FINAL PROJECT REPORT

CRITICAL OPERATING CONSTRAINTS FORECASTING A DECISION SUPPORT TOOL

Prepared for CIEE By:

Electric Power Research Institute

ELECTRIC POWER RESEARCH INSTITUTE

Project Manager: Stephen Lee
Authors: Stephen Lee

Date: March, 2008

University of California ciee

A CIEE Report

Acknowledgments

The work reported in this document is a result of collaborative research between EPRI and The Transmission Research Program (TRP), with major funding from the PIER Program and some cost sharing from EPRI.

The Transmission Research Program (TRP) is a partnership between the California Energy Commission (CEC) Public Interest Energy Research (PIER) Program and the University of California. The purpose of the TRP is to research, develop and demonstrate advanced technologies for improving the electric transmission system for the public benefit of California. The **Electric Power Research Institute** (EPRI) is an independent, nonprofit center for public interest energy and environmental research, with extensive expertise in electric energy production, delivery and end-use technologies.

Funding for this research came from the PIER Program, with cost-sharing contributed by EPRI. The original idea and the need for this project came from Jim Detmers, Vice President of Operation in the California Independent System Operator (ISO). Participation, technical contribution and review of this project by California ISO are greatly appreciated. It is an important factor for the success of this research project.

The work produced by this research project was presented in the first half of a workshop on November 7, 2007, held in Folsom, California. The goal of this workshop was to present the results of two research projects under the TRP, performed by EPRI on the related subject of transmission operation constraints and the forecasting of short term and long term congestion. The first project is this project. The second project is called Probabilistic Transmission Congestion Forecasting and deals with operational planning and long term transmission planning. Attendance from electric utility operators and planners, researchers, software developers and vendors, regulators, policy makers, consumers, and non-governmental organizations made that workshop a success.

The authors wish to thank Jim Detmers for the technical vision and the support of this project. Other individuals in the California ISO also contributed by supplying data and reviewing results. They include Jim McIntosh, Jamal Batakji, Tamara Elliott, Dave Hawkins and Patrick Truong. The EPRI project team included Peter Hirsch and Guorui Zhang, both of them contributed significant efforts in this project.

The contribution by the TRP managers in the project reviews and technical guidance is also much appreciated. A special thank is due Jim Cole, Larry Miller and Merwin Brown.

Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by brining environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End Use Energy Efficiency
- Energy Innovations Small Grants
- Energy Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Critical Operating Constraints Forecasting – A Decision Support Tool is the draft final report for the Critical Operating Constraint Forecaster (COCF) project (contract number 500-02-005, work authorization number MR050) conducted by Electric Power Research Institute. The information from this project contributes to PIER's Transmission Research Program and Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916 654 5164.

Table of Contents

Abstract

In an interconnected electric power grid with limited transmission capacities, bottlenecks and low voltages occur when the power flows across the grid increase with load demands and diversity of electricity costs in different parts of the interconnection. Up to now, the technical capability to forecast when and where these bottlenecks and low voltage problems occur over the next 24 hours is not available. The mathematical problem had not been formulated to enable this forecasting to be done. Existing Energy Management Systems are not adequate for providing such a key decision support tool to grid operators like the California ISO. That decision support tool, if available, would enable the grid operator to predict when and where the critical operating constraints would occur, under the current assumption about the short term load forecast and the forecast of the hourly generation and external transactions. If certain critical operating constraints are forecasted to be violated in the near term horizon, then the grid operator needs the capability to seek and simulate a number of scenarios for generation and external transactions which would avoid the operating constraints. In the event no adjustments in generation and external transactions can avoid the operating constraint violations, then the grid operator needs the ability to determine how much load reduction would be needed to avoid a system blackout, and by what time such amount would be needed. This technical capability may also be called a Forward Looking State Estimator. The ability to look ahead to these potential constraints will provide extremely valuable lead time to the grid operator to ensure that the lowest cost options to mitigate the potential reliability problems can be taken. In the worst case when load reduction is needed, the practice of using such a decision support tool will enable regulators to verify that the grid operator has been prudent and has taken all reasonable precaution and mitigation to maintain system reliability and minimize customer interruptions.

This project has developed a methodology for such a decision support tool. It is called the Critical Operating Constraints Forecaster (COCF). The methodology was tested and demonstrated in a prototype, with participation and technical support by the California ISO. The functional specifications for a commercial software application using the research results were presented in a workshop on November 7, 2007 in Folsom, California. That report is available to the public. This final report summarizes the technical research and the results of the testing and demonstration.

The significance of this project is that a technically viable tool can be developed by commercial vendors of Energy Management Systems, using the functional specifications in a companion report of this project, which was presented and made available at the previously mentioned workshop. The mathematical equations behind the methodology were also detailed in that report. The knowledge for developing such a decision support tool is now in the public domain. The ability of this method to forecast and simulate where and when potential operating constraints will become critical is of tremendous value to grid operators under some situations. On a normal day, such critical conditions may not occur. However a tool like this can ascertain that this is indeed the fact for the current day, and provide situational awareness of a reassuring kind. When the conditions become more stressed, e.g., when there are transmission lines on scheduled or unscheduled outages, and when loads are increasing and imports or exports are also increasing, the ability to look through the rest of the day would become critically needed. Such an emergency operation tool would pay for itself with one such use.

Executive Summary

The technical challenge addressed by this research project was brought up by Jim Detmers, Vice President of Operation, California Independent System Operator (CAISO), in early 2005 as a potential need by the CAISO to maintain the reliability of the transmission-limited Southern California during the summer peak months. During peak load periods, when Southern California requires imported electricity to meet its load demand, such imports may come from the Pacific Northwest or from the Arizona/New Mexico/Nevada Southwest. Because the transmission capacities into Southern California are limited, and the power flows across the WECC interconnection result from power market operations, when additional contingencies occur, e.g., losing major transmission lines or power plants in Southern California, the situation may worsen to the point where lead time is needed to plan for load reduction. This is both a future situational awareness challenge and a need for a decision support tool to manage those situations.

Up to now, the technical capability to forecast when and where these bottlenecks and low voltage problems occur over the next 24 hours is not available. The mathematical problem had not been formulated to enable this forecasting to be done. Existing Energy Management Systems are not adequate for providing such a key decision support tool to grid operators like the California ISO. That decision support tool, if available, would enable the grid operator to predict when and where the critical operating constraints would occur, under the current assumption about the short term load forecast and the forecast of the hourly generation and external transactions. If certain critical operating constraints are forecasted to be violated in the near term horizon, then the grid operator needs the capability to seek and simulate a number of scenarios for generation and external transactions which would avoid the operating constraints. In the event no adjustments in generation and external transactions can avoid the operating constraint violations, then the grid operator needs the ability to determine how much load reduction would be needed to avoid a system blackout, and by what time such amount would be needed. This technical capability may also be called a Forward Looking State Estimator. The ability to look ahead to these potential constraints will provide extremely valuable lead time to the grid operator to ensure that the lowest cost options to mitigate the potential reliability problems can be taken. In the worst case when load reduction is needed, the practice of using such a decision support tool will enable regulators to verify that the grid operator has been prudent and has taken all reasonable precaution and mitigation to maintain system reliability and minimize customer interruptions.

The main objective of this report is to describe the main functionality of a software tool for performing the critical operating constraints forecasting (COCF) with simulation and decision support capabilities for the time periods of several to 24 hours ahead of the current day, running in continuous execution mode. This software tool will forecast the trajectories of these constraints and monitor them for their criticality during the day. The following types of operating constraints will be modeled.

- MVA loading of a list of critical lines or transformers, under a postulated contingency condition
- MW flow of a list of critical transmission paths under N-0 base case conditions
- Voltages at critical buses under N-0 base case conditions projected from recent historical data for indication of short term trends
- Voltages at critical buses under N-0 or postulated contingency conditions as affected by system load levels and simulated power transfer scenarios

The solution approach with this methodology includes:

- Develop trajectory forecasts of critical operating constraints
- Perform short term (minutes) trending of recent historical data on bus voltages
- Simulate different import scenarios
- If unavoidable, plan for load reduction in advance

This project has developed a methodology for such a decision support tool. The functional specifications for a commercial software application using the research results were presented in a workshop on November 7, 2007 in Folsom, California. That report is available to the public. This final report summarizes the technical research and the results of the testing and demonstration.

The methodology and the mathematical formulation of the problem were put to a test for the California ISO with a prototype code of the COCF, built on top of the EPRI CAR™ software (Community Activity Room). The test dates were set to start with a half day of preparation on May 30, 2006, following by a day of actual testing and demonstration on May 31, 2006. The location of the testing was at the control center of the California ISO.

The testing and the validation of the methodology were divided in two parts. The first part was to validate the COCF methodology for online grid operation, in a short term predictive mode. The prototype COCF was not connected to real-time data. Rather, data were taken manually or through manual transfer and processing of data files. The results were also obtained and stored for comparison afterwards. The COCF model was updated for the network topology of those two days, and using the Day-Ahead load and resource schedules for May 31, 2006. Only the path flow measurements were used to anchor the forwarding looking estimates of the operating constraints along a number of transmission paths. Snapshots and forecasts were conducted at 08:00, 10:00, 12:00 and 13:00. Afterwards, a reconstruction of the day was also created and used to compare the accuracy of the forecast with the actual flows.

The second part of the testing was to validate the COCF methodology when it is applied to a system planning study. California ISO had performed an internal study of the impact of the summer 2006 operating plan, focusing on the CAISO south. The extreme load condition (1 in to probability) analysis assuming the contingency of the largest transmission resource would require a load reduction in CAISO south. The second test involves a comparison of the COCF results under similar conditions to show that COCF would accurately determine the amount of load reduction.

In the afternoon of May 31, 2006, the current-day testing of COCF was completed and a demonstration and presentation of the results were made to the CAISO staff.

The results were very encouraging. The COCF was capable of predicting where and when the transmission grid would be congested if additional purchases were imported from the PNW versus the SW and in 50/50 mix. The CAISO system actually was running close to two operating limits during the day. These limits were COI and PATH 26. These limits were not exceeded in the real operation because of adjustments in the grid operation and the market. From the transmission operation side, the DC tie to the Pacific Northwest was used to take power directly from the PNW into southern California, thereby relieving the potential congestion on COI. The potential overloading of PATH 26 was relieved by adjustments in the internal generation distribution between northern and southern California. The COCF was useful in its predictive mode to indicate where the stresses would be located in the absence of these mitigation actions.

The comparison of the COCF forecasts with the actual flows on the three major paths showed the remarkable accuracy of the COCF. From one to seven hours ahead, the average accuracy of the COCF for the three major paths was within 10%, plus or minus. The worst inaccuracy was 24% five hours out for PATH 26. The difference was likely due to the mitigation effects. In other words, COCF could not know ahead of time what mitigation would be taken. However, it is anticipated that if sufficient details are added to the data, and increased details on the internal modeling of the CAISO network are included, more accuracy can be achieved by the COCF.

A second demonstration of the COCF was to compare the COCF to the CAISO's Summer 2006 assessment of southern California under the extreme conditions of "1 in 10" load forecast. This demonstration was done with two COCF models, one for summer 2006 with all lines in service and one with PDCI out of service. The results demonstrated the necessity to have load reduction in Southern California in order to withstand such extreme conditions. This demonstration shows that the COCF can also be used for planning studies.

The significance of this project is that a technically viable tool can be developed by commercial vendors of Energy Management Systems, using the functional specifications in a companion report of this project, which was presented and made available at the previously mentioned workshop. The mathematical equations behind the methodology were also detailed in that report. The knowledge for developing such a decision support tool is now in the public domain. The ability of this method to forecast and simulate where and when potential operating constraints will become critical is of tremendous value to grid operators under some situations. On a normal day, such critical conditions may not occur. However a tool like this can ascertain that this is indeed the fact for the current day, and provide situational awareness of a reassuring kind. When the conditions become more stressed, e.g., when there are transmission lines on scheduled or unscheduled outages, and when loads are increasing and imports or exports are also increasing, the ability to look through the rest of the day would become critically needed. Such an emergency operation tool would pay for itself with one such use.

The conclusion of this research project is that this methodology is mathematically sound and is supported and validated by the testing and demonstration described in this report.

It is recommended that commercial vendors of Energy Management Systems or other software companies study this methodology, review the final report and the Functional Specifications, and to consider developing a commercial software program that would be offered to potential customers.

1.0 Statement of the Problem

The technical challenge addressed by this research project was brought up by Jim Detmers, Vice President of Operation, California Independent System Operator (CAISO), in early 2005 as a potential need by the CAISO to maintain the reliability of the transmission-limited Southern California during the summer peak months. During peak load periods, when Southern California requires imported electricity to meet its load demand, such imports may come from the Pacific Northwest or from the Arizona/New Mexico/Nevada Southwest. Because the transmission capacities into Southern California are limited, and the power flows across the WECC interconnection result from power market operations, when additional contingencies occur, e.g., losing major transmission lines or power plants in Southern California, the situation may worsen to the point where lead time is needed to plan for load reduction. This is both a future situational awareness challenge and a need for a decision support tool to manage those situations.

In an interconnected electric power grid with limited transmission capacities, bottlenecks and low voltages occur when the power flows across the grid increase with load demands and diversity of electricity costs in different parts of the interconnection. With industry restructuring, the deregulation of the generation sector, and open transmission access by buyers and sellers of wholesale electricity, whether in a power market or not, the grid operators have to maintain system reliability without all the central controls that they previously had under a vertically-integrated power system. For example, they may not have direct control over the generation dispatch of all generators which serve the customer loads in the grid operator's footprint. They rely on the generators to produce the amount of electricity they have scheduled with the grid operators at the agreed-upon time. When load exceeds forecasted or committed resources, the grid operators must procure enough additional resources to meet the load. When transmission capacities are limited, they may prevent additional resources to be brought into a load center from certain areas.

Up to now, the technical capability to forecast when and where the bottlenecks and low voltage problems occur over the next 24 hours is not available. The mathematical problem had not been formulated to enable this forecasting to be done. Energy Management Systems (EMS) have evolved to some extent to provide more tools for the operators to operate in a market environment, e.g., in the scheduling of wholesale power transactions and in the application of security constrained optimal power flow to avoid violation of contingency criteria in the dispatch of generation and transactions. However, state estimation in combination with contingency analysis is a tool which has not kept up with the needs of the operators under certain operating conditions. It is a well-proven tool for analyzing the current snapshot of the power system. The state estimator derives from measurement data the best estimate of the bus voltages and bus angles of the whole transmission grid so that a fully-specified online power flow base case is established. Running contingency analysis on top of this state estimator power flow case will check whether the system will violate any operating constraints if a set of contingencies should happen independently. If the EMS also has a security-constrained optimal power flow, then it can reschedule generation and transactions in such a way that these contingency constraints will not be violated. However, if the operator wants to look ahead a few hours to check whether the grid will run into any operating constraints, the EMS does not provide a flexible tool for that type of analysis. The current approach is to set up a future snapshot case on which to run contingency analysis. The process of doing this when the future forecasts are uncertain is daunting, because of the amount of data preparation involved. Even if it can be done relatively painlessly, it does not allow the grid operator to easily run many what-if scenarios about the future demand and resource forecasts, especially when there are many options for where future resources may come from.

In other words, tools for projecting and simulating the resource and demand balance, riding through the rest of the current day are not available. When resource margins should fall short, for the peak period of the day, knowing in advance when and how severe various operating constraints would become limiting is tremendously valuable to the grid operators. Having sufficient lead time and knowing where these constraints would appear would enable the operators to activate operating procedures, arrange for additional resources such as out-of-the-market purchases, re-dispatch generators, or appeal for conservation and activate demand management, etc. In other words, this tool is a decision support tool for grid operators to manage the uncertain near future if the tool should indicate that at some time in the near future, some critical operating constraints may become limiting. When such conditions are indicated, the grid operator will use this tool to simulate different strategies of changing the locations of the imports and exports, and/or the need to initiate demand management when constraint violations are unavoidable with such drastic action.

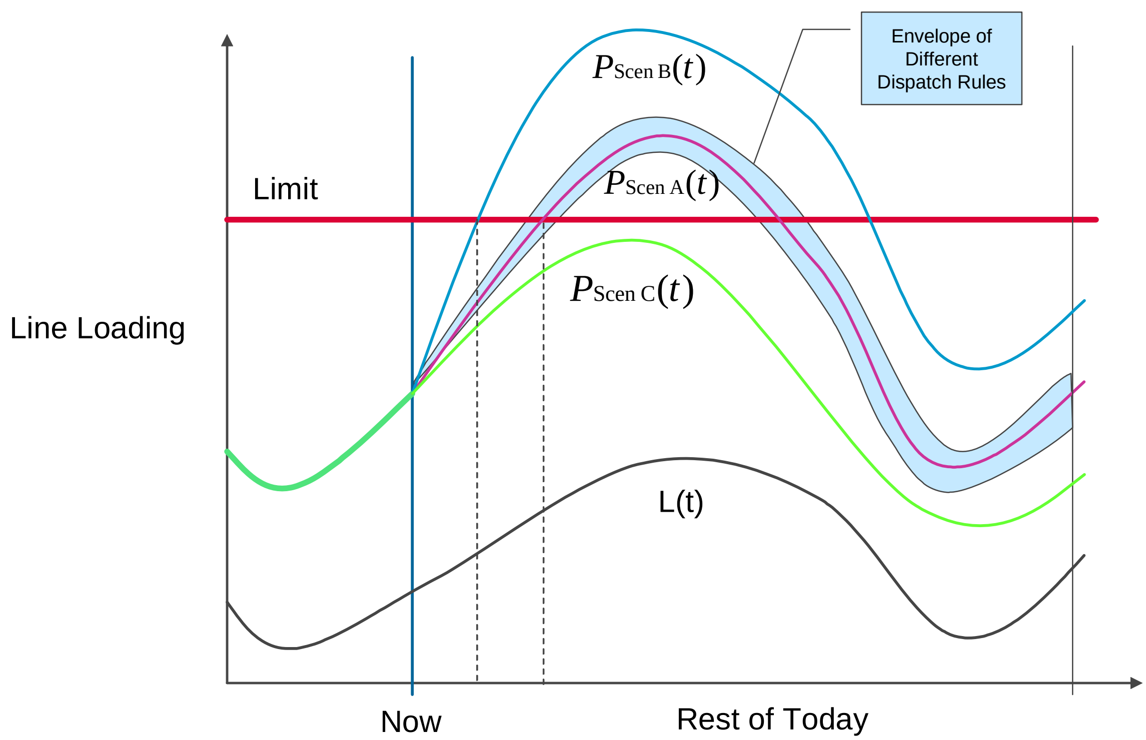


Figure 1.1 Forecasting When Line Loading May Exceed Limit

In Figure 1.1, the problem to be solved is to derive the trajectory of the forecasted line loading of a particular transmission path as a function of time, starting from now to the rest of today. It is expected that the forecast will be influenced by the load forecast curve, indicated by L(t). As the load increases, depending on the power flow distribution over the power grid, the line loading of a particular transmission path may increase also, and eventually decrease when the load decreases. As shown in Figure 1.1, it is illustrated that the line loading also depends on the scenario of external power purchases or sales, indicated by Scen A, Scen B, and Scen C. For each external power purchase or sale scenario, the line loading would also vary as the internal generation dispatch changes. Therefore, future line loading may be influenced or managed by changing the scenario of external transactions as well as internal generation dispatch. In other words, forecasting line loading involves making decision about external transactions and internal generation dispatch. The benefit of using a tool that can forecast the trajectories of various operating constraints, e.g., line loadings, is that the grid operator will be given early warning about the lead time before an operating constraint becomes critical.

1.1. Project Objectives and Approach

Existing Energy Management Systems are not adequate for providing a key decision support tool to grid operators like the California ISO. That decision support tool, if available, would enable the grid operator to predict when and where the critical operating constraints would occur, under the current assumption about the short term load forecast and the forecast of the hourly generation and external transactions. If certain critical operating constraints are forecasted to be violated in the near term horizon, then the grid operator needs the capability to seek and simulate a number of scenarios for generation and external transactions which would avoid the operating constraints. In the event no adjustments in generation and external transactions can avoid the operating constraint violations, then the grid operator needs the ability to determine how much load reduction would be needed to avoid a system blackout, and by what time such amount would be needed. This technical capability may also be called a Forward Looking State Estimator. The ability to look ahead to these potential constraints will provide extremely valuable lead time to the grid operator to ensure that the lowest cost options to mitigate the potential reliability problems can be taken. In the worst case when load reduction is needed, the practice of using such a decision support tool will enable regulators to verify that the grid operator has been prudent and has taken all reasonable precaution and mitigation to maintain system reliability and minimize customer interruptions.

The main objective of this report is to describe the main functionality of a software tool for performing the critical operating constraints forecasting (COCF) with simulation and decision support capabilities for the time periods of several to 24 hours ahead of the current day, running in continuous execution mode. This software tool will forecast the trajectories of these constraints and monitor them for their criticality during the day. The following types of operating constraints will be modeled.

- MVA loading of a list of critical lines or transformers, under a postulated contingency condition
- MW flow of a list of critical transmission paths under N-0 base case conditions
- Voltages at critical buses under N-0 base case conditions projected from recent historical data for indication of short term trends
- Voltages at critical buses under N-0 or postulated contingency conditions as affected by system load levels and simulated power transfer scenarios

The solution approach with this methodology includes:

- Develop trajectory forecasts of critical operating constraints
- Perform short term (minutes) trending of recent historical data on bus voltages
- Simulate different import scenarios
- If unavoidable, plan for load reduction in advance

1.2. Testing and Demonstration

In order to prove that this methodology works, this project included the work of developing a prototype of the COCF and used data supplied by the California ISO which modeled the entire WECC interconnection to develop the forecasting equations. This prototype was then applied in a test and demonstration which took place over a two-day period, from March 30, 2006 to March 31, 2006, at the CAISO control center.

The functional specifications for a commercial software application using the research results were presented in a workshop on November 7, 2007 in Folsom, California. That report is available to the public.

2.0 Technical Approach of Critical Operating Constraints Forecasting

2.1. COCF and Energy Management Systems

The functional block diagram which shows the overall functional blocks of the COCF and how they integrate with an existing Energy Management System (EMS) is shown in Figure 2.1.

