NORTHERN TIER
TRANSMISSION GROUP

ColumbiaGrid

Wind Integration Study Team

Dynamic Transfer Capability Task Force

Phase 2 Report

20 July 2011

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Table of Contents

1. Executive Summary

The Electric Power industry operating model in which scheduled power transfers between Balancing Authorities ("BAs") are generally fixed for the hour is transitioning to one where there will be significantly increased intra-hour power flow variations. Drivers for this new operating model include installation of renewable generation and demand from transmission customers to have increased intra-hour scheduling flexibility. In the Northwest the new renewable generation is primarily wind generation.

Dynamic Transfers, namely schedules that can change within an hour, have been reliably used for decades, albeit on a relatively small scale relative to fixed 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 become concerned about the need to limit Dynamic Transfers across designated paths and flowgates 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 and California transmission providers and sub-regional entities, to further explore the issue of Dynamic Transfer Limits. The fundamental question when considering limits on Dynamic Transfers is: How much can power flows across the system vary within a defined time period (e.g. 15 minutes) and how frequently, while still ensuring acceptable performance and reliable operation given restrictions on how often system operators can readjust the system each hour?[1]

The purpose of the Task Force is to facilitate increases in Dynamic Transfers without compromising system reliability. The Task Force concluded that determining Transfer Variability Limits (TVLs) for flowgates was important to achieving its purpose and accordingly organized its work into three phases: Phase 1 defined the issues and framed the problem (completed March 2011); Phase 2 developed a proposed TVL methodology that could be applied by transmission providers to their system (completed July 2011); Phase 3 will refine the TVL methodology in light of the experience gained by Transmission Providers as they apply the TVL methodology to their systems and may identify possible system improvements to increase TVLs. While the PNW transmission

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[1] There are several proposals being considered to reduce the standard scheduling time period between operator initiated schedule adjustments, including 30 minutes as planned for implementation in the Northwest in July 2011 and 15 minutes as recently proposed by FERC. Reducing the scheduling time period between operator adjustments, however, does not make the underlying power flow variations go away, but rather changes the way the system is operated and there would be an implication of acceptance of some higher costs (e.g. increased maintenance of voltage switching equipment);

system is the focus of these three phases, the conclusions in this report have been presented to WECC, and it is anticipated that the work 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 resources across multiple BAAs, increases in Transfer Variability Limits 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 enhanced state-awareness, automation of controls, additional new 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 impacted by varying sources and/or balancing resources should have limits established for Dynamic Transfers that flow across them. The proposed common methodology would enable all BAAs to determine Transfer Variability Limit (TVL) for flowgates impacted by Dynamic Transfers in a consistent manner using standard terminology. Specific differences in systems however may dictate that for some flowgates that are interties between adjacent BAs there could be a TVL for each side of the flowgate. Consequently, the dynamic transfers from the varying 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 need for each Balancing Authority to develop their own TVLs based on their expert knowledge of their system. In addition, once a TVL is established for a flowgate, the host BAA will need to determine how to allocate its Variable Transfer Capability to Dynamic Resources that would impact that flowgate.

The conclusions of this Phase 2 report are:

1. New terms are needed to facilitate a common understanding of the issues associated with Dynamic Transfers. The Task Force proposed that the term TVL (Transfer Variability Limit) be used to describe the maximum amount of frequently anticipated variability that could be imposed on a path/flowgate for a defined timeframe;

2. Increased Dynamic Transfers could lead to increased wear on switching devices – hence some equipment could need more maintenance and there could be a possible reduction in lifespan;

3. The timeframe during which transfers assumed to be under automatic control could differ from one BAA to another to reflect the way individual systems are operated. In the Northwest where 30 minute scheduling will be common practice by July 2011, 15 minutes seems an appropriate timeframe given that this corresponds to the time between ramps (e.g. XX:10 to XX:25 or YY:35 to YY:50). For the California ISO's BAA, 5 or 10 minutes seems appropriate given its automated real-time dispatch and transmission control equipment.

4. The Task Force does not propose any change to the authority or discretion of a Transmission Provider. Because Transmission Providers are responsible for the reliability of their individual systems and must meet reliability and other standards, the Task Force assumed that they have authority to apply the proposed methodology to their system. Local issues include, but are not limited to, the following:
    a. Choose which paths/flowgates should be studied;
    b. Determine the amount of voltage deviation that is acceptable;
    c. Determine the resources to be considered for the path/flowgate under study, including whether some resources could be considered a single clustered resource for the flowgate under study;
    d. Calculate the resulting TVLs for their system;
    e. Coordinate TVL impacts with neighboring BAAs.

5. The Balancing Resources need to be identified for each Variable Resource that is going to be dynamically scheduled as the variability impact on the transmission system stems from this resource pair. This concept can be extended to cover situations where resources are clustered together. A pre-condition to an effective study is that the Balancing Resources are able to fully compensate for the variability injected by the Variable Resource.

6. Simply because a BAA could accommodate TVL across a particular flowgate, there is no guarantee that Dynamic Transfers could flow because of limited Balancing Resources and/or limitations from other flowgates in the transfer path;

7. Calculation of TVLs should involve a three step study process to confirm the proposed variation: 1) Is reliable; 2) Equipment impacts acceptable & 3) Customer Impacts acceptable;

8. Dynamic Transfers may interact with static scheduling process. For instance, the System Operating Limit, which the total of Dynamic and Static schedules may never exceed, may be reduced depending on study assumptions made to facilitate increased Dynamic Transfers;

9. Transmission Providers need to share additional information about their transmission system from what traditionally has been shared, including identification of voltage control devices that could be adjusted automatically within the TVL timeframe without the need for operator action.

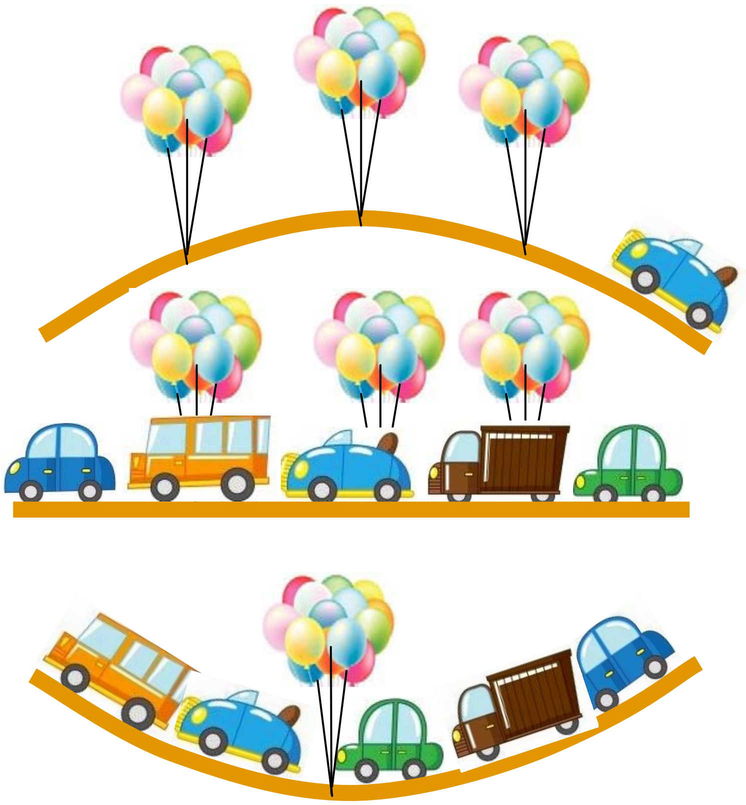
10. Phase 3 of the DTC Task Force's work will include the determination of specific TVLs on several paths/flowgates and a determination of system improvements that could increase the TVLs to desired levels.

11. To implement expanded Dynamic Transfer capability in the WECC, several additional activity streams should be initiated and pursued in parallel including:
    a. Resolution of physical and commercial concerns raised by WECC members in relation to Dynamic Transfers, including those in the proposed Dynamic Transfers Issues Matrix (Appendix F);
    b. Broadening technical analysis and member system review across the Western Interconnection;
    c. Incorporation of TVL determination into WECC Planning and Operating processes;
    d. Development and application of applicable standards and terminology;
    e. Development and application of Scheduling and Operating procedures and protocols.

2. 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. 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.



Light loading - High voltages may damage equipment: capacitive power must be reduced

Maximum TTC: voltages are tuned to optimum level

High loading - Low voltages are a risk to system security: capacitive power needed to avoid voltage collapse

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.

Dynamic Transfers cause energy schedules to vary in between the 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.

The Task Force organized its work into three phases. The goal of the 2nd phase is to develop a DTC Limit Methodology. In the course of our discussions, five other insights emerged:

1. New terms related to 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 Dynamic Transfers on equipment and customers;
3. The interactions between static transfers, dynamic transfers and the impact on the SOL need to be better understood and quantified;
4. The assumptions and approach adopted when applying the TVL methodology will impact the resulting Dynamic Transfer limit;
5. Increased 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 proposed TVL methodology and major issues discussed in Phase 2 and the Appendices provide back-up details for the readers who want to dive deeper.

3. Proposed TVL Methodology

When considering the impact of Dynamic Transfers on the transmission system the fundamental question that needs to be answered is: *"How much can 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 Transfer Variability Limits (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 Dynamic Transfers.

To begin the discussion of methodology, two key terms need to be defined: A glossary of terms introduced throughout the report is included in Appendix A.

Dynamic Transfer [Existing Term in NERC Glossary] - 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. In addition, to the NERC definition the Task Force expanded the meaning of the term to include variable transfers, scheduled or unscheduled, across paths or Flowgates both within and between Balancing Authority Areas.

Transfer Variability Limit (TVL) – The amount of frequently anticipated 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 SOL (System Operating Limit). The TVL could be less than the SOL which has traditionally been calculated using constant, not variable flows.

For Dynamic Transfers across a given Flowgate, the Task Force proposed that the Transfer Variability Limit could be calculated by quantifying adverse impacts from three perspectives: 1) Reliability; 2) Impact on System Equipment and 3) Impact on Customers. These three perspectives can be translated into conditions that the TVL must meet. Figure 2 below illustrates the proposed three-part TVL methodology.

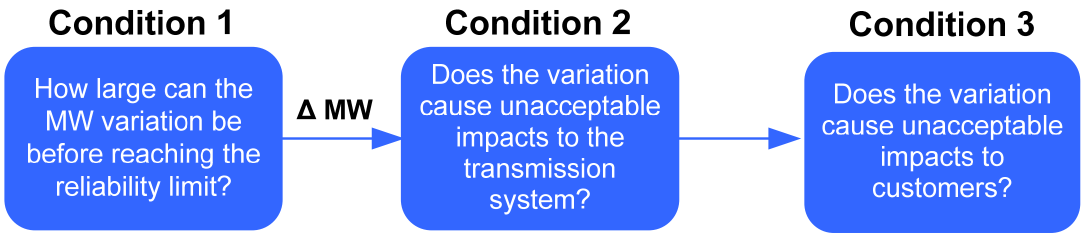


Figure 2: Proposed three part methodology for calculating Transfer Variability Limits

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.

Condition 1: Reliability Limit:
The amount of change in 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 (System Operating Limit) 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. A detailed procedure for calculating a reliability limit is shown in Appendix B. The basic steps are:

1. Assume that the system was tuned for an initial baseflow, namely, 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, namely, only automated RAS arming adjustments and automated voltage control adjustment would be modeled;
3. 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).

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 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.

