PLANS TO DEMONSTRATE DECISION TREE CONTROL USING PHASOR MEASUREMENTS FOR HVDC FAST POWER CHANGES

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ABSTRACT - This paper describes one task of the WSCC Phasor Measurements Project, EPRI RP-3717-01, and related research on real-time, wide-area, discontinuous transient stability control. Five utilities in the Western Systems Coordinating Council (WSCC) region are installing phasor measurement units over a large geographic area. We plan to implement, for monitoring, decision tree based control for the Intermountain Power Project (IPP) and the Pacific Intertie HVDC links located in the western North American power system. Our ultimate objective in this research is to continually observe the measurements and apply control when a particular combination of thresholds are met. For the present implementation we will rely on a direct detection of events so that the immediate post-event phasor measurements can be used for input to the decision tree. This is a limitation that probably can and likely will be overcome with additional research.

One or more performance indices will be used to determine whether a combination of fast power changes on the DC lines improves the dynamic performance. The performance index criteria will be used in deciding which control combination is right for each case in the training set. In real-time following an event, the decision tree classifier(s) will order control actions based on comparing the post-event phasor measurements with what it learned from the training set. We are planning for new training sets and decision trees to be computed on-line as operating conditions change.

Large-scale simulations indicate that HVDC fast power change based on measurements at major power plants could have prevented the December 14, 1994 breakup of the western North American power system. Although generation or load tripping is the most powerful control action, a more logical place to begin with wide-area control is the two HVDC links that connect Los Angeles to the Pacific Northwest and Utah. It will be relatively inexpensive to make fast power changes on the DC lines, and such a control could be "trigger happy" without incurring excessive risk.

Our simulations indicate that fast power changes on the order of 500 MW can aid stability with small consequence for false operation. Usually a difficult to predict sequence of related events is required for instability. After taking any DC control action we will likely require a new set of simulations and a new decision tree before any subsequent control. This prevents inappropriate control because the operating condition has significantly changed. This also means pure open loop control. When a critical sequence of events like that of December 14 occurs, the control will act in response to initial events, and then be disabled until a new on-line assessment has been performed. Controlling the HVDC links within these constraints is a low risk way to explore wide-area, phasor measurement based control.

2. DECISION TREES

Decision trees (DTs) are a learn by example pattern recognition technique [3-6]. In our application we associate phasor measurements following a disturbance with control to either do nothing, increase HVDC transfer 500 MW, or decrease HVDC transfer 500 MW. A few successive samples from all of the PMUs will be used, and these inputs are combined into what is usually called the input vector. One advantage of decision trees is that when you have a training set with maybe 250 variables in each input vector, the trained DT requires only a much smaller subset, perhaps 25 of these variables to make a classification. This means a much lower chance of being inoperable because of missing data. It also saves a lot of design time trying to find the right combination of input variables to use. Decision trees are sometimes used just for selecting a combination of input variables or "features" for another classification technique such as k-nearest neighbor which does not discard the unimportant predictor variables [7].

The training set contains transient stability simulations designed to cover the set of contingencies we are trying to control [8,9]. The decision trees classify a case by comparing variables in the input vector with threshold values previously obtained though a statistical analysis of the training set. With a highly equivalenced simulation model it is difficult to replicate the real system closely enough that future behavior of the real system can be predicted based on comparing measured quantities with numbers derived from the simulated case trajectories. Fortunately it is straightforward to parallelize the different transient stability
runs in the training set, and as computers become faster and more parallel we can hope to use better, larger simulation models and generate more cases. Also system reduction techniques may be used to automatically reduce full-size cases, perhaps 5000 buses, to 1000-2000 bus size in order to speed computation. In our work we use the EPRI Power System Analysis Package (PSAPAC) which includes the ETMSP stability program and the DYNRED dynamic reduction program [10].

