Priority-based
Control
Engineering

FINAL REPORT

PHASE I

DIRECTED RESEARCH
FOR
BALANCE RESOURCES AND DEMAND STANDARD'S PROCEDURES FOR DEVELOPING FREQUENCY-RELATED LIMITS

DRAFT 4

Prepared by:

Priority-based Control Engineering (PCE)

for

Consortium for Electric Reliability Technology Solutions (CERTS)

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I. Abbreviations and Definitions

ACE – Area Control Error

BA – Balancing Authority

BAAL – BA ACE Limit

BRD SDT – Balance Resources and Demand Standard Drafting Team

CERTS – Consortium for Electric Reliability Technology Solutions

Contingency operation – Interconnection operation during a period of time that starts from occurrence of a load or generation contingency and ends when the frequency recovers from that event.

FAL – Frequency Abnormal Limit

FRL – Frequency Relay Limit

FRCC – Florida Reliability Coordinating Council

FTL – Frequency Trigger Limit

GADS – Generation Availability Data System

NAESB – North American Energy Standards Board

NERC – North American Electric Reliability Council

RA – Reliability Authority

SAR – Standard Authorization Request

Standard - Balance Resources and Demand Standard. Also referred to as Standard 300.

T_{vb} – A limit on the number of consecutive minutes that a BA may allow its ACE to go above $BAAL_{high}$ or below $BAAL_{low}$ without violating the measure in the Standard. This limit is referred to as T_v in the proposed Standard.

T_{vfh} – A limit on the number of consecutive minutes that the Interconnection frequency can be above FTL_{high} without exposing it to unacceptable risk. This limit is also referred to as T_v in the proposed Standard.

T_{vfl} –A limit on the number of consecutive minutes that the Interconnection frequency can be below FTL_{low} without exposing it to unacceptable risk. This limit is also referred to as T_v in the proposed Standard.

II. Executive Summary

The BRD SDT has defined the objectives described in the left column of Table 1 below for validating the proposed Standard. CERTS has subcontracted PCE to prioritize and perform research toward these objectives, and CERTS and PCE have defined analysis and deliverable items described in the second column of Table 1 as the objectives of this phase. Table 2 describes issues and conclusions arrived in this phase, and the research steps left for the next phase.

Table 1. Analysis and deliverables for each NERC BRD SDT Research item.

NERC BDR SDT Directed Research Scope	Analysis and Deliverables for Phase I	Status
Validate the Concept of Using Probabilistic Acceptable Risk Limits, Based on Unwarranted Under Frequency Load Shedding and Unit Outages	Report estimates of FTL, High, Low with corresponding errors and risks	Analysis following the proposed process gives these estimates: FTL_{low} = 59.948 Hz[1] FTL_{high} = 60.170 Hz[2,3]
Validate the Concept of Using Interconnection Frequency Response to Estimate Response to Generation/Load Mismatches	Report estimates of FAL, High, Low with corresponding errors and risks	Analysis following the proposed process gives these estimates: FAL_{low} = 59.907 Hz[1] FAL_{high} = 60.201 Hz[2,3]
Validate the Concept of Using Frequency-related Relay Settings to Establish Interconnection-wide Limits	Report estimates of FRL, High, Low with corresponding errors and risks	Collected data indicates that FRLs for the Eastern Interconnection are set as follows: FRL_{low} = 59.820 Hz[1] FRL_{high} = 60.500 Hz[2]

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[1] Based on FRCC under-frequency load-shedding relay settings

[2] Based on preliminary data regarding generator over-frequency relay settings

[3] Additional study is necessary to establish more accurate estimates of positive-side frequency limits

Table 1. PCE deliverables for each NERC BRD SDT Research item; continued.

NERC BDR SDT Directed Research Scope	**Analysis and Deliverables for Phase I**	**Status**
Validate the Concept of Using Supply-side Contingencies to Estimate Interconnection Reliability Risk	Report if the three types of frequency limits can be established as conceptually proposed, using and analyzing real historical generation outage data	Method used to analyze real historical generation outage data and establish the low frequency limits, using the concepts proposed by the BRD SDT, has been created and reported
Validate Steps in Process for Developing Frequency Limits.	Report soundness and effectiveness for the methodology proposed in section 305 from the standard for producing frequency limits	Reported results of following proposed methodology and issues discovered during analysis
Validate that the Frequency Limits Work as Intended	Report if the three types of frequency limits will work as intended and proposed, using real scenarios based on historical data	Relegated to next phase of research in agreement with CERTS
Validate the steps in the process for developing BAALs	Report soundness and effectiveness for the methodology proposed in section 306 from the standard for producing BAALs	Reported analysis regarding the effectiveness of the proposed BAAL measures in limiting the risk of frequency moving beyond FRL
Validate that the BAALs Work as Intended	Report if the BAALs, high and low can be established as conceptually proposed, using and analyzing real scenarios with historical ACE, Frequency data.	Relegated to next phase of research in agreement with CERTS

Table 2. Issues, conclusions and next research steps.

NERC BDR SDT Directed Research Scope	Issues	Conclusion or Next Research Steps
Validate the Concept of Using Probabilistic Acceptable Risk Limits, Based on Unwarranted Under Frequency Load Shedding and Unit Outages	• Consideration should be given to the impact of ACE and frequency measurement errors • Under the measures in the proposed Standard, too many parameters, such as future generation control practice, can affect the risk of reaching FRL associated with setting FTL to a particular value. Sufficient information is not available to confidently set FTL to an optimum value that ensures that this risk is bounded to a targeted value.	• The concept of using a statistical approach to limit the rate of occurrence of frequency excursions is sound • Study should be performed of the magnitude of ACE and frequency errors, and their potential impact on the risk of reaching FRL under the proposed Standard • Given the conservative proposed method of setting FAL, NERC may be able to use the method suggested by BRD SDT for setting FTL as long as FTL can be quickly adjusted if future practice causes frequency to exceed FAL too often.
Validate the Concept of Using Interconnection Frequency Response to Estimate Response to Generation/Load Mismatches	• Frequency response may vary based on system conditions • Since the applicable load-shed relays are expected to activate within a fraction of a second of frequency reaching their limit[1], we should consider only a portion of the full primary response for estimating the relevant frequency departure resulting from the final contingency	• It is technically feasible to estimate frequency response from available data • Process of calculating FAL should be modified to take into account only the portion of the frequency response likely to be realized before the load-shedding relays activate • Analysis should be performed of the impact of variations in frequency response on the risk of reaching FRL associated with contingencies

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[1] Ten cycles of frequency or about 0.167 s for the FRCC load-shed relays whose setting is used to set FRL in this report

Table 2. Issues, conclusions, and next research steps; continued.

NERC BDR SDT Directed Research Scope	Issues	Conclusion or Next Research Steps
Validate the Concept of Using Frequency-related Relay Settings to Establish Interconnection-wide Limits	• Recommend clarifying the phrase "approved (firm load) Under Frequency Load Shed relay setting" in step (i) of the Frequency Limit calculation process described in [1] to clearly delineate which types of relays are to be considered by this Standard	• All NERC regions should be requested to submit under- and over-frequency relay settings approved by them or known to be utilized in their territory
Validate the Concept of Using Supply-side Contingencies to Estimate Interconnection Reliability Risk		• Concept of using supply-side contingencies to estimate risk of reaching under-frequency relay limits is fundamentally sound • Recommend verifying results of proposed method using historical short-scan frequency data • Data regarding historical failure statistics of DC lines and converters should be added to input data for the process
Validate Steps in Process for Developing Frequency Limits.	• Determining difference between the lowest frequency operating setpoint and FRL_{low} in steps (ii) and (iii) of the Frequency Limit calculation process [1] is not necessary in the process of determining frequency limits • No probabilistic procedure is available to set T_{vfh} and T_{vfl} in a way that reliably limits the risk of reaching FRL to a targeted level	• Several steps of the proposed process should be revisited before it can be validated • Additional statistical analysis is necessary to establish FAL_{high}

Table 2. Issues, conclusions, and next research steps; continued.

NERC BDR SDT Directed Research Scope	Issues	Conclusion or Next Research Steps
Validate the steps in the process for developing BAALs	• Under the measures in the proposed Standard that only require each BA to limit the number of consecutive minutes that its ACE exceeds BAAL to T_{vb}, too many parameters, such as future generation control practice, can affect the risk of reaching FRL associated with the proposed BAAL equation. • The proposed BAAL formulation is based on an assumption that risk of reaching FRL is proportional to frequency deviation from schedule. This assumption is not supported by analysis.	• With the measures in the proposed Standard, the risk of reaching FRL that results from implementing the proposed BAAL formulation cannot be confidently estimated

III. Background

1. Summary

Traditional objectives of frequency control have included bounding unscheduled flows in transmission facilities, inadvertent energy exchange among the control areas, and time error. Another major objective has been to ensure that frequency remains away from levels that would cause under or over frequency relays to be activated. Extremely low frequency can lead to shedding firm load, while high frequency can cause wear and tear in generating equipment. Additionally, those entities that cause the Interconnection to operate at a lower frequency cause a reduction, due to load response, in other members' paying load.

2. Project Purpose

The purpose of this research is to validate that the following processes and their supporting concepts are technically sound and will be effective if implemented by the industry:

- Process for developing Frequency Limits.
- Process for developing BAALs.

The validation process requires using actual data to determine whether the limits can be developed as proposed, and then using actual data to show whether the limits work as intended for various sized BAs in each of the major Interconnections (Eastern, Western, ERCOT). The process for developing frequency limits and the process for developing BAALs are embedded in the draft Balance Resources and Demand Standard as Requirements 305 and 306 [1].

The SAR for the proposed Standard describes this Standard development process as follows:

> Maintain Interconnection frequency performance within a targeted frequency profile as demonstrated through control performance measures.
>
> This standard will require the use of a technically defensible mathematical method to enable each Interconnection to disburse control responsibility among its entities to achieve its targeted Interconnection frequency profile.
>
> This standard will require that the Reliability Authority have the authority to monitor system frequency and have the authority to direct actions (to control frequency) that include load shedding.

PCE requests that BRD SDT clarify whether all of the projected purposes of this Standard, such as maintaining a targeted frequency profile, described in the SAR are still expected to be covered by this standard.

PCE understands that other standards defined by NERC and NAESB will cover the other crucial characteristics and objectives of proper interconnected operation that have traditionally been addressed using frequency control. Also, the conclusions in this report assume that CPM1 will be implemented as described in the proposed Standard with the current epsilon targets remaining unchanged for all NERC Interconnections.

With that in mind, PCE commends NERC's goal of developing a Balance Resources and Demand Standard in order to reduce the costs of frequency control without impacting reliability, security, and equitability. The principal component of frequency control, generation control, has an impact on the order of many hundreds of millions of dollars on the bottom lines of North American utilities and that figure can be reduced with more relevant and fair standards.

3. Scope of this Report

Limited to the deliverables stated in column 2 of Table 1, this report evaluates as many procedures in the proposed Standard as possible within the resources allocated to this project. These procedures are evaluated to ensure that implementing the proposed Standard would limit the expected occurrence of activating the under- and over-frequency relays to once per 10 years each. Also, this report follows the proposed processes for defining frequency limits and BAALs to make initial estimates of frequency limits for the Eastern Interconnection and evaluate the consistency and validity of those processes.

4. Scope of the Operation Understood to be Covered by the Proposed Standard

The once per 10 years targeted risk of activating the under- and over-frequency relays specified in the proposed Standard as acceptable excludes the activation of such relays occurring in islands, separated from the bulk of an Interconnection. This exclusion applies irrespective of the cause of such separations, even if any of them is due to aggregate impact of mismatch between resources and demand in various BAs on some transmission facilities.

The above targeted risk also excludes the activation of such relays in an Interconnection during times of abnormal operation such as natural disasters impacting a significant portion of an Interconnection or disconnections of significant portions of an Interconnection.

IV. Validate the Concept of Using Probabilistic Acceptable Risk Limits, Based On Unwarranted Under Frequency Load Shedding and Unit Outages

1. Summary

The proposed method requires the Standards Developer to define frequency limits, which will ensure that the expected rate of occurrence of load-shedding events due to negative frequency excursions does not exceed once in 10 years and that the same is true for tripping over-frequency generator trip relays due to positive frequency excursions. PCE finds sound the concept of limiting unwarranted under-frequency load shedding to establish frequency limits and using the probability of generating unit outages (along with multi-unit plant outages and HVDC line or converter trips) as a factor in defining these limits. PCE has also found that the probabilistically calculated frequency limits used to define requirements in the proposed Standard are likely to limit the rate of load-shedding occurrences. However, it is impossible to estimate with sufficient accuracy what that rate will be given the proposed measures.

Given the generation control performance measures in the proposed Standard, PCE believes that too many parameters, such as future generation control practice, can affect the risk of reaching FRL_{low} associated with a particular value of FTL_{low}. This is certainly true for the value derived from the proposed process. An estimate will be used for the purposes of this report, but insufficient information is available to confidently set FTL_{low} to an optimum value that ensures that this risk is acceptably bounded.

Moreover, the proposed process would result in a value of FTL_{low} that is excessively high for the Eastern Interconnection.

PCE also suggests that further research be performed to study the impact on the risk of the above measures failing, due to potential errors in calculated ACE and measured frequency, to prevent reaching FRL.

2. Proposed Method of Frequency Control Operation

PCE understands that the use of the frequency limits to prevent load shedding will be as follows. They will impact generation control practice in a way that bounds the tails of the frequency distribution. The goal is to ensure that frequency does not reach FRL_{low} for a period of time sufficient to activate load-shedding relays (with the current relay setting choices this period is 10 cycles or about 0.167 s) more than once every ten years. The Standard would achieve this goal through control measures, which should attempt to prevent frequency from reaching FAL_{low}. One of those measures will be setting FTL_{low} to a value that allows sufficient time for BAs and RAs to respond before reaching FAL_{low}.

PCE's understanding of the method in the proposed Standard is as follows. FAL_{low} should be set at the lowest value, such that the frequency is not expected to reach the associated FRL_{low} more than once in ten years. This rate of reaching FRL_{low} should be expected even if frequency is at this particular FAL_{low} at all times in this ten-year period during non-contingency operation.

In this report, PCE has described a method to estimate the minimum frequency change resulting from contingencies that happens no more than once every ten years. An initial estimate of the magnitude of that frequency change for the Eastern Interconnection is performed in section VIII. Therefore, preventing frequency from going beyond FAL_{low} during non-contingency operation ensures that frequency is not expected to reach FRL_{low} unacceptably often during contingency operation.

The proposed Standard intends to prevent frequency from going beyond FAL_{low} through the following measures:

- Penalizing BAs that exceed BAAL limits for longer than T_{vb}.
- When frequency is beyond FTL_{low}, encouraging coordination by RA to get frequency above FTL_{low} within the specified time limit (T_{vfl} or T_{vfh}).

