

Proven Drop-In Control House Turnkey Solution for Total Protection, Monitoring, Automation, and Control of T&D Substations: A Case Study in Justification and Implementation

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Proven Drop-In Control House Turnkey Solution for Total Protection, Monitoring, Automation, and Control of T&D Substations

A Case Study in Justification and Implementation

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Abstract—New protection, monitoring and control installations have evolved into complete turnkey control house installations. The entire control house, or just the panels, are pre-engineered, designed, pre-constructed, and pre-tested off-site and then installed in the substation. This new solution is less expensive and more reliable due to enhanced functionality of today's microprocessor-based relays and communications processors.

The Belmont Tie Substation is not the first substation upgraded as part of Duke Power's Substation Automation and Relay Upgrade program. However, it is the first to be built as a complete control house off-site and then delivered intact and "dropped in" to the substation yard. Once positioned in the yard, field wiring is terminated and the station is commissioned.

Although the "drop-in control house" design and implementation strategy is innovative in its own right, the true advancements were the integration of the substation control, monitoring, and data acquisition functionality into the protective relay and communications processors. The following is a list of achievements:

1. Control and monitoring functions are performed by the microprocessor relays installed at the substation. The microprocessor relays are responsible for tripping and closing the breakers either via automation settings, or via local or remote operator contacts. The relays send back the status of the breakers along with the operational and maintenance data for the substation apparatus.
2. Communications processors perform the data concentration and remote terminal functionality. These communications processors are the link between the relays and the substation computer. They also provide the link through a digital lease line to Duke Power's Transmission Control Center (TCC). The TCC is responsible for the monitoring and operations of Duke Power's transmission system.
3. Capacitor control is performed by the microprocessor relay protecting the capacitor. This relay is programmed to perform the switching of the capacitor banks as needed for correct operation.
4. Analog data from the electrical lines is measured by the microprocessor relays. This includes the Thermal Demand readings, Energy readings, Voltage readings, Current readings, and Instantaneous Megawatt and Megavar readings.
5. Breaker Condition Monitoring is performed by the microprocessor relays. This includes the breaker operational counters, the integrated peak and average fault current readings, and the percent contact wear.
6. Sequential Events Recorder (SER), or sequence-of-events (SOE) is performed by the microprocessor relays. At one station over 1100 SOE points are assigned in the relays. The SOE data reports automatically to the station computer and Duke Power's database server where they are stored, sorted, and displayed. A web-based browser is used to display the SOE log remotely.
7. Analog fault recordings are performed automatically through the microprocessor relays. Whenever a fault occurs and the relay operates the breaker, an analog fault record is recorded.
8. Fault location and magnitude is calculated by the relay, this information is mapped back to the station computer for display on the Human-Machine Interface (HMI) and made available to the TCC.
9. The microprocessor relay collects substation alarms. These alarm points are mapped back to the station computer for display on the HMI, stored, and transferred to Duke Power's, Electric Transmission (ET) PI database server. A web-based browser is used to display the alarm log remotely.
10. All equipment tagging (Red, Yellow, Orange, and Blue) is displayed on the microprocessor relay's LCD display and the substation computer. A history of the tags is maintained through a database file.
11. All backup control, monitoring, and data displaying is performed by the microprocessor relay. The control and monitoring of the station does not rely on the station computer; complete control and monitoring remain available through the communications processors and the microprocessor relays.
12. Quantity of installed electrical panels was reduced by a factor of two.
13. RTD inputs providing top oil, ambient, and winding temperatures are collected from a transformer monitor IED. The communication system digitally collects this temperature information, along with fan current and status points such as low liquid, sudden pressure, and slow gas. Decisions are also made to control the cooling system and report alarm indications.

- 14. Rather than simply monitoring the battery voltage level, the system digitally communicates with the battery charger, which provides metering functions for the battery charge current, battery voltage, service voltage, and battery temperature. The charger also provides alarm conditions for low battery voltage, high charge rate, high battery voltage, battery symmetry, positive ground, negative ground, and component failure.**

The Belmont Tie Substation is one of several substations being upgraded as part of this ongoing project. This paper was created as a case study of a total substation control house design and installation.

