Real Time Dynamics Monitoring System (RTDMS™): Phasor Applications for the Control Room

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Abstract

The Real Time Dynamics Monitoring System (RTDMS) has been developed to enable utilization of time-synchronized phasor measurements for reliability management with the overall objective of accelerating the adoption and fostering greater use of the technology within North America. Since 2003, it has been serving as a platform to translate research concepts and algorithms into actual applications for power system operators, reliability coordinators, and operating engineers both within the Eastern and Western Interconnections. The system supports an open, scalable and modular system design that adheres to a Server-Client architecture offering a suite of applications for wide-area real time visibility, monitoring and alarming on key metrics related to grid stress, dynamics, and the power system’s proximity to instability, and performing offline forensic event analysis and baselining functions on normal operating conditions, limits and alarms. This paper provides an overview of the RTDMS system: its system architecture functionalities and applications.

1. Introduction

The electric power grid in the US has evolved from a vertically integrated system to a mixture of regulated and deregulated competitive market system. Grid oversight is transitioning from local utilities to an assortment of transmission companies, regional Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). Regulatory and economic pressures have caused new transmission construction to lag the growth in demand. These forces have increased pressure on electricity markets and caused operators to maximize the utilization of the system. The result is an operating environment where operators are faced with quick changing and previously unseen power flow patterns and operational conditions with limited information available for real-time operation and decision-making. Furthermore, the aging transmission lines, lack of transmission expansion and environmental constraints makes reliable system operation a more challenging task.

Reliable electricity supply is continually becoming more essential for society, and blackouts are becoming more and more costly whenever they occur. In recent years, there have been major blackouts in North America, Europe and Asia. The August 14, 2003 blackout in the Eastern Interconnection impacted 50 million people. Recommendations from the investigation of this blackout carried out by the US-Canada Joint Task Force included the need for wide-area visibility and situational awareness to address problems before they propagate, the use of time-synchronized data recorders, and better real-time tools for operators and reliability coordinators (RCs).

The key issue that has emerged in reliability management is the transition from local utility managed control areas to regionally managed grids and markets. Utilities planned and operated the power system under their control on an integrated basis. Utility operating systems all use SCADA systems to collect local real-time data to monitor and control their portion of the power system. While control areas share their SCADA data with reliability coordinators via Inter-control Center Communications Protocol (ICCP), ICCP data is transmitted at varying rates (up to minutes in periodicity) and is not time synchronized.

Recent advances in the field of phasor technologies offer great promise in providing the industry with new tools and applications to address the blackout recommendations and to tackle reliability management and operational challenges faced by system operators, reliability coordinators and utility engineers.

Phasor technology complements existing SCADA systems to address the new emerging need for wide area grid monitoring and management, while
continuing to use existing SCADA infrastructure for local monitoring and control. Traditional SCADA/EMS systems are based on steady state power flow analysis, and therefore cannot observe the dynamic characteristics of the power system – phasor technology augments these existing systems by overcoming this limitation. These measurements provide time synchronized sub-second data which are ideal for real-time wide area monitoring of power system dynamics. The precise timing information of this data makes this data useful outside the confines of the local substation buses where these measurements were taken. Additionally, they improve post disturbance assessment capability using high-resolution time synchronized data. While not a replacement for SCADA, the phasor infrastructure will provide a layer of backup visibility should the operator’s primary tools fail.

Phasor measurement based systems, algorithms and applications have been researched and prototyped in the lab and test environments for the last 20 years, and have reached a level of maturity where they are ready to transition into the field and into operational environments. Technical developments in communication technologies and measurement synchronization have also made the design of wide area monitoring, protection and control systems realizable. These advance measurements in conjunction with FACTS and HVDC technologies are essential in extending the controllability of network flows across the power grid.

