ESCUELA SUPERIOR POLITÉCNICA DEL LITORAL

Facultad de Ingeniería en Electricidad y Computación

"DESARROLLO DE ESCENARIOS DE PROTECCIÓN MEDIANTE MENSAJERÍA GOOSE BAJO LA NORMA IEC 61850 EN RELÉS ARCTEQ"

INFORME DE MATERIA INTEGRADORA

Previo a la obtención del Título de:

INGENIERO EN ELECTRICIDAD ESPECIALIZACIÓN POTENCIA

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DEDICATORIA

A Dios por darme el conocimiento. A mis padres ejes invaluables en mi vida que me han ayudado todos estos años para llegar a formarme como persona y como profesional.

Iván Arturo Morán Gárate

A mis padres y hermanos que me brindaron su apoyo incondicional durante todos mis años de estudio.

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RESUMEN

El presente trabajo fue realizado con la idea de demostrar la mejora al implementar la normativa IEC 61850 frente a los esquemas tradicionales de las protecciones eléctricas. Mediante tres ejemplos comparativos se evaluará la mejora, demostrando que implementar la normativa representa el futuro de las protecciones eléctricas.

En el capítulo 1, se explica la necesidad de implementar la norma IEC61850 en los sistemas eléctricos de potencia por el avance tecnológico que ofrece. Una vez explicada la motivación del proyecto se describen los objetivos y el alcance del mismo.

En el capítulo 2, se detalla todo el marco teórico en el que se basa el proyecto. En un principio la jerarquía en las subestaciones, luego se explican conceptos básicos de las protecciones eléctricas, en la siguiente sección se explica información relevante de la norma aplicada al proyecto, y por último los pasos para configurar IEC 61850 en los relés ARCTEQ.

En el capítulo 3, se describen los tres escenarios propuestos: Breaker Failure, protección de barra Reverse Interlocking, transferencia de barra M-T-M. Todos estos implementando la mensajería GOOSE, comparando con un esquema tradicional sin la implementación del mismo.

Finalmente, las conclusiones y recomendaciones son descritas indicando los beneficios de implementar la normativa junto con las sugerencias para aplicarlas en más escenarios.

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CAPÍTULO 1

1. INTRODUCCIÓN

El objetivo principal de los sistemas de potencia es mantener un alto nivel de continuidad de servicio y en caso de ocurrir condiciones intolerables, minimizar el impacto reduciendo los daños en el sistema, los tiempos sin servicio, las zonas afectadas, los costos de no producción e inconformidad del usuario. En un sistema de potencia es seguro que se experimenten pérdidas de potencia, caídas de voltaje y sobrevoltajes, puesto que es imposible evitar consecuencias de eventos naturales, accidentes físicos, daños en los equipos y maniobras incorrectas debido a errores humanos. Es por eso, que es necesario invertir en equipos de protecciones eléctricas en todos los sistemas de potencia a nivel de generación, transmisión, distribución, cargas industriales y residenciales; y de esa manera asegurar el cumplimiento del objetivo principal.

Las comunicaciones de los sistemas de potencias juegan un rol vital en la operación segura y eficaz de las redes eléctricas. La automatización, control y monitoreo en tiempo real de los sistemas eléctricos dependen de redes de comunicación seguras y confiables. Con un rol, constantemente creciente, las redes de comunicación permiten el uso de más dispositivos controlados por computadoras y microprocesadores. Es decir que las redes eléctricas manejarán tecnología de punta y bien enrumbados hacia el futuro tecnológico.

En vista que las redes de comunicación evolucionaron rápidamente en las últimas décadas, los ingenieros eléctricos hicieron uso de estas nuevas tecnologías implementándolas en la automatización y control de las subestaciones. Creando varios protocolos de comunicación para aplicaciones y marcas específicas. Debido a esto el Comité Internacional Eléctrico (IEC), estandariza la comunicación entre dispositivos electrónicos inteligentes (IEDs) creando la norma IEC 61850.

1.1 Justificación

Uno de los principales problemas de tener varios protocolos de comunicación es que los fabricantes de los equipos de protección los usaban de forma específica en la ingeniería de sus equipos. Esto acarreaba, que muchas ocasiones exista incompatibilidad entre marcas. El problema iba más allá, porque al no poder intercambiar equipos libremente, se limitaban a tener un solo proveedor.