I. INTRODUCTION

In the spring of 1998, Duke Power, Electric Transmission (ET) began developing an automation strategy for transmission substations. Historically, ET had utilized separate equipment for Supervisory Control and Data Acquisition (SCADA) and protective relaying functions in the substation. This legacy equipment consisted of electro-mechanical relays and telemetry SCADA systems; combining protection and SCADA functionality was not possible. Beneficial functionality, such as sequence-of-events (SOE), digital fault recording (DFR), breaker condition monitoring (BCM), and annunciation would require installation of separate equipment. Since additional equipment from multiple vendors does not typically utilize a common communication pathway, this would have resulted in higher installation and maintenance costs as well as low reliability.

ET's ability to retrieve operating information to assist in maintenance and engineering analysis is greatly hampered by this system architecture. Furthermore, most of the SCADA and protective relaying equipment is approaching an age where end-of-life issues must be considered. The Transmission Substation Automation & Relay Team (TSAR-Team) was formed to develop and implement an automation strategy to address these obsolete terminals.

Albemarle Switching Station was the first Duke Power Substation designed using the microprocessor relay to fully integrate all protection, control, and monitoring functions required from an electrical terminal perspective. This station proved successful and formed the basis for ET's automation/integration strategy.

A. Lessons Learned

Albemarle Switching Station created many new design standards, and as such, significant learning took place on the pilot project. The following is a summary of some of the "Lessons Learned."

1) Partnerships Offset Learning Costs

The learning curve for implementing substation automation is a steep one. Significant in-house training must be performed. Industry standards are not available to aid in the design process. The unavailability of standards is further complicated by the lack of integration tools to perform the necessary work. Methods for mitigating these costs include partnering with a systems integrator and sharing lessons learned with other utilities.

2) Standards Reduce Cost

The automation of Albemarle Switching Station paved the way for Duke Power's transmission upgrade program. Subsequent station upgrades used the standards developed here to speed the engineering design process, thereby reducing cost. Difficulties arose with maintaining design standards due to the frequency of new product offerings that afforded enhanced protection/control functionality. The challenge then became holding off implementing new product offerings to allow the cost savings to be achieved while using the design standards in place.

3) Dedicated Team Brings Success

The importance of a dedicated team cannot be overstated. The engineering complexities of substation automation make a focused core group critical for long-term success. The need for representation from all support groups is important not only to achieve buy-in across departmental lines, but also to provide the needed expertise to implement a long-term program.

4) Vendor Relationships Benefit Project

As standards are developed it is necessary to involve the manufacturers in the program objectives. This serves as a win-win relationship for both sides with the utility receiving faster service in equipment deliveries/modifications and the manufacturers enhancing their product lines, making them more marketable to the industry. There are many additional positives that can be gained by the utility as well, including training, system design recommendations, and engineering support.

5) Pretested Panels Improve Design

At Albemarle it was decided early in the design process to reuse the control house. During the installation of the new protection and control system it became evident that this was not the best business decision for several reasons:

- Refurbishment costs of aged buildings can be quite expensive and add to operation and maintenance expenditures.
- Existing house designs are not suited for new integrated systems and are typically three times larger than necessary for the new equipment.
- At Albemarle, the complete electrical terminal infrastructure was assembled and tested at Duke Power's Relay Lab. All parties deemed this laboratory-commissioning phase critical to the success of the pilot project.

