ABB Inc.
FINAL TECHNICAL REPORT

Smart Grid Research, Development, and Demonstration
DE-FOA-0000313

Award:	DE-OE0000547
Lead Recipient:	ABB Inc.
Project Title:	Real-Time Distribution Feeder Performance Monitoring, Advisory Control, and Health Management System
Principal Investigators:	James Stoupis, Mirrasoul Mousavi
Date of Report:	December 29, 2013
Reporting Period:	April 1, 2011 – September 30, 2013

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Executive Summary

New data collection system equipment was installed in Xcel Energy substations and data was collected from 6 substations and 20 feeders. During Phase I, ABB collected and analyzed 793 real-time events to date from 6 Xcel Energy substations and continues today.

The development and integration of several applications was completed during the course of this project, including a model-based faulted segment identification algorithm, with very positive results validated with field-gathered data discussed and included in this report. For mostly underground feeders, the success rate is 90% and the overreach rate is 90%. For mostly overhead feeders, the success rate is 74% and the overreach rate is 50%. The developed method is producing very accurate results for mostly underground feeders. For mostly overhead feeders, due to the bad OMS data quality and varying fault resistance when arcing, the developed method is producing good results but with much room for improvement. One area where the algorithm can be improved is the accuracy for sub-cycle fault events. In these cases, the accuracy of the conventional signal processing methods suffers due to most of these methods being based on a one-cycle processing window. By improving the signal processing accuracy, the accuracy of the faulted segment identification algorithm will also improve significantly. ABB intends to devote research in this area in the near future to help solve this problem.

Other new applications developed during the course of the project include volt/VAR monitoring, unbalanced capacitor switching detection, unbalanced feeder loading detection, and feeder overloading detection.

An important aspect of the demonstration phase of the project is to show the ability to provide adequate "heads-up" time ahead of customer calls or AMI reports so that the operators are provided with the much needed time to collect information needed to address an outage. The advance notification feature of the demonstration system provides this time and helps accelerate service restoration ultimately. To demonstrate the effectiveness of this feature, a demo system <u>using substation data alone</u> was set up to compare the minutes saved over a period of 22 months for two feeders where the real-time notification system has been deployed. The metric used for performance assessment is the time difference between the actual outage time from the OMS versus the time the notification email was received on the operators desk. Over the period of 22 months, we have accumulated over 7600 minutes (32 hours) ahead of actual outage time compared to the OMS timestamps. The significance of this analysis is that it shows the potential to reduce the SAIDI minutes and directly impact utility performance in terms of outage duration. If deployed at scale, it would have a significant impact on system reliability. To put this number in perspective, it would be helpful to assign a dollar figure to the potential savings that could be realized. According to the host utility, the average cost for each customer-minute-out (CMO) is approximately $0.30 across the operating company. This includes both direct and indirect costs such as bad press. The outage data over the previous 4 years show that the average customer count on primary/tap level outages is about 56. Accordingly, the total minutes saved amounts to 425,600 CMOs on the average. This would in turn result in a potential cost savings figure of $127,680 for two feeders alone over the period of performance. This empirical evidence validates the strong value proposition of the project that was contemplated at the onset and its potential impact to reduce outage duration in support of DOE's goal of 20%.

Main Accomplishments

The main accomplishments to date for the project are described in the table below. Equipment was installed and event data was captured at 6 substations, providing data from 20 connected feeders. The development and integration of several applications was completed, including a model-based faulted segment identification algorithm, with very positive results that are discussed and included in this report.

Milestones and Metrics	Actual Performance
Project Milestones: Installation of new data collection systems in the Xcel Energy substations completed. The gathering of data on the Xcel Energy feeders was completed.	The new data collection system equipment was installed in Xcel Energy substations and data was collected from 6 substations and 20 feeders.
Development and integration of a faulted segment identification algorithm was completed.	Using an automated feeder modeling technique to determine the updated, as-operated feeder connectivity, a faulted segment identification algorithm was tested and integrated for on-line verification and validation.
Developed and integrated new real-time feeder monitoring applications into the substation computer-based monitoring solution.	New applications include volt/VAR monitoring, unbalanced capacitor switching detection, unbalanced feeder loading detection, and feeder overloading detection.

Task #2 – R&D Project Management

Project management activities have been ongoing in the project since the start of Phase I. The coordination of research and development activities was challenging, since it involved not only internal coordination within different groups within ABB but also with the subcontractors. However, the project management and coordination was very successful for the project, as the field data collection, R&D, and demonstration activities have been successfully carried out.

Task #3 – Field Data Collection for R&D

The new data collection system equipment was installed in four Xcel Energy substations starting in August 2012. The individual device configurations were completed in Q4/2012, in time for the start of the demonstration part of Phase I of the project. After a workshop between ABB and Xcel Energy in March of 2012, it was decided to employ safer equipment installation options than the “temporary” installation methods used in the previous project. This decision resulted in additional time and money spent on the project, but affords the project team and DOE permanent installation sites to showcase the deployed technologies.

Each installation required a 3-step process executed over a few weeks. In the first step, Xcel Energy personnel would finish all the wirings and cable routings from the secondary of voltage and current transformers to the IED panels according to the approved engineering drawings per substation standards and safety rules. In the second step, a relay technician would help switch over the feeders for cut-overs and final connection of the wires to the relay panels while the feeders or switchgear being worked on were de-energized. In the 3rd step, the ABB team would visit the substations to configure each IED, the substation computer, and deploy the real-time feeder health and performance system. Unexpected issues and field problems did occur during the course of execution which were successfully addressed by the team. Final tweaking and setup configurations occurred remotely over a dedicated 3G communications infrastructure.

Subtask 3.3: Field Data Collection Equipment Installation
The new data collection system equipment was installed in Xcel Energy substations starting in August 2012. The individual device configurations were completed in Q4/2012, in time for the start of the demonstration part of Phase I of the project.

Subtask 3.4: Testing of Field Data Collection System
The project team (ABB and Xcel Energy) started and continued the data collection, interpretation, analysis, and verification process during all of Phase I, since the legacy equipment was still in place at the beginning of Phase I. During Phase I, ABB has collected and analyzed 793 real-time events to date from 6 Xcel Energy substations and continues today. Some event waveform examples are shown in the Task #8 Demonstration section.

Task #4 – Modeling, Simulations, and Studies
Subtask 4.1: Literature Survey:
The literature survey has been completed on fault location application and sensitivity analysis approaches. In summary, the existing fault location techniques have been classified based on the type of data they use to pinpoint a fault as follows:

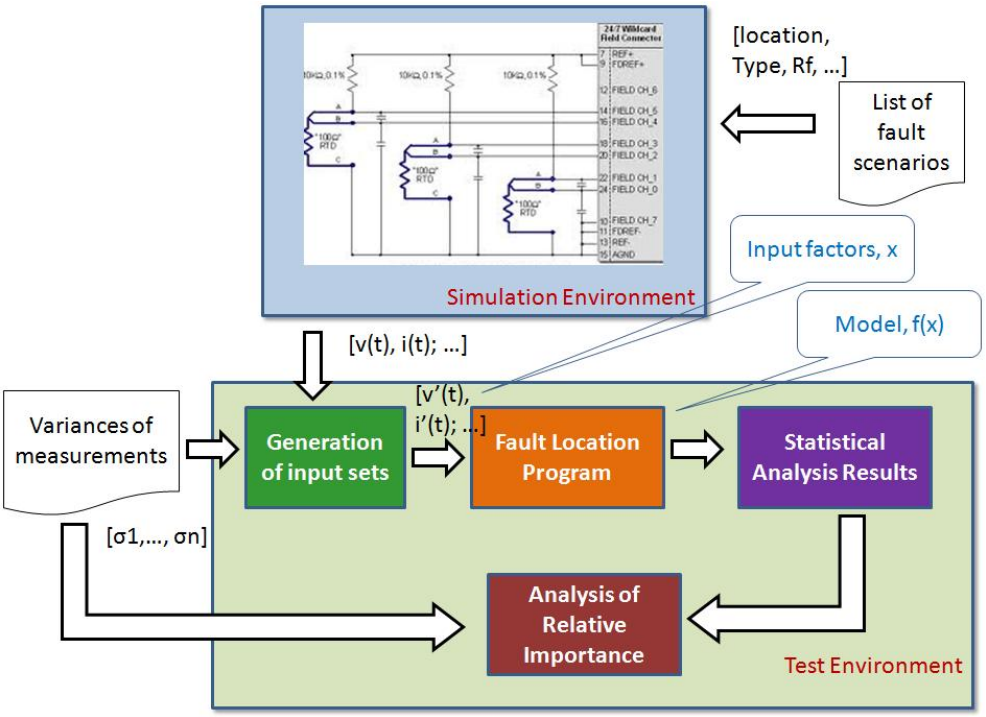
- Impedance measurement
- Direct three-phase circuit analysis
- Superimposed components
- Traveling waves
- Power quality monitoring data
- Artificial intelligence

The focus for fault location for Phase I was on the impedance-based techniques as the belief was that, given the data and model requirements, these methods were more suited to achieve the project objectives while minimizing the eventual cost of the solution.

Subtask 4.2: Characterization of Selected IEDs and Impact Study:
Texas A&M focused on researching methodologies related to sensitivity and uncertainty analysis generally and as they are related to fault localization in particular. The progress is as follows:

- Texas A&M surveyed the general methods for sensitivity analysis from technical literature. These methods were studied and the variance-based method was chosen for the sensitivity analysis of fault location algorithms.

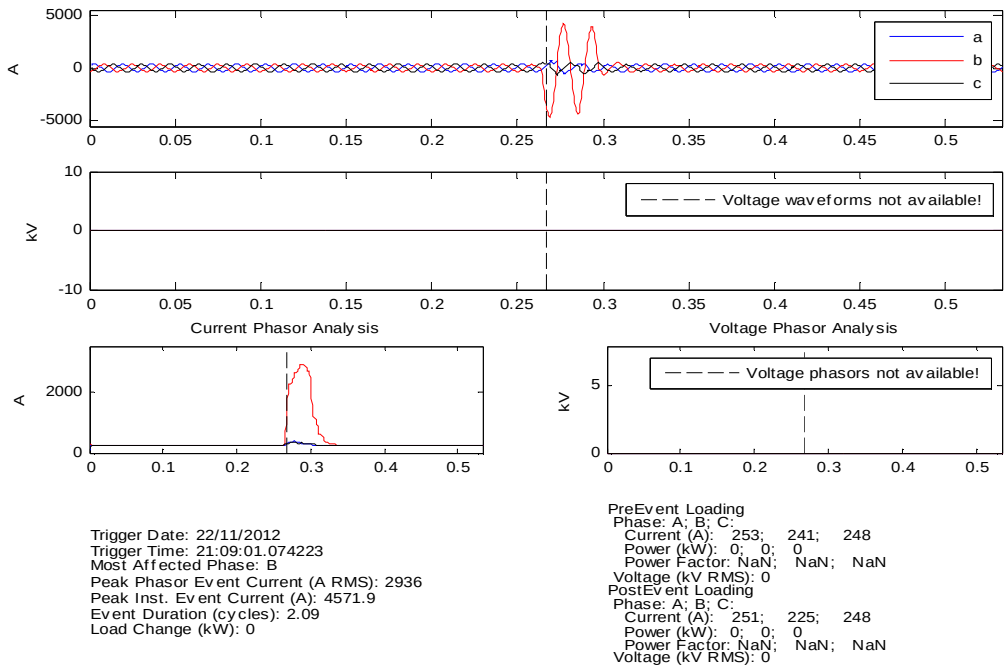
- A literature search of variance-based sensitivity analysis related specifically to fault location algorithms was performed. The references found described various approaches in applying measurements about performance of algorithms and data sources to sensitivity analysis at the transmission level. The goal was to understand the details involved in applying the specified methodology to the sensitivity analysis task, and develop the methodology that fits for testing fault location algorithms at the distribution level.
- Texas A&M generated and executed a test plan for this subtask and the overview is shown in the figure below. The upper part of the figure is the simulation of fault scenarios in a simulation environment such as RTDS, and the lower part is the testing of the fault location algorithm in a data processing environment such as MATLAB. For a specific fault scenario, the simulation was performed on a system model first to record "pure" measurements (measurements without errors). The measurements will then be used to generate sets of input needed for fault location, adding error according to their deviation. The input sets will then be fed to the fault location program one by one and the errors of output (distance between calculated location and actual location) will be reported, based on which distribution function of the output will be determined.
- On the modeling and simulation of systems with distributed energy resources connected to the distribution grid, Texas A&M completed this modeling, which will aid in the aforementioned sensitivity analysis in order to determine the effect of DERs on fault location algorithms. The remaining work in Phase I on this task is to incorporate the developed models in the test system and evaluate the impact of DG resources on the selected fault location algorithm.