Con el fin de garantizar la interoperabilidad entre los equipos de diferentes marcas, nace la norma IEC 61850, definiendo modelos organizados de datos para facilitar el envío y recepción de mensajes entre IEDs. La norma no define un uso específico para el mensaje enviado, solo la forma de transmitirlos. Esto quiere decir que una vez receptado el mensaje, los IEDs lo utilizan según sus funciones programadas con la ingeniería de cada uno de sus fabricantes.

Actualmente miles de sistemas y una vasta cantidad de proyectos se han desarrollado en más de 70 países utilizando el estándar IEC 61850 resultando en nuevos proyectos, nuevas instalaciones, modernización y migración a nuevas tecnologías aplicadas por marcas reconocidas como General Electric, ABB, SEL, Schneider Electric. También se conoce que, en el Ecuador, la compatibilidad de este estándar con los relés de protección es una de las condiciones necesarias para comprar e instalar nuevos relés, esto según los requisitos que se publican en el sistema oficial de contratación pública ecuatoriana.

Por esta razón queremos tomar ventaja de este proyecto para conocer a fondo el uso y la programación basada en la norma IEC 61850. De esa manera llegar a ser ingenieros competentes y a la vanguardia de las protecciones eléctricas. Y a su vez dejar un documento guía para los nuevos estudiantes de ingeniería eléctrica que sientan el deseo de comenzar a investigar sobre la norma.

1.2 Objetivos

1.2.1 Principal

Desarrollar escenarios de protección utilizando mensajería GOOSE bajo la norma IEC 61850 en relés ARCTEQ.

1.2.2 Específicos

- Proponer escenarios de control y protección en donde su filosofía de funcionamiento se base en la utilización de mensajería GOOSE.

- Demostrar las ventajas de tiempos de respuesta de la mensajería GOOSE comparadas con los medios tradicionales de enclavamiento.

1.3 Alcance

Este proyecto tiene como prioridad la concepción de los siguientes entregables:

- Procedimiento estándar, guiado paso a paso para la configuración de mensajes GOOSE en relés ARCTEQ.
- Tres escenarios de protecciones eléctricas utilizando mensajería GOOSE.
- Recomendaciones acerca de la implementación de escenarios de protección mediante GOOSE.

Para el desarrollo de este proyecto se cuenta con los siguientes elementos:

- Dos relés ARCTEQ AQ-F215.
- Un equipo Omicron CMC 356.
- Un Switch ethernet de 5 puertos SEL – 2725.
- Dos Relés auxiliares 125V AC de 8 pines.

Los relés que se utilizarán deben ser compatibles con el estándar IEC 61850. Para simular señales de voltajes y corrientes secundarias provenientes de transformadores de instrumentación se utilizará la maleta de inyección Omicron CMC 356, y además para medir los tiempos de actuación de las salidas binarias de los relés. Se asume que el lector conoce la operación de la maleta de inyección. Para simular los estados de los disyuntores se utilizarán los contactos de los relés auxiliares. Finalmente, para establecer comunicación entre los equipos a través de una red LAN se utilizará un switch ethernet de 5 puertos.

Cabe recalcar que existen diversos escenarios de protección donde la mensajería GOOSE es aplicable y útil, mas debido al corto tiempo disponible para la realización de este proyecto, enfocaremos nuestra atención solo en 3 escenarios.

CAPÍTULO 2

2. MARCO TEÓRICO

Para comprender el proyecto es necesario hacer una breve explicación de las subestaciones y sus componentes haciendo referencia a los conceptos de protecciones eléctricas utilizados. Además de realizar una vista general del contenido de la norma IEC 61850 y la familiarización con el manejo de los relés Arcteq para su implementación.

2.1 Subestaciones eléctricas

Una subestación eléctrica es una instalación, o conjunto de dispositivos eléctricos, que forma parte de un sistema eléctrico de potencia. Estos elementos permiten realizar cambios en el sistema eléctrico como: seccionamiento del sistema y transformar los niveles de voltajes. Dependiendo de la función que desempeñe la subestación puede ser de elevación, reducción o seccionamiento.