For the present installation we plan to use the 176 bus simplified equivalent with the initial operating condition reflecting the pre-fault, steady state phasor measurements. This model and operating condition will be used for the on-line training set generation (2-10 minutes depending on training set design) and subsequent DT training (1 minute). There is potential for improvement over present stability control where settings are usually based on a small number of off-line simulations.

![Decision Tree Image]

Figure 1: Simple decision tree for illustration purposes

Artificial neural networks could also be used for a pattern recognition tool, and are more general than decision trees. Neural networks can associate their input vectors with a continuous range of output values, whereas decision trees are only suited for classification problems having a small number of output categories such as stable/unstable. But when a problem can be reduced to a small number of choices, then decision trees have important advantages. Decision trees require approximately one minute to train for this size problem whereas neural networks usually require much more computation for the training. When a particular case is classified we can see which threshold criteria were met, i.e., why the case was classified and how the outcome would have changed if certain input variables had been different. The input variables are the PMU quantities taken after an event and may include bus voltage magnitudes and angles, line currents, generator accelerating powers, and other derived quantities.

A single decision tree could potentially handle the different combinations of changes that could occur on either or both of the DC lines. We could also use separate decision trees for each control, and our research indicates that controls selected individually according to their effect on the performance index have approximately additive effects when used in combination.

3. PERFORMANCE INDEX

The objective function

\[ J = \int \sum M_i (\delta_i - \delta_{\text{ref}})^2 \, dt \]

0 \[ i \]

can be computed from simulated transient stability runs. The sum does not have to contain all the generators in the model. A sampling on the order of 10-100 of the larger generators distributed throughout the power system is sufficient to have J be a fairly good numerical measure of the amount of inter-area oscillation following a disturbance. Between two simulations everything is held fixed except for some control action that needs to be evaluated. Controls that reduce J tend to have the strongest smoothing and stabilizing effects on the post event oscillations and are likely to have other benefits as described below. We expect to use a performance index such as this to assign the right control to every case in the training set.

This performance index is like the weighted sum squared "error" comparing the simulated behavior to a hypothetical "ideal" trajectory of all the generator angles constant with no angle differences. The angle swings in a transient oscillation are related to the power flow surges and voltage excursions, and we expect to find that a reduction in J also reduces post-transient power surges and voltage magnitude deviations. This was our motivation for using the performance index to determine whether and how much a particular control improved the transient response to a simulated event. The fact that we rely on time domain simulation data has advantages in that detailed models can be used, and with the future availability of parallel computers, the main limitation in model complexity is expected to be with determining all the parameters that represent the current operating condition. One possibility for overcoming this limitation would be to have a database of detailed model loadflow and dynamic data files and select from this collection one which hopefully represents the current operating condition.

When trying to stabilize an unstable event with a combination of discrete event controls, the controls which have the greatest effect on J are adopted first and then the sensitivity to all controls is recalculated. Additional controls are added as necessary to stabilize the simulated event [11]. This approach makes it much easier to determine a combination of discrete event controls that will stabilize an unstable event. Using this performance index it is possible in simulation to find powerful stabilizing control combinations without further analyzing the simulated angle trajectories, accelerating powers etc.

For events that are already stable the performance index provides a computational method of deciding whether a particular control improves the simulated response. The idea for the present work is to use the index to assign the right control (HVDC fast power change of either -500, 0 or 500 MW) to each simulated disturbance in the training set. For validation of this method we will want to see whether the control that we would implement improves the behavior in large scale simulation. Here again we benefit from having limited the control options to three choices: the control we would have ordered is one of three things and each can be simulated.

Small oscillations are approximately governed by the linearized equations and it is helpful for understanding how
reduction in $J$ relates to improved transient response to evaluate the performance index for a damped linear system trajectory. The criteria for having a stable equilibrium in a dynamical system is for the matrix representing the linearized equations to have all the eigenvalues with negative real parts. The real part of the eigenvalues determines the damping of its corresponding natural mode. Calculating the performance index on a typical eigenmode shows its dependence on the coefficients $A$ and $\sigma$ representing the oscillation magnitude and damping respectively. For a single (i.e. non-repeated) eigenvalue the corresponding natural mode is a damped sinusoid. Here we have set $\Omega = 1$ and will integrate $\dot{y}(t)$ over one period.