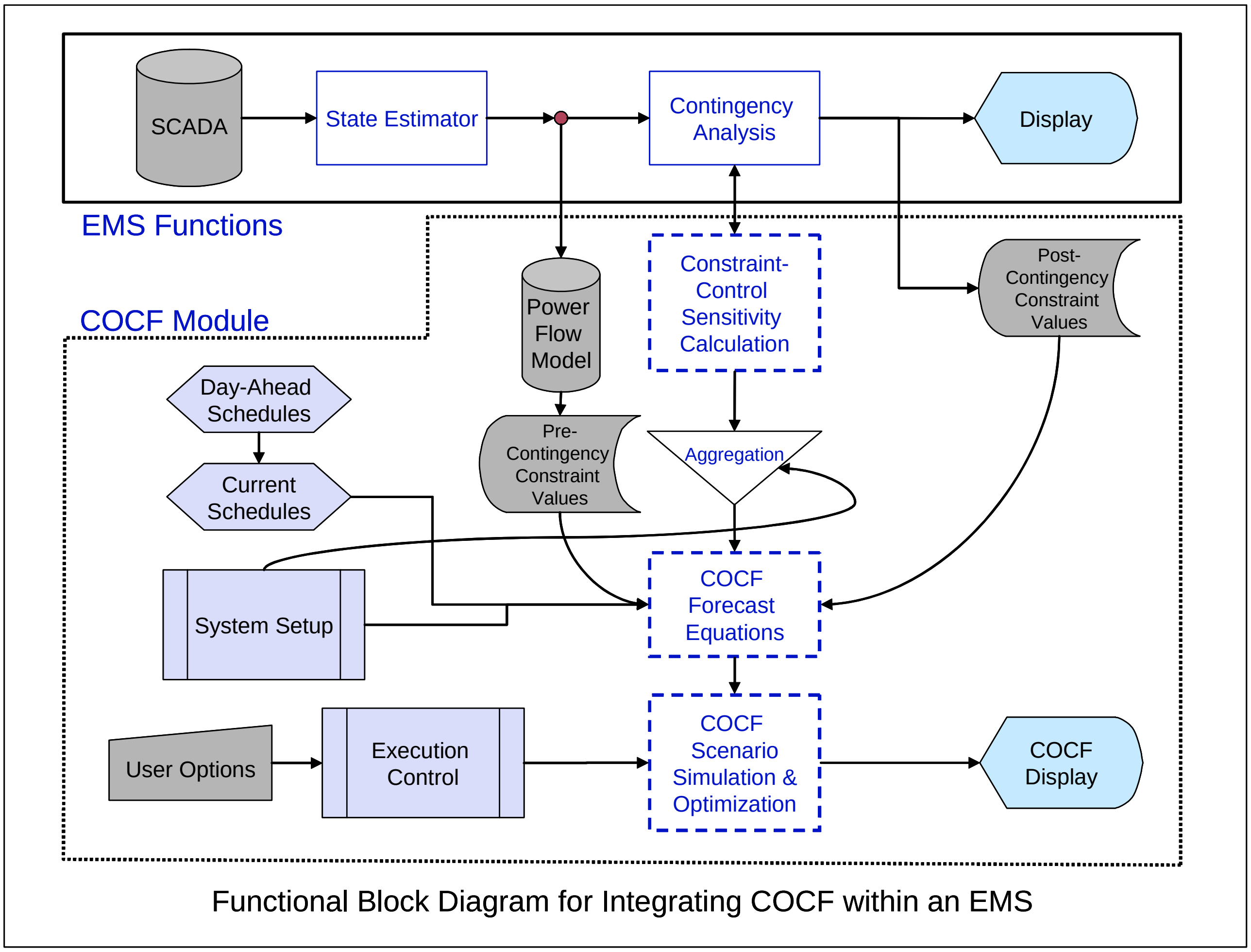


Figure 2.1 Functional Block Diagram for Integrating COCF within an EMS

The upper part of Figure 2.1 shows those EMS functions which would interface with the COCF. They consist of the SCADA data, the State Estimator, and the Contingency Analysis. The result of the State Estimator is the solution of the current power system model. This may be stored in a database, or may be output in the form of a power flow base case suitable for further use by other application programs, e.g., on-line voltage stability analysis, on-line dynamic stability analysis, etc. Typically, this output is in a text file compatible with commercial network analysis programs such as PSSE or PSLF. For the most efficient implementation of the COCF, a database is preferred over a text file. One consideration which should be remembered is that the State Estimator output is in the detailed topology that models breakers explicitly. For COCF, the details of the breakers are not necessary. For computational efficiency, an intermediate step of "Topology Processor" may be used to convert the breaker configurations into the bus-branch model that is used in system planning models.

For input to the COCF, the current values of the pre-contingency constraints are needed. These values are already contained in the output of the State Estimator, as part of the power flow model data. Also needed by the COCF are the current values of the post-contingency constraints. They are available from the output of the EMS's Contingency Analysis module. Typically they are shown in the output display as well as stored in the internal storage of the EMS. They need to be accessible by the COCF.

The block labeled "Constraint-Control Sensitivity Calculation" is a key function that is needed by the COCF. Most likely it is not already done in the details or in the form needed by the COCF. However, their computations are likely to come out of the Contingency Analysis module. The details of these calculations will be described later in this document. Where possible, it would be desirable to streamline these calculations for supporting both the Contingency Analysis module of the EMS and the COCF.

The COCF requires a setup step. That process is shown in the Figure 2.1 as "System Setup". The purpose of this setup is to define the boundaries that divide the internal system into its control or balancing areas, and define the makeup of the external regions. This function drives the "Aggregation" block in Figure 2.1 for combining the constraint-control sensitivities into aggregated variables that will be used by COCF for the simulation and forecasting.

Another major function of the COCF is the setup of the "COCF Forecast Equations". This is the result of the aggregation of the constraint-control sensitivities according to the system setup. With the COCF forecast equations setup efficiently this way, it will make it easy for the "COCF Scenario Simulation and Optimization" function to generate forecasts of the critical constraints with input from the user that defines the scenarios. The "Execution Control" block takes direction from the user input to execute the COCF forecast equations. The current data are taken from the "Current Schedules" of load, resources, and import/exports. The starting values of the critical constraints are taken from the EMS values of the pre- and post-contingency constraints. At the beginning of the day, the "Day-Ahead Schedules" are taken as the "Current Schedules" until the next time interval when more current data are available.

The results of the COCF Scenario Simulation and Optimization module will be displayed for the user to see and take decision for further scenario analysis.

2.2. COCF as a Decision Support Tool

Forecasting critical operating constraints does not provide a unique answer when the future is not completely specified deterministically. For example, actual load and resources may deviate from the day-ahead or current forecasts, due to many possible reasons. In a day when the forecasted load exceeds the day-ahead forecasted resources, as is possible during the peak load periods of a year, there is no single forecast for critical operating constraints. The answers would depend on assumptions about the unfolding values of load and resources. In this type of situation, the operator has to rely on recent events, e.g., from the previous days, and the best information available about the potential amount of resources available for the rest of the day. Within the internal system, sources such as additional reserve capacity, or plants returning from maintenance, or interruptible loads, are potential resources. It is especially important to assess the availability of external resources for purchases. Some of those purchases may come from the market operation, while other purchases may have to be procured on an emergency basis by the grid operator. In a tight supply and tight transmission constraint situation, even if some external resources are available, it may not be possible to bring them into the internal system if there are critical operating constraints. Therefore, there is a need for a decision support tool to simulate the feasibility of satisfying all critical operating constraints when the alternative sources are brought together to meet the remaining resource requirements for the rest of the day.

The COCF application includes the ability to perform fast simulation of alternative scenarios of meeting the load and resource balances for the rest of the day. For each scenario, the critical operating constraints must be simulated and forecasted quickly and those that cause violations must be visible to the user immediately. Fast response will enable the user to quickly revise the scenarios and observe how the critical operating constraints would be either alleviated or worsened, and whether new critical operating constraints will appear from other parts of the system.

A useful feature of the decision support tool is to solve for the feasible scenario so that all critical operating constraints will be satisfied. In the case where no feasible solution is possible, the decision support tool will provide the answer on the minimum amount of load curtailment that is needed in order to satisfy all critical operating constraints.

2.3. Technical Problem Formulation

The technical problem of the COCF is stated as follows. Given the hourly load forecast of the internal control areas or balancing areas for the rest of the day, the scheduled internal generation for the internal areas, the scheduled purchases and sales with the external regions, there may be a net deficit or net surplus of the load and resource balance. The assumption is then made by the user, in the decision support mode, to allocate among the external regions the percentage mix for the net deficit or net surplus, so that there is a balance of load and resources. For the user-specified mix of the external transactions, the COCF will project into the remaining hours of the day the critical operating constraints and sort them according to the user-specified criteria. Then the user selected critical operating constraints will be plotted graphically and also tabulated. If any critical operating constraint exceeds its limit during the study period, COCF will interpolate the graph to estimate the time when the constraint changes from within the limit to exceeding the limit. This information is then displayed to the user.

In a second mode of operation, COCF will search for a feasible solution consisting of the mix of external transactions which will result in all critical operating constraints staying within their limits for the remaining hours of the day. In the event, no feasible solution is found, COCF will solve for the minimum amount of load curtailment in any of the internal areas which will result in all critical operating constraints staying within their limits for the remaining hours of the day.

The internal area load data are forecast data and are input data. As new forecasts are available during the course of the day, they should be automatically brought into COCF from the source. The internal area generation schedule data are also input data. As new schedules are available during the course of the day, e.g., typically every hour if a market situation, they would be automatically brought into COCF from the source.

The mathematical basis for the COCF is the computation of the constraint-control sensitivities for pre-contingency constraints, and for post-contingency constraints. The algorithms for computing them are described in details in the Functional Specifications.

2.3.1. Forecasting Equations

The algorithm for projecting critical operating constraints into the near future is based on the recognition that the current State Estimator and its associated real-time Contingency Analysis module provide the best and most accurate estimate of the current value of the critical operating constraint. Starting from this measured or State-Estimated pre or post-contingency constraint value, the linearization approach for constraint-control sensitivities would provide a means to forecast how these constraints will change over time. The time element is linked mathematically into the forecasting equations through the load forecasts, and the generation and transaction forecasts (or assumptions). It is recognized that time makes a difference only because the load and resources will be different, unless there is also going to be change in network topology, in which case, the constraint-control sensitivities will reflect those changes.

Therefore, the algorithm for projecting the operating constraints is to link the change in the internal area load levels through the constraint-control sensitivities, by treating load levels as net changes in bus injections of MW at all load buses within an internal area.

For example, using MW power flows on a transmission line as an example of a critical constraint, the equation relating the power flow is given below:

$$P_{Line}(t) = P_{Line}(t0) + \begin{bmatrix} \frac{\partial F1}{\partial \delta} & \frac{\partial F1}{\partial V} \end{bmatrix} \begin{bmatrix} A1 \\ B1 \end{bmatrix} \Delta P(t) \qquad (2.1)$$

Among the set of all buses included in $\Delta P(t)$ are load buses in an internal balancing area. By setting each of these load buses to equal a fraction of the internal balancing area's total load, the vector $\Delta P(t)$ is broken down into the generation bus injections, and the load bus injections, grouped by the internal areas. With these simplications, the forecasting equation for MW line flows becomes as follows.

$$P_{Line}(t) = P_{Line}(t0) + [\mathrm{A}]\Delta P_G(t) + \phi_A \Delta P_{LATotal} + \phi_B \Delta P_{LBTotal} + \phi_C \Delta P_{LCTotal} \qquad (2.2)$$

Note that the $\Delta P_G(t)$ can be viewed as not only the generation in the internal balancing areas. It can be separated additionally into Net Exports or Net Imports from the external areas, e.g., Pacific Northwest, Arizona/New Mexico, etc., and their loads. In the COCF formulation, external regions' load levels are not modeled. Instead, only their transactions with the internal system are directed modeled. Also, it should be noted that there is a time dependence of $\Delta P_{LATotal}(t)$, etc., in Equation 2.2. Therefore the time variation of the constraint $P_{Line}(t)$ is driven by the time variation of the $\Delta P_G(t)$ and $\Delta P_{LATotal}(t)$, etc.

Without repeating the derivation, it can be noted that the similar mathematical approach will take the equation about bus voltage magnitude into a forecasting equation, as shown below.

$$V(t) = V(t0) + [B]\Delta P_G(t) + \eta_A \Delta P_{LATotal} + \eta_B \Delta P_{LBTotal} + \eta_C \Delta P_{LCTotal} \qquad (2.3)$$

2.3.2. Updating of Current Values of Operating Constraints

The forecasting equations require the current values of the operating constraints to be available and used as the starting value of the forecast time profile. This is indicated by $P_{Line}(t0)$ and $V(t0)$. Note that these contain both pre-contingency and post-contingency variables. Pre-contingency values are simply the current State Estimator or SCADA values for the N-0 network topology. The post-contingency values can only be obtained from the real-time Contingency Analysis application in the EMS based on the State Estimator power flow.

Establishing a direct linkage between COCF and the EMS/SCADA is essential in order for COCF to be accurate and dependable.

2.3.3. Critical Operating Constraint Forecasting Using Import /Export Scenarios

Given the equations for forecasting MW line flows and bus voltage magnitudes, it is possible to use these equations as the model for simulating the time profiles of any of these equations when the independent variables are changed by user input.

The following are independent variables that would be available for user input in the decision support tool.

- Percent mix of import or export to balance the load and resources from the list of external regions
    - In the simplest form, this will be a constant number applied from the current hour onward till the end of the study period.
    - If more detailed data is available, an hourly MW schedule may be entered by the user into the schedule for the respective external regions.
    - An automatic calculation could be done by COCF to check whether the manually entered schedule completely balance the load and resources. If not, the simple percent mix will be applied for the remaining amount.
- Changes to internal area generation schedules
    - In the simplest form, this will be a constant percentage for each internal area. This percentage may apply to the load forecast of each internal area. This may be used to simulate the effect of energy conservation appeal if it is used as an emergency procedure.
    - Alternatively, an hourly MW schedule may be entered by the user for each internal area. This could be used to simulate load curtailment by representing it as a fictitious generator. This feature can be very useful in verifying the effect of load curtailment on the critical operating constraints.

2.3.4. Screening of Critical Operating Constraints

After the user has specified the scenario to simulate, the COCF should respond to the user command and automatically rank all the modeled operating constraints time profiles according to the user-specified ranking criteria.

Four ranking schemes were tested:

- (Max – Min)
  The maximum value over the study period and the minimum value over the period study of each operating constraint are calculated. Then the difference (Max – Min) is used as the index for ranking all the operating constraints. The rationale for using this ranking scheme is to detect those constraints that are affected the most in terms of the magnitudes of the swings in line flow or voltage.
- (Max – Min) as % of Limit
  The maximum value over the study period and the minimum value over the period study of each operating constraint is calculated. Then the difference (Max – Min) is divided by the operating limit to give the percentage value. For example, if a post-contingency line flow limit is 2000 MW, the maximum value of the line flow over the study period is 1800 MW, the minimum value of the line flow is 1200

MW, then the (Max – Min) value is 600 MW, and the percent of limit is 600/2000 = 30%. If this is a voltage constraint, a similar percent can be calculated, although such a ranking may not be meaningful when compared with line flow limits. The rationale for using this ranking scheme is to detect those constraints that are affected the most in terms of the % swings in line flow or voltage relative to the limits.

- Max Viol
  The maximum value over the study period of each operating constraint is compared with its limit. If there is a violation of the limit, the maximum amount of violation, i.e., (maximum value – limit) over the study period is used as the ranking index. This is the most effective ranking scheme to detect any violations of operating constraints.
- Max Viol as % of Limit
  The maximum value over the study period of each operating constraint is compared with its limit. If there is a violation of the limit, the maximum amount of violation, i.e., (maximum value – limit) over the study period is divided by the limit and then used as the ranking index. This ranking scheme can be used to shed more light on the results of the Max Viol ranking scheme, so as to select those violations that are more significant when compared to their respective limits.

2.3.5. Output Results

Two types of output results of the COCF decision support tool could be available, a tabular output that provides the accurate numerical values of the operating constraints as forecasted over the study period, and a graphical output that shows these values in comparison with their limits.

- Tabular Output
  - Hourly values of the operating constraints over the study period
  - For the time period that is already past, the historical values as obtained from the EMS could be displayed.
  - The value of the limit could also be displayed for reference
  - If the operating constraint will exceed the limit during the study period, the time at which the critical constraint is violated will be prominently displayed, e.g., in a highlighted and red font. This value is an interpolated value because the forecast has an hourly resolution only. But a linear interpolation to estimate the crossing time is helpful for the user to see.
- Graphical Output
  - Not more than three operating constraints can be visualized effectively by a user. They could be displayed in a scale relative to their respective limits. Thus, the operating constraints could be first normalized by their respective limits before they are plotted. Therefore, a horizontal line at the vertical axis value of 1.0 would represent the operating limits of all the displayed operating constraints.
  - Each operating constraint will be labeled and colored. The graph would cover the entire study period, including the hours that have already passed.
  - When any of the operating constraints cross over the limit line, a vertical line would be dropped to the horizontal axis, marking the critical time of constraint violation. It would also be useful to show the time of crossing on the graph.

3.0 Testing and Demonstration

The methodology and the mathematical formulation of the problem were put to a test for the California ISO with a prototype code of the COCF, built on top of the EPRI CAR™ software (Community Activity Room). The test dates were set to start with a half day of preparation on May 30, 2006, following by a day of actual testing and demonstration on May 31, 2006. The location of the testing was at the control center of the California ISO.

The testing and the validation of the methodology were divided in two parts. The first part was to validate the COCF methodology for online grid operation, in a short term predictive mode. The prototype COCF was not connected to real-time data. Rather, data were taken manually or through manual transfer and processing of data files. The results were also obtained and stored for comparison afterwards. The second part of the testing was to validate the COCF methodology when it is applied to a system planning study. California ISO had performed an internal study of the impact of the summer 2006 operating plan, focusing on the CAISO south. The extreme load condition (1 in to probability) analysis assuming the contingency of the largest transmission resource would require a load reduction in CAISO south. The second test involves a comparison of the COCF results under similar conditions to show that COCF would accurately determine the amount of load reduction.

In the afternoon of May 31, 2006, the current-day testing of COCF was completed and a demonstration and presentation of the results were made to the CAISO staff.

3.1. Validating COCF for Grid Operation

For the first test, the COCF was exercised in a simulated online environment for grid operation. The necessary data were prepared a day ahead. This would be similar to what would happen after COCF is implemented in an actual online environment. Certain amount of data preparation and analysis takes place in the day before.

Then in the morning of the actual online testing, which started at 8 a.m. in the morning and ran through 2 p.m., the input data were updated at regular time intervals, and the forecasts for the rest of the day were made by running the COCF. The results were collected and compared. In the afternoon, the results of the tests were presented for discussion and validation by the CAISO staff.

3.1.1. Day-Ahead Preparation

The power flow case of the WECC interconnection was provided by the CAISO planning department earlier in the research project. This case modeled the 2006 normal peak load conditions, assuming no transmission facilities on maintenance outage. The research project had used that case to test the COCF methodology before this simulated online testing. For the day-ahead preparation, additional data were required to prepare the forecast.

Day-ahead load and resource forecasts

From the CAISO day-ahead market, data were collected from CAISO which projected the day-ahead load forecasts and resource forecasts.

For example, the hourly load forecast data for the three investor-owned utilities in California were as shown below:

Table 2.1 Day-Ahead Load Forecast for California ISO

Date	Hour	SDGE	SCE	PGAE	ISO
5/31/2006	1	1766	10542	10667	22975
5/31/2006	2	1686	10115	10478	22279
5/31/2006	3	1643	9876	10292	21811
5/31/2006	4	1646	9851	10291	21788
5/31/2006	5	1739	10250	10501	22490
5/31/2006	6	1909	10819	10869	23597
5/31/2006	7	2166	11812	11838	25816
5/31/2006	8	2370	12761	12349	27480
5/31/2006	9	2544	13716	12576	28836
5/31/2006	10	2703	14601	13031	30335
5/31/2006	11	2820	15371	13366	31557
5/31/2006	12	2886	15830	13446	32162
5/31/2006	13	2928	16351	13625	32904
5/31/2006	14	2957	16751	13821	33529
5/31/2006	15	2965	16933	13887	33785
5/31/2006	16	2944	16978	13939	33861
5/31/2006	17	2873	16624	13856	33353
5/31/2006	18	2768	15906	13632	32306
5/31/2006	19	2708	15165	13337	31210
5/31/2006	20	2834	15185	13229	31248
5/31/2006	21	2825	15227	13590	31642
5/31/2006	22	2554	14164	12903	29621
5/31/2006	23	2222	12762	11964	26948
5/31/2006	24	1938	11380	11138	24456

Likewise, the day-ahead generation schedules for CAISO were collected. The data are shown below.

Table 2.2 Day-Ahead Generation Forecast for California ISO

Date	Hour	SCE + SDGE	PGAE	ISO
5/31/2006	1	6365	8693	15058
5/31/2006	2	6240	8691	14931
5/31/2006	3	6281	8670	14950
5/31/2006	4	6295	8676	14971
5/31/2006	5	6367	8761	15128
5/31/2006	6	6382	9094	15477
5/31/2006	7	6959	11062	18020
5/31/2006	8	7557	12175	19732
5/31/2006	9	8208	12590	20797
5/31/2006	10	8876	12957	21833
5/31/2006	11	9262	13789	23051
5/31/2006	12	9595	14049	23644
5/31/2006	13	9864	14180	24044
5/31/2006	14	10121	14363	24484
5/31/2006	15	10213	14291	24504
5/31/2006	16	10238	14335	24574
5/31/2006	17	10224	14366	24590
5/31/2006	18	10222	14366	24587
5/31/2006	19	10008	14162	24170
5/31/2006	20	9888	14101	23989
5/31/2006	21	9813	13830	23643
5/31/2006	22	8498	13276	21774
5/31/2006	23	7104	11499	18603
5/31/2006	24	6859	10067	16925

Because the data for the generation schedule of SCE and SDGE were combined, in order to supply data to COCF, the total was split into SCE and SDGE according to the following rule, which was reasonable for that day. Split SCE and SDGE generation schedule by letting SCE be 70.7% and SDGE be 29.3% of the total, while ensuring that the SDGE maximum generation was 3000MW.

The following graphs show the shapes of the load curves and the CAISO generation resource schedules based on the day-ahead information.

