8 NWE & BPA	Path 14 IPCO & BPA	Path 71 S of Allston BPA
Path Rating	**S>N 3675** **N>S 4800**	**N>S 3150** **S>N 2000**	**E>W 2200** **W>E 1350**	**E>W 2400** **W>E 1200**	**N>S 3430**
3 times an hour	152 -156	75 -99	65 -65	70 -70	54 -52
once an hour	251 -268	146 -188	90 -93	98 -100	95 -92
12 times a day	322 -343	203 -254	105 -112	116 -121	123 -120
6 times a day	397 -428	276 -326	122 -132	136 -142	151 -148
once a day	618 -654	601 -563	172 -192	192 -214	231 -238
once a month	1026 -1070	1254 -1210	270 -728	783 -720	389 -447
once a year	1139 -1223	1407 -1399	1231 -1198	899 -900	591 -1021

Table D-2: Magnitude & Frequency of Path Variability for 15 minute intervals only including Ramp Periods - 2009 Calendar Year

Percentile	Number of Occurrences	BC Hydro				BPA			IPCO		NWE	CAISO
		G. M. Shrum 500kV	Williston 500kV	Kelly Lake 500kV	Ingledow 500kV	Custer 500kV	Monroe 500kV	Echo Lake 500kV	Borah 345kV	La Grande 230kV	Garrison 500kV	Round Mountain 500kV
90%	29 times a day	-0.26	-0.49	-0.45	-0.40	-0.65	-0.60	-0.57	-0.54	-0.53	-0.60	-0.51
		0.26	0.46	0.43	0.40	0.65	0.58	0.52	0.56	0.53	0.70	0.51
91%	26 times a day	-0.27	-0.53	-0.48	-0.42	-0.71	-0.65	-0.58	-0.60	-0.53	-0.60	-0.51
		0.27	0.48	0.48	0.40	0.71	0.65	0.52	0.61	0.53	0.70	0.51
92%	23 times a day	-0.30	-0.53	-0.49	-0.48	-0.72	-0.65	-0.58	-0.64	-0.53	-0.62	-0.51
		0.30	0.53	0.48	0.46	0.72	0.65	0.58	0.64	0.53	0.70	0.51
93%	20 times a day	-0.33	-0.59	-0.56	-0.55	-0.76	-0.71	-0.65	-0.64	-0.60	-0.67	-0.51
		0.32	0.55	0.54	0.52	0.78	0.71	0.58	0.64	0.59	0.72	0.51
94%	17 times a day	-0.38	-0.59	-0.59	-0.60	-0.78	-0.76	-0.71	-0.64	-0.60	-0.70	-0.51
		0.37	0.59	0.56	0.60	0.78	0.71	0.65	0.64	0.60	0.77	0.51
95%	14 times a day	-0.42	-0.66	-0.64	-0.60	-0.84	-0.78	-0.78	-0.64	-0.60	-0.72	-0.63
		0.41	0.66	0.64	0.60	0.85	0.78	0.71	0.64	0.60	0.82	0.51
96%	12 times a day	-0.48	-0.68	-0.72	-0.68	-0.91	-0.84	-0.84	-0.69	-0.66	-0.80	-0.76
		0.47	0.67	0.72	0.67	0.91	0.84	0.84	0.75	0.66	0.90	0.63
97%	9 times a day	-0.56	-0.72	-0.80	-0.80	-0.98	-0.91	-0.91	-0.80	-0.66	-0.89	-0.76
		0.56	0.73	0.80	0.80	0.98	0.91	0.91	0.80	0.66	1.00	0.76
98%	6 times a day	-0.69	-0.82	-0.89	-0.92	-1.04	-1.04	-1.04	-0.85	-0.77	-1.00	-0.89
		0.68	0.85	0.95	0.93	1.10	1.04	1.04	0.96	0.77	1.10	0.89
99%	3 times a day	-0.94	-0.98	-1.12	-1.15	-1.17	-1.26	-1.17	-1.11	-0.90	-1.25	-1.02
		0.96	1.01	1.12	1.20	1.23	1.30	1.23	1.17	0.92	1.37	1.02
99.50%	1.5 times a day	-1.18	-1.12	-1.25	-1.40	-1.36	-1.95	-1.36	-1.27	-1.06	-1.90	-1.14
		1.20	1.18	1.36	1.53	1.43	1.86	1.43	1.43	1.13	2.18	1.14
99.95%	once a week	-2.03	-1.84	-2.00	-2.20	-1.95	-2.46	-1.73	-2.19	-3.72	-5.29	-1.52
		2.44	1.90	2.32	2.45	2.09	2.66	1.95	2.31	3.71	5.06	1.78
99.99%	once a month	-3.04	-2.63	-4.49	-2.81	-2.88	-2.84	-2.23	-2.69	-5.45	-6.35	-1.78
		3.38	2.88	5.93	3.00	2.42	2.84	2.26	2.98	5.27	7.20	2.41
100.00%	once a year	-3.59	-3.21	-5.90	-3.90	-3.89	-5.01	-2.44	-3.32	-6.26	-7.01	-2.19
		6.38	4.62	7.42	3.74	2.83	3.51	2.69	3.83	7.59	9.58	3.40

Table D-3: Summary of Positive and Negative 15 minute Voltage Deltas (%) at Critical 500kV, 345kV and 230kV Buses

Appendix E – Dynamic Transfer Issues

Introduction:

While recognizing the gamut of Dynamic Transfer issues, the DTC Task Force and the Phase 3 report has focused on a few of the physical issues. While several commercial issues are mentioned in this Appendix, they are clearly not within the mandate of the DTC Task Force, however, they are summarized so that they can be addressed in appropriate forums (e.g. inter-Balancing Authority discussions, in tariff or other regulatory discussions).

Shown below is a summary of the Physical and Commercial issues raised by WECC members. Descriptions of each question follow the summary.

#	**Primary Issue**	**Type**	**Jurisdiction**	**Status**
1	How should the TVL Methodology & the Phase 3 report of the DTC Task Force be reviewed and acted upon by WECC and its members?	Physical	WECC	- Referred to WECC JGC in Sept 2011

	#	**Related Secondary Issues**	**Type**	**Jurisdiction**	**Status**
	1a	How would the TVL Methodology need to be modified if an EIM was established? / How would an EIM affect the TVL Methodology?	Physical	WECC	- EIM / TVL workshop held on 22 August to explore issues; - Further work is needed to better understand the interactions between EIM & TVL.
	1b	What impact will TVLs have on the three-phase rating process?	Physical	WECC	- TBD in 2012 once Transmission Providers have determined their need for TVLs.
	1c	How much variability in transfer levels is reliable & acceptable for generation, transmission & loads?	Physical	WECC	- See Phase 3 report Appendix F for initial assessments of need to calculate TVL. Actual limits to be calculated by Transmission Providers.
	1d	How should TVLs be calculated?	Physical	WECC	- Complete. See Section 4.0 and Appendix B of this Phase 3 Report.
	1e	How much VTC is required for intermittent renewable generation?	Physical	WECC	- See example in Section 7.0 of this Phase 3 report. Ultimately, this will be determined by individual Balancing Authorities.

	1f	How much time should we assume in between System Operator initiated manual system adjustments?	Physical	WECC	- Complete. Will vary by Transmission Provider, however, in the Northwest 15 minutes is a common assumption (given 30 min scheduling) and for CAISO 5 minutes is appropriate (given automated voltage control and 5 minute dispatch cycles).
	1g	How do unpredictable Dynamic Transfers differ from dispatchable Dynamic Transfers?	Physical	WECC	- Will vary by Transmission Provider. Difference in who is in control – a local system operator, and remote system operator or weather.
	1h	What operating tools will be required to help manage the complexity of increased, unpredictable Dynamic Transfers?	Physical	WECC	- The three most significant tools to increase Dynamic Transfers are: 1) Automated RAS arming; 2) Automated voltage control; 3) Real-time SOL calculation. This issue will need to remain with Transmission Providers for implementation as they consider the need to expand TVLs.

#	Primary Issue	Type	Jurisdiction	Status
2	What process should be followed if a TP determines it must apply TVLs on some of its paths/flowgates?	Commercial	Non-WECC	- Issue referred to the Wind Integration Forum in November 2011 with two points emphasized: 1) commitment needed to increase transmission flexibility to facilitate increase Dynamic Transfers; 2) BAs need to work together to coordinate Business Practices and reduce Dynamic Transfer seams issues.

	#	Related Secondary Issues	Type	Jurisdiction	Status
	2a	What will the contract term and roll-over rights be for Variable Transfer Capability?	Commercial	Non-WECC	- Awaiting decisions of individual Transmission Providers and potentially the creation of an appropriate commercial forum.
	2b	How will historic variable transfer capability rights be determined and allocated?	Commercial	Non-WECC	- Awaiting decisions of individual Transmission Providers and potentially the creation of an appropriate commercial forum.
	2c	What obligation do TPs have to upgrade their networks to increase TVLs (e.g. automate RAS arming)?	Commercial	Non-WECC	- The only apparent obligation would be to be responsive to customer needs; however, individual transmission providers will need to determine how far they are prepared to go to increase TVLs.
	2d	Who should pay for the costs of increasing TVLs across a system?	Commercial	Non-WECC	- Awaiting decisions of individual Transmission Providers and potentially the creation of an appropriate commercial forum.
	2e	How should the trade-off between improving TVLs to increase on-peak supply options for LSEs and containing costs to transmission customers be managed?	Commercial	Non-WECC	- Awaiting decisions of individual Transmission Providers and potentially the creation of an appropriate commercial forum.

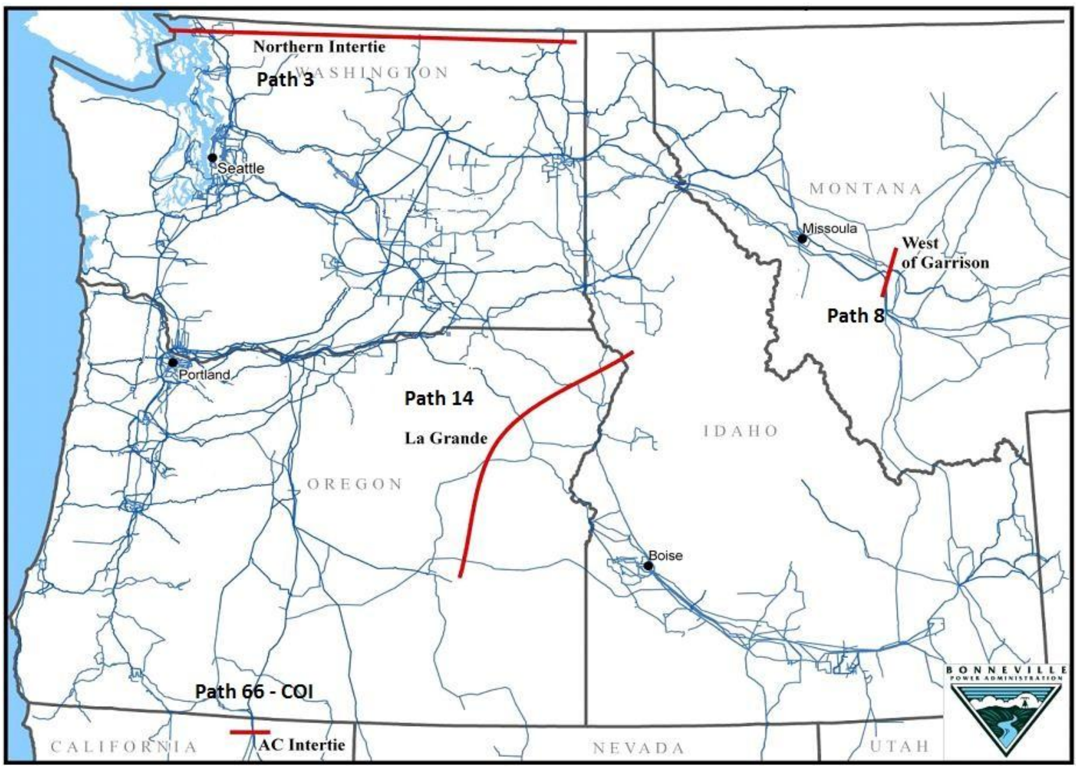
#	Primary Issue	Type	Jurisdiction	Status
3	How will scheduling practices change if TVLs are introduced for specific Transmission Providers?	Commercial /Physical	Transmission Providers (Initially)	- Awaiting decisions of individual Transmission Providers and potentially the creation of an appropriate commercial forum.

	#	Related Secondary Issues	Type	Jurisdiction	Status
	3a	How will customers understand the relationship between TVLs and their dynamic schedules?	Commercial /Physical	??	- There is a relationship between Static and Variable Transfers. The interaction will be better understood as Path TVLs are calculated.
	3b	How to reconcile restriction on access to transmission by dynamic resources?	Commercial /Physical	??	- Calculating Path TVLs will be crucial to determining what, if any, restrictions on a dynamic transfers will be required. .
	3c	How will unpredictable Dynamic Transfers be curtailed if they cause the TVL to be exceeded?	Commercial /Physical	??	- Awaiting decisions of individual Transmission Providers and potentially the creation of an appropriate commercial forum.
	3d	How will the risk of operating above path SOLs as a result of overgeneration be managed?	Commercial /Physical	??	- To be determined by System Operators.
	3e	How can TVLs be applied so that the terms and spirit of an OATT are respected?	Commercial /Physical	??	- Awaiting decisions of individual Transmission Providers and potentially the creation of an appropriate commercial forum.
	3f	How will ramp rates be limited and enforced?			- To be determined by System Operators.