Subtask 4.3: Fault Location Algorithms for Demonstration:
Integration and testing of a short circuit-based fault location algorithm were completed during Q1/2013. Effective fault location methods were identified in a previous project between ABB and Texas A&M University. The method applies a short circuit analysis method to determine if a fault could possibly have occurred on each section of the feeder. The potential faulted segments of the feeder are identified one by one and reported as potential faulted segments using a priority ranking based on fault impedance.

Using the table generated from the Xcel Energy data described in the Subtask 4.4 section, the algorithm is being tested and demonstrated on new fault events obtained from the real-time system. The figure below illustrates one of the newest cases where there were 7 segments identified as most likely faulted segments in the tested feeder network model out of a possible 1753 line segments, with the actual fault segment (the green line in the right section of the feeder) identified as one of those segments. The number of potential faulted segments varies depending upon the actual location of the fault. There tend to be less potential faulted segments the closer the fault is to the substation. As more feeder sensor data is available, more potential faulted segments can be eliminated from the list, helping to narrow down the actual faulted location. In turn, this will result in faster fault location identification and less outage time for affected customers.

Event information for this case is given in the following figure where a confirmed cable fault has been indicated by Xcel Energy on B phase. The peak phasor fault current for this case was 2936A whereas the instantaneous peak topped 4571A.



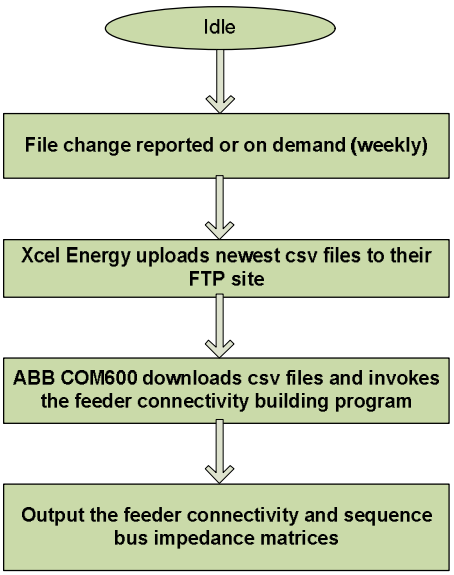
Based on the previously developed sequence-domain short-circuit analysis based faulted segment identification method, ABB further developed a new sequence-domain bus impedance matrix based fault location pinpointing method in Q2/2012. The network model is still the short-circuit model, which has ignored all the loads and line shunts. The input of the algorithm is the feeder head current measurements during fault. This method sweeps all the line segments and directly calculates the fault location estimate for each segment by exploiting the bus impedance matrices and boundary conditions for different types of fault. If the produced fault location estimate is between 0 and 1 p.u., the corresponding segment is regarded as a faulted section candidate. As a result, the output of the fault location algorithm is a set of candidate faulted segment associated with respective fault location estimate.

The fault location pinpointing algorithm was validated in a simulated network first. Furthermore, ABB tested the algorithm on two actual feeders using the connectivity table generated from the Xcel Energy GIS data described in the Subtask 4.4 section. ABB has compared the results of the sequence-domain short-circuit analysis based faulted segment identification method and the newly developed sequence-domain bus impedance matrix based fault location pinpointing method. The results were, for all the actual cases, both methods yielded the same faulted segment candidates, whereas the pinpointing method also provided a fault location estimate for each potential segment.

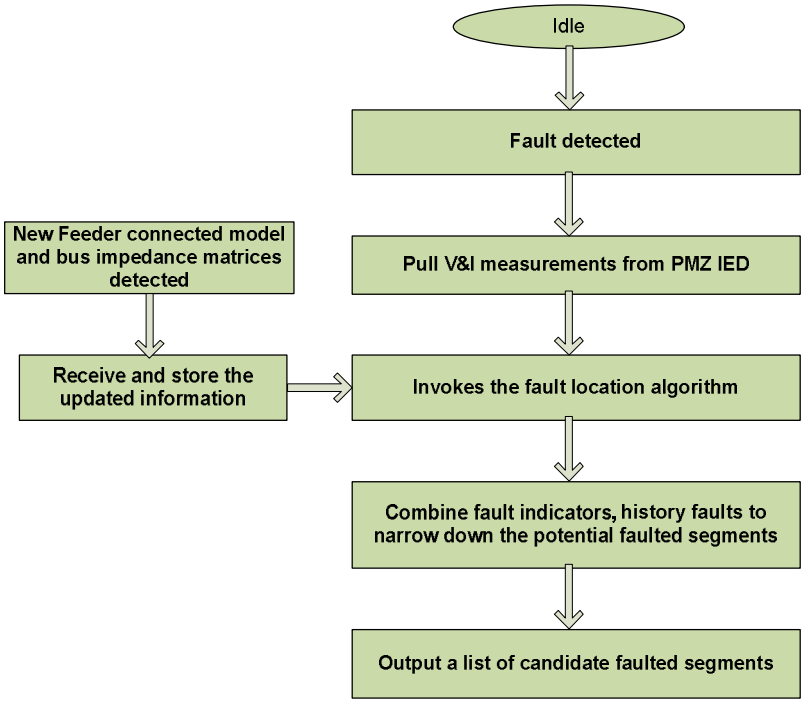
Utilizing Matlab Compiler and Builder NE, the fault location code originally written in Matlab script was deployed as a .NET assembly. It was then readily integrated into the existing feeder health and monitoring solution. During the field trip to Xcel Energy in the end of February, the integrated solution was deployed on a COM600 substation computer. It only requires the pre-fault voltage and during-fault current measurements from the REF615 installed at the head of the

faulted feeder. The feeder models utilized in the fault location algorithm are updated once a week upon a new extract from the OMS and are obtained by executing the feeder connectivity automation program developed in 4.4. The built network connectivity models are cached in the memory and ready to be called by the fault location program. When a fault is detected on any of the monitored feeders, the fault location by segments result is calculated and reported in a text file in a real-time fashion. The flow chart of the off-line feeder connectivity automation program and the on-line fault location program are shown as follows:

Off-line network connectivity building program flowchart

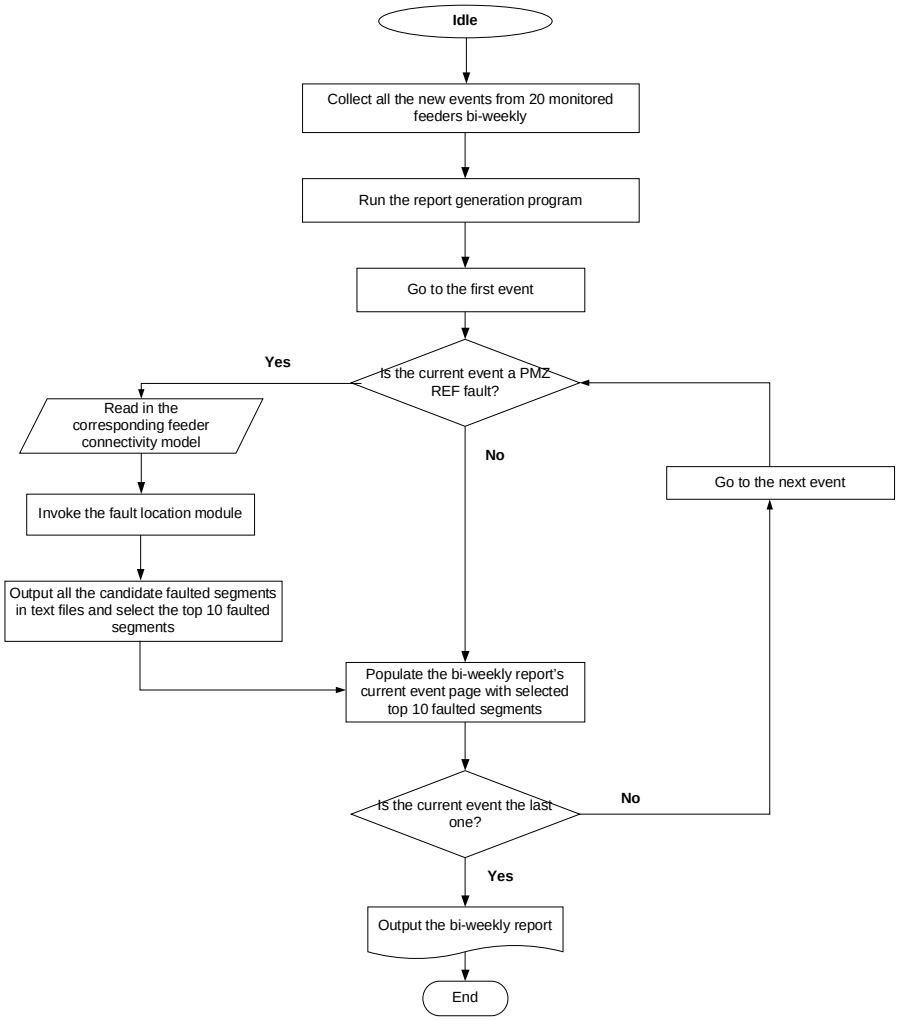


On-line fault location program flowchart



In Q2 2013, for the "fault location algorithms and demonstration" package, the main focus was on integrating the faulted segment identification result as an essential part of the bi-weekly report. This milestone was achieved by delivering the first bi-weekly report including the identified faulted segments where applicable on May 23, 2013. The idea is to execute the fault location algorithm off-line when running the bi-weekly report and populate the "Top Faulted Segment" column on the corresponding event page of the bi-weekly report for each and every eligible fault event. In the meanwhile, for each eligible fault event, the full set of identified faulted segments is outputted in a JSON (JavaScript Object Notation) file. Then the Xcel Energy analysis expert checks with their OMS and verifies the results. Xcel's analyst uses coloring schemes to indicate a direct hits and adjacent segments. This iterative approach allows ABB to validate and possibly improve the fault location methodology. There have been 22 bi-weekly reports processed to date since May 23, 2013. The flowchart delineating the aforementioned procedure is shown as follows.

Off-line DFEVA-integrated fault location program flowchart



Two on-going work packages have been integrating the identified faulted segments in the real-time notification emails and at the same time updating the substation data websites with the identified segments visually shown on a feeder map. Once completed, the solution will be deployed on a COM600 substation computer.

In Q3 2013, an off-line fault location visualization program was developed to facilitate validating the faulted segment identification methodology. Bringing up the actual faulted segment and the identified faulted segments on feeder maps provides an intuitive way to evaluate the performance of the faulted segment identification algorithm. For each and every qualified fault event from the bi-weekly report, a corresponding map is produced. The procedure to create a fault location visualization map is elaborated as follows. According to the feedback from the Xcel Energy Analyst, ABB manually edits all the faulted segment identification result files in JSON format by adding the actual faulted segment/device. These augmented JSON files contain a unique identifier for each identified faulted segment and the actual faulted segment/device. Suppose the GIS shapes files of the relevant feeders are available, which include layers corresponding to line segments, transformers, fuses, switches, circuit breakers, busbars and etc. For each JSON file, the visualization program searches the relevant GIS layers to extract the latitude and longitude coordinates for its elements according to their unique identifier. Then the visualization program converts all the JSON files into a KML (Keyhole Markup Language) file, which can be brought up on Google Maps or Google Earth. Next, the visualization program converts all the GIS shape files from all the relevant feeders into another KML file. Eventually, one imports both KML files to Google Earth or Google Maps to visualize the faulted segment identification result. One has the option to visualize each fault event individually by choosing the specific event. The program uses the green color to highlight the actual faulted segment/device, the red color to highlight the identified faulted segments and the yellow color to display the feeder segments. A snapshot of Google Earth map of an actual fault case on an actual feeder is shown below. For this fault event, one can see that the faulted segment identification program has identified several segments in red and one of them is adjacent to the actual faulted segment in green.