2. RTDMS Overview

The Real Time Dynamics Monitoring System (RTDMS) was developed to enable utilization of time-synchronized phasor measurements for reliability management with the overall objective of accelerating the adoption and fostering greater use of the technology within North America. Since 2003, it has been serving as a platform to translate research concepts and algorithms into actual applications for power system operators, reliability coordinators, and operating engineers both within the Eastern and Western Interconnections.

The overall functional block diagram for the RTDMS platform is shown in Figure 1. The central point of this system is the RTDMS Data Management Server serves as a data hub for its various applications. With the very high sampling rates (typically 10 to 60 times a seconds) and the large number of Phasor Measurement Unit (PMU) installations at the substations that are streaming data in real time, most phasor acquisition systems are handling large amounts of data. As a reference, the central Phasor Data Concentrator (PDC) at Tennessee Valley Authority (TVA), which is currently responsible for concentrating the data from over 90 PMUs across the Eastern Interconnection is handling over 31 GigaBytes of data per day. Fortunately, the data requirements are very much application dependent; none of the applications require all the data at its highest sub-second acquisition rate and in real time. For example, low latency prerequisites but only small subsets of the data may be required for performing control functions, while reliability monitoring applications need data from a larger set of monitored points but at lower data rates and can tolerate higher latencies. Hence, a key function of the RTDMS Data Management server is to buffer all the data at its highest sampling rate in memory for fast data access, and then to handle application specific data requests leveraging tradeoffs between latency, data rates, and amounts of data that is needed by the particular applications.

RTDMS adheres to open and modular system architecture, allowing for deployment over distributed hardware for scalability as the phasor acquisition network and the offered functionalities grow with time. The various input/output interfaces of its modules are publically exposed using standard technologies (e.g. web services, Microsoft’s Common Object Model or COM) and protocols (e.g. IEEE C37.118) permitting easy integration with other third-party applications. As an example, within the Eastern Interconnection, RTDMS has been integrated with VirginiaTech’s Frequency Network (FNET) system [1] – it can receive remote alarms from the FNET system and forwards these alarms in real time to all its Visualization Clients. At the California ISO (CAISO), it has been integrated with their PI Historian as a potential link into the EMS system.

Where possible, RTDMS has also been designed to be ‘plug-n-play’, automatically adapting to changes upstream at the phasor network as PMUs are constantly integrated, removed or reconfigured, thereby minimizing system downtime and the need for manual user intervention during such changes. It also allows for online system configuration changes (e.g. adding monitoring points, changing alarming parameters, etc.) and balances the need for having central configurability on the RTDMS Data Management Server for consistency across all users through common displays, alarming thresholds, etc., along with the desire for end-user configurability on the Client side to develop their own displays.

The applications that have been developed on the RTDMS platform, are designed as Client applications
that interact with the central RTDMS Data Management Server for its specific data requests and fulfill different functions ranging from wide-area visualization for situational awareness, to real time monitoring and alarming on key grid metrics related to voltage or dynamic stability to assess grid stress, to offline event analysis, and long term analysis and reporting services in support of baselining functions. These Client applications may either interact locally with the RTDMS Server over the utility’s LAN or remotely via a secure web connection for data & information needs.

![Figure 1. Phasor-RTDMS functional block diagram.](image)

**3. System Architecture**

In the conventional ‘hub-n-spoke’ type of a phasor network setup that is currently most prevalent with North America, data flows from the PMUs at the substation measuring the phasors (voltages and currents) and frequency at the very high sub-second rate and communicating it in real time along with precise timing information to the PDCs at a utility’s control center which concentrate and time-synchronize the data across the utility’s footprint and then forward it to a central PDC (a.k.a SuperPDC) at a central host site (at an ISO for example) where this data is concentrated once again to provide a precise Interconnection-wide snapshot. These comprehensive sets of measurements are streamed directly to RTDMS for local or remote viewing via its client terminals (Figure 2).