Appendix F – Detailed TVL Summaries by Path

This appendix summarizes that studies that were run and shares the perspectives of the Transmission Entities involved with the four paths that were studied in Phase 3, namely: Path 66, Path 3, Path 8 and Path 14. The WECC 2011 Heavy Summer and WECC 2011 Light Summer were used as the basecases for the studies. While there are several transmission projects that are expected to be completed within a few years, these were not represented in the cases.

Please note that we did not forget to format this appendix consistently: the findings are color coded to differentiate between companies so that it is easier to associate a path perspective with a company.



Path 66: California – Oregon Intertie

Region:	WECC (Between Oregon and northern California)
SOL Setters:	BPA & CAISO
Path Owners[20]:	BPA, PAC, PGE, PG&E, WAPA, TANC
Path Ratings:	(N>S Path Rating = 4800 MW) & (S>N Path Rating = 3675 MW)

Need to manage TVL, why and what would change your assessment?

BPA (COI Northern Path Operator) view:

Plan to calculate TVLs (& associated nomograms):

The concerns raised by the work of this Task Force, and the independent analysis and operational experience of BPA, indicate the need for further assessment and establishment of TVLs until sufficient improvement in procedure, monitoring, and control are implemented to alleviate the need for them. Within the BPA BAA, a number of issues have been considered including:

- Significance of path and potential for widespread impact of reliability issues
- Coordination with operators on both sides of path. Situational awareness and understanding changing flows, impacts, drivers.
- Voltage stability limited path. Voltage is sensitive to path flows
- RAS, other dependence on historic generation scenarios to achieve high SOL and support operation.

In BPA's case, the issue is further complicated by the configuration of the transmission system itself: with over 3,000 MW of installed variable generation surrounded by multiple constrained paths crossing the transmission system between the major interties, increasing implementation of Dynamic Transfers must be evaluated in the context of the system as a whole.

Could be reassessed with:

- The need for TVLs will be reassessed on a regular basis, as BPA gains a better understanding of risks associated with new generation patterns, operating experience with higher variability, and identifies and implements reinforcements providing greater dynamic operating margin.

[20] The COI has multiple owners and parties with scheduling rights on both sides of the California Oregon Border (COB). Pacific Northwest parties own and operate the COI north of COB and Pacific Southwest parties own and operate the COI south of COB. The California ISO (CAISO) is the southern path operator and the Bonneville Power Administration (BPA) is the northern path operator. Three balancing authorities, CAISO, BPA and Sacramento Municipal Utility District intersect at the northern end of COI (Malin and Captain Jack substations). Further information on the utilization of the COI path can be found at: http://transmission.bpa.gov/Customer_Forums/tug/documents/coi_utilization_report.pdf

CAISO (COI Southern Path Operator) view:

Do not plan to calculate TVLs for COI because:

During the course of its recent Dynamic Transfers stakeholder process (completed in January 2011), the CAISO contracted with GE Energy for technical studies concerning the potential for maximum Dynamic Transfer limits for intermittent resources. This study concluded that no limits need to be applied across its Pacific AC Intertie or within the CAISO's BAA at this time. In the terminology of Appendix A, the CAISO's study used NREL data on wind resource variability to determine the Dynamic Resource Variable Demand (DRVD) at several levels of Dynamic Percentile Limit (DPL) and Dynamic Resource Maximum (DRmax), including levels significantly exceeding COI's SOL, and to determine the resulting Variable Transfer Capacity (VTC) on the COI flowgate. For example, at a frequency of once per 1.5 days (i.e., the 99th percentile), the profile for 5000 MW of Pacific Northwest wind resources would have an increase of 301 MW and decrease of 376 MW.

The CAISO study concluded that the operational impacts, including voltage and dynamic stability, resulting from scenarios in which Dynamic Transfers of intermittent wind resources were limited only by the COI SOL would be within acceptable levels on the COI flowgate and south of COI, and within the design capability of the California transmission system. Therefore, the levels of Variable Transfer Capacity (VTC) examined in the CAISO's study establish a lower limit on COI's Transfer Variability Limit (TVL) for the California transmission system, at a level that does not require limitations on Dynamic Transfers into the CAISO.

While recognizing the potential need for other transmission providers to impose TVL limitations north of COI, the CAISO believe that the California system can manage higher levels of variability based on this and other studies and on the operating experience that has been documented in the task force's Phase 1 and 2 reports. The reader should bear in mind that all schedules will be managed within the ATC in both pre-scheduling (day-ahead and hour-ahead) time horizons and in real-time operations.

Could be reassessed with:

As part of the CAISO's overall operational response to increasing levels of generation by intermittent resources, the CAISO will monitor any operational issues that relate to Dynamic Transfers, and coordinate with other affected BAAs to study regional issues affecting Dynamic Transfer capability. If such limitations become apparent in the future, the CAISO will identify appropriate responses, including potentially limiting new Dynamic Transfers of intermittent resources.

TANC (COI Southern Owner) view:

Still considering need to manage TVLs on COI.

TANC believes that TVLs are needed based on the information currently available. Goals & Plans for addressing the TVL issue are:

- Ensure that NERC/WECC Standards are met.
- Ensure the exposure to contingencies that could damage facilities is not increased.
- Investigate possible impact of Dynamic Transfers on rating (SOL) of WECC paths
- Coordinate operational implementations of Dynamic Transfers between Balancing Authorities
- Manage technical issues vs. commercial issues
- Investigate the impact on possible under-utilization of paths
- Resolve the different assumptions about the Dynamic Transfer time intervals and what impacts would result from those differences

SMUD (BANC Operator – which schedules & manages flows on COTP) view:

Do not plan to calculate TVLs for COI because:

- Willing to assess and study TVL, but do not see a need to manage TVLs for limits south of COI at this stage.

Could be reassessed with:

If future operating experience or system studies of the northern CA system highlights the need for TVLs, then SMUD would revisit the need for TVLs for limitations south of COI. The reader should bear in mind all flows will be managed within the SOL.

PGE (COI Northern Owner) view:

Still considering need to manage TVLs on COI. Thoughts include:

- TVL is a MW limit for a fixed interval of time, hence suggest results be presented as such (i.e. XX MW of variation over 15 minutes). A TVL MW/min change that can be accommodated across flow gates at one transfer level could be seen at a higher transfer level with automatic/dynamic voltage control equipment. Such For example a 100 MW/30 min TVL to be increased to a 100 MW/15 min TVL

PAC (COI Northern Owner) view:

Still considering need to manage TVLs on COI. Thoughts include:

Description of TVL Methodology:

1) Assumptions:
   a) Timeframe:
      The transfer variability limit (TVL) Timeframe for Dynamic Transfers under automatic control can vary to reflect the way individual systems are operated. To implement the dynamic wind transfers across the flowgates within the WECC system, a timeframe of *15 minutes* was assumed to accommodate the Dynamic Transfers. This was deemed appropriate owing to the 30 minutes scheduling and time between ramps being implemented in the northwest from July 1, 2011. California ISO (CAISO) can accommodate Dynamic Transfers within an even smaller timeframe, possibly 5-10 minutes given their automated real-time dispatch and transmission control equipment.

   b) Wind Variation Analysis:
      Based on the consensus that transmission providers will have *15 minutes* to allow Dynamic Transfers on the flowgates, some charts were developed using BPA's 5 minute average 2010 system data to show the wind variations we have experienced for the year 2010. As seen in the graphs below, the variation caused by one single wind farm is much greater than a cluster of wind farms for the given time period. This implies that the transmission operators for individual system will have the freedom to apply the TVL methodology taking in to consideration how they perceive their variable resources. The ultimate goal will be to maintain the reliability of the system by choosing the operating parameters, like voltage deviation, to accommodate the wind variation on their paths.

Initial TVL Results for Summer 2011

**Note: Further cases would need to be studied before a TVL could be established*

BPA (COI Northern Path Operator): Initial Results

Using the methodology presented above COI Transfer Variability Limit (TVL) was calculated by not adversely impacting the following three perspectives:

- Reliability
- Impact on System Equipment
- Impact on Customers

TVL = MINIMUM of (Reliability Limit, Equipment Limit, Customer Limit)

Test Case

WECC 2011 heavy summer case was used for this study with the following significant changes:

- Bridger from 2200 MW to 2080 MW
- Ehunt Unit 1 off line (modify HMSL flow)
- Decreased BCH 200 MW at GMS (modify P3 flow)
- Increased Northern Cal Hydro to 70%
- Decreased SCIT by 300 MW (modify COI flow)
- BPA area generation: hydro increased; increased Centralia, Big Hanaford; reduced Beaver, KCGN; set up Columbia Gorge wind for 1500 MW.
- Locked BPA manually switched shunts
- Table MT shunt C2 - change the value to 454 MVAR and made it continuous. Regulated bus voltage is 1.0619 pu
- Units ELKHIL1G, ELKHIL2G, ELKHIL3G made it online generating 0 MW
- Units MOSSLND6 and MOSSLND7 made it online generating 0 MW and changed the desired voltage to 1.01 PU

Only limited set of contingencies were studied and they are listed below:

Initial COI Flow	4796	4670	4467	4050	Associated RAS
Double Palo Verde w/FACRI	120	120	120	120	load trip (MW)
Grizzly-Malign/Grizzly-CaptJack	2400	2400	2400	2400	High Gen Drop (MW)
BUCKLEY500 GRIZZLY500					N/A
Malin-Round Mt 1&2	2400	2400	2400	2400	High Gen Drop (MW)
MALIN500-SUMMERL500					N/A
DC-BIPOLE	2550	2550	2550	2550	PDCI Loss Gen Drop (MW)

Reliability Results for COI (Path 66)

Reliability study was performed using PV analysis using the test case described in previous section. The results are limited to PV study. To get the actual limits other analysis and different operating conditions need to be performed.

In this first test the initial COI flow was 4796 MW. The transformers and shunts are allowed to change. The voltage collapse happens at 5190 MW. The PV plots for this case is shown in Figure BPA-1.

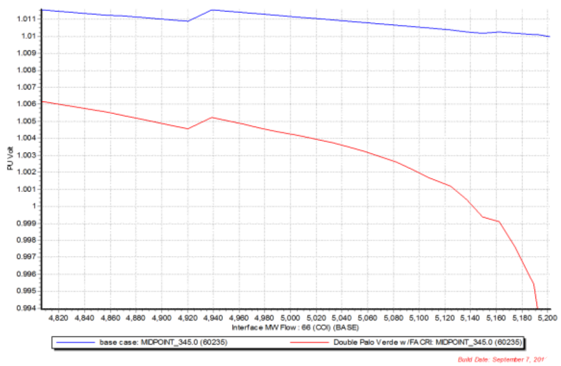


Figure BPA (P66) –1: Starting COI flow at 4796 MW Voltage collapse at 5190 MW

For Test 2 transformers and shunts are fixed. The initial COI flow is 4690 MW and the PV study was performed. The voltage collapse happens at 5140 MW. The PV results are show in Figure BPA-2.

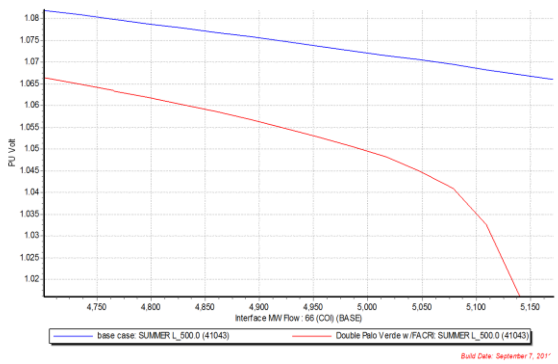


Figure BPA (P66) -2. Starting COI flow at 4690 MW Voltage collapse at 5140 MW

For Test 3 transformers and shunts are fixed. The initial COI flow is 4467 MW and the PV study was performed. The voltage collapse happens at 5080 MW. The PV results are show in Figure BPA-3.

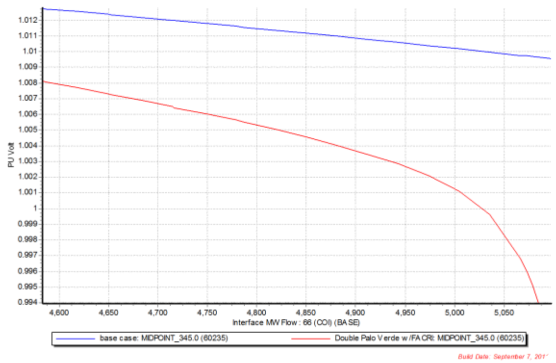


Figure BPA (P66) -3. Starting COI flow at 4467 MW Voltage collapse at 5080 MW

For Test 4 transformers and shunts are fixed. The initial COI flow is 4050 MW and the PV study was performed. The voltage collapse happens at 4980 MW. The PV results are show in Figure BPA-4.