2.1.1 Componentes de la arquitectura de una subestación

Dentro de la subestación existen jerarquías de mando en los que se pueden maniobrar los estados de los elementos. De la misma manera se definen los elementos que lo conforman. Cada nivel tiene la opción de seleccionar en estado remoto o local, donde el estado local deja sin acción a los niveles superiores permitiendo cambiar de estados los elementos en el sitio, y el estado remoto habilita a los niveles superiores tener el control. [1]

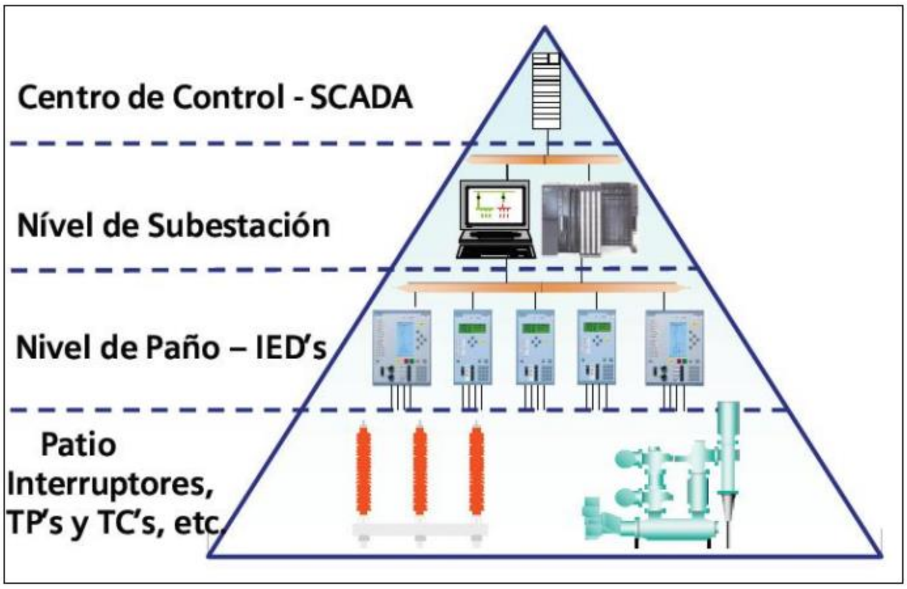


Figura 2.1 Jerarquías de mando de subestación [1]

2.1.1.1 Nivel de campo

En el sistema de control, todos los elementos que permiten la adquisición de datos y canales de comunicación se encuentran en este nivel. Los datos obtenidos pueden ser de tipo analógicos o digitales. Comúnmente la información obtenida son mediciones de Voltajes y corrientes de los CT y PT, lecturas de presión, temperatura de los equipos, estados de seccionadores e interruptores.

2.1.1.2 Nivel de paño o bahía

Luego del nivel de campo sigue el nivel de bahía. En este se agrupa todos los elementos que conforman la parte de protección, supervisión, almacenamiento, comunicación y control. Comúnmente encontramos relés, IEDs, medidores, PLC entre otras.

2.1.1.3 Nivel de subestación

En este nivel se realizan las funciones de control, supervisión y adquisición de datos de toda la subestación. También se puede contar con un desarrollo de ingeniería para la integración de todos los IED's en un solo sistema SCADA HMI. Todo esto controlado por un operador de la subestación.

2.1.1.4 Sistemas SCADA

Se conoce como SCADA al control de equipos en un área extensa y no a un solo sistema. Se forma por un conjunto de equipos que proveen información suficiente del sistema al operador, que se encuentra en una locación remota, para la toma de decisiones. Las actividades que un SCADA se encarga son tanto para adquisición de datos como las de supervisión.

2.1.1.5 Nivel Superior

Este nivel refiere a un nivel macro, que agrupa a varias estaciones de control. Es decir, cada subestación dentro de una cuidad manda la información a un centro de control y a su vez todos estos se reportan con un nivel superior. En el Ecuador el CENACE es el nivel superior el cual es el ente encargado de control de la producción, distribución y transmisión de la energía en el país.

2.1.2 Enclavamientos

Los enclavamientos son una medida de seguridad que impide una operación inadecuada de los equipos de subestación. Para poder realizar una maniobra deben cumplirse una serie de restricciones y hasta que todas ellas no se cumplan no se podrá realizar dicha acción.