B. Automation Upgrade Program Developed

After the success of Albemarle Switching Station, the Transmission Automation and Relay Upgrade Team at Duke Power immediately implemented two more integrated solutions: Acrerock Tie Station and Walker Tie Station. These substations were smaller than Albemarle, but allowed the standards developed at Albemarle to be used. These standards allowed a very rapid engineering design phase and coupled to pre-commission laboratory testing, provided a robust solution. Although these substations were commissioned without incident, retesting due to the dismantling and reassembling of

the panels resulted in additional cost. At the time Walker Tie Station was laboratory tested, several members of the TSAR-Team were invited to a large California electrical utility to view a “turnkey” control house automation project. This proved to be the event that turned on the proverbial “light bulb” for the project. These team members witnessed a very effective delivery method for an integrated protection and control system. The system was delivered to the substation as a complete, pre-engineered and pre-assembled control house. Not only would this method lower the construction cost, but also provide the opportunity to outsource the project engineering and construction. By treating the electrical terminals as an “apparatus” a complete “Factory Acceptances Test” could be performed before the control house was shipped to the substation. Problems could be corrected and retested before the unit arrived on site. This would dramatically reduce the field commissioning time thus reducing the overall cost of the project.

After returning from this trip, the TSAR-Team developed a high-level business case that compared the cost of replacing the obsolete terminals using an integrated complete control house approach versus a traditional panel-for-panel replacement. A long-term implementation plan was developed which prioritized ET’s substations and placed them on a 20-year replacement program. This became known as the Automation Upgrade Program. The following is a summary of the business case objectives.

C. Business Case Overview

The Automation Upgrade Program focuses on the replacement of the protection, control, and data acquisition functions within existing transmission tie stations. The primary drivers for this upgrade work are reliability concerns associated with the aging infrastructure and good economic business decisions where failure to fund programs today would result in higher costs in the future. The two options reviewed were terminal upgrade and station upgrade.

Terminal Upgrade Alternative. Replacement of aging assets with new microprocessor technology that is multifunctional in nature. Replacement is limited to a “protective terminal” basis that represents only a portion of the total station protection/control requirements.

Station Upgrade Alternative. Applying the new technology using an integrated approach (i.e. protection, control, and data acquisition functions), to the entire station. The many benefits associated with this alternative clearly made it the best solution. Primary benefits provided by the new technology are listed below.

1. **Reduced Capital Costs.** The newer technology is multifunctional with lower initial cost compared with purchasing many discrete components to perform the same required functions.
Note: A reduction of 15 to 25% in capital requirements has been realized using this alternative.
2. **Reduced O&M Costs.** The new method achieves a lower O&M total life-cycle cost by reducing complexity and using more reliable hardware. This

hardware provides advanced apparatus diagnostics that reduce station inspection times. O&M expenditures are lowered due to an integrated approach using automatic data capture for both record keeping and asset management.

3. **Enhanced Operability.** The new protection/control computer interface provides operators with additional information that reduces the potential for operator error. Total outage duration is minimized, by providing easy-to-use station one-line and control displays, which facilitate service restoration.
4. **Enhanced Functionality.** The new protective relays provide all metering, alarming, sequence-of-events, and status information that would normally be provided by discrete components or be unavailable. These data are automatically retrieved daily and compared with predefined limits for automatic notification to operation and maintenance personnel. This automatic notification provides opportunities for improved work deployment on these assets. Additional functions available within the relays are fault location, fault current magnitude, 0.2% voltage metering accuracy for load profiling and meter checking (a benefit in an RTO business), and power quality functions. Breaker monitoring is built into the relay to aid in determining more optimum maintenance cycles.

The TSAR-Team developed a detailed prioritization station list placing all ET substations on a 20-year replacement cycle. Under this plan, 11 transmission class substations had to be implemented each year to fulfill a 20-year cycle. With this in mind, ET realized a close relationship would have to be established with an integrator to achieve this goal. In the spring of 2000, the TSAR-Team sent out an RFQ to provide seven 100/44 kV substation control houses based on ET’s automation standards. This work was awarded to SEL Systems and Services Division (SSD) in May 2000; the first “drop-in” substation control house was delivered for Belmont Tie Station.