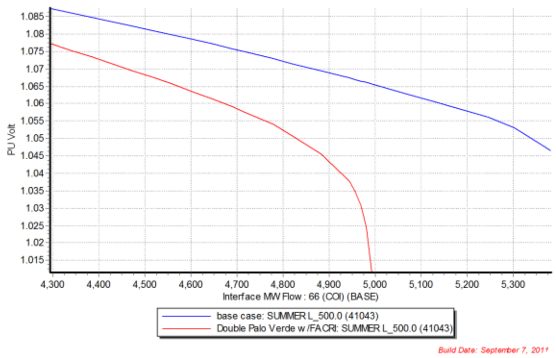


Figure BPA (P66) -4. Starting COI flow at 4050 MW Voltage collapse at 4980 MW

The worst contingency was the Double Palo Verde generator outage (2PV) for the cases tested and results are summarized in the table below.

No	COI flow	Collapse point	Margin 2.5 % n-2 5% n-1	Voltage Stability Limit
1	4796 MW	5190 MW	130 MW	5060 MW
2	4670 MW	5140 MW	128 MW	5012 MW
3	4467 MW	5080 MW	127 MW	4953 MW
4	4050 MW	4980 MW	125 MW	4855 MW

Findings

From the results it is clear that
- Voltage stability limit is decreasing as the “modified point” moved further from the initial cases.
- TVL limit is taking the margin out of point at path rating

Impact on Equipment

For this study impact on BPA equipment is not considered. During this study all Transformers and shunts are fixed. Test included only COI transfer levels where RAS arming is constant.

Impact on Customer

Task force is working on impact of customers.
Individual utilities need to determine acceptable impact on customers. For this study following criteria is used
- 500 KV & 345 KV buses – 5 KV voltage change
- 230 KV and 115 KV buses – 3 KV voltage change

To identify the impact power flows were run with different wind levels. The results are presented in table below.

No	Amount of Wind Change	COI Flow	Delta Max Voltage Change	COI flow change for allowed delta voltage
1	450 MW	4444 MW	5 KV	356 MW
2	500 MW	4407 MW	5.5 KV	393 MW
3	700 MW	4259 MW	7.5 KV	541 MW

For the results it is clear that TVL is dependent on allowed impact to customers. For the given scenario the transfer on COI could change 356 MW for allowed impact of 1% voltage change.

Observations for COI Study

A recommendation that resulted from these COI studies, is that the allowed impact on customer/equipment be determined first, rather than last, as this will reduce number of scenarios to be tested. Method to verify reliability does work. It is an iterative process and we need to decide to fix the SOL or allowed to reduce.

To set TVL further testing on different scenarios are needed. Impact of other paths need to be included in the TVL calculations.

CAISO (COI Southern Path Operator): Studies

CAISO completed a significant study on the Dynamic Transfer of Intermittent Resources in January 2011, in which it studied the variability that would be expected on COI if 5000 MW of wind generation was scheduled on COI. The CAISO/GE study can be downloaded at http://www.caiso.com/Documents/FinalReport-Impact-DynamicSchedulesonInterfaces-PreparedbyGE.pdf.

Detailed summary of the CAISO/GE Study is contained in Appendix D of the DTC Task Force’s Phase 1 report which can be downloaded from: http://www.columbiagrid.org/download.cfm?DVID=2281

Limiting Contingencies & Facilities (& Potential Measures to Increase TVL)

** Potential measures cited below were will need to be studied to quantify their actual impact on TVL, they are offered as initial thoughts.*

BPA (COI Northern Path Operator) View:

Path 66 is a voltage stability limited path. As a result, it is expected that TVL will be limited by many of the same contingencies that limit the path SOL. The initial studies performed for this report included the same contingencies which typically determine the SOL (e.g. Double Palo Verde, DC Bipole, etc.) which similarly limited TVL. More extensive studies would be required to identify specific facilities or controls requiring reinforcement, however, it is clear that an important aspect of reinforcement for TVL is controllability of voltage and reactive prior to the contingency. Measures taken to increase TVL should therefore consider installation of reactive devices in smaller steps than might be used for meeting post-contingency criteria, and extensive use of automatic controls.

CAISO (COI Southern Path Operator) View:

To ensure that worst-case scenarios had been considered, GE Energy's Dynamic Transfer capability study prepared for the CAISO examined the following contingencies for analysis of COI:

- Loss of 2 Palo Verde units, including SPS tripping of 120 MW load in Arizona
- Loss of PDCI, including SPS tripping of Northwest generation
- Loss of 2 San Onofre units
- Loss of 2 Diablo Canyon units

TANC (COI Southern Owner) view:

TANC has not yet conducted any studies to determine the most limiting TVL contingency and therefore cannot provide a response at this time.

PGE (COI Northern Owner) view:

Agree with BPA that more extensive studies are required to identify specific facilities or controls to increase TVL by allowing a more dynamic control of system voltage through reactive devices. However; there is a concern about what increased maintenance costs would be due to such devices operating significantly more often than they do today.

PAC (COI Northern Owner) view:

Being a voltage stability limited path, there should be reinforcement made to accommodate the variations in the form of automated reactive devices. The Southern Oregon load bubble is voltage sensitive and the implementation of TVL's could potentially reflect in voltage variations beyond reliable limits. However, studies have not been conducted by PAC to determine the sensitivities on its load buses caused by TVL contingencies.

Next Steps?

BPA (COI Northern Path Operator) View:

Improving real time visibility and monitoring tools for system operators, developing new operational procedures to manage the expected changes to path operation, and continuing to monitor the system impacts as operation moves from the historical predominately "static" flows toward accommodating higher levels of variability are first steps. Using the recommended methodology to understand the wider interactions with other paths and control systems, and identifying areas where improvements would be most beneficial and cost effective will be longer term goals and areas of continuous improvement as we gain operational experience over time.

CAISO (COI Southern Path Operator) View:

Recognizing the result of detailed CAISO studies concluding that the CAISO does not need to limit Dynamic Transfers of intermittent resources due to impacts on its system, monitor any operational issues that relate to Dynamic Transfers as the level of variable generation increases, and if needed, identify appropriate responses.

TANC (COI Southern Owner) view:

Conduct detailed studies.

PGE (COI Northern Owner) view:

WIST and/or the DTC Task Force should look at the work that WECC's Joint Synchronized Information Subcommittee has done with their wide area measurement systems and integrated monitoring devices i.e. synchrophasors and PMU's.

PAC (COI Northern Owner) view:

Assist in performing TVL studies on the path to determine the areas of concerns going forward. Refine the operating and scheduling practices to incorporate the TVL. The practical implementation of TVL is largely contingent upon proper operational and scheduling tools being developed and resolving the commercial issues should be the next step.

Path 3: Northwest-Canada

Region: WECC-NWPP (Washington & southern British Columbia)
Path Monitors/SOL Setters: BCH & BPA
Path Owners: BPA, BCH, PSE, Fortis BC

Path Ratings: (N>S Path Rating = 3150 MW) & (S>N Path Rating = 2000 MW)

Need to manage TVL, why and what would change your assessment?

BPA (Path 3 Southern Path Operator) View:

Plan to calculate TVLs (& associated nomograms):

The concerns raised by the work of this Task Force, and the independent analysis and operational experience of BPA, indicate the need for further assessment and establishment of TVLs until sufficient improvement in procedure, monitoring, and control are implemented to alleviate the need for them. Within the BPA BAA, a number of issues have been considered including:

- Significance of path and potential for widespread impact of reliability issues
- Coordination with operators on both sides of path. Situational awareness and understanding changing flows, impacts, drivers.
- Concern for voltage sensitivity impacts to nearby load areas. Although Path 3 is thermally limited on the US side of the path, area voltage is sensitive to path flows.

In BPA's case, the issue is further complicated by the configuration of the transmission system itself: with over 3,000 MW of installed variable generation surrounded by multiple constrained paths crossing the transmission system between the major interties, increasing implementation of Dynamic Transfers must be evaluated in the context of the system as a whole.

Could be reassessed with:

- The need for TVLs will be reassessed on a regular basis, as BPA gains a better understanding of risks associated with new generation patterns, operating experience with higher variability, and identifies and implements reinforcements providing greater dynamic operating margin.

BCH (Path 3 Northern Path Operator) View:

Plan to calculate TVLs (& associated nomograms):

- The relationship between static and variable transfer limits for Path 3 was established for certain system conditions;
- Path 3 is capable of increased Dynamic Transfers provided it is managed properly;
- If left unmanaged, increased levels of Dynamic Transfers could put the BC Hydro system into unsafe operating conditions;

What could change your view?

- The issue of TVLs is expected to be with us for sometime. The addition of dynamic resources (e.g. SVCs or STATCOMs) to improve the automatic voltage regulating capability across the system would move TVL close to the SOL for Path 3 and reduce the impact of variable transfers on equipment. In the absence of new voltage control investments there would be a need of regular revaluation of the equipment impacts for the planned TVL level.

PSE (Path 3 Southern Owner) View:

Plan to calculate and monitor TVLs (& associated nomograms) primarily as an affected system:

PSE loads are sensitive to voltage changes, particularly voltage changes that occur quickly. Existing voltage regulation equipment cannot respond fast enough to mitigate impacts to customer loads from rapid voltage changes;

- The relationship of bus voltage to Dynamic Transfer changes associated with variable generation is new for PSE in terms of day to day operations;
- The relationship will probably be more severe when facilities in the network are out of service, such as for maintenance and construction;
- Managing TVLs is a means to knowing of the extent and shape of variability and its impact to transmission equipment and to our loads, and for the path operators to share information with others;

What could change your view?

- Given the lack of dynamic reactive resources in the Puget Sound Area, several significant reinforcements are needed (e.g. SVCs, STATCOMs, RAS automation) for TVLs to approach SOLs.

Initial Results for Summer 2011 Snapshot:

**Note: Further cases would need to be studied before a TVL could be established*

BPA (Path 3 Southern Path Operator) Initial Results:

Using the methodology presented above the Path 3 Transfer Variability Limit (TVL) was calculated by not adversely impacting the following three perspectives:

- Reliability
- Impact on System Equipment
- Impact on Customers

TVL = MINIMUM of (Reliability Limit, Equipment Limit, Customer Limit)

For Path 3, the methodology was modified to evaluate the customer impact first, followed by the evaluation of impact to system equipment and reliability. By reordering the steps, the number of scenarios evaluated could be reduced by taking into account the expected limiting conditions (e.g. voltage deviation at area load busses) first, and reducing the number of cases that would be checked for meeting to reliability criteria to only those that already demonstrated acceptable customer performance.

Test Case

WECC 2011 heavy summer case developed for the COI (Path 66) TVL studies was used as the basis for this study.

Only limited set of contingencies were studied and they are listed below:

Initial Path 3 Flow	Associated RAS
ECHOLAKE500-SNOKTAP500C1	BCH to NW Gen Drop, Fredonia Whitehorn Gen Drop
Snoh-Bothell	N/A
SNOKING500-SNOKS2230C1	N/A
CUSTERW500-CUSTERW230C1	N/A
CHIEFJO500-MONROE500C1	N/A
Bellgham-Custer W	N/A
EchoLk-MpVl 1&2	N/A
MONROE500-MONROE230C1	N/A
CUSTERW500-MONROE500C1	N/A

Customer Limit:

Goal of this test is to identify how much voltage variation happens as path flows are adjusted by Dynamic Transfers (e.g. with no manual actions taken to manage area voltage impacts).

In the initial case, wind is 1499 MW and the Path 3 initial flow 1348 MW (N to S) (Path 3 N to S limit is 3150 MW). Wind was balanced by BCTC Hydro generation which started at an initial generation level of 5807 MW. Other area generation included: Puget generation at 919 MW, and Seattle City Light + Snohomish PUD at 244 MW. Variations in generation resulted in the following changes to the path flow:

Wind increases to 2200 MW.	**Path 3 flow decreases to 657 MW due to wind**
Wind decreases to 500 MW	**Path 3 flow increases to 2225 MW due to wind**

The following figure shows the change in voltage at Custer 500 to these changes in path flow:

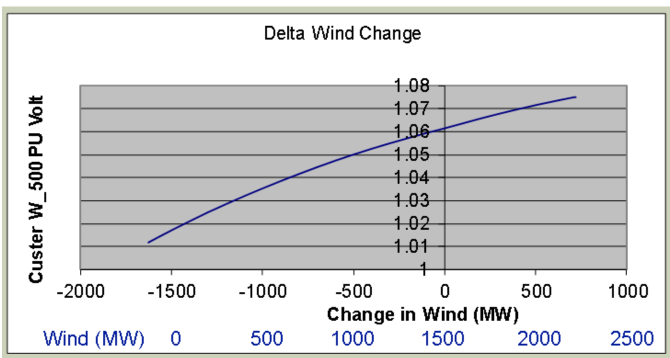


Figure BPA (P3) -1. Custer 500kV Bus voltage change

If TVL is limited by the customer impact, then the TVL level is dependent on allowed impact to customers.

Canada - NW Path 3 MW Flow	Delta Wind Change	TVL	Voltage Change
657	700	691	6.67
753	600	595	5.87
847	500	501	5.05
947	400	400	4.12
1046	300	301	3.17
1148	200	200	2.16
1249	100	98	1.08
1347	0	0	0.00
1437	-100	90	-1.04
1526	-200	179	-2.12
1615	-300	267	-3.24
1703	-400	356	-4.43
1791	-500	444	-5.70
1879	-600	531	-7.02
1966	-700	619	-8.45
2053	-800	705	-9.93
2139	-900	792	-11.47
2225	-1000	878	-13.07

Selecting the right bus is critical to calculate the TVL, and a systematic methodology should be used when selecting critical buses.