3. Estimating Risk of Reaching FRL Associated with the Proposed Method of Setting FTL

PCE understands that the proposed process for calculating FTL_{low} and FTL_{high} sets those limits by finding the highest contingency smaller than those considered for setting the corresponding FAL, dividing it by the estimated Interconnection frequency response, and subtracting the result from the appropriate FAL. In case of FTL_{low} for the Eastern Interconnection, the next highest such contingency would be a trip of a power plant with expected output of around 2,500 MW. The FTL_{low} resultant from considering this to be the next highest contingency would be very close to or above 60 Hz.

It is highly unlikely that generation outages of a combined magnitude necessary to move the frequency from FTL_{low}, defined per the proposed process, to FRL_{low} will occur closely spaced in time. This is only true when trips of units and power plants are independent of each other (e. g. the trips are not caused by events that lead to the separation of a large section of an Interconnection). In fact, the estimate of FAL_{low} should take into account the probability of all possible combinations of contingencies, always erring on the side of caution. Then, simply adding one more contingency to calculate FTL does not have a sound theoretical basis. Using the method described in section VII, PCE estimates that, excluding natural disasters and other events which preclude assumption of independence of events mentioned above, the Eastern Interconnection will not experience an immediate loss of 4,000 MW due to generation contingencies more than once every 500 years.

To estimate FTL for this report, PCE uses the contingency equivalent to a trip of the largest single unit in the Eastern Interconnection. However, PCE does not suggest that this approach has a sound scientific basis.

PCE is not proposing an improvement to this method of calculating FTL. PCE does not believe that, given the measures based on FTL in the proposed Standard, a reliable method is available for evaluating the risk of reaching FRL associated with a particular value of FTL.

However, if it can be shown that it is likely that the non-contingency frequency distribution resulting from implementing the measures in the proposed Standard will be less risky than the one assumed by the proposed process for setting FAL, then we can assume that the risk of reaching FRL under the proposed Standard will be within acceptable bounds. Alternatively, the measures proposed in the Standard could be modified to make possible a more reliable calculation of risk stemming from their implementation. This should be a subject for further discussion and analysis.

4. ACE and Frequency Errors

PCE would also like to note that real-time control to this Standard would be working with non-audited values of ACE and frequency and, therefore, the proposed Standard should take into account the impact of possible errors in data entry, telemetry, or calculation. PCE has heard anecdotal evidence of several cases in which control areas operated with an erroneous ACE for extended periods of time. The expected error in the Interconnection ACE times frequency error for a given time interval can be estimated using available CPS1 scores and data from a reliable frequency source, assuming that the effect of errors in CPS1 calculations is negligible.

PCE recommends that a study of the impact of ACE and frequency errors on the risk of reaching FRL under this Standard be performed in the next phase of this research.

V. Validate the Concept of Using Interconnection Frequency Response to Estimate Response to Generation/Load Mismatches

1. Summary

The proposed Standard specifies that a Frequency Response based on an average of the prior three years data should be used to calculate the Minimum Safe Frequency Band.

It is technically feasible and defensible to use estimated Interconnection primary frequency response based on past frequency performance during generation and load contingencies.

The process could also be made more accurate and more cautiously conservative by taking into account the fact that following generation contingencies frequency relays may act before the full primary frequency response is realized. It should also take into account the fact that risk is increased as a result of the variation of frequency response with season, time of day and other factors. The impact of the effect of these and other approximations made in the model of frequency response in the proposed Standard may be a target for further discussion and research (see Comment 2 in Outstanding BRD SDT Comments).

The chart in Figure 1 shows plots of the frequency change versus MW change for the samples used to measure frequency response of the Eastern Interconnection (see Comment 3 in Outstanding BRD SDT Comments).

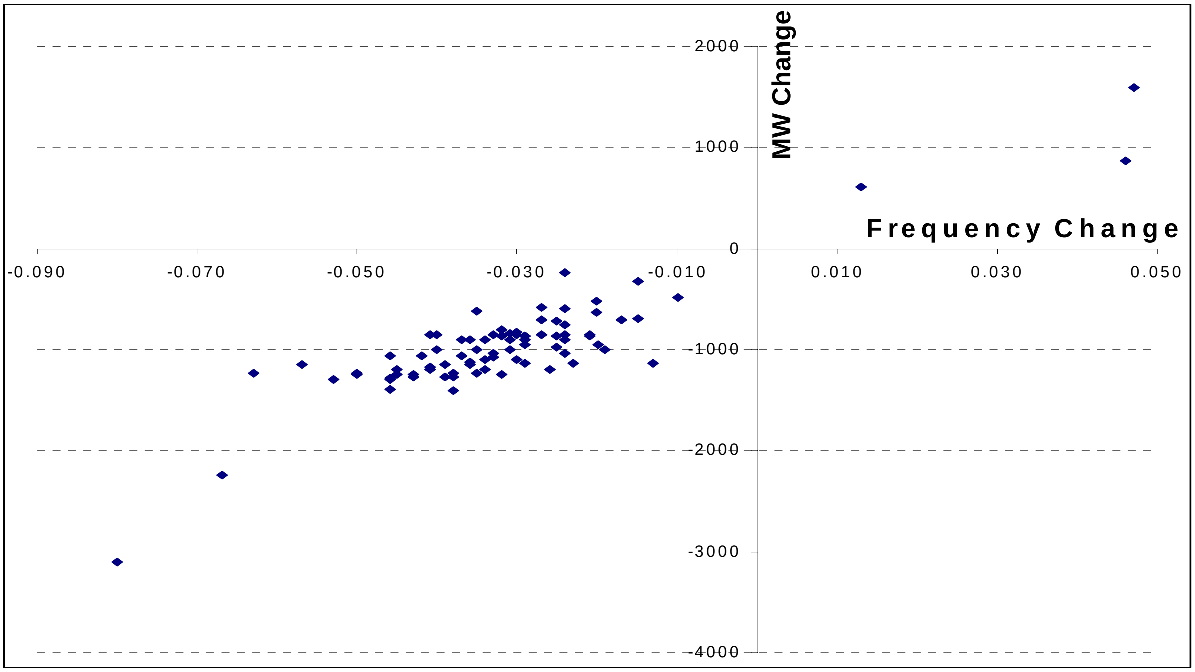

Figure 1

2. Response to Negative Frequency Events

PCE obtained Eastern Interconnection frequency event data from Elmer Bourque of New Brunswick Power. PCE verified that the events recorded by New Brunswick Power frequency measurements had a very good correlation with the generation trip data obtained from GADS. PCE was able to fill in an estimated generation value for some frequency events to increase the number of samples for measurement of frequency response. As utilities do not report the generation at the time of the trip to GADS, PCE used the average generation of the unit or plant during its service in that year. PCE recommends that, in order to increase further the usefulness of the GADS database for generation control research, it request and store data regarding actual MW loss due to immediate forced outages.

PCE then computed the primary frequency response for the 79 events between 9/1/2001 and 8/31/04 for which the approximate MW value was known. The result came to 3,175 MW/0.1Hz, with a 95% confidence interval of ±222 MW/0.1Hz.

3. Response to Positive Frequency Events

PCE also used the Eastern Interconnection frequency event data provided by Mr. Bourque to calculate the primary frequency response to positive frequency events. The set of such events between 9/1/2001 and 8/31/04 for which the MW value was independently obtained by Mr. Bourque consisted of only 3 samples. This is mainly due to three factors: the typical MW level of supply contingencies is much larger than that of load contingencies, they occur more frequently for a given large MW level, and data is more readily available regarding generation losses. The mean of that measurement was 3,333 MW/0.1Hz, with a 95% confidence interval of ±2,565 MW/0.1Hz. Considering the large potential error, PCE recommends that the mean of the frequency response for all recorded positive as well as negative frequency events be used in its place. That value has been calculated as 3,180 MW/0.1Hz, with a 95% confidence interval of ±219 MW/0.1Hz.

PCE recommends that further data collection and analysis be performed in the next phase of the research to increase the accuracy of the estimate of positive frequency event response.

4. Impact of Activation of Load Shedding Relays before Full Realization of Primary Response on the Risk of Reaching FRL

Data provided to PCE by Don McInnis indicates that the load-shed relays located in FRCC, which PCE used to set an initial estimate of FRL in this report, indicates that the relevant load-shed relays will open within 10 cycles, or less than 0.2 seconds, of the moment at which frequency reaches FRL_{low}. This means that a portion of primary response to the last contingency in a sequence of generation trips will not be realized in time to protect the load from being disconnected from the Interconnection.

In order to take this into account in estimating the Minimum Safe Frequency Band as required by the proposed process, PCE recommends that the process be changed to calculate the potential frequency change from each contingency directly. This can be done as follows:

- In case of single contingencies, the frequency change would be calculated by dividing the MW change by the frequency response expected to be realized within the expected activation time of the relevant frequency relays.
- In case of multiple contingency events, the frequency change of the last contingency would be calculated by dividing the MW change by the frequency response expected to be realized within 0.2 seconds. The frequency change due to contingencies occurring prior to that can be calculated by dividing the MW change by a frequency response value related to the recovery time available until the final contingency. When the recovery time becomes approximately 6-8 seconds, that value becomes equal to the full primary response. The frequency change due to contingencies occurring more than 30-60 seconds prior to the last contingency should also take into account the secondary response of the Interconnection.

A more accurate description of the Interconnection primary frequency response in terms of time can be done by studying sudden frequency change events using frequency data collected with a resolution of 0.1 seconds. PCE is aware that some data with that resolution may be available for this type of analysis and recommends that this be performed in the next phase of the research. These improvements are subject to further discussion (see Comment 4 in Outstanding BRD SDT Comments).

5. Impact of Variations in Operating Conditions

Currently, the proposed Standard does not take the impact of variations of frequency response into account. The proposed process for setting frequency limits uses the approximation that frequency response of the Interconnection is constant. As directed in [3], the next phase of the research can expand on this analysis to determine how the variations in primary frequency response impact the Interconnection risk of reaching FRL.

Available associated information in the contingency data collected is not sufficient to reliably estimate the impact of this factor. If it is possible to gather the necessary information associated with contingencies with sufficient accuracy, the next phase of the research can expand on this analysis to determine how the variations in frequency response can impact primary frequency response, and hence Interconnection risk of reaching FRL.

VI. Validate the Concept of Using Frequency-related Relay Settings to Establish Interconnection-wide Limits

1. Under-frequency Limits

PCE contacted Don McInnis of FRCC (which is believed to contain the highest under-frequency load-shedding relay settings due to its specific needs of handling islanding conditions) and Don Badley of WECC to obtain the relevant information for Eastern Interconnection and the WECC. PCE recommends that in the next phase of research, all NERC regions be contacted in order to obtain more complete information.

Information obtained for Eastern Interconnection indicates that its FRL_{low} should be 59.820 Hz. Information obtained for WECC indicates that its FRL_{low} should be 59.500 Hz.

2. Over-frequency Limits

In order to obtain the FRL_{high}, the Standard proposes to use the lowest high-frequency relay or turbine over-speed settings that are in line with the approved reliability guidelines. Information provided by Don Badley indicates that this limit should be set to 60.500 Hz for WECC. PCE is working on obtaining sufficiently accurate information for the Eastern Interconnection, but for the purpose of this report assumes that 60.500 Hz is an adequate initial estimate.

VII. Validate the Concept of Using Supply-side Contingencies to Estimate Interconnection Reliability Risk

1. Summary

PCE's understanding of the process for establishing FAL for each Interconnection, gathered from [1] and [5], is as follows. The Standards Developer is to gather information regarding the largest contingencies in that Interconnection. The contingencies are to be sorted from largest to smallest. The Standard Developer should then, using historical generation loss information, establish a set of contingencies that constitutes the size of the MW drop that is not expected to be exceeded more than once every ten years ("Minimum Safe Megawatt Band"). That MW drop will then be a result of several events, spaced closely in time, which for establishing FAL_{low} can be generating unit or plant trips and HVDC line or converter disconnections. The calculated MW drop is to be divided by the Interconnection frequency response, also estimated using historical data, to establish the Minimum Safe Frequency Band. That band is to be added to FRL_{low} to calculate FAL_{low}.

2. Determining the Minimum Safe Megawatt Band

PCE found that in order to validate the proposed Standard and calculate a reasonably accurate Minimum Safe Megawatt Band, it needed to consider not only the largest contingencies, but also all permutations of the significant supply-disruption events possible, attaching a probability to each event.

A great resource for this purpose turned out to be GADS (http://www.nerc.com/~gads). To obtain the necessary information PCE contacted its administrator Michael Curley, who provided data for the past 10 years as reported by utilities in all NERC regions. This data represents approximately 90% of the generators in the four major Interconnections and an even more significant percentage of the higher-capacity units, which are the ones most important to this project. Mr. Curley filtered out data related to immediate forced unit trips and supplied information regarding the set of generators that may be synchronized to the Interconnection along with their capacity, average output, and hours on service.

Using this data PCE calculated the expected trip rate for all types (separated by fuel type as well as hydro) of units and capacity. Additionally, PCE calculated expected trip rates for entire plants of each fuel type by filtering events where multiple units from a single plant tripped within a short interval. PCE then calculated the predicted trip rates for the units and plants likely to be online by using 2003 data to represent the current distribution of generation. The methods used in this analysis are discussed in Appendix A (Preparation of Data Obtained from NERC GADS).

PCE then used contingency statistics obtained from GADS to calculate the expected number of times that a given MW drop could occur in the Interconnection as a result of single or multiple events in an interval of ten years (set as the measure of reliability in the proposed Standard). In order to estimate the impact of multiple events that can occur within several minutes, PCE introduced a recovery rate for the Interconnection, based on predicted secondary response estimated at 300 MW/min for the purposes of this analysis. This model of Interconnection recovery was chosen conservatively based on PCE observation of available frequency excursion data, and it may be subject to further discussion (see Comment 1 in Outstanding BRD SDT Comments).

The result is a complex statistical calculation based on the input data. The process and theory produced for this analysis, as well as the assumptions and approximations applied in the process, are described in detail in Appendix B (Process for Determining the Minimum Safe Megawatt Deadband). That analysis yielded an estimated Minimum Safe Megawatt Deadband of 2,750 MW.

PCE feels strongly that the value predicted by the proposed method is reasonable. However, it is aware that the method can certainly be further refined. PCE suggests that further work to validate this method be performed in the next phase of the research.

3. Using Actual Frequency Data to Verify Results

PCE recommends that the next phase of research undertake the task of verifying the results of the process for determining the expected rate of generation contingencies using available frequency. Frequency data collected at a resolution of about 6 seconds or less over extended periods of time (at least 5-10 years) can be utilized for this purpose. Such a verification process would count the number of times various large MW deficiencies occurred over the range of the data, compare that number with the prediction of the method proposed by PCE, and, using statistical tools, calculate the degree of confidence provided by it.