The RTDMS Data Management Server integrates directly with the PDC (or SuperPDC) and receives the complete data stream in one of the standard phasor protocols such as the BPA PDCStream or the IEEE C37.118 formats. Its PDCStream/C37.118 Drivers have been designed to connect with the data source (i.e. PDC) over a local area network, and to parse the data packets in real time by applying the appropriate scaling/offset factors that convert the data into engineering units, as well as to compute certain derived values (such as MW & MVAR). The inbuilt Data Quality Filters are capable of removing suspect data as it is streamed to (1) the Real Time Buffer in memory for temporary caching; (2) the Real Time Alarm & Event Detector for real time alarming and event detection; and (3) the long-term RTDMS Database for historical archival. The Real Time Buffer sorts and stores data by timestamp and is designed to provide high performance data write/read capability for downstream applications. Information from various algorithmic modules (such as the Small Signal Stability Module) as well as third-party applications (such as the FNET system) can also be simultaneously cached into this buffer via its exposed interfaces. The Real Time Alarm & Event Detector component is responsible for processing the real time information against a set of alarming criteria & event detection triggers, and save these results back into the Real Time Buffer for real-time alarming within the RTDMS.
Client applications, the RTDMS Database for offline report generation, and into an alarm log as text file. In case of event detection, the RTDMS Server will automatically save pre- and post-event data into binary Event Files which could be loaded into the RTDMS Clients for offline forensic analysis. The RTDMS Server GUIs provide a user-friendly interface for configuring various server-side settings that are common to all applications & users such as data filtering options, editing PMU/Signal static information, setting alarm and event detection criteria, etc.

Like the Real Time Alarm & Event Detector, the Small-Signal Stability Module is also an independent component that interfaces with the Real Time Buffer for data retrieval, pre-processes the data, and performs the real time mode estimation functions for small signal stability monitoring.

The Alarm Email Server and the Report Server are stand-alone server based applications which query the RTDMS Database and are responsible for sending out email notifications on system status, data quality, threshold violation alarms, as well as Daily Performance or Disturbance Analysis reports respectively.

A set of Web Services, exposed behind a secure login, serve as open input/output interfaces between the RTDMS Server and the RTDMS Clients (or other third-party applications). These include an Alarms Web Service for receiving real time alarm messages from external applications, the Output Web Service for receiving and responding to web based requests for real time data by remote applications, and the Reports Web Service for remotely accessing historical data archived within the RTDMS Database.

On the client side, (1) the Visualization & Event Alarms Client, (2) the Event Analyzer Client, and (3) the RTDMS Long Term Analysis & Reports Client are the various stand-alone applications that have been build on the RTDMS platform in support of real-time, offline and long-term monitoring and analysis functions respectively. They all have the ability to acquire data and information from the RTDMS Server, RTDMS Database or captured Event Files via the standard data access interfaces, to process this data, and to present the results within geo-graphic charts and displays.

Figure 2. RTDMS system architecture.
4. Applications and Functionalities

The RTDMS platform offers a suite of phasor-based applications that are geared towards translating phasor data into information that can be monitored, tracked, analyzed and acted upon by operators, reliability coordinators, and operating engineers in support of the following functions:
- Real time wide-area visibility within common situational awareness displays.
- Monitoring and alarming on key metrics related to grid stress, dynamics, and the power system’s proximity to instability.
- Perform offline forensic event analysis.
- Baseline normal operating conditions, limits & alarms.

Each of the various applications and their functionalities are discussed in greater detail below.

Visualization & Event Alarms: The main focus of this application is to bring phasor-based wide-area visibility and situational awareness into the control room. To achieve this goal, it’s crucial that the visualization application provide meaningful & actionable information for operators and reliability coordinators (RCs) in a concise fashion without either overwhelming them or resulting in unnecessary screen clutter. There is also the additional need to establish common displays to facilitate easy communication across organizations for consistency. To address these issues, the RTDMS visualization adheres to a tiered visualization architecture with drill-down capabilities from centrally configured and standardized “global” displays for wide-area viewing at the Interconnection & RC levels to “local” end-user customized displays at the utility level, offers a “dashboard” type summary display at the highest tier where all key information is integrated into one display in a concise fashion (Figure 3).