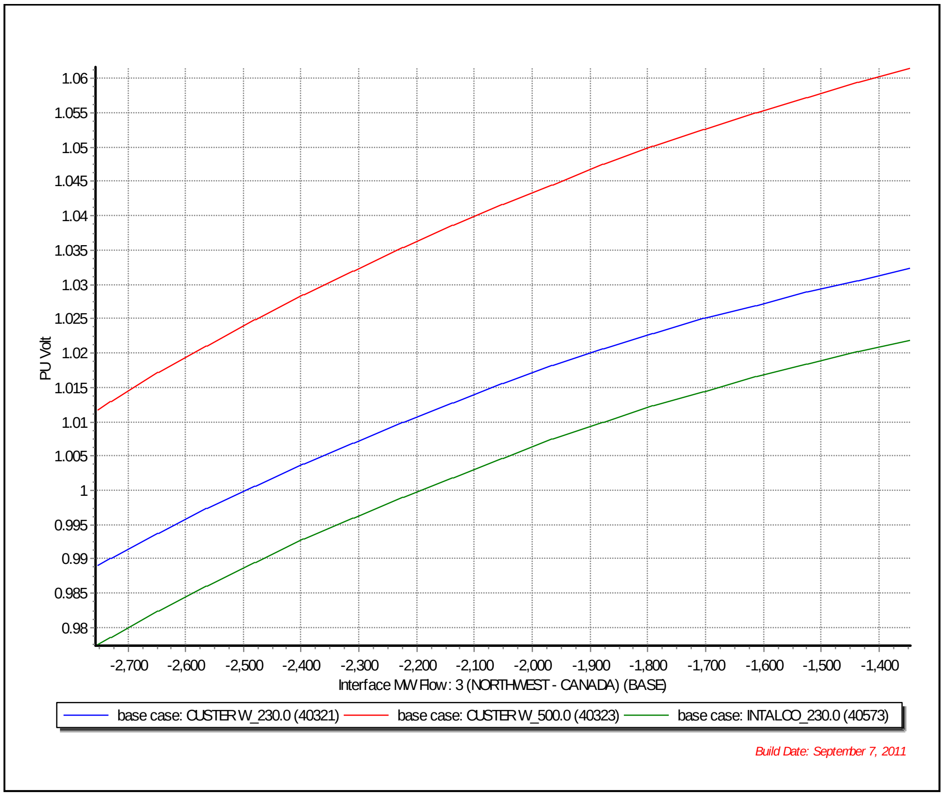


Figure BPA (P3) -2. Bus voltage variation

TVL can change based on the operating point for the same impact on customers (5 KV Voltage change). Individual utilities will need to determine acceptable impact on customers, but for illustrative purposes, this study used the following criteria:

- 500 KV & 345 KV buses – 5 KV voltage change
- 230 KV and 115 KV buses – 3 KV voltage change

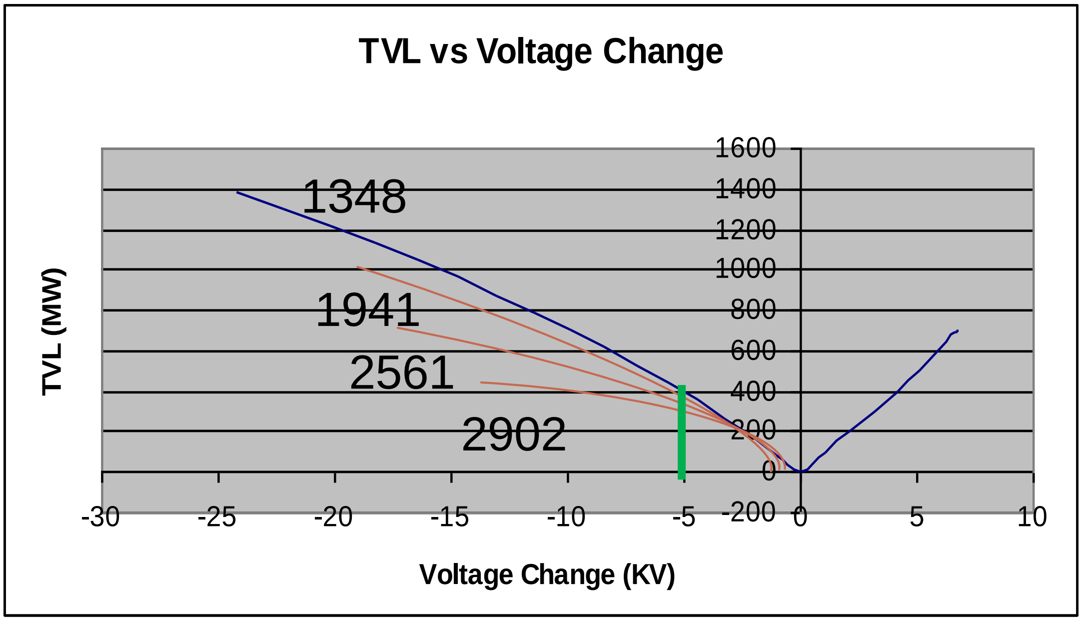


Figure BPA (P3) -3. TVL as a function of allowed voltage deviation

<u>Equipment Limit</u>:

- For this study impact on BPA equipment is not considered
- During this study all Transformers and shunts were fixed
- Test included only transfer levels where RAS arming is constant

<u>Reliability Limit</u>:

As mentioned previously, by considering the customer limit first, the problem of verifying reliability limits was reduced from finding the operating point where reliability was compromised, to simply verifying that operation over the range identified by the customer limits meets all reliability criteria.

For the case studied, the TVL range that met the customer impact criteria was 400 MW as path flows were increased, and 500 MW as path flows were decreased (the allowed range up or down from the base point can be different due to how the bus sensitivity to flow varies with the operating point).

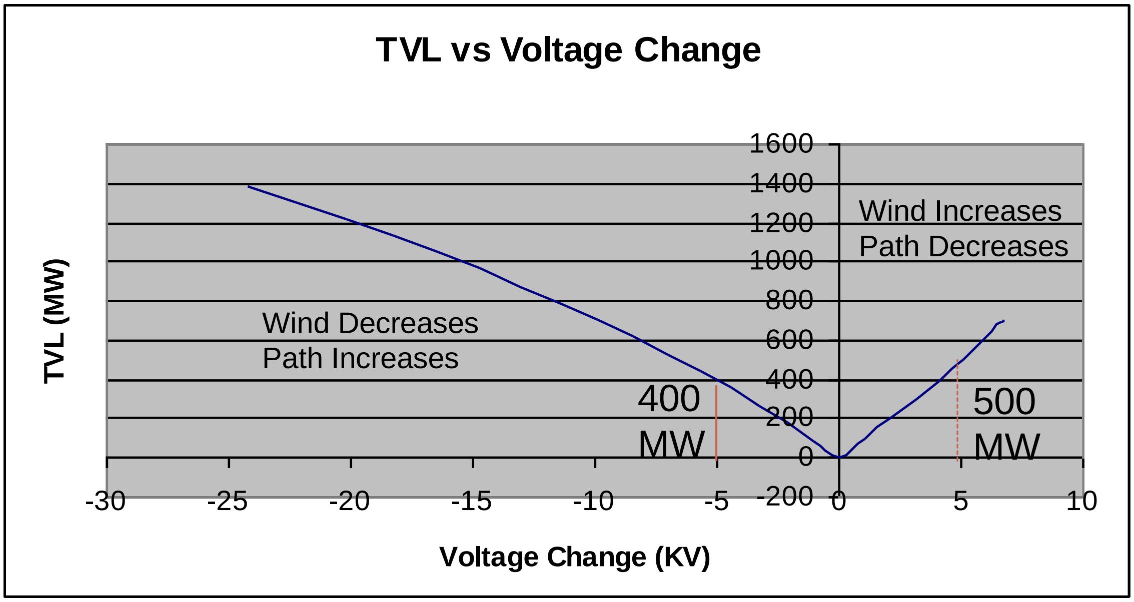


Figure BPA (P3) -4. TVL as a function of Voltage Change

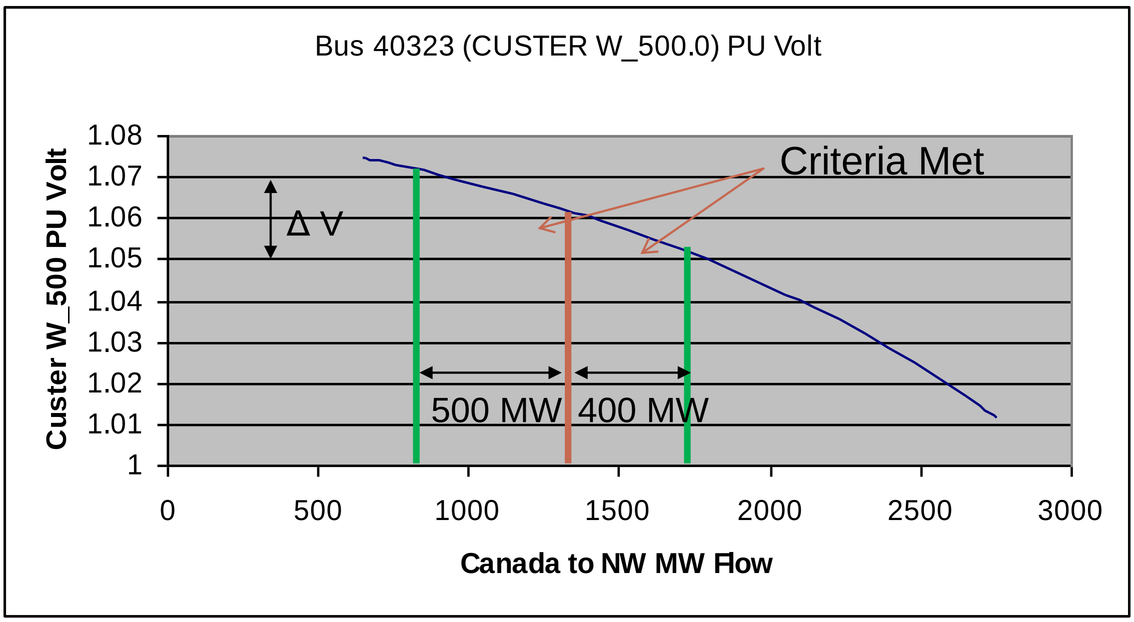


Figure BPA (P3) -5. Test of Reliability Criteria

With N to S flow of 1348 MW and TVL of 400 MW system meets reliability criteria for the contingencies tested. As shown, the bus voltage can float the range shown and meet the reliability criteria.

BCH (Path 3 Northern Path Operator) Initial Results:

Customer Limit:

- Figure BCH #1 shows the voltage deviations at some critical BCH busses for variable transfer increases on Path 3 (N to S), based on the operating condition of 0 MW BC to US and 800 MW BC to AB. GMS generations are used to balance the wind generation reductions in the North West. Automatic switchable voltage regulation devices in BC are turned on, with others locked.
- Acceptable levels of voltage reduction at critical buses can serve as a first cut assessment in determining the severity of stress caused by transfer increases from balancing resource.
- Auto vars schemes (e.g. control schemes that automatically adjust voltage) including ones at Ingledow and Meridian are effective to support variable transfer increases on Path 3.
- Williston and Kelly Lake area experience the largest voltage reductions due to lack of automatic switchable voltage support devices when GMS units are used as the balancing resource.

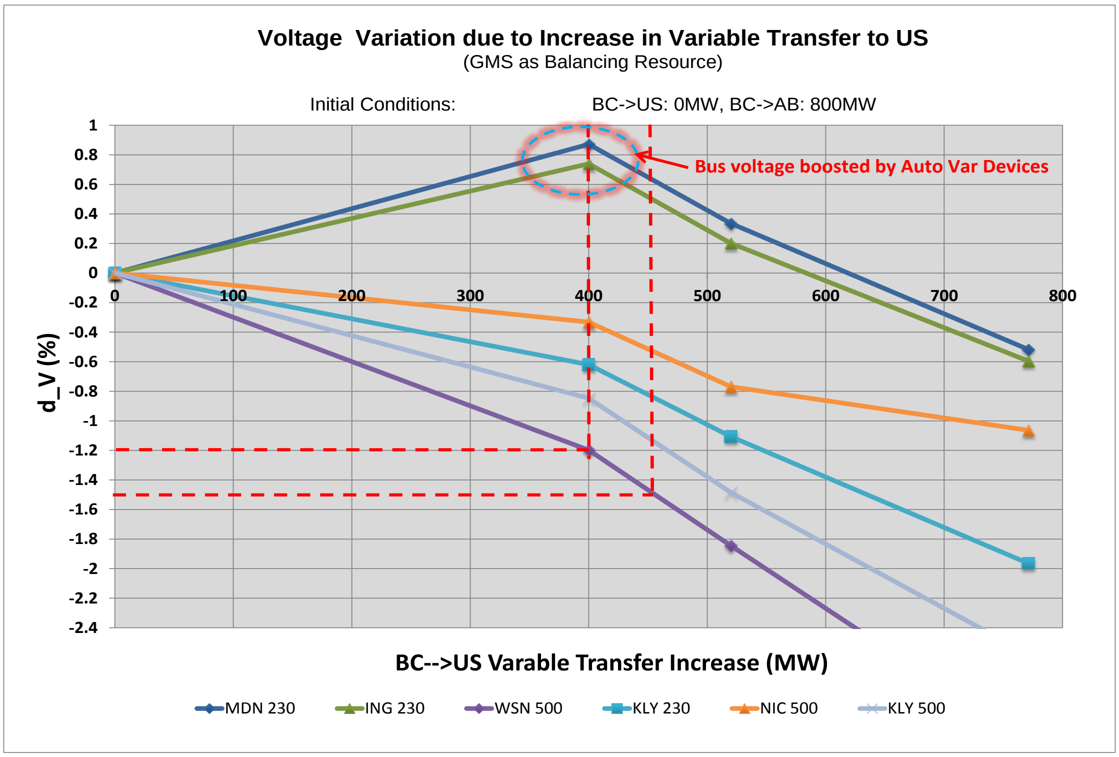


Figure BCH #1 – Effect of Variable Transfer Increase on Voltage Deviation

Equipment Limit:

- For this analysis, the impact on equipment due to increased switching of voltage regulating devices is not included.