VIII. Validate Steps in Process for Establishing Frequency Limits

1. Determining lower frequency limits

Table 3. Determining lower frequency limits.

	Process Specification	Analysis
i	Determine the highest approved (firm load) Under Frequency Load Shed relay setting for the Interconnection. This shall be the Interconnection Frequency Relay Limit $_{\text{Low}}$.	Initial data gathered by PCE to-date supports placing FRL_{low} at 59.820 Hz.
ii	Determine the lowest frequency operating setpoint for the Interconnection.	The lowest frequency operating setpoint for the Eastern Interconnection is 59.980 Hz. PCE believes that this step plays no role in calculation of the frequency limits.
iii	Calculate the difference between the lowest frequency operating setpoint and the Under Frequency Load Shed $_{\text{High}}$ for the Interconnection. This is the maximum allowable frequency drop for the Interconnection without an unwarranted load shed.	The difference between the lowest frequency operating setpoint and FRL_{low} is 59.980 Hz – 59.820 Hz = 0.160 Hz. PCE believes that this step plays no role in calculation of the frequency limits.
iv	Establish the Interconnection's Frequency Response based on an average of the prior 3 years' data (Beta in MW/0.1Hz.)	Initial research performed by PCE indicates that Eastern Interconnection's Frequency Response to negative frequency events is 3,175 MW/0.1Hz.
v	Identify the largest single contingency events for the Interconnection and order them from largest to smallest.	PCE has done so using data made available by NERC GADS.
vi	Determine the number of allowable contingencies for the Interconnection and sum these contingencies to determine the low Minimum Safe Megawatt Deadband for the Interconnection.	PCE has created a method to estimate the MW drop associated with a once in 10 years probability. Preliminary and approximate estimates using these methods using generation and plant trips (excluding multi-unit plant trips and HVDC line or converter disconnections) indicate a necessary Minimum Safe Megawatt Deadband of approximately 2,750 MW.

Table 3. Determining lower frequency limits; continued.

	Process Specification	Analysis
vii	Calculate the frequency change associated with the low Minimum Safe Megawatt Deadband for the Interconnection by dividing the low Minimum Safe Megawatt Deadband in Megawatts by the Frequency Response of the Interconnection in Megawatts per Hertz. This gives you the low Minimum Safe Frequency Deadband for the Interconnection.	Using figures discussed above the Minimum Safe Frequency Deadband is equal to 2,750 MW/(10*3,175 MW/0.1Hz) = 0.087 Hz.
viii	Calculate the low Interconnection Frequency Abnormal Limit by adding the low Minimum Safe Frequency Deadband$_{Low}$ to the highest approved Under Frequency Load Shed relay setting for the Interconnection.	FAL$_{low}$ for the Eastern Interconnection is calculated as 59.820 Hz + 0.087 Hz = 59.907 Hz from the figures above.
ix	Calculate the Frequency Trigger Limit Low by adding the next largest single contingency to the Frequency Abnormal Limit Low.	The proposed process indicates that the next largest contingency after those that have been included in the Minimum Safe Megawatt Band should be used to calculate the Frequency Trigger Limit. If we count large plant trips, this would add an additional contingency of well over 2,000 MW. If we limit contingencies to unit trips the additional contingency would be approximately 1,300 MW. Using the latter estimate puts FTL$_{low}$ at 59.907 Hz + 1,300 MW/(10*3,175 MW/0.1Hz) = 59.948 Hz.
x	Establish the Frequency Trigger Limit $_{Low}$'s T_v by determining the time at which the probability of a second contingency exceeds acceptable limits.	PCE interpreted the above instruction to mean: "Establish an interval, T_{vfl}, such that frequency should return to a level above the FTL$_{low}$ once it surpasses this limit in order to avoid exceeding the FAL$_{low}$ without a large contingency occurring". Following this interpretation, it is not obvious how to set T_{vfl} with the available data considering measures in the proposed Standard. This is subject to further discussion with BRD SDT (see Comment 5 in Outstanding BRD SDT Comments)

2. Determining upper frequency limits:

Table 4. Determining upper frequency limits.

	Process Specification	Analysis
i	Determine the lowest approved high frequency relay or turbine over speed setting for the Interconnection consistent with the Interconnection's reliability requirements. This shall be the Interconnection Frequency Relay Limit $_{\text{High}}$.	Initial data gathered by PCE to-date supports placing FRL_{high} at 60.500 Hz.
ii	Determine the highest frequency operating setpoint for the Interconnection.	The highest frequency operating setpoint for the Eastern Interconnection is 60.020 Hz. PCE believes that this step plays no role in calculation of the frequency limits.
iii	Calculate the difference between the highest frequency operating setpoint and the lowest approved high frequency relay or turbine over speed setting for the Interconnection. This is the Maximum Allowable Frequency Rise for the Interconnection without an unwarranted relay action or turbine over speed trip.	The difference between the lowest frequency operating setpoint and FRL_{high} is 60.020 Hz – 60.500 Hz = -0.480 Hz. PCE believes that this step plays no role in calculation of the frequency limits.
iv	Determine the Frequency Response of the Interconnection as calculated above for the Interconnection low frequency limits.	PCE used data available for all frequency events to estimate Frequency Response of the Interconnection as related to high frequency limits. PCE would appreciate the BRD SDT's input on this subject. Initial data gathered by PCE indicates that Eastern Interconnection's Frequency Response to such frequency events is 3,180 MW/0.1Hz.
v	Identify the largest high frequency producing contingency events for the Interconnection and order them from largest to smallest.	PCE has done that using data from Elmer Bourque of New Brunswick Power.

Table 4. Determining upper frequency limits; continued.

	Process Specification	Analysis
vi	Determine the number of allowable contingencies for the Interconnection as discussed above and sum these contingencies to determine the upper Minimum Safe Megawatt Deadband for the Interconnection.	While it is not immediately clear what data can be used to estimate the Maximum Allowable Frequency Rise defined in the proposed process, PCE believes that in the past 10 years the largest single event has been the partial blackout on Aug 14, 2003. PCE will use this event to make the initial estimate. However, PCE understands that relay activation occurring as a result of a separation of a large portion of the Interconnection does not count toward violating the one-in-ten-years targeted rate. Further study is needed to isolate frequency events covered by this Standard and set these limits accordingly.
vii	Calculate the frequency change associated with the Minimum Safe Megawatt Deadband High for the Interconnection by dividing the sum of the allowable contingencies (in Megawatts) by the Frequency Response (in MW/Hz). This gives you the high Minimum Safe Frequency Deadband for the Interconnection.	Data has been presented that frequency error reached about 0.299 HZ (during fast time error correction). That will be used as the working and very conservative estimate of Minimum Safe Frequency Deadband for evaluating this process. PCE strongly recommends that further research, most likely using short-scan frequency data, be directed to refine the calculation of this value if FAL_{high} is to be implemented in the final Standard.
viii	Calculate the high Interconnection Frequency Abnormal Limit by subtracting the high Minimum Safe Frequency Deadband from the lowest approved reliability-related high frequency relay setting for the Interconnection.	Using the above preliminary estimate of the Maximum Allowable Frequency Rise, FAL_{high} will be set to 60.500 Hz – 0.299 Hz = 60.201 Hz.

Table 4. Determining upper frequency limits; continued.

	Process Specification	Analysis
ix	Calculate the Frequency Trigger Limit $_{High}$ by adding the next largest single contingency to the Frequency Abnormal Limit $_{High}$.	Data available to PCE and experience in the field leads PCE to believe that load losses of up to 1,000 MW occur with some frequency in the Eastern Interconnection. PCE believes that this would serve as a good approximation for the value requested by the proposed process. However, PCE does not see a statistical justification for using a contingency of any particular size in this calculation and believes that this step in the process needs to be modified to have a solid theoretical foundation. Using this preliminary estimate puts FTL_{high} at 60.201 Hz – 1,000 MW/(3,180 MW/0.1Hz) = 60.170 Hz.
x	Establish T_v for the Frequency Trigger Limit $_{High}$ by determining the time at which the probability of a second contingency exceeds acceptable limits.	PCE interpreted the above instruction to mean: "Establish an interval, T_{vfh}, such that frequency should return to a level below the FTL_{high} once it surpasses this limit in order to avoid exceeding the FAL_{high} without a large load loss occurring". Following this interpretation, it is not obvious how to set T_{vfh} with the available data considering measures in the proposed Standard. This is subject to further discussion with BRD SDT (see Comment 5 in Outstanding BRD SDT Comments)

IX. Validate the Steps in the Process for Developing BAALs

1. Summary

PCE understands that the portion of the proposed Standard relevant to BAs requires that they continuously calculate the BAAL applicable to them. The Standard also suggests penalizing any BA whose ACE exceeds its BAAL for T_{vb} contiguous minutes at each instant.

In attempting to establish T_{vb} associated with the BAALs, PCE tried to estimate how Interconnection frequency may behave once some BAs exceed or are close to exceeding those BAALs. However, PCE does not believe that sufficient information is available to reliably evaluate the risk of reaching FRL associated with a particular T_{vb} under the measures specified by the Standard.

PCE analysis also found that the proposed BAAL equation is based on an assumption that a linear relationship exists between the current product of a BA's ACE and frequency error, and its contribution to the risk of the Interconnection exceeding under- or over-frequency limits. PCE did not find justification for making this assumption. This is a subject for further discussion with BRD SDT (see Comment 6 in Outstanding BRD SDT Comments).

2. Relationship between BAALs and Safe Operation

In all scenarios shown below the BA under consideration is the same. We also assume that the BAAL trend, shown in red in the figures below, for the BA under consideration is the same. Therefore, the frequency trend in the Interconnection is also the same in all of the scenarios.

In scenario A (Figure 2), the BA fails to return ACE above its BAAL in time to satisfy the T_{vb} time limit:

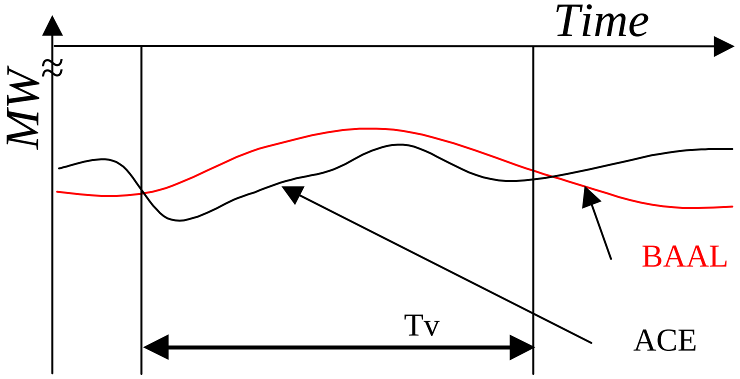

Figure 2

In scenarios B (Figure 3) and C (Figure 4) the BA satisfies the T_{vb} time limit. In scenario B, it operates with a very negative ACE for an extended period of time, particularly when frequency error magnitude becomes very large. In scenario C, it operates with a negative ACE that exceeds its BAAL for a time interval shorter than T_{vb}, then for a period of time bounds its ACE to its BAAL, but then its ACE exceeds its BAAL in the same T_{vb} interval again.

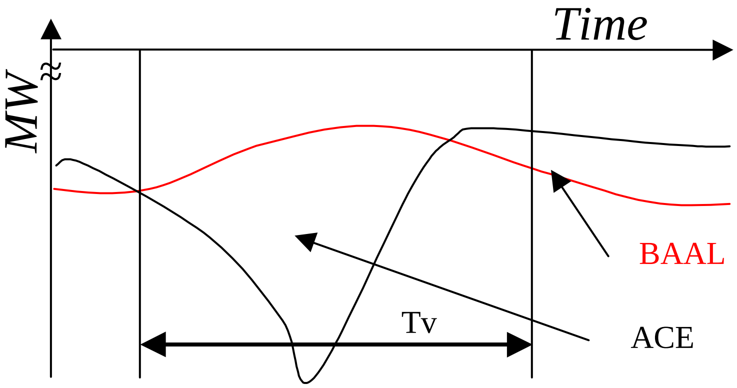

Figure 3

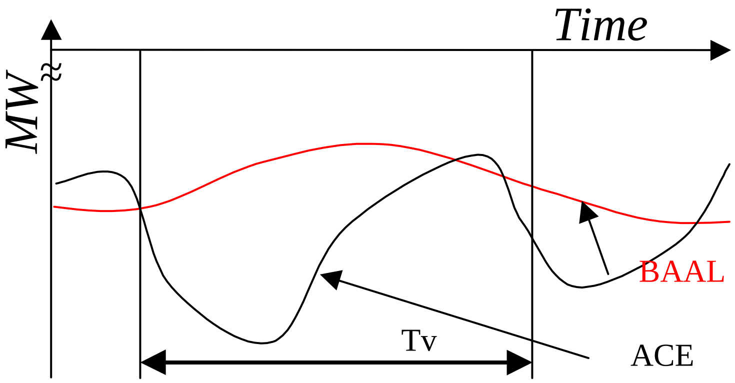

Figure 4

PCE believes that in scenarios B and C the risk of reaching FRL imposed on the Interconnection by the BA is greater than in scenario A. This creates a difficulty in definitively evaluating the risk contributed to the Interconnection at a given frequency by a given BA and raises the question whether a T_{vb} that adequately protects the Interconnection in all situations without imposing undue control requirements can be determined.

PCE believes that the proper measure should adequately evaluate the risk of reaching FRL imposed on the Interconnection by BAs. For each instant of time, a formulation for that risk can be found as a function of frequency and ACE. One alternative idea for measuring performance is finding the average of that function over a targeted interval, and penalizing BAs that exceed a predefined limit in that interval.

3. Relationship between Frequency Error and Risk of Reaching FRL

PCE understands that the BAAL equation has been developed with the idea that it should designate an acceptable amount of risk of reaching FRL a BA should be allowed to contribute to the Interconnection and penalize the BA should it contribute any additional risk [2]. Specifically, for the high frequency side, the standard intends that:

$$ACE \le BAAL_{high} = (-10B_i \times (FTL_{high} - F_S)) \times \frac{(FTL_{high} - F_S)}{(F_A - F_S)}$$

Multiplying all terms of the above condition by $F_A - F_S$ gives the following:

$$ACE \times (F_A - F_S) \le BAAL_{high} \times (F_A - F_S) = -10B_i \times (FTL_{high} - F_S) \times (FTL_{high} - F_S) = R_{\max}$$

Where $R_{\max}$ can be interpreted as the maximum risk of reaching FRL that a BA is allowed to impose to the Interconnection for a given frequency error. The condition above assumes that we are bounding the risk, described by the product of *ACE* and frequency error, by a maximum value:

$$ACE \times (F_A - F_S) = R \le R_{\max} \qquad \text{(IX-1)}$$

Condition (IX-1) derived from the proposed Standard implies that for a given ACE the risk contributed by a BA to the Interconnection is proportional to $F_A - F_S$, or $R \sim F_A - F_S$. In other words, the risk imposed on the Interconnection of exceeding a given FRL by operating at a given frequency is proportional to the difference between that frequency and scheduled frequency.