Drill-down to appropriate display by:
1) Geographic Region (Interconnection, Reliability Coordinator, Local, etc.)
2) Monitored Metric (Frequency, Voltage, Angle, Separation, MW, MVAR, Small Signal Stability, S sensitivities, etc.)

Within the RTDMS Visualization & Event Alarms application, the dashboard display is the highest tier in the visualization architecture and serves as the point of entry into the application (Figure 4). Here, simple gauges and traffic light concepts on various monitoring metrics are used to indicate whether there is or isn’t a problem with a particular metric, and therefore provide a quick assessment on the overall system status, as well as information on the associated geographic region(s) associated with the poor performance. Metrics well within alarming limits are shown in Green, those metrics approaching their alarming limits are shown in Yellow indicative of an alert condition, while metrics either exceeding their low or high alarming limits are shown in Red or Blue respectively implying an alarm situation. The set of predefined metrics that can be monitored via the dashboard include:
- Interconnection frequency, computed as a spatial average of the local frequency measurements at key monitoring points, with respect to acceptable operating limits as a measure of generation-load imbalances within the Interconnection.
- Frequency instability, computed as the maximum separation within all local frequency measurements, to assess system coherency and dynamic stress.
- Angle differences across key flowgates and between neighboring regions indicative of static stress across the power grid.
- Voltages at all monitored points with respect to their individual high/low operating limits to identify low voltage zones and adequate reactive support.
- MW and MVAR flows at important interfaces and tie lines with respect their operating limits.
- Damping on all oscillatory modes as a measure of grid robustness to potential disturbances and proximity to small-signal instability.
- Voltage sensitivities at critical interfaces/key load pockets indicative of proximity to voltage instability.
- Angular sensitivities at critical generating locations indicative of proximity to dynamic instability.

As new monitoring metrics are researched and validated, they can also be added into this summary display.

Once a problem with a particular metric and the associated region has been identified via the dashboard, the end user can then drill down to the display that is specifically dedicated for that problematic metric and region in which additional monitoring, tracking and analysis information on the metric is made available from all monitored points within and in the periphery of the problematic region (e.g. if there is a voltage problem, then only the voltage profiles and trends of all monitored substations in and around the affected jurisdiction are shown). Restricting the information that is presented to the operator through a systematic navigation mechanism is an effective way of preventing information overload and avoiding screen clutter.

**Small-Signal Stability Monitoring:** Low frequency electromechanical modes characterize the stability of the power system and limit the power flow across regions. While there is a danger that such modes can lead to instability in the power system following a sizable contingency in the system, there is also the risk of these modes becoming unstable (i.e., negatively damped) due to gradual changes in the system. The ability to continuously track the damping associated with these low frequency modes in real time and under normal conditions is therefore a valuable tool for power system operators.
RTDMS offers the ability to monitor and track modal frequency, damping and amplitude properties of multiple electromechanical modes using real time measurements taken under ambient system conditions using parametric system identification methods and thus presents a measurement-based approach for performing small-signal stability analysis without dependence on a power system model. In particular, three modal-estimation block-processing algorithms have been implemented to solve for the Auto-Regressive (AR) coefficients in the parameter estimation: extended modified Yule Walker (YW), extended modified Yule Walker with Spectral Analysis (YWS), and Sub-Space State Space System Identification (N4SID). The inherent assumption here is that the power system is primarily in steady-state driven by random processes when operating in an ambient condition due to the random variation of loads for example (i.e. the input can be modeled as white noise within the frequency range of interest) and the measurements then are colored by the power system dynamics. This coloring allows one to estimate the modal frequencies and damping terms. The problem formulation and algorithmic details can be found in [2-3]. Within the tool, operators are alarmed if the damping of any of the estimated modes falls below predetermined thresholds (e.g. 3% or 5%).