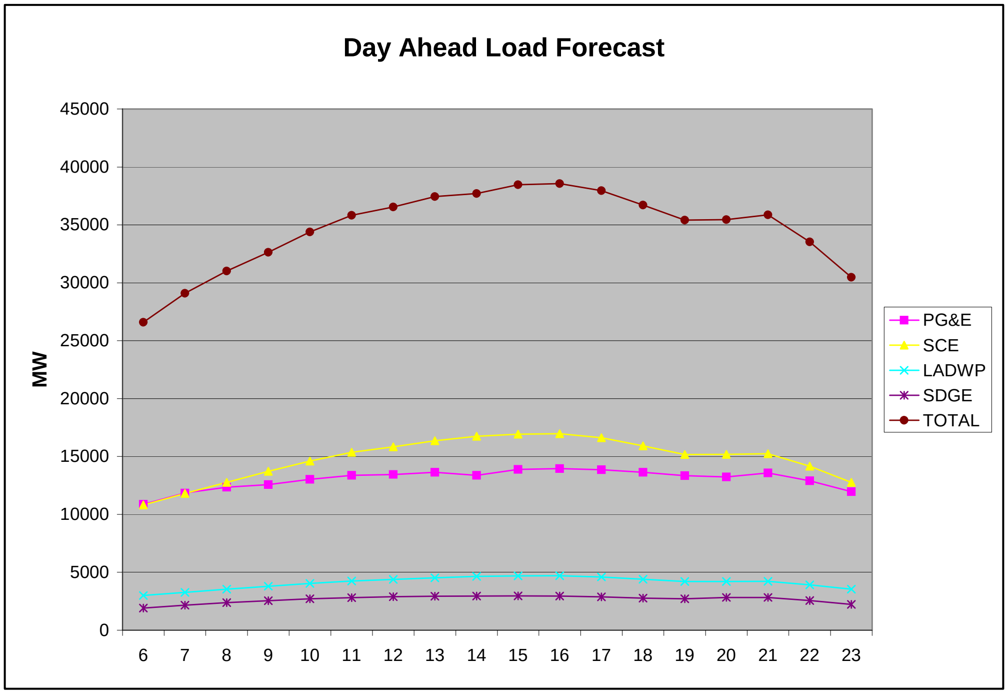


Figure 3.1 Day-ahead Load Forecasts for CAISO

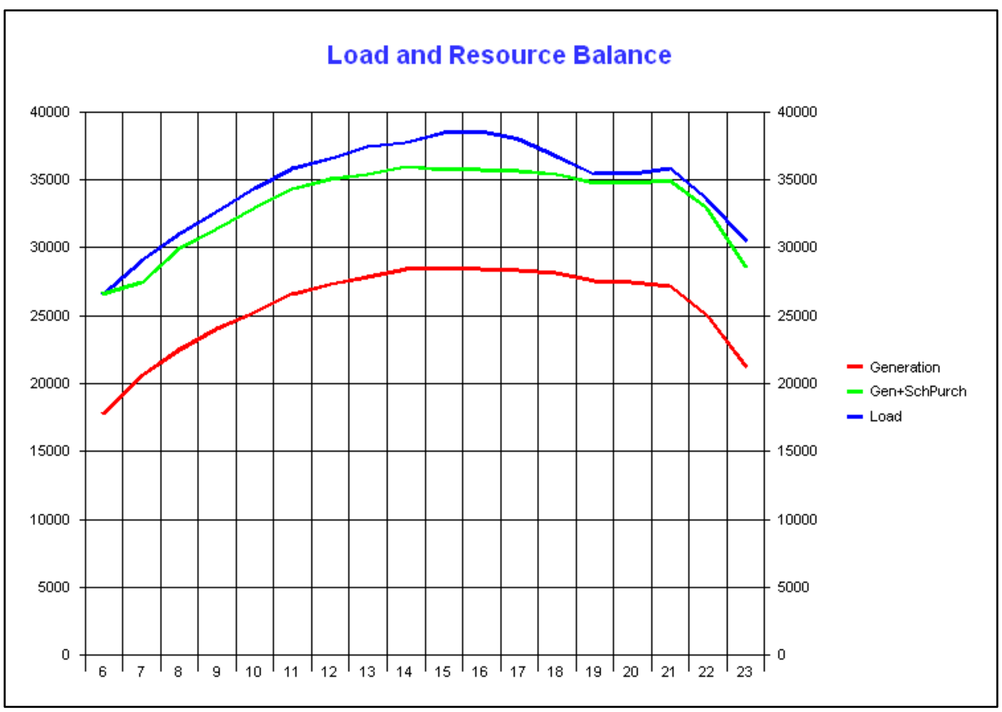


Figure 3.2 Day-ahead Load and Resource Balance for CAISO

In addition to the California ISO's internal area generation, there are external net interchange forecasts for the day-ahead market. These were contained in detailed spreadsheets and a lookup table was built to map the names of the purchases and sales into the geographical regions as shown in the following table.

Table 2.3 Day-Ahead Net Interchange Forecast for California ISO

Sum of Total net Interchange	Hour																							
Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ARIZONA	-2334	-2190	-2195	-2195	-2195	-2190	-2273	-2253	-2338	-2648	-2629	-2615	-2500	-2480	-2476	-2455	-2455	-2455	-2470	-2485	-2575	-2718	-2724	-2604
LADWP	-660	-590	-590	-590	-590	-590	-494	-790	-724	-627	-660	-765	-732	-792	-981	-888	-889	-822	-782	-691	-672	-828	-836	-874
MEXICO	60	-10	-10	-10	-10	-10	-6	2	52	-19	-11	43	78	80	81	113	103	57	66	102	178	181	113	30
NEVADA	-231	-231	-231	-231	-231	-286	-459	-459	-459	-459	-459	-459	-459	-459	-459	-459	-459	-459	-459	-404	-404	-404	-231	-231
PNW	-3584	-3470	-3345	-3334	-3359	-3579	-3776	-3793	-3683	-3735	-3781	-3777	-3751	-3752	-3756	-3759	-3768	-3776	-3768	-3698	-4033	-3993	-3787	-3758
SMUD	-645	-753	-786	-792	-783	-578	-463	-414	-639	-563	-485	-456	-461	-488	-405	-357	-337	-342	-346	-437	-522	-501	-352	-469
WALC	-187	-167	-164	-164	-170	-182	-383	-960	-852	-875	-873	-928	-836	-857	-623	-640	-626	-565	-543	-753	-742	-740	-608	-634
Grand Total	-7581	-7411	-7321	-7316	-7338	-7415	-7853	-8667	-8643	-8926	-8898	-8957	-8661	-8748	-8619	-8445	-8431	-8362	-8302	-8366	-8770	-9004	-8425	-8540

The COCF prototype was designed to accept two sources of external net imports. Therefore, to fit into these two groups, the net interchanges from Table 2.3 were aggregated into two groups:

- PNW
- SW (Arizona about 89%, Nevada about 11%)

The small amount of net interchanges with Mexico was ignored in the COCF. Net interchange with SMUD was rolled into the PG&E area.

To model LADWP, the peak load forecast for the day ahead was 4700 MW with its maximum generatioin of 3700 MW and import of1000 MW. The LADWP load curve was assumed to have the same shape as SCE.

As a result of these modeling assumptions, the base case for the day ahead was set up.

Table 2.4 Day-Ahead Load and Resource Schedules as Input to COCF

Load	**Maximum**	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
PG&E	13939	10869	11838	12349	12576	13031	13366	13446	13625	13366	13887	13939	13856	13632	13337	13229	13590	12903	11964
SCE	16978	10819	11812	12761	13716	14601	15371	15830	16351	16751	16933	16978	16624	15906	15165	15185	15227	14164	12762
LADWP	4700	2995	3270	3533	3797	4042	4255	4382	4526	4637	4688	4700	4602	4403	4198	4204	4215	3921	3533
SDGE	2965	1909	2166	2370	2544	2703	2820	2886	2928	2957	2965	2944	2873	2768	2708	2834	2825	2554	2222
Total	38561	26592	29086	31013	32633	34377	35812	36544	37430	37711	38473	38561	37955	36709	35408	35452	35857	33542	30481
Gen	**Maximum**	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
PG&E	14851	9672	11525	12589	13229	13520	14274	14505	14641	14851	14696	14692	14703	14708	14508	14538	14352	13777	11851
SCE	7238	4512	4920	5343	5803	6275	6548	6783	6973	7155	7220	7238	7228	7226	7076	6991	6938	6008	5022
LADWP	3500	1795	2070	2333	2597	2842	3055	3182	3326	3437	3488	3500	3402	3203	2998	3004	3015	2721	2333
SDGE	3000	1870	2039	2214	2405	2601	2714	2812	2890	2966	2993	3000	2996	2995	2933	2897	2876	2490	2082
Total	28431	17850	20553	22479	24033	25238	26591	27282	27831	28409	28397	28431	28329	28132	27514	27430	27180	24996	21288
Net Def	**Maximum**	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Total	10131	8742	8533	8534	8600	9139	9221	9262	9599	9302	10076	10131	9626	8577	7894	8022	8677	8546	9193
Sch Purch	**Maximum**	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
NW	4033	3579	3776	3793	3683	3735	3781	3777	3751	3752	3756	3759	3768	3776	3768	3698	4033	3993	3787
SE	4002	2658	3115	3672	3649	3982	3961	4002	3795	3796	3558	3554	3540	3479	3472	3642	3721	3862	3563
Total	7855	6237	6891	7465	7332	7717	7742	7779	7546	7548	7314	7313	7308	7255	7240	7340	7754	7855	7350
Rem Def	**Maximum**	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Total	2817	2505	1642	1069	1268	1422	1479	1483	2053	1754	2762	2817	2318	1322	654	682	923	691	1843

These data, after they were entered through computer file importing into the COCF, are shown in the following screen shot of the COCF input screen.

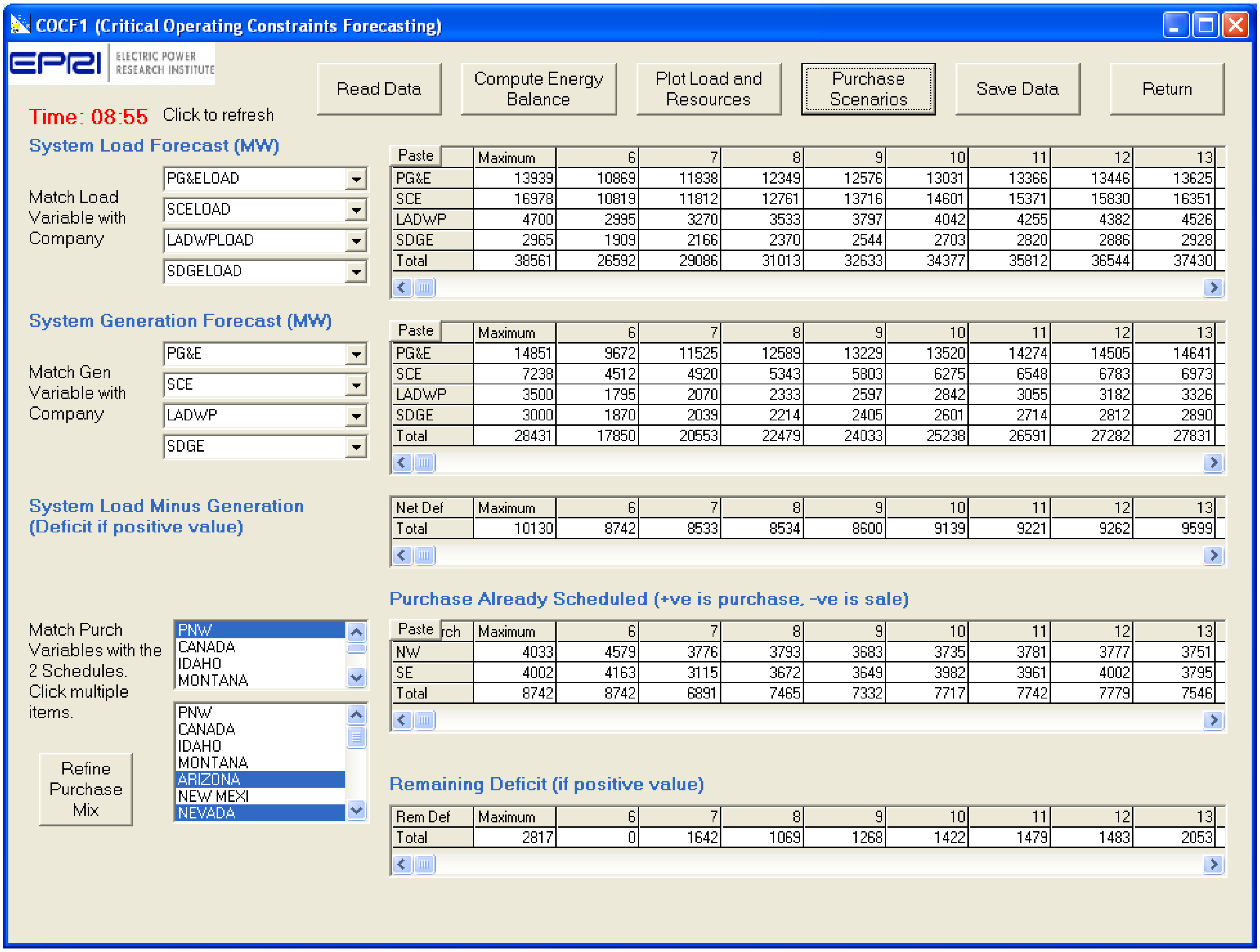


Figure 3.3 COCF Input Data Screen with Day-Ahead Forecasts

Identification of Major Network Topology Changes

Because network topology has a major effect on power flow distributions in an interconnected power grid, the accuracy of the COCF forecast depends on the accuracy of the network topology. Discussion was held with the CAISO system operators the day ahead about the status of the WECC transmission grid. It was pointed out that there was a major line outage, line Round Mountain – Table Mountain #2 (500KV) was on outage resulting in the COI (California Oregon Interface) limit being derated to 2750 MW from 4800 MW. That condition was expected to continue into the following day.

Therefore, it was vital that the summer 2006 power flow base case be updated to remove that line from the data, and the constraints-control sensitivity coefficients be recomputed to supply an updated set of forecasting equations for the COCF. This was done in a run of the EPRI TRACE software, which produced the set of constraints-control sensitivities, which were then converted into the forecasting equations for COCF. These computation steps were performed in the afternoon, and the updated COCF model was ready to be tested for the following day.

Selection of Major Paths for Testing

The COCF model contained 735 constraints. Many constraints (506) were of the N-0 type, i.e., normal loading of transmission lines without postulation of contingencies. Out of these 506 constraints, fourteen were voltage constraints, distributed inside California. The other constraints (229) were N-1 contingency constraints. Out of them, seventeen were post-contingency voltage constraints.

For comparison with the actual operation during the following day, it was important to familiarize with the major paths to be monitored and forecasted and also with the stations whose voltage magnitudes were to be forecasted. Also, because post-contingency line flows and voltages would not be readily available for the test team without interfering with the actual grid operation and demanding additional contingency analysis studies, it was decided that only N-0 constraints would be forecasted and compared with actual system operation. These data would be readily available by reading off the display boards in the control center. Seven transmission MW flows were chosen for the testing. They are:

- COI (California Oregion Interface)
- PATH 26
- EAST OF RIVER
- VICTORVILLE – LUGO
- LUGO – MIRA LOMA (S. of LUGO)
- PALO VERDE - DEVERS
- HASSYAMP – N. GILA
- IMPERIAL VALLEY - MIGUEL

3.1.2. Simulated Current-Day Online Application

The simulated online testing began on May 31, 2006 at 8:00 a.m. Actual MW flows were read off the control center display board. The COCF model was run using these measured values, and the forecasts for three different scenarios were made.

- Remaining Deficits Supplied by 50%/50% from PNW (Pacific Northwest) and AZ (Arizona)
- Remaining Deficits Supplied by 100% from PNW
- Remaining Deficits Supplied by 100% from AZ

First Snapshot at 08:00

The following graphs were produced by the COCF for each of these three scenarios.

Three major transmission paths were most interesting to compare. They are COI, PATH 26 and EOR (East of River).

What is interesting to note is that the two potential critical constraints during that day were COI and PATH 26. When the remaining power requirements were all to come from the PNW, then both COI and Path 26 would exceed their limits during the day (see Figures 3.4 and 3.6). If the remaining power requirements were all to come from AZ, then both COI and PATH 26 will likely get through the day without any significant overloads (see Figure 3.5).

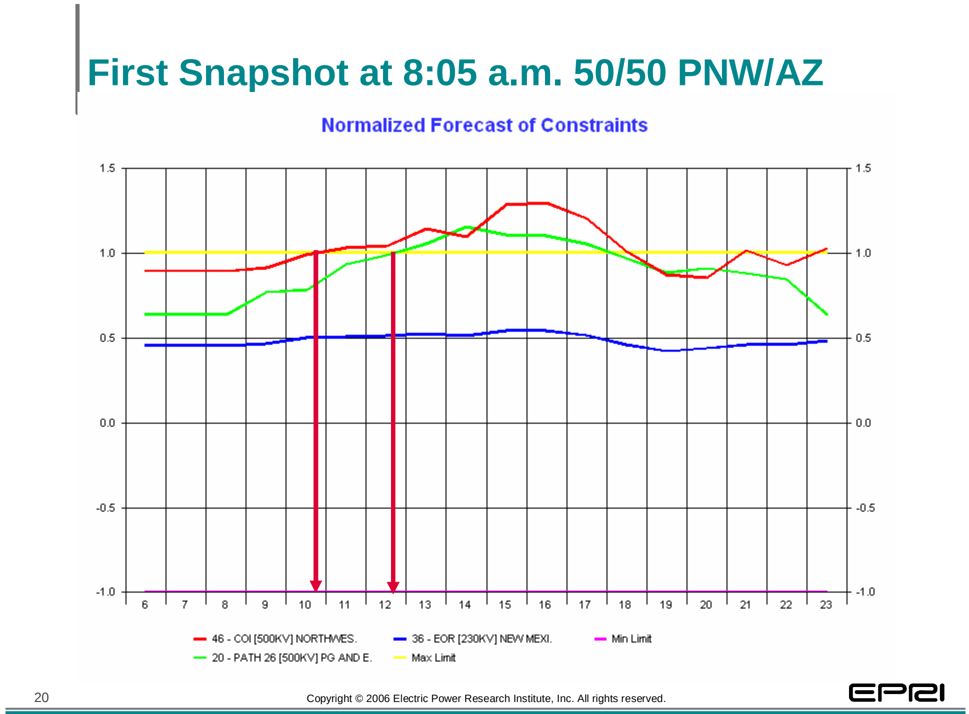


Figure 3.4 Forecast Made at 08:00 with 08:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

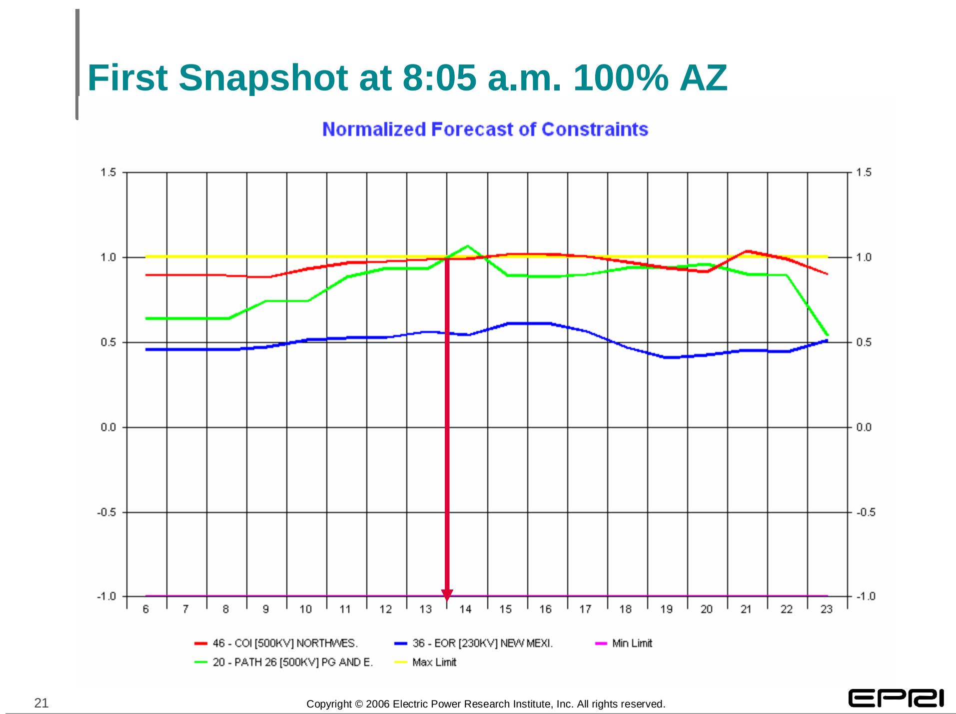
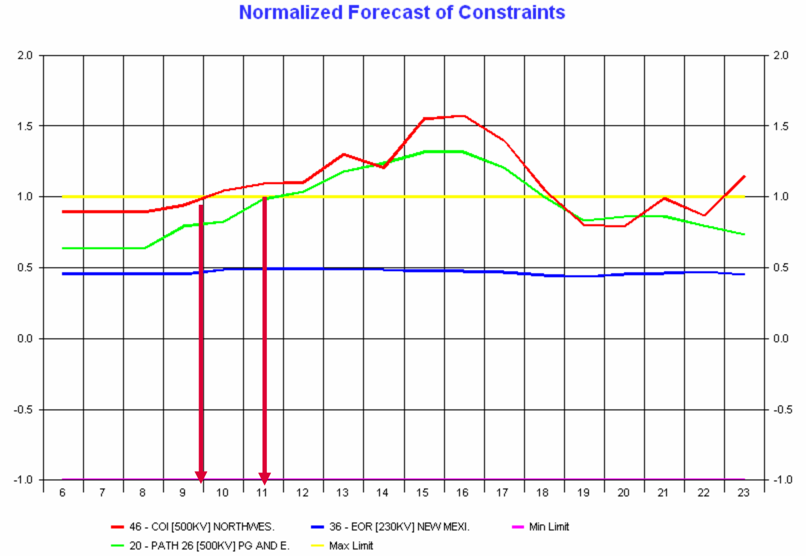


Figure 3.5 Forecast Made at 08:00 with 08:00 Flow Measurements and Day-Ahead Data, assuming 100% AZ

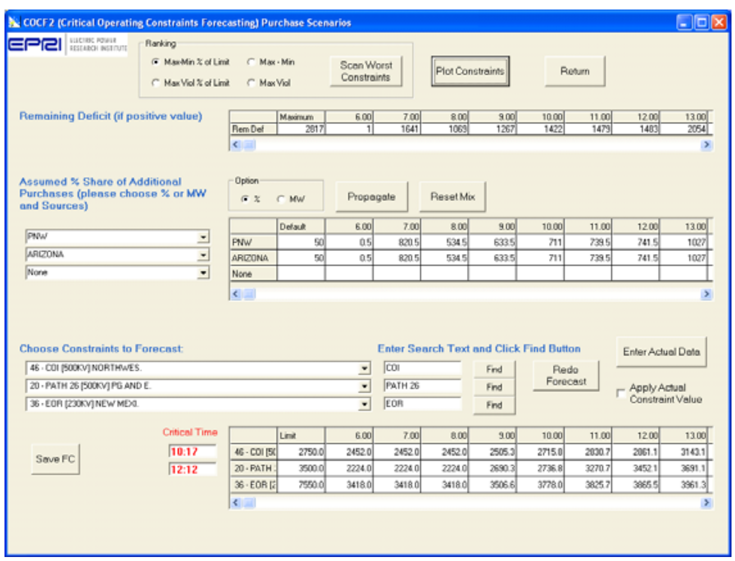
First Snapshot at 8:05 a.m. 100% PNW



22

Figure 3.6 Forecast Made at 08:00 with 08:00 Flow Measurements and Day-Ahead Data, assuming 100% PNW

First Snapshot at 8:05 a.m. 50/50 PNW/AZ



23

Figure 3.7 Numerical Forecast Made at 08:00 with 08:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

In addition to the three major transmission paths that were potentially critical on that day, three other transmission paths were also forecast and monitored. They are:

- LUGO – VICTORVL (500KV)
- LUGO – MIRALOMA (500KV)
- PALO VERDE –DEVERS (500KV)
- HASSYAMP – N. GILA (500KV)
- IMPERIAL VALLEY – MIGUEL (500KV)

Their flows were not expected to be sensitive to the conditions forecasted for that day, as shown in Figures 3.8 and 3.9. But they did show that their flows would decrease starting with the late afternoon.