Given

$$y(t) = Ae^{-\sigma t} \cos t$$

the integral of $\dot{y}(t)$ is the performance index calculation for this one trajectory. The result is

$$J = A^2 \left( 1 - e^{-4\pi \sigma} \right) \left( \frac{1}{4\sigma} + \frac{1}{4\sigma - 4/\sigma} \right) \text{for } \sigma \neq 0,$$

$$J = A^2 \pi \text{ for } \sigma = 0.$$ 

which shows that $J$ increases with the square of the amplitude coefficient. The dependence on $\sigma$ is harder to see because the expression for $J$ has a singularity at $\sigma = 0$. Fortunately $J$ is continuous at $\sigma = 0$ and the first expression approaches $A^2 \pi$ in the limit as $\sigma$ goes to zero. For damped systems ($\sigma > 0$) the graph of $J$ as a function of $\sigma$ is shown in Figure 2. For the figure $A=1$.

![Graph](image)

**Figure 2:** Performance index as a function of the damping coefficient $\sigma$.

The eigenvalue real part is represented by $-\sigma$, so that larger $\sigma$ increases the damping. Figure 2 shows how $J$ becomes smaller as the damping coefficient increases. Any shifting of the sinusoid relative to the center of angle also increases $J$.

The large nonlinear oscillations in border-line stable cases can frequently be described in terms of their amplitude, period, decay rate, etc..., qualitatively at least and perhaps quantitatively with suitably defined measures. Speaking qualitatively our experience in simulation is that controls which reduce $J$ will reduce the amplitude and/or improve the decay rate of post-event generator oscillations. They also cause the angle differences in the post-event operating point to be smaller. In practice we find that as more controls which reduce $J$ are added to the switching specification file, the simulated behavior changes from unstable to stable [11]. Generators which were initially losing synchronism are pulled in toward the center of angle by the combination of controls acquired using the performance index.

Some of the events we have been able to control have been very challenging like a 10 cycle three phase fault on an equivalent transmission line that could not be removed without causing instability. Our rough approximation to the December 14, 1994 event on the 176 bus reduced order model turned out to be much harder to control than the actual event [11]. The difficult cases require a large combination of wide-area generator and load tripping to stabilize the event. As controls are added the loss of synchronism in the simulated event takes longer and longer to occur. One frequently observes the transition from unstable on the first swing to unstable on later swings, until finally stable.

4. SIMULATED FAST POWER CHANGES ON 176 BUS WSCC MODEL

This section presents simulation results on the 176 bus simplified equivalent for the west coast power system where the DC power transfers are modeled as constant power injections at the terminal busses. This modeling may be sufficient however for choosing the right direction to make a real HVDC power change. It also seems likely that a real DC power change would be slightly less effective than the ADD ADMITTANCE (+/- 500 MW) commands used in our ETMSP simulations. There is a ramp time required to change the DC power flow, and other dynamics that could slow the power change. The 176 bus simulations can therefore be taken as an approximate bound on the stabilizing power of real HVDC fast power changes. This information is used to justify the specification that any control be one of three things: +500 MW, -500 MW or no change. These simulations also indicate that the ramp should be initiated as soon and fast as practicable.

We have experimented with the ETMSP ADD ADMITTANCE command enough to know that it is a decently reliable way to make fast power changes at the DC terminal busses. We found for example that the ADD ADMITTANCE command performs similarly to the SHED LOAD command when the sign of the power change is reversed. Shedding negative load is observed to have the same effect as subtracting power injection from the bus with the ADD ADMITTANCE command. We have experimented with different expressions involving SHED LOAD and ADD ADMITTANCE, placing opposite control orders together in the switching specification file to see whether they exactly cancel each other as expected.