Additionally, appropriate pre-processing of the data including removing outliers based on PMU status flag information and setting tolerance thresholds on the various signal types (e.g. frequency, voltages) beyond which the data is marked as suspect, interpolating across missing data, detrending, normalization, and anti-aliasing filtering prior to down sampling are techniques used to improve the performance of these estimating algorithms. Furthermore, to eliminate false or undesirable modal estimates, proper post-processing of the modal estimation results is also desired that focuses on the interested range of frequency for the modes (i.e. frequency range associated with inter-area oscillations). Such post-processing logic includes setting the maximum number of modes for display, setting the maximum associated damping ratio, setting the energy threshold for the modes, and setting proper frequency ranges. These pre- and post-processing stages have been embedded into the Small-Signal Stability module within RTDMS (Figure 2).

Some of the visualization capabilities associated with the Small-Signal Stability Monitoring display include:
- mode meter gauges that provides information on damping ratios and damping frequencies of the observable modes in the system.
- mode tracking plots that offer valuable information on the most recent mode damping trends to operators (Figure 5).
- a waterfall plot which is a joint time-frequency domain plot and an illustration of the power-spectral density within the frequency range of interest and its recent trends over time (Figure 6).

Initial experiences have shown that under ambient system conditions, approximately 10-15 minutes of measurement data is required for reliable modal estimation. All three algorithms are found to be very consistent in their modal frequency estimates and over time (within a few mHz). However, the modal damping estimates exhibit greater variability over time (a few percent) especially when damping levels are higher than 10%. This variability goes away and the damping estimation accuracy improves under lightly damped conditions which is where the accuracy is most desirable (i.e. less stable modes). An explanation for this is that at lower damping, the...
Oscillations are more prolonged, therefore more observable in the data, and hence the modal properties can be estimated with greater accuracy. Additionally, the use of low-level pseudo random noise probing signals injected into the power system is an alternate way of improving the accuracy of the modal estimates as it increases the “signal-to-noise ratio” of the measurements. Within WECC, such probing tests are conducted on a routine basis each summer to obtain seasonal benchmarks for dynamic performance of the WECC system, and include energization of the Chief Joseph Break and modulation of the Pacific HVDC Intertie. Figure 7 shows RTDMS’s modal estimation trends for the most prominent inter-area modes during the 2006 low level probing tests (0.24Hz mode with 9-10% damping and a 0.36Hz mode with 7-8% damping) while Table 1 compares these modal damping estimates with those obtained during the recent 2008 low level probing tests.

Table 1. Comparison of modal estimates during 2006 and 2008 probing tests

<table>
<thead>
<tr>
<th>Modal Freq.</th>
<th>2006 Tests</th>
<th>2008 Tests</th>
</tr>
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<tbody>
<tr>
<td>0.24 Hz</td>
<td>9-10 %</td>
<td>13-14 %</td>
</tr>
<tr>
<td>0.36 Hz</td>
<td>7-8 %</td>
<td>6-7 %</td>
</tr>
</tbody>
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The variability in the mode estimates mentioned above is primarily due to the stochastic nature of the problem. Hence, using system identification methods used to estimate the electromechanical modes will always have a certain amount of random error associated with them [4]. More recently, a newly developed ‘bootstrapping’ method that quantifies this level of uncertainty (i.e. confidence bounds) associated with each of the modal estimates has also been incorporated into the application. In the future, this additional information could also be used in the post-processing stages to eliminate poor modal estimates as well as provide valuable feedback in fine-tuning the algorithm parameters towards improving the estimation process.

The real time small-signal stability monitoring capability has been well received at California ISO (CAISO), Bonneville Power Administration (BPA), and other utilities as it adds a new level of visibility and information on system dynamics that wasn’t previously available. The natural question that is being asked by operators is what control actions may be taken if poor damping conditions are observed. There is a parallel collaborative effort currently underway between Washington State University (WSU), Electric Power Group (EPG) and BPA which is investigating such corrective actions to mitigate oscillatory problems and to implement this capability on the RTDMS platform.