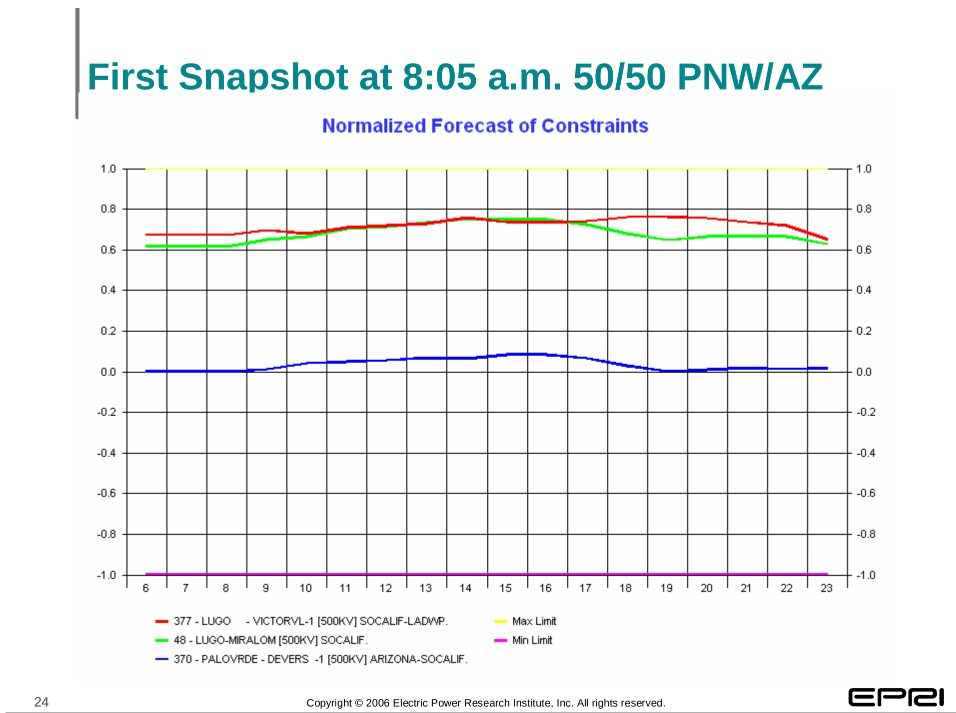


Figure 3.8 Forecast of Other Line Flows Made at 08:00 with 08:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

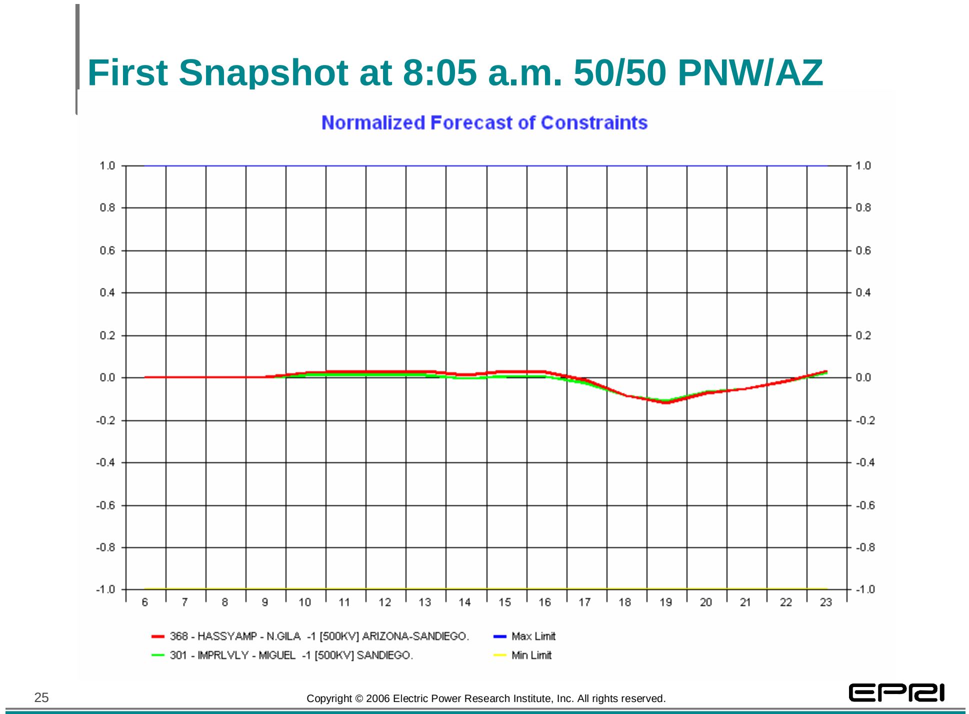


Figure 3.9 Forecast of Other Line Flows Made at 08:00 with 08:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

As a test of the COCF's ability to forecast voltage magnitudes, voltages at three stations in Southern California were forecasted. Figure 3.10 shows how these voltages would dip during the peak period of the day and then recover in the late afternoon. The low voltage of 0.8 P.U. would be an unacceptable voltage level if it was to come about. However, before the voltage would drop to such levels, the system would have adjusted by generating more reactive power from generators that would come online, and additional static reactive compensation would also be put on line, e.g., capacitors. What the COCF forecasting equations do is to mathematically relate the phenomenon of P-V effect. This means that the partial effect of MW (P variable) loading on the system on dragging down the voltage is represented by the COCF. The other partial effect, which is the effect of Q on V, by the reactive resources (reactive generation or reactive compensation) on the system voltages, is not modeled by the COCF. Therefore, the COCF forecast is pessimistic, but would be accurate if the system runs out of reactive resources. Thus the COCF is capable of providing useful warning about potential voltage problems, but it is necessary to supplement that warning with information which monitors how much reactive reserve is still available in the system near the locations where the voltage problem is predicted.

The subjet of voltage prediction and voltage stability analysis and their relationship to reactive power management is an important research area. It is not in the scope of this research project. However, much research work has been done by EPRI in this subject area called Interregional Reactive Power Management.

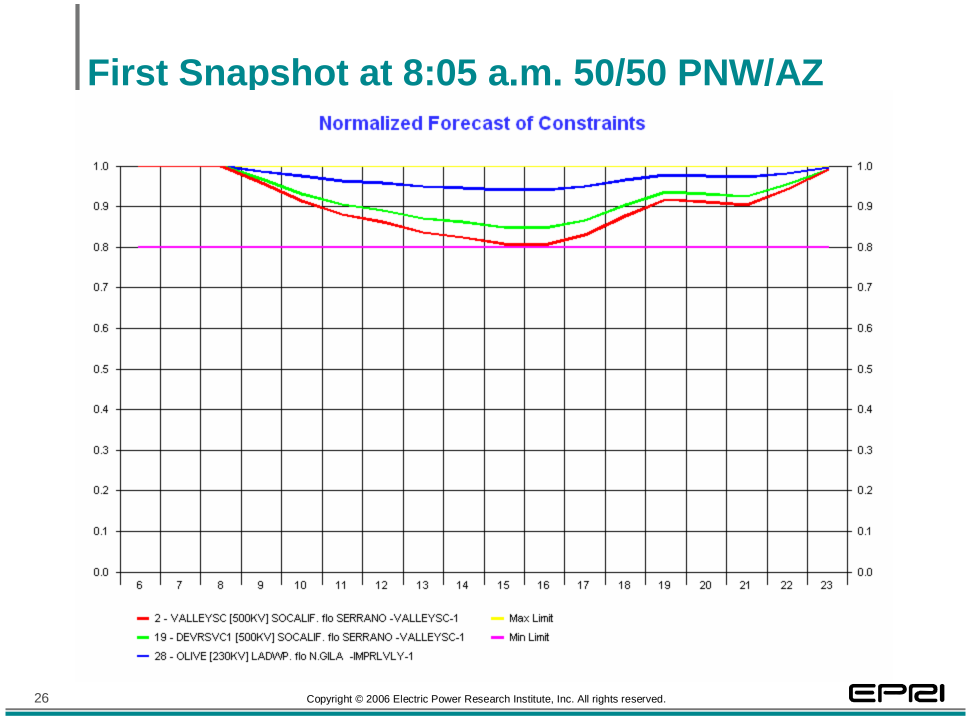


Figure 3.10 Forecast Voltages Made at 08:00 with 08:00 Voltage Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

Second Snapshot at 10:00

The second forecast using COCF was made at 10:00. Measurement data were taken off the control center display board, and the COCF model was run. The following results were obtained from COCF.

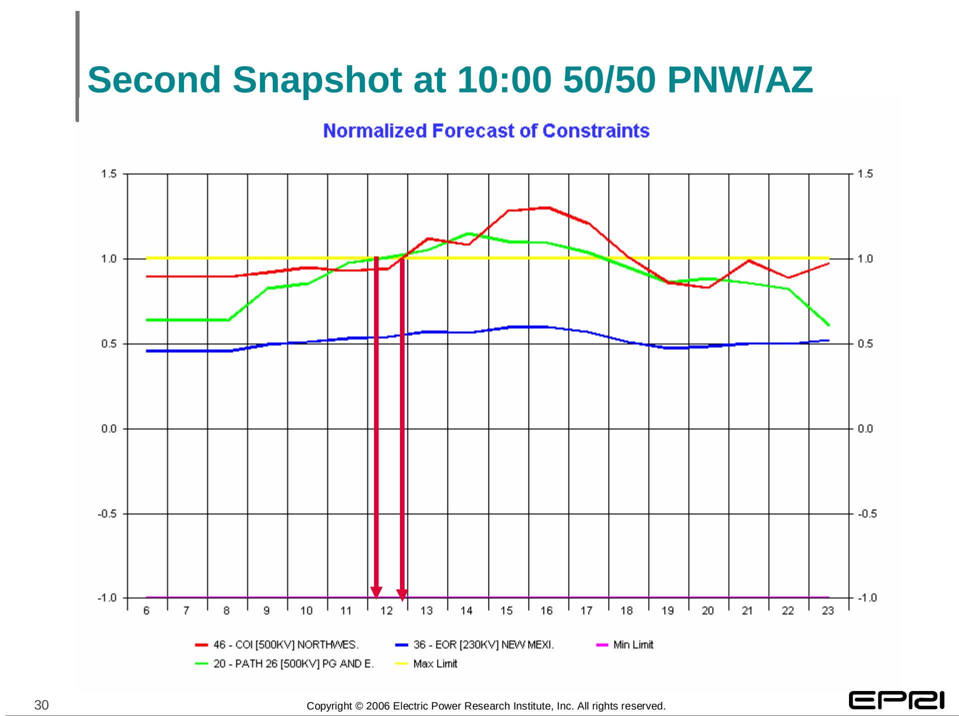


Figure 3.11 Forecast Made at 10:00 with 10:00 and Previous Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

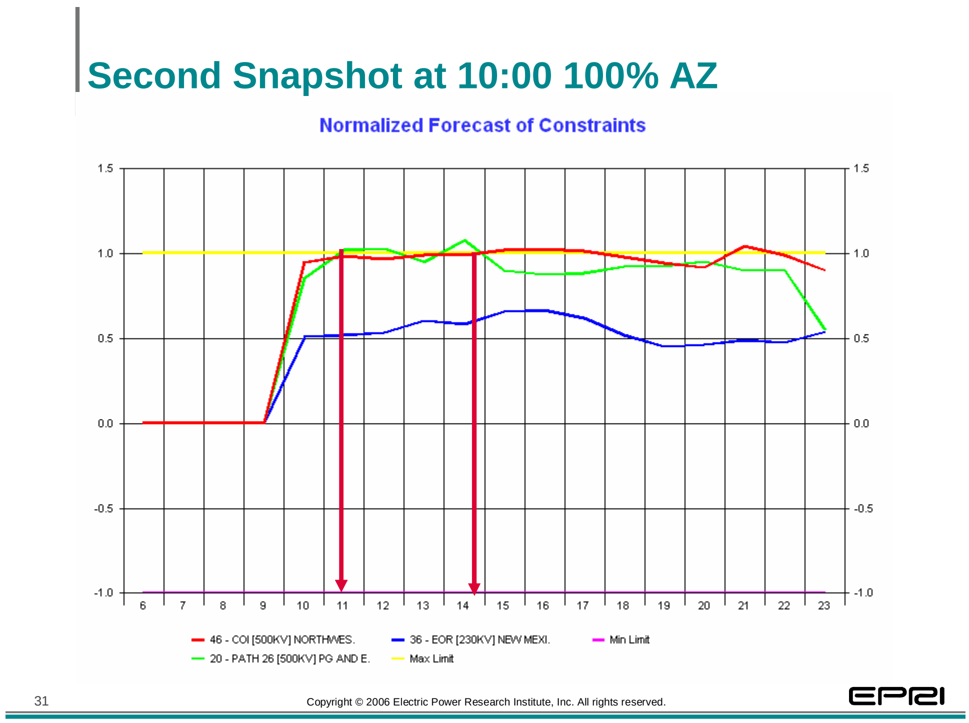


Figure 3.12 Forecast Made at 10:00 with 10:00 Flow Measurements and Day-Ahead Data, assuming 100% AZ

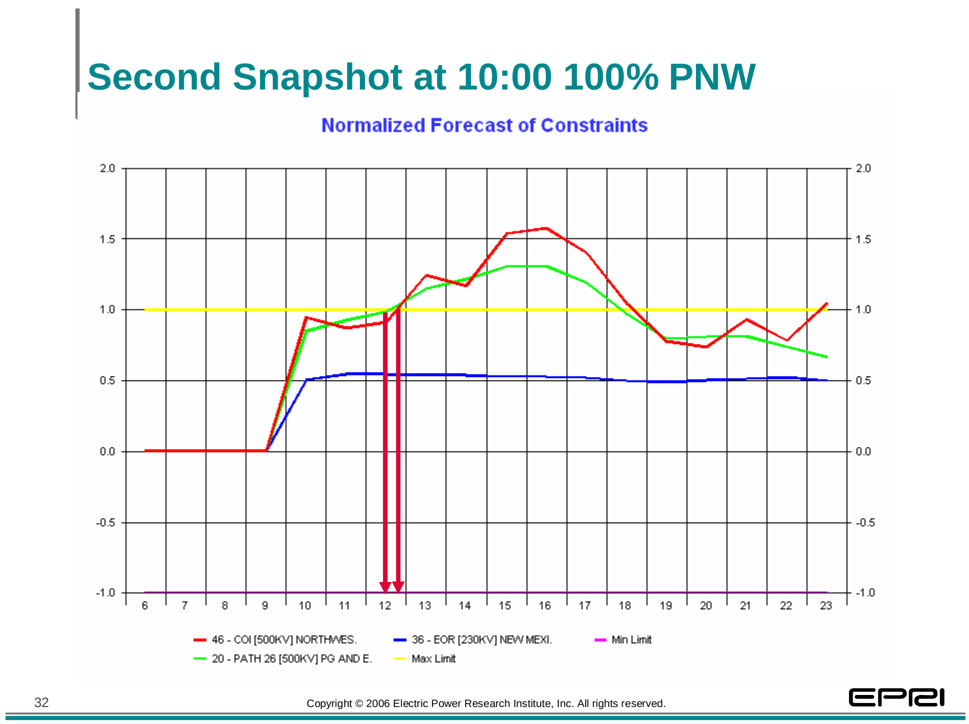


Figure 3.13 Forecast Made at 10:00 with 10:00 Flow Measurements and Day-Ahead Data, assuming 100% PNW

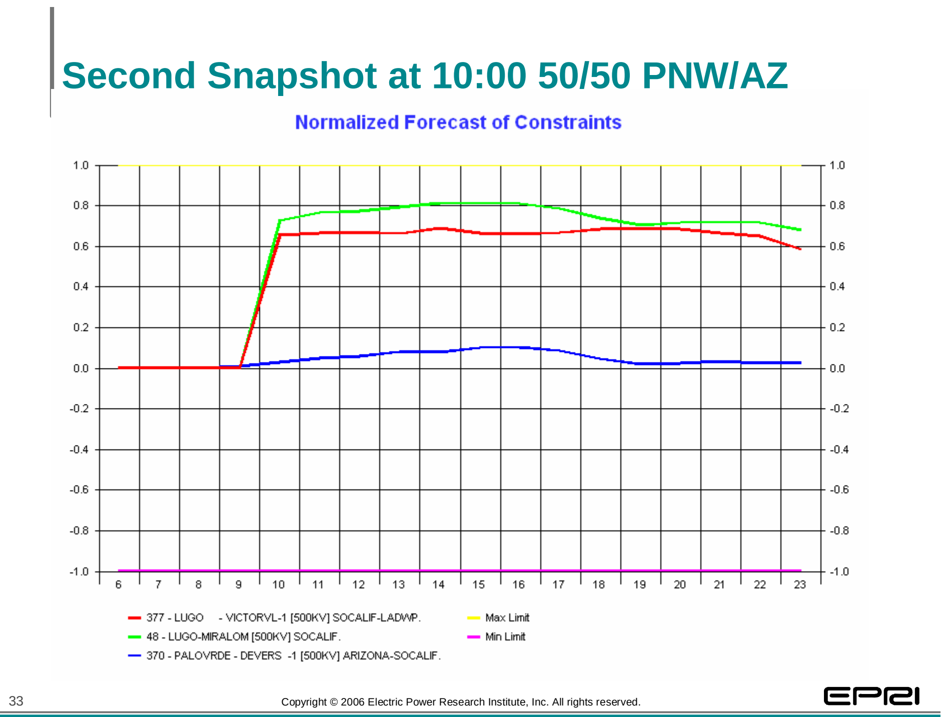


Figure 3.14 Forecast of Other Line Flows Made at 10:00 with 10:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

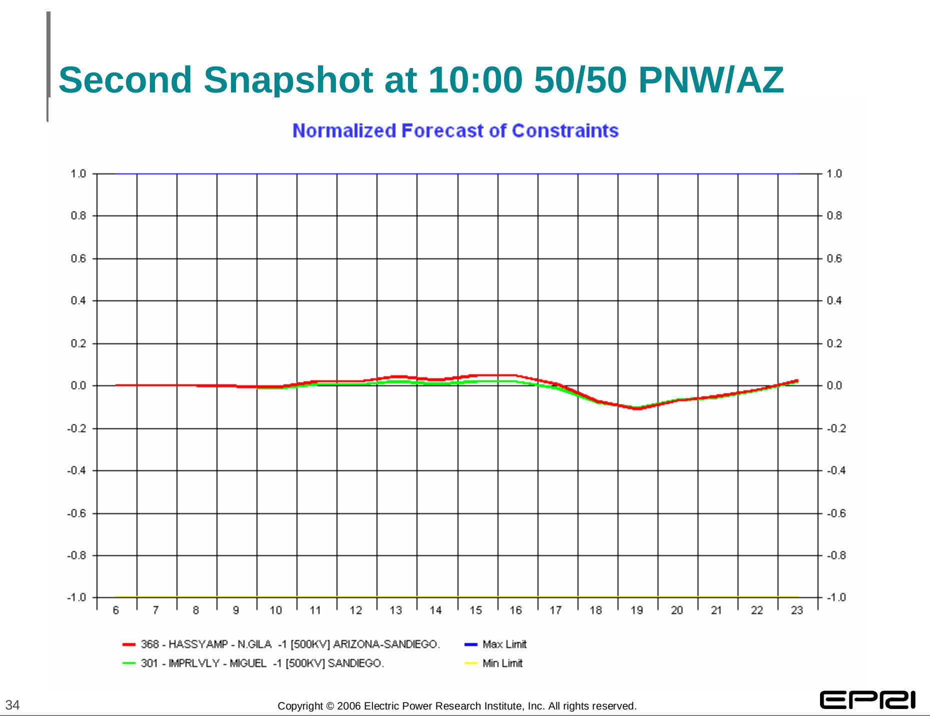


Figure 3.15 Forecast of Other Line Flows Made at 10:00 with 10:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

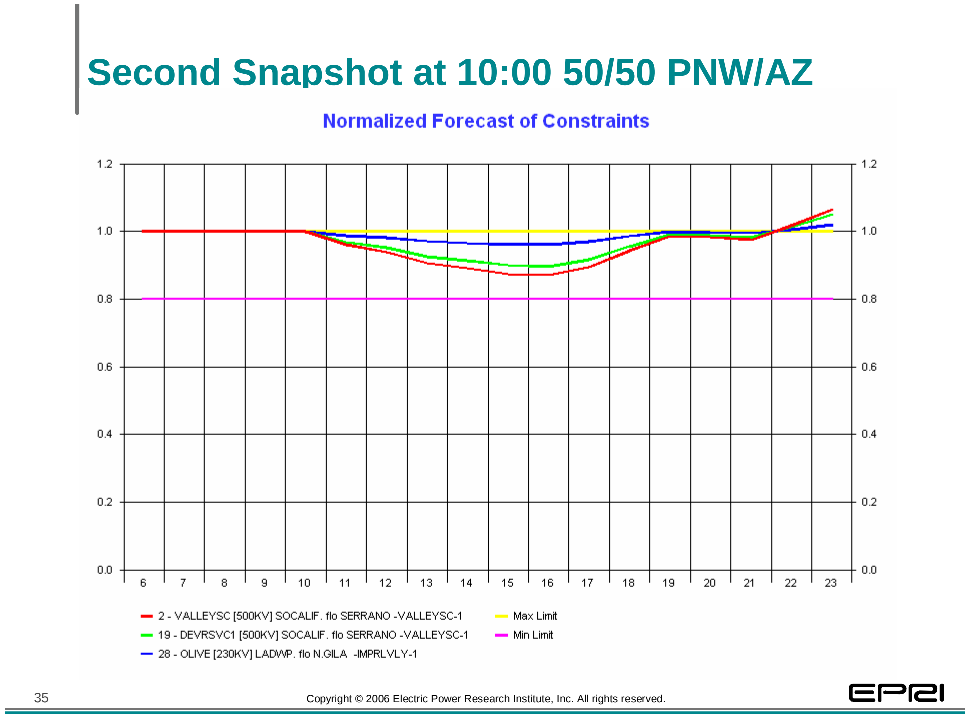


Figure 3.16 Forecast Voltages Made at 10:00 with 10:00 Voltage Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

What is noteworthy about the second snapshot and forecast was that the same concern about COI and PATH 26 existed but the time when they would become critical was being pushed further into the future. This meant that there were already adjustments in the market dispatch to reduce the loading of these paths. As the system load increased everywhere, additional internal generation within California started to pick up the load increases, and reduced the future loading on these transmission paths. It was noted in the historical summary of the final hour-ahead schedules that more generation did come out from SMUD on that day than were forecasted in the day-ahead schedule. Another factor was the DC tie to the Pacific Northwest. Given the known deration of the COI, the setting of the DC was used by operators to relieve the loading on the COI.