2.2 Vista general de las protecciones eléctricas.

El objetivo de la implementación de las protecciones eléctricas es aislar rápidamente una zona afectada del sistema de potencia, de tal manera que se minimice el impacto en el resto del sistema. Bajo este contexto hay 5 puntos importantes que se deben cumplir para aplicar protecciones. Estas son:

- Confiabilidad: la certeza de que la protección actúe en el momento correcto.
- Selectividad: máxima continuidad del servicio con la minima desconexión del sistema.
- Velocidad de operación: mínima duración de falla.
- Simplicidad: mínimo equipamiento y circuitería asociada.
- Económico: máxima protección al menor costo

2.2.1 Protección de tiempo contra sobrecorriente.

En un sistema sólidamente aterrizado, es normal que se produzcan grandes corrientes cuando existe una falla en el sistema. La magnitud exacta de esta corriente depende netamente de la topología de la red. En esta protección se definen dos términos Corriente de Arranque (Istart o pick-up), TAP y Time Dial (TD). La corriente de arranque refiere a la mínima corriente de operación del relé. Es el dispositivo que permite seleccionar la corriente de operación del relé dentro de un rango de tomas o derivaciones dispuestas para este efecto. En relés modernos, los valores de ajuste se expresan como múltiplos y submúltiplos de la corriente nominal (1 ó 5A dependiendo del CT). Por ejemplo 0.4 a 4.0 veces Inom en pasos de 0.01. En relés antiguos se utilizaba el concepto de TAP o valores discretos de corriente (5, 6, 8, 10A). El Time Dial permite obtener diferentes tiempos de operación para una familia del mismo tipo de curvas para una corriente dada. [2]

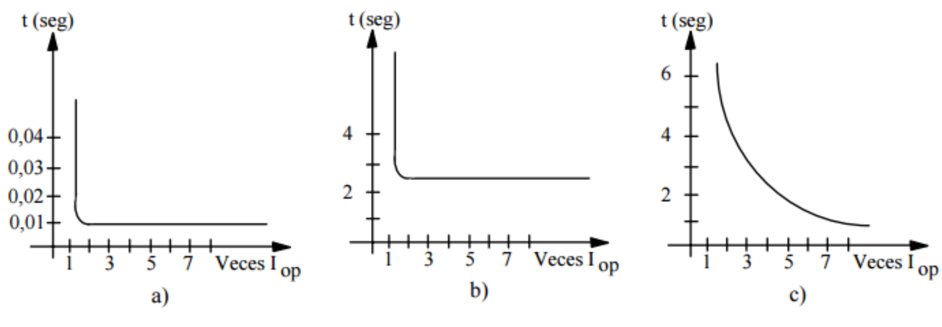


Figura 2.2 Curvas de corrientes de tiempos de relés. [2]

2.2.1.1 Protección de sobrecorriente instantánea.

Estos relés, como unidades aisladas, se usan poco en los sistemas eléctricos de potencia. Generalmente se utilizan en conjunto con otras protecciones, con el fin de combinar sus características. Los tiempos de operación son del orden de los 10 a los 60 milisegundos. La característica de este tipo de protección es la mostrada en la figura 2.2 a.

2.1.1.1 Protección de sobrecorriente definido.

Una protección simple de tiempo definido podría obtenerse usando un relé instantáneo en conjunto con un elemento temporizador (T) que produzca el retardo necesario, (Figura 2.2 b). El relé opera sólo si la sobrecorriente se mantiene durante el tiempo necesario. En caso contrario, el relé no opera.

2.1.1.2 Protección de sobrecorriente de tiempo inverso.

La principal característica de este tipo de relés es que mientras mayor sea la corriente aplicada, menor es su tiempo de operación. Este principio da origen a una variedad de relés con diversas características de tiempo de operación y pequeñas diferencias de diseño eléctricas y mecánicas. Este tipo de característica se encuentra graficado en la figura 2.2 c.

2.1.2 Coordinación Relé-Relé

El proceso de ajustar la selectividad se denomina “coordinación de protecciones”. Para esto se organiza las curvas tiempo-corriente de cada uno de los relés que se encuentran en entre el dispositivo que usa la energía y la fuente. De tal manera que los relés distingan entre aquellas condiciones para las cuales está pensado operar y aquellas para las cuales no debe operar.