II. DROP-IN CONTROL HOUSE TURNKEY SOLUTION

The ET drop-in control house solution is based on the protection, integration, and automation technology from a single vendor. The microprocessor relays perform protection, monitoring, control and automation. Using the intelligence and functionality of the relays, ET not only eliminated the need for RTUs and PLCs but also added the ability to perform distributed automation. This distributed automation, as near to the apparatus as possible, is more robust and flexible than centralized automation in RTUs and PLCs and provides advantages never before available. The communications processors integrate communications among the microprocessor relays and other intelligent electronic devices (IEDs) such as equipment monitors, weather stations, and battery chargers to create a powerful substation-wide database. Alarms and reports are sent to personnel or applications via several communications media.

The drop-in control house solution has become a pre-engineered, pre-designed, pre-assembled, pre-wired, and pre-tested building that arrives ready for installation and field wiring.

The control house solution delivers a wealth of power system information that provides users an increased understanding of power system asset status and operation. This information permits risk assessment and outage avoidance, reduced labor and outages for maintenance, and helps create a more competitive and reliable power system. Information from the system is being used to monitor asset return-on-investment (ROI), identify and replace obsolete equipment, strategize effective use of resources and financial capital, and increase device and system productivity.

ET recognized that the traditional SCADA approach does not fit the new information management needs of the substation. SCADA protocols pass only a small amount of the intelligent information that is available within the IEDs. Choosing the truly open communications architecture of the communications processor allows ET to take advantage of all the information in the relays and other IEDs. RTU and PLC solutions restrict the type and amount of information that can be retrieved, used, and passed on to operators.

A. Success Achieved Using Single Vendor for Dual Primary Protection

In the past, many utilities have attempted to minimize their risk of failed protection by installing a primary protection system and then installing another protection system as backup, often from a separate vendor. Early on, ET examined their goal of ensuring the health and availability of the power system. Their solution was to:

- Maximize protection security by correctly operating to protect power system apparatus from faults, and
- Maximize dependability by minimizing protection downtime so equipment is available to operate.

Protection security was ensured by choosing a well-designed protection system to minimize misoperations. This protection system consisted of protection devices and a unique redundant system. Protection devices were chosen with the following characteristics:

- Expected performance is indicated by quantity and type of vendor testing.
- Future performance is predictable based on in-service units and operation history.

To further increase security a dual primary¹ application was chosen with a unique scheme to prevent weaknesses from overlapping.

Dependability was ensured by choosing reliable, high availability products to minimize downtime. Protection systems were chosen to maximize dependability based on the following characteristics.

¹ New product capabilities and integration technology have created opportunities for utilities to install redundant products, which are both considered primary protection. This application is referred to as “dual primary.”

- Reliability of individual microprocessor relays – High Mean-Time-Between-Failure (MTBF) and high Mean-Time-Between-Removals (MTBR) measures demonstrate that devices fail infrequently and are thus available to perform protection. High MTBF products offer maximum dependability.
- Redundant protection products – two products simultaneously in service to eliminate the possibility that failure of one device will jeopardize protection. Redundant protection in the “drop-in control house” solution also provides redundant monitoring and control.
- Unique redundant protection platforms – unique product platforms reduce the possibility that component failures will affect both protection products simultaneously. However, both platforms must be individually reliable to maximize dependability. Redundant protection products of the same platforms are often more dependable than using a second platform with a lower MTBF.

ET chose microprocessor relays to maximize protection reliability and dependability based on the above criteria. ET chose a communications processor based on similar criteria. ET found that all products could be selected from the same vendor and still maintain the highest possible reliability and dependability. The decision to use a single vendor provided many other benefits that are listed below.