Third Snapshot at 12:00

The third forecast using COCF was made at 12:00. Measurement data were taken off the control center display board, and the COCF model was run. The following results were obtained from COCF.

The situations were getting a bit tighter along COI and PATH 26. They were both near their limits. If more external purchases were to come from the PNW, they would likely exceed the limits within one hour. However, it was noted that the congestion of these paths forecasted for 12:00 at the time of 10:00 did not materialize as previously explained. So it appeared that the market in the Hour Ahead markets was adjusting to the congestion in the system and only the feasible amount of power that could get through these paths was allowed by the market dispatch. In other words, the COCF continued to give a good indicator of the potential congestion paths of the grid, and the market continued to be operated without overloading those paths.

As for the system voltage concern, by this time, it appeared that the voltages in Southern California were normal and the voltage could drop slightly during the late afternoon. But they will recover after that and may in fact present some reactive power management in the opposite direction in the late evening (See Figure 3.22).

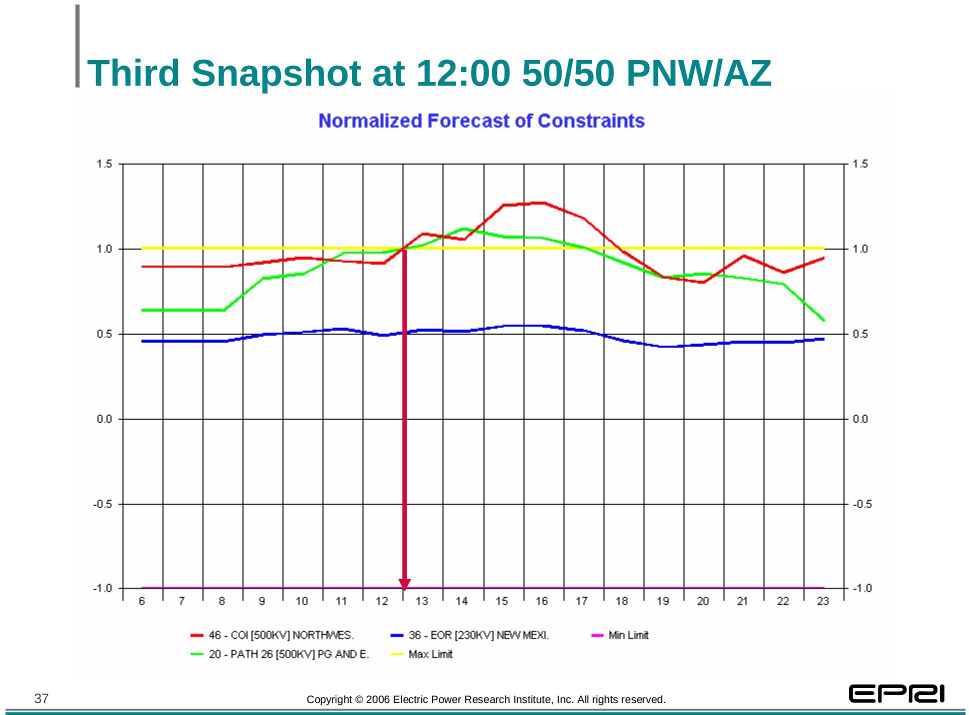


Figure 3.17 Forecast Made at 12:00 with 12:00 and Previous Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

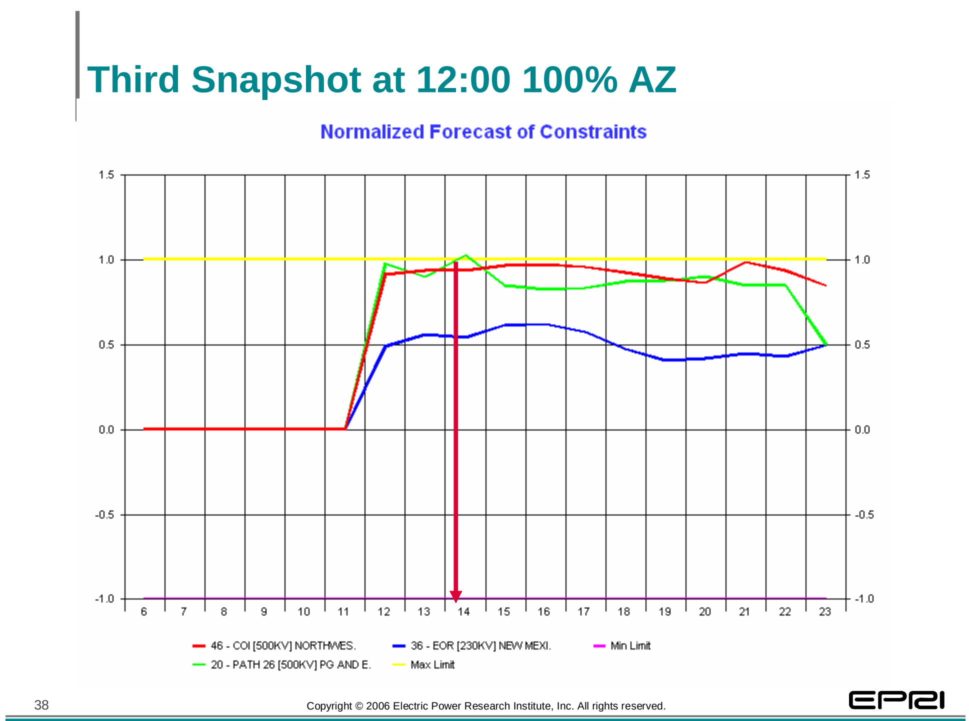


Figure 3.18 Forecast Made at 12:00 with 12:00 Flow Measurements and Day-Ahead Data, assuming 100% AZ

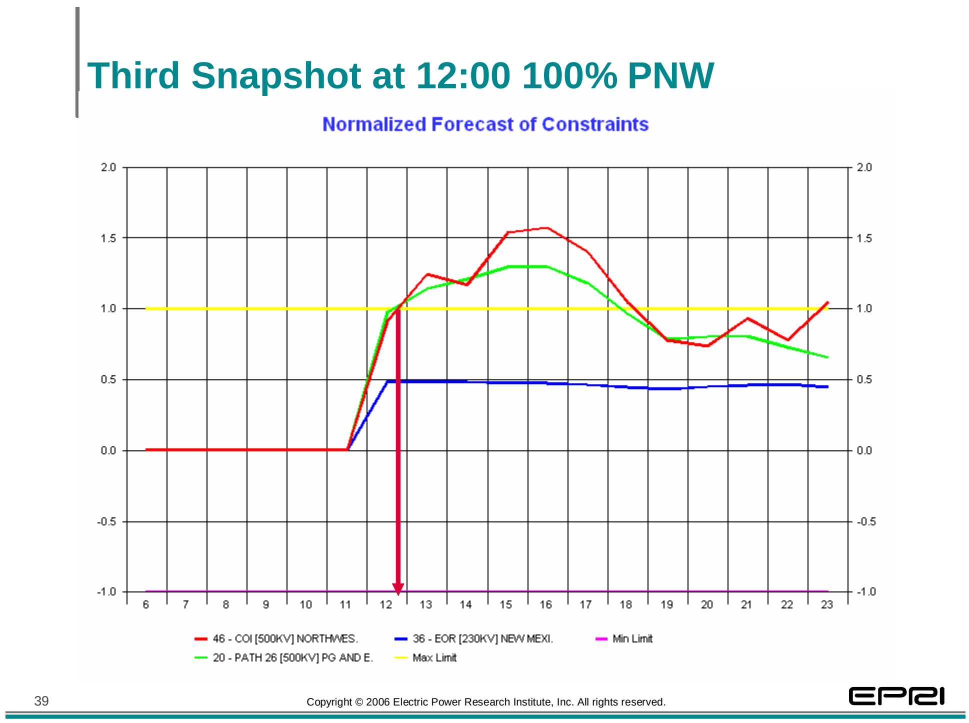


Figure 3.19 Forecast Made at 12:00 with 12:00 Flow Measurements and Day-Ahead Data, assuming 100% PNW

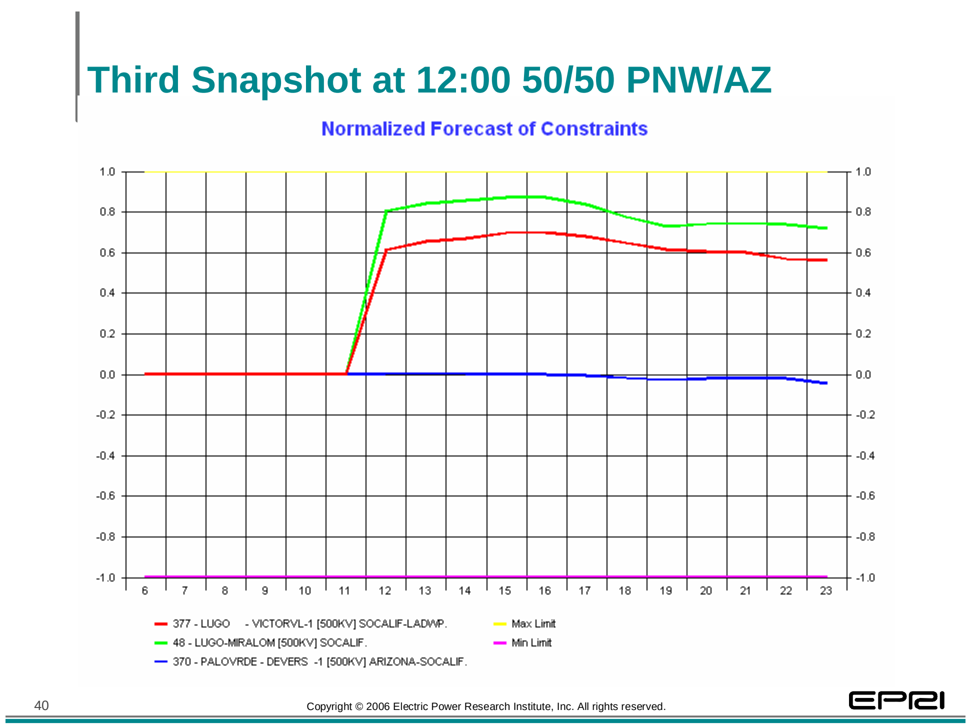


Figure 3.20 Forecast of Other Line Flows Made at 12:00 with 12:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

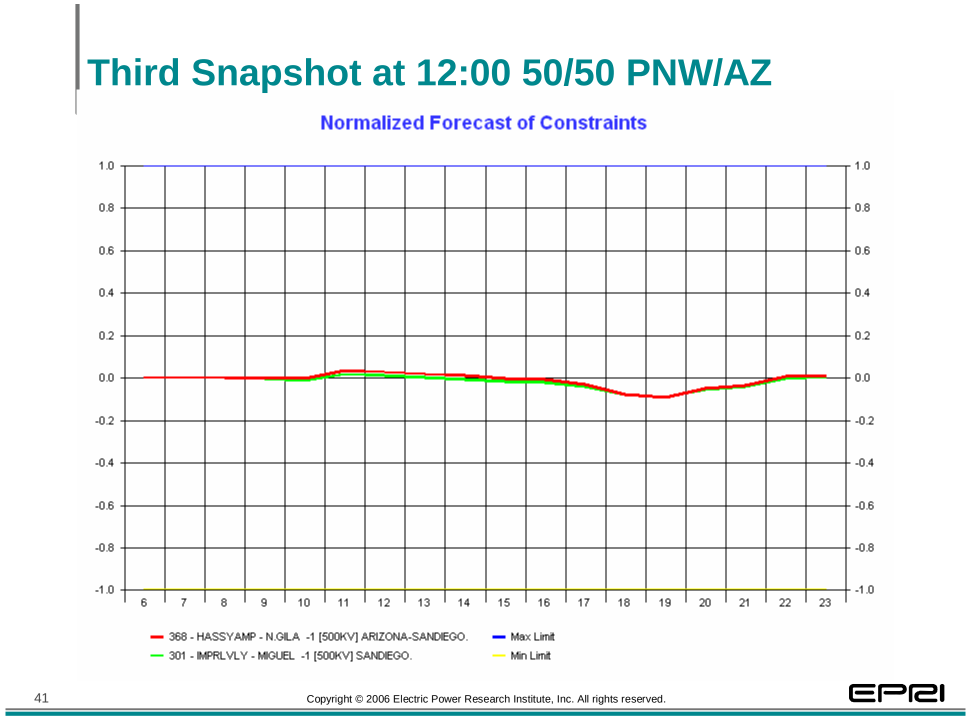


Figure 3.21 Forecast of Other Line Flows Made at 12:00 with 12:00 Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

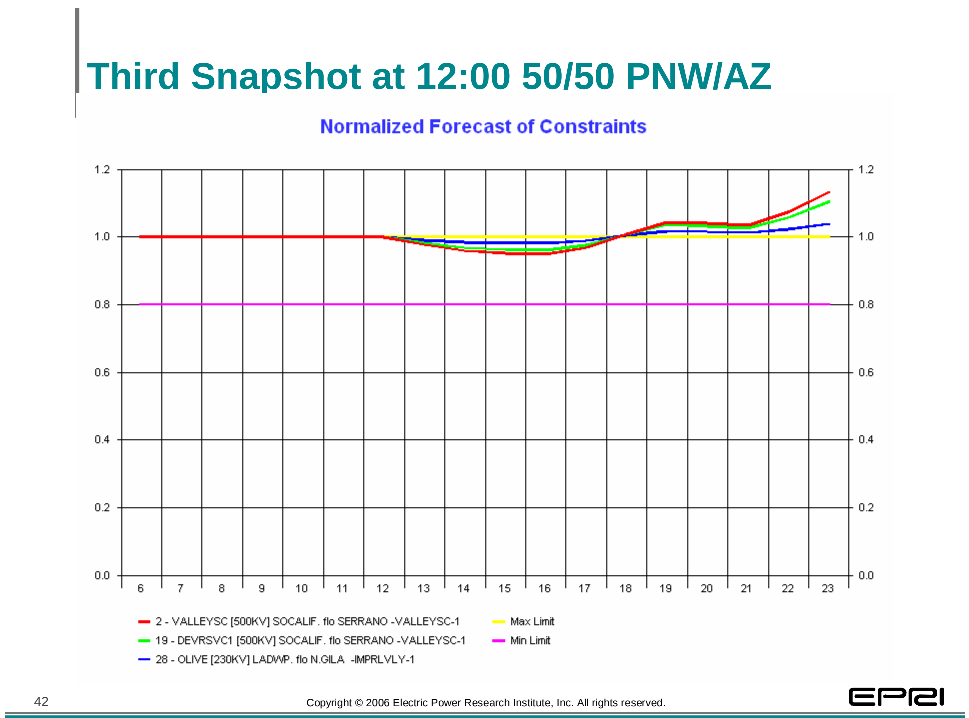


Figure 3.22 Forecast Voltages Made at 12:00 with 12:00 Voltage Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

Fourth Snapshot at 13:00

The fourth forecast using COCF was made at 13:00. Measurement data were taken off the control center display board, and the COCF model was run. The following results were obtained from COCF.

By this time, it was clear that the worst would be over for the day for COI and PATH 26 if the same trend continued. In other words, internal area generation and, if necessary, import from AZ would enable the system to avoid the limits on these two paths. However, if more import would come from the PNW, then the COI would potentially exceed its limit in the late afternoon.

The same observation made at 12:00 about the future trend of voltages remained accurate (See Figure 3.28).

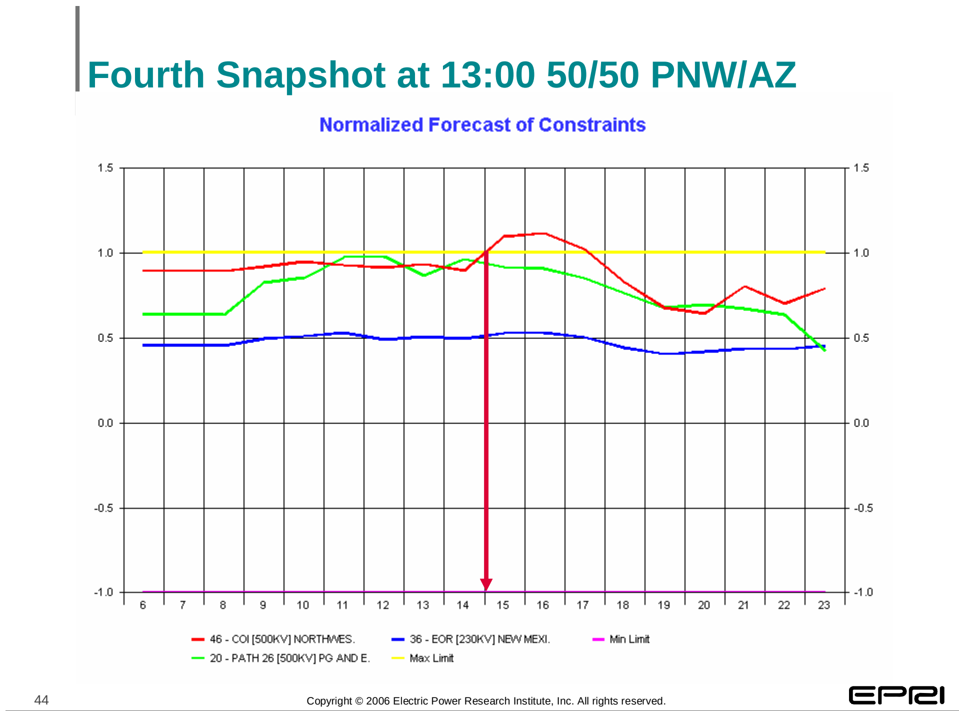


Figure 3.23 Forecast Made at 13:00 with 13:00 and Previous Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

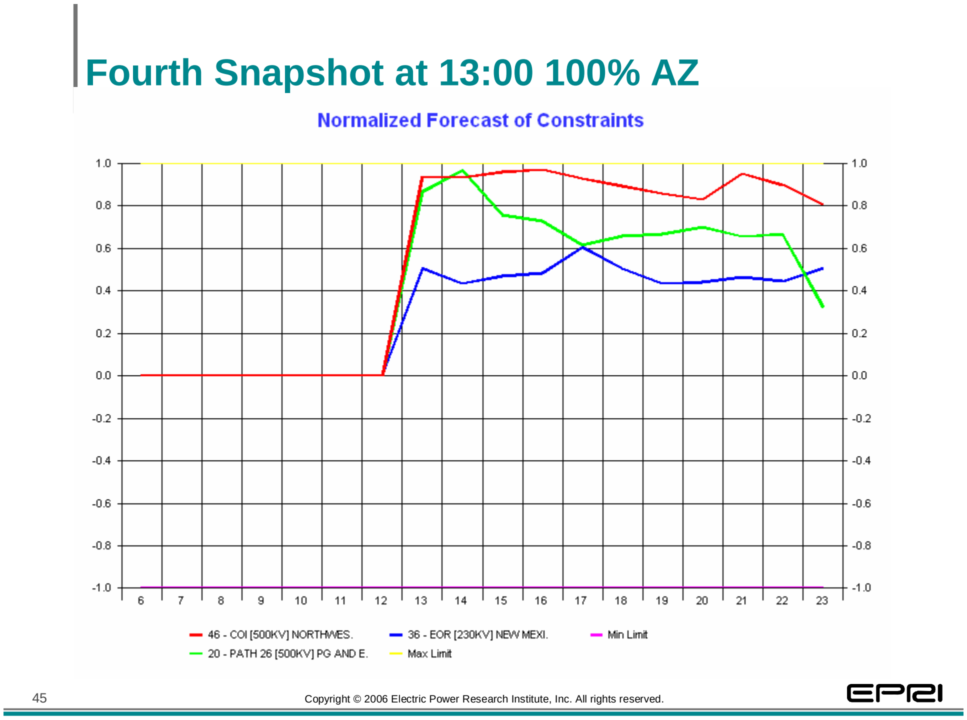


Figure 3.24 Forecast Made at 13:00 with 13:00 Flow Measurements and Day-Ahead Data, assuming 100% AZ