In this section we are going to use a method different than the performance index for looking at the improvement in transient response from discrete controls. Our reason for using the following technique is because it is the same calculation required to generate a database of simulation results for a pattern recognition technique such as decision trees [8,11]. Basically it means simulating maybe 10 transient stability runs with three phase faults 0, 1, 2, ... 9 cycles in duration for every transmission line you are concerned about. We have typically used a simulation length of 4 seconds for all the cases. Each case
is checked for loss of synchronism and the results of this test are stored as a matrix.

The 176 bus simplified equivalent of the WSCC has 259 branch elements including transmission lines and transformers. For a heavily loaded summer peak operating condition we found 31 transmission lines where the CCT for a 3 phase fault (with faulted line removal) was less than 9 cycles. In some cases removing one of these equivalent lines is more severe than the actual Dec. 14 1994 disturbance due to the lack of any supporting parallel transmission. There were some additional transmissions lines which would disconnect part of the system when removed and they were not included in the 31 lines. Three phase short circuit to ground faults from 0 to 9 cycles in duration were simulated on the 31 lines without any control action for a total of 310 transient stability runs. In this database there were 174 stable cases and 136 unstable cases.

We repeated the 310 simulations with a 500 MW fast power increase on both DC lines in every case, and counted the number of cases that were stabilized by the control. For this particular operating condition it turned out that a 500 MW increase on both DC lines did not cause any cases to become unstable, and caused 17 of the 136 unstable cases to become stable. The above power change was made in one step at 0.1 sec. (10 cycles) after the fault clearing time. We also simulated ramped power changes which were performed by a sequence of any 40 ADD ADMITTANCE commands spread uniformly over the ramp interval and totaling 500 MW.

We said earlier that a step change would probably be stronger than a ramped power increase and would therefore stabilize the most cases. Our simulations of different ramps and steps on the same 310 contingencies show the effects of taking longer to initiate and ramp the fast power change. Only 11 cases are stabilized if the change is made in a step at 0.2 sec. (20 cycles) after the fault clearing time. A fast ramp starting at 0.1 sec (10 cycles) after clearing time stabilizes 14 cases. A slower ramp that starts right after clearing time has a similar effect: 13 cases stabilized. No stable cases were made to be unstable by any of the controls. These results which are depicted in Figure 3 indicate that a DC ramp should be initiated as soon and fast as practicable in order to achieve the maximum effect.

Figure 4 shows the effect of delaying the power change and helps to quantify the reduction in effectiveness. Again all the steps were 500 MW increases on both DC lines. About half as many cases are stabilized when the control is changed from 0.1 sec. to 0.3 sec. after clearing time.

Figure 3: Number of cases stabilized (out of 310 transient stability runs) by various 500 MW ramp and step power changes.

Figure 4: Number of cases stabilized by 500 MW step power changes at different times.

All the steps and ramps represented in Figure 3 were 500 MW increases on both DC lines. They were modeled as changes in the bus power injections which represent the HVDC power transmission in our version of the 176 bus simplified equivalent. The ETMSP ADD ADMITTANCE command requires the user to specify an amount of reactive power change as well. Some simulations had reactive power changes (in addition to the real 500 MW) and other simulations had no reactive power change. The number of cases stabilized did not change very much as the reactive component was varied. The identities of the stabilized cases were sometimes different but the total number was always close. This phenomenon explains why the step at 0.2 seconds stabilizes 11 cases in Figure 3, and stabilizes 12 cases in Figure 4.

Figure 5 shows that within limits a larger power change is more effective. The first three bars have a step change of the specified magnitude on both DC lines. The last two bars have a
500 MW step change on each DC line individually. These are the Pacific DC Intertie and the IPP DC line respectively.