<u>Condition 3: 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. Figure C-1 in Appendix C shows the Information Technology Industry's Curve for acceptable voltage performance and it indicates minimum requirements for voltage deviation from a customer's perspective. Analysis of voltage variation at key busses across the WECC shown in Appendix C suggests that current system voltage performance is much tighter than what customers plan for. 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 3 below illustrates the TVL challenge as it relates to voltage variation.

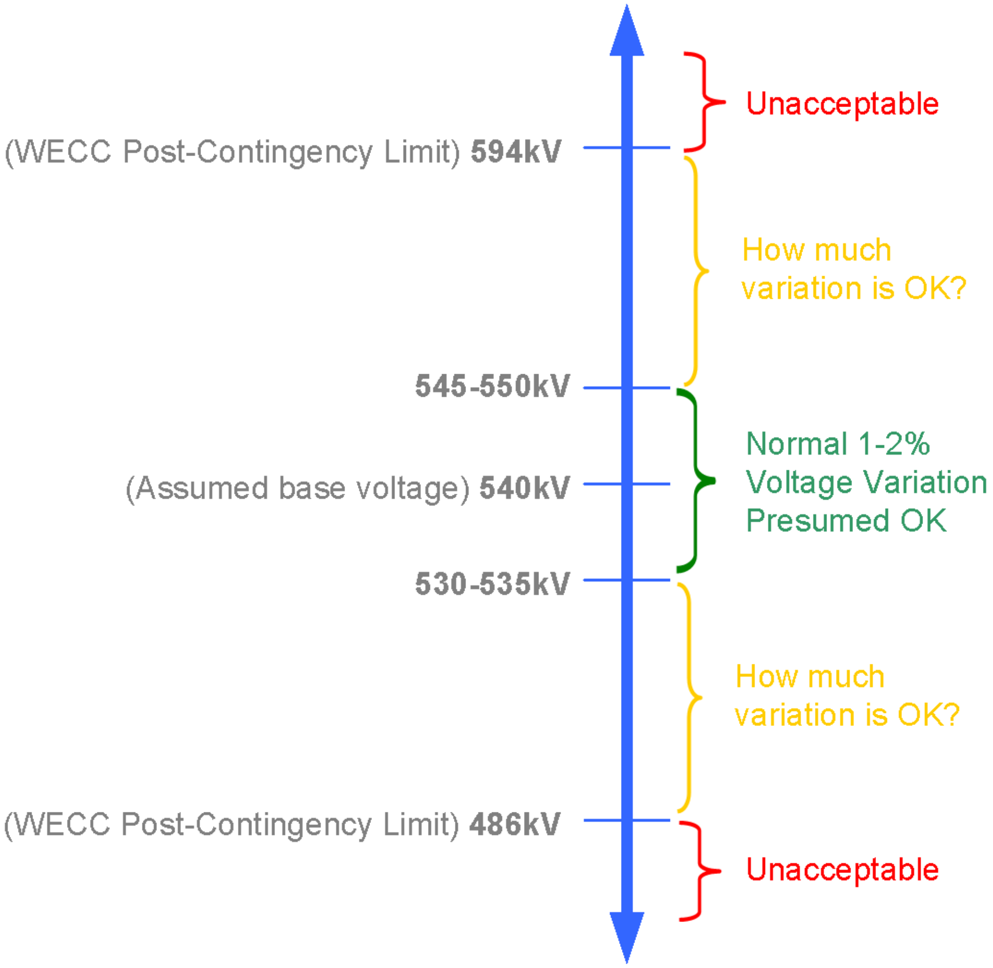


Figure 3: TVL and the relationship to acceptable voltage variation

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

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

4. TVL and Dynamic Resources

Once Transfer Variability Limits are determined for particular flowgates, the question will arise on how dynamic resources will impact these variability limits. All generators, and even some loads, 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[2]; 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 Northwest parties believe that 15 minutes[3] 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:

> **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: %)

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[2] 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.

[3] 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. Further discussion of TVL specified timeframes is included in Appendix E – Assumptions & Issues related to the TVL Methodology.

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, measured in MW, that a Dynamic Resource injects into the transmission system at its interconnection point. DRVD = DRVI x DRmax. (Units: MW)

Variable Transfer Capacity (VTC) – The amount of variable transfer that a Dynamic Resource's DRVD would contribute across a Flowgate during the TVL specified timeframe: VTC = DRVD * PTDF. (Units: MW)

Available Variable Transfer Capacity (AVTC) – The amount of variable transfer that could still be accommodated across a Flowgate during the TVL specified timeframe. For a specific Flowgate AVTC = TVL - ∑VTC. (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[4].
(Units: %)

For a particular path/flowgate, if the involved Dynamic Resources[5] injected their maximum historic variation over the same TVL timeframe, it would be important to ensure that the flowgate would operate within its Reliability Limit. Consequently, when comparing dynamic transfer commitments to the Reliability Limit a DRVI assuming the 100th percentile for variability would be applied, whereas a DRVI assuming a variability percentile less than 100% (to be defined by the Transmission Provider and known as the DPL) would be applied when assessing the Equipment and Customer Limits. The feasibility of this two tiered approach will be explored in Phase 3 of the DTC Task Force's work.

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

[5] The Dynamic Resources would be defined by the Transmission Provider performing the TVL study and could include several individual projects in the same region that are clustered together and treated as a single variable resource.

5. Current System Performance Benchmarks

The proposed DTC methodology will determine whether a the new operating point that results from dynamic transfers will be reliable even though all manually adjusted system equipment (e.g. tap changing transformers, switchable shunt devices, and manually armed RAS) will remain in the state that was tuned for the original operating point. Going a step further, it is possible that while the new operating point is reliable, the repeated moving from one operating point to another will cause an unacceptable impact on equipment and customers. This may be due to factors that include increased voltage variations, increased operations of switchable shunts and increased frequency disturbances. This highlights the importance of benchmarking the existing system performance in order to evaluate whether the performance in these categories has unacceptably degraded due to the introduction of increased dynamic transfers.

This section of the report outlines techniques for quantifying the existing voltage variation, shunt device operation and frequency disturbance performance. The results obtained by Task Force members are also presented in the Appendices.

Voltage Variations

An investigation was taken by the Task Force to establish a baseline for existing variation at key points on the bulk system. Voltage variations were calculated using the following process.

1. Voltage records of maximum and minimum values from 2009 were collected over 5 minute intervals at critical 500kV and 230kV substations;
2. The difference between each adjacent sample was calculated to form a voltage delta over 5 and 15 minute intervals;
3. Positive and negative voltage deltas were separated from one another;
4. The percentile of positive and negative voltage deltas at each bus was calculated.

From the Table C-1 in Appendix C, we see that for 15 minute time periods at the buses studied in this analysis the maximum voltage changes were about 0.6% on an hourly basis, and about 1.5% once a day. From the Table C-2 in Appendix C, we see that for 5 minute time periods at the buses studied in this analysis the maximum voltage change were about 0.3% on an hourly basis, and about 1.0% once a day.

Switched Shunt Devices

The number of operations of for some switched shunt devices was quantified. Increased use of switchable shunt devices will result in increased wear on the circuit breakers that are switching them in and out. Circuit breakers in the BC Hydro system are known to require a major overhaul every 2000-3000 operations and have a mean life of approximately 40 years. Whether increased transmission variability has a substantial impact on circuit breaker mean life and maintenance costs could be quantified by looking at the number of circuit breaker operations.

The number of operations (switching in or switching out) for circuit breakers can be calculated using an automated script or could be manually calculated. The results shown in Appendix C for the BC Hydro system are the output from an automated script. The number of operations varied from one operation per month (a 500 kV breaker at Ashton Creek {ACK 5RX4}) to over 2 operations per day (a 230 kV breaker at Ingledow {ING 2RX1}).

The results shown in Appendix C for the CAISO system are the output from manual polling on five-minute intervals, for the substations containing switched shunts that are most affected by flows across COI. The number of operations varied from averaging less than one operation in three days (Vaca-Dixon 230 kV) to no operations during the year (breaker 782 at Metcalf 500 kV). The typical nature of these operations is that the normal switch status is "open", and when a switch becomes closed, it re-opens once the triggering condition is resolved, most often within five to ten minutes. Thus, one can view the frequency of close-open operations as half of the stated values.

Frequency Disturbances

The Dynamic Transfer Task Force was interested in determining whether wind down ramps could impact the interconnection frequency and this will be investigated more fully in Phase 3. To benchmark the magnitude and severity of Frequency Disturbances, WECC Generator Forced Outage data for 2009 was analyzed: the 119 reported generator forced outages ranged in magnitude from 5 MW to 1805 MW. The results are summarized below in Table 1 and a graph is shown in Appendix D:

Range of MW Change	Generator Forced Outages in WECC (2009)
0 MW to -99 MW	2
-100 MW to -249 MW	2
-250 MW to -499 MW	50
-500 MW to -749 MW	36
-750 MW to -999 MW	20
-1000 MW to -2000 MW	9

Table 1: Number of Forced Generator Outages in WECC (2009)

For an initial assessment of the impact of wind variability, the Task Force analyzed 15-minute wind down ramps in the BPA BAA from 2009. As shown in Table 2 below, the vast majority of down ramps were less than 100 MW, however, there were a few down ramps that were comparable in magnitude to generator forced outage events. It should be noted that the 2009 BPA wind data reflects a peak installed capacity of 2,617 MW in December 2009. The frequency and magnitude of the downramps would likely change as the BPA wind fleet increases. The installed capacity of wind farms in the BPA BAA had grown to 3,372 MW[6] in December 2010 and it is forecast to increase to 5,393 MW by December 2012[7].

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[6] BPA Website for Installed Wind Capacity: http://transmission.bpa.gov/Business/Operations/Wind/WIND_InstalledCapacity_CHART.pdf

[7] BPA Forecast of Future Wind Capacity See Table 2.1 on page 1: http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-05A.pdf

Range of MW Change	Number of 15 min Down Ramps of BPA Wind (2009)
0 MW to -99 MW	18,688
-100 MW to -249 MW	23
-250 MW to -499 MW	36
-500 MW to -749 MW	5
-750 MW to -999 MW	1[8]
-1000 MW to -2000 MW	0

Table 2: 15-minute Wind Down Ramps from BPA BAA

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[8] The measured variability is a function of the sampling period (e.g. 1 min vs 5 min samples) and the time-intervals (e.g. four fixed 15 minute intervals each hour vs twelve 15 minute intervals 5 minutes apart). For instance, in the 2009 data there were two 15 minute intervals where the down ramp exceeded 750 MW: 1) -803 MW down ramp between 04:10 and 04:25 on 27 April; 2) -752 MW down ramp between 17:35 and 17:50 19 May 2009. These two events averaged to 0.67 due to standardizing from twelve rolling 15 minute intervals down to four 15 minute intervals per hour.

6. Next Steps

In Phase 1, the WIST DTC Task Force defined the DTC problem and confirmed that it is a legitimate issue that Transmission Providers should study in order to determine their system's DTC limits and risks. In Phase 2, the Task Force proposed new terms for describing Dynamic Transfers and a methodology for calculating the Transfer Variability Limits. In addition the Task Force developed a framework that WECC could use to capture, sort and assign significant Dynamic Transfer issues that need to be resolved. In order to reliably increase the level of Dynamic Transfers across the WECC multiple issues will need to be resolved, and it is the Task Force's hope that many of the issues could be resolved in parallel with the work it is doing on Transfer Variability Limits. The issues matrix is shown in Appendix F.