Reliability Limit:

- Figure BCH #2 shows the BCH Path 3 (N to S) maximum variable transfers, or Transfer Variability Limit (TVL) for various levels of static transfers. GMS units are used as balancing resource for generation reduction in the North West. The secure region below the solid line meets the reliability performance requirement for the most severe contingencies in BC. Appropriate RAS action, e.g. generation shedding at GMS has been applied to mitigate the impact of the contingencies in the analysis.
- The trade off between variable transfer and static transfer is less than (one to one); about (0.06 to one) for the region of static transfer less than 2100 MW and (0.56 to one) for the region of static transfer greater than 2100 MW for the studied condition. The curve could be refined with added granularity of additional study points.
- The reliability limit corresponds to the largest voltage reduction of 1.2% in the BCH system.

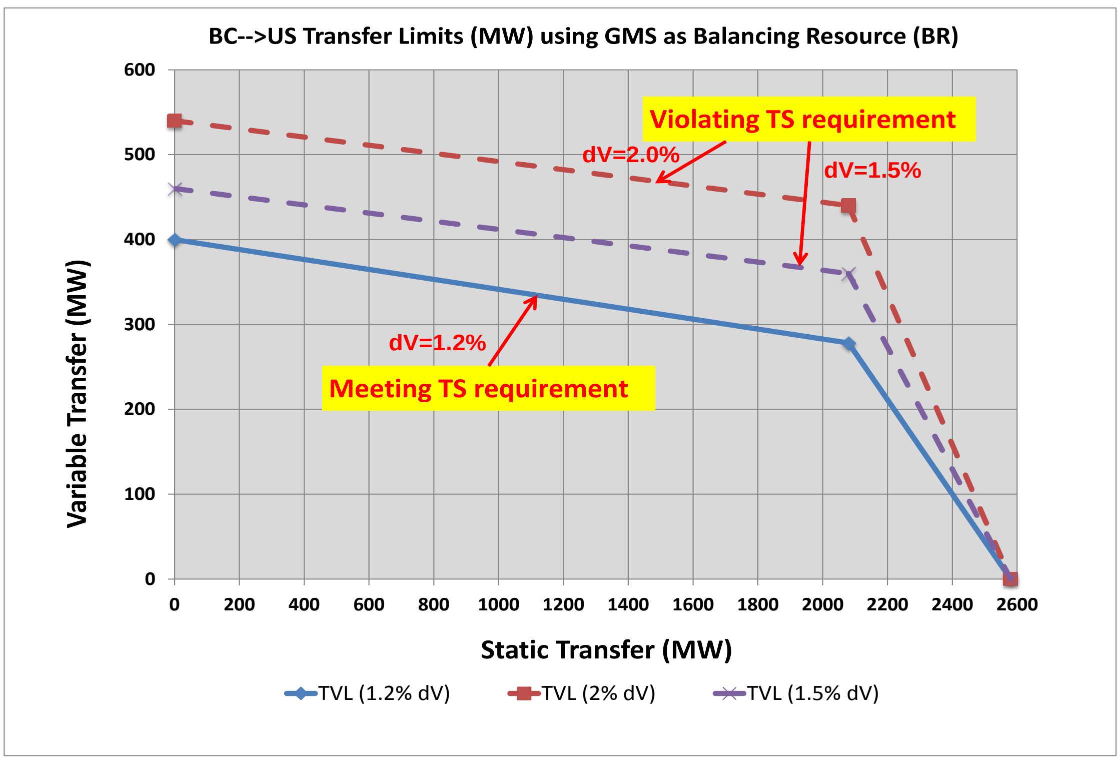


Figure BCH #2 - Path 3 N to S Transfer Limits (Static vs. Variable) with GMS as Balancing Resource

- Figure BCH #3 shows selecting MCA as the balancing resource could significantly increase BCH Path 3 TVL, assuming the largest voltage deviation of 1.65% is of no concern from a power quality and equipment perspective. The curve shows a TVL of about 610 MW based on the operating point of 0 MW static transfer; whereas with GMS units as the balancing resource the TVL is only 400 MW as in Figure BCH #2.

- For the less stressed pre-redispatch flow conditions on the transmission path from the balancing resource to Lower Mainland, TVL (dV of 2 – 2.5%) would be larger than the stressed case (dV of 1.65%). The figure shows TVL of 820 MW vs. 610 MW for a static transfer of 0 MW.

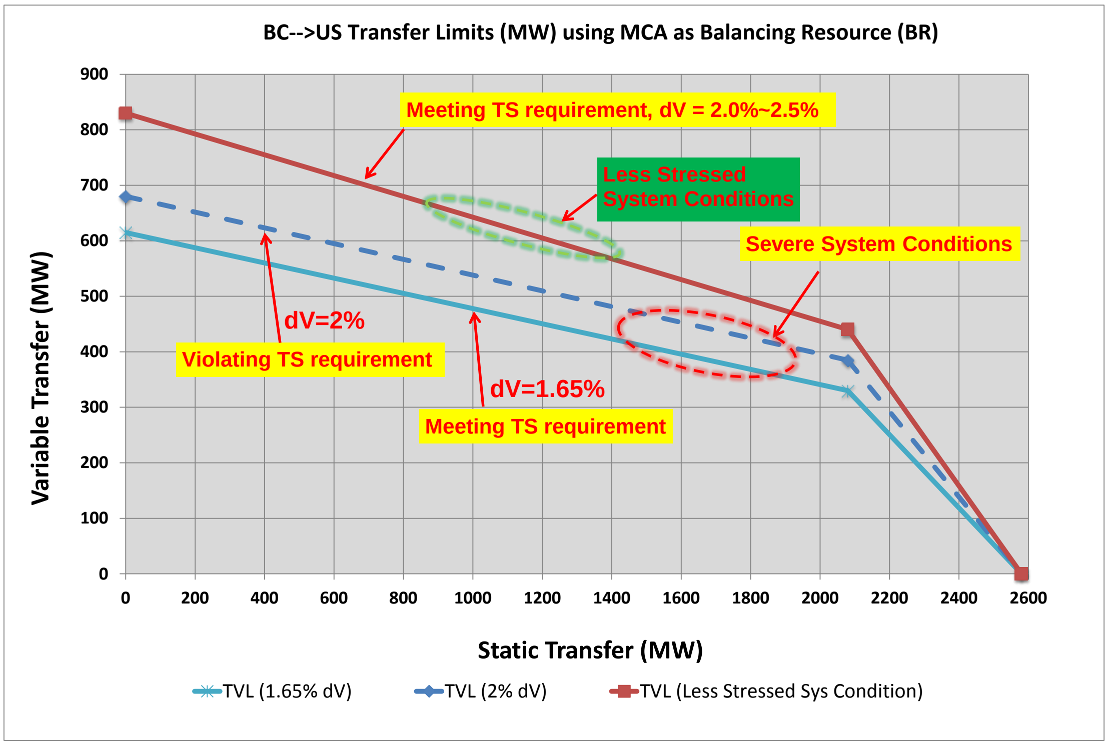


Figure BCH #3 - Path 3 N to S Transfer Limits (Static vs. Variable) with MCA as Balancing Resource

- Figure BCH #4 compares the effect of selecting MCA vs GMS units as the balancing resource to wind variations in North West. The diagram also shows the interrelationship between committed transfers (both static and variable) and also that they would affect the available static transfers.

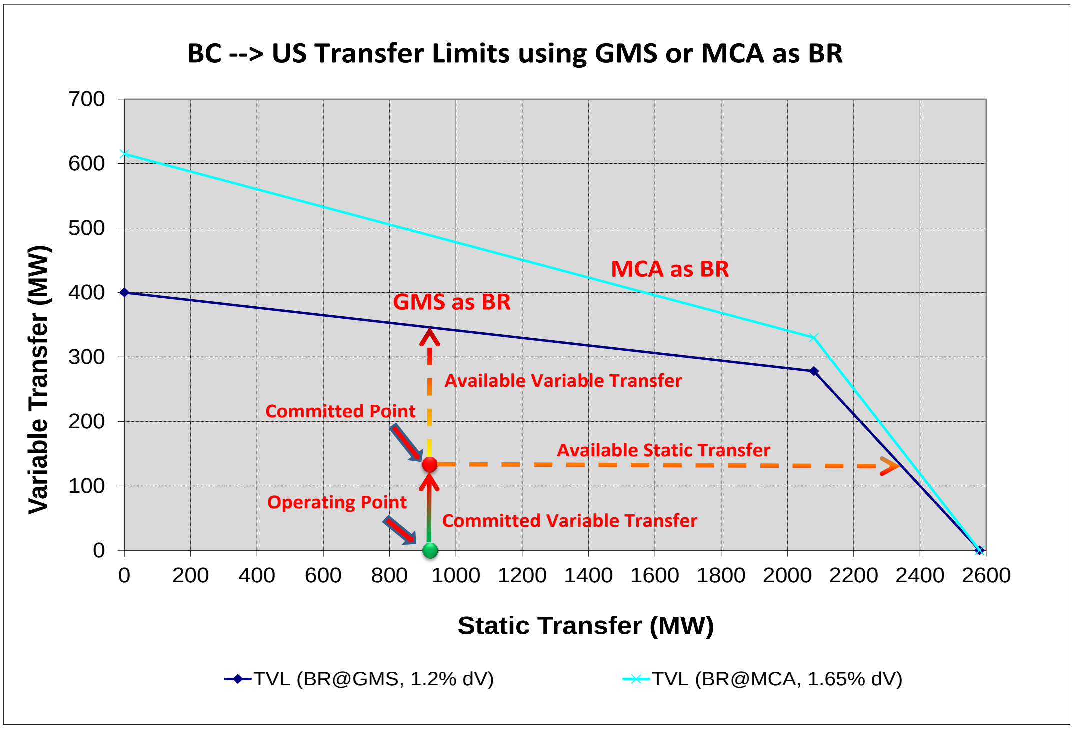


Figure BCH #4 – Effect of Different Balancing Resources (GMS vs. MCA)

Limiting Constraints & Facilities (with Potential Measures to Increase TVL)

* *Potential measures cited below were will need to be studied to quantify their actual impact on TVL, they are offered as initial thoughts.*

BPA (Path 3 Southern Path Operator) View:

The initial studies performed for this report indicate that TVL on Path 3 would be limited by impact load area bus voltages. Path 3 system operating limits are typically limited by thermal criteria on the BPA system, so additional screening studies will be necessary to determine whether a new set of contingencies will be identified as causing the limitations based on voltage impact considerations. While extensive studies would be required to identify specific facilities or controls requiring reinforcement, it is clear that an important aspect of that reinforcement for TVL is controllability of voltage and reactive prior to the contingency. Measures taken to increase TVL should therefore consider installation of reactive devices in smaller steps than might be used for meeting post-contingency criteria, and extensive use of automatic controls.

BCH (Path 3 Northern Path Operator) View:

The selection of balancing resources determines the parts of the BC Hydro transmission system that would be negatively impacted by TVL. Placing adequate dynamic var support at the critical locations would significantly increase TVL. Specifically, when generation on the Peace River is used as balancing resources, installation of dynamic vars to regulate and support voltages at major 500 kV substations on the Peace side of the transmission system (e.g. WSN and KLY) would be helpful. Alternatively, when generation on the Columbia River is used as balancing resources, dynamic vars to regulate and support voltages at major 500 kV substations on the Columbia side of the transmission system (e.g. NIC) would be preferable.

PSE (Path 3 Southern Owner) View:

PSE has urged that the percentage or per unit voltage change criteria being currently used at 500 kV also be applied to the 230 and 115 kV system in the Puget Sound area for the benefit of loads served. Both metered and simulation historical data are showing that the voltage changes to the underlying 230 and 115 kV systems due to real and simulated Path 3 changes are no more severe on a percentage or per unit basis to the 230 and 115 kV system and loads.

Next Steps?

BPA (Path 3 Southern Path Operator) View:

Improving real time visibility and monitoring tools for system operators, developing new operational procedures to manage the expected changes to path operation, and continuing to monitor the system impacts as operation moves from the historical predominately "static" flows toward accommodating higher levels of variability are first steps. Using the recommended methodology to understand the wider interactions with other paths and control systems, and identifying areas where improvements would be most beneficial and cost effective will be longer term goals and areas of continuous improvement as we gain operational experience over time.