Although more testing remains to be done we make the following observations. The intention in this project is not to use decision trees for predicting stability/instability in the hopes of detecting some unstable event which could be stabilized by fast DC power changes. To do so would require much more simulation accuracy than we are going to have with the 176 bus model. We are however fairly confident that the 176 bus model will be sufficient for predicting the right direction to make a fast power change that improves the transient oscillations whether stable or unstable. The simulations in this section show for one heavily loaded operating point at least that a 500 MW power change in the right direction is unlikely to cause harm from being excessive. Because DC power changes are inexpensive and less powerful compared to generator and load tripping (in the right locations), it seems reasonable to specify that the control action be one of three things: +500 MW, -500 MW or no change. This simplification in control strategy is very important for facilitating planning studies that are normally performed by utilities, for our own testing of how the control would perform in simulation, and for limiting the possibilities of inappropriate control orders.

5. TESTING DC CONTROL ON THE DECEMBER 14, 1994 BREAKUP

The December 14, 1994 breakup of the western North American power system was one of the most disruptive and widespread power disturbances in recent years. We approximated the December 14 event on the 176 bus equivalent [11] and found through the performance index that a fast power increase on the IPP improved but did not stabilize the simulated event. While this simulation was very crude in terms of the operating point, it did have power flowing generally in the right direction. After adjusting the operating point to more closely fit a 4700 bus loadflow we found that a fast power increase on the IPP was still appropriate. It also indicated that tripping generation at Jim Bridger had the greatest stabilizing effect.

WSCC utilities have reproduced the breakup with transient stability program simulation. Using this large-scale data set, the simulations described below show that a 500 MW DC fast

![Graph showing rotor angle swings with and without 500 MW fast power change on IPP HVDC link.](image-url)

**Figure 6:** Absolute rotor angle swings with and without 500 MW fast power change on the IPP HVDC link. The fault is applied at 0.5 seconds and the fast power change starts at 1.0 seconds.
power increase on the IPP HVDC link would have prevented the cascading and instability.

The Pacific Northwest was importing power from both the south (Pacific AC and HVDC Interries) and the east (Montana and Wyoming). The incident started at 0125 hours Mountain Standard Time, and centered around transmission lines connecting the Jim Bridger coal-fired plant in Wyoming to the Pacific Northwest. The Jim Bridger plant consists of four 590-MVA units and was generating around 2000 MW. A single-phase fault on a short 345-kV three-terminal line in southern Idaho (Borah-Adelaide-Midpoint #1) initiated the disturbance. The line was tripped normally, but a protective relay mis-operated and opened the Borah end of the parallel Borah-Adelaide-Midpoint #2 line. Because of the bus arrangement at Borah, the long, series-compensated Borah-Jim Bridger 345-kV line also tripped. Two parallel 138-kV lines then tripped on overload about 9 and 41 seconds after the initial fault. About 52 seconds after the fault, the third short parallel 345-kV line (Kínpport-Midpoint) tripped by impedance relay due to high current and low voltage (0.81 per unit), severing Jim Bridger ties to the Pacific Northwest and leading to instability.

Following these outages, lines from southern Idaho/Wyoming/Utah/Colorado to Arizona/New Mexico/Nevada tripped due to out-of-step conditions. Lines to Montana also tripped because of either overload or out-of-step. Out-of-step conditions subsequently developed between northern and southern California. Three, and later four, islands formed with large amounts of controlled under-frequency load shedding in the Northwest island consisting of northern California, Oregon, Washington, Montana, parts of Idaho, British Columbia, and Alberta. Many generating units also tripped.

Focusing on the initial events, the 138-kV lines tripping on overload led to the cascading. Effective stabilizing action would be to trip one of the Jim Bridger generating units. A controller similar to the Colstrip power plant Acceleration Trend Relay (ATR) relay [12] would likely work, perhaps operating before the 138-kV lines tripped. Other generator tripping controls would also work. Here, however, we discuss less costly discontinuous control action involving HVDC fast power changes. False or unnecessary operation of HVDC fast power change control is not very disruptive so the controls can be somewhat trigger happy.