ABB has created a fault location result library to book keep all the faulted segment identification results. It is a database with each row representing a fault case. The columns containing information related to the fault event itself such as duration, fault type, event date and time, and some key factors that impact the accuracy of the faulted segment identification result such as OMS extract data quality. Most importantly, it keeps a column which counts how many segments away the estimated segment is from the actual faulted segment/device to evaluate the accuracy of the result. A “0” value indicates a “direct hit” situation; a “1” value indicates the estimated segment is adjacent to the actual faulted segment and so on and so forth. For those non-direct hit cases, a column is reserved to record whether the identified segment overreaches the actual faulted segment, i.e. downstream of the actual faulted segment, due to the maintenance crew prefering to work towards the substation when they are searching for the fault. An overreach situation is ideal for their working mode.

To date, ABB has collected 85 fault events that belong to PMZ (Primary Monitoring Zone) and are not re-fusing attempts. Re-fusing events occur when the repair crew is repeatedly blowing the protection fuse on purpose to search for the faulted segment. About 90% of the faults have occurred on the laterals, which do not cause circuit breaker trips and thus invisible in SCADA (Supervisory Control and Data Acquisition). Fault location on laterals today is still very hard to achieve and is the main goal of this work package. To quantitively evaluate the faulted segment identification method, two metrics “*Success Rate*” and “*Overreach Rate*” are defined as follows:

$$Success\ Rate(\%) = \frac{No.\ of\ \ Cases\ with\ Acceptable \mathrm{Re}\,sults}{Total\ \ No.\ of\ \ Cases} \times 100$$

$$Overreach\,Rate(\%) = \frac{No.\ of\ \ Cases\ with\ Identified\ Segment(s)\ Downstream\ of\ \ AFS}{Total\ \ No.\ of\ \ Cases\ that\ were\ not\ "Direct\ \ Hit"} \times 100$$

In this study, if the identified segment is within 3 segments of the actual faulted segment (AFS), the result is considered acceptable.

Some events come from the primarily underground feeders and others from the primarily overhead feeders. For mostly underground feeders, the success rate is 90% and the overreach rate is 90%. For mostly overhead feeders, the success rate is 74% and the overreach rate is 50%. The fault resistance is assumed as 0 ohm in the faulted segment identification algorithm, which is mostly the case for underground cable faults. Therefore, the developed method is producing very accurate results for mostly underground feeders. For mostly overhead feeders, due to the bad OMS data quality (there is still remaining issue with the sub-length of the sub-segment) and varying fault resistance when arcing, the developed method is producing good results but with much room for improvement. This work has paved the road to a more accurate and robust algorithm that will work equally well on both underground cables and overhead lines. One area where the algorithm can be improved is the accuracy for sub-cycle fault events. In these cases, the accuracy of the conventional signal processing methods suffers due to most of these methods being based on a one-cycle processing window. By improving the signal processing accuracy, the accuracy of the faulted segment identification algorithm will also improve significantly. ABB intends to devote research in this area in the near future to help solve this problem.

ABB has presented the faulted segment identification result summary to Xcel Energy management teams during three webinars on September 12, September 23 and October 9.

Another work completed in 2013 is the upgraded DFEVA-integrated fault location solution. Compared to the version deployed on the Xcel Energy COM600 substation computer during February's field deployment, the improvement is that the identified faulted segments are integrated as part of the real-time notification via email service. The solution has been tested on a local computer set up as a substation computer and the upgraded solution is working properly.

Subtask 4.4: Simulation Model Development and Validation:

Existing distribution test system models used in previous ABB research projects were analyzed to determine their applicability to this project. Three distribution system models were evaluated, including a real utility system, an IEEE 34 node system, and a microgrid-type system. The high level features and main electrical elements of each test system were summarized. The three systems were originally developed in MATLAB/ SimPowerSystems software and were also implemented in RT-LAB simulator to achieve real-time simulation. To test multiple IEDs hardware in the loop (HIL) simulation, a RT-LAB HIL simulation system including 5 physical IEDs was created. In this new test system, each physical IED obtains current signals from the simulated distribution system and sends the switch control signals to the simulated system. The limitations of the RT-LAB simulator to simulate large scale distribution systems were also

studied. The simulation studies indicated that the simulation step size of the distribution system should be no less than 12 microseconds and the total number of electrical elements in the distribution system model should be no more than 300.

Various existing DER models in ABB were also studied and summarized for their applicability to this project. Existing DERs that have been previously modeled include a wind turbine generator, PV panel, battery (lead-acid type), flywheel, and diesel engine generator. These DERs were implemented in the MATLAB/SimPowerSystems software. The wind turbine generator, battery, flywheel, and diesel engine generator were implemented in the RT-LAB simulator. In order to ensure real-time simulation, all the power electronics interfaces of DERs were implemented using averaged models. Since the PV panel model includes algebraic loops, it could not be directly implemented in the RT-LAB simulator. Another two types of DERs, microturbine and gas turbine generators, were also modeled in the RT-LAB simulator. The simulation studies for DERs in RT-LAB simulator indicates that it is reasonable to choose the simulation step size for DERs between 50-100 microseconds, which ensures that simulation results are accurate enough and the simulation can be finished in reasonable amount of time.

ABB has developed a way to take the shape files from Xcel Energy's geographic information system (GIS) and to automate the reading of that data, converting it into tables that can be used by any application. Each table represents the connectivity and other attributes pertaining to a feeder. The plan in the future is for ABB to obtain the updated GIS files from Xcel on a regular basis, so that the feeder models can be updated, representing the as-operated system, and the developed algorithms can be validated as event data is subsequently captured. This method is an effective means of preparing the algorithms for effective realization in a real-time operation environment, i.e., the demonstration stage.

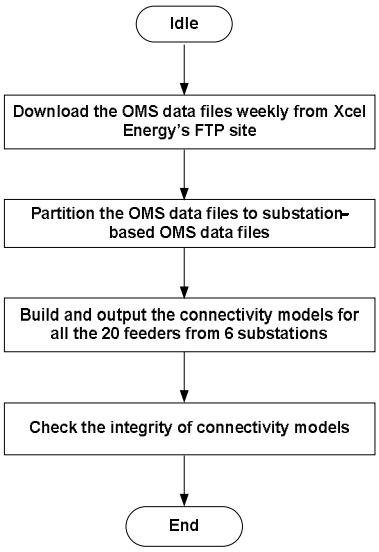
ABB received the first set of object files from Xcel Energy through a custom program that was developed to extract the required information from the OMS (Outage Management System). The automated program to derive the feeder connectivity from the OMS data files was revised to work with the new data files received. Currently, ABB is working with Xcel Energy to resolve minor lingering data quality issues to fully automate this task. Once the data file attributes are finalized, an automated program will output the connectivity table which will be used for Phase I real-time applications including fault location. Compared to the connectivity established from the GIS shape files, the OMS model is closer to the as-operated system topology and therefore it is expected that the fault location results will be improved. This has been observed to be b in the case studies using actual field data. The current plan is for ABB to obtain a fresh set of OMS extracts in a bi-weekly fashion via a secure FTP site, and demonstrate the fault location algorithms with the actual event data captured as part of Phase I work. The event notifications will be augmented to include fault location information in addition to other event information currently being communicated in the notification email messages.

During Q4/2012, the feeder connectivity automation program was finalized and was already deployed on an actual substation computer to demonstrate the Phase I fault location application for this substation. Since February 22 2013, ABB started to receive full sets of OMS data containing all the monitored 20 feeders from 6 substations in a weekly fashion. Due to some new issues emerging from the new data sets, some more work is required to further modify the

feeder connectivity automation program to fully develop connectivity models for all the feeders. Once this is done, the fault location results will be reported both in the bi-weekly feeder event report and through the real-time notification system.

During Q2/2013, the comprehensive feeder connectivity automation program was developed and validated. It is able to process the full OMS data sets from Xcel Energy and output feeder connectivity models for all the monitored 20 feeders from 6 substations. The models have been employed to calculate the fault location results in the bi-weekly report. The procedure to execute the feeder connectivity automation program is displayed below.

Off-line network connectivity building program flowchart



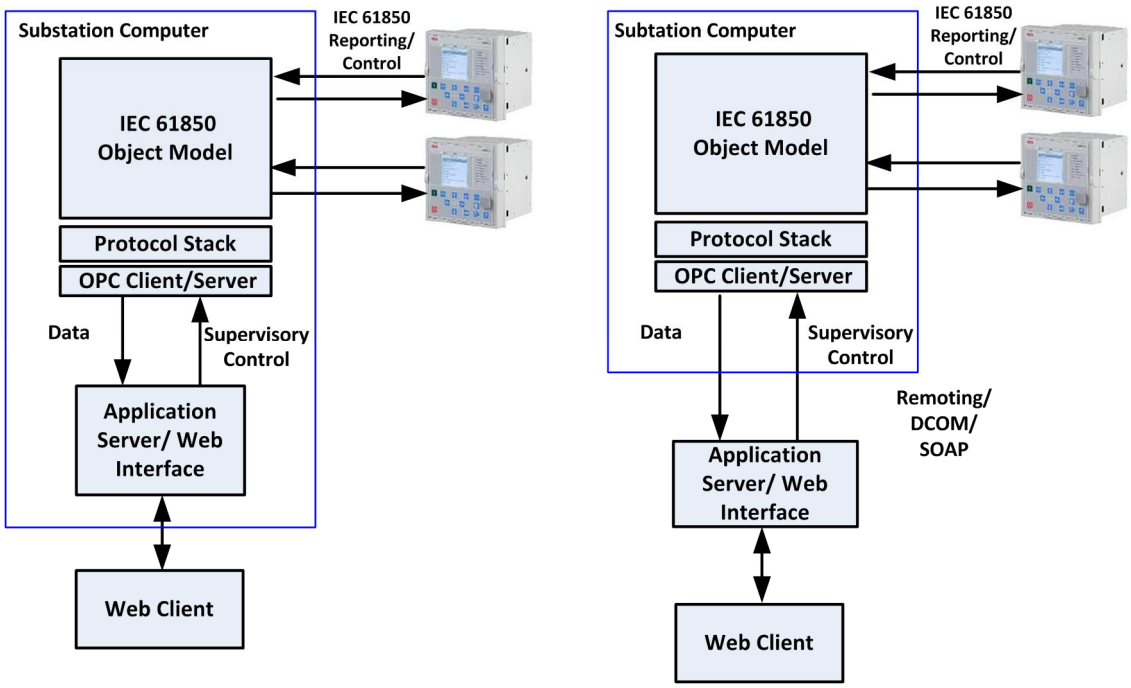
Subtask 4.5: Simulation Runs and Feedback Collection:
This subtask is ongoing, and will be completed by the end of Phase I.

Task #5 – Application Server Architecture and Development
Subtask 5.1: Design and Architecture:
Since IEC 61850 has been selected for collection of the data from field devices, the field data collection system must be able to receive the data as defined in IEC 61850-8-1 Specific Communications Service Mapping to MMS. The substation computer selected for the project includes full support for IEC 61850 data objects and services, as specified in Edition 1 of the International Standard. Accordingly, it will communicate with the IEDs using the built-in IEC 61850 protocol stack. In addition, substation computer includes support for Object Linking and Embedding for Process Control Data Access (OPC DA) standard specifications. Both OPC DA Client and Server technologies are supported, which can be used to provide gateway functionality and the ability to read and write real-time data for the main data collection and advisory control system. Therefore, the application server will use OPC DA mechanisms to exchange real-time data with the IEC 61850 automation system.

Two architectural options are currently being investigated: first with the application server

residing on the substation computer, and with the external application server. In the current implementation deployed in the select substations, the application server resides on the station computer side; in the future an alternative architecture will be investigated with the applications server moved completely outside the substation. This architecture requires the implementation of remoting services. However, it is expected that some part of the data processing and logging may still occur at the substation computer level in order to be able to maintain functionality even if the external WAN link is down. The overall objective is to obtain a balance between local data acquisition and processing speed versus communications bandwidth and storage requirements for reporting and data archiving.

The following figure shows the overview of the two application server architectures.



Subtask 5.2: Development and Implementation:
In Q2/2012, the major effort was put on the feasibility estimation and the implementation of Architecture 1 from the above figure, i.e. the case when the application/web server interface both reside on the substation computer side. The feasibility estimation part includes the analysis of the data objects and attributes available through IEC 61850 communications interface, evaluating and if necessary correcting the built-in datasets and reporting mechanisms, testing the OPC Data Access reporting and logging functions, and establishing the overall application framework.