BCH (Path 3 Northern Path Operator) View:

Assess the additional TVL requirement on Path 3 for the near term and if so, scope the work internal to BCH that will be required to develop and implement TVLs and associated services for Path 3;

- Identify & cost potential projects that could be included in the BC Hydro transmission capital plan that would increase the BCH TVL for Path 3.

PSE (Path 3 Southern Owner) View:

PSE concurs with BPA in the context of Path 3 impacts to the Puget Sound area that next steps would be to understand the interactions with BPA, PSE and neighboring voltage regulation and control systems. The expectation would be endeavors to identify areas where improvements would be most beneficial and cost effective.

Path 8: Montana to Northwest

Region:	WECC-NWPP (Western Montana & the Northwest US)
SOL Setters:	BPA & NWE
Path Owners:	BPA, AVA, NWE, PSE, PGE, PAC

Path Ratings: (E>W Path Rating = 2200 MW) &
(W>E Path Rating = 1350 MW)

Need to implement TVLs, why and what would change your assessment?

BPA (Path 8 Western Path Operator) View:

Plan to calculate TVLs (& associated nomograms):

The concerns raised by the work of this Task Force, and the independent analysis and operational experience of BPA, indicate the need for further assessment and establishment of TVLs until sufficient improvement in procedure, monitoring, and control are implemented to alleviate the need for them. Within the BPA BAA, a number of issues have been considered including:

- Significance of path and potential for widespread impact of reliability issues;
- Coordination with operators on both sides of path. Situational awareness and understanding changing flows, impacts, drivers;
- Concern for voltage sensitivity impacts to nearby load areas;
- RAS, other dependence on historic generation scenarios to achieve high SOL and support operation.

In BPA's case, the issue is further complicated by the configuration of the transmission system itself: with over 3,000 MW of installed variable generation surrounded by multiple constrained paths crossing the transmission system between the major interties, increasing implementation of Dynamic Transfers must be evaluated in the context of the system as a whole.

Could be reassessed with:

- The need for TVLs will be reassessed on a regular basis, as BPA gains a better understanding of risks associated with new generation patterns, operating experience with higher variability, and identifies and implements reinforcements providing greater dynamic operating margin.

NWE (Path 8 Eastern Path Operator) View:

Still considering need to implement TVLs on Path 8:

Outstanding questions:

- What would constitute a customer impact (e.g. voltage level of 500 kV vs load serving busses 115kV, 66kV & 25kV);
- How much variation is permissible on 500 kV busses (while remaining within NERC/WECC criteria) if acceptable performance is maintained at load serving busses?
- What would the impact be on system operations of almost continuous voltage variation on critical 500 kV busses?
- How sensitive is Path 8 TVL to location of dynamic resources in Montana?

AVA (Path 8 Owner) View:

Still considering need to implement TVLs on Path 8:

Support continued investigation. Would want to have a clear sense of the reliability issues before implementing TVLs on Path 8.

PSE (Path 8 Owner) View:

Still considering need to implement TVLs on Path 8:

Initial TVL Results for Light Summer 2011

BPA (Path 8 Western Path Operator): Montana to NW Initial Results

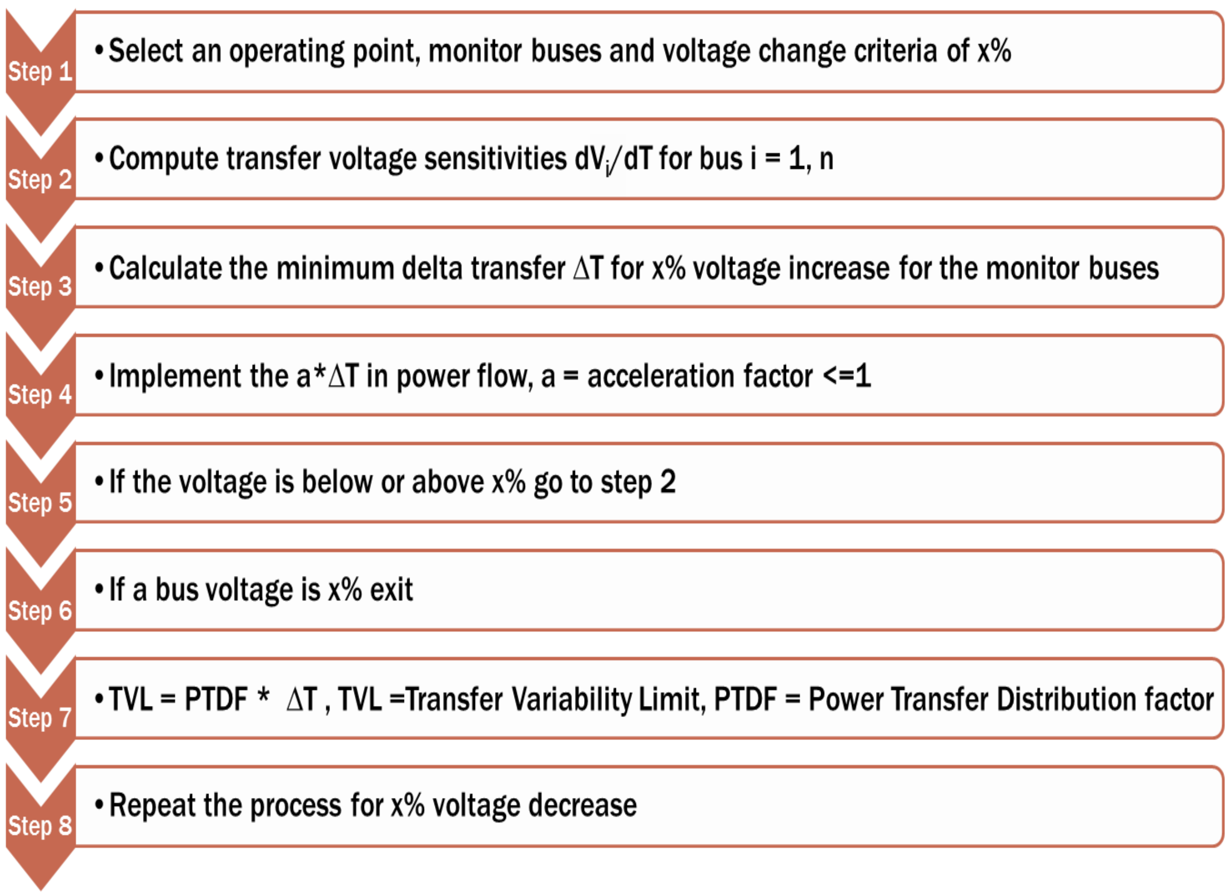
This path is lines between Montana and Northwest. The transfer limit East to West is 2200 MW and West to East is 1350 MW.

Test Case

For this study 2011 light summer case was used. During the light loading conditions the flow from East to West is high. The base case flow for path 8 was 2200 MW east to west. MT Wind was balance by Upper and Mid-Columbia Generation.

Impact on Customers

The Path 8 flow was adjusted to 1889 MW (East to West). Following steps were followed



For this study following criteria is used

- 500 KV & 345 KV buses – 5 KV voltage change
- 230 KV and 115 KV buses – 3 KV voltage change

The voltage change with respect to change in wind is presented below in Figure BPA (P8) -1.

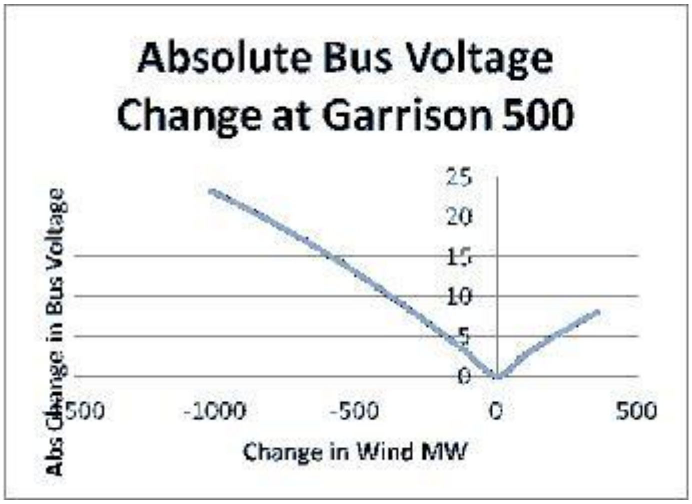


Figure BPA (P8) -1: Voltage change with change in Wind in Montana.

Currently in Montana we have only 250 MW of wind. To study 500 MW of wind Colstrip combined with wind was used to increase or decrease generation.

The next case was tested using the same 2011 light summer case. But the path 8 flow was adjusted to 1693 MW (East to West). The absolute bus voltage versus change in wind is plotted in Figure BPA (P8) -2.

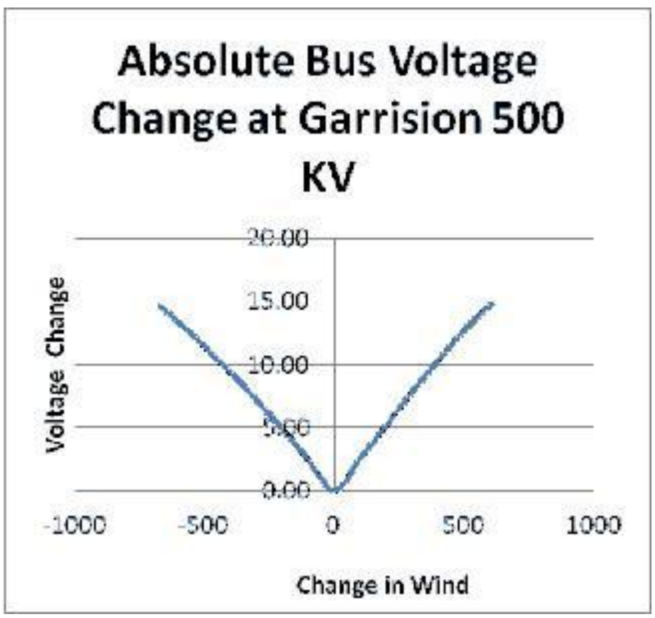


Figure BPA (P8) -2: Voltage change with change in Wind in Montana.

The TVL for both the cases are presented below for the 5 kV voltage change for the 500 kV buses.

No	Path 8 Flow E to W	TVL
1	1889 MW	143 MW
2	1693 MW	153 MW

Impact on Equipment

For this study impact on BPA equipment is not considered. During this study all Transformers and shunts are fixed. Test included only transfer levels where RAS arming is constant.

Reliability

Generally following methods are used to calculate the reliability:

- Contingency Analysis
- Voltage Stability
- Transient Stability
- ATC Limit

In this study only voltage stability was used and no issues were identified with E to W flow of 1889 MW TVL of 143 MW system reliability is not compromised. Also When the East to West flow is 1669 MW TVL of 153 MW system reliability is not compromised

Transfer Variability Limit

TVL = MINIMUM of (Reliability Limit, Equipment Limit, Customer Limit)

TVL for the case studied for 1889 MW East to West is 143 MW and for 1669 East to West is 153 MW for 1% voltage change. Further testing is needed to set the actual TVLs.

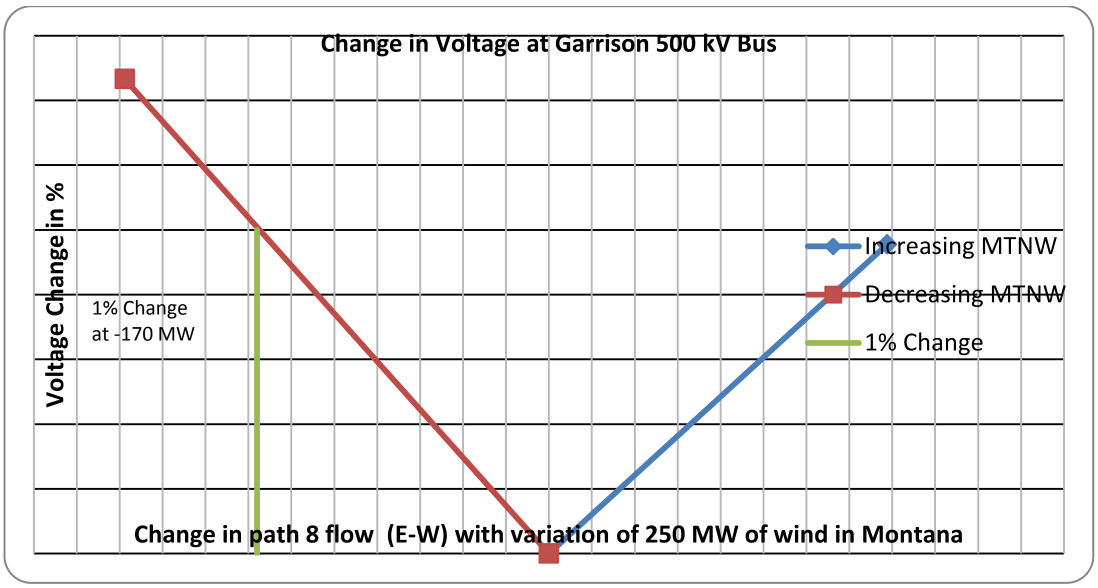
NWE (Path 8 Eastern Path Operator) Montana to NW Initial Results:

Customer Impact:

Light load case was used to study Path 8 as this path is heavily loaded during the light load conditions for East-to-West direction. The reference base case has 1954 MW of flow on Path 8.