- Same settings configuration and management methods reduced cost and complexity
- Same testing platform and processes reduced cost and increased efficiency
- Same operator interface reduced mistakes and lowered cost
- Same integration technology reduced cost and simplified information management
- Same communication technology simplified communication design and reduced cost
- Same event collection technology simplified collection and analysis
- Same remote engineering access technology reduced cost and enhanced accessibility
- Same troubleshooting methods and practices reduced cost and increased efficiency
- Same installation methods and practices reduced cost and increased efficiency
- Same training methods and technology reduced cost and complexity
- Fewer product types increased efficiency of operations and maintenance
- Fewer product types reduced documentation costs and minimized spare parts stock

The selected vendor yielded the following benefits:

- Ability to access and use all information within the IEDs via innovative communication technologies

- High-speed and robust distributed protection, control, and automation via Fast Operate commands and MIRRORED BITS™ communications
- High MTBF and MTBR and 10-year warranty
- Excellent product and application support
- Lower total ownership cost

B. Justification Based on Shareholder and Customer Benefits

The integrated system within the “drop-in control house” solution provides enhanced SER and analog fault recording (AFR) capabilities. The value of these capabilities is further enhanced by an automated data collection infrastructure, which makes the data quickly and automatically available to operators and engineers to quickly determine and document operations and events. As each new “drop-in control house” is brought on line, a larger area of ET’s transmission system is monitored by synchronized and coordinated SER and AFR. The integrated system provides additional benefits in the power quality arena, voltage load profiling and voltage surveillance. Power factor monitoring, energy metering, and interval demand metering are additional benefits realized through this system.

Each new “drop-in control house” provides shareholder value through lowering the capital requirements for protection and control upgrades, retrofits and new installations. Additional value is realized through real-time performance monitoring of substation assets; this allows operating these assets at higher ratings while maintaining safe limits. By operating the assets with confidence at these higher ratings, a delay or cancellation of major capital additions and substation rebuilds can be realized. As ET’s protective and control infrastructure ages and becomes obsolete, this integrated solution becomes the most attractive and cost effective approach for replacement programs.

Customer value is added through enhanced monitoring of substation apparatus. Outage prevention and quicker restoration times are realized through better information provided from the integrated system. Scheduled condition-based maintenance instead of time-based maintenance lowers O&M costs. Service response costs are lowered due to an accurate apparatus assessment program implemented through EPRI’s Maintenance Management Software (MMW). This system provides early warning of apparatus and protection failure, preventing possible misoperations and outages. With fault location available, dispatching line crews right to the transmission span in need of repair lowers O&M costs while restoring service more quickly. Power quality and load-profiling features provide enhanced service to the customer.

C. Technical Innovation Simplifies and Improves Implementation

Simplifying interconnections and minimizing the installed assets by combining substation functionality, traditionally performed in separate single function devices, required a tremendous amount of logic programming to take place inside the microprocessor relays. ET relay engineers worked closely with apparatus engineers to develop new standards for applying this monitoring and control functionality. Settings

templates for these standards were created with input from field engineers and service technicians. These templates allow ET to benefit from reduced implementation cost through reuse of standards and templates.

An integrated microprocessor-based system is an active system that continuously monitors system conditions and interacts with the substation computer, TCC, and ET’s corporate database. The new integrated IED system monitors over 6,000 data points in contrast to the traditional system that it replaced which monitored 96 status points. Alarm criteria for each data point were defined and new methods for handling this massive amount of data were developed. ET purchased two large servers for the MMW and PI software. The standards developed provide a consistent implementation methodology for future substation integration projects. Current efforts focus on integrating these data into ET’s work management system so work orders can be generated automatically based on automatic data analysis. This closes the loop on the management of the substation assets by providing a proactive maintenance system.

D. Innovation Improves Information Management

The integrated architecture within the “drop-in control house” provides an innovative approach and level of integration unparalleled in the industry to date. Past integration efforts focused on integrating functional blocks of equipment through various communications media. This required many different types of equipment often from different manufacturers. This not only complicates the design, but also presents a support challenge from an operation and maintenance perspective. The “drop-in control house” approach leverages the functionality available in microprocessor relays to form a completely integrated protection, control, monitoring, and automation system.

The integrated system reaches beyond the substation; ET sought out an innovative and efficient solution to the data storage and analysis of the substation data. ET implemented PI and MMW software on two large servers that met the requirements of the data storage and analysis needs. These applications provide efficient data storage, links to ET’s asset database, and fast data retrieval for analysis. Currently PI automatically generates a notification of the alarms to the appropriate operating, maintenance, or engineering personnel and automatically triggers the generation of work orders in the future.