To retrieve the data from the OPC Server, an OPC Client was developed in C++, which connects to the IEC 61850 OPC Server on the substation computer and monitors the data changes. Then it passes the new data on to the main application, which handles the feeder performance analysis algorithms and then logs the data in the database accessible by the web client. MySQL Community Server database was selected for the database implementation and the database

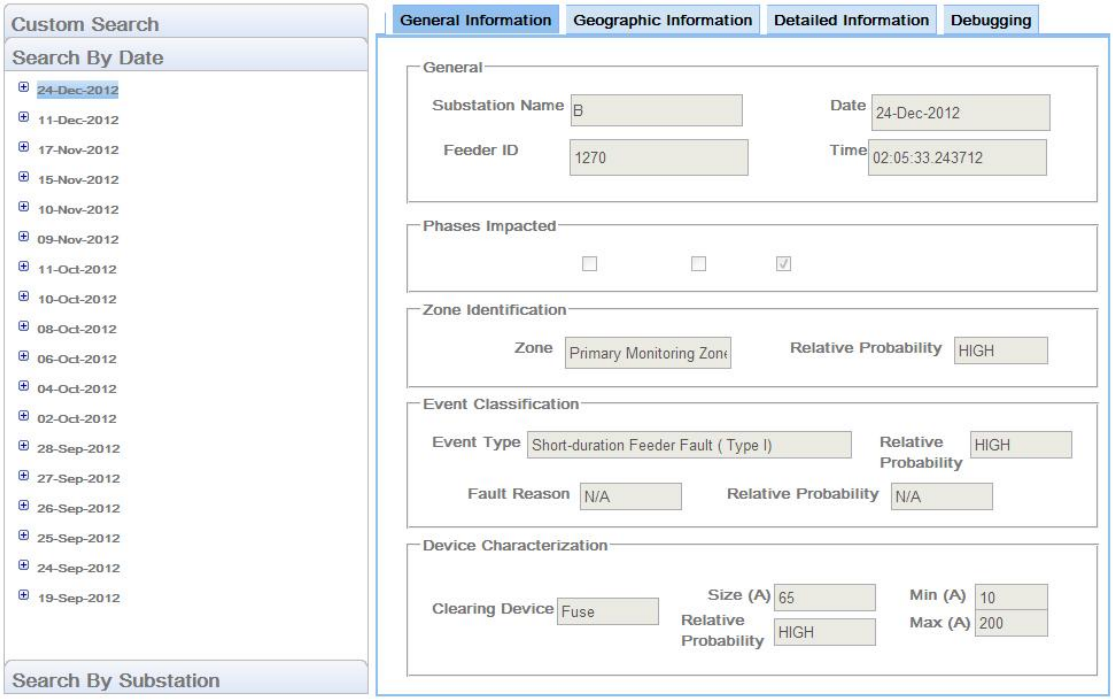
schema for feeder health monitoring application has been created accordingly. The database operations are performed using Oracle MySQLConnector/C++ database API.

The algorithms for voltage unbalance, power monitoring, unbalanced capacitor switching, unbalanced feeder loading, voltage regulation and power factor tracking have been instantiated in C++ on Windows platform. The event data is stored in MySQL database.

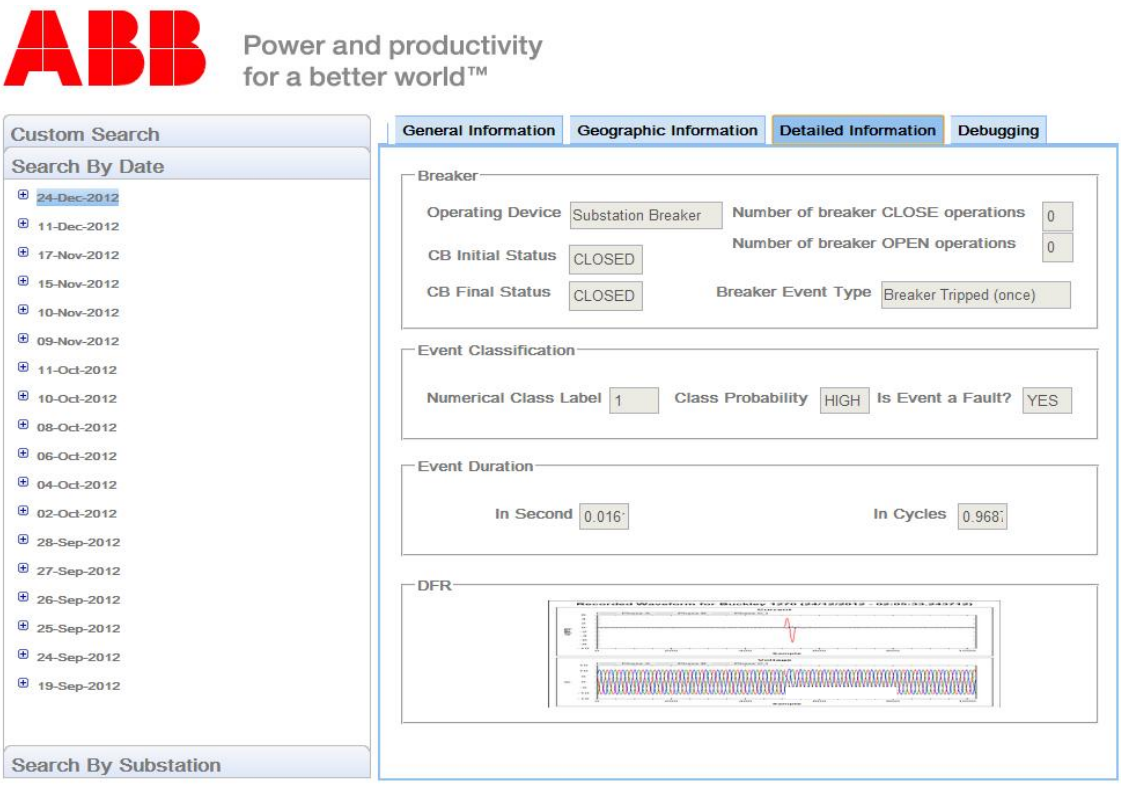
The real-time monitoring application has been commissioned at the Xcel Energy substations in Q3 and currently is going through the field trial stage. For more details refer to Section 8.

Subtask 5.3: Web User Interface Development:
A web user interface was developed to display the captured events for each substation. Below are some screen shots from the developed interface.

This screenshot shows a list of events on the left hand pane for one of the substations (substation name abbreviated for data privacy reasons). On the right hand side, the results of the real-time analysis have been displayed which include event date and time, phases impacted, event zone, event classification attributes, and device attributes that have cleared the fault event including an estimation of the size.



Detailed information about the event including a screen capture of the recorded COMTRADE data for the same event is shown under the “Detailed information” tab as given below. The user can navigate through the events and observe the derived information about each event seamlessly through this interface.



Task #6 – Application Research, Development, and Integration

Subtask 6.1: Underground Cable Fault Algorithm Design:

Several improvements were made to the initially-developed cable fault detection algorithm. The latest version of the real-time system deployed at the select substations for Phase I incorporates the latest improvements and parameter changes. In particular, an improvement was made to better identify impacted phases for cases where a cable fault occurs on a feeder adjacent to the feeder being monitored. In the original algorithm, a super set was being reported where for example an A-phase fault could also include the B-phase. The improved algorithm takes this result and fine tunes it for fault events so that "impacted phase" is equivalent to "faulted phase" for fault events regardless of the zone in which the event takes place.

Subtask 6.2: Instantiation of Real-Time Applications for Feeder Performance Monitoring, Advisory Control, and Fault Location:

This work started in Q2/2012 to investigate new real-time feeder monitoring applications, including volt/VAR monitoring, unbalanced capacitor switching detection, unbalanced feeder loading detection, and feeder overloading detection. Literature searches, feasibility studies and the implementation/field trials were the main tasks initially worked on related to this subtask.

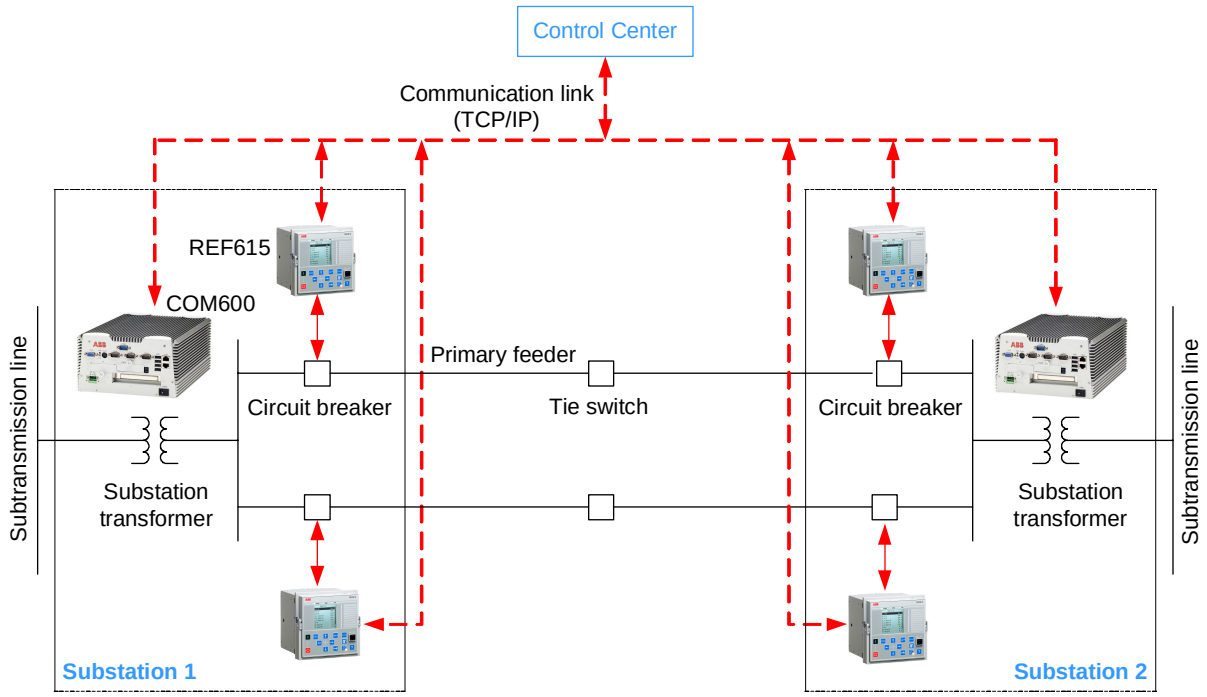
Feeder unbalance monitoring and detection feature was realized within the project framework by monitoring and processing the three phase current magnitude and angle data, as well as the sequence component currents. These attributes are calculated internally and reported by the IEDs to the application server via standard IEC 61850 mechanisms, as described in the previous section. For Phase I of the project only monitoring and notification functions will implemented;

possible corrective actions would have been investigated at Phase II. In contrast to voltage unbalance, there is no standard definition or thresholds for current unbalances. Therefore, a user configurable threshold will be added to the application server. Unbalance loading beyond this threshold triggers an event, which is posted on the web-site, and an e-mail notification.

Feeder overloading is another new application being developed for the project. It most likely happens in peak hours. The overload may cause device failure in distribution systems and make devices deteriorate faster. Thus, the overload of distribution feeders should be avoided. In the current literature, distribution transformer overload monitoring method has been widely studied. Current solutions for distribution transformer overload monitoring were evaluated. To avoid overloaded distribution feeders, many techniques have been developed, such as reconfiguration method, demand side management, loading balance method, etc. These methods were summarized and the advantages and disadvantages of each method were detailed. A literature review document for feeder overload monitoring was also prepared.

In Q2/2012, the feeder overload monitoring work package was developed. A literature review on feeder thermal overload monitoring was conducted. The thermal dynamics of power cables and transformers were also reviewed. Steady state ratings, such as ampacity and power capacity, are constant values, which are determined based on conservative assumptions (loading factor is 100%; ambient air temperature is 40 degree C and ambient soil temperature is 20 degree C; thermal inertia of the power element is neglected). On the other hand, dynamic ratings are determined by real-time loading information, real-time or forecasted ambient temperature, and thermal dynamics of the power elements, which eliminates all the conservative assumptions used in steady state ratings. Thus, the dynamic rating system may increase the loadability and reliability of the distribution system.