Voltage Stability Monitoring: It is well understood that with additional loading on the power grid, there is degradation in the voltages across the system. This relationship is typically represented by the P-V or Q-V curves (a.k.a. nose curves). Furthermore, the gradient at any point along such a curve provides the voltage sensitivity at that bus with respect to the loading conditions. This voltage sensitivity also serves as a measure of the proximity to voltage instability because it typically increases as the system operating point moves down the nose curve and closer to voltage collapse point. The traditional method for performing such steady-state voltage sensitivity analysis requires a detailed system model, especially the load model, which is built from historical data.

Phasor measurements offer the ability to obtain this very same voltage sensitivity information directly from the real time measurement without requiring any modeling information. They are therefore free of errors introduced by model inaccuracies and are a true representation of the actual system conditions. Specifically, PMU devices installed at a substation measure the voltage phasors (both magnitudes & angles) at a bus and the MW and MVAR flows on the monitored lines. With the precise time-synchronized alignment and the high sub-second resolution of these measurements, it is possible to trace out portions of the P-V or Q-V curves for a monitored critical load bus or interface in real time. Additionally, there is enough loading variation within the system to estimate the local gradient of such curves using linear regression techniques which map changes in one variable (MW or MVARs) to changes in the other (voltages) – i.e., the most current voltage sensitivities at that location/interface. It is also possible to quickly
detect discrete changes in the system such as control actions (e.g. insertion of cap banks), which cause these curves to shift outward (or inward).

Figure 8. RTDMS voltage sensitivity monitoring.

RTDMS has a display dedicated for monitoring voltage sensitivities (Figure 8). The visualization used to convey this information includes:

- The voltage sensitivity scatter plot that traces the P-V curve (correlation between MW flow and voltage) along with the best-fit straight line through the data whose slope characterizes the voltage sensitivity.
- A bar chart illustrating the most recent voltage sensitivity (in kV/100MW) trends color-coded to indicate proximity to its threshold limits.

More recently, algorithms capable of extrapolating beyond the linear sensitivity information to estimate the actual voltage stability margin are being implemented in RTDMS. Such methods utilize parameter estimation techniques to compute one generator Thevenin equivalents (or Thevenin equivalents at both sides of the bus) [5], which in turn are used to estimate the entire P-V curve to ascertain voltage stability margins (Figure 9).

Figure 9. Estimating voltage stability margins with phasor measurements.

The voltage stability margins described above have yet to be validated against model based simulation studies. Thus far, the results are found to be consistent across the various data sets available for testing purposes. It is our premise that while such a measurement-based voltage stability assessment approach may not account for any discrete controls such as capacitor bank switching that may potentially occur as the system is further stressed, it will nonetheless be capable of tracking the system conditions through such topology changes in real time and this would be reflected in its margin updates.

**Event Analyzer:** The main objective of this application is to enable operating engineers and planners to perform offline forensic analysis using phasor data captured during major disturbances. The applications allows the user to load and merge either a single or multiple event files provided in standard formats into the tool and, through its various displays, perform analysis on the chosen dataset. Some of the key design principles that have been used in developing the application are:

- Intuitive user-friendly graphic interfaces for ease of use.
- Extreme flexibility for the end-user in defining the pre-processing, algorithm parameters, and the post-processing settings.
- Incorporate state-of-art algorithms for the offered analysis functions.

The first stage in the analysis process requires the user to select a subset of signals over chosen time duration for further analysis. These signals may include both the raw (voltage magnitudes, current magnitudes, voltage angles, current angles, frequency, status flags) and derived (MW, MVAR) values. Here, a set of standard data cleansing operations, such as automatic removal of suspect data and patching of the missing data gaps is available to the user. At this stage, the selected data may be exported as .csv file for data sharing purposes or optional analysis within other standard tools such as Excel or Matlab. Once the data set of interest has been selected, the user can then proceed to perform further analysis on this dataset within the tool. The offered analysis options shall include trending, spectral analysis and modal analysis capabilities.

The application’s trending analysis display lets the user view and process selected data trends. Some of the available processing operations include detrending of data (e.g. detrend frequency to view the off-nominal frequency deviation trends), normalization (e.g. normalize voltage magnitudes by their base kV levels to show these trends in per-unit),
differentiation (e.g. differentiate frequency to view the frequency rate-of-change), low-pass filter, re-sampling, etc. Other capabilities offered here include the ability user to zoom-in or zoom-out, and set and drag trace markers to read x-y values (or Δx-Δy values) along the trends.

The purpose of spectral analysis display is to allow the user to analyze the spectral content of the chosen signals. The three primary calculations that may be viewed within this display include (Figure 10):
- **Power Spectral Density (PSD) or Auto-Spectrum**: to identify sharp peaks indicative of strong oscillatory activity observable in the signal.
- **Coherency**: to identify a signal’s correlation or participation in a particular mode.
- **Cross Spectral Density (CSD) or Cross-Spectrum**: to identify the relative phase information associated with a particular mode (i.e. mode shape information).

Appropriate pre-processing options such as detrending, normalization, low-pass filtering, downsampling to condition the data prior to applying the algorithms are also offered to the user.

**Figure 10. RTDMS Event Analyzer spectral analysis display.**

While spectral analysis is a useful tool for analyzing oscillatory activity and in the selection process of signal sets where a particular mode is most observable, the modal analysis displays offer a mechanism for assessing the stability of the power system by estimating the mode frequency, damping and the energies associated with these oscillatory modes. Here, the user may choose a set of signals and apply various system identification algorithms (e.g. Prony, extended modified Yule Walker, etc.) used for modal analysis of both disturbance and ambient data.

As in the case of spectral analysis, the many pre-processing options are also presented to the end-user as are the various parameter settings for the different algorithms. The user may easily modify these setting and view the associated algorithm results (i.e. mode
frequency, damping and energy) as trend plots within the display.

**Long-Term Analysis & Reports:** The focus of this application is to assist in performing baselining functions to facilitate better understanding and an Interconnection-wide prospective of local and inter-area grid dynamics under normal conditions and during disturbances. The application offers both on-demand and automated reporting feature providing long term historical trending and statistics (e.g. box-and-whisker plots, XmR control plots) of PMU data and derived quantities, phasor data quality performance charts, and alarm logs captured by the real-time alarming component of the RTDMS platform. The automated reporting feature adds the ability of automatically generating a compilation of the above mentioned information and charts into summary Daily Performance Reports or Disturbance Analysis Reports which are emailed to a predefined subscriber list (Figure 11).

**Figure 11. Sample daily performance report.**

4. Conclusions

The RTDMS platform is being used across North America to translate research concepts into tools for operators, reliability coordinators and operating engineers. Within the Western Interconnection, it is installed at BPA, CAISO, and BC Hydro where it integrates directly with their local PDCs over a LAN setup and provides real time visibility, analysis and assessment capabilities on their phasor data. At the CAISO which receives real time phasor data from over 50 PMUs across the Interconnection, it runs on production grade hardware, and has been migrated to the corporate secure network supported by CAISO IT. There are 12 RTDMS Clients at CAISO’s main Folsom facility include a client at the Reliability Coordinator desk in the Folsom Control Room. Within the Eastern Interconnection, under the North American SynchroPhasor Initiative (NASPI), it is currently the primary tool in place for viewing the Eastern Interconnection phasor data in real time. The RTDMS Server installed at the TVA host site integrates with their SuperPDC receiving real time phasor data from over 80 PMUs, and disseminates the processed information over secure internet connection to remote RTDMS Visualization Clients for real time monitoring and alarming installed at over 25 utilities and ISOs within the Interconnection.

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