Since the initial opening of the 345-kV lines greatly weakened the direct Jim Bridger to Northwest transmission, power flow shifted to parallel paths through Montana and the Southwest. In ac networks this synchronizing power flow shift occurs naturally—and very robustly. Unfortunately, the parallel transmission paths includes long distance HVDC links that operate in constant power control and thus do not provide synchronizing support. The HVDC links are the 780 km, 1920 MW Intermountain Power Project (IPP) link from the Intermountain power plant in Utah to the Los Angeles area, and the 1350 km, 3100 MW Pacific HVDC Intertie between the Pacific Northwest and Los Angeles. Of general interest are previous investigations that showed significantly improved system stability with the Intermountain Power Project HVDC link replaced with a similar cost double-circuit, series compensated 500-kV ac link [13].

Simulation results in Figure 6 show rotor angle swings following the December 14, 1994 event. Jim Bridger rotor angles at 0.5 seconds after the fault have advanced 32.9° on an absolute basis and 35.7° relative to Grand Coulee in the Pacific Northwest. Intermountain and Colstrip rotor angles have advanced, respectively, about 10° and 2° on an absolute basis. There is about 1° deceleration of California generators on an absolute basis. As part of the EPRI project, PMUs are planned for the Grand Coulee, Intermountain, and Colstrip high voltage switchyards, but not for Jim Bridger.

Assuming measurements at Jim Bridger are available, the rotor angle swings provide one basis for HVDC fast power change control decisions. In the EPRI project, the decision tree input vector will be based on related PMU measurements, namely generating plant EHV bus voltage angle and frequency, and power plant acceleration computations.

Figure 6 shows the effects of an IPP HVDC link 500 MW fast power increase starting 0.5 seconds after the fault. Jim Bridger rotor angles are reduced by about 8°, improving stability margin and reducing overloads. Simulation analysis indicates that 138-kV lines would not trip due to overload, thus preventing cascading instability.

These simulations are consistent with what we had predicted with the 176 bus model. Even though the 176 bus event was unstable with and without the IPP 500 MW increase, the performance index was found to be decreased by this control. On this basis we predicted that this control, if applied to more realistic simulations (or to the real system), would reduce the angle differences during the post-fault oscillations and generally improve the dynamic performance. This turned out to be the case, fairly dramatically, in the large scale simulations of the Dec. 14, 1994 event.

Our prediction of what to do in response to the December 14 disturbance was made by performing the 176 bus simulations for that specific event and operating condition. The ultimate goal is for decision trees to predict the correct control based on the immediate post-event phasor measurements. The training set for the decision trees will contain cases similar but not identical to the actual event. We are proposing that controls be assigned to each case in the training set using the performance index. The results in this section add evidence to the assertion that the performance index calculated with and without control on the 176 bus model is a good way to assign controls to each case in the training set.

6. PLANS TO INSTALL FOR MONITORING

We intend to demonstrate a capability of performing the following computational tasks on-line:

(1) [PMU central monitoring computer] Determine an operating point for the 176 bus model according to the steady state PMU measurements. The plan is to directly measure, compute, or estimate the 176 complex voltage phasors. It makes sense to implement this calculation on the PMU monitoring computer. The increase in file transfer time from doing it this way is negligible. Since the remote computer will only be connected at first as a temporary demonstration, performing this task on the PMU monitoring computer will provide more installed capability.

(2) [File transfer] Transmit the 176 phasors to a remote computer which will perform and analyze the simulations. The transmission time should be small (seconds) compared to the time required for all the simulations (a few minutes).

(3) [Remote computer] Produce a solved loadflow file in a format that ETMSP accepts based on the 176 voltage phasors.
(4) [Remote computer] Run a number of ETMSP simulations and save the simulated phasor measurements along with the performance index measure of all the cases in a file for the DT software to use.

(5) [Remote computer] Run the decision tree software and convert the DT report file into something usable by a subroutine running on the PMU monitoring computer.