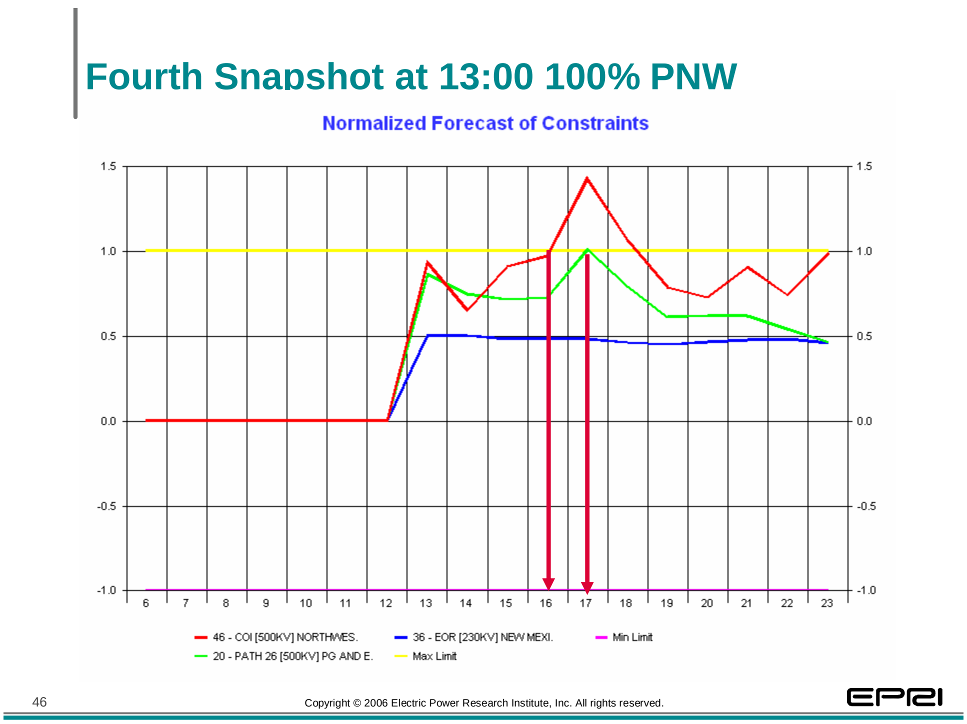


Figure 3.25 Forecast Made at 13:00 with 13:00 Measurements and Day-Ahead Data, assuming 100% PNW

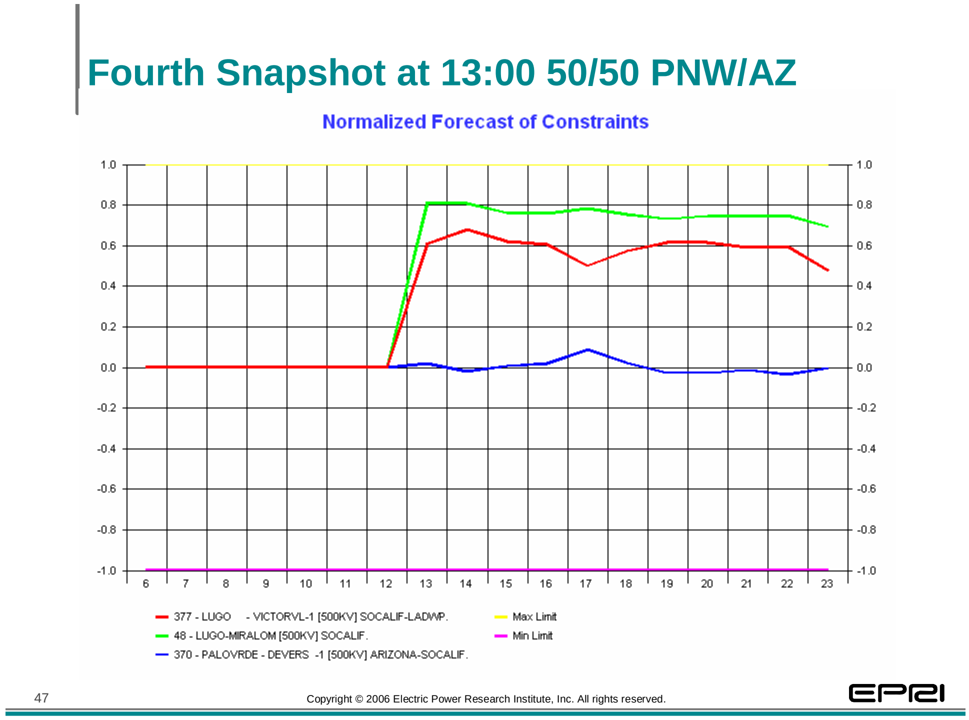


Figure 3.26 Forecast of Other Line Flows Made at 13:00 with 13:00 Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

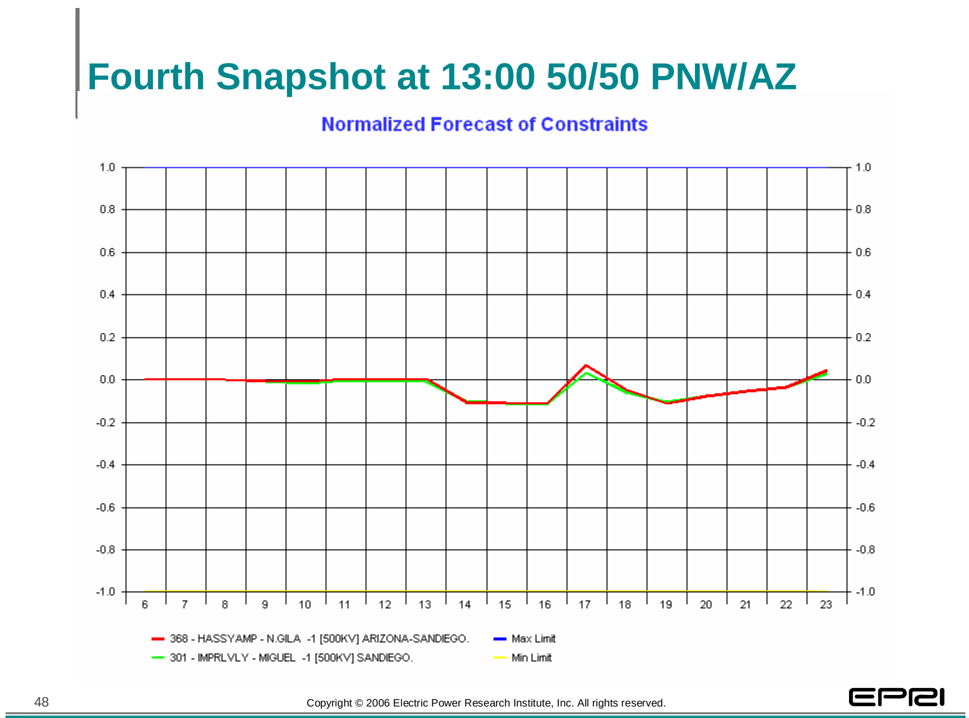


Figure 3.27 Forecast of Other Line Flows Made at 13:00 with 13:00 Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

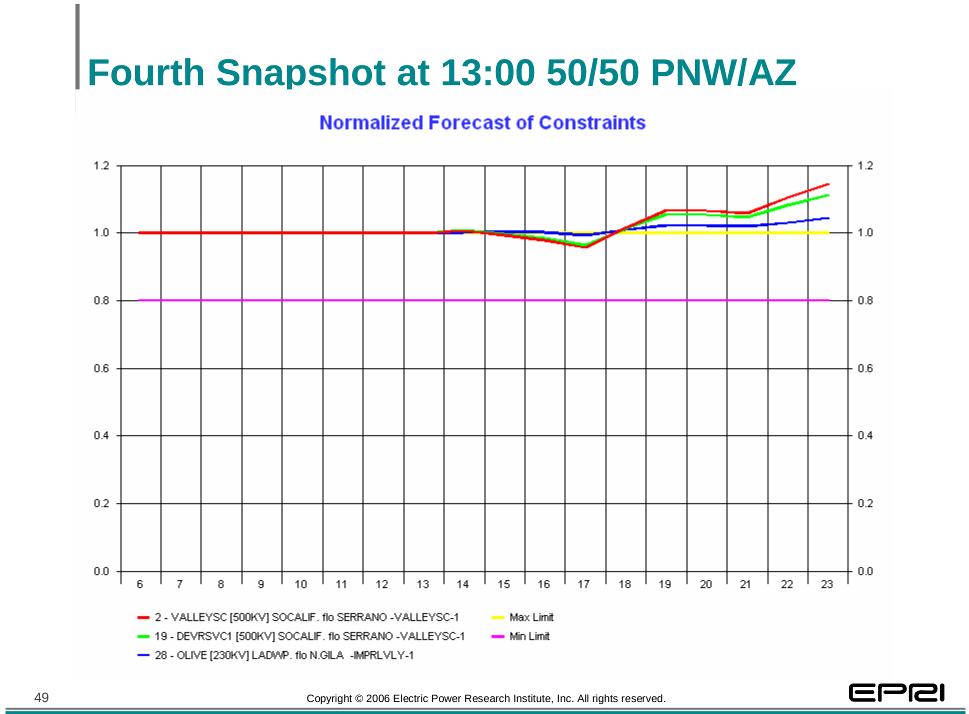


Figure 3.28 Forecast Voltages Made at 13:00 with 13:00 Voltage Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

Final Snapshot at 15:00

The final forecast using COCF was made afterwards from measurement data recorded at 15:00. Measurement data were taken off the control center display board, and the COCF model was run afterwards. The following results were obtained from COCF.

By this time, the trend of the declining load forecast was driving the COCF's forecast of the critical constraints. As shown in Figure 3.29, the line flows were all projected to be declining, and no operating problems were anticipated. The line loadings of the three major paths during the day all came below their operating limits.

This simulated online testing of the COCF on this day came to an end with interesting results. These results were presented to the CAISO technical staff in the afternoon.

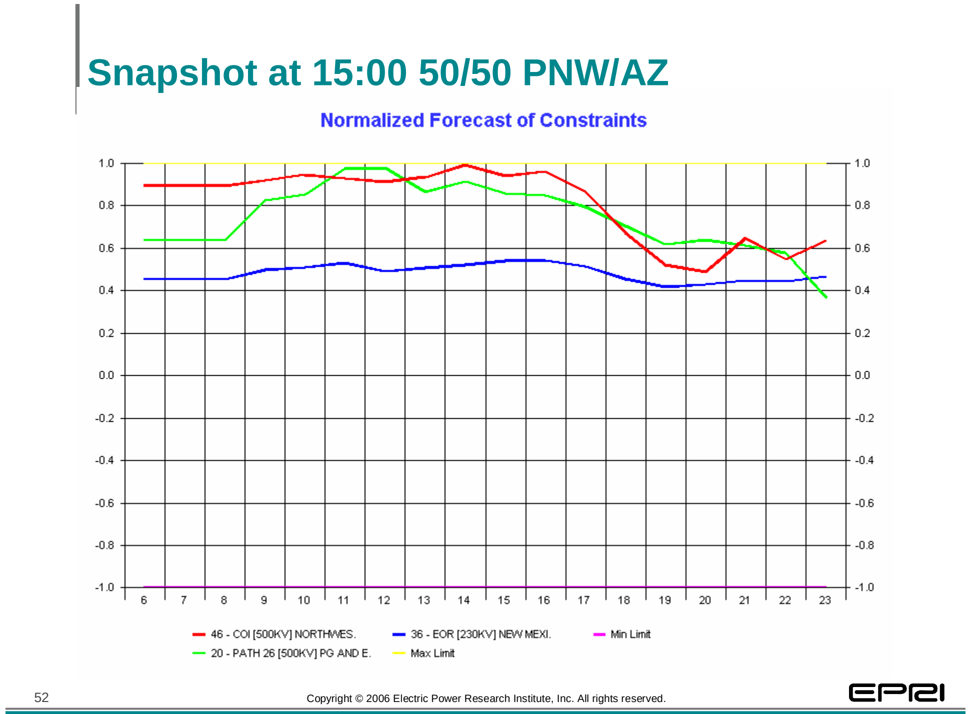


Figure 3.29 Forecast Made at 15:00 with 15:00 and Previous Flow Measurements and Day-Ahead Data, assuming 50/50 PNW and AZ

Final Comparison with Reconstructed COCF Model Based on Final Hour-Ahead Schedules

An analysis of the forecasting accuracy of the COCF was conducted some time after the on-site demonstration was completed. This analysis took the final summary of the hour-ahead schedules and reconstructed the "actual" load and resource schedules. Note that this was not based on the actual data of load and resources, but rather the compilation of all the hour-ahead schedules during the day. As such these data were still approximations of the actual system operation, but at least would be much more accurate than the Day-Ahead schedules which were used for the testing and demonstration. Figure 3.30 shows the input data to the COCF using the reconstructed data.

Because the final schedules had the load and resources all balanced, the COCF model would not be using the remaining deficit to simulate different scenarios of the sources of the external purchases. But what was necessary was to use the COCF scenario feature to simulate the DC schedule and the changes in internal generation dispatch within California. The maximum scheduled total import from PNW for the day was about 3800 MW. The DC schedule was approximated in COCF by a constant schedule of 1050 MW. This would be approximately the necessary amount to keep the COI path flows to within 2750 MW. To set this up in COCF, a net injection of -1050 MW was set at the PNW region, and a corresponding 1050 MW net injection was set at the SCE area. This essentially moved 1050 MW of PNW export through the DC tie into the SCE area, without having to pass through the AC interconnection. Figure 3.31 shows the COCF screen with the scenario set to model the DC tie schedule.

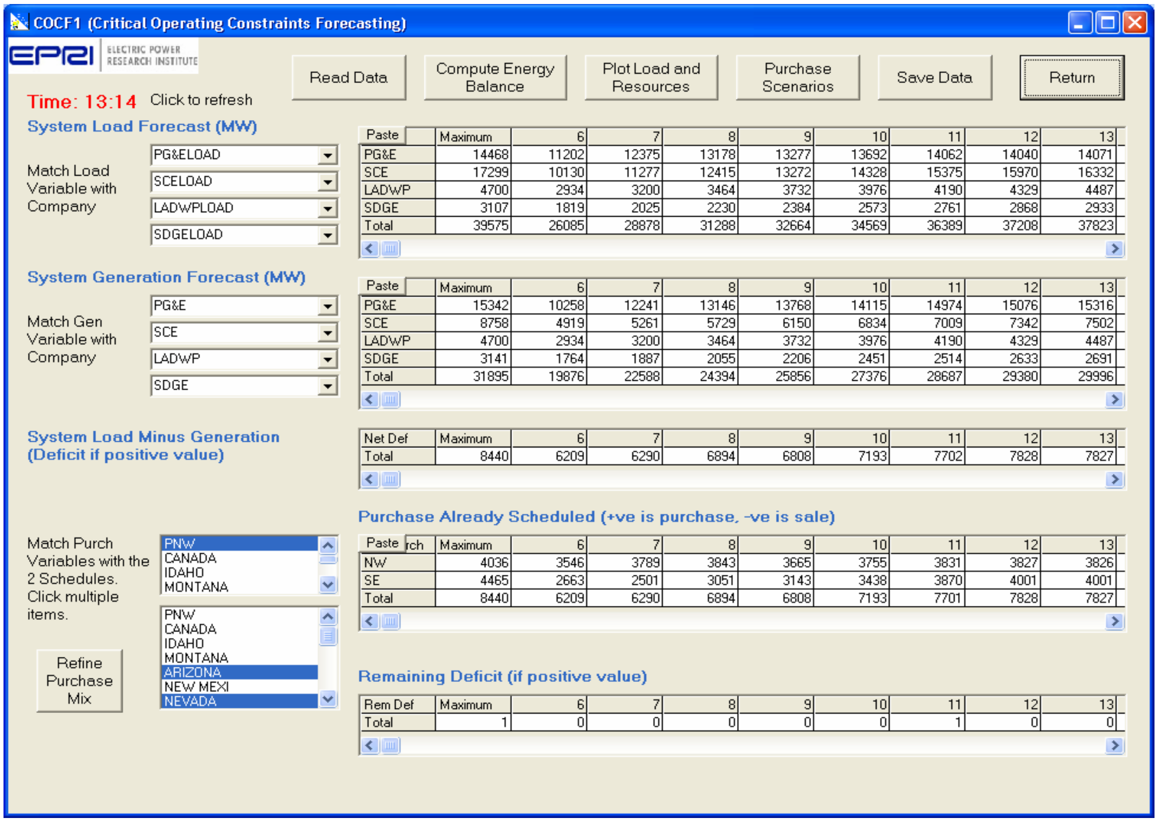


Figure 3.30 Input Data to COCF for Reconstructed Model

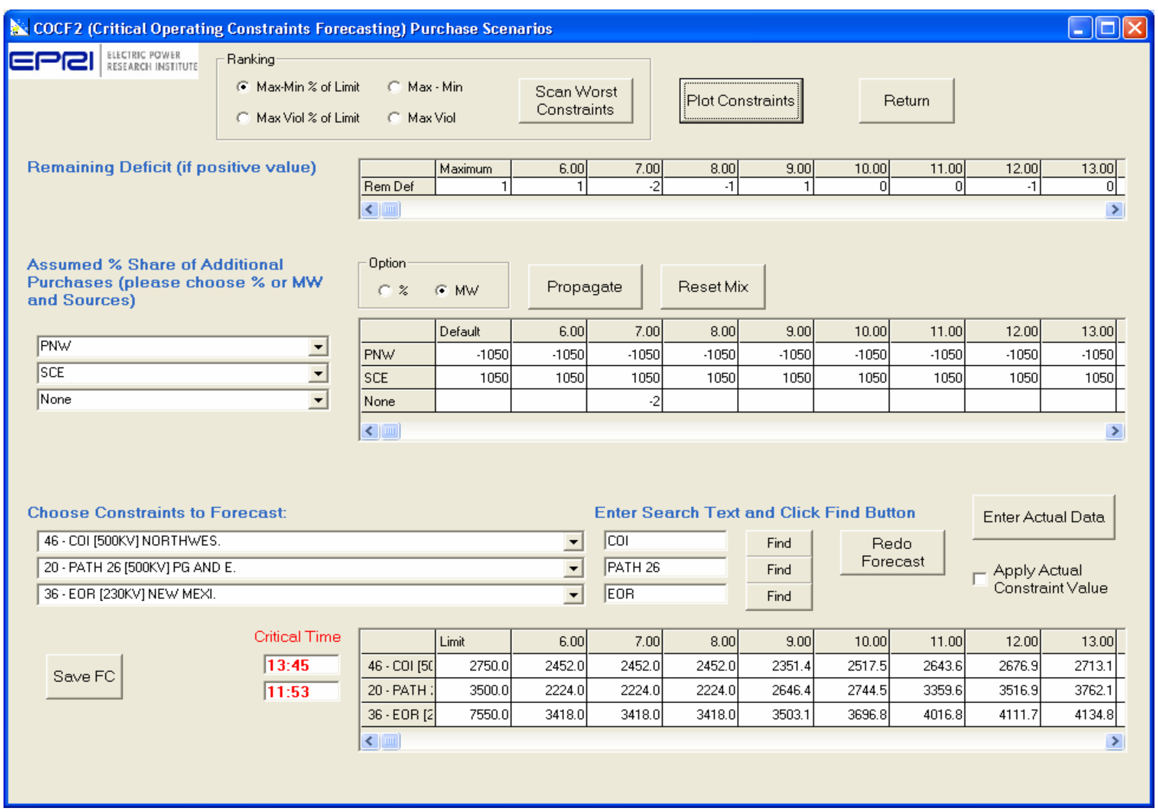


Figure 3.31 Input Data to COCF for Assumed DC Schedule

With these input data to COCF, the forecast of the three major transmission paths were obtained from COCF. Figure 3.32 shows the result of the COCF forecast and Figure 3.33 compares them with the actual flows.

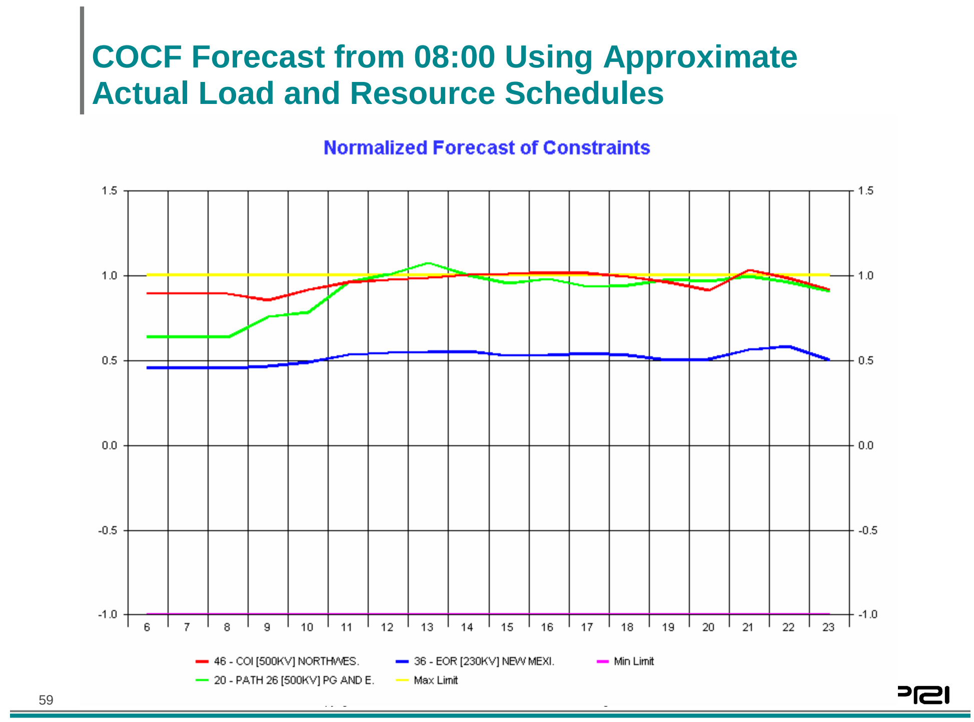


Figure 3.32 COCF Forecast at 08:00 Using 08:00 Flow Measurements for Reconstructed Model

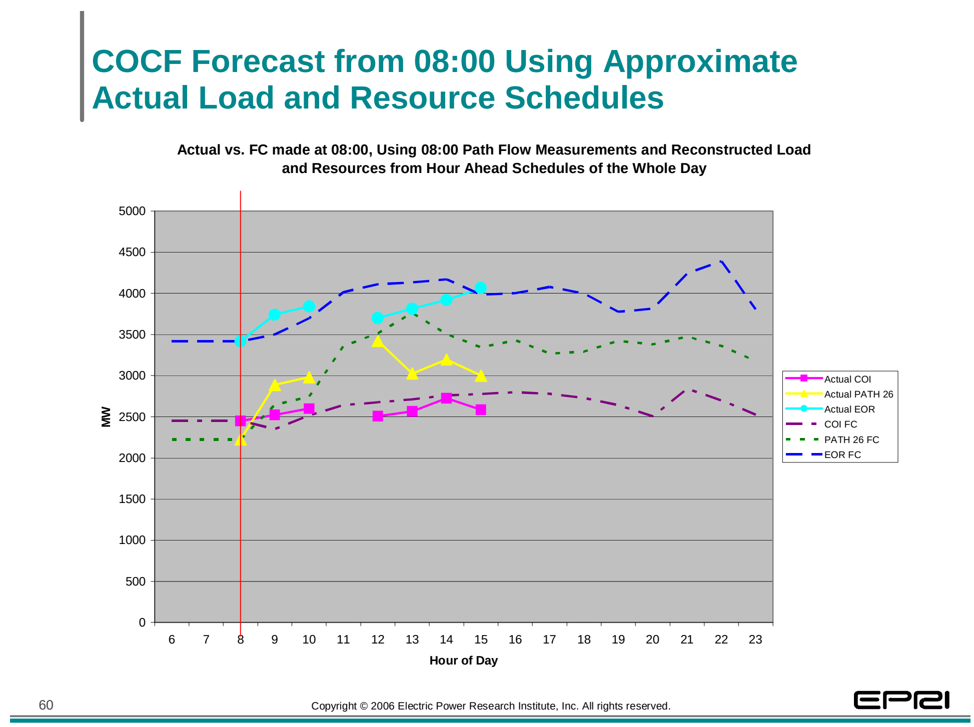


Figure 3.33 COCF Forecast at 08:00 with Reconstructed Model Compared with Actual Flows

The fact that Figure 3.32 shows that the three major operating constraints for that day would be practically within their limits was quite amazing, as what did happen. Earlier in this report, it was shown that the COCF was able to show the potential overloading of COI and PATH 26 during the day. With the same COCF forecasting equations, but with the reconstructed model of load and resource schedules, it was reassuring to see that the COCF forecasting equations had the sensitivity and the ability to modify reasonably the forecasted line flows when the load and resources were adjusted to reflect close to the actual conditions for the whole day. This was further amazing because these were forecasted from as early as 08:00 in the morning using the 08:00 flow measurements only.

Figure 3.33 shows the amount of uncertainty for the COCF forecasts. The top forecasted curve, EOR, was the most accurate when compared to the actual measurements. The middel forecasted curve, PATH 26, was the least accurate of the three. It was actually quite accurate from 08:00 to 12:00. The forecast continued to increase for PATH 26 after 12:00 when the actual flow dropped by about 400 MW. The total amount of the error in the PATH 26 forecast at hour 13:00 was about 735 MW. The reason for this inaccuracy is not clear. What seems to be the problem is that the loading of PATH 26 is sensitivity to the distribution of the load and generation between northern and southern California. Changes in the dispatch between these two regions of California would change the loading of PATH 26. Within the uncertainty between the actual system conditions and the model, this amount of discrepancy, 735 MW, compared to the actual flow of 3027 MW, was about 24%. It should be noted that this forecast was made at 08:00 for 13:00, in other words, five hours into the future.

The results of the comparison are shown in Table 2.5 for all three transmission paths. *Apart from the outlying error for PATH 26 at hour 13:00, all the other erros were within 10%, plus or minus, for a forecasting window of up to seven hours into the future.* This performance by the COCF forecasting equations was actually quite remarkable.

Table 2.5 Accuracy of COCF Forecasts

Time of Day Hour into Future	09:00 1	10:00 2	11:00 3	12:00 4	13:00 5	14:00 6	15:00 7
FC COI	2351	2518	2644	2677	2713	2762	2778
FC PATH 26	2646	2745	3360	3517	3762	3506	3344
FC EOR	3503	3697	4017	4112	4135	4170	3984
Actual COI	2524	2601	NA	2509	2567	2728	2586
Actual PATH 26	2888	2981	NA	3422	3027	3198	3001
Actual EOR	3743	3842	NA	3701	3813	3921	4066
MW Error COI	-173	-84	NA	168	146	34	192
MW Error PATH 26	-242	-237	NA	95	735	308	343
MW Error EOR	-240	-145	NA	411	322	249	-82
% Error COI	-7%	-3%	NA	7%	6%	1%	7%
% Error PATH 26	-8%	-8%	NA	3%	24%	10%	11%
% Error EOR	-6%	-4%	NA	11%	8%	6%	-2%

3.2. Validating COCF Against a Planning Study

To prepare for the validation of the COCF against the extreme case planning study, more information about the study assumptions on the CAISO Summer 2006 Assessment for the 1 in 10 Forecast was obtained in the day before. The actual comparison of the COCF results and the CAISO study results were made in between the online testing of the COCF. The results were presented in the demonstration and the project review meeting in the afternoon.

3.2.1. Assumptions of Planning Study

The assumptions regarding Southern California (SP26) are summarized in the following table.

Table 2.6 Assumptions Related to Summer 2006 Planning Study for Southern California

Description	Assumed
Extreme SP26 Demand ("1 in 10")	29,560 MW
SP26 Total Generation Dispatched	20,000 MW
SP26 Imports	9,560 MW
Extreme LADWP Demand	7,071 MW
LADWP Total Generation Dispatched	4,500 MW
Total California Imports assumed scheduled	10,000 MW
Total Southern California Imports required = (29560+7071-20000-4500)	12,131 MW
California ISO Control Area Demand ("1 in 2")	46,063 MW
SP26 Demand ("1 in 2")	27,299 MW

Data for the normal forecast ("1 in 2") were obtained from the CAISO report, "2006 Summer Loads and Resources Operations Assessment", April 10, 2006. Data for the extreme forecast ("1 in 10") were obtained from the CAISO presentation, "Summer 2006 Operating Plan: Focusing on the CAISO South," made to the Market Surveillance Committee (MSC) at its meeting on May 31, 2006, by Dariush Shirmohammadi.

These data were used to modify the Summer 2006 COCF input data to represent the Extreme "1 in 10" load forecast and resources. The COCF input screen for this planning study is shown in the following Figure 3.34.

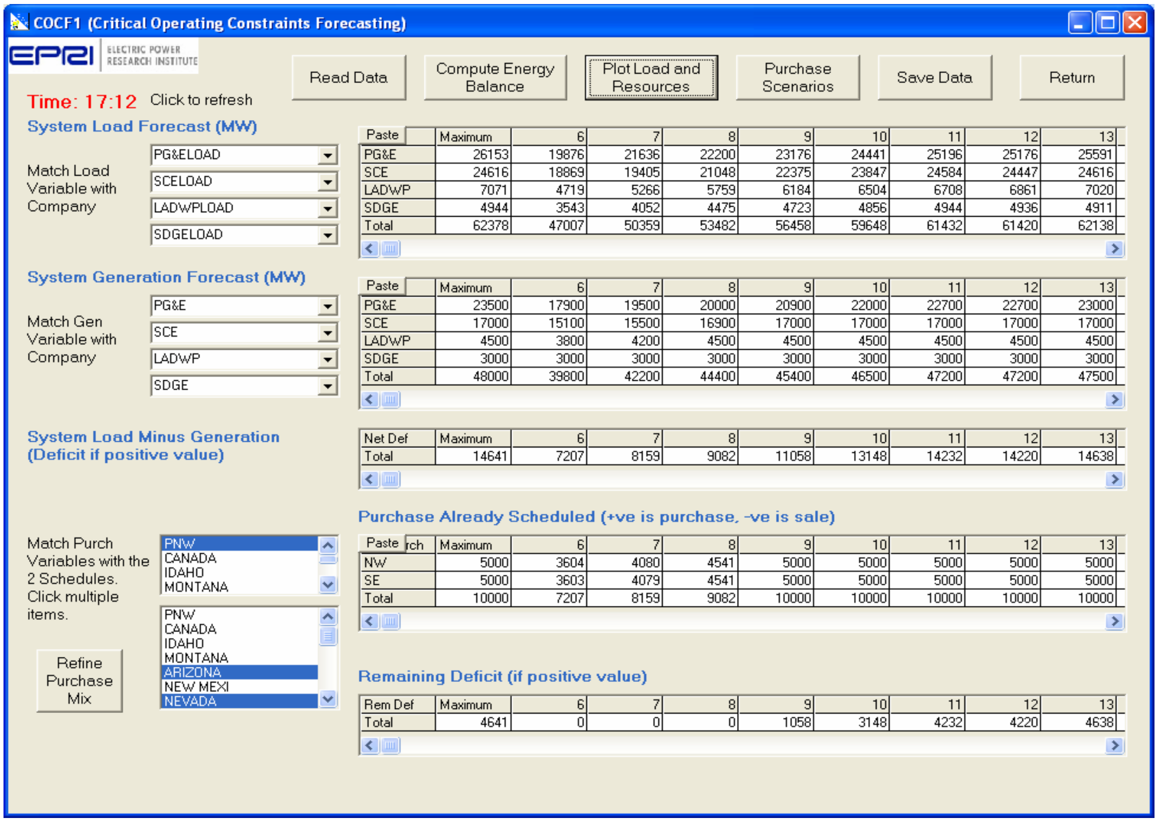


Figure 3.34 COCF Input Screen for Summer 2006 Extreme Conditions

The graph showing the load and resource balance for this case is shown in Figure 3.35 below.

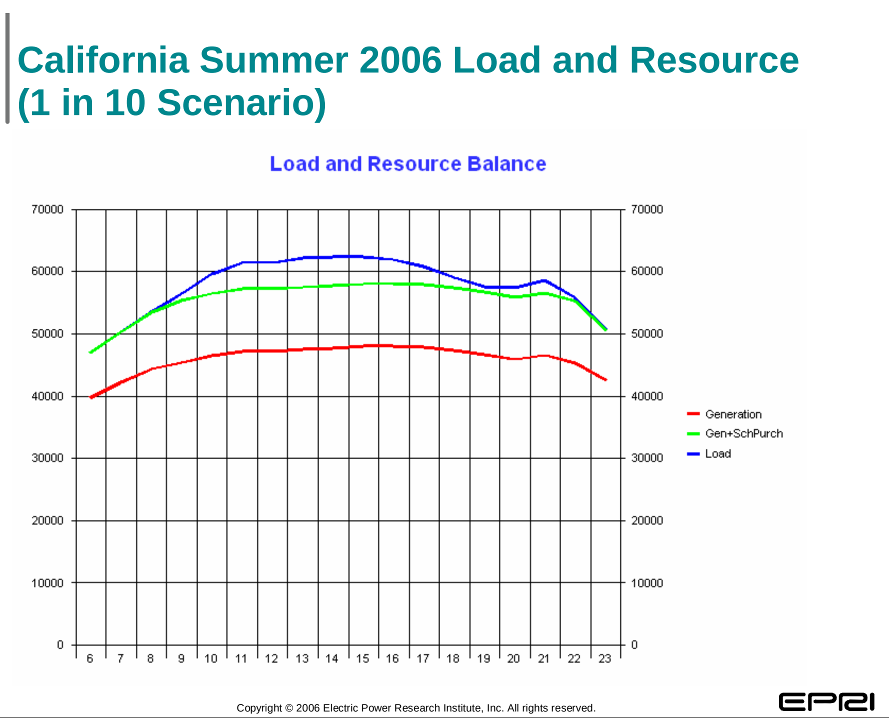


Figure 3.35 COCF Screen for Summer 2006 Extreme Conditions Load and Resource Balance

All Transmission In Service

Using COCF, a number of scenarios were simulated. The normal case assuming all transmission lines were in service provided a picture of tight operating conditions. If 100% of the remaining generation deficit came from AZ, then the path loadings would barely make it (See Figure 3.36 and 3.37).

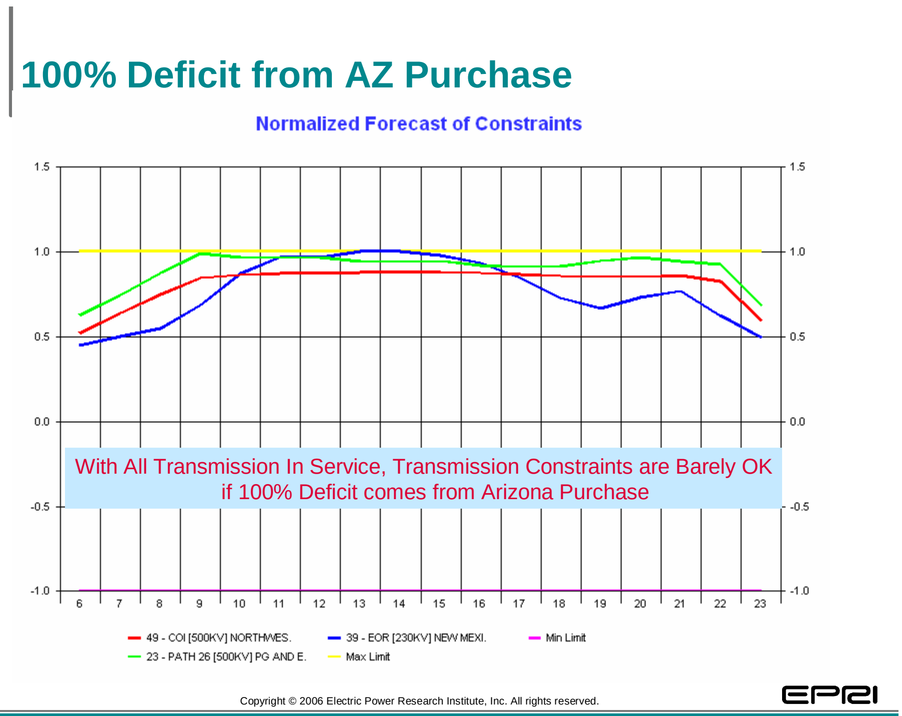


Figure 3.36 COCF Forecast of Path Flows for Summer 2006 Extreme Condition With All Transmission in Service, Assuming 100% Deficit from AZ

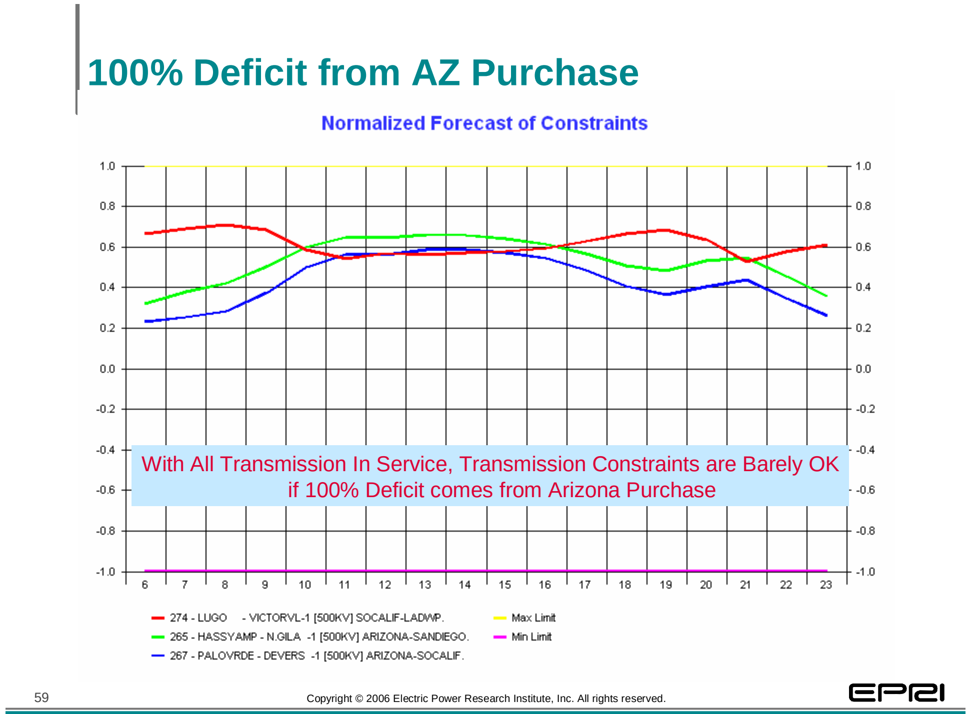


Figure 3.37 COCF Forecast of Other Path Flows for Summer 2006 Extreme Condition With All Transmission in Service, Assuming 100% Deficit from AZ

However, if 100% of the deficit came from PNW, COI and PATH 26 would definitely exceed their limits (See Figures 3.38 and 3.39).

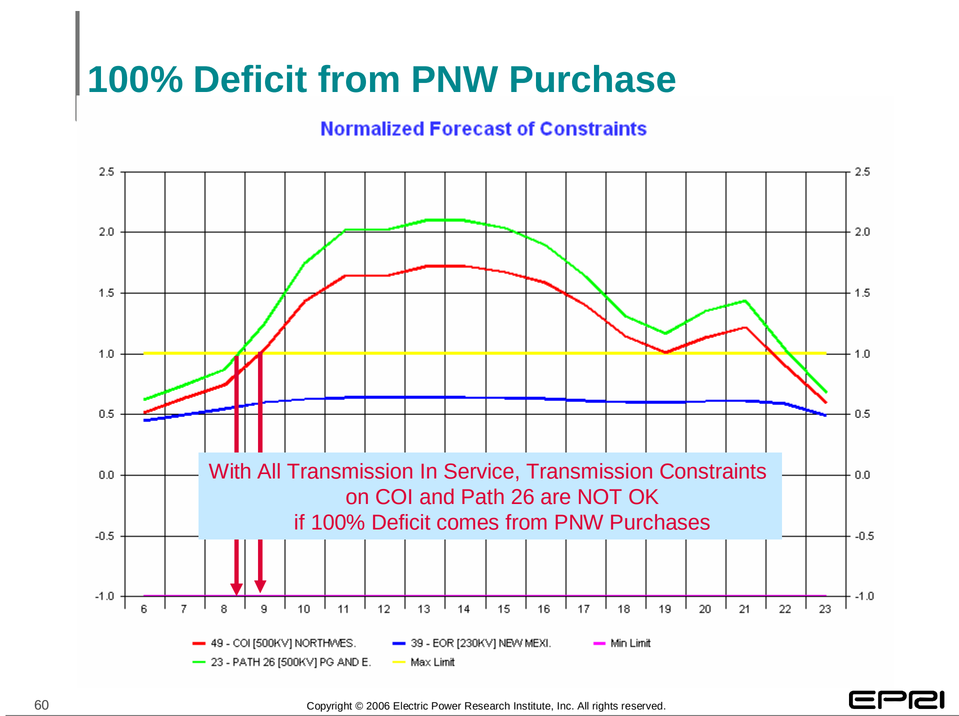


Figure 3.38 COCF Forecast of Path Flows for Summer 2006 Extreme Condition With All Transmission in Service, Assuming 100% Deficit from PNW

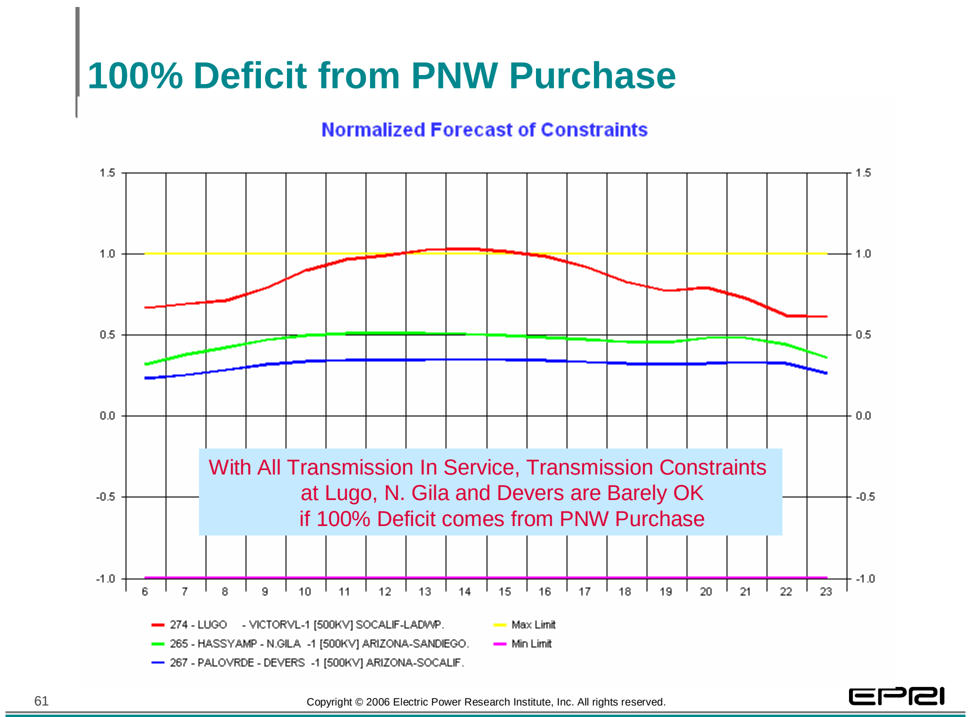


Figure 3.39 COCF Forecast of Other Path Flows for Summer 2006 Extreme Condition With All Transmission in Service, Assuming 100% Deficit from PNW

PDCI Transmission Out of Service

The largest single transmission contingency in California is the loss of the PDCI tie to the Pacific Northwest. This DC tie is rated for 2990 MW into California. A new set of COCF forecasting equations was developed from the summer 2006 base case with the PDCI tie removed. These new forecasting equations for the COCF were used to create the following set of forecasts.

Figure 3.40 shows that the COI and PATH 26 would again be overloaded way above their limits if 100% of the deficit came from the PNW.

Not only would COI and PATH 26 be in trouble, another path (Hassayampa – N. Gila) would also exceed its limit (See Figure 3.41).

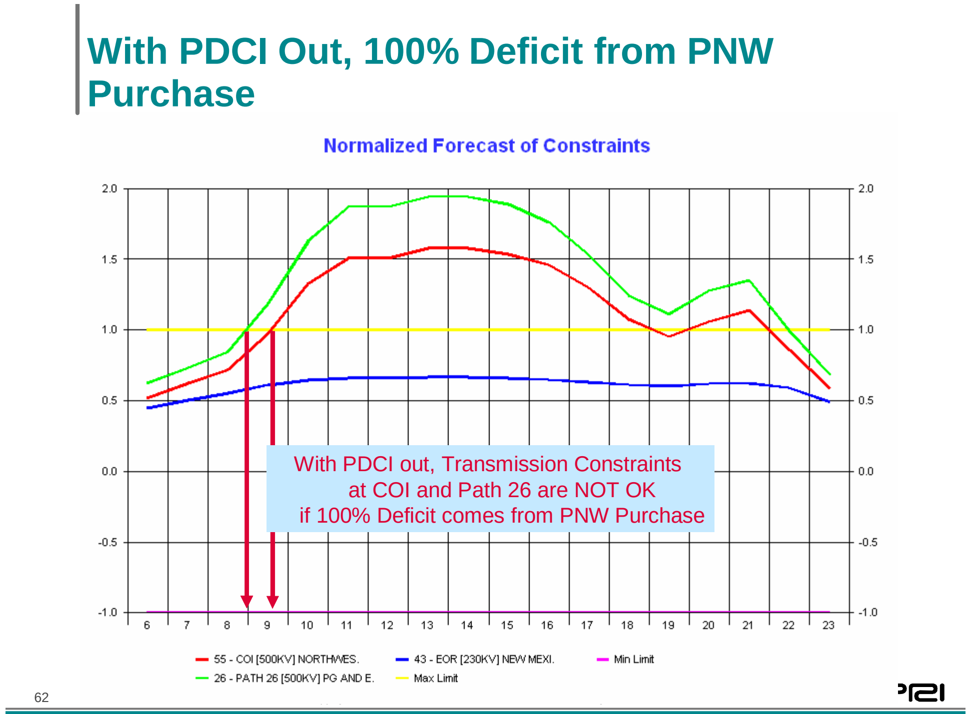


Figure 3.40 COCF Forecast of Path Flows for Summer 2006 Extreme Condition With PDCI Out of Service, Assuming 100% Deficit from PNW

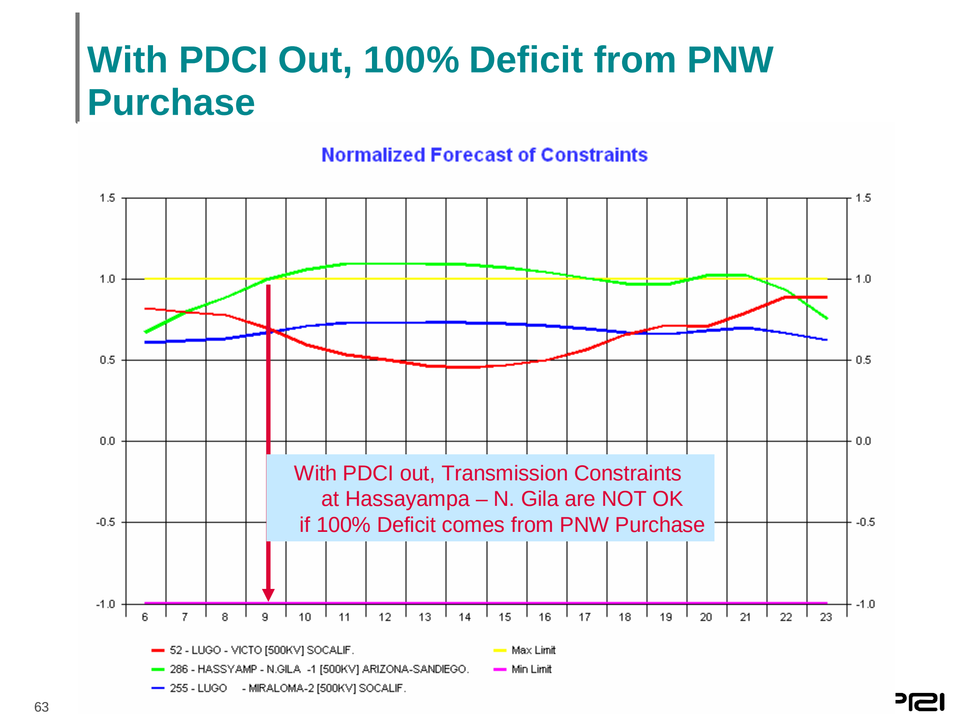


Figure 3.41 COCF Forecast of Other Path Flows for Summer 2006 Extreme Condition With PDCI Out of Service, Assuming 100% Deficit from PNW

If the deficit should all be supplied from Arizona, the paths of COI, PATH 26 and East of River would stay below their limits, as seen in Figure 3.42. However, the path Hassayampa – N. Gila would exceed its limit (See Figure 3.43).

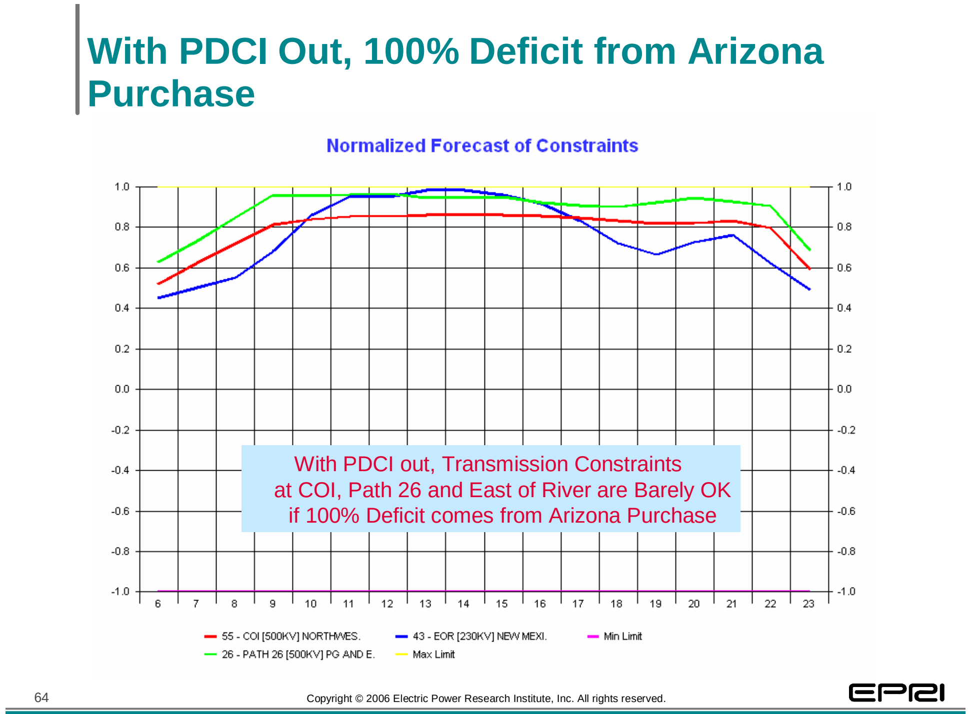


Figure 3.42 COCF Forecast of Path Flows for Summer 2006 Extreme Condition With PDCI Out of Service, Assuming 100% Deficit from AZ

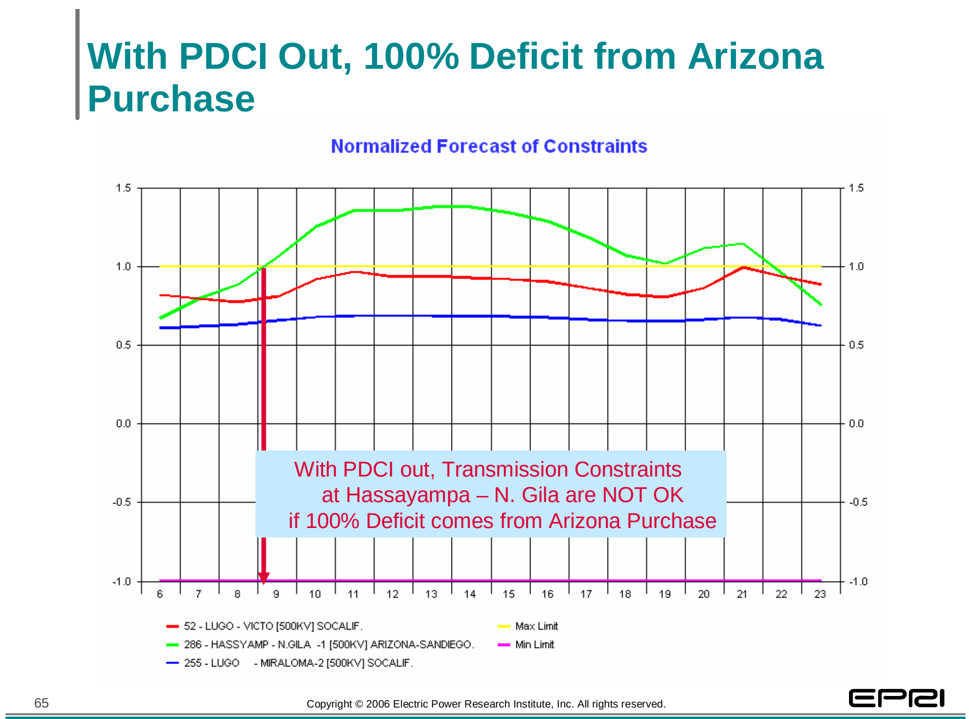


Figure 3.43 COCF Forecast of Other Path Flows for Summer 2006 Extreme Condition With PDCI Out of Service, Assuming 100% Deficit from AZ

What these two scenarios showed was that it would not be possible to avoid overloading at least some transmission path(s) no matter where the deficit would be supplied from outside California. Therefore, the only option is to reduce the load in Southern California. This was the conclusion of the "Summer 2006 Operating Plan: Focusing on the CAISO South" referenced earlier.

The research question was then to see if the COCF could be used to estimate the amount of load reduction in Southern California, in order to keep all path loadings within limits. The solution to make up all the deficit from Southern California was tested. This was achieved by using the feature of COCF to let SCE be the area to supply the deficit. This would not be possible with actual generation in SCE because the maximum generation available in SCE was already dispatched in the COCF model. Therefore, this imaginary generation would actually represent the amount of load reduction in the SCE area. This is shown in Figure 3.44, where the SCE area and the amounts of the load reduction during the hours of 12:00 to 16:00 were encircled in a red ellipse. Note that the amount was about 4600 MW around these hours.

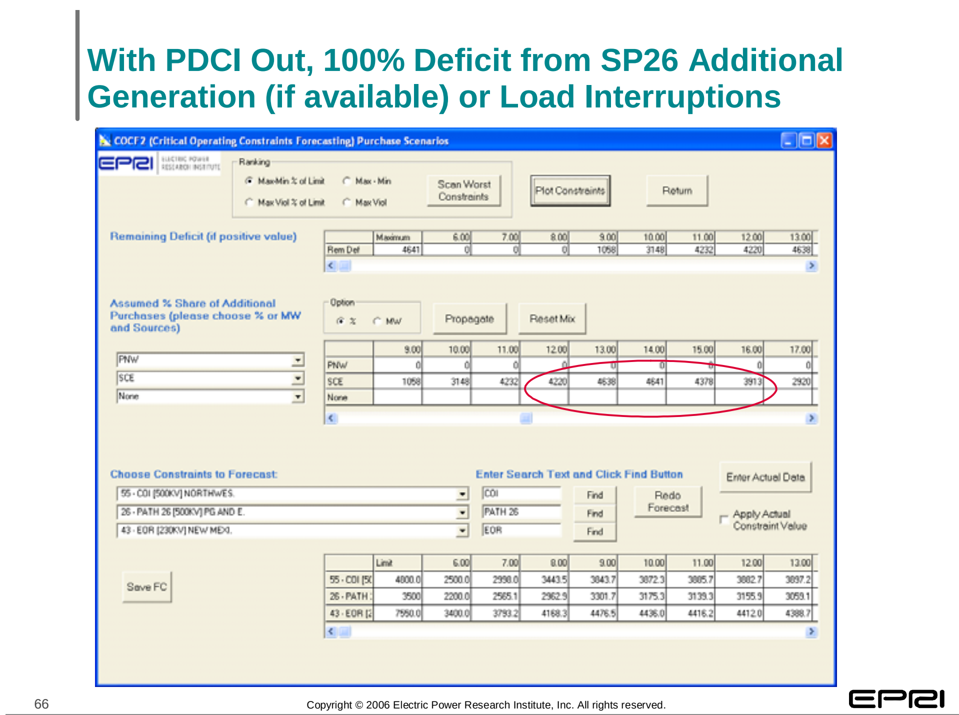


Figure 3.44 COCF Scenario for Summer 2006 Extreme Condition With PDCI Out of Service, Assuming 100% Deficit from SCE

The COCF forecasts for the three major paths were shown in Figure 3.45. Both COI and PATH 26 were within limits now.

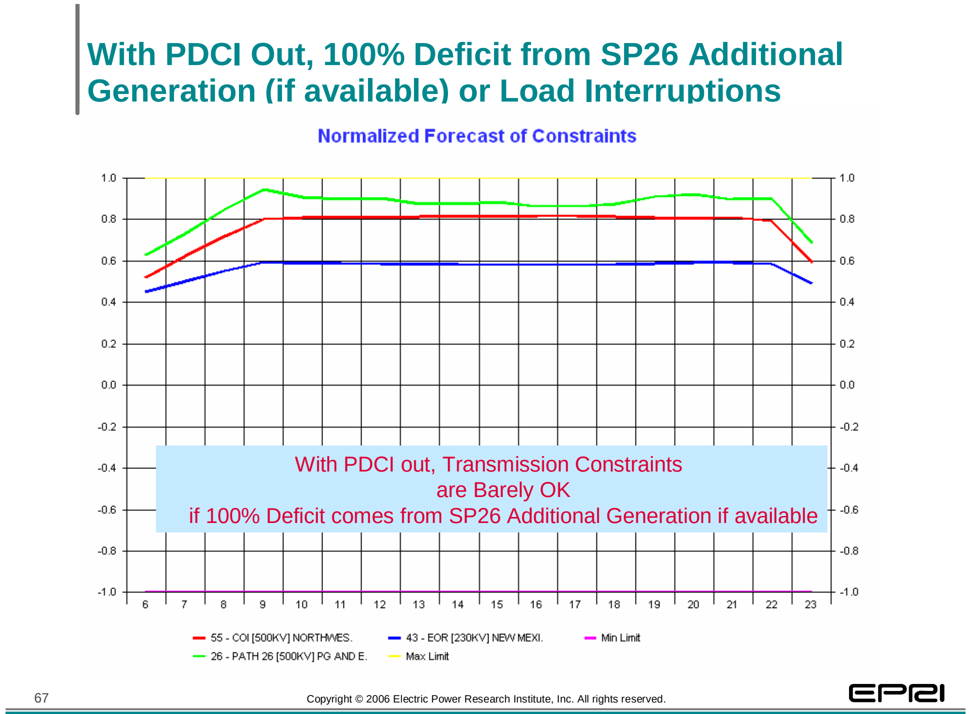


Figure 3.45 COCF Forecast of Path Flows for Summer 2006 Extreme Condition With PDCI Out of Service, Assuming 100% Deficit from SCE

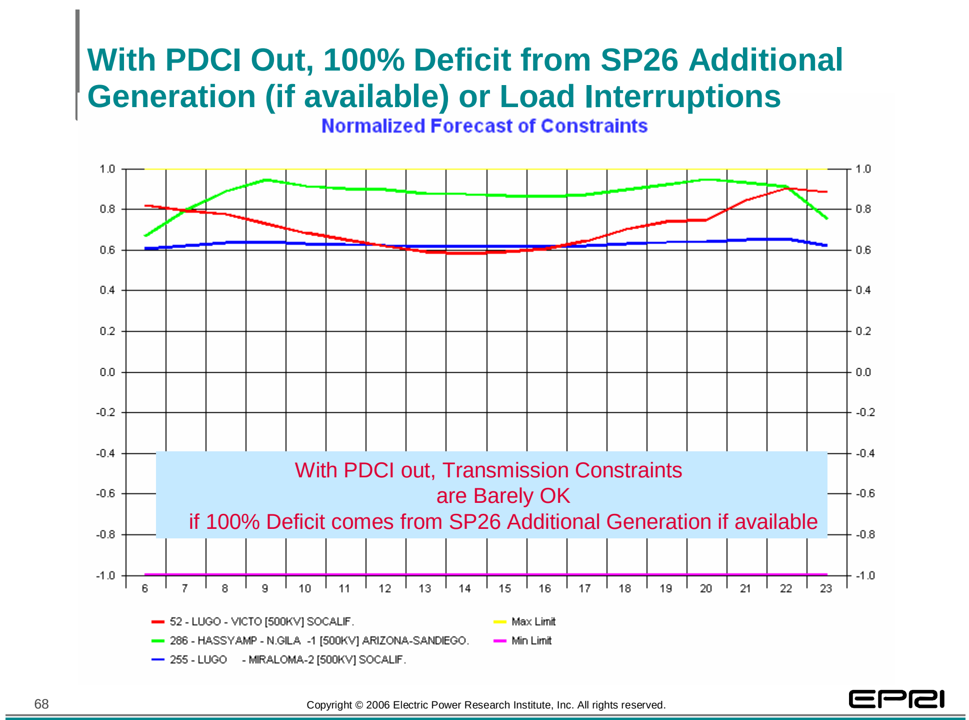


Figure 3.46 COCF Forecast of Other Path Flows for Summer 2006 Extreme Condition With PDCI Out of Service, Assuming 100% Deficit from SCE

As shown in Figure 3.46, the path of Hassayampa – N. Gila was also within limits now. Thus it was demonstrated that the COCF model was capable of modeling the Summer 2006 extreme conditions with the PDCI out of service, and was validating the results of the CAISO operational plannnig study, which came up with similar results about the necessity to have load reduction in Southern California in order to withstand the "1 in 10" load forecast and the simultaneous loss of the PDCI transmission facility.

3.3. Conclusions of Testing and Demonstration

This research project has succeeded in developing a methodology for forecasting certain types of critical operating constraints, and demonstrating that it works for a real practical situation for the California ISO, which operates within the WECC interconnection.

The testing and demonstration were performed on May 30-31, 2006 at the CAISO control center. Two tests were conducted, a simulated online test using the COCF model updated for the network topology of those two days, and using the Day-Ahead load and resource schedules for May 31, 2006. Only the path flow measurements were used to anchor the forwarding looking estimates of the operating constraints along a number of transmission paths. Snapshots and forecasts were conducted at 08:00, 10:00, 12:00 and 13:00. Afterwards, a reconstruction of the day was also created and used to compare the accuracy of the forecast with the actual flows.

The results were very encouraging. The COCF was capable of predicting where and when the transmission grid would be congested if additional purchases were imported from the PNW versus the SW and in 50/50 mix. The CAISO system actually was running close to two operating limits during the day. These limits were COI and PATH 26. These limits were not exceeded in the real operation because of adjustments in the grid operation and the market. From the transmission operation side, the DC tie to the Pacific Northwest was used to take power directly from the PNW into southern California, thereby relieving the potential congestion on COI. The potential overloading of PATH 26 was relieved by adjustments in the internal generation distribution between northern and southern California. The COCF was useful in its predictive mode to indicate where the stresses would be located in the absence of these mitigation actions.

The comparison of the COCF forecasts with the actual flows on the three major paths showed the remarkable accuracy of the COCF. From one to seven hours ahead, the average accuracy of the COCF for the three major paths was within 10%, plus or minus. The worst inaccuracy was 24% five hours out for PATH 26. The difference was likely due to the mitigation effects. In other words, COCF could not know ahead of time what mitigation would be taken. However, it is anticipated that if sufficient details are added to the data, and increased details on the internal modeling of the CAISO network are included, more accuracy can be achieved by the COCF.

A second demonstration of the COCF was to compare the COCF to the CAISO's Summer 2006 assessment of southern California under the extreme conditions of "1 in 10" load forecast. This demonstration was done with two COCF models, one for summer 2006 with all lines in service and one with PDCI out of service. The results demonstrated the necessity to have load reduction in Southern California in order to withstand such extreme conditions. This demonstration shows that the COCF can also be used for planning studies.

4.0 Conclusions and Recommendations

The challenges facing a grid operator are many. Under some situations when the transmission capacity into an area is severely limited, and the internal generation of that area is also limited, there would be situations where the location where the external import comes from would affect where the transmission bottlenecks would occur and when these bottlenecks would create reliability problems. Such problem may be overloads, low voltages or even voltage instability. In the extreme conditions, when it is not feasible to import the necessary power without violating these operating limits somewhere in the system, then the only recourse may be to appeal for conservation and eventually to shed the minimum amount of loads.

The existing Energy Management Systems do not provide such a tool to support the decision making of a grid operator under these conditions. It is necessary to have a tool which is forward looking, capable of satisfying the contingency criteria of grid operation, and enables the user to simulate very quickly a number of scenarios on the imports. This would become a decision support tool for the grid operator and would provide the lead time for the grid operator to make the necessary preparation for the mitigation measures. This tool would also be useful for documenting that the grid operator is diligent in analyzing the potential operating constraints, not only for the current hour, but for the rest of the day. In other words, more complete situational awareness. When the emergency decisions become necessary to shed load, having such a tool to do the analysis and to estimate the amount and location of the load shed would be extremely valuable.

This project has developed the methodology for such a forward-looking decision support tool. It is called the COCF (Critical Operating Constraints Forecasting). This method is documented in a Functional Specifications document and was presented in a workshop to the industry on November 7, 2007 in Folsom, California. This report summarizes the results of this research project and presents the results of the testing and the demonstration.

The conclusion of this research project is that this methodology is mathematically sound and is supported and validated by the testing and demonstration described in this report.

It is recommended that commercial vendors of Energy Management Systems or other software companies study this methodology, review the final report and the Functional Specifications, and to consider developing a commercial software program that would be offered to potential customers.

5.0 Bibliography

1.0 S.T. Lee, E. Hnyilicza, F.C. Schweppe, "Steady-State Security Regions: Set-Theoretic Approach", Proc. PICA Conference, New Orleans, pp. 347-355, June, 1975.

2.0 P. Zhang, S.T. Lee, "Probabilistic Load Flow Computation Using the Method of Combined Cumulants and Gram-Charlier Expansion," Paper submitted to IEEE, 2003.

3.0 S.T. Lee, "Community Activity Room as a New Tool for Transmission Operation and Planning Under a Competitive Power Market," IEEE Power Tech 2003 Conference, Bologna, Italy, June 22-26, 2003.

4.0 S.T. Lee, "A New Vision for Transmission Operation and Planning Under An Open Power Market," Joint CIGRE and IEEE Conference, Montreal, October 7-10, 2003.

5.0 Stephen T. Lee, "Holistic Planning for an Electric Power System", IEEE Power and Energy Magazine, September/October 2007.

6.0 Liang Min, S. T. Lee, P. Zhang, V. Rose, J. Cole, "Short-Term Probabilistic Transmission Congestion Forecasting", presented at the IEEE 2008 International Conference on Electric Utility Deregulation and Restructuring and Power Technologies (DRPT), Nanjing, China, April 6-9, 2008.

7.0 Lee, Stephen, 2008. *Critical Operating Constraints Forecast Functional Specification - A Decision Support Too)*. California Energy Commission, PIER Program. CEC contract 500-02-004, Work Authorization MR-050.

8.0 Modern Power Systems Control And Operation, by Atif S. Debs, Kluwer Academic Publishers, 1988.