The Task Force plans to conclude the current round of studies in Fall 2011. The goals for the last phase are:

Phase 3: Calculate DTC limits for several BAs in the WECC;
List of automatically switchable voltage devices within the TVL timeframe;
Develop a diagram to explain Dynamic Transfer terms;
Identify coordination issues for Dynamic Transfer implementation between BAs;
Identify some specific projects to enhance DTC transfer levels;
Refine the DTC methodology to reflect lessons learned by individual BAs;
Present methodology to WECC Members for buy-in.

Complete by October 2011

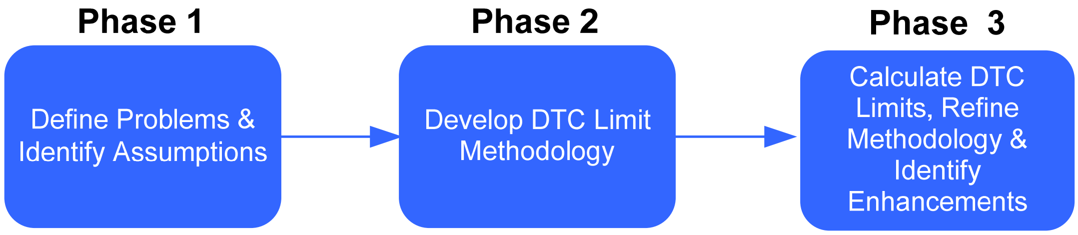

Figure 4: Phases of the DTC Task Force's Work Plan

7. Conclusions

Should 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 second of three phases is now complete and the conclusions of this report are:

1. New terms are needed to facilitate a common understanding of the issues associated with Dynamic Transfers. The Task Force proposed that the term TVL (Transfer Variability Limit) be used to describe the maximum amount of frequently anticipated variability that could be imposed on a path/flowgate for a defined timeframe;

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6. Simply because a BAA could accommodate TVL across a particular flowgate, there is no guarantee that Dynamic Transfers could flow because of limited Balancing Resources and/or limitations from other flowgates in the transfer path;

7. Calculation of TVLs should involve a three step study process to confirm the proposed variation: 1) Is reliable; 2) Equipment impacts acceptable & 3) Customer Impacts acceptable;

8. Dynamic Transfers may interact with static scheduling process. For instance, the System Operating Limit, which the total of Dynamic and Static schedules may never exceed, may be reduced depending on study assumptions made to facilitate increased Dynamic Transfers;

9. Transmission Providers need to share additional information about their transmission system from what traditionally has been shared, including identification of voltage control devices that could be adjusted automatically within the TVL timeframe without the need for operator action.

10. Phase 3 of the DTC Task Force's work will include the determination of specific TVLs on several paths/flowgates and a determination of system improvements that could increase the TVLs to desired levels.

11. To implement expanded Dynamic Transfer capability in the WECC, several additional activity streams should be initiated and pursued in parallel including:
    a. Resolution of physical and commercial concerns raised by WECC members in relation to Dynamic Transfers, including those in the proposed Dynamic Transfers Issues Matrix (Appendix F);
    b. Broadening technical analysis and member system review across the Western Interconnection;
    c. Incorporation of TVL determination into WECC Planning and Operating processes;
    d. Development and application of applicable standards and terminology;
    e. Development and application of Scheduling and Operating procedures and protocols.

Appendix A – Glossary of Dynamic Transfer Terms

To ensure consistent and reproducible results in a study methodology, it is imperative that everyone shares 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. The Task Force assumes that these terms may evolve as the methodology is further refined and that terms would eventually be added to the NERC Glossary.

Dynamic Transfer [Existing Term in NERC Glossary] - 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. In addition, to the NERC definition this term herein is expanded to include variable transfers, scheduled or unscheduled, across paths or Flowgates both within and between Balancing Authority Areas.

Transfer Variability Limit (TVL) – The amount of frequently anticipated 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 SOL. The TVL could be less than the SOL which has traditionally been calculated using constant, not variable flows. (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)

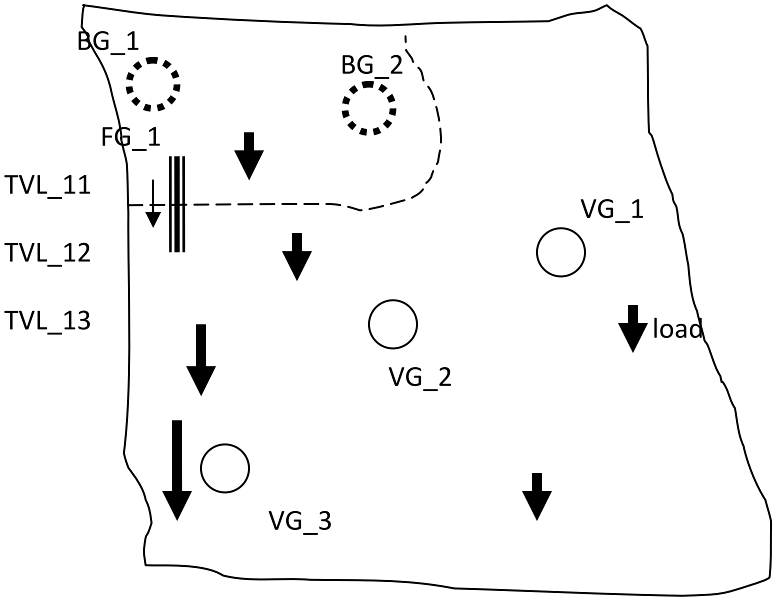
Variable Transfer Capacity (VTC) – The amount of variable transfer that a Dynamic Resource's DRVD would contribute across a Flowgate during the TVL specified timeframe: VTC = DRVD * PTDF. (Units: MW)

Available Variable Transfer Capacity (AVTC) – The amount of variable transfer that could still be accommodated across a Flowgate during the TVL specified timeframe. For a specific Flowgate: AVTC = TVL - ∑VTC.
(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. (Units: %)

Appendix B – Proposed Detailed TVL Methodology and related Issues

TVL could be computed for a given pair of Variable Generation (VG) and Balancing Generation (BG) using the following procedures:



A. To compute individual TVL:

For a given flow gate (FG_1), the Transmission Variability Limit (TVL_11) for a balancing generation (BG_1) to mitigate the impact caused by the generation variation (VG_1) can be computed with the following steps:

1. Since the system load served is the same regardless of the generation dispatches, we only need to address the power flow changes caused by generation re-dispatch due to generation variation.
2. For the given base case, reduce VG_1 generation by the expected maximum amount and increase BG_1 with the corresponding amount. Turn on (or not?) the automatic devices (taps and shunt devices) and solve the pre-outage power flow. If the voltage variation is within the set limit, ok.
3. Conduct the post contingency analysis of the credible contingencies to ensure meeting the thermal, voltage dip, voltage stability and transient stability performance requirements. If so, ok. If not, reduce the allowed amount of generation variation and repeat the process until the limit is determined.
4. So for variable generation reductions:
    - BG_1 and -VG_1, there is TVL_11
    - BG_1 and -VG_2, there is TVL_12
    - BG_1 and -VG_3, there is TVL_13

B. To compute combined TVL:

The combined effect of VG_1, VG_2, and VG_3 on BG_1 could be computed using the similar approach of changing the generations at VG_1, VG_2 and VG_3 with respective coincidence factors. Then check the pre-outage voltage deviation and post contingency performance as described before.

So for BG_1 and (-VG_1, -VG_2, -VG_3), there is TVL_1_123

To simplify the computation, one might consider different options:

1. Assuming TVL_13 being the worst case from a transmission perspective, then simply apply TVL_13 for all VG variations.

2. Another option is to apply respective coincidence factors to TVLs, i.e.
   TVL_1_123 = $\alpha 1$ x TVL_11 + $\alpha 2$ x TVL_12 + $\alpha 3$ x TVL_13

   Assuming $\alpha 1$ is the coincidence factor of VG_1

   This approach needs to be verified.

C. To compute opposite direction TVL:

For flows in the opposite direction on FG_1, apply the similar methodology. This shouldn't be a problem, unless the incremental change is in the same direction, i.e. increasing the flow from generation re-dispatch.

D. To compute TVL for the service entity:

For BG_2, if the entity has determined that BG_2 causes reduced TVL on the subject flow gate due to internal constraints and BG_2 is to be used to provide the service, then BG_2 should be used to compute the TVL for that entity.

Issues related to the TVL Methodology:

a. Approach impacts TVL

The approach employed for managing some key power system parameters will have an impact on the resulting TVLs and in turn on some power system equipment. To illustrate the concept, some possible approaches for computing the TVL are listed below:

1. Approach #1: Find the TVL that does not cause the pre-outage voltage variation δV exceeding 1.5% with all moveable devices locked after the generation re-dispatch.
2. Approach #2: Find the TVL that does not cause the pre-outage voltage variation δV exceeding 1.5% with all automatically moveable devices turned on after the generation re-dispatch.
3. Approach #3: Allow slightly higher δV, but lock all moveable devices when solving for the pre-outage power flow after the generation re-dispatch.
4. Approach #4: Allow higher δV, turn on all automatically moveable devices when solving for the pre-outage power flow after the generation re-dispatch.

All four approaches will require the same level of post contingency performance, namely that the requirements are met to address thermal, voltage dip, voltage stability and transient stability concerns.

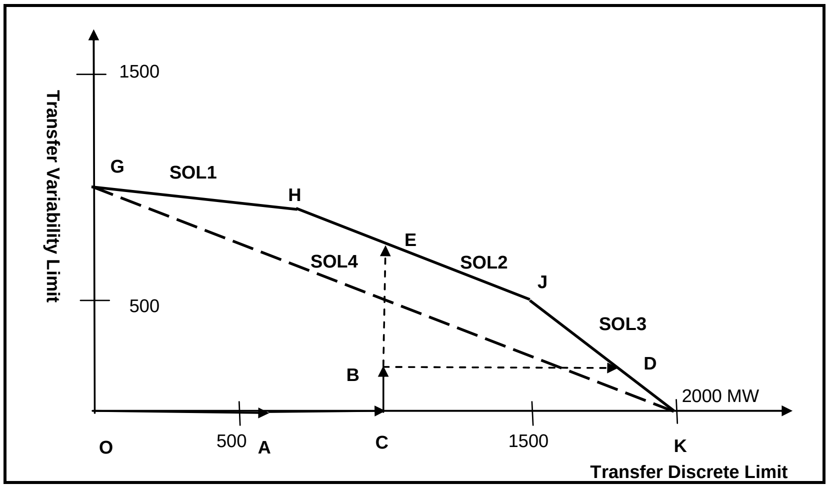
	TVL Study Approaches			
	#1	**#2**	**#3**	**#4**
1. **Pre-outage condition after generation re-dispatch responding to wind generation variations**				
o Preoutage max voltage deviation due to generation re-dispatch	**δV ≤ 1.5%** (i.e. assuming 1.5% as the adopted normal operation voltage variation range)	**δV ≤ 1.5%** (i.e. assuming 1.5% as the adopted normal operation voltage variation range)	**δV ≤ 3%** (i.e. assuming 3% as adopted max)	**δV ≤ 3%** (i.e. assuming 3% as adopted max)
o Transformer tap and switchable shunts	locked	Not applicable	locked	Not applicable
o Automatic actions of Transformer tap and switchable shunts (assuming 5 min limit)	Not applicable	Turned on	Not applicable	Turned on
2. **Post contingency performance**				
o thermal, voltage dip, voltage stability & transient stability performances	acceptable	acceptable	acceptable	Acceptable

Comment:

- Approach #1: The most conservative among the four approaches described above, as the pre-outage voltage variations are within the normal operation range.
- Approach #2: Similar to Approach #1 but allows automatic devices to move.
- Approach #3: Offers a small margin of incremental gain by accepting the potential customer impacts of allowing greater pre-outage voltage deviation than Approach #1, while avoiding extra wear and tear caused by additional transformer tap movements and CB switching.
- Approach #4: Offers the most TVL as the benefits of automatic devices are considered in determing the TVL.

b. Tradeoffs between SOL & TVL

For a given flow gate or transmission path, the scheduled and actual transfers must be below the SOL. With the introduction of TVL, the SOL can be considered to consist of two components, the generally static type and the variable type for a given time frame. Assuming the actual operating point has a static transfer, then the dynamic transfer is a potential to be realized when called upon. For a given operating point, there is a corresponding limit of static transfer (Transfer Discrete Limit) and dynamic limit (Transfer Variability Limit). As the scheduled static transfer is changed, the corresponding remaining TDL and TVL will also change, for a given SOL.