Assumption was made that for a change of 1% voltage on the 500 kV buses and 3% change on the lower KV buses would be considered as the Customer Impact. This is one of the assumptions that will have to be evaluated and agreed upon by the path owners and affected parties as the TVL would depend on how much voltage deviation could be tolerated without affecting the reliability of the system.

The plot below shows the percent change in the voltage at the Garrison 500 kV bus with a variation of 250 MW of wind in Montana balanced by 250 MW of Upper, Mid and Lower Columbia. The plot also shows that higher the voltage deviation is allowed higher changes in Path 8 flows could be achieved without affected the reliability of the system.

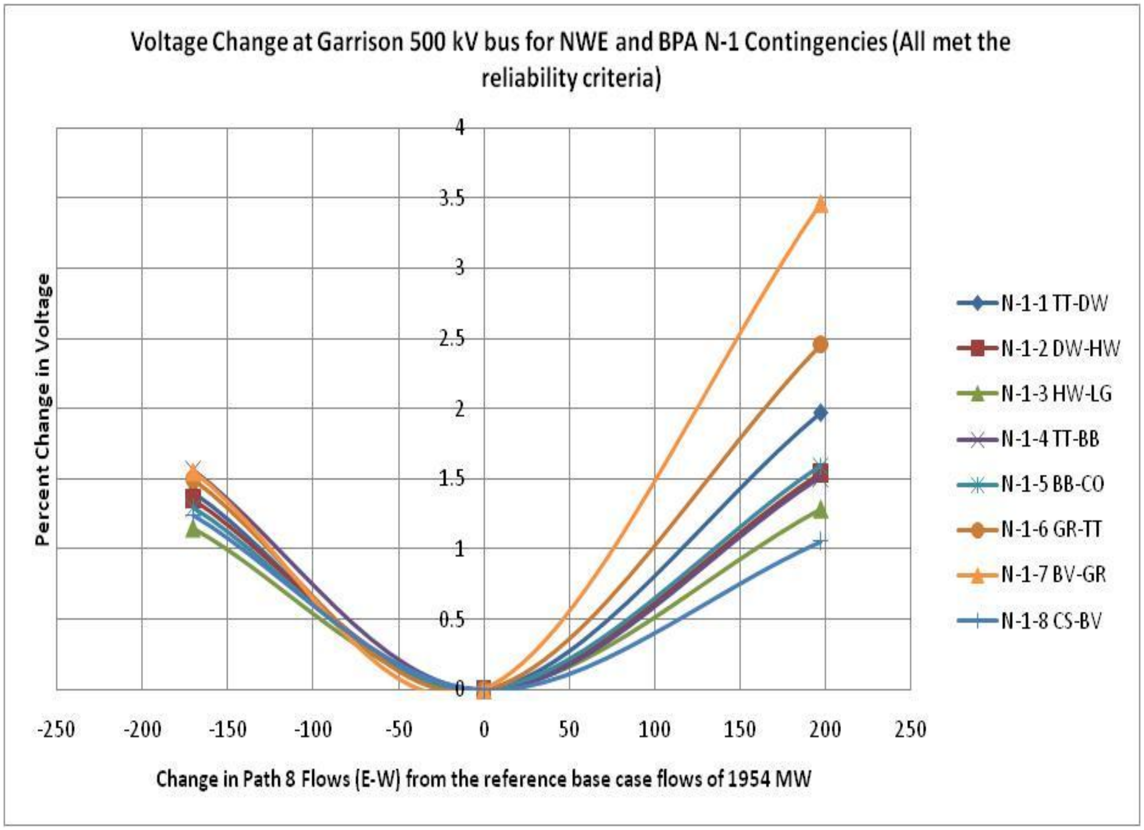


The study showed that 1% change in voltage at Garrison 500 kV bus was observed at approximately 170 MW of reduction in Path 8. This change in voltage reflects the change without the operation of any shunt devices. Only the Shunt devices that were continuous control in the base case were allowed to change.

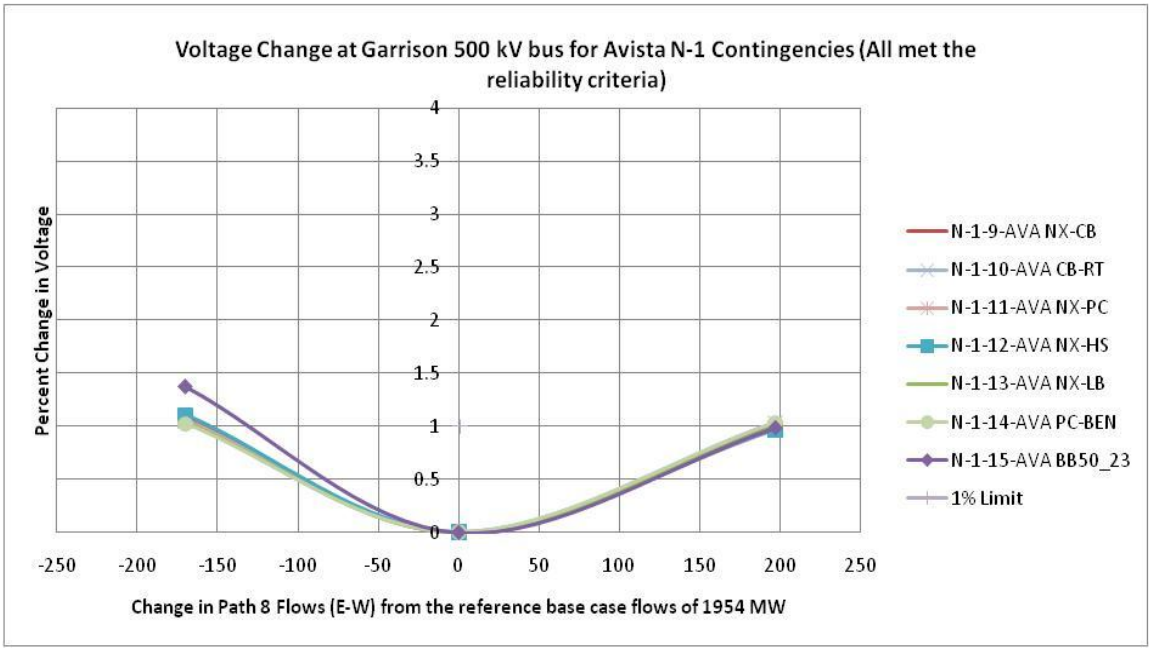
The study also showed that 1% change in voltage at Garrison 500 kV bus was observed at approximately 197 MW of increase in Path 8. This change in voltage reflects the change without the operation of any shunt devices. Only the Shunt devices that were continuous control in the base case were allowed to change.

Two different base cases were created from the reference base case, one with 170 MW less on Path 8 then the reference base case and one with 197 MW more on Path 8 then the reference base case. A subset of contingencies were run to make sure that the changes in the flows from the reference base case causes any reliability issues. The study showed that with the reduction of Path 8 by 170 MW and increase of 196 MW did not cause any reliability issues. Also certain critical N-2 outages were also performed along with automatic RAS which also showed that the reliability of the system was not affected by this change in Path 8 flows. The plots below shows the voltage deviation under outage conditions.

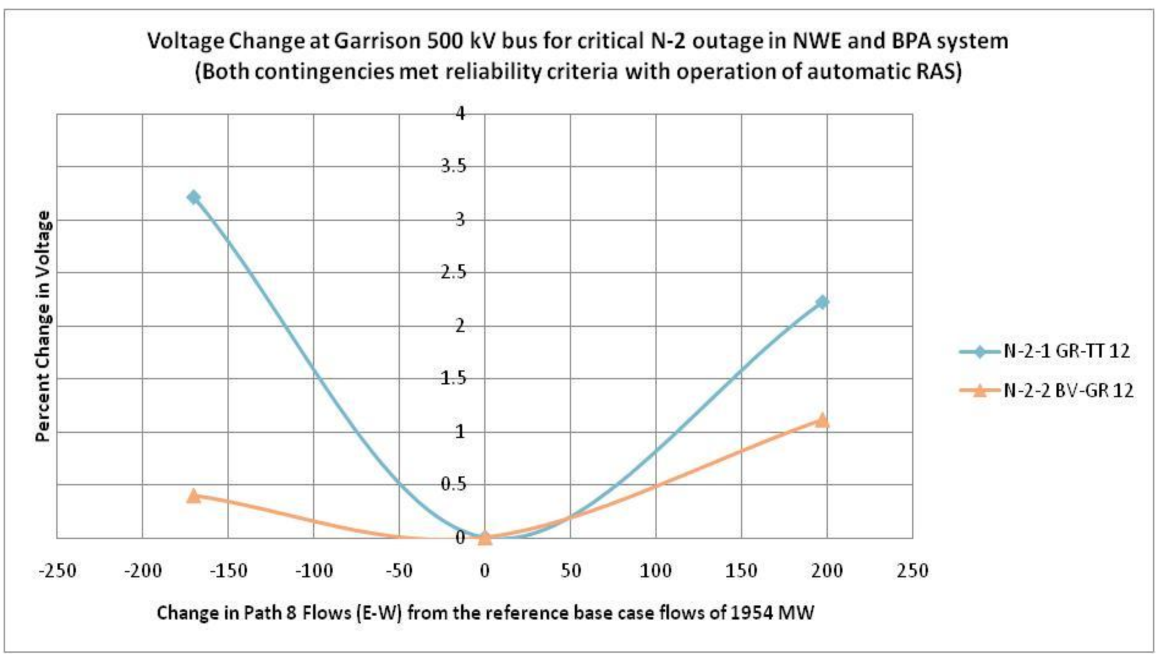
The plot below shows the voltage performance for certain critical 500 kV N-1 contingencies in NWE and BPA transmission system while the flows on Path 8 were reduced and increased from the reference base case by 170 MW and 196 MW respectively. The plot shows that all the contingencies met the reliability criteria in terms of voltage performance.



The plot below shows the voltage performance for certain N-1 contingencies in Avista's transmission system while the flows on Path 8 were reduced and increased from the reference base case by 170 MW and 196 MW respectively.The plot shows that all the contingencies met the reliability criteria in terms of voltage performance.



The plot below shows the voltage performance for certain critical N-2 contingencies in NWE and BPA's transmission system while the flows on Path 8 were reduced and increased from the reference base case by 170 MW and 196 MW respectively.The ATR RAS response was modeled while performing the contingencies. The plot shows that all the contingencies met the reliability criteria in terms of voltage performance.



For the reference base case and the assumptions made for the study, NWE found that varying(reducing) Path 8 by 170 MW changes the voltage at Garrison by 1% and does not affect eh reliability of the system under certain outage conditions. The study also found that varying(increasing) Path 8 by 197 MW changes the voltage at Garrison by 1% and does not affect the reliability of the system under certain outage conditions. No other sensitivity studies like the transient stability were performed.

The differences in assumptions as well as the different flows in BPA and NWE study may be the reason for the difference in the results found. The study showed that the TVL may vary depending on whether the flow on the path is being reduced due to changes in the variable resources or vice versa. Also different outages may have the different impact on the TVL. What level of Customer impact is allowed can also change the TVL values.

Due to several variables affecting the TVL, futher investigation is necessary to accurately determine the need for the TVL and if necessary then perform detailed analysis to accurately calculate the TVL.

PSE (Path 8 Owner) View:

Concur with TVL study results shared by BPA and NWE to date.

Limiting Contingencies & Facilities (& Potential Measures to Increase TVL)

* *Potential measures cited below were will need to be studied to quantify their actual impact on TVL, they are offered as initial thoughts.*

BPA (Path 8 Western Path Operator) View:

Studies were run on a sub-set of Path 8 contingencies, hence, it would be premature to focus on particular limiting contingencies and suggest measures to increase the TVL. While extensive studies would be required to identify specific facilities or controls requiring reinforcement, it is clear that an important aspect of that reinforcement for TVL is controllability of voltage and reactive prior to the contingency. Measures taken to increase TVL should therefore consider installation of reactive devices in smaller steps than might be used for meeting post-contingency criteria, and extensive use of automatic controls.

NWE (Path 8 Eastern Path Operator) View:

Single 500 kV outages (i.e. Broadview to Garrison & Garrison to Taft) are the most severe. These are being actively studied and may result in revisions to the Path 8 RAS design, hence, it is difficult to be definitive on what is needed at this time. That said, Garrison 500 kV bus saw voltage variation and dynamic reactive support near Garrison may help TVLs on Path 8.

Next Steps?

BPA (Path 8 Western Path Operator) View:

Improving real time visibility and monitoring tools for system operators, developing new operational procedures to manage the expected changes to path operation, and continuing to monitor the system impacts as operation moves from the historical predominately “static” flows toward accommodating higher levels of variability are first steps. In order to calculate Path 8 TVLs, further studies, with a complete set of contingencies and different operating conditions are required in addition to an agreed definition of what the acceptable voltage range is for Path 8. Using the recommended methodology to understand the wider interactions with other paths and control systems, and identifying areas where improvements would be most beneficial and cost effective will be longer term goals and areas of continuous improvement as we gain operational experience over time.

NWE (Path 8 Eastern Path Operator) View:

Agree with BPA’s view of Next Steps.

AVA (Path 8 Owner) View:

Agree with BPA view.

PSE (Path 8 Owner) View:

Agree with BPA view.