Todos los elementos de un sistema de potencia deben estar correctamente protegidos de tal forma que los relevadores solamente operen ante la ocurrencia de fallas. Algunos relevadores operan solo para fallas que ocurren dentro de su zona de protección; esto es llamado “protección tipo unitaria”. De otro lado, otros relevadores son capaces de detectar fallas dentro de una zona particular y fuera de ella, usualmente en zonas adyacentes, y pueden usarse como respaldo de la protección primaria como una segunda línea de defensa. Es esencial que cualquier falla sea aislada, aún si la protección principal asociada no opera. Por lo tanto, en lo posible, cada elemento en el sistema de potencia debe estar protegido por los relevadores primarios y de respaldo. [3]

2.1.3 Protecciones en el mundo

En el mundo las protecciones y los sistemas de comunicación han ido evolucionando, teniendo que adaptarse al mismo. De manera que se automatice la mayor parte del trabajo y simplifique las conexiones. En las grandes potencias mundiales se implementa el protocolo IEC 61850 para la automatización de las empresas eléctricas. Las marcas más reconocidas del mercado como ABB, General Electric, Schneider Electric, SEL, Siemens presentan el estándar como una solución innovadora, confiable y "a prueba del futuro" para protección, control y monitoreo.

2.1.4 Protecciones en el Ecuador

En el Ecuador las empresas generadoras, de transmisión y distribuidoras pertenecen al sector público. Para la realización de nuevos trabajos y suministros de equipos en las empresas eléctricas, las contrataciones se realizan a través del sistema de contratación pública ecuatoriana. En este sistema se determinan los requerimientos a cumplir por los nuevos equipos a instalar. La compatibilidad del estándar IEC 61850 con los relés de protección, es una de las condiciones necesarias para comprar e instalar nuevos relés. Se conoce que para pocas aplicaciones específicas se utiliza el estándar, aunque, a la fecha actual, aún predomina el esquema tradicional. Esto refleja la intención y posibilidad de implementar la norma con visión al futuro.

2.2 Vista general del estándar IEC 61850

En esta sección se explicará de forma breve los aspectos fundamentales del estándar IEC 61850. Iniciando desde su historia, beneficios, objetivos de su implementación, los aspectos fundamentales, explicar servicios y mapeos con sus métodos de comunicación. De esa manera el lector se familiarizará con los conceptos asociados a la norma en el momento de programarlas en los relés Arcteq.

2.2.1 Historia de la automatización de subestaciones

A lo largo de los años las subestaciones se han ido modernizando a pasos agigantados. Uno de los principales problemas fue que cada compañía diseñaba su propio protocolo de comunicación para la interacción con los dispositivos. Para el consumidor fue una gran dificultad ya que solo podían comprar una marca para comunicar relés entre sí, el problema no se remitía solo a una subestación sino también a la comunicación entre IEDs de distintas subestaciones.

Ya en el 1987 con el fin de crear una recomendación en la estructura de un sistema de automatización, la Asociación de Empresas Eléctricas Alemanas se dio a esta labor. En ella mostraban los modelos en que habitualmente se divide un proceso de automatización, nivel de proceso, nivel de campo y nivel de subestación. En el caso del nivel de campo, la adquisición de señales se hace casi siempre de manera cableada, tanto para protección, medición y control. Para la comunicación entre los niveles, las empresas eléctricas suelen usar diferentes protocolos de comunicaciones.

2.2.2 Historia IEC 61850 [4]

El grupo de trabajo 10 (WG10), con el título de "*Comunicaciones de IEDs del sistema de potencia y modelos de datos asociados*", tiene la tarea de mantener todos los documentos de la norma IEC 61850 y trabajar en futuros proyectos dentro del rango de aplicación de la misma. La norma IEC 61850 se publicó en 2003/2004 bajo el título "IEC 61850 Redes y Sistemas de Comunicación en Subestaciones". Puede verse por el título que el rango de aplicación de la norma es la descripción de las comunicaciones entre equipos y sistemas en el interior de una subestación. Originalmente, no se pretendía describir comunicaciones fuera de la subestación.