Where:

A: actual operating point
OA: actual transfer
OC: Discrete transfer scheduled
CB: Variable transfer scheduled
BD: Remaining discrete transfer capability
BE: Remaining variable transfer capability

In scheduling: SOL = Discrete transfer limit + Variable Transfer Limit

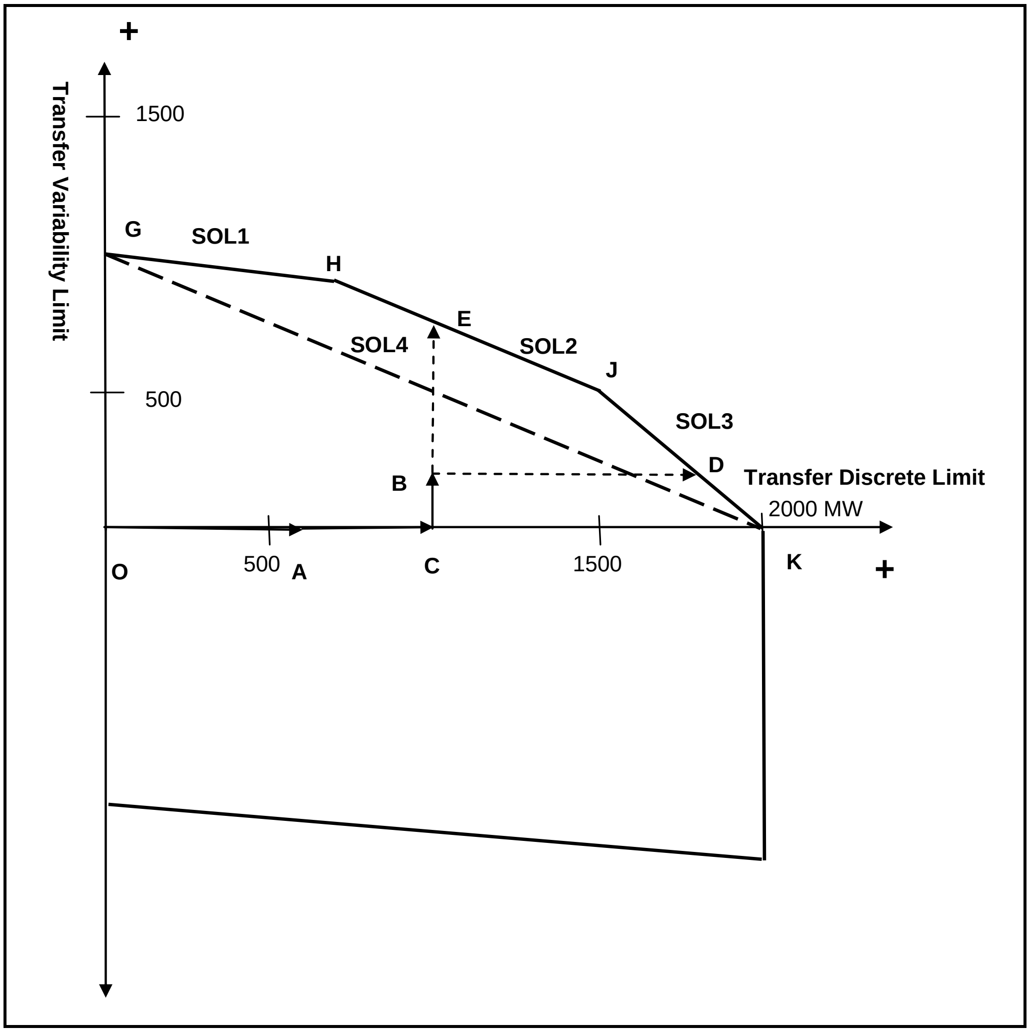
But the computed SOL limits are specified as:

- $X + 7Y \leq 7000$ MW …… (SOL1)
- $X + 2Y \leq 2500$ MW …… (SOL2)
- $X + Y \leq 2000$ MW …… (SOL3)
- $X + 2Y \leq 2000$ MW …… (SOL4)

The number of SOL lines depends on the study granularity, as shown the SOLs defined by lines (GHJK) vs line (GK).

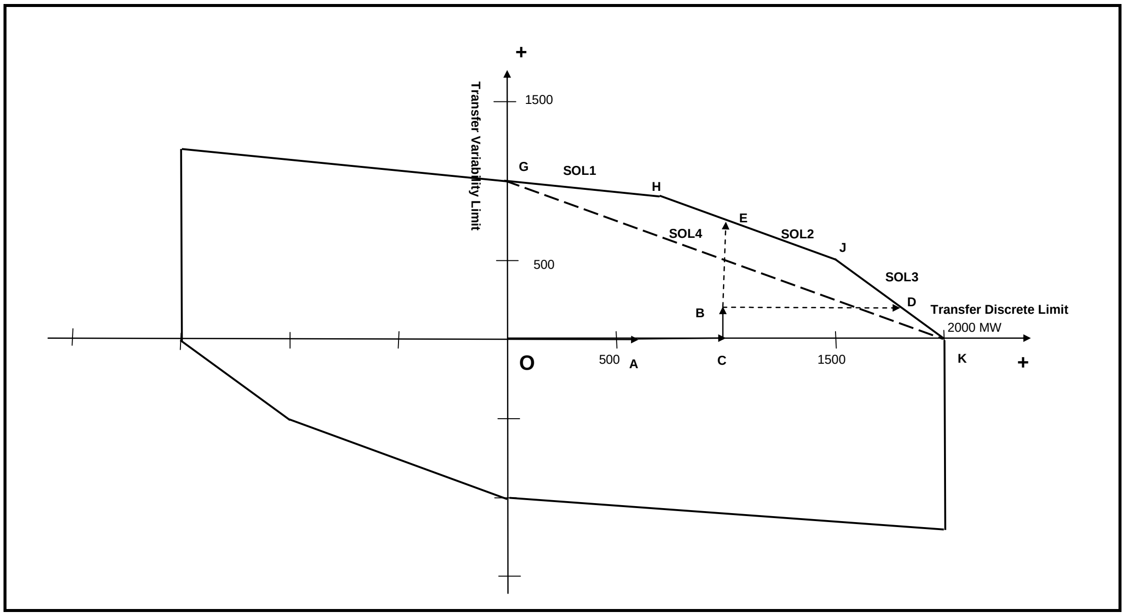
c. Simultaneous TVL

When there is a large pool of variable generation across the transmission path, the variations could be in either direction. Hence there may be a need to ensure sufficient TVL in both directions. It is expected that the TVL of the opposite direction to the static flow should be greater than the TVL of the same direction as the static flow due to reduction in net flow, hence a relief to system stress, as illustrated below.



d. Transmission Path SOL, TDL and TVL Nomogram

For a given transmission path or flow gate, there are SOL limits in both directions. With TVL incorporated, the SOL can be considered conceptually as shown in the diagram below.



Appendix C – Benchmarks of Normal System Voltage Performance

This Appendix summarizes some of the data and standards that the DTC Task Force reviewed to understand what normal and acceptable voltage performance would look like. It begins with the Information Technology Industry's Curve for acceptable voltage performance, shown in Figure C-1: Transmission Planners could interpret this curve as the poorest level of voltage performance that their customers expect under normal conditions. In practice, transmission planners generally want to plan to exceed the minimum voltage sag performance standards so that there is some margin to account for the vagaries, such as peak loads or outages, of normal system operations.

Subsequently, we examine voltage variations measured at some critical busses across the WECC for 15 minute and 5 minute increments. From the Table 1a we see that for 15 minute time periods at the buses studied in this analysis the maximum voltage changes were about 0.6% on an hourly basis, and about 1.5% once a day. From the Table 1b we see that for 5 minute time periods at the buses studied in this analysis the maximum voltage change were about 0.3% on an hourly basis, and about 1.0% once a day.

Next we examine the frequency of switching associated with some voltage control devices located on the voltage control devices on the BC Hydro and CAISO systems. Breakers have a limited number of operations that they can perform over the course of their lifetime. Increasing the frequency of operations for voltage control equipment will impact the equipment's lifespan, its need for maintenance and the likelihood that it may be unavailable due to outages. Consequently, tracking the number of breaker operations is important to understand what normal practice is now as well as a preventive measure to anticipate potential maintenance issues in the future.

Lastly, CAISO describes a voltage analysis it carried out to understand the cause of voltage control measures that took place at Table Mountain.