Path 14: Idaho to Northwest

Region: WECC-NWPP (Southwest Idaho & eastern Oregon/Washington & Northern Idaho)

SOL Setters: IPCO

Path Owners: BPA, IPCO, AVA, PAC

Path Ratings: (E>W Path Rating = 2400 MW) & (W>E Path Rating = 1200 MW)

Need to manage TVL, why and what would change your assessment?

BPA (Path 14 Western Path Operator) View:

Plan to calculate TVLs (& associated nomograms):

The concerns raised by the work of this Task Force, and the independent analysis and operational experience of BPA, indicate the need for further assessment and establishment of TVLs until sufficient improvement in procedure, monitoring, and control are implemented to alleviate the need for them. Within the BPA BAA, a number of issues have been considered including:

- Significance of path and potential for widespread impact of reliability issues;
- Coordination with operators on both sides of path. Situational awareness and understanding changing flows, impacts, drivers;
- Concern for voltage sensitivity impacts to nearby load areas;
- Interdependency of P14 with other paths such as COI.

In BPA's case, the issue is further complicated by the configuration of the transmission system itself: with over 3,000 MW of installed variable generation surrounded by multiple constrained paths crossing the transmission system between the major interties, increasing implementation of Dynamic Transfers must be evaluated in the context of the system as a whole.

Could be reassessed with:

- The need for TVLs will be reassessed on a regular basis, as BPA gains a better understanding of risks associated with new generation patterns, operating experience with higher variability, and identifies and implements reinforcements providing greater dynamic operating margin.

IPCO (Path 14 Eastern Path Operator) View

Still considering need to implement TVLs on Path 8:

At this time the need to manage TVLs is probably not required, because of relatively small penetration (< 300MW), but conditions will are expected to change in the near future. By participating in this effort IPCO expects to develop the expertise & know-how to perform these studies in the future.

AVA (Path 14 Owner) View:

Still considering need to implement TVLs on Path 8:

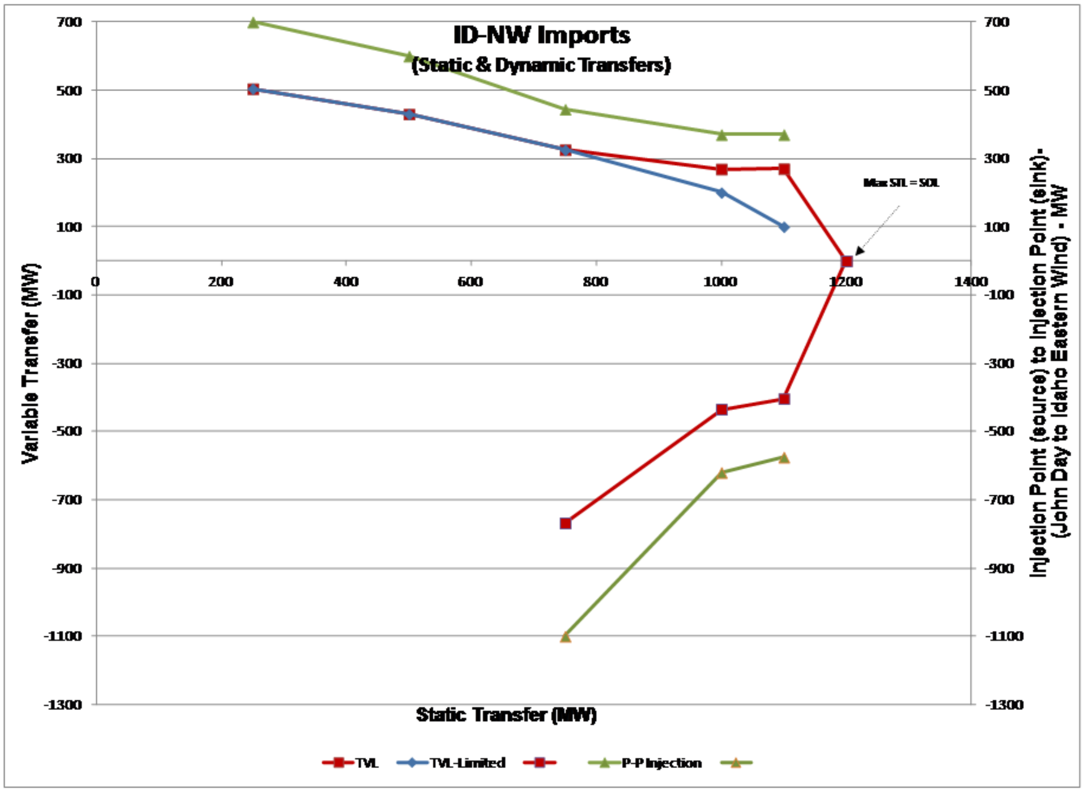
Continue to evaluate and develop expertise.

PAC (Path 14 Owner) View:

Do not feel the need to calculate TVL's owing to the smaller DRVD index on the path. But is willing to assist in the TVL studies if and when deemed necessary with the increase in the renewable generation footprint.

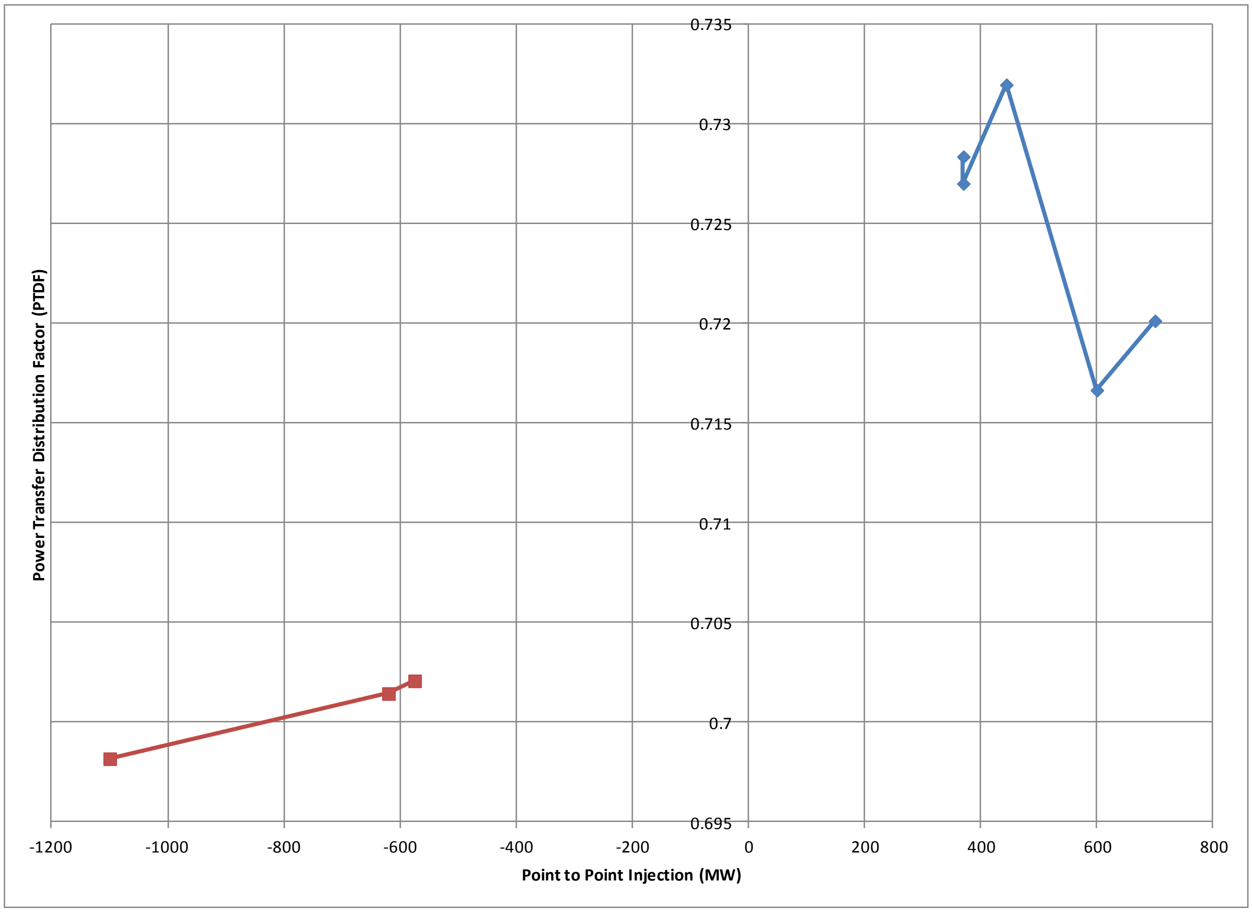
Initial TVL Results for Summer 2011

IPCO (Path 14 Eastern Path Operator) Initial Results:



Starting with the 2011HS WECC case, additional cases with different levels of imports (250MW to 1200MW) from the Northwest into Idaho on Path 14 were developed as starting cases, at different Static flow levels on the Path, from which to compute the associated TVLs. As previously indicated the TVL determination in this work only took into account acceptable voltage changes (without automatic reactive switching devices and/or RAS) at Idaho's 500kV and 345kV buses (1%) and other remaining BES buses (3%). For example in the attached graph, at 750MW import it was determined that given the pre-determined injection points for source (John Day) and sink (Eastern Idaho Wind sites), and considering only the voltage change constraints, the associated TVL in the same flow direction (Eastbound) is 325MW. Either voltage constraints in the BPA area, or reliability related requirements could further reduce this limit. At the same Static flow level of 750MW, an attempt was made to determine the TVL in the opposite direction to this flow. This TVL is represented by the negative red square data point (-768MW) on the graph at the given Static level. This last point turned out to be not so much created by a voltage change limit, but due to lack of resources, at the injection points, necessary to achieve that limit. Because the TVL is being determined opposite to the Static flow, the stresses on the system are less pronounced, resulting in the potential for higher TVL as verified by the simulations.

Because the Static flow + associated TVL should not exceed the Path's SOL, the blue curve shows this limitation as the Static flow approaches the SOL value (1200MW). The graph also shows the level of MWs required at the injection points (green curve) that results in the observed Path TVLs.



This second graph shows the power transfer distribution factors for each of the TVLs (positive and negative) determined. This shows the fraction of the point to point MW injection that shows up across the cutplane. This values ranges between 0.698 to 0.732 (less than 5% change), for levels of injection considered in this work.

Reliability Limit: See previous SOL/TVL nomogram curve – Future work should additionally consider BPA's TVL requirements as well thermal and stability constraints under the associated critical outages of the Path.

Equipment Limit:

- For this study impact on IPCO equipment is not considered

- Transformer regulation and switching of manual shunts is blocked
- Test included only transfer levels where RAS arming is constant

Customer Limit: Based on 1% voltage change on buses at 300kV and above or a 3% voltage change on BES buses below 300kV, whichever is more limiting.

Limiting Contingencies & Facilities (& Potential Measures to Increase TVL)

** Potential measures cited below were will need to be studied to quantify their actual impact on TVL, they are offered as initial thoughts.*

BPA (Path 14 Western Path Operator) View:

Studies were run on a sub-set of Path 14 contingencies and operating scenarios, hence, it would be premature to focus on particular limiting contingencies and suggest measures to increase the TVL. While extensive studies would be required to identify specific facilities or controls requiring reinforcement, it is clear that an important aspect of that reinforcement for TVL is controllability of voltage and reactive prior to the contingency. Measures taken to increase TVL should therefore consider installation of reactive devices in smaller steps than might be used for meeting post-contingency criteria, and extensive use of automatic controls.

IPCO (Path 14 Eastern Path Operator) View

By implementing automatic switching controls of new & existing shunt capacitor banks and/or other reactive devices it might be possible to increase the TVLs on this Path. This should probably be a coordinated effort with BA's on either side of the Path.

AVA (Path 14 Owner) View:

No additional comments.

PAC (Path 14 Owner) View:

Reinforcing the reactive support to accommodate the increase in TVLs.

Next Steps?

BPA (Path 14 Western Path Operator) View:

Improving real time visibility and monitoring tools for system operators, developing new operational procedures to manage the expected changes to path operation, and continuing to monitor the system impacts as operation moves from the historical predominately "static" flows toward accommodating higher levels of variability are first steps. In order to calculate Path 14 TVLs, further studies, with a complete set of contingencies are required. In addition, a clear understanding of how new and unexpected operating conditions may result from the use of resources in both BAAs to balance existing and future wind resources. Using the recommended methodology to understand the wider interactions with other paths and control systems, and identifying areas where improvements would be most beneficial and cost effective will be longer term goals and areas of continuous improvement as we gain operational experience over time.

IPCO (Path 14 Eastern Path Operator) View

It might be a good practice to track intermittent resource variability and observed voltage changes at critical buses to validate the findings of the TVL work.

There is a need to determine these TVLs on a Path basis real time as well as an allocation mechanism between injection points that ensures the TVLs of interested will not be exceeded.

Further development work, both new and/or enhanced software tools and additional refinements in the methodology, will be required to achieve the necessary level of maturity in this area that will support real time management and operation of TVLs.

PAC (Path 14 Owner) View:

Assist in performing TVL studies on the path to determine the areas of concerns going forward. Refine the operating and scheduling practices to incorporate the TVL. The practical implementation of TVL is largely contingent upon proper operational and scheduling tools being developed and resolving the commercial issues should be the next step.