La IEC 61850 va mucho más allá de otras normas de comunicaciones. Incluye:

- Comunicaciones entre procesos, definiendo qué y cómo comunicar;
- Modelos de objetos normalizados y extensibles;
- Lenguaje de configuración normalizado;

Dentro de la cooperación con otros grupos de trabajo y la adición de extensiones a IEC 61850 para incluir otros dominios (como centrales hidroeléctricas y aerogeneradores), se cambió el título de la norma en su segunda edición a: "*IEC 61850 Redes y Sistemas de Comunicación para la Automatización de las Empresas Eléctricas*", de esta manera se abría un abanico de posibilidades al alargar el alcance la norma.

2.2.3 Objetivos principales de la norma IEC 61850 [5]

Los objetivos principales se describen a continuación:

Interoperabilidad: IEDs de diferentes fabricantes son capaces de intercambiar información y de utilizar dicha información para sus funciones.

Configuración Libre: La norma soportará diferentes filosofías. Deberá permitir a fabricantes y empresas eléctricas un cierto grado de libertad para soportar requerimientos específicos de diferentes sistemas.

Estabilidad a largo plazo: La norma debe ser capaz de incorporar los progresos en las tecnologías de comunicaciones, así como los cambios en los requerimientos del sistema.

Para poder alcanzar la interoperabilidad se estableció un modelo de datos normalizados e intercambio de información. La plataforma de libre configuración no define que funciones deben implementarse en un dispositivo, ni tampoco limita la funcionalidad de un relé dado. Los fabricantes pueden asignar funciones que soporten la evolución de los productos. La norma no define la estructura (algoritmo) ni la potencia de las funciones. Debe ser posible diseñar distintas arquitecturas de red dependiendo de los requerimientos del cliente. Para asegurar la Estabilidad a largo Plazo de la norma, se emplearon objetivos de diseño empleados en el pasado para otros protocolos.

2.2.4 Aspectos fundamentales IEC 61850 [5]

La norma IEC 61850 define los siguientes aspectos fundamentales:

Modelos de información normalizados: Las señales de la subestación se modelan de forma virtual utilizando datos. Ejemplo de datos son: estados del interruptor de potencia, comandos, medidas, señal de disparo, etc.

Servicios normalizados: define cómo utilizar los datos del modelo de información. Ejemplos de servicios: control de un interruptor de potencia, informe de estados del interruptor y acceso a la señal de disparo de un relé de protección.

Red normalizada: se seleccionan protocolos normalizados para transportar los servicios y la información en una red de comunicaciones.

Configuración normalizada: para la completa descripción de un dispositivo.

2.2.5 Vista general del modelado [5]

La norma IEC 61850 define un mecanismo de intercambio de información que puede separarse en cuatro aspectos fundamentales: modelos de información, interfaz de servicio, mapeado a protocolos y configuración del sistema. Estos mecanismos de intercambio de información dependen principalmente en modelos de datos bien definidos. Este modelado de datos es el primer paso del método de comunicación definido en la serie de documentos IEC 61850.

Las series IEC 61850 utiliza el método de modelar la información hallada en equipos de la subestación. Este modelo de datos permite representar todas las variables en el sistema de automatización de subestación. De manera que toda información de un IED que pueda ser útil para el intercambio de información con otro IED se ve definida en la norma.

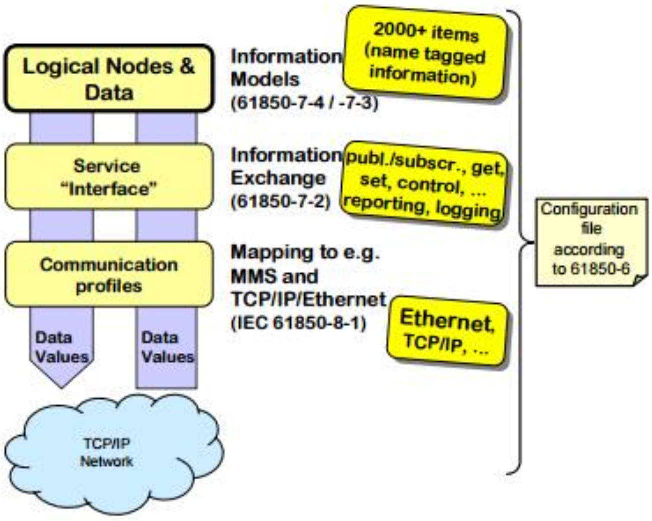


Figura 2.3 Modelado de datos en el método de comunicación [5]

Los distintos niveles del modelo de información se definen como:

1.-Servidor: Representa el IED que contiene los datos. Contiene un punto de conexión a la red de comunicaciones.