In Q2/2012, a preliminary feeder thermal overload monitoring framework was proposed and later developed. This framework is an application function in the substation (feeder) level of distribution system operation, which is different from the thermal protection function of REF 615. The feeder overload monitoring framework is shown as follows.



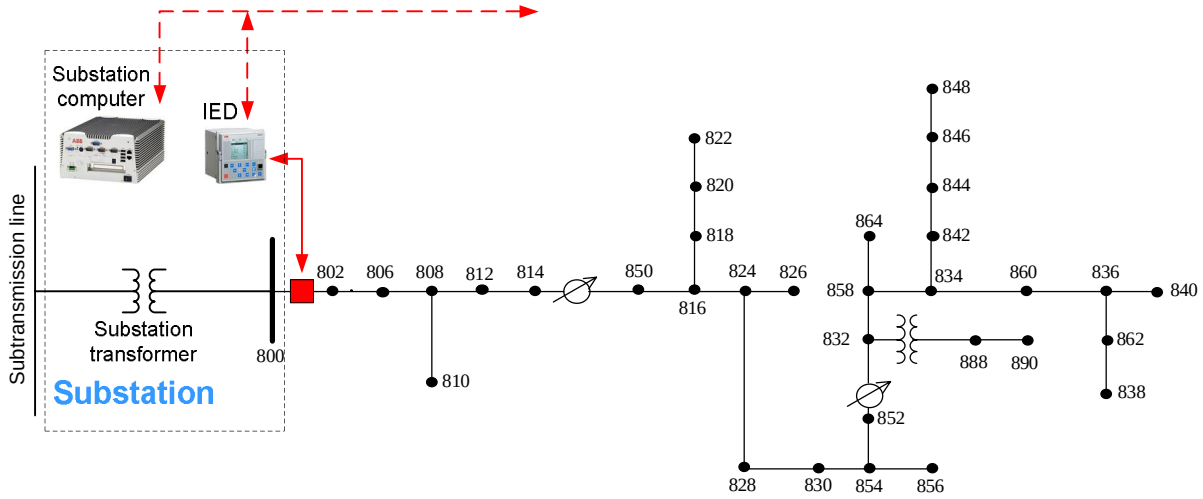
The thermal dynamic models of underground cables, overhead lines, and transformers were developed later in 2012. These three types of devices have different thermal dynamics. The model library for each type of device was also developed. These thermal models were used to estimate the conductor temperatures of lines and hot-spot temperatures of transformers in operational real time. These temperatures were used to check if feeder overload happened. If the temperature is close to the maximum limit, warning signal can be generated. A dynamic rating system for each type of device was also developed to estimate the maximum loading every 15 minutes, every hour, and every 4 hours.

To execute the dynamic rating calculation, real-time conductor currents are required. There different cases were considered.

1. AMI data from control center are available
2. IED current measurements are available
3. Real-time data are not available

The feeder overload monitoring solution for each case was also developed.

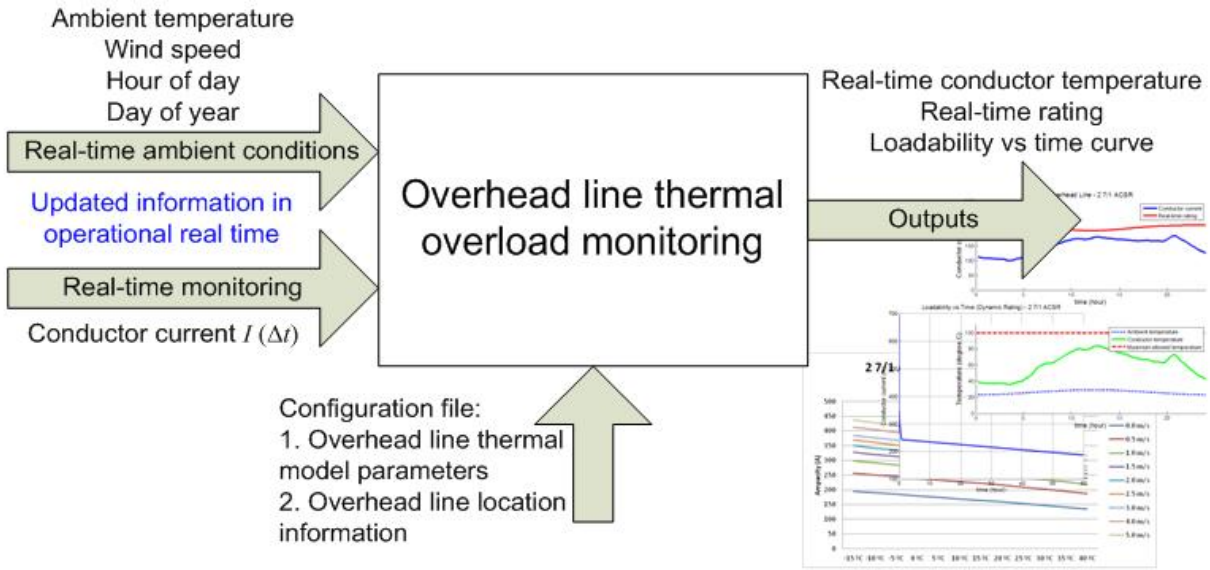
A revised IEEE 34 node feeder system was utilized to illustrate the developed feeder thermal overload monitoring framework, which is shown in the following figure.



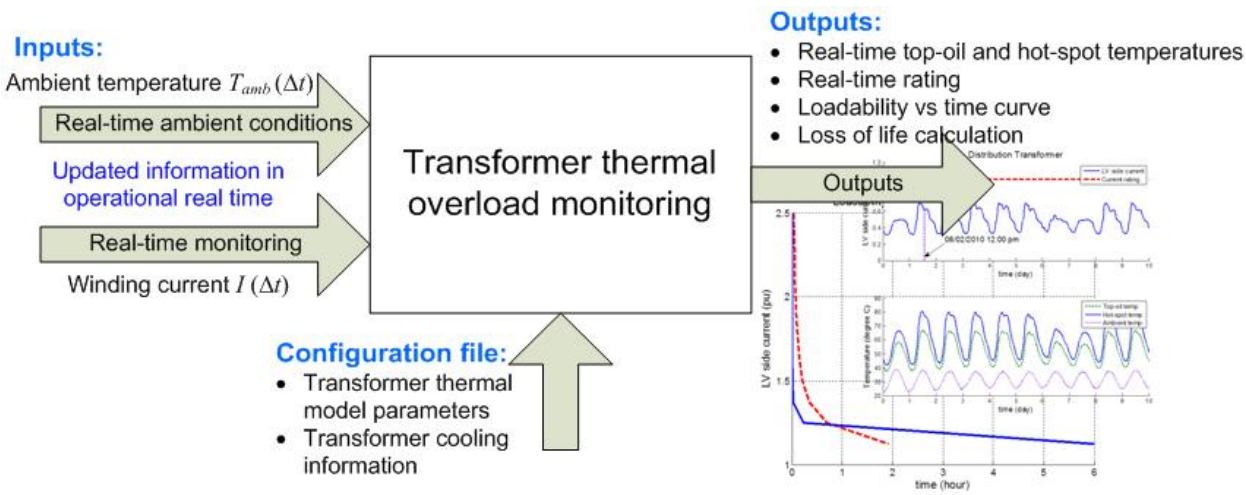
The test system was implemented in the OpenDSS software. Currently, only underground cables on the main feeder have been integrated in the framework. The feeder thermal overload monitoring code was implemented in MATLAB. Preliminary case studies were conducted in MATLAB and the OpenDSS environment.

In Q4/2012 and Q1/2013, thermal overload monitoring systems for overhead lines and oil-immersed transformers were implemented and tested in MATLAB.

For overhead lines, the thermal overload monitoring system requires ambient air temperature, wind speed, wind direction, and conduct current as inputs; the outputs include the real-time steady state rating, conductor temperature, and loadability vs time curve. A configuration file is used to store the thermal model parameters and overhead line locations. The thermal overload monitoring system operates in operational real time. The output information is updated periodically (such as 5 min, which can be specified by users). The high-level diagram of the monitoring system is shown in the following figure.



For oil immersed transformers, the ambient temperature and conductor current are input signals; the outputs include real-time estimated top-oil and hot-spot temperatures, real-time rating, loadability vs time curve, and loss-of-life calculation. The outputs are also updated in operational real time (5 min or 15 min). The high-level diagram of the transformer thermal overload monitoring system is shown in the following figure.



Various cases studies were conducted to validate the developed thermal overload monitoring system. Case studies considered various operational conditions such as different ambient temperatures and different loading levels to study the performance of the developed overload monitoring system. Typical cases are summarized in the thermal overload monitoring application case study report.

In Q1/2013, some novel applications of the oil-immersed transformer thermal overload monitoring were also studied. One application is to use the thermal overload monitoring system to detect the cooling system failure. Another application is to use the parameter identification

method to identify transformer oil thermal capacitance, which could be used to detect transformer oil leak. One extra requirement for these applications is that the top-oil temperature measurement is needed.

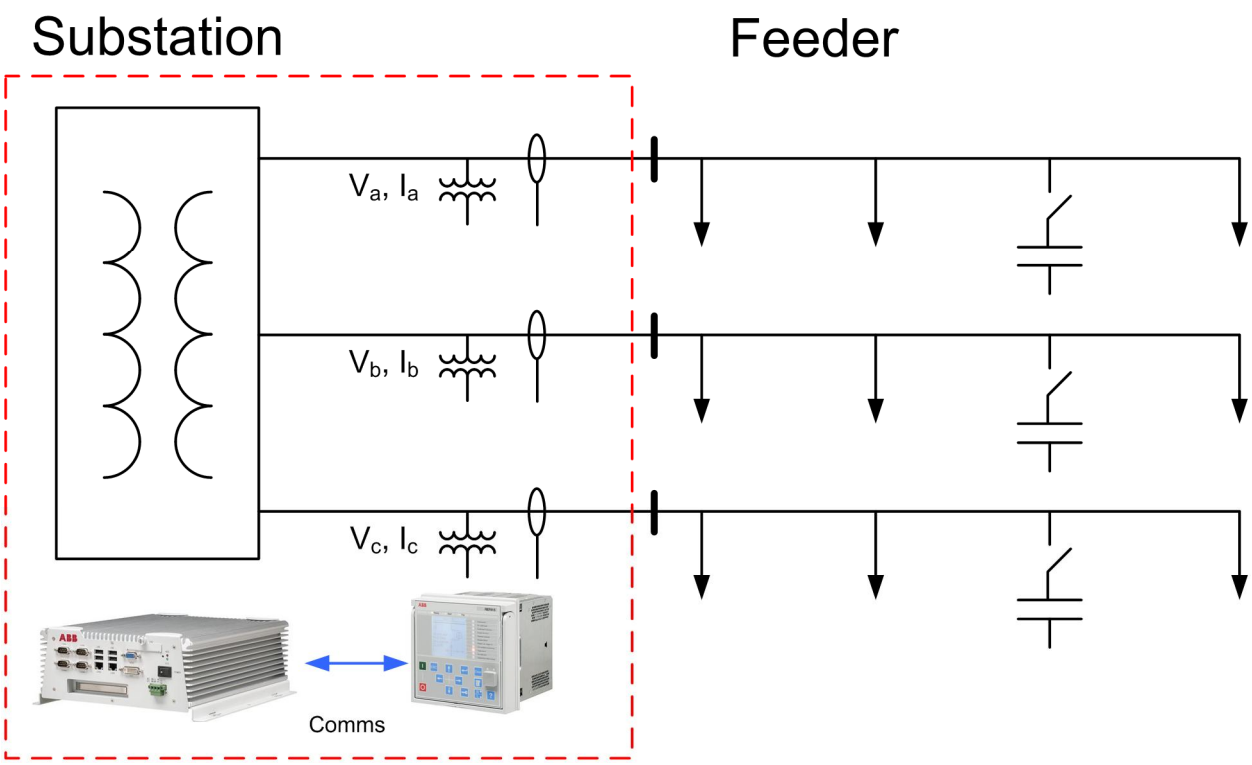
To demonstrate the real-time application of thermal overload monitoring, the transformer thermal overload monitoring system was implemented in C/C++ platform. The developed application was tested on a PC. This application could periodically read in real-time data from field measurement database and execute the transformer thermal overload code to get the real time thermal status of the transformer. A simple visualization function was also developed to show the main results of the application in real time. The developed application can be installed on ABB COM600 (substation computer) with minor revisions to achieve real time operation.