III. BELMONT TIE DROP-IN CONTROL HOUSE SOLUTION

Belmont Tie Station is a small 100/44 kV substation consisting of four 44 kV lines, two 100 kV lines, two transformer banks, and a swap-over control scheme. The control house was placed on site in November 2000 and successfully in service by December of 2000.

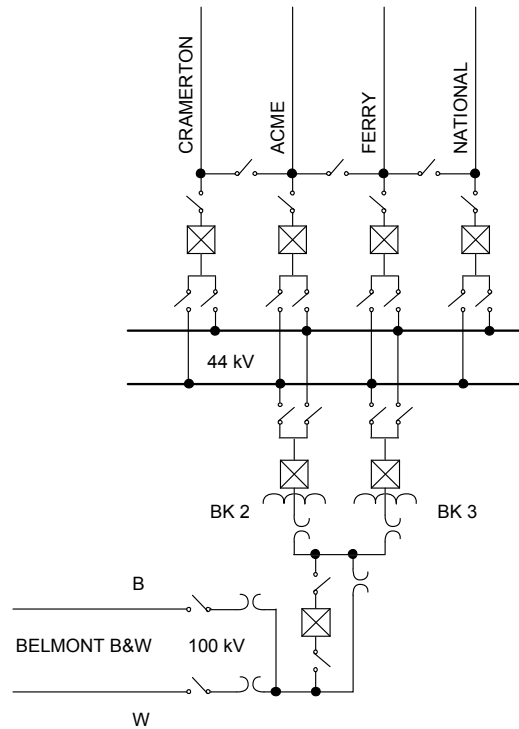


Fig. 1. Belmont Tie One-Line Drawing

A. Key Benefits and Improvements Realized by this Solution

Improvements to current performance and standards are achieved in many areas.

1) Lower Equipment Costs

Capital equipment costs are dramatically reduced due to minimized quantity of devices. The design at Belmont Tie Switching Station allowed the consolidation of over 1000 discrete components to less than 80. This is achieved primarily due to the use of the microprocessor relays and utilizing the internal functionality of these devices.

2) Lower Installation Costs

Simplified field interconnections are achieved by providing a field termination box in the control house. This allows a simple above ground trench system to be utilized, which brings all apparatus interconnections into the control house for termination. This system is a cost effective alternative to other trenching methods when replacing substation cabling and provides an easy method for adding terminals in the future. All wiring from the termination box to the relays was verified and checked during the "Factory Acceptance Testing" (FAT), so additional verification is not necessary. This reduces the commissioning time dramatically compared to the previous retrofit stations.

3) Lower Operations Costs

Operating costs are reduced, and the chance of operator error minimized, through the use of automation and control products from one vendor. Similar look and feel of the local operator interfaces on the relays simplifies the operation and training for the control system. Operators are more efficient in an emergency when they have fewer types of control interfaces to learn and use. The PC-based HMI provides useful

information in innovative ways to streamline the operations further.

4) Lower Maintenance Costs

Applying microprocessor relays with self-test diagnostics and instant digital communications eliminates all periodic maintenance (PM) cycles for the installed electrical terminals. Maintenance of the power system apparatus is enhanced through the collection of information from the IEDs. Periodic maintenance of power system assets is being replaced with predictive maintenance because better information indicates when and what type of maintenance to perform.

5) Lower Enhancement and Upgrade Costs

The integrated design is robust and flexible due to the fact that the protection, monitoring, control, and automation are performed by IEDs distributed throughout the system. This design also permits easy enhancement of the system via upgrades and/or replacement of individual in-service IEDs. These changes are minimized but when necessary, the impact on the system is greatly reduced due to the integrated and distributed design. By treating the electrical terminals as an apparatus, when end-of service is reached, a new control house complete with the newest technology can be dropped in, commissioned, and placed in service before the old control house is taken away.