2.-Dispositivo Lógico: permite la subdivisión de un dispositivo físico en varias partes, cada una de las cuales recibe el nombre de "dispositivo lógico". Esta división permite la organización de los datos, por ejemplo, dependiendo de su aplicación o función, permite identificar y gestionar los datos más fácilmente. El número de dispositivos lógicos y sus nombres no están definidos en la norma: los fabricantes son libres de implementar soluciones individuales.

3.- Nodos Lógicos: se organizan en el interior de los dispositivos lógicos y corresponden a funciones bien establecidas en los dispositivos reales. Para todos los nuevos lógicos normalizados, IEC 61850 define un nombre de 4 caracteres.

4.- Objetos de Datos: de acuerdo a su funcionalidad, un nodo lógico contiene un cierto número de datos. En la norma se define que objetos de datos deberá contener cada uno. Dichos datos tienen una estructura y una sintaxis bien definida.

5.- Atributo de Datos: Cada paquete de datos contiene atributos dedicados. Éstos contienen la información detallada del valor del paquete de datos. Dado que muchos de los paquetes tienen siempre los mismos atributos de datos, la norma define las clases comunes de datos. Una clase común de datos define qué atributos se incluyen en un tipo específico de paquete de datos.

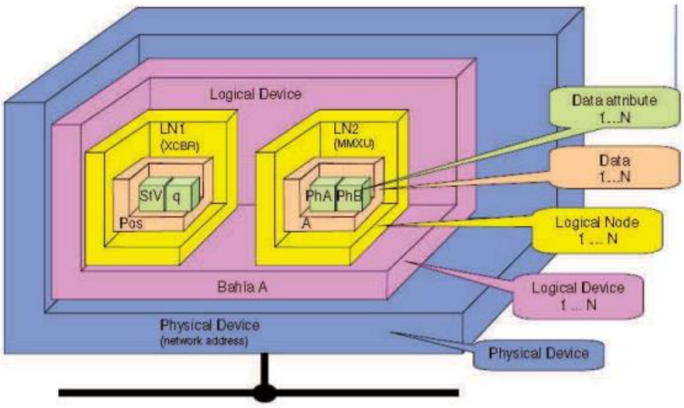


Figura 2.4 Vista del grupamiento del modelado [5]

Logical group	Name	Number of logical nodes
L	System LN	2
P	Protection	28
R	Protection related	10
C	Control	5
G	Generic	3
I	Interfacing and archiving	4
A	Automatic control	4
M	Metering and measurement	8
S	Sensor and monitoring	4
X	Switchgear	2
T	Instrument transformers	2
Y	Power transformers	4
Z	Further power system equipment	15

Tabla 1 Grupos lógicos de señales

Ejemplos de nodos lógicos

- PDIF Diferencial
- PDIS Distancia
- PSCH Esquema de protección
- PTOC Sobrecorriente
- PTOV Sobretensión
- XCBR Interruptor
- XSWI Seccionador

Ejemplos del dato de posición del disyuntor asociado a un IED

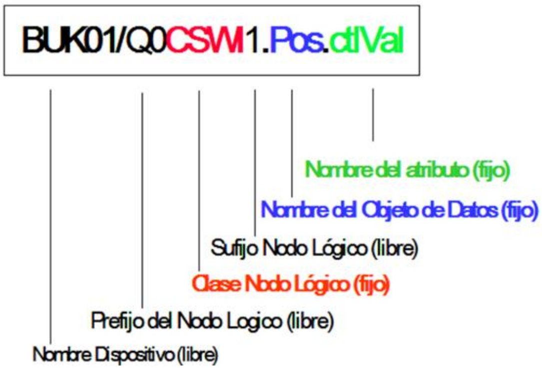


Figura 2.5 Ejemplo de dato en agrupamiento.