Volt/Var monitoring, proposed as an application development, was also developed during Phase I. The purpose of the volt/var monitoring function is to use per phase voltage and current measurements taken by a digital relay at the beginning of the feeder to assess the performance of the circuit. The functionality is based on calculating various performance indices and does not require a model of the actual feeder itself. These quantities to be calculated include real and reactive power per phase and power factors, voltage regulation indices, voltage unbalance indices, current unbalance indices, unbalanced capacitor switching indication, and power factor indices. The user then needs to enter threshold values on which to generate alarms.

Unbalanced capacitor switching monitoring is a new application that was also developed. The purpose of the capacitor switching monitoring function is to use per phase voltage and current measurements taken by a digital relay at the feeder head to determine when capacitor switching on the feeder is occurring and whether or not the capacitor is switching correctly. The user needs to specify the minimum size of switched capacitor banks per phase and an alarm will be issued when capacitor switching is unbalanced.

The details of the software application prototypes implemented on the ABB substation computer is summarized below.

The starting point for the algorithm is the phase voltage and current measurements calculated and reported by the IEDs installed at the feeder head (as shown in following figure) to assess the performance of the circuit. The IEDs are installed at the substation, which allows facilitating fast Ethernet reporting mechanisms between the IEDs and the substation computer through standard IEC 61850 services. The algorithm itself is executed on the substation computer.



The software prototype functionality is based on calculating various performance indices and currently does not require a model of the actual feeder as long as certain parameters are preset by the user. The inputs for the algorithms are timestamped voltage and current magnitudes and angles available on a per-phase basis through IEC 61850 interface, as well as the user defined threshold settings.

IEC 61850 mandates that each data attribute that is reported through communications interface is properly timestamped. Additionally, the data attribute quality information must be reported with each attribute, so that if there is for example an internal sensor failure, the bad quality data can be discarded by the main application. The IEDs assign the timestamps for the IEC 61850 events according to their internal clock. However, the internal clock may not be accurate enough and subject to time drift. In order to avoid time drift in the IEDs real-time clock, the substation computer is configured to provide time synchronization for the IEDs based on its built-in SNTP server. The substation computer also includes SNTP client, which can be configured to synchronize with an external SNTP server, such as for example nist.gov time servers.

The threshold values for generating the alarm setpoints and desired regulation deadbands are user-configurable and must be provided in advance in the configuration file.
The settings currently include the following parameters:

i. Voltage setpoint and desired regulation deadband
ii. Voltage maximum and minimum targets
iii. Unbalanced voltage alarm setpoint
iv. Unbalanced current alarm setpoint
v. Minimum size of switched capacitor banks per phase
vi. Power factor target and desired regulation deadband

vii. Thresholds for excess/insufficient reactive power support.

Computing these values automatically based on a model of the feeder will be investigated in Phase II of the project.

The feeder health performance indices are updated whenever a new measurement is available from the feeder IED. IEC 61850 reporting mechanisms allow flexible configuration of the data reporting. The instantaneous measured phasor data (instCVal) as well as the deadbanded data (cVal) can be reported. Additionally, periodical reporting may also be used. For example the IED may send the new analog values through IEC 61850 interface every 10 seconds for applications that involve slower time constants.

The following major feeder health performance indices are being determined through the real-time analysis:

1. Real and reactive power per phase and power factors
2. Voltage regulation indices
3. Voltage unbalance indices
4. Current unbalance indices
5. Unbalanced capacitor switching indication
6. Power factor /reactive compensation indices

Voltage regulation indices include average voltage, and maximum/minimum voltage tracking, as well as the amount of time the voltage is above/below a pre-determined threshold. Further analysis of these quantities can help, for instance, to evaluate the performance of feeder voltage regulators. Also, links with other performance indices may potentially be established at the demo phase.

Voltage unbalance index in its current implementation is based on tracking the ratio of negative sequence voltage to positive sequence voltage. The maximum value of the imbalance and the amount of time the voltage unbalance is over a pre-defined threshold are also reported and stored in the database.

Current unbalance on the feeder causes additional line losses and unbalanced voltages for customers with three-phase loads. The ratio of the zero-sequence current to the positive-sequence current is used to track the current unbalance.

Unbalanced capacitor switching index is calculated upon a significant change in reactive power between the consecutive measurements, which can be associated with capacitor bank switching. Mismatches between reactive power quantities of different phases are detected and checked against the minimum size of a capacitor can on the feeder. The capacitor banks are assumed to be connected in a grounded-wye configuration.

Power factor tracking indices include the average power factor, the maximum and minimum reactive power consumed by the feeder, time intervals during which the power factor is below the setpoint, and the reactive power is over/under the user-defined thresholds.

The user can also define the length of the monitoring period. When this period expires, the sample counter and the accumulated indices are reset and the process starts over again from zero initial conditions. This allows to accumulate and store the data for instance by days, weeks, months, or even certain shorter periods of the day, such as peak load hours.

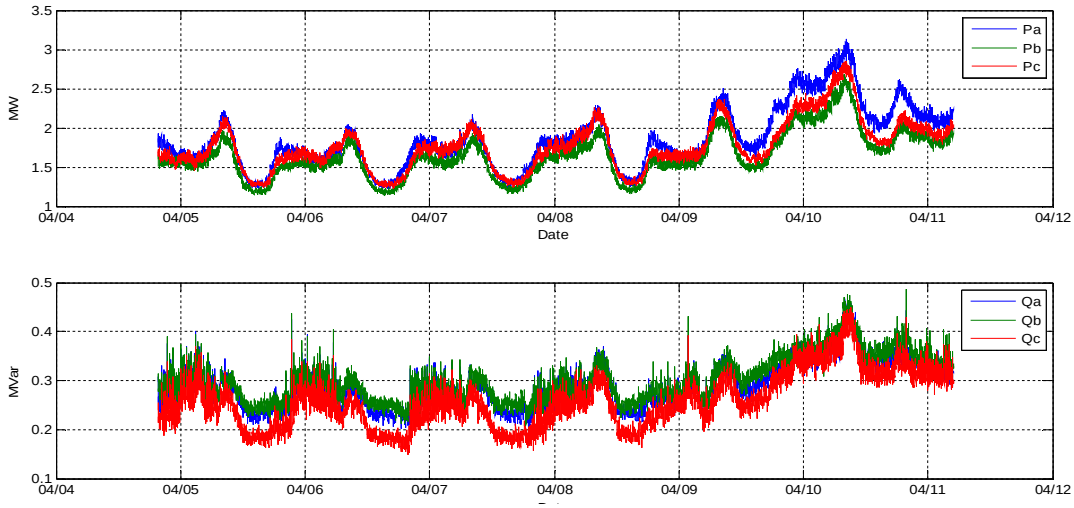
Subtask 6.3: Application Integration and Testing:
The applications developed for subtask 6.2 were integrated into the COM600 substation computer framework and testing in the lab via simulations and in the field using real utility data from the Xcel Energy system.

Task #7 – Demonstration Project Management
Project management for the demonstration phase of Phase I started in Q4/2012, when the demonstration phase itself began. Coordination between ABB and Xcel Energy on the demonstration equipment installation, deployment of the developed applications, and the performance monitoring of the demonstration system have been completed.

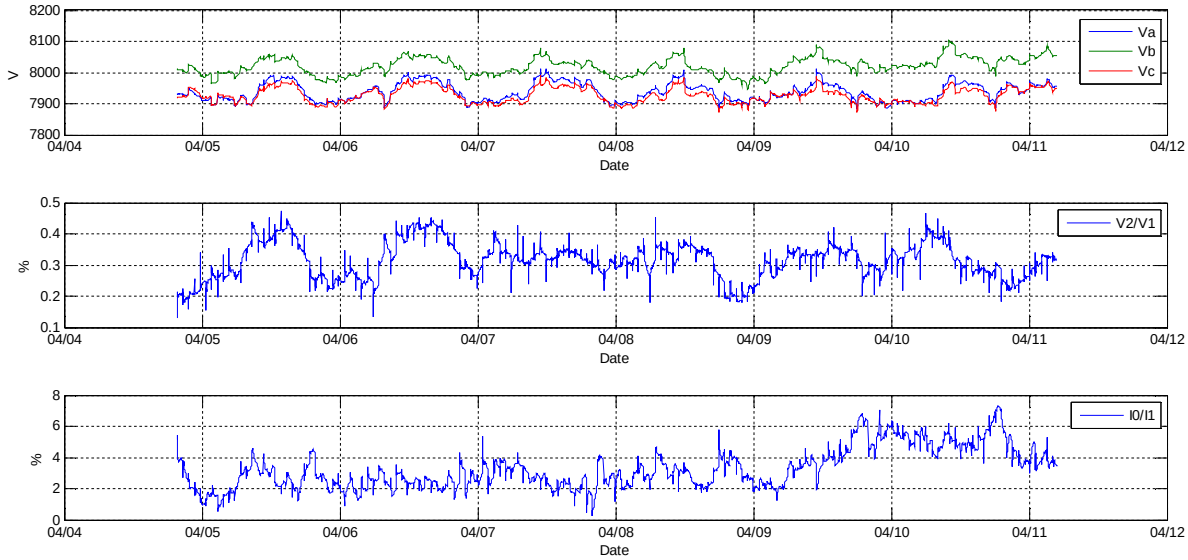
Task #8 – Demonstration
Subtask 8.2: Deployment of Phase I/ BP 1 Applications:
In Q4/2012, demonstration hardware and software setup was completed for the Xcel Energy substations. This setup includes ABB COM600 Grid Automation Controller with real-time health performance indices monitoring application and the database management system installed onto it. The application is structured as described in Section 6. ABB REF615 feeder protection IEDs are used as the main feeder health monitoring device in addition to the event detection function. The setup was also used for the initial field testing of the integrated solution. Device, software, and application configurations and re-tuning continued and were completed during the remainder of the demonstration phase.

Subtask 8.3: Performance Monitoring and Testing of the Demonstration System:
Some sample feeder health performance data has been collected and analyzed over various monitoring periods i.e. 1 hour and 24 hours. The data includes raw measurements, as well as the results of the real-time feeder performance monitoring analysis. The raw measurements are then used for debugging and performance assessment purposes.
It was determined that the initial method as described in Section 6 had to be modified in order to accommodate some limitations of the existing hardware, which were discovered during the field trial. The work on modification of the original algorithms was completed in Q4/2012. The work is focused primarily on using the alternative IEC 61850 data objects to calculate the health performance indices.
Some examples of real-time monitoring and feeder health performance calculations for one of the feeders over approximately one week time period are shown in the following diagrams. The data reporting mechanism used by the IEDs is set to ‘on data change’ so that every time a change in the monitored quantity is detected the IEC 61850 report is sent through communications interface triggering automatic online recalculation of the feeder health performance indices. The deadband feature typically used by SCADA for reports to limit the data volume was not used in the testing, which allowed capturing large number of data samples at high resolution. On average, the data set is comprised of 10,000-15,000 samples per 24 hours monitoring period.

The first diagram shows high resolution active and reactive power profile calculated using voltage and current phasors reported by the IEDs, with reactive power showing much more relative fluctuations compared to the active power. It should be noted that the load profile shows distinct daily pattern over the monitoring period. Further analysis may be required to discover correlations of the load profile with external factors such as weather.