(6) [File transfer] Transmit the decision tree information back to the PMU monitoring computer.

(7) [PMU central monitoring computer] Report that the decision tree control algorithm has been trained for the present operating condition, and arm the controller (for monitoring).

(8) [PMU central monitoring computer] Detect an event and input the next usable set of phasor measurements to the DT logic and decide whether the HVDC control should be +500 MW, -500 MW or no change.

There are a number of issues to address. Some of them are:

(1) The frequency of transmitting the phasor measurements increases demand on the communication channels. Since it has been decided to transmit the PMU measured current phasors as well as the bus voltage phasors, there is already a large demand for communication. Previous research shows that a 4 cycle transmission rate is adequate. For this installation it should be adequate to transmit the phasor measurements to the central monitoring computer every 5 cycles.

(2) The sampling window that the PMU uses to estimate the positive sequence phasors should be two or preferably one cycle long. This would make the real measurements more like the quantities that ETMSP generates for the simulated phasor measurements. Switching events during the sample window are likely to render those measurements unusable. Therefore another reason for using a shorter sampling window is so that the first post-event PM's will be available sooner.

(3) The PMUs provide an opportunity to detect events throughout the network and to identify (with high confidence) such events in real-time. This is an important area of research that we have not yet fully explored. For the present installation we will have to rely on the direct detection of a line outage by one of the PMUs. We could possibly do the following: find a very "trigger happy" event detector from among existing equipment and use decision trees to decide whether each event is worth controlling with a 500 MW fast DC power change.

(4) There are two HVDC lines to control here, and we could also possibly use decision tree logic to decide whether an event is worth controlling with a 500 MW power change on either or both DC lines.

(5) We are intending to demonstrate that the proposed on-line computations could be repeated automatically in order to adapt to changing operating conditions. There may be some details regarding the file transfer for example where there will have to be some human intervention in the initial installation. This should not be an obstacle to demonstrating the process or to understanding that it could be fully automated.

We already have the following components:

(1) Program subroutine to extract generator trajectories and simulated phasor measurements from the ETMSP output file.

(2) Program subroutine to compute the performance index from the generator trajectories. Also checks for loss of synchronism.

(3) Main program to run multiple ETMSP simulations with various switching specification files and compile the results into a file which can be used by the decision tree software.

We need to have the following components in order to implement the present design:

(1) Program subroutine to specify the 176 bus voltage phasors using the bus voltages at the PMU buses, and computations or estimates for the remaining voltage phasors. This design will ensure that the simulated PMU values will be matched to the actual PMU outputs for their pre-fault equilibrium values.

(2) Program subroutine to produce a loadflow file for the 176 bus model given the 176 bus voltage phasors. It would be very helpful to have an existing loadflow program perform the bulk of this task but we have not yet found a bus model in one of the standard loadflow formats where the voltage magnitude and angle are held fixed during the loadflow solution.

(3) Program subroutine to translate the decision tree software output into something usable by the DT classification subroutine. This task will be time consuming, and it seems somewhat unfortunate because the DT software could have been designed reasonably easily to produce a small portable subroutine in C or FORTRAN that implements the DT. Instead one needs to run the DT software to classify a case. It is easy to convert an individual decision tree into computer code by hand, but we need a program to do it automatically.

(4) Program subroutine to detect the outage of any transmission lines connected to a PMU bus, or have some other way of detecting an event and processing the immediate-post-event phasor measurements through the decision tree.

The following components would be helpful, but probably will not be completed within this project:

(1) Program subroutine to run ETMSP simulations in parallel.

(2) Program subroutine using PMUs to detect events other than losing a line connected to a PMU bus.

(3) Automated file (or message) transfer between the PMU monitoring computer and the remote computer.

(4) Improved DC modeling.

We are relatively optimistic that the present modeling of DC fast power changes in the 176 bus model will be sufficient for deciding among +500 MW, -500 MW, or no change for both DC lines.

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8. REFERENCES