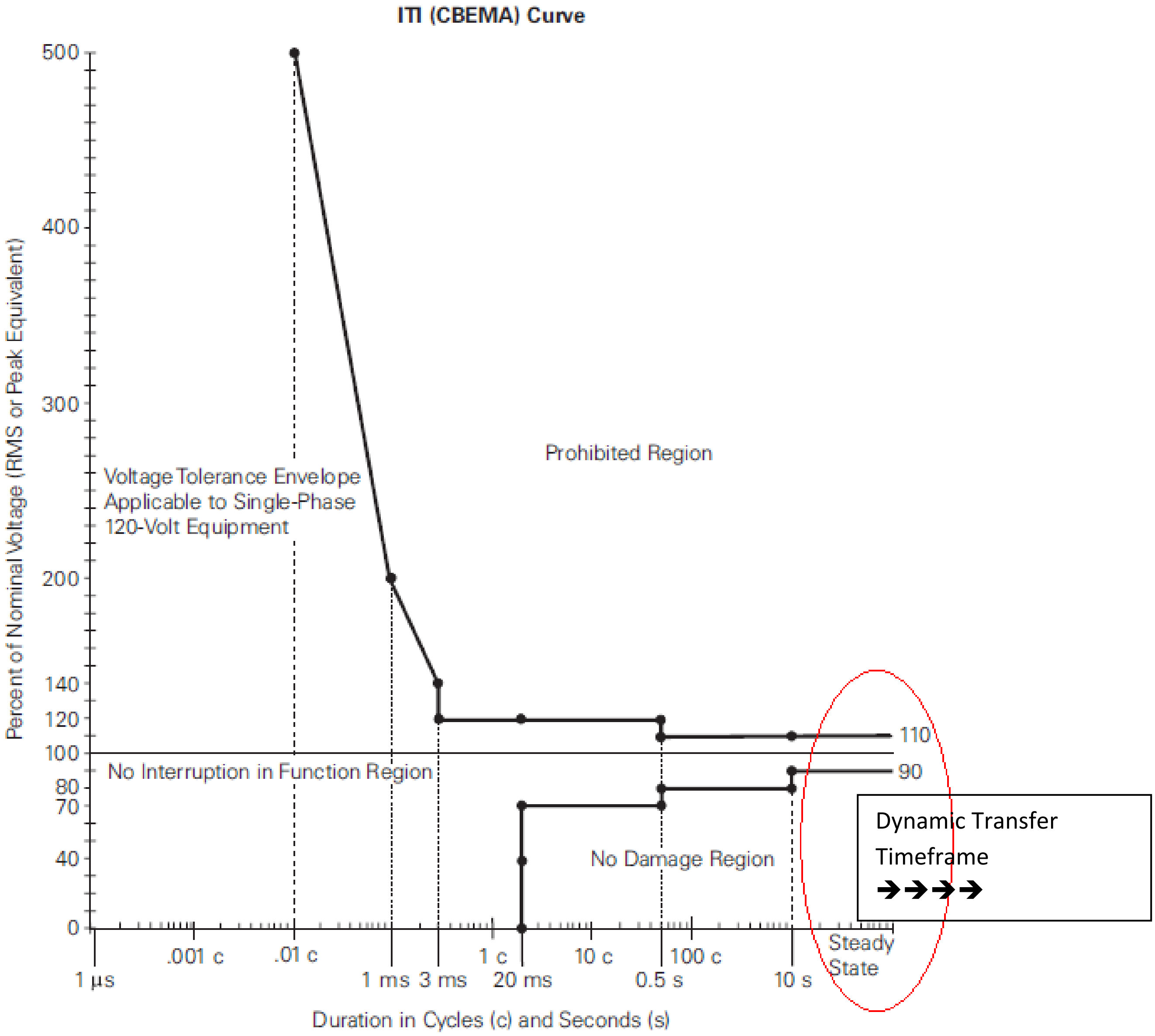


Figure C-1: Voltage Sag criteria relative to Dynamic Transfer Timeframe

Percentile	Number of Occurrences	BC Hydro				BPA			IPCO		PacifiCorp	CAISO
		G. M. Shrum 500kV	Williston 500kV	Kelly Lake 500kV	Ingledow 500kV	Custer 500kV	Monroe 500kV	Echo Lake 500kV	Borah 345kV	La Grande 230kV	Midpoint 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	-0.52	-0.51
		0.26	0.46	0.43	0.40	0.65	0.58	0.52	0.56	0.53	0.52	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	-0.54	-0.51
		0.27	0.48	0.48	0.40	0.71	0.65	0.52	0.61	0.53	0.54	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	-0.58	-0.51
		0.30	0.53	0.48	0.46	0.72	0.65	0.58	0.64	0.53	0.56	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	-0.60	-0.51
		0.32	0.55	0.54	0.52	0.78	0.71	0.58	0.64	0.59	0.60	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	-0.64	-0.51
		0.37	0.59	0.56	0.60	0.78	0.71	0.65	0.64	0.60	0.64	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	-0.68	-0.63
		0.41	0.66	0.64	0.60	0.85	0.78	0.71	0.64	0.60	0.68	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	-0.74	-0.76
		0.47	0.67	0.72	0.67	0.91	0.84	0.84	0.75	0.66	0.74	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	-0.80	-0.76
		0.56	0.73	0.80	0.80	0.98	0.91	0.91	0.80	0.66	0.84	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	-0.94	-0.89
		0.68	0.85	0.95	0.93	1.10	1.04	1.04	0.96	0.77	0.98	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	-1.20	-1.02
		0.96	1.01	1.12	1.20	1.23	1.30	1.23	1.17	0.92	1.24	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	-1.58	-1.14
		1.20	1.18	1.36	1.53	1.43	1.86	1.43	1.43	1.13	1.66	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	-4.00	-1.52
		2.44	1.90	2.32	2.45	2.09	2.66	1.95	2.31	3.71	4.00	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	-5.99	-1.78
		3.38	2.88	5.93	3.00	2.42	2.84	2.26	2.98	5.27	5.24	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	-7.23	-2.19
		6.38	4.62	7.42	3.74	2.83	3.51	2.69	3.83	7.59	6.30	3.40
100%	-	-3.63	-3.31	-6.24	-4.29	-4.09	-5.40	-2.47	-3.35	-6.29	-7.46	-2.29
		7.87	5.38	7.84	3.85	2.90	3.57	2.73	3.95	7.69	6.32	3.68

Table C-1: Summary of Positive and Negative 15 minute Voltage Deltas (%) at Critical 500kV, 345kV and 230kV Buses

Percentile	Number of Occurrences	BC Hydro				BPA			IPCO		CAISO
		G. M. Shrum 500kV	Williston 500kV	Kelly Lake 500kV	Ingledow 500kV	Custer 500kV	Monroe 500kV	Echo Lake 500kV	Borah 345kV	La Grande 230kV	Round Mountain 500kV
90%	29 times a day	0.13	0.23	0.30	0.26	0.35	0.32	0.31	0.32	0.33	0.25
		-0.13	-0.24	-0.32	-0.33	-0.39	-0.32	-0.32	-0.32	-0.33	-0.25
91%	26 times a day	0.15	0.25	0.32	0.29	0.39	0.32	0.32	0.32	0.33	0.25
		-0.15	-0.26	-0.32	-0.33	-0.39	-0.33	-0.32	-0.32	-0.33	-0.25
92%	23 times a day	0.17	0.28	0.32	0.33	0.39	0.32	0.32	0.32	0.33	0.25
		-0.17	-0.29	-0.32	-0.37	-0.39	-0.37	-0.34	-0.32	-0.37	-0.25
93%	20 times a day	0.20	0.31	0.34	0.36	0.41	0.38	0.32	0.33	0.39	0.25
		-0.20	-0.32	-0.36	-0.39	-0.44	-0.39	-0.38	-0.33	-0.39	-0.25
94%	17 times a day	0.24	0.35	0.40	0.39	0.46	0.39	0.36	0.37	0.40	0.25
		-0.23	-0.36	-0.40	-0.46	-0.46	-0.39	-0.39	-0.36	-0.40	-0.25
95%	14 times a day	0.26	0.40	0.40	0.46	0.49	0.39	0.39	0.40	0.40	0.25
		-0.26	-0.40	-0.41	-0.49	-0.51	-0.42	-0.39	-0.40	-0.40	-0.25
96%	12 times a day	0.30	0.40	0.48	0.53	0.52	0.45	0.39	0.45	0.40	0.38
		-0.29	-0.40	-0.48	-0.53	-0.52	-0.45	-0.45	-0.45	-0.40	-0.38
97%	9 times a day	0.36	0.47	0.56	0.59	0.59	0.52	0.45	0.48	0.46	0.51
		-0.34	-0.47	-0.56	-0.59	-0.58	-0.52	-0.48	-0.48	-0.46	-0.51
98%	6 times a day	0.45	0.60	0.72	0.66	0.70	0.65	0.54	0.48	0.47	0.51
		-0.45	-0.60	-0.72	-0.66	-0.65	-0.65	-0.58	-0.48	-0.51	-0.51
99%	3 times a day	0.68	0.80	0.88	0.79	0.91	0.84	0.81	0.64	0.60	0.76
		-0.70	-0.76	-0.88	-0.79	-0.84	-0.84	-0.82	-0.64	-0.60	-0.76
99.5%	1.5 times a day	0.94	1.00	1.04	0.93	1.04	0.97	1.04	0.82	0.73	0.89
		-0.95	-1.00	-1.04	-0.92	-0.98	-0.99	-0.97	-0.78	-0.66	-0.89
99.95%	once a week	1.90	2.00	1.84	1.64	1.56	2.21	1.56	1.58	1.62	1.27
		-1.65	-1.80	-1.60	-1.46	-1.43	-2.18	-1.47	-1.43	-1.86	-1.32
99.99%	once a month	2.96	2.44	5.59	2.63	2.12	2.60	1.95	2.55	3.82	2.03
		-2.19	-2.22	-3.89	-2.27	-1.87	-2.45	-1.64	-2.10	-3.77	-1.66
99.999%	once a year	5.26	3.25	7.06	3.98	3.04	3.40	2.62	5.75	7.38	4.24
		-5.34	-2.79	-5.41	-2.92	-2.39	-5.35	-1.94	-3.26	-5.75	-3.72
100%	-	7.60	3.85	7.84	5.06	3.64	3.57	2.73	7.93	7.64	5.71
		-7.86	-2.80	-5.59	-2.96	-2.44	-5.97	-2.08	-3.35	-6.29	-3.94

Table C-2: Summary of Positive and Negative 5 minute Voltage Deltas (%) at Critical 500kV, 345kV and 230kV Buses

Company	Station	Device	Voltage	Equipment Name	Device Type	Operations Per Day
BCH	Ashton Creek	Reactor - 122MVAR	500kV	ACK 5RX4	Automatic	0.315
BCH	Ashton Creek	Reactor - 122MVAR	500kV	ACK 5RX8	Automatic	1.618
BCH	Ingledow	Capacitor - 110MVAR	230kV	ING 2CX11	Automatic	0.099
BCH	Ingledow	Capacitor - 110MVAR	230kV	ING 2CX31	Automatic	1.058
BCH	Ingledow	Reactor - 132MVAR	230kV	ING 2RX1	Automatic	2.370
BCH	Ingledow	Reactor - 132MVAR	230kV	ING 2RX2	Automatic	1.905
BCH	Kelly Lake	Reactor - 122MVAR	500kV	KLY 5RX3	Manual	1.505
BCH	Meridian	Capacitor - 110MVAR	230kV	MDN 2CX1	Automatic	0.926
BCH	Meridian	Capacitor - 110MVAR	230kV	MDN 2CX3	Automatic	0.108
BCH	Meridian	Reactor - 132MVAR	230kV	MDN 2RX1	Automatic	1.702
BCH	Meridian	Reactor - 132MVAR	230kV	MDN 2RX2	Automatic	1.895
BCH	Nicola	Reactor - 122MVAR	500kV	NIC 5RX3	Manual	1.762
BCH	Williston	Reactor - 122MVAR	500kV	WSN 5RX4	Automatic	0.802

Table C-3: Number of Operations for some key BC Hydro Shunt Devices in Calendar 2010

Company	Station	Device	Voltage	Equipment Name	Device Type	Operations Per Day
CAISO	Metcalf	Capacitor	500 kV	METCLF 772_CB5	Automatic	0.066
CAISO	Metcalf	Capacitor	500 kV	METCLF 782_CB5	Automatic	0.000
Page nujmCAISO	Table Mt.	Capacitor	500 kV	TBLMTN 672_CB5	Automatic	0.011
CAISO	Table Mt.	Capacitor	500 kV	TBLMTN 682_CB5	Automatic	0.005
CAISO	Tesla	Capacitor	230 kV	TESLA 856_CSW2	Automatic	0.236
CAISO	Tesla	Capacitor	230 kV	TESLA 866_CSW2	Automatic	0.055
CAISO	Tesla	Capacitor	230 kV	TESLA 876_CSW2	Automatic	0.055
CAISO	Tesla	Capacitor	230 kV	TESLA 886_CSW2	Automatic	0.071
CAISO	Vaca-Dixon	Capacitor	230 kV	VACADX 556_CSW2	Automatic	0.312
CAISO	Vaca-Dixon	Capacitor	230 kV	VACADX 566_MOD2	Automatic	0.312

Table C-4: Number of Operations for some Key CAISO Shunt Devices in Calendar 2010

To gain an understanding of the factors that drive the operation of these switched shunts, the following graphs examine much finer details of the operations at CAISO's Table Mountain substation, using data on the switch operations and related data at five-second intervals. These graphs focus on Table Mountain substation as it is the closest of the CAISO's switched shunts to COI, noting that (1) the 230 kV voltage controls may be more affected by local conditions than by COI flows, and (2) similarly, at Metcalf's location near San Jose, California, its 500 kV voltage controls may be more affected by overall Bay Area conditions.