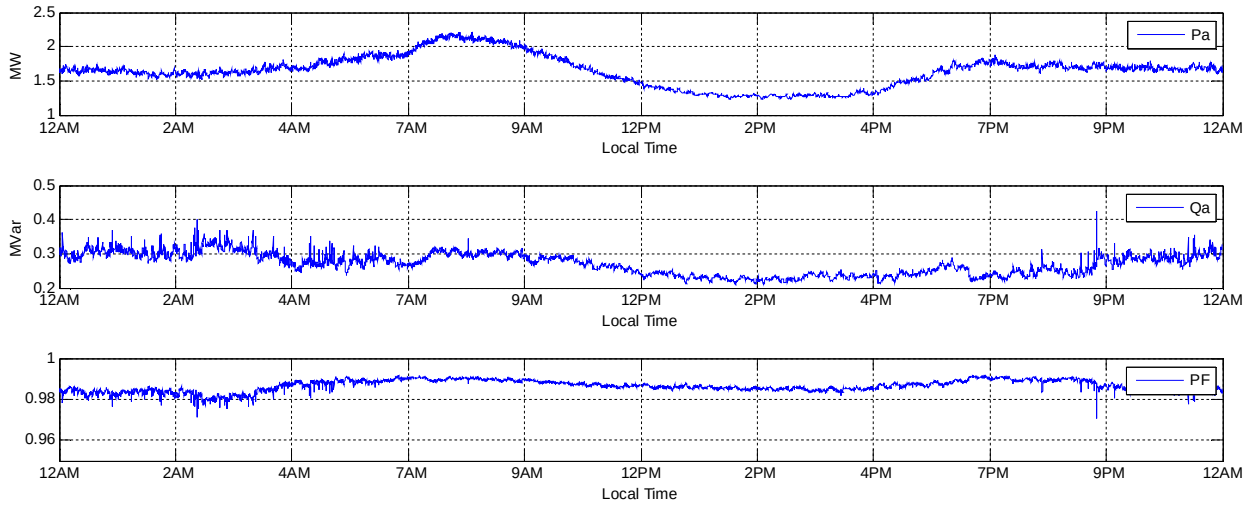


Feeder health performance indices calculation engine also includes provisions for averaging the monitored quantities as well as the calculated indices over a pre-defined monitoring period, which is set to one hour in this test case. The second diagram shows the averaged voltage profile over the one week monitoring period, the average voltage unbalance (determined as ratio of negative sequence voltage to positive sequence voltage), and the average current unbalance (ratio of zero sequence current to positive sequence current). It can be observed that phase b voltage is consistently higher than phases a and c voltages. However the relative unbalance in this case is not significant, whereas the current unbalance exceeds the user defined threshold of 5% towards the end of the monitoring period triggering an alarm.



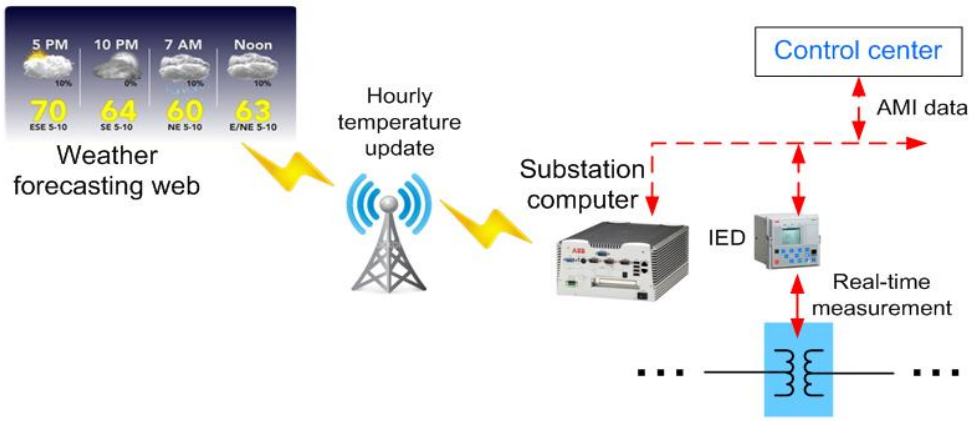
The third example shows active and reactive power profile as well as power factor and

current/voltage unbalance indices over the 24 hour monitoring period.

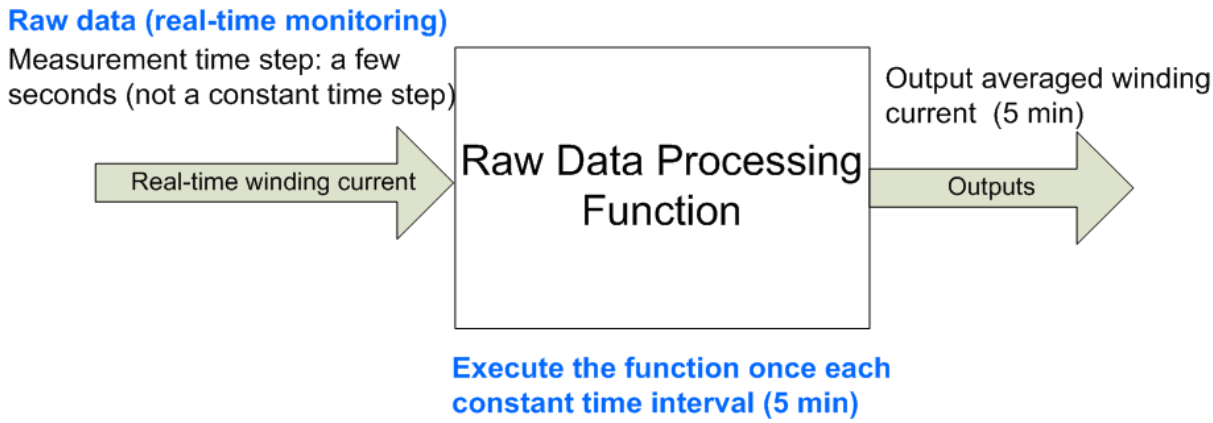


The data shown in the examples above is stored locally at the substation per feeder and then broadcasted to centralized database for further processing and visualization. The next step is to integrate the data from multiple substations into the central database and perform extensive data analysis in order to find possible cross-correlations between the substation events.

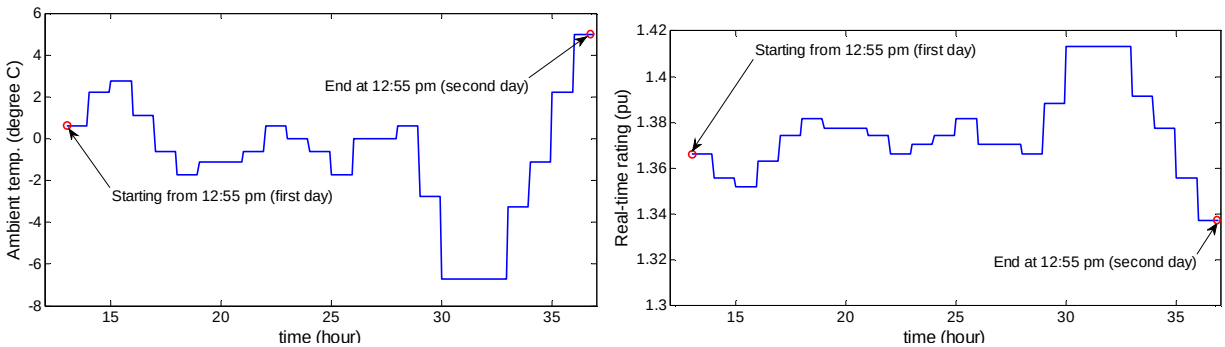
For thermal overload monitoring work package, the developed transformer thermal overload monitoring system was demonstrated off-line using real-time field data. The diagram of the system is shown in the following figure. In current stage, this method is demonstrated on PC. In the future, the system will be implemented and operated in substation computer in operational real time.



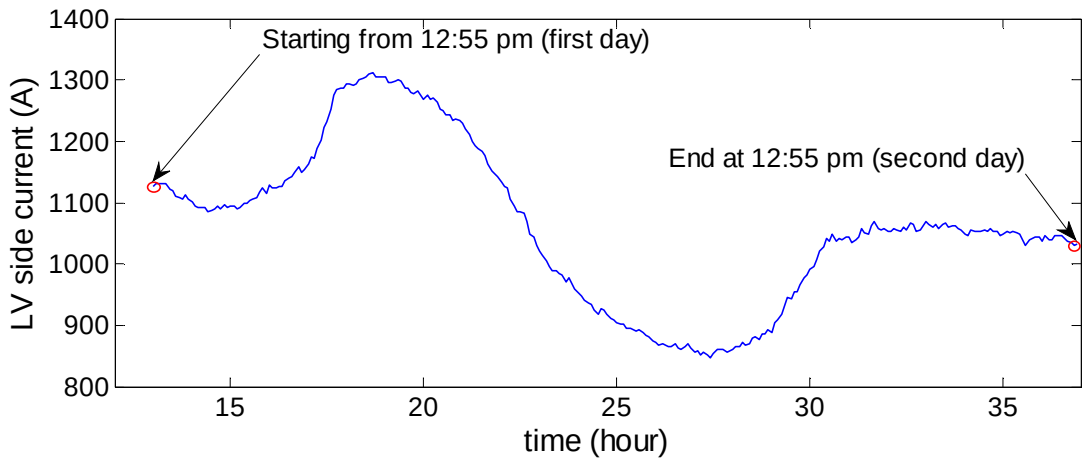
One-day winding current data from a transformer IED (REF615) were captured by the real-time monitoring application. The corresponding ambient temperature was also captured from weather forecasting website. Since the current measurement was updated each a few seconds (not a constant time interval), the raw data were processed before they are used in the thermal overload monitoring system as shown in the following figure.

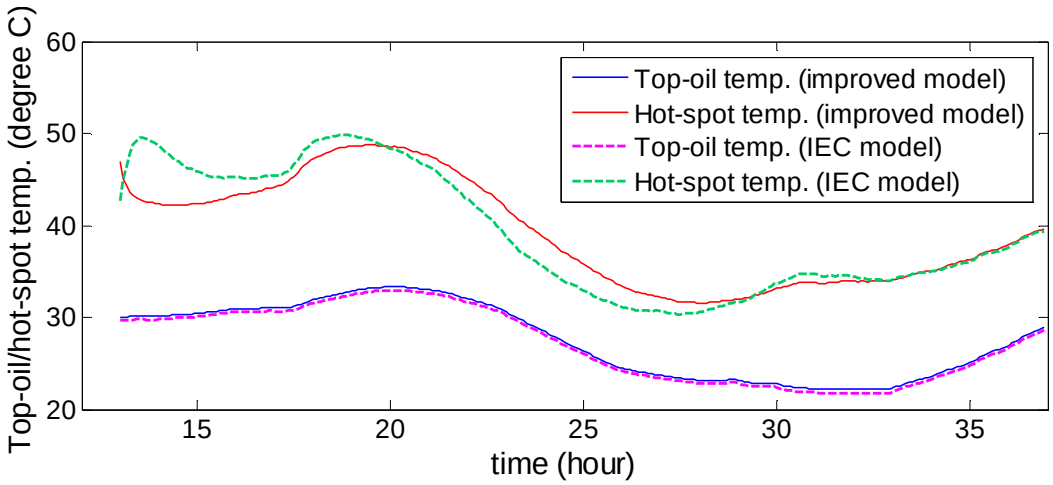


The following two figures show the transformer ambient temperature and real-time steady state rating. The real-time rating is updated once the ambient temperature is changed. The real-time steady state rating is increased with the decrease of the ambient temperature.

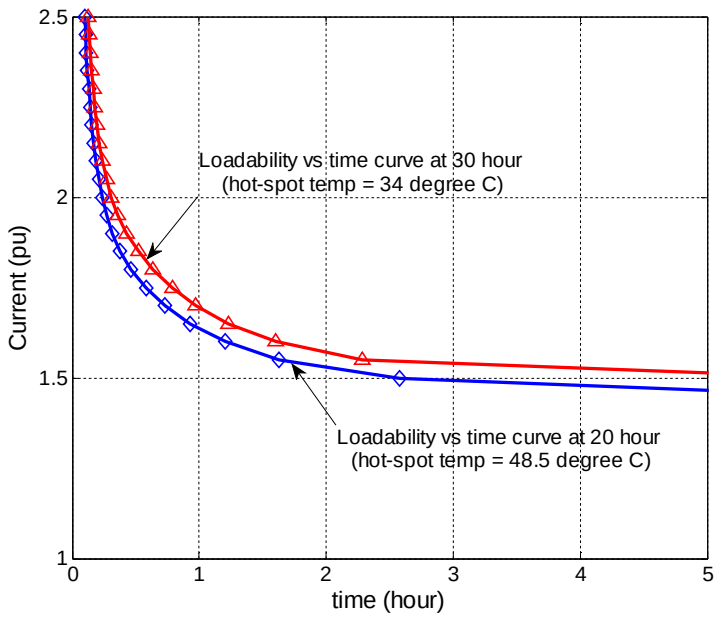


The following two figures show the real-time winding current and estimated hot-spot and top-oil temperatures (IEC model and improved model). In the operation, real-time data and estimated temperatures in the past 24 hours (which can be determined by users) can be displayed.