2.2.6 Servicios y mapeos específicos de comunicación [5]

La norma establece un interfaz normalizado y neutral entre la aplicación y las comunicaciones. Los servicios se definen de forma abstracta. Esto quiere decir que la definición se centra en la descripción de lo que el servicio debe proporcionar, no se describe como se aplican los servicios a una red real de comunicaciones. Por lo tanto, nos referimos a ellos como *ACSI - Abstract Communication Service Interface / Interfaz Abstracta de Servicios de Comunicación.*

Para el intercambio de información, se define entre otras categorías de servicios:

1.- Intercambio del tipo *Sampled Values* para señales de voltaje y corriente proveniente de transformadores de instrumentación.

2.- Intercambio rápido (GOOSE) ya sea para datos de protección o control.

3.-Señales de control.

4.-Ingeniería y configuración.

5.-Monitoreo y supervisión.

6.-Comunicación con el centro de control.

Existen bloques de control definidos para informes, GOOSE, Sampled Values y grupos de ajustes. Se modela de forma similar a un objeto de datos que contienen atributos para configurar los servicios de comunicación asociados. Cualquier nodo lógico puede contener uno o más bloques de control para informes, pero sólo el nodo lógico cero (LLN0) puede contener los bloques de control para GOOSE, Sampled Values y grupos de ajustes.

El modelo de datos puede contener uno o más DataSets. Los DataSets se utilizan para distintos servicios y constan de atributos de datos.

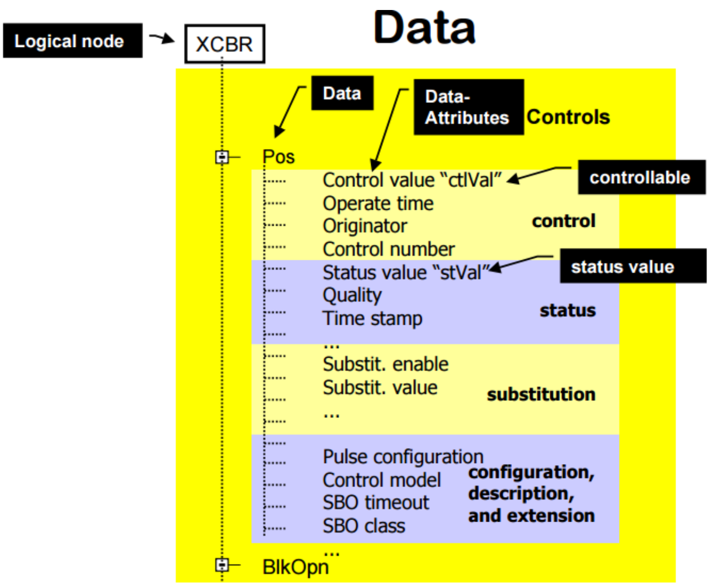


Figura 2.6 Categoría de la información de los nodos lógicos. [5]

Estas referencias se denominan "miembros" del DataSet. Los DataSet se utilizan por los bloques de control de algunos servicios, como informes y GOOSE. Por ejemplo, un bloque de control de informe tiene asociado un DataSet que define qué valores deberán transmitirse en caso de que uno de los cambios. Cualquier objeto o atributo de datos puede verse referenciado por uno o más DataSets.

2.2.7 Métodos de comunicación [5]

Los servicios ACSI se dividen en dos grupos de acuerdo a su método de comunicación.

-Servicio Cliente / Servidor: describen la comunicación entre un cliente y servidor con servicios tales como:

- Auto descripción;
- Informe;
- Control;

-Servicios en tiempo real: describe una comunicación mediante mensajes multicast para los servicios:

- GOOSE (Generic Objects Oriented Subestations Events)
- Transmisión de Sampled Values.

2.2.8 Servicios cliente / servidor [5]

Un servidor contiene todo lo que está definido para ser visible y accesible desde la red de comunicaciones. Un cliente es cualquier dispositivo físico que utiliza los servicios ACSI para interactuar con un servidor. La norma define solamente el papel del servidor, es decir, el modelo de datos alojado en el servidor y los servicios definidos para el intercambio de información. Los clientes, su estructura interna y sus funciones no están definidos en la norma. Los clientes solicitan servicios de un servidor y reciben confirmaciones del servidor. Es posible que reciban también informes de un servidor sin solicitarlos.