PCE research has shown that the above-defined risk formulation is not strongly correlated with the probability of exceeding the FRL over a specified future period of time (e. g. 10 years). An index that describes such a risk is more likely related to the inverse of the MW change in the balance between resources and demand needed to move the frequency to FRL. Therefore the risk may be related to the inverse of the difference between FRL and the current frequency, $1/\left(FRL - F_A\right)$.

The implied risk in (IX-1) can be challenged using a couple of simple examples. If FRL_{high} for the Eastern Interconnection is set at 60.500 Hz and scheduled frequency is 60 Hz, condition (IX-1) evaluates the risk imposed on the Interconnection by a given BA ACE at frequency errors of 5 mHz and 10 mHz to, respectively, to be:

$$R_{60.005Hz} = ACE \times (60.005 - 60.000) = 0.005 \times ACE$$

$$R_{60.010Hz} = ACE \times (60.010 - 60.000) = 0.010 \times ACE$$

However, it is apparent that the frequency change due to contingencies or other causes required in these two cases to take Interconnection frequency to FRL = 60.500 Hz, i.e. 495 mHz for frequency error 5 mHz and 490 mHz for 10 mHz, have a ratio close to 1. As seen above, however, the risk implied by the BAAL equation in the latter case is twice that of the former case. More importantly, condition (IX-1) implies:

$$R_{60.400Hz} = ACE \times (60.400 - 60.000) = 0.400 \times ACE$$
$$R_{60.450Hz} = ACE \times (60.450 - 60.000) = 0.450 \times ACE$$

The two equations above imply that the risk of the frequency exceeding 60.500 is not significantly different between the cases where frequency error is 400 mHz and 450 mHz. However, it is clear that the latter case requires only half the contingency size of the former to bring the Interconnection to the critical point, which is likely to happen more than twice as often and carries therefore more than twice the probability and twice the risk. This can be shown from study of frequency error change distribution or, for generation contingencies, analysis discussed in Appendix B.

In fact, it can be shown that the risk of exceeding FRL is related to the inverse of the difference between that FRL and the current frequency. The details of such a relationship are complex, but PCE believes that statistical analysis can be used to establish a statistically defensible method, which results in a measure that is easily understandable and can be functionally applied in operations.

X. Other Considerations

1. Impact of Generation Control Practice

PCE would like to note that its analysis of frequency events indicates that sudden losses of generation and load constitute only a portion of large frequency excursions. PCE suggests that interconnection power deficiencies that are imposed through generation control and business practices create additional risk. The increase in risk is especially uncertain taking into account how practices may change as a result of the implementing the proposed Standard.

This premise is supported by the data available for this project. Using CERTS one-minute average frequency database, CERTS staff identified every instance from 1/1/2003 to 12/31/2003 and from 5/12/04 to 9/10/04 where magnitude of frequency error in the Eastern Interconnection from schedule exceeded 50 mHz. PCE also obtained Eastern Interconnection frequency event data from Elmer Bourque of New Brunswick Power, which is believed to be a fairly comprehensive listing of sudden large frequency changes. Of the 206 separate frequency excursions PCE identified in the period from 5/12/04 to 9/10/04, PCE found only 2 that were noted in Mr. Bourque's data as contingencies. The rest did not show a signature of a sudden change in frequency expected after a generation loss and were apparently a result of generation control practice. The example shown in Figure 5 is representative of that category:

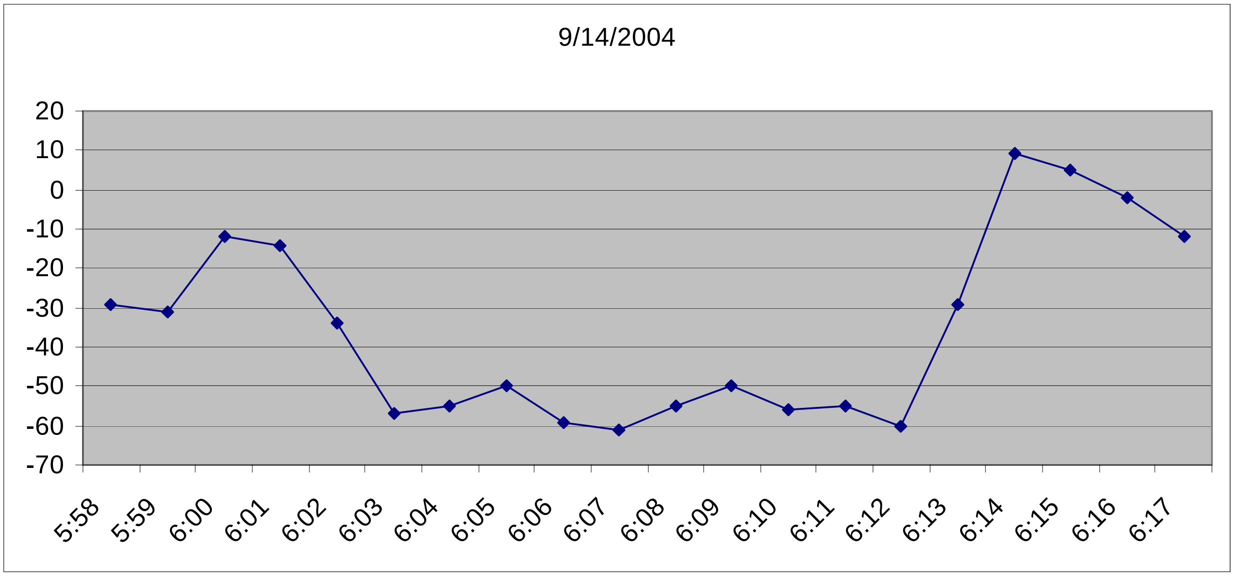

Figure 5

Another event, graphed in Figure 6 using six-second data, illustrates one of the largest recent frequency excursions. Frequency error went as far as –95 mHz without any apparent signature of

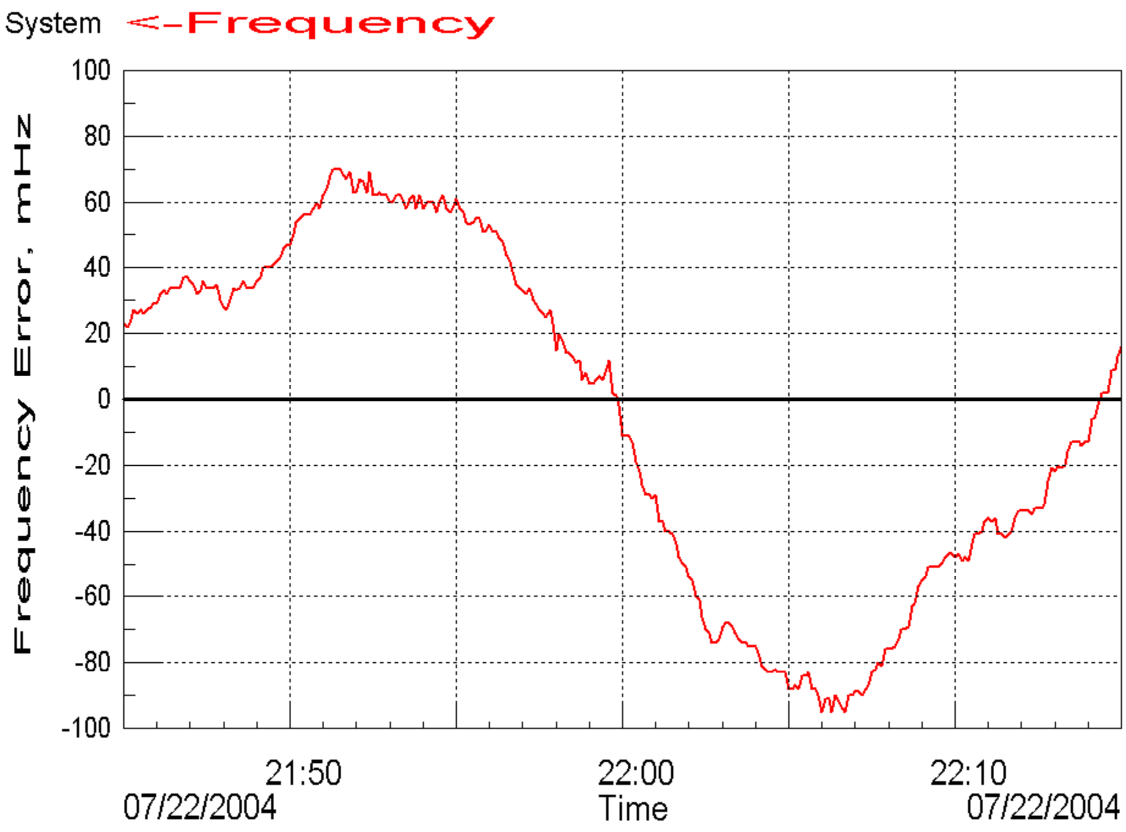

Figure 6

a significant generation contingency. As indicated by studies performed of the hour 22 problem, this is most likely due to poor planning, highly correlated scheduling, and other points of practice.

Extensive PCE experience in enhancing generation control practice to take full advantage of the existing control standards indicates that current practice is mainly constrained by CPS2. This is true in every Interconnection excluding ERCOT. Therefore, PCE is certain that should the BAs take advantage of the latitude permitted by the proposed Standard, generation control practice will loosen further. It is impossible to precisely predict BA behavior once the new standards are implemented, as it will depend on the magnitude of the compliance incentives and rapidity of implementation of new methods of control. However, PCE experience with optimizing generation control software indicates that BAs wishing to take maximum advantage of the new standard will be able to relax their control considerably. Therefore, frequency error at times may substantially, more often than under current practice and with larger magnitude, depart from schedule. While under the new frequency control paradigms frequency excursions are not a problem as long as load or generation is not tripped, the larger the magnitude of such events is and the more frequently they happen, the more significant the risk of reaching FRL becomes.

2. Basing Predicted Non-Contingency Performance on Experienced/Targeted CPM1 Performance

PCE is also aware that FAL_{low}, and possibly FTL_{low}, can be loosened considerably by removing the implicit assumption that frequency could be at FAL_{low} for the entire ten years when the Interconnection is not in contingency operation. This can also be done for FAL_{high} and FTL_{high}. PCE proposes that it could modify the process of setting frequency limits by assuming a (still conservative) non-contingency operation frequency distribution based on the targeted CPM1 performance.

Doing so would make the setting of FAL less conservative with regard to reaching FRL, but more statistically in line with its proposed use as the limit not to be exceeded in non-contingency operation. We can assume a very safe non-contingency frequency distribution, which should compensate fully for known asymmetry or other deviation from the normal distribution, and account for any likely changes in generation control practice. Given that compliance with other measures will bound frequency to FAL under non-contingency operation, the value of FAL calculated based on this assumption will be farther from 60 Hz without introducing unacceptable risk of reaching FRL.

However, PCE believes, given the uncertainties stemming from other measures, that it is still impossible to produce an accurate enough estimate of the risk inherent in the proposed Standard. As a result, adjusting the corresponding FTL accordingly would make it impossible to assume that the overall risk of reaching FRL would be not greater than acceptable. This concept can be subject to further discussion and analysis in the next Phase of this research.

Appendix A Preparation of Data Obtained from NERC GADS

1. Summary

This appendix describes how the parameters how PCE derived the interconnection generation contingency model (represented by N_i, G_i, and E_i) for use in deriving expected occurrences of various MW deficiencies. These parameters are derived from real historical generation data of immediate forced outages provided by Michael Curley of NERC GADS and obtained from the GADS database.

The process of calculating model parameters involves the following steps:

- Obtaining and organizing input data
- Separating unit and plant trips
- Obtaining trip rates for various sets of units and power plants
- Calculating a projected profile of the current generation system
- Calculating trip rates for the different sets of units and power plants in the current generation system

2. Obtaining and Organizing Input Data

The following information was available about each unit in the NERC generation system:

K	The total number of units in the interconnection.
Cap_k	The capacity of unit k, to the nearest MW.
$Type_k$	The type of unit k (hydro, fossil, etc.)
$Shrs_{k, L}$	The number of service hours of unit k over time span L.
$NOF_{k, L}$	Net Output Factor of unit k, which provides the average actual generation of unit k over time span L as a percentage of capacity.

Also, for each time span L, GADS provided data regarding the time of every reported immediate forced outage, or trip of those units.

3. Separating Unit and Power Plant Trips

PCE counted the number of trips for each unit. PCE also defined a power plant trip as an event in which more than one unit from one power plant trips within a short time interval (5 minutes was used for the purposes of this study). The following variables were then calculated for units:

$Trips_{k,\,L}$	The number of trips of unit k over time span L.

$Trips_{k,\,L}$ is computed by counting all trips of unit k over time span L, except those trips of unit k that were part of a trip of a power plant containing unit k.

$Gen_{k,\,L}$	The expected generation of unit k at time of trip during time span L, rounded to the nearest integer MW.

$$Gen_{k,\,L} = NOF_{k,\,L} \times Cap_k$$

The following variables were then gathered or computed for power plants:

${}^{P}K$	The total number of power plants in the interconnection.

${}^{P}Cap_k$	The capacity of plant k, to the nearest MW

${}^{P}Cap_k$ was calculated as the sum of Cap_i of the units in that power plant.

${}^{P}Type_k$	The predominant type of power plant k (hydro, fossil, etc.)

${}^{P}Trips_{k,\,L}$	The number of trips of power plant k over time span L.

${}^{P}Trips_{k,\,L}$ was obtained by counting all power plants trips as defined above over a time span L.

${}^{P}Shrs_{k,\,L}$	The number of service hours of power plant k over time span L.

${}^{P}Shrs_{k,\,L}$ was calculated as the average of the $Shrs_{i,\,L}$ of the units in that power plant.

${}^{P}Gen_{k,\,L}$	The expected generation of power plant k at time of trip during time span L, rounded to the nearest integer MW.

${}^{P}Gen_{k,\,L}$ was calculated as the sum of the $Gen_{i,\,L}$ of the units in that power plant.

4. Calculating Trip Rates for Various Sets of Units and Power Plants

For the purpose of smoothing the model, PCE separated all units in the available data into several sets. The trip rates were assumed to be consistent for all units inside that set. The sets were defined by a capacity integer index c and type t. Each set, defined by (c, t) contains all units with capacity between $(c-0.5)*R_1$ and $(c+0.5)*R_1$ of type *t*, where R_1 was a constant selected to be the set capacity range. For this study PCE used R_1 of 100 MW.

PCE then calculated the total unit-years of service provided by each such set during the past 10 years of operation in the entire NERC system, $M_{t,c}$, and the average number of trips per unit-year of operation for units in that set, $W_{t,c}$. The value of *L* in the following calculations is set to 10 years.

$$M_{t,c} = \sum_{k=1}^{K} \begin{cases} \dfrac{Shrs_{k,10yrs}}{8760\ {hrs}/{yr}} & c+0.5 < Cap_k / R_1 \le c-0.5 \ \ and \ \ Type_k = t \\ 0 & otherwise \end{cases}$$

$$W_{t,c} = \begin{cases} \dfrac{\sum_{k=1}^{K} \begin{cases} Trips_{k,10yrs} & c+0.5 < Cap_k / R_1 \le c-0.5 \ \ and \ \ Type_k = t \\ 0 & otherwise \end{cases}}{M_{t,c}} & M_{t,c} > 0 \\ 0 & otherwise \end{cases}$$

Similarly, power plants are divided into sets, using R_2 as a constant power plant set capacity range. For this study PCE used R_2 of 500 MW. PCE then calculated the total plant-years of service provided by each such set of plants during the past 10 years of operation in the entire NERC system, ${}^{P}M_{t,c}$, and the average number of trips per plant-year of operation for power plants in that set, ${}^{P}W_{t,c}$. The value of *L* in the following calculations is set to 10 years.

$${}^{P}M_{t,c} = \sum_{k=1}^{{}^{P}K} \begin{cases} \dfrac{{}^{P}Shrs_{k,10yrs}}{8760\ {hrs}/{yr}} & c+0.5 < {}^{P}Cap_k / R_2 \le c-0.5 \ \ and \ \ {}^{P}Type_k = t \\ 0 & otherwise \end{cases}$$

$${}^{P}W_{t,c} = \begin{cases} \dfrac{\sum_{k=1}^{{}^{P}K} \begin{cases} {}^{P}Trips_{k,10yrs} & c+0.5 < {}^{P}Cap_k / R_2 \le c-0.5 \ \ and \ \ {}^{P}Type_k = t \\ 0 & otherwise \end{cases}}{M_{t,c}} & M_{t,c} > 0 \\ 0 & otherwise \end{cases}$$

5. Calculating Generation Contingency Model Parameters

Next, PCE found the total unit-years in service X_g, and an average trip rate per unit-year U_g for units with an expected generation of g, where g is an integer that represents a MW value. In these calculations, PCE only used the most recent data (specifically the complete set of 2003 data), to get a better idea of the actual configuration of the units currently on the interconnection. As a result, L in these calculations is set to 1 year.

$$X_g = \sum_{k=1}^{K} \begin{cases} Shrs_{k,\,1yrs} / 8760 & Gen_{k,\,1yrs} = g \\ 0 & otherwise \end{cases}$$

$$U_g = \sum_{k=1}^{K} \begin{cases} W_{Type_k, \lfloor Cap_k / R_1 + 0.5 \rfloor} X_g & Gen_{k,1yrs} = g \\ 0 & \text{otherwise} \end{cases}$$

Separately, PCE found the total plant-years in service ${}^{P}X_g$, and an average trip rate per plant-year ${}^{P}U_g$ for plants with an expected generation of g.

$${}^{P}X_g = \sum_{k=1}^{{}^{P}K} \begin{cases} {}^{P}Shrs_{k,\,1yrs} / 8760 & {}^{P}Gen_{k,\,1yrs} = \mathrm{g} \\ 0 & otherwise \end{cases}$$

$${}^{P}U_g = \sum_{k=1}^{{}^{P}K} \begin{cases} {}^{P}W_{{}^{P}Type_k, \lfloor {}^{P}Cap_k / R_2 + 0.5 \rfloor} {}^{P}X_g & {}^{P}Gen_{k,1yrs} = g \\ 0 & \text{otherwise} \end{cases}$$

Next, units are sorted into I_u sets, based on their expected average generating level, rounded to R_3 MW. For this study R_3 was set to 100 MW. Each such set has an associated index i, expected generation at time of trip G_i, total unit-years in service N_i, and trip rate per unit-year E_i. Min_i defines the minimum average generating level for each set i, and Min_{i+1} defines the maximum.

$$1 \le i \le I_u$$

$$Min_i = (i - 0.5) \times R_3$$

$$Min_{I_u + 1} = \infty$$

$$G_i = i * R_3$$

$$N_i = \sum_{g = Min_i}^{Min_{i+1} - 1} X_g$$

$$E_i = \frac{\sum_{g=Min_i}^{Min_{i+1}-1} U_g}{N_i}$$

Power plants were also sorted into J_p sets, based on their expected average generating level, rounded to R_3 MW. Their associated statistics were then appended to those defined above for the units.

$$1 \le j \le J_p$$

$$^{P}Min_j = (j - 0.5) \times R_3$$

$$^{P}Min_{J_p+1} = \infty$$

$$G_{I+j} = j * R_3$$

$$N_{I+j} = \sum_{g={}^{P}Min_j}^{{}^{P}Min_{j+1}-1} {}^{P}X_g$$

$$E_{I+j} = \frac{\sum_{g={}^{P}Min_j}^{{}^{P}Min_{j+1}-1} {}^{P}U_g}{N_{I+j}}$$

In the final step, the final data collection of sets is created by combining the I_u sets of units and J_p sets of plants. The input to the method described in Appendix B is a collection of I sets of units or plants, where $I = I_u + J_p$.

Appendix B Process for Determining the Minimum Safe Megawatt Deadband

1. Introduction

This Appendix describes a process for determining the level of MW deficiency due to generation contingencies that is not expected to occur more than once per 10 years based on available generation contingency data. The process presented here at this time takes into account only immediate forced outages of generating units or entire power plants and ignores potential loss of power delivered through DC/AC converters. Data on generation contingencies necessary to follow this process was produced from information retrieved from the NERC GADS database as described in Appendix A.

This process takes into account probabilities of events involving trips of single as well as multiple unit or power plants. It uses a linear secondary response model to estimate interconnection recovery between generation trips separated in time.

In order to determine the expected number of times a given MW deficiency is likely to occur in a 10-year period, we assume that the 10-year period is a series of T-length time intervals. We consider each such time interval to be a binomial trial, where success is defined by reaching the given deficiency level. The distribution of the number of times a success occurs in a 10-year period can be approximated by a binomial distribution, with an expected value of $P * 10yrs/T$, where P is the probability of success in a T-length time interval and $10yrs/T$ is the number of trials. The following sections present a process for estimating P for a given interconnection and a given T.

2. Definitions

For ease of study, the following provides a list of all variables mentioned in this Appendix with their definition:

Set i: a set of units or plants with associated expected number of trips per year and expected generation at the time of the trip. Set 0 refers to a special set which is used in our calculations to express the probability of not having a trip of a unit or plant in any set and an expected tripped generation level of 0 MW.

I: total number of sets of units and power plants.

G_i: the expected generation of any unit or power plant in set i at time of potential trip.

n_i: a variable used in the process to indicate the number of units or power plants in set i available to trip in the interconnection, given the outages already assumed in the ancestral steps.

N_i: expected number of units and power plants in set i synchronized at any given time. Equivalent to total unit-years of service for set i (calculated in Appendix A).

E_i: expected number of trips in a year for any individual unit or power plant in set i.

T: a time interval, in seconds, that is small enough to make the likelihood of having two independent contingencies within it negligible. A trip of a multi-unit plant is considered for this purpose to be a single independent contingency.

R: secondary response recovery rate of the interconnection, in MW per T interval.

D: in MW, indicates effective MW deficiency required to affect frequency such that load will be shed.

P: the probability that, in a given interval of size T, the level of MW deficiency will reach magnitude D.

d: in MW, indicates the effective MW deficiency in the interconnection at some given time. It must become greater than D for a successful trial.

z: the amount of error in the calculation of P. Given a maximum and a minimum estimate of P, the difference between the two.

Z: a value of z that we consider necessary to make the associated estimate of P acceptably accurate.

T_y: number of seconds in one standard year.

3. Assumptions and Approximations

1) In determining the probability of the interconnection facing a MW deficiency equal to or greater than D in a T-length time interval, if the MW deficiency in the interconnection reaches D, all other such instances before the value of d returns to 0 belong to the same successful outcome. We prevent these instances from contributing to probability of success, by not counting them as separate successful outcomes. As a result, when determining P for an interval, we exclude from consideration all cases where $d > D$ in chronologically earlier intervals.
2) We assume that if a power plant trips, the impact of the loss of the units inside that plant on probability of subsequent unit trips is negligible. In other words, though the probabilities we calculate account for the fact that the plant cannot trip again, they do not account for the fact that the individual units within the power plant cannot. The impact of this simplification of the actual probability is negligible, given that the number of units in the Eastern Interconnection is around 2,600 according to GADS data. However, the reduction of the total number of permutations, and hence computation time, resulting from making this assumption is significant.
3) We assume that secondary response of the interconnection will not reduce the MW deficiency of the interconnection below zero, and, therefore, the value of d must always be zero or positive.
4) It is assumed that a particular unit is not likely to trip more than once during the total time span considered by this process to estimate the impact of multiple contingencies. Thus, when considering possible combinations of contingencies, the number of trips involving the i^{th} set of units can never exceed the original N_i.

5) The generation of any given unit in set *i* at the time of a trip is approximated to be at a level G_i, which is its average expected generation calculated from GADS information.

6) As noted in the definition of *T*, we choose a value such that the probability of two units or plants tripping in the same interval is minimal. Therefore, we can make the assumption that two units or plants will not trip in the same *T*-length interval, removing many permutations that add very little to probability, but which enormously increase the computation time.

7) Unit trip events, if any, are assumed to happen at the very end of the interval.

4. Initial Functions

We need to derive several functions in order to explain the process.

Since it should be physically impossible for a single unit to trip twice in time *T*, the expected number of trips per *T*-length interval of for any unit/plant in set *i* is calculated as:

$$E_{i,T} = \frac{TE_i}{T_y} \qquad \text{(B-1)}$$

We need to estimate the probability $P_{i,T}$ that one unit in set *i*, where $i > 0$, will trip in a given *T*-length time interval. As we have assumed that we set *T* small enough to ensure that the probability of having more than one unit trip in a given time interval of length *T* is negligible, it can be approximated by:

$$P_{i,T} = n_i \times E_{i,T} \qquad \text{(B-2)}$$

The probability that no units will trip in a given interval of length *T* is the product of the probabilities of each unit not tripping:

$$P_{0,T} = \prod_{i=1}^{I} \left(\left(1 - E_{i,T} \right)^{N_i} \right) \qquad \text{(B-3)}$$

Since each of the NERC interconnections has such a significant number of units that removing one or several units is not likely to change $P_{0,T}$ significantly, in each step of the process we will calculate this value by using all of the units in the interconnection without considering that some units may have already tripped. While this may have an impact on the results in the example scenarios below where only a small number of units are considered to be available, it does not have a noticeable impact on calculations performed for actual NERC interconnections.

5. Determining *P*

This section, using several examples, gradually develops the basis for a process of determining *P*, i.e. the probability of the interconnection facing a MW deficiency of magnitude *D* in a *T*-length time interval. It is not practically feasible to exactly determine this probability for a typical data set, such as the data we have used for 2,600 units in the Eastern Interconnection.

Instead, this process determines a maximum and minimum between which the probability of this outcome should fall, and tries to reduce the difference between the two, referred to as “error” or *z*, below some threshold of acceptability, referred to as *Z*.

In general, the process makes use of a tree structure for representing all known data regarding the system so far. For each step, the process determines whether *z* is below *Z*; if not, it expands the tree and performs additional calculations to further reduce this difference. Otherwise, it reports the final results for the maximum and minimum *P*, which we can then directly use to estimate the expected number of successes in ten years.

We are trying to find the probability that, for a certain interval, *d* will exceed *D*. We will refer to this certain interval as interval 0 for the remainder of this section. We will also refer to other intervals in terms of their chronological relationship to interval 0. For example, the interval immediately preceding and ending at the beginning of interval 0 would be interval 1. The interval that precedes interval 1 would be interval 2. Interval *j* begins $j \times T$ seconds before and ends $(j-1) \times T$ before the beginning of interval 0. To emphasize, <u>higher</u> numbers actually represent <u>earlier</u> intervals, not <u>later</u> intervals.

<u>Overview of notation</u>

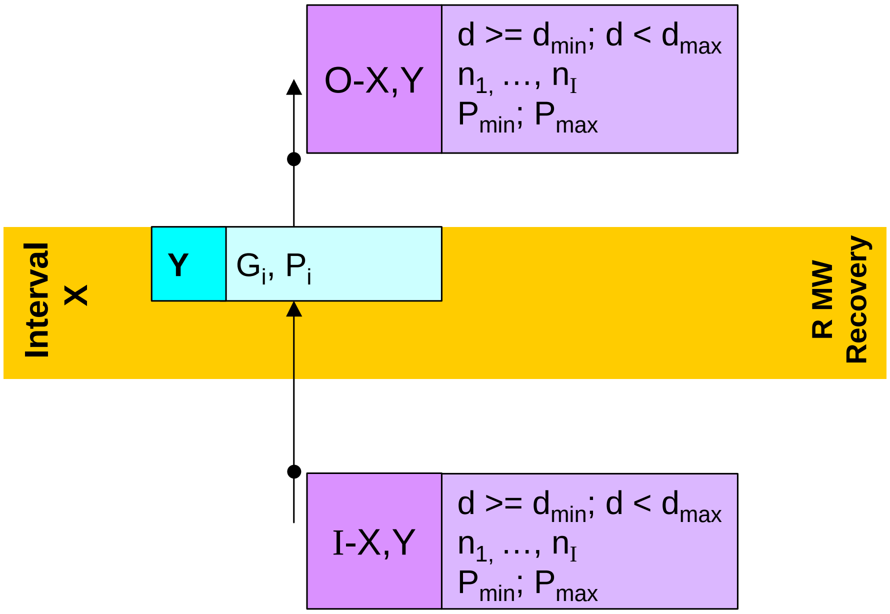

Figure 7

In general, our process utilizes a tree consisting of branching chains of events. Each “element” on the tree, as shown in Figure 7, deals with a certain event *Y* occurring in a certain interval *X*. While different elements in the same interval *X*, indicated with distinct values of *Y*, can refer to the same event, they will differ as to their ancestors. Thus, any element or series of events in the solution tree can be referenced by a unique combination of “*X*, *Y*”. The maximum value of *Y* for a certain interval tends to have an exponential relationship with the value of *X*.

In any interval X, we assume that the interconnection decreases the power deficiency by R MW due to secondary frequency response during the interval.

Event Y either represents the trip of one unit or plant in some set i, or no trip of any unit. The increase in deficiency is either G_i, or 0 if no unit or plant trips. There is a probability associated with each event as well. The probability that a unit or plant of a certain set will trip is defined in Equation B-2. The probability that no units or plants will trip is defined in Equation B-3.