6) Lower Life-Cycle Costs

Life-cycle cost is dramatically reduced. By eliminating most of the discrete components and standardizing on one vendor for microprocessor relays, significant O&M savings are achieved over the life of the installed assets.

7) Increased Availability and Reliability

Reliability and availability have both been extended due to the use of microprocessor relays. The old protective system relied on electro-mechanical relays that do not perform self-diagnostics or self-alarming. True condition of this equipment cannot be verified until called upon to operate, by then it is too late. The microprocessor relays have very high reliability and availability numbers. The probability of failure when called to operate is very low due to the self-diagnostics and self-alarming functionality of these relays. Planned repairs can be performed when alarmed. By providing this type of warning, guaranteed availability can be assured when needed. Combining the control and monitoring functionality in these relays achieves additional reliability through higher MTBF measures, which are dramatically greater for the selected relays than for traditional SCADA equipment. The installed microprocessor relay-based system is simplified over the traditional system, which improves MTBF estimates. Another important factor is the integration of the automatic diagnostics into ET's corporate database and alarming system, this ensures that proper early warning of failure is detected.

8) Eliminated RTUs and PLCs

The microprocessor relays and communications processors perform traditional SCADA plus many new innovative automation and monitoring functions. ET was able to eliminate failure prone RTUs and PLCs from their designs.

Dramatic cost savings were realized since ET no longer needed to buy RTUs, PLCs, and their accessories. In addition, ET saved the expense of drafting, configuring, and installing RTUs or PLCs, and the cost of frequent maintenance.

9) *Increased Productivity*

Productivity is increased due to the automatic collection and storage of substation data. This includes monthly relay and breaker operations reports, meter reading reports, breaker condition reports, and transformer bank thermal reading reports. During fault operations, an increase in productivity is realized via automatic fault location calculations provided to the dispatch center. Better analysis takes place after an unexpected event occurrence with the use of enhanced SER reports and extended alarms at the transmission control center (TCC). This results in better determination of asset condition and faster restoration of service. Efficiency is increased through better monitoring of the loading and temperatures of the bank transformers. Additional information is collected from an on-site weather station, which provides ambient temperature, solar radiation, wind speed and direction, and precipitation. This is useful for transformer cooling performance analysis, other asset management, as well as planning.

10) *Replacement of Periodic Maintenance With Predictive Maintenance*

Real-time predictive maintenance is realized through the use of EPRI's "Managed Maintenance Workstation" and the substation data collected. This software provides an optimized look at the data and allows data correlation with many other databases for complex trending analysis. Automatic analysis of these data is achieved using previously developed templates. When the software detects an "out of limits" condition, appropriate maintenance personnel are notified.

11) *Prediction and Prevention of System Apparatus Failures*

In addition to predicting the appropriate maintenance times and procedures, the system monitors power system apparatus and alarms warnings of impending failure. Examples include detecting and reporting a leaky compressor and monitoring and reporting the health and performance of a breaker. The compressor alarm can trigger action prior to its failure, allowing operators to avoid use of marginal breakers, thus avoiding outages.

12) *Reduced Potential Human Errors*

Potential human errors are reduced through intelligent supervisory programming of the microprocessor relays. One error, which has been prevented through this system, is the operation of a circuit breaker due to improper switching procedures. The microprocessor relay will prevent the unblocking of the 51G element if it is picked up, thus preventing a misoperation. This information is also displayed for the operator to see on the local substation computer.

13) *Increased Safety*

Safety is increased due to the enhanced protective features incorporated in the microprocessor relays. Traditionally when

the 24 kV transformer low-tension breaker is bypassed for maintenance, the bus and transformer protection is blocked. Protection is most critical for field crews at this time. The protective scheme implemented provides the selection of a "Station Differential" when the low-tension breaker is bypassed. This is one of many safety improvements afforded by the new integrated design.