The CAISO's outage records show that the single period of operation of Table Mountain breaker 682 actually did not result from voltage variations, but rather from planned testing upon the completion of work on related equipment. Table Mountain breaker 672 operated twice during the year, which may have been triggered by events outside the CAISO (since no cause was apparent in the CAISO's outage records) and may have been part of a remedial action scheme (RAS).

Figure C-2 shows the voltage variation at major 500 kV buses from Malin to Los Banos (in central California) during the first of these events. After stable voltages of about 536 kV at Table Mountain, an event somewhere in WECC caused a sudden drop in voltage to 530 kV at 9:46, which recovered to nearly 532 kV by 9:47. At 9:55, the Table Mountain voltage had a sudden rise to over 535 kV, but declined to 534 kV by 10:03, when the switched shunt operated and raised the voltage to 535 kV. The switched shunt breaker reverted to its normal "open" status at 10:13, resulting in the voltage dropping to about 530 kV, followed by recovery due to other conditions to 534 kV by 12:20. Figure C-3 provides more information about this operation by showing flows on the 500 kV lines through Table Mountain (two 500 kV lines from Round Mountain, and two 500 kV lines south through the Sacramento Valley). Notably, the sudden voltages are accompanied by sudden changes in flow through Table Mountain, with the initial voltage change coinciding with an increase in flow through Table Mountain, varying suddenly at the times noted above, and flows stabilizing at 10:03 when the Table Mountain switched shunt operated.

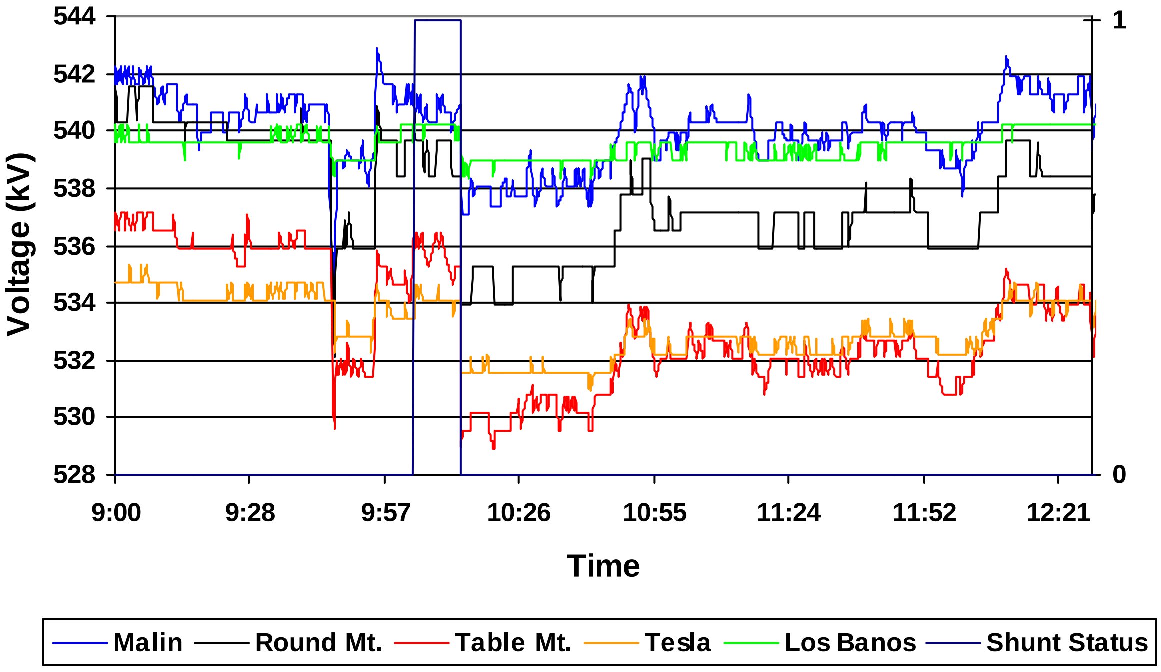


Figure C-2: Voltage Variation for Table Mountain Operation # 1

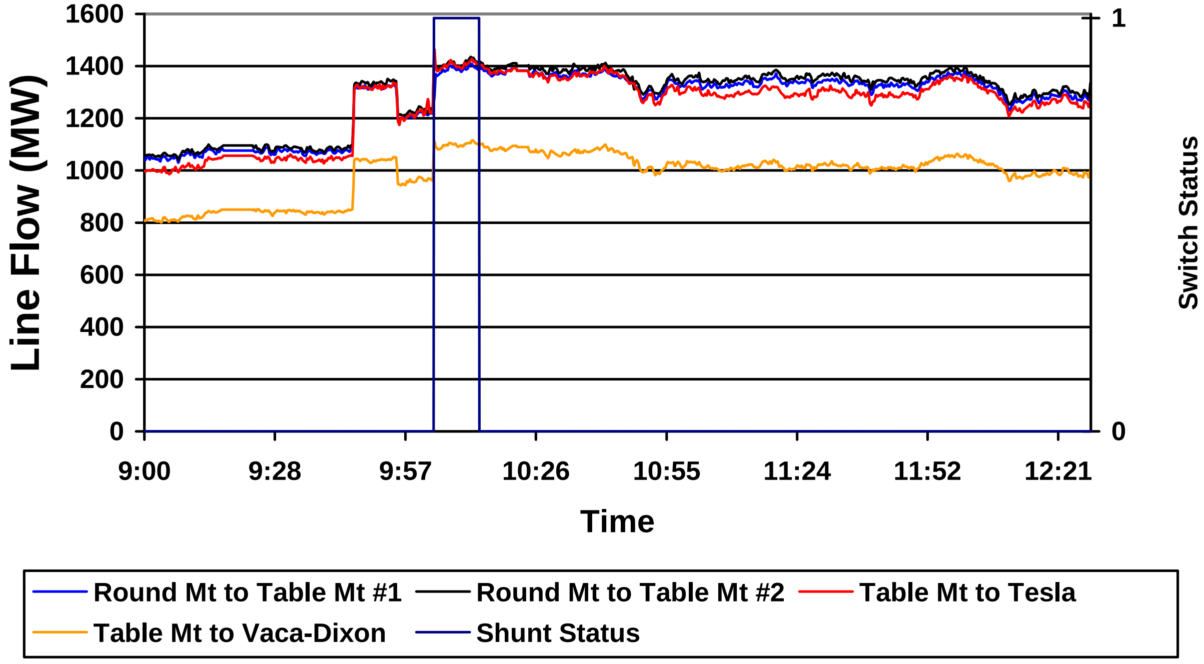


Figure C-3: 500 kV Line Flows at Table Mountain for Operation # 1

Figures C-4 and C-5 show the voltage and flow variations during the second of the two events. (Voltage data for the Los Banos 500 kV bus are not available for this event.) After stable voltages of about 530 kV at Table Mountain (shown in Figure C-4), an event somewhere in WECC at 22:07 caused a sudden increase in flows through Table Mountain (shown in Figure C-5), which could have caused a drop in voltage. With activation of the switch shunt at 22:07, voltages did not decline, and instead increased until the Table Mountain switched shunt return to its normal open status at 22:16, after which voltages were stable. Other actions elsewhere (which have not been identified) at about 22:14 had first reduced the line flows to about the previous level.