At the point indicated by "O-X, Y" ("O" represents output, as the point is immediately after the end of interval X and event Y) d_{min} and d_{max} represent conditions that d must meet immediately after interval X. The values $n_1, \ldots, n_I$ are the number of units in the I sets of units or plants whose trips have not been considered in the elements of the tree ancestral to this element. The values P_{min} and P_{max} represent the minimum and maximum probability that $d_{min} <= d < d_{max}$, as specified above.

At the point indicated by "I-X, Y" ("I" represents input, as the point is immediately before the start of interval X, with event Y occurring at the end of the interval), d_{min} and d_{max} represent conditions that d must meet immediately before interval X so that, if the event occurs, the conditions in "O-X, Y" are fulfilled. In general, d_{min} of "I-X, Y" is equal d_{min} of "O-X, Y" minus the generation change in interval X, both from event Y and the recovery of R MW, but d_{min} cannot be lower than 0, as per Assumption 3. Similarly, d_{max} of "I-X, Y" is equal to d_{max} of "O-X, Y" minus the generation change in interval X, both from event Y and the recovery of R MW, but d_{max} cannot be higher than D, as per Assumption 1.

$$d_{\max,child} = \min(d_{\max,parent} - G_{parent} + R, D) \qquad \text{(B-4)}$$

$$d_{\min,child} = \max(d_{\min,parent} - G_{parent} + R, 0) \qquad \text{(B-5)}$$

The values $n_1, \ldots, n_I$ for point "I-X, Y" are the number of units in each of the I sets of units or plants that are available for trip consideration in the preceding elements. If event Y is the trip of a unit/plant from set i, then n_i in "I-X, Y" is one lower than n_i in "O-X, Y", and $n_1, \ldots n_{i-1}$, as well as $n_{i+1}, \ldots n_I$ are the same as the corresponding values in "O-X, Y". This is because the one unit/plant from this set that tripped in interval X could not have tripped earlier. If event Y is no trip, then $n_1, \ldots, n_I$ are the same as the corresponding values in "O-X, Y".

P_{min} and P_{max} represent the minimum and maximum probability that $d_{min} <= d < d_{max}$, using the value of d at the start of interval X and d_{min} and d_{max} as specified in point "I-X, Y".

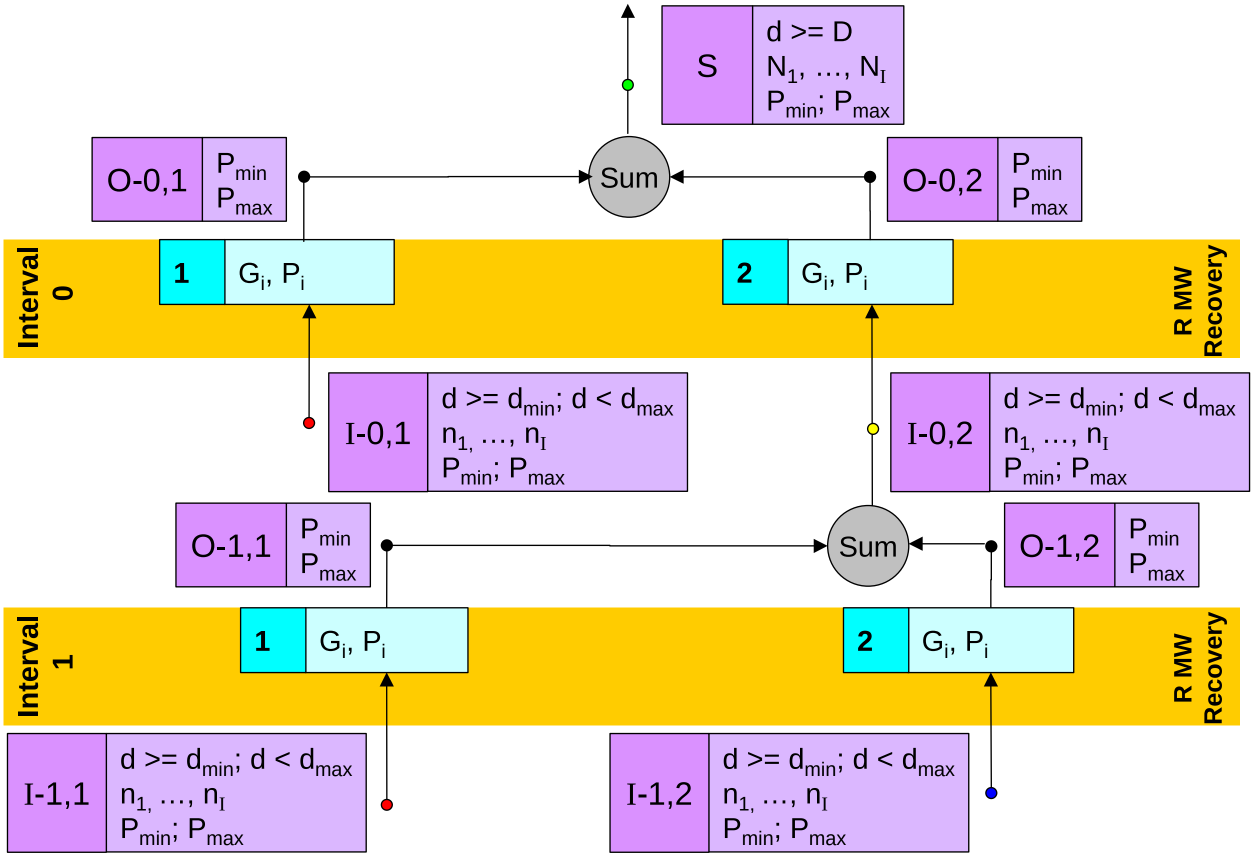

Figure 8

Figure 8 shows how these elements link together to form a full tree.

The points that actually link the elements of the tree together are shown in yellow (e.g. “I-0, 2”) and black (e.g. “O-1, 1”, “O-1, 2”). Each element containing a yellow point can connect to up to *I+1* other elements containing black points, one associated with a trip of a unit in each set where a unit is available, or no trip. The values of d_{min} and d_{max} are shared between all of them; thus only the yellow points show them. P_{min} and P_{max} of the yellow point are the respective sums of the P_{min} and P_{max} values for each of the connected black points.

We can follow a “path” from the black point of one element to the yellow point of another; and from the black point of that element to the yellow point of another; and so on, until we reach the green point at the top of Figure 8, discussed below. By doing so, we can trace a “chain of events” over several intervals, ending immediately after interval 0. For example, from Figure 8, Event 1 in interval 1 is followed by Event 2 in interval 0.

The red “I-X, Y” points are terminal. These represent a chain of events where the conditions on *d* will either definitely be met, or cannot be met. If d_{min} is less than *R*, then P_{min} and P_{max} are equal and are considered to be 1 at “I-X, Y”. The reasoning is as follows:

- As per Assumption 3, *d* must always be greater than 0. Therefore, for any value of *d* where $d <= R$ at an “I-X, Y” point before the event interval, we can assume that deficiency has decreased to 0 at the time of the trip, which is assumed to occur at the end of the interval.

- The probability that $d < d_{max}$ is very near to 1.

On the other hand, if d_{min} is higher than d_{max}, the conditions are contradictory. The value of d can never be less than d_{max} and greater than d_{min} so P_{min} and P_{max} at "I-X, Y" are exactly 0. Either way, there is no need to examine earlier intervals.

Note that any "I-X, Y" points that are shown in blue at end of each calculation step are elements that can be expanded, but are considered terminal for the purpose of calculating z at the end of each step. In this case, the chain of events can branch, as was the case with the yellow points. However, we have not yet performed the necessary calculations to do so. Instead, an estimate of the minimum and maximum probability is substituted. These points are the source of the error that must be minimized through the process being described in this section.

Finally, note that the topmost point, in green, is identified as "S". This is the solution point. The d_{min} for this point is D. There is no d_{max}. n_1, …, n_I are equivalent to N_1, …, N_I. P_{max} and P_{min} represent the total maximum and minimum probability of success, the difference of which is z.

Example 1

Consider an interconnection with $I = 1$, $G_1 = 1{,}000$ MW, $N_1 = 2$, and a secondary response rate of 200 MW/min. Use $T = 30$ s, $E_1 = 2{,}102$, $D = 1{,}400$ MW, and $Z = 1.4\text{e-}4$ to find the minimum and maximum values of P, such that $z < Z$.

First, from Equation B-1, we can determine that $E_{1,30} = 0.002$. Also, we calculate $R = 200MW * 30s / 60s = 100MW$.

Example 1, Step 1

Figure 9 shows our initial knowledge. We have no elements in the tree, only point "S". We understand that, for a successful outcome, our final level of deficiency must exceed 1,400 MW. What are good initial estimates for the minimum and maximum probabilities of fulfilling this condition, without extensive examination of the possible events that may have occurred in interval 0 or earlier?

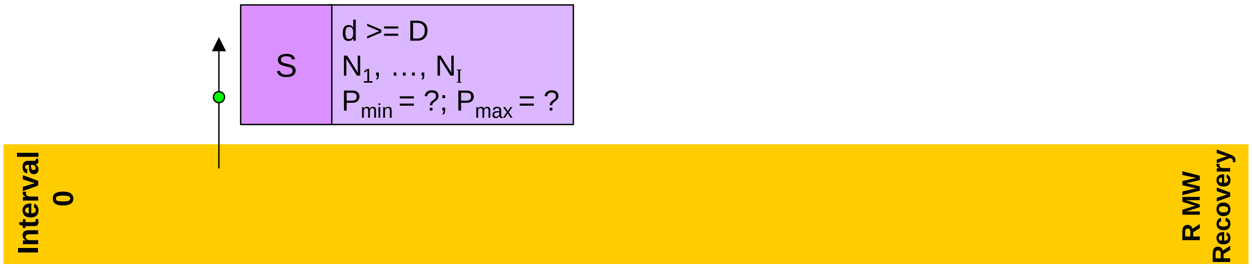

Figure 9

We can immediately set P_{min} to 0 and P_{max} to 1, as these are the logical extremes of probability. However, there is one simple calculation that will remove a great deal of this error. From Assumption 1, we know that we can discard scenarios where $d >= D$, except in the last interval.

We can say with certainty that if $d < D$ at the end of interval 1 and we trip no units in interval 0, then $d < D$ at S. Therefore, we should remove from the maximum probability of success the probability that we trip no units in interval 0, which is approximately 0.996, per Equation B-3. The value of P_{max} at S, therefore, becomes 1- 0.996, or 0.004.

We calculate error from P_{min} and P_{max} at point S. The difference between 0.004 and 0 is 0.004, which is larger than the specified Z.

Example 1, Step 2

There is too much error in the probabilities calculated in Step 1. If we look at all possibilities for trips in the current interval 0 then we can refine our estimates of the minimum and maximum probability values, by expanding the depth and accuracy of our calculations.

To expand the accuracy of our calculation, we must first enumerate the possible events to consider in the current interval. We have assumed that the probability of multiple units tripping in the same interval is negligible. Only two other possibilities exist. One is that one of the 1,000 MW units will trip. The other is that no unit will trip. These possibilities are illustrated in Figure 10.

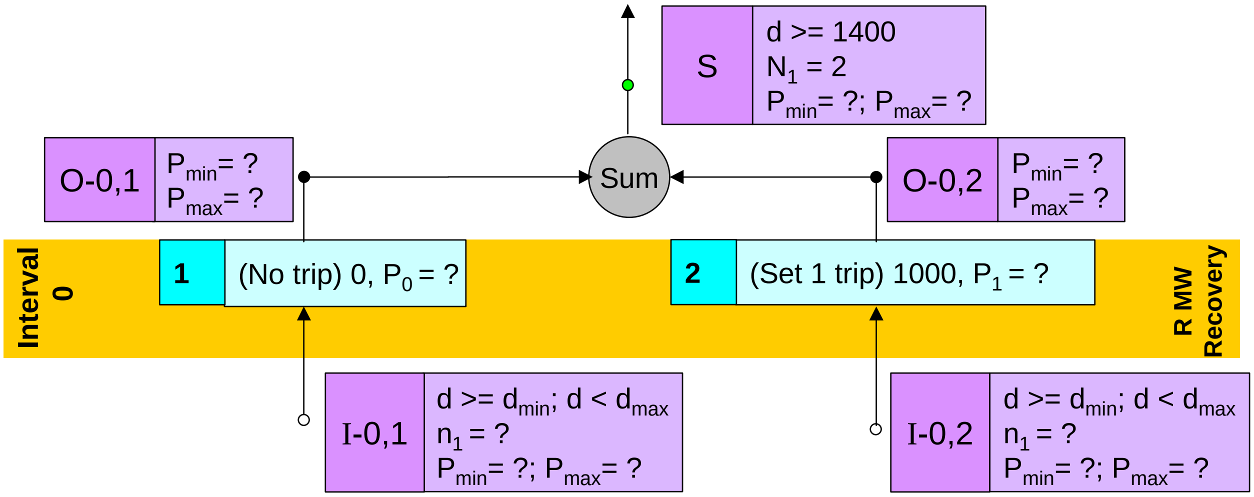

Figure 10

Next, we need to determine how much each possible event contributes to P_{min} and P_{max}. First, let us examine the case where no unit trips in interval 0. From examining Figure 10, we can see that we must determine P_{min} and P_{max} for point “O-0, 1”. Doing so will require determining P_0, and d_{min}, d_{max}, n_1, P_{min}, and P_{max} for point “I-0, 1”.

A. What is the probability that no unit will trip in interval 0?

   The answer, from Equation B-3, is 0.996.

B. What is d_{min} for point “I-0, 1”?

   From Equation B-5, d_{min} = 1,500 MW.

C. What is d_{max} for point “I-0, 1”?

Because we only want to ensure that the final level of MW deficiency is above some number, there was no d_{max} for point "S". Thus, no condition is propagated to point "I-0, 1". However, d must be less than D. Therefore d_{max} for point "I-0, 1" is 1,400 MW.

D. What number of units in set 1 will be available for consideration in elements derived from "I-0, 1"?

No unit trips are involved in this event, so n_1 remains at 2.

E. What is P_{min} for point "I-0, 1"?

The value of d_{min} is higher than the value of d_{max}. These conditions are contradictory, so P is exactly 0. Thus, P_{min} is 0.

F. What is P_{max} for point "I-0, 1"?

From above, P is exactly 0. Thus, P_{max} is 0.

We now have enough information to estimate P_{min} and P_{max} for point "O-0, 1". As we have determined that there is no chance whatsoever that d in interval 1 can meet the needed conditions, both the minimum and maximum probability that we can meet the conditions for point "O-0, 1" are also 0.

Next, let us determine the contribution of the potential 1,000 MW unit trip to P_{min} and P_{max}.

G. What is the probability that a 1,000 MW unit will trip in interval 0?

The answer, from Equation B-2, is 0.004.

H. What is d_{min} for point "I-0, 2"?

From Equation B-5, $d_{min} = 500$ MW.

I. What is d_{max} for point "I-0, 2"?

Because we only want to ensure that the final level of MW deficiency is above some number, there was no d_{max} for point "S". Thus, no condition is propagated to point "I-0, 2". However, d must be less than D. Therefore d_{max} for point "I-0, 2" is 1,400 MW.

J. What number of units in set 1 will be available for consideration in elements derived from "I-0, 2"?

One set 1 unit is tripped in this event, so n_1 decreases by 1, to 1, for preceding intervals.

K. What is P_{min} for point "I-0, 2"?

The values of d_{min} and d_{max}, are not contradictory, nor do they imply guaranteed success. Without further examination of past conditions, we can set P_{min} to 0, as in Step 1.

L. What is P_{max} for point "I-0, 2"?

As in Step 1, we can immediately rule out some portion of P_{max}. Consider the case where no unit trips in interval 1. Because d must have been less than 1,400 MW at the start of interval 1 (from Assumption 1), and because 100 MW were recovered over interval 1, d could be at most 1,300 MW in interval 0. Likewise, if no units tripped in both interval 1 and interval 2, then d could be at most 1,300 MW in interval 1 and therefore 1,200 MW in interval 0.

How is this relevant? We know that d_{min} is 500 MW. Therefore, a situation that would force d to be less than 500 MW will not contribute to the probability of success at this point. How many consecutive intervals with no trips would it require to result in such a situation? The answer is dependent on D, on the d_{min} for this point, and on the recovery rate, using the formula $\lceil (D - d_{\min})/R \rceil$. We use the ceiling function, because any fraction of an interval implies another full interval is required to force d below d_{min}. Using this formula for D of 1,400 MW, d_{min} of 500 MW, and R of 100 MW gives us 9.

Thus, we calculate P_{max} by subtracting the probability that no unit will trip for 9 consecutive intervals, or 0.996 to the 9th power, from 1. P_{max}, then, is 0.035429. In general, we can always initially estimate P_{max} for point "I-X, Y" as

$$1 - P_0^{\lceil (D - d_{\min})/R \rceil} \qquad \text{(B-6)}$$

using the value of d_{min} at element "I-X, Y".

We now have enough information to estimate P_{min} and P_{max} for point "O-0, 2". P_{min} is determined by multiplying the probability that the event will occur (0.996) by the minimum probability that the additional conditions for "I-0, 2" will be met, which is 0. Thus, $P_{min} = 0$. P_{max} is determined by multiplying the probability that the event will occur (0.004) by the minimum probability that the additional conditions for "I-0, 2" will be met (0.035429). Thus, P_{max} = 1.4172e-4. (The notation 1.4172e-4 indicates a value of 1.4172×10^{-4})

Having examined each possible event at interval 0, what are more accurate estimates of P_{min} and P_{max} for point "S"? What is the remaining error? Figure 11 illustrates this question.

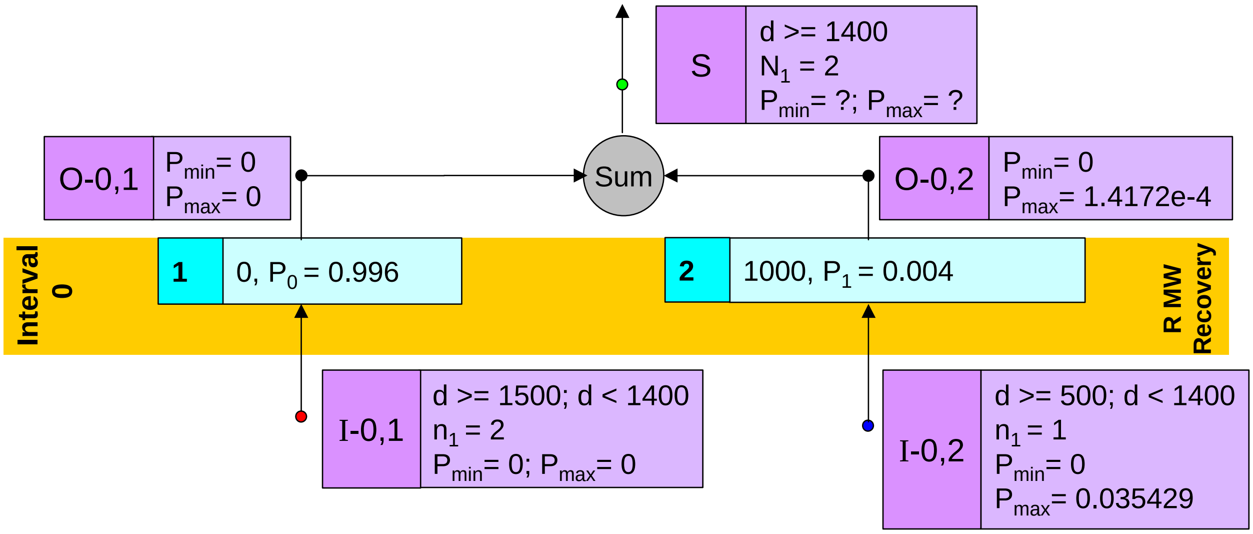

Figure 11

To find P_{min} for point S, add the individual P_{min} values for "O-0, 1" and "O-0, 2". Thus, $P_{min} = 0 + 0 = 0$. To find P_{max} for point S, add the individual P_{max} values for "O-0, 1" and "O-0, 2". Thus, P_{max} = 0 + 1.4172e-4 = 1.4172e-4. Finally, $z = P_{min} - P_{max}$, or 1.4172e-4.

Example 1, Step 3

Because 1.4172e-4 is still larger than Z, we must perform more calculations and increase our tree of knowledge. Only blue points are candidates for expansion, and the only blue point is “I-0, 2”.

Figure 12 shows the possible events that could occur in interval 1, given the occurrence of event 2 in interval 0.

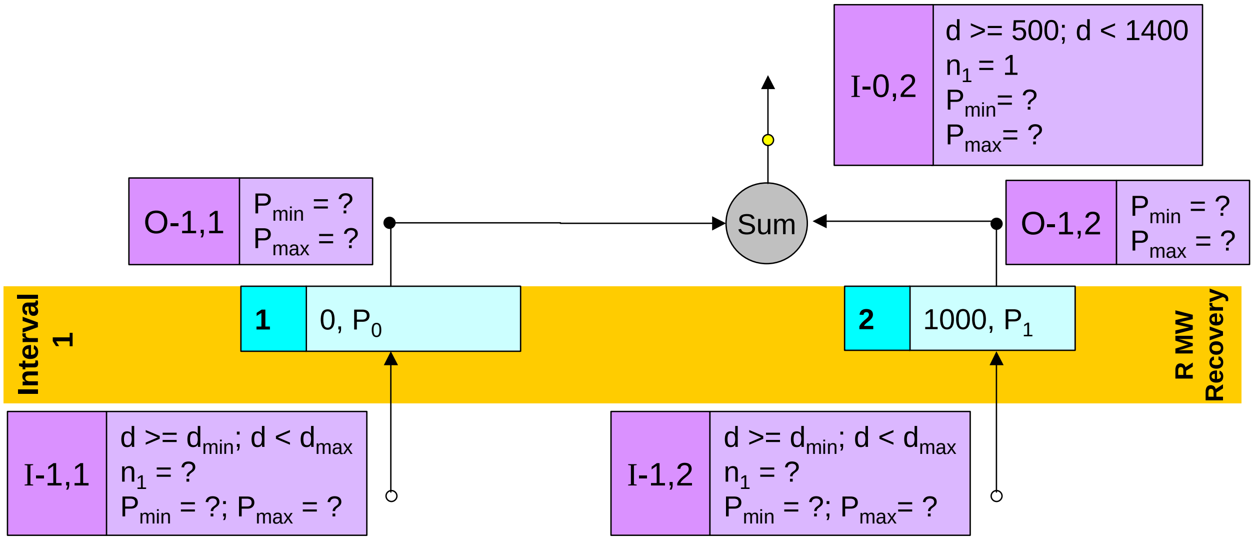

Figure 12

Figure 13, below, shows the correct values in place of each question mark. It also uses these values to update the values of P_{min} and P_{max} for point “I-0, 2”. Note that both P_{min} and P_{max} for point “I-1, 2” are set to 1, because d will definitely be greater than the specified d_{min} of 0, and d_{max} plays a negligible role in probability. Refer to previous sections for more information on how these values were calculated.

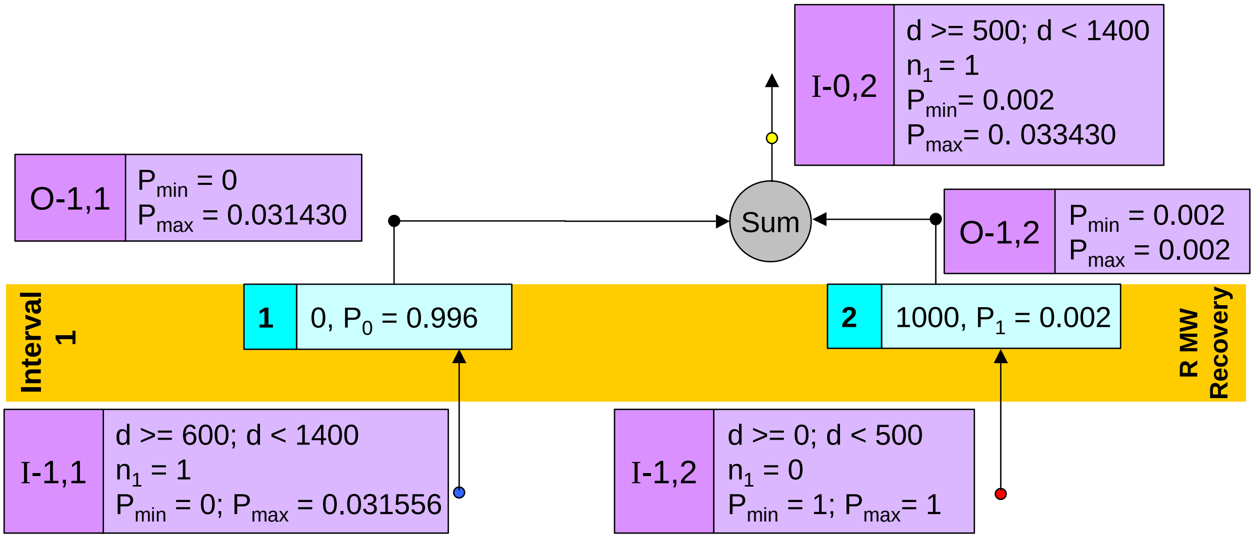

Figure 13

Now that we have updated P_{min} and P_{max} for point "I-0, 2", we can update point "O-0, 2". In general, we would continue directly up the tree from child element to parent element. Each time, we would do the following:

1. Use the new "O-" point of the child element to recalculate the values in the "I-" point of the parent element.
2. Use the "I-" point of the parent element to recalculate values in the "O-" point of the parent element.
3. Consider the parent element to be the new child element (for the next closest element to S).
4. Consider the next closest element to S to be the new parent element.
5. Repeat the process from step 1 with the new child and parent elements determined in steps 3 and 4.

Finally, we would use the "O-" point of the element in interval 0 to update point "S".

Figure 14, below, shows the updated tree, with new values of P_{min} and P_{max} for point "S".

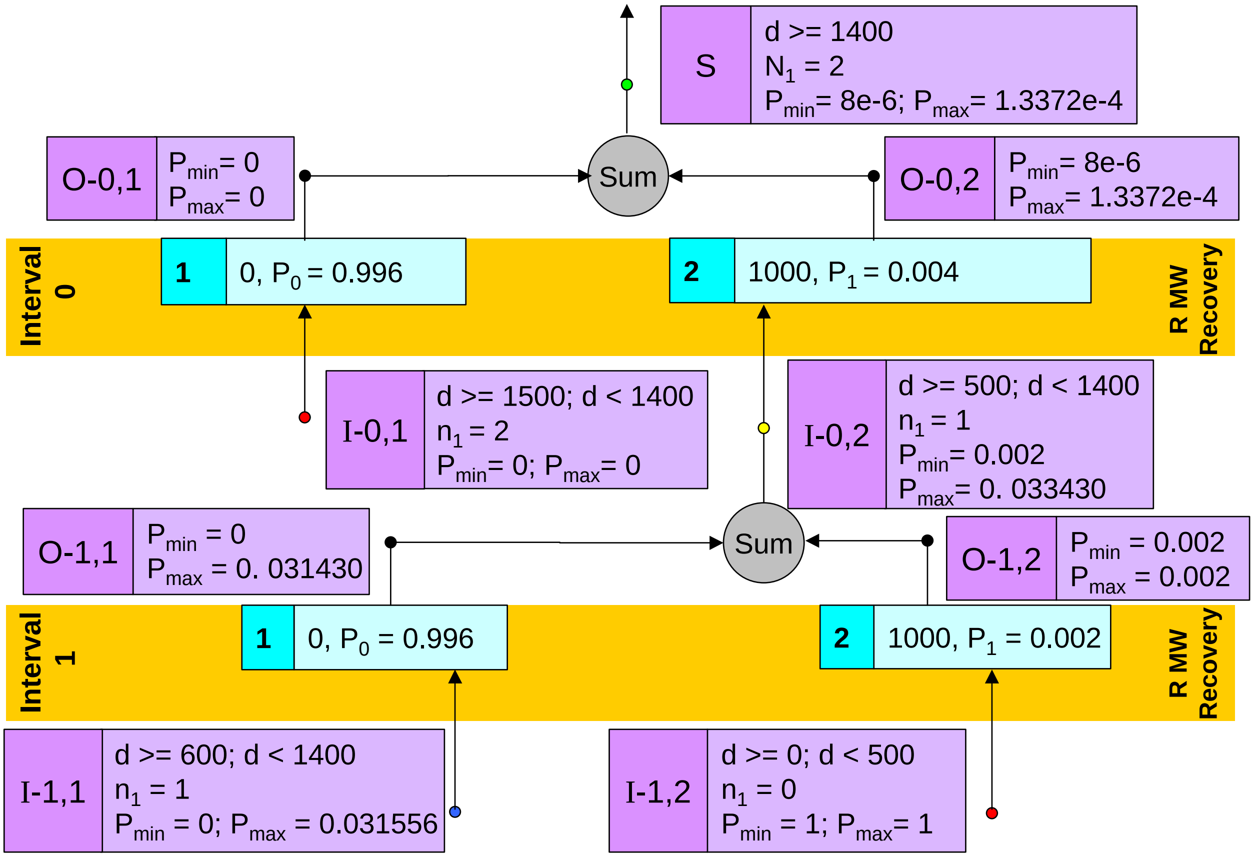

Figure 14

Thus, we consider the final probability of success to be between 8.0e-6 and 1.3372e-4. Based on the newly calculated values of P_{min} and P_{max} for point "S", $z = P_{max} - P_{min}$ = 1.2600e-4, which is less than Z. We have reached a level of error that we have deemed acceptable for this example.

Since T is 30s in this example, in 10 years there are 10,512,000 trials, so we expect the number of successes in 10 years to range from approximately 84 to 1406. In general, in utilizing this process to estimate the size of the contingency that is not expected to occur more than once per 10 years we will set *Z* so as to target a much smaller magnitude of the range in the number of successes in 10 years.

Example 2

This problem features a slightly more complicated interconnection, with three potential sets of units that can trip. *T*, *R*, and *D* remain the same as in Example 1.

Set 1: $G_1 = 500$; $E_{1,30} = 0.01$; $N_1 = 3$

Set 2: $G_2 = 1{,}000$; $E_{2,30} = 0.02$; $N_2 = 2$

Set 3: $G_3 = 1{,}500$; $E_{3,30} = 0.01$; $N_3 = 1$

For the given tree pictured in Figure 15, which elements are available to expand next? Of these, which elements might reduce the error faster?

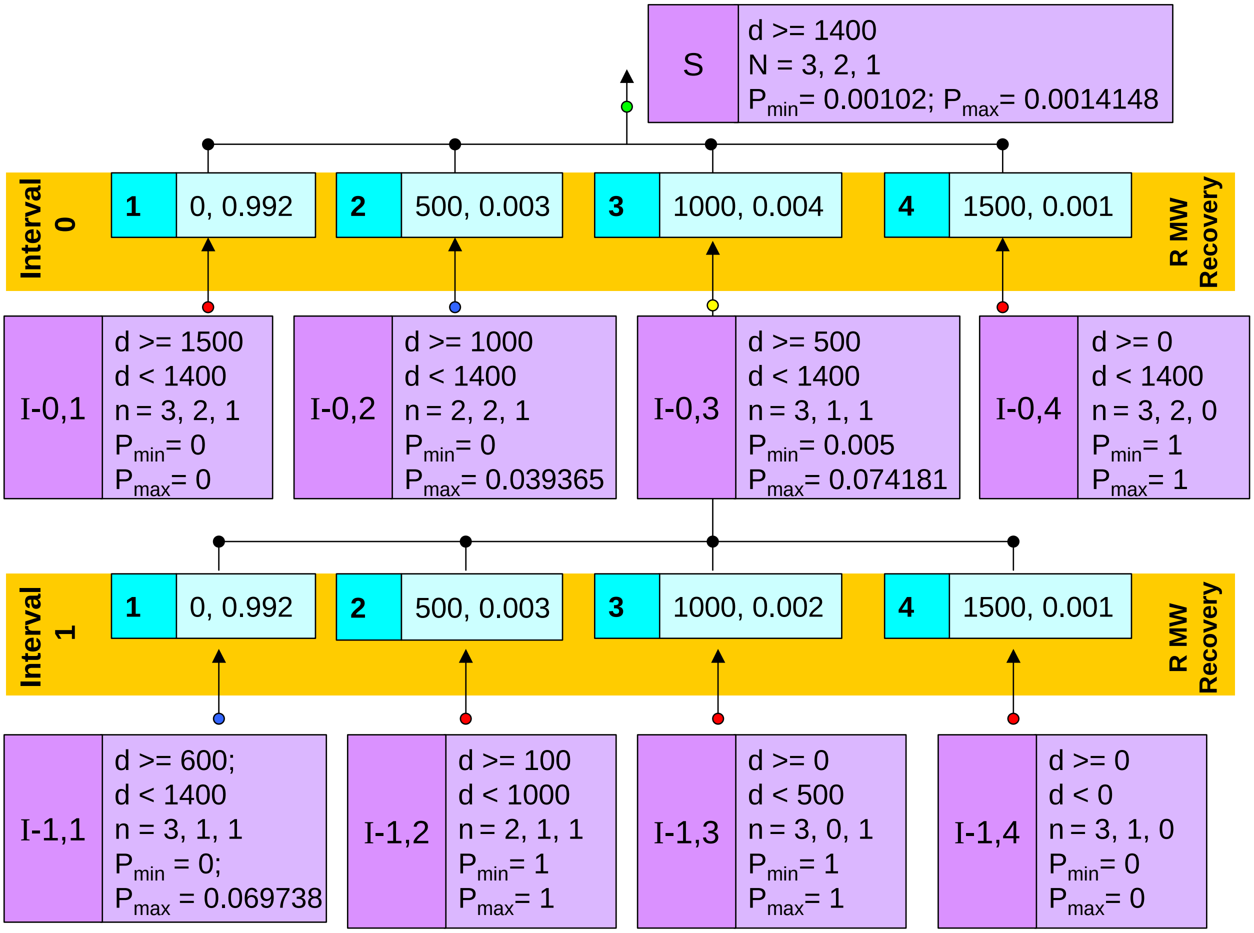

Figure 15

At the point in calculations shown by Figure 15, there are only two blue points, each contributing some portion of *z*, point “I-0, 2” and “I-1, 1”.

We can use a simple heuristic to decide which of the two elements to expand, in order to reduce error with fewer steps: simply compare the amount contributed to *z* by each element. If we assume that the reduction in total error, or *z*, resultant from expansion of an element has a somewhat proportional relationship with the amount of error contributed by that element, then expanding the element that accounts for the largest portion of the error is likely to remove the largest amount of error.

Figure 16 shows only the portion of Figure 15 that is ancestral to the two elements that we can expand, as well as the elements themselves.

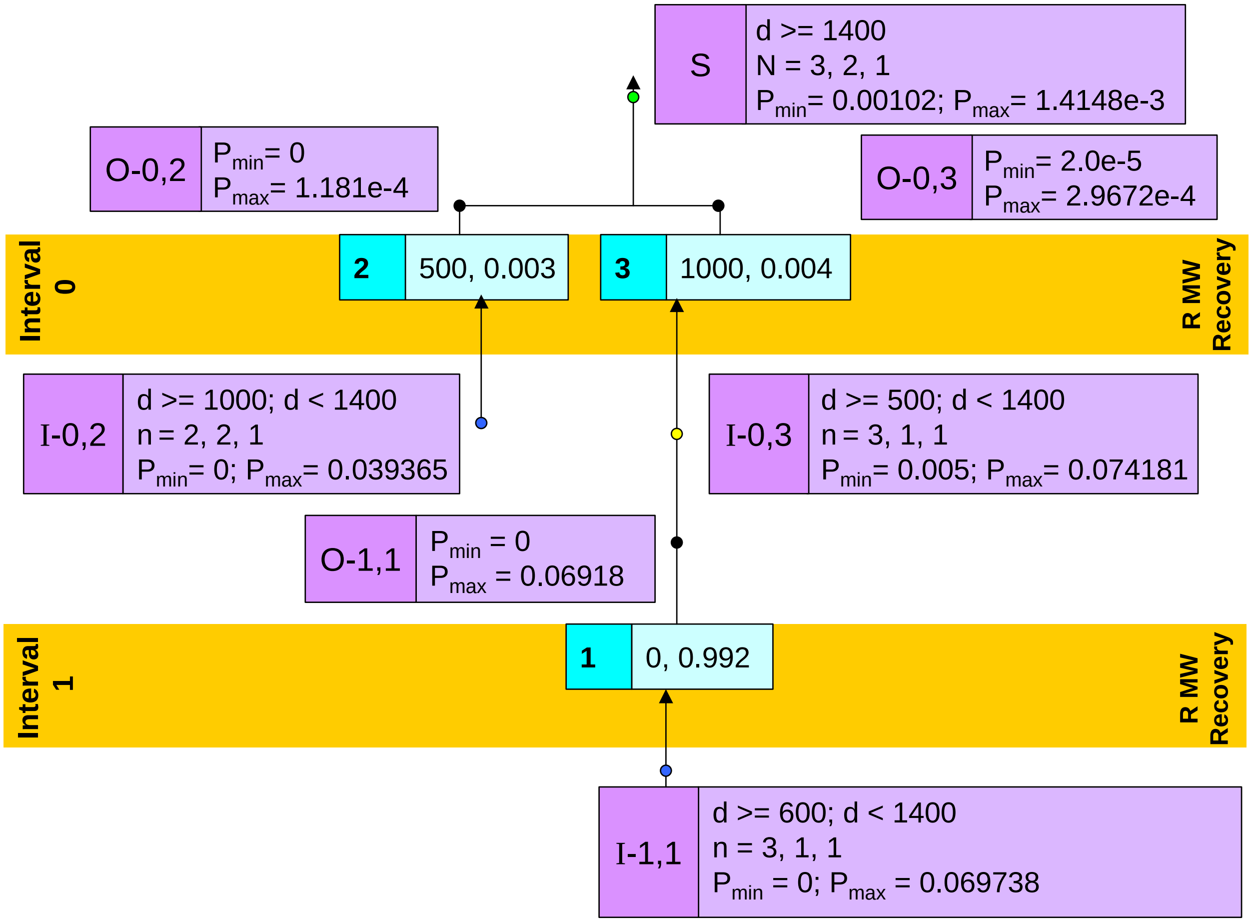

Figure 16

For element “0, 2”, the portion of *z* is the difference between P_{max} and P_{min} for point “O-0, 2”, or 1.1810e-4. For element “1, 1”, however, it is somewhat more complicated. From Figure 16, we can see that the element contributes to a sum probability at point “I-0, 3”, which is then multiplied by an event probability for event “0, 3” to calculate P_{max} and P_{min} for point “O-0, 3”, which contribute directly to z. Thus, the portion of z derived from “1, 1” is equal to the difference between P_{max} and P_{min} of point “O-1, 1” (0.069738), multiplied by the probability of event “0, 3” (0.004), or 2.7672e-4.

More generally, the contribution of an element “X, Y” to z is calculated by taking the difference between P_{max} and P_{min} at point “O-X, Y”, then multiplying it by the event probability for each higher connected element.

In this case, element “1, 1” contributes 1.1810e-4 to the error, while element “0, 2” contributes 2.7672e-4 to the error. In our next step, we would expand element “0, 2”.

Conclusion

In summary, our process is an iterative method that continually traverses and expands a knowledge tree. For each step, we perform the following actions:

1. Find the element “X, Y” that makes the greatest contribution to the error. For the first step, all elements will be expanded from point “S”, which is considered to be an element for that purpose.
2. Create up to $I+1$ sub-elements in interval $X+1$, branching from element “X, Y”, one representing the case where no unit trips and one for each set in which a unit or plant is available to trip. For the first step, substitute interval 0 for interval $X+1$.
3. For each sub-element, referenced by X, Y, thus created, use the values of d_{min}, d_{max}, and n_1, …, n_I from point “O-X, Y” to determine the values of d_{min}, d_{max}, and n_1, …, n_I for the sub-element.
4. For each sub-element, use the conditions to determine P_{min} and P_{max}. If the values differ, then the element contributes to z and is a candidate for expansion in future steps.
5. Use the P_{min} and P_{max} for each sub-element to recalculate P_{min} and P_{max} for element “X, Y”. Continue to propagate modified values directly up the tree until point “S” is updated.
6. Use P_{min} and P_{max} at point “S” to recalculate z. If $z >= Z$, go to step 1 to expand another element.

Once $z < Z$, we have determined an acceptable range of values for P, which we will use to determine the number of expected successes in ten years.

Appendix C Outstanding BRD SDT Comments

The following comments were provided by BRD SDT in [4]. PCE recommends that they be discussed further in order to arrive at a common understanding between BRD SDT and PCE.

1) Section VII.1 (In regard to the modeled recovery rate of 300 MW/min):

   Pretty good estimate, but I would suggest using 1% of the average (peak?) load. This is the regulating reserve required by operational practices in both PJM and CalISO, I believe.

2) Section V.1 (In regard to using a single frequency response value):

   The process should be modified to take into account the fact that, following multiple generation contingencies over a period of time, frequency relays may act much earlier than anticipated because the bulk of the primary frequency response on the system is realized (utilized?) during the initial contingency and is not available for frequency support during following contingencies.

3) Section V.1 (In regard to the plot of frequency response events):

   Might want to add a trend line w/ slope and correlation coefficient.

4) Section V.4 (In regard to the impact of activation of load shedding relays before full realization of primary response):

   My data indicate that under frequency relay delay settings, particularly for the first (initial) step, may be anywhere from 3 cycles (~50 milliseconds) to 100 seconds. While I agree that, for maximum accuracy, this should be taken into account I think that it is beyond the scope of our initial investigation and should be offered up as a future improvement rather than integrated into the initial calculation. It probably should be identified as an issue to be further investigated in the future.

5) Section V.4 (In regard to the impact of activation of load shedding relays before full realization of primary response):

   This is a misinterpretation. It should be interpreted as the time interval at which the probability of a next largest single contingency generator trip is equal to 50%. That is, the average time until the next generator will trip. It has nothing to do with anything else.

6) Section IX.1 (In regard to PCE finding that the proposed BAAL equation is based on an assumption that of a linear relationship exists between the current product of a BA's ACE and frequency error, and its contribution to the risk of the Interconnection exceeding under- or over-frequency limits, which is not justified):

   I do not believe this is true. BAAL was developed based on the assumption that if all BAs operated exactly at their BAAL then the frequency would be exactly at the FTL. Thus FTL can not be violated unless at least one BA exceeds its BAAL. Since BAAL varies with frequency, this is true regardless of where the frequency is at any given point.

Appendix D References

[1] BRD SDT, "Standard 300 – Balance Resources and Demand," Draft 2, June 1, 2004.

[2] Howard Illian, "Consideration of Comments on 1st Posting of Balance Resources and Demand Standard," March 11, 2004.

[3] "Directed Research for Balance Resource and Demand Standard's Procedures for Developing Frequency-related Limits", North American Electric Reliability Council. Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, NJ 08540, July 14, 2004.

[4] "Final Report, Phase I - Directed Research for Balance Resource and Demand Standard's Procedures for Developing Frequency-related Limits (Draft 2)," commentary by Raymond Vice, released on December 16, 2004.

[5] BRD SDT, "Introduction to the Balance Resource and Demand Standard", Draft 2, June 2, 2004.

Appendix E Areas of Potential Improvement Discussed in this Report

1) A study of the impact of ACE and frequency errors on the risk of reaching FRL under this Standard.
2) Further data collection and analysis to increase the accuracy of the positive frequency event response.
3) Improving the process of calculating frequency limit to use a modified frequency response for the last contingency to account for the fact that a portion of the primary response is not expected to be realized before under-frequency load-shed relays activate.
4) A more detailed study of Interconnection primary frequency response using frequency data of a span shorter than 1 second, such 0.1 second.
5) A study of the impact of variation in frequency response on the risk associated with this method.
6) Gathering data from all NERC regions in order to obtain more complete information regarding under- and over-frequency relay settings.
7) Verification of the results of proposed method for estimating the probability of frequency changes due to generation contingencies using historical short-scan frequency data.
8) Clarification of "approved (firm load) Under Frequency Load Shed relay" in the proposed process for setting frequency limits.
9) Study be performed, likely using frequency data, to define FAL_{high}.