Substation status is conveyed via screens that were designed by the station operators for quick and easy comprehension. One example of this is the mimic bus that is displayed while the operator is switching a circuit breaker. Only the affected circuits are visible on the mimic display with the circuit breaker that will operate shown in flashing red. This display shows all the currents and power flows on the mimic bus. This leads to a safer operating environment.

B. *Additional Benefits*

Many more improvements were realized with this system. The microprocessor relays used in the complete substation control house solution at Belmont Tie not only satisfy the protection requirements but also meet the SCADA and monitoring needs. This integrated system, based totally on microprocessor relays and communications processors, delivers all the functionality of ET's long-term automation strategy. This functionality includes protection, automation, monitoring, control, SCADA, SOE, DFR, HMI, BCM, annunciating, fault location, temperature monitoring, performance trending, etc.

ET's process for engineering the protection and control was improved by performing a "Factory Acceptance Test" before this complete substation control house solution was shipped. This provided ET and vendor engineers the opportunity to completely test and verify all protection schemes and integration infrastructure before installation/commissioning took place at the substation. By performing this test, and integrating the electrical terminals and the control house solution into a program, confidence was gained in the system that provided a smooth field-commissioning execution plan.

This integrated system provides the required functionality through the microprocessor relay and communications processors while providing the lowest capital installed cost. Long-term O&M savings are projected based on elimination of protective equipment PM's, better managed apparatus maintenance and higher equipment reliability. Redundant protection has become so inexpensive with this design that ET is applying it to circuits which were previously not redundant. The cost is often less than a single trouble call.

Another benefit with the drop-in control house strategy is that while Belmont Tie was being commissioned, another control house was undergoing its "FAT" and prepared for delivery. This system allows concurrent activities to take place with each control house in a different construction phase. This approach allows 9 to 11 substation upgrades per year to be achieved. Without this integrated, drop-in strategy, ET would not have the resources necessary to retrofit 11 substations per year.



Fig. 2. Old and New Control Houses in Belmont Tie Substations



Fig. 3. Panel Configuration Inside Control House

IV. CONCLUSION

The drop-in control house strategy using integrated microprocessor relays and communications processors provides a good solution to the problem of obsolescing substation electrical terminal assets. As more and more of our assets are approaching “end-of-service life” new and innovated methods must be explored to address this need. The capital cost requirements realized by this program are significantly less than traditional methods, while providing O&M savings. By developing good relay and control standards, integrators and relay vendors can successfully deliver a quality pre-commissioned control house that meets asset and business requirements far into the future. Even though ET is near the beginning of their program diagnostic and data archival tools, like PI and MMW, they have already produced significant asset management benefits. These benefits include, hourly VAR monitoring, capacitor operational data, accurate voltage and power flow trending, and transformer heat monitoring.

V. BIOGRAPHIES

Brian A. McDermott received his AS degree from Gaston College in 1981. He started work at Duke Power in the Transmission Department and has progressed through several assignments, including test supervisor. He is currently employed in Duke Power’s Electric Transmission Department. In his current assignment, Brian provides technical direction for transmission automation and integration, performs engineering studies, develops Electric Transmission’s automation strategy, and is project manager and Alliance Manager for Electric Transmission’s automation team. He holds US Patent number 5,055,766, titled “Voltage regulator compensation in power distribution circuits.”

David J. Dolezilek received his BSEE from Montana State University in 1987. In addition to independent control system project consulting, he worked for the State of California, Department of Water Resources, and the Montana Power Company before joining Schweitzer Engineering Laboratories, Inc. in 1996 as a system integration project engineer. In 1997 Dolezilek became the Director of Sales for the United States and Canada, then moved on to serve as the Engineering Manager of Research and Development in SEL’s Automation and Communications Engineering group. In 2000, Dolezilek was promoted to Automation Technology Manager to research and design automated systems. He continues to research and write technical papers about innovative design and implementation affecting our industry, as well as participate in working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, and the International Electrotechnical Commission (IEC) Technical Committee 57 tasked with global standardization of communication networks and systems in substations.

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