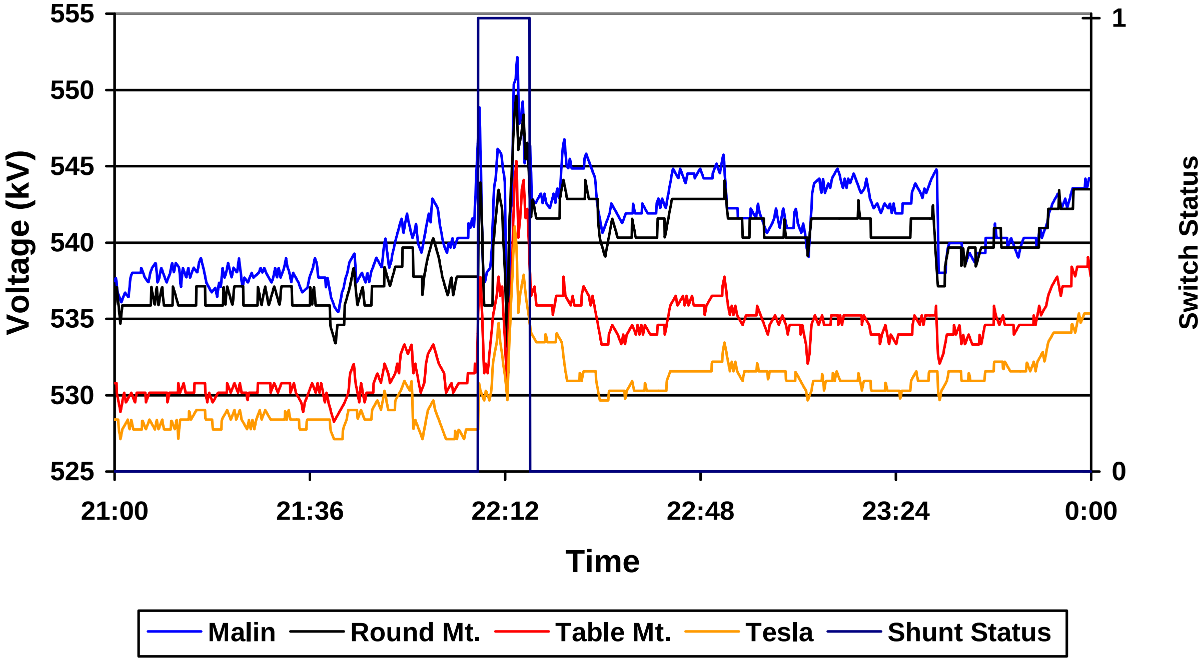


Figure C-4: Voltage Variation for Table Mountain Operation # 2

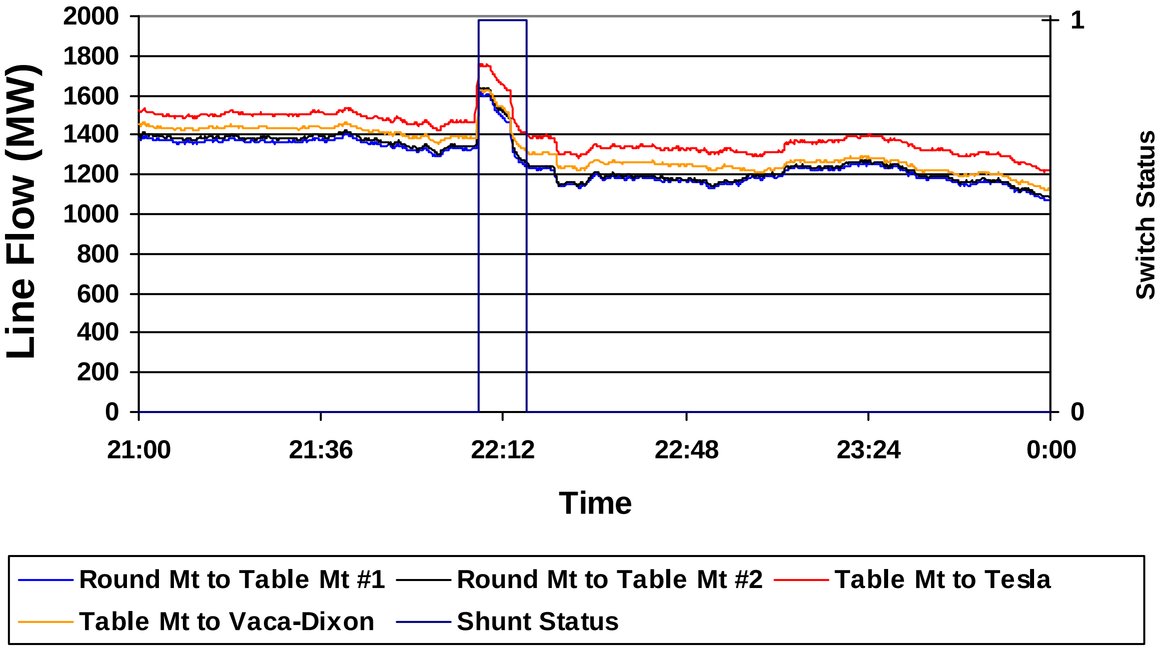
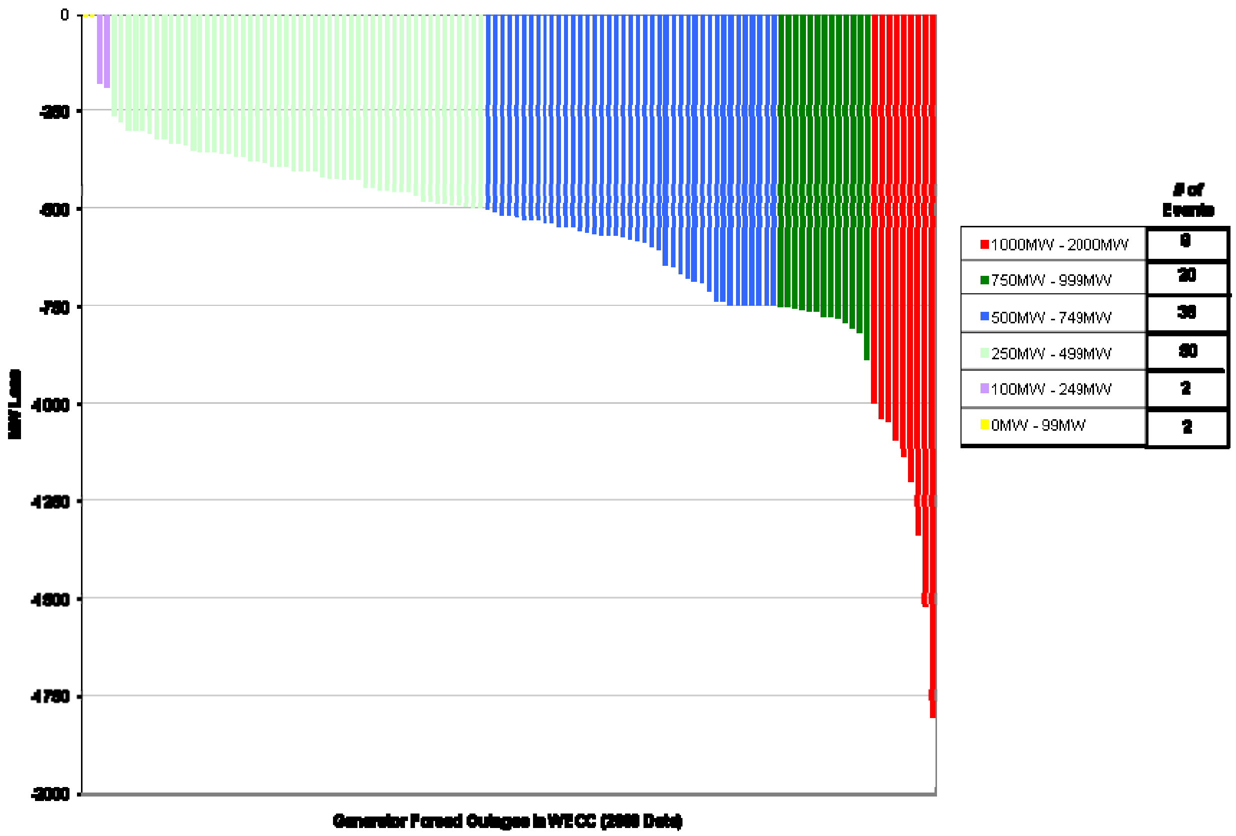


Figure C-5: 500 kV Line Flows at Table Mountain for Operation # 2

Appendix D – WECC Generator Outage Information (2009 Data)



Appendix E – Assumptions & Issues related to the TVL Methodology

This Appendix explores some of the assumptions and issues raised in conjunction with the proposed TVL Methodology.

What is the TVL specified timeframe and how is it used?

"Dynamic" Transfers are not fixed for the hour, in fact, they specifically enable the power transfer to vary inside the hour as a function of the sending or receiving counterparties' requirements. When we are measuring the variability occurring during the hour, the TVL specified timeframe provides a standard period for measurement, evaluating impacts, and establishment of limitations and criteria.

The TVL specified timeframe is used when evaluating how much variability can be expected/ modeled in assessing the impact of a variable source on the transmission system (Dynamic Resource Variability Index). It is also used when calculating the change over time used in assessing the total impact of variability on the system (Transfer Variability Limit, and Variable Transfer Capacity).

While the length of time is somewhat arbitrary, it can be chosen for convenient analysis and constancy with future commercial concepts. Though it may appear that variability may be reduced by using smaller timeframes, the reduction is only the result of measuring over a shorter period.

Just as a choice of measurement unit (English or metric) does not change the length of the object being measured, choice of timeframe does not change the underlying conclusions if the choice is used consistently throughout the analysis. Reducing the scheduling time period between operator adjustments does not change the behavior of variable resources.

Timeframe also indicates acceptable repetitive action (e.g. if one action is ok per timeframe, then if a 15 min timeframe is used, that implies 4 actions per hour is acceptable. If a 5 min timeframe is used, then 12 actions per hour is acceptable).

Why did several Northwest parties choose a 15 min timeframe?

The Transfer Variability Limit (TVL) Timeframe for dynamic transfers under automatic control can vary to reflect the way individual systems are operated. For example, 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.

Most of the northwest schedules on an hourly basis. Leaving a 40 min period between ramp times that would measure the variability resulting from variable generation. However, intra-hour scheduling procedures implemented in the northwest starting July 1, 2011 are allowing shorter scheduling periods of 30 minutes, leaving 15 minutes between the ramps. FERC also is proposing a shorter scheduling timeframe of 15 minutes.

It is possible that once adequate operational experience is gained with shorter scheduling periods that a shorter TVL timeframe could be appropriate for most Transmission Providers, however, at this point, 15 minute periods provide a good balance between measuring the change in the time between ramps (now and future) and considering the change over a sustained period.

Comparing Variation Magnitude using 15 min and 30 min timeframes

Based on the consensus that transmission providers will use *15 minutes* as the TVL specified timeframe, 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.

Comparing the 15 minute charts to the 30 minute charts clearly shows how the magnitude of variation will increase based on the timeframe chosen for analysis. For example, the variation of One Wind Farm (light blue) on the 15 min positive ramp is < 20% of capacity 99% of the time, while over 30 min, the positive ramp is < 33% of capacity.

Why would we use a percentile? We want to consider what we would normally expect, rather than accounting for the extraordinary. While the data shows that ramps higher than 20% have been observed, it is infrequently enough (less than 1% of the time) to consider the impact of these occasional events to system operations differently than those ramps that occur more often.

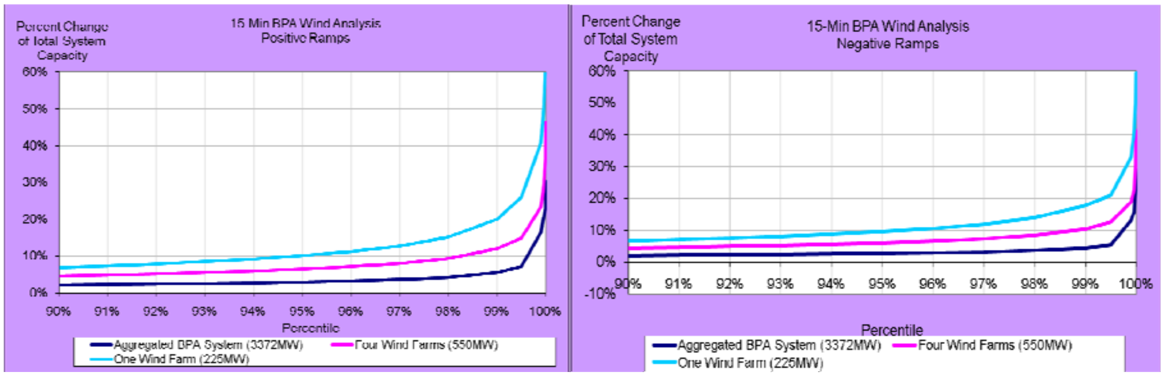


Figure E-1: Comparison of 15 Min Wind Ramps (Positive & Negative) from a Single Wind Farm, Group of Four Wind Farms and the aggregated BPA system

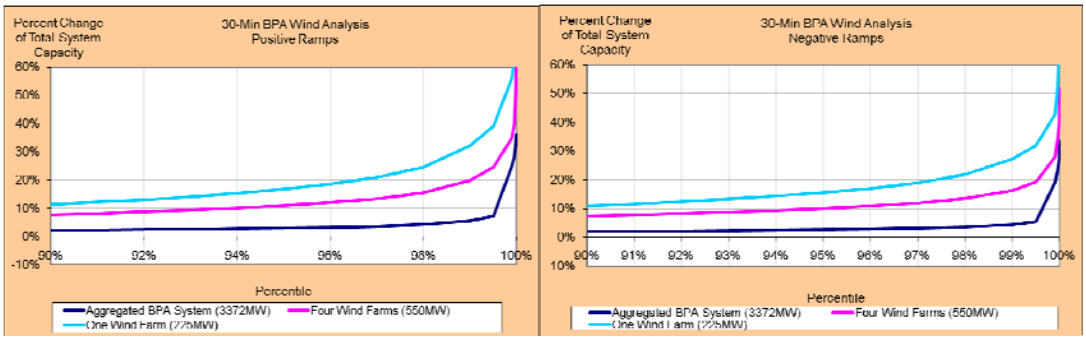


Figure E-2: Comparison of 30 Min Wind Ramps (Positive & Negative) from a Single Wind Farm, Group of Four Wind Farms and the aggregated BPA system

It can also be seen in the graphs that the variation caused by one single wind farm is much greater than a cluster of wind farms for the given time period. For example, using the 15 min positive ramp graph, while One Wind Farm ramps will be less than 20 % of capacity 99% of the time, when considering Four Wind Farms, the maximum expected ramp 99% of the time drops to 12% of capacity, and the Aggregate BPA System wind fleet drops to 5% of capacity.

Grouping of wind plants to take advantage of diversity demonstrates a net benefit by smoothing out the variation. The size of the grouping is constrained by the transmission paths surrounding the variable generation (ie. Constrained transmission paths would bound the group. Netting of resource by BA for TVL purposes could only be done if there were no constrained paths dividing the BAA.). This implies that the transmission operators for individual system will have the freedom to apply the TVL methodology taking into consideration how they perceive their variable resources relative to the transmission system. 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.

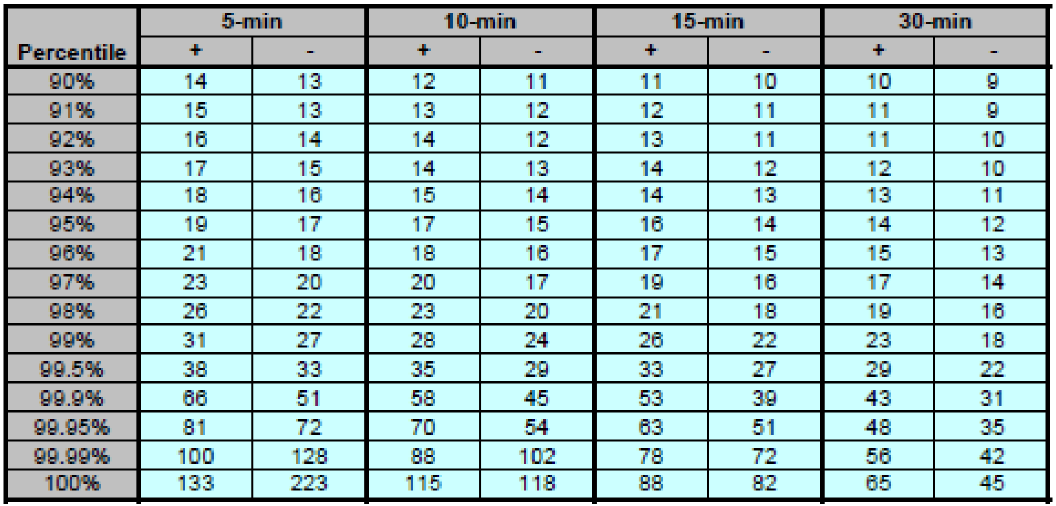
Comparison of ramp rates using 5, 10, 15, and 30 min timeframes

For dynamic transfers, both the magnitude of variation and the rate of variation are of concern. The timeframe chosen should be useful for the analysis and characterization of both of these concerns and their impact on transmission operation.

For TVL, we are interested in how much variation can occur over a specific time. In many ways this makes the ramp rate more important than the possible ramp magnitude.

The chart below shows rate of variation analysis performed on BPA's 5 minute average 2010 system data.

Wind Ramp Rate Calculations



Percentile	5-min		10-min		15-min		30-min	
	+	-	+	-	+	-	+	-
90%	14	13	12	11	11	10	10	9
91%	15	13	13	12	12	11	11	9
92%	16	14	14	12	13	11	11	10
93%	17	15	14	13	14	12	12	10
94%	18	16	15	14	14	13	13	11
95%	19	17	17	15	16	14	14	12
96%	21	18	18	16	17	15	15	13
97%	23	20	20	17	19	16	17	14
98%	26	22	23	20	21	18	19	16
99%	31	27	28	24	26	22	23	18
99.5%	38	33	35	29	33	27	29	22
99.9%	66	51	58	45	53	39	43	31
99.95%	81	72	70	54	63	51	48	35
99.99%	100	128	88	102	78	72	56	42
100%	133	223	115	118	88	82	65	45

Table 1: Positive (+) and Negative (-) Ramp Rates (MW/min) During Different Sample Periods (BPA 2009 Wind Data)

That shorter timeframes have higher average ramp rates than long timeframes may indicate that the ramps are sustained only for the shorter periods. During the longer timeframes, periods of short fast ramps are averaged with slower rates of change.

Of interest is the sustained rate of change over the TVL specified timeframe. Using the 15 min timeframe chosen by the task force, there is a 5% chance that the ramp rate will exceed 16 MW/min upramp and 14 MW/min downramp. If that ramp rate was sustained over the 15 min period, it could be expected that under normal operation, the resource may vary by a total of
16*15 (up) + 14*15 (down) = 240 MW (up) + 210 MW (down) = 450 MW.

Implications of Dynamic Transfer limits on the proposed Energy Imbalance Market.

The proposed Efficient Dispatch Toolkit (EDT) will employ the Energy Curtailment Calculator (ECC) and the Energy Imbalance Market (EIM) to measure flows on path/flowgates and dispatch the most efficient resources to satisfy imbalances. It will determine the flows on path/flowgates and the amount of additional transmission capacity up to the path/flowgate limit that economic energy could flow over to balance the system. It is proposed that the EIM would recalculate and redispatch the system every 5 minutes. It will endeavor to maintain actual flows within the physical and reliable path/flowgate limit.

Dynamic Limits are a function of how fast the transmission system can be tuned to accommodate large power swings across a path/flowgate and maintain voltage deviations within reliable levels. Therefore the transmission limits that must be considered by the ECC and EIM should include both the dynamic and static limits of the involved path/flowgates.

Any flow measured by the ECC and subsequent redispatch by the EIM must anticipate and assume the addition of the maximum ramp from wind or other renewables during the 5 minute recalculation period that might not be present at the start of the EIM cycle. Dynamic schedule limits will vary as a function of how quickly a transmission system and path/flowgate can be retuned or reset and therefore the assumption of limit recalculation time will be important and may vary by system.

Appendix F – Dynamic Transfer Issues Matrix & Issue Template

Several Dynamic Transfer issues were raised during DTC Task Force discussions that did not fall within our mandate to address. The Task Force decided that it would summarize the issues and pass them onto appropriate entities. As part of that process we developed a framework for classifying issues and a recommendation for which WECC Standing Committees would be well placed to take them on. Shown below is the Issue Matrix that the Task Force developed (with a few issues included) and a Dynamic Transfer Issue Template that could be used to summarize Dynamic Transfer issues identified by WECC members.

Dynamic Transfer Issue Template:

Category:	Commercial
Jurisdiction:	WECC Issue
Type:	Cost/Tariff/Business Practice Issues (MIC)

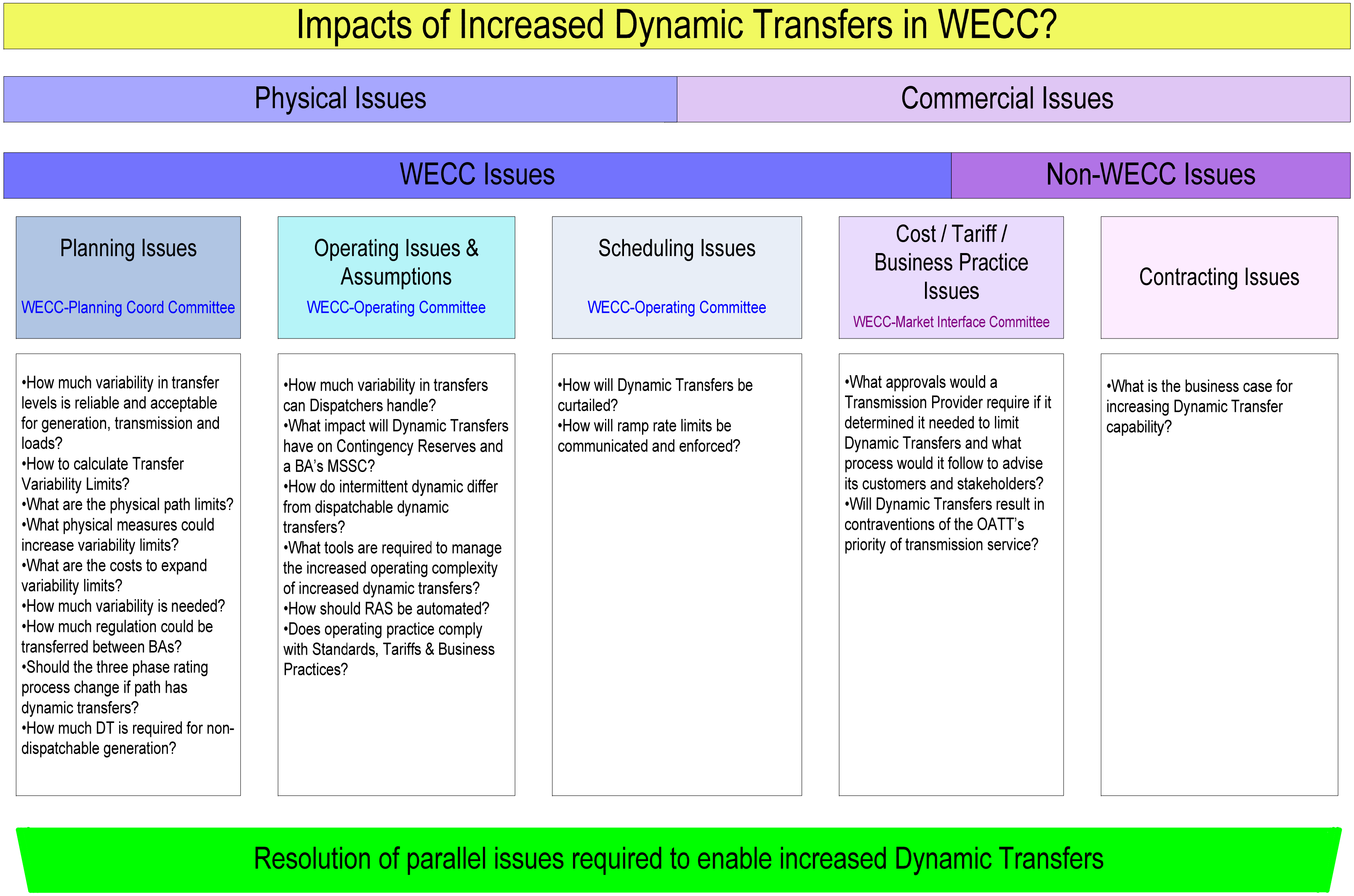
Question:

If a Transmission Provider decided it needed to limit dynamic transfers across its system, what approvals would it require (if any) to limit dynamic transfers across its system and what process should it follow to advise its customers and stakeholders?

Background:

Transmission Providers have a clear mandate to ensure that their transmission system does not negatively impact the reliability of the grid. At the same time, the introduction of unique business practices combined with non-standard products and terms can negatively impact the market's ability to provide cost effective solutions to operating challenges, such as the delivery of economic balancing resources from a remote generator to help manage the integration of intermittent generation.

Question Author:	DTC TF (Contact: Gordon Dobson-Mack, 604-891-6004)
Date Submitted:	24 June 2011
Standing Committee Assignment:	????
Assignment Decision Made by:	????
Index:	DTI-MIC 2011-001
Date of Assignment:	XX YYY 2011
Priority:	???
Response Timeline:	???



Impacts of Increased Dynamic Transfers in WECC?

Physical Issues

Commercial Issues

WECC Issues

Non-WECC Issues

Planning Issues

WECC-Planning Coord Committee

- How much variability in transfer levels is reliable and acceptable for generation, transmission and loads?
- How to calculate Transfer Variability Limits?
- What are the physical path limits?
- What physical measures could increase variability limits?
- What are the costs to expand variability limits?
- How much variability is needed?
- How much regulation could be transferred between BAs?
- Should the three phase rating process change if path has dynamic transfers?
- How much DT is required for non-dispatchable generation?

Operating Issues & Assumptions

WECC-Operating Committee

- How much variability in transfers can Dispatchers handle?
- What impact will Dynamic Transfers have on Contingency Reserves and a BA's MSSC?
- How do intermittent dynamic differ from dispatchable dynamic transfers?
- What tools are required to manage the increased operating complexity of increased dynamic transfers?
- How should RAS be automated?
- Does operating practice comply with Standards, Tariffs & Business Practices?

Scheduling Issues

WECC-Operating Committee

- How will Dynamic Transfers be curtailed?
- How will ramp rate limits be communicated and enforced?

Cost / Tariff / Business Practice Issues

WECC-Market Interface Committee

- What approvals would a Transmission Provider require if it determined it needed to limit Dynamic Transfers and what process would it follow to advise its customers and stakeholders?
- Will Dynamic Transfers result in contraventions of the OATT's priority of transmission service?

Contracting Issues

- What is the business case for increasing Dynamic Transfer capability?

Resolution of parallel issues required to enable increased Dynamic Transfers