The loadability vs time curve can also be calculated and displayed in operational real-time. This curve can help user to determine if the transformer can be overloaded in the next few hours. If the transformer is already overloaded, a warning signal will be generated.

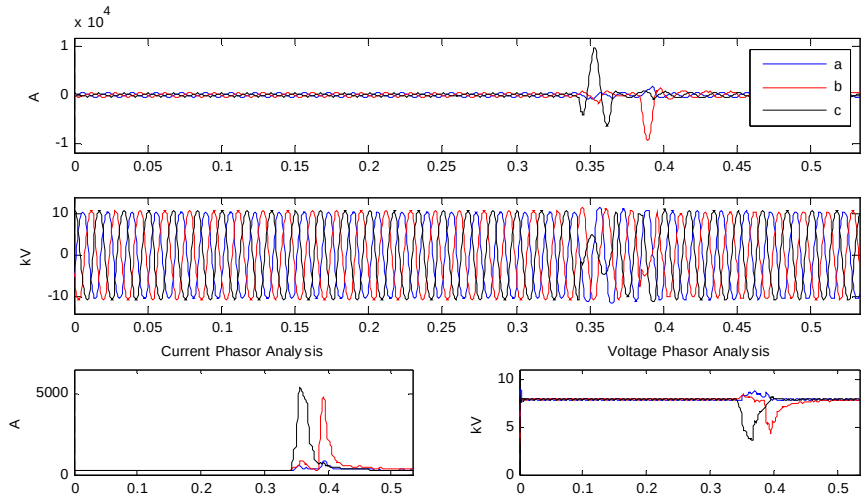


The transformer loss-of-life is also calculated in operational real time. In the 24 hour period, the loss-of-life is updated every 5 minutes. The actual loss-of-life in the 24 hour period is 9.8959 hours, which is much smaller than 24 hours since the ambient temperature is very low and loading level is also less than the conservative rating.

Data collection has been ongoing since the demonstration phase began. During Phase I in 2012 and 2013, ABB collected and analyzed close to 800 real-time and non-real-time events from 6 Xcel Energy substations. Some event waveform examples are shown below.

The first example shows an evolving fault due to vegetation. Weeds grew into a switch cabinet

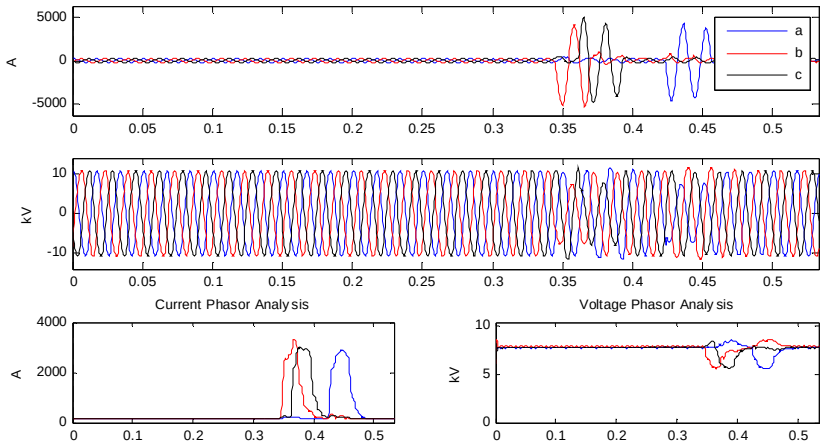
and blew a C-phase fuse then propagating to the B-phase within the same cabinet.



Trigger Date: 06/02/12
Trigger Time: 12:45:53.390000
Most Affected Phase: CB
Peak Phasor Event Current (A RMS): 5437
Peak Inst. Event Current (A): 9967.2
Event Duration (cycles): 3.5
Load Change (kW): 135

PreEvent Loading
Phase: A; B; C:
Current (A): 292; 266; 226
Power (kW): 2229; 2049; 1721
Power Factor: 0.975; 0.967; 0.965
Voltage (kV RMS): 7.89
PostEvent Loading
Phase: A; B; C:
Current (A): 297; 359; 255
Power (kW): 2262; 2402; 1856
Power Factor: 0.971; 0.85; 0.93
Voltage (kV RMS): 7.85

The second example shows another rare example of evolving fault that starts as a single phase to ground fault due to a dig-in in one switch cabinet and propagates into another phase in another cabinet eventually taking all three phases out.



Trigger Date: 03/15/12
Trigger Time: 08:03:12.140000
Most Affected Phase: CBA
Peak Phasor Event Current (A RMS): 3374
Peak Inst. Event Current (A): 5283.8
Event Duration (cycles): 6.78
Load Change (kW): -122

PreEvent Loading
Phase: A; B; C:
Current (A): 136; 152; 154
Power (kW): 1045; 1183; 1193
Power Factor: 0.985; 0.984; 0.986
Voltage (kV RMS): 7.85
PostEvent Loading
Phase: A; B; C:
Current (A): 133; 141; 149
Power (kW): 1015; 1060; 1145
Power Factor: 0.977; 0.947; 0.978
Voltage (kV RMS): 7.85

The third example shows a series of half cycle arcing activity after the 1st full cycle fault event

resulting in an outage on B phase. The detailed analysis afforded by this project helps reveal these types of faults and facilitate outage cause modeling and mitigation actions in addition to determining their occurrence and location in (near) real-time.

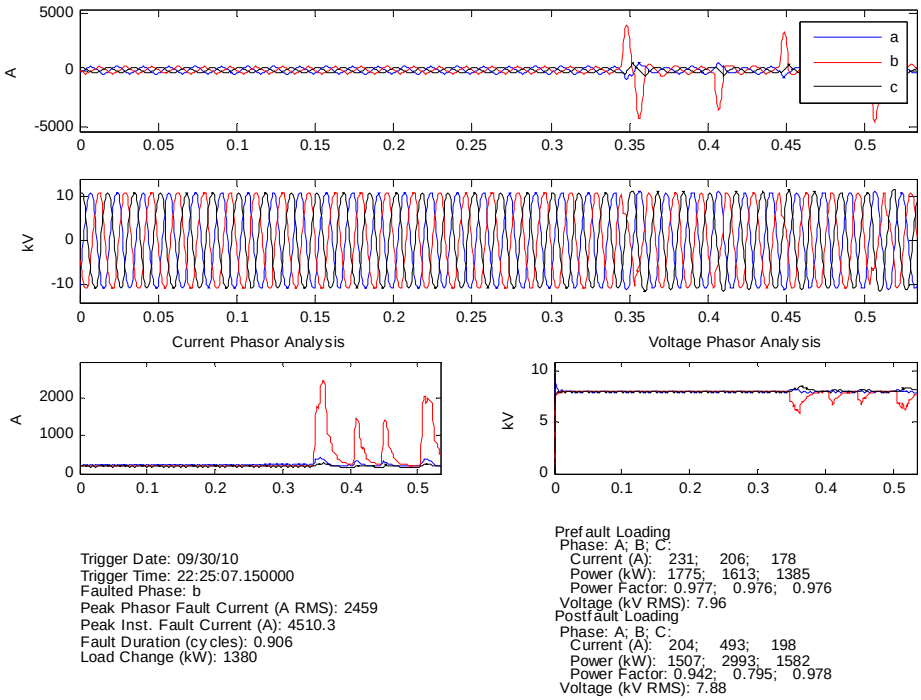
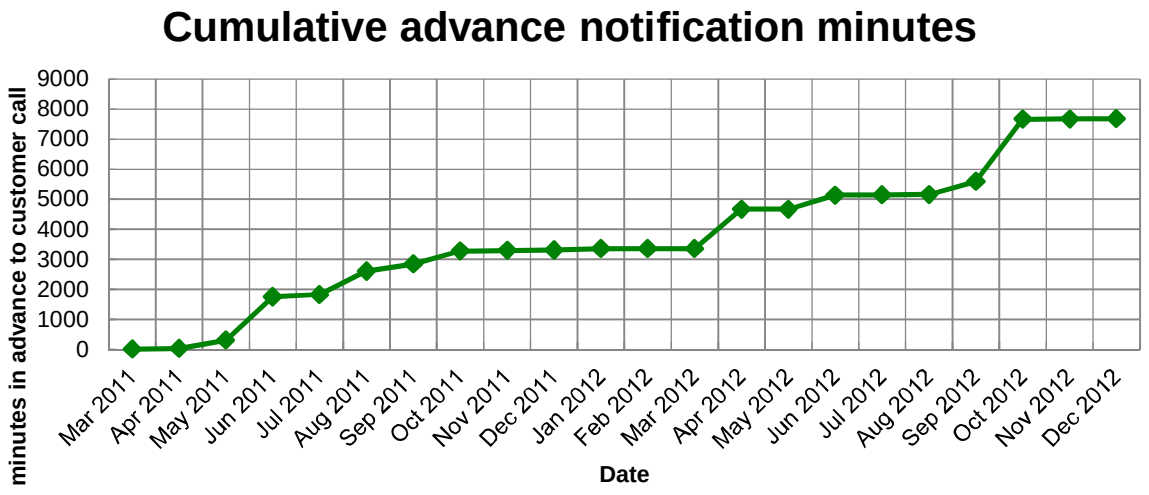


ABB has integrated the fault location by segments result into the existing real-time feeder health and monitoring system. The enhanced application package was installed on a COM600 substation computer with four feeders monitored. This was achieved in a field trip to Xcel Energy during the week of February 25, 2013. When a fault is detected on any of the monitored feeders, the fault location by segments result will be calculated in addition to fault type, faulted phases and etc. At this stage, the calculated fault location result is reported in a text file and saved in the database of the COM600 computer. The results are then retrieved off-line and verified by Xcel Energy OMS experts. In the coming months, ABB will be working on integrating the fault location results into the real-time notification emails and visualizing the results on a google map which will empower the maintenance crew.

An important aspect of the demonstration phase of the project is to show the ability to provide adequate “heads-up” time ahead of customer calls or AMI reports so that the operators are provided with the much needed time to collect information needed to address an outage. The advance notification feature of the demonstration system provides this time and helps accelerate service restoration ultimately. To demonstrate the effectiveness of this feature, a demo system was setup to compare the minutes saved over a period of 22 months for two feeders where the real-time notification system has been deployed.
The metric used for performance assessment is the time difference between the actual outage time from the OMS versus the time the notification email was received on the

operators desk. All faults in the performance period were confirmed faults from OMS. Of all faults recorded over the said period, 60% were due to restoration attempts and/or subsequent faults. Those have been removed from this analysis.

The result of this analysis has been demonstrated in the following figure where the horizontal axis shows the date, and the vertical access is the minutes in advance of customer calls that would eventually contribute to the SAIDI reduction.



As can be seen, over the period of 22 months, we have accumulated over 7600 minutes (32 hours) ahead of actual outage time compared to the OMS timestamps. Since the graph is cumulative, it's monotonic. Faults do not occur on regular intervals and therefore the graph has sharp increases as well as constant periods corresponding to periods of no fault activity over the cold season.

The significance of this analysis is that it shows the potential to reduce the SAIDI minutes and directly impact utility performance in terms of outage duration. If deployed at scale, it would have a significant impact on system reliability,

To put this number in perspective, it would be helpful to assign a dollar figure to the potential savings that could be realized. According to the host utility, the average cost for each customer-minute-out (CMO) is approximately $0.30 across the operating company. This includes both direct and indirect costs such as bad press. On the other hand, the outage data over the previous 4 years show that the average customer count on primary/tap level outages is about 56. Accordingly, the total minutes saved amounts to 425,600 CMOs on the average. This would in turn result in a potential cost savings figure of $127,680 for two feeders alone over the period of performance. This empirical evidence validates the strong value proposition of the project that was contemplated at the onset and its potential impact to reduce outage duration in support of DOE's goal of 20%.

Subtask 8.4: Documentation:
Documentation for Phase I has been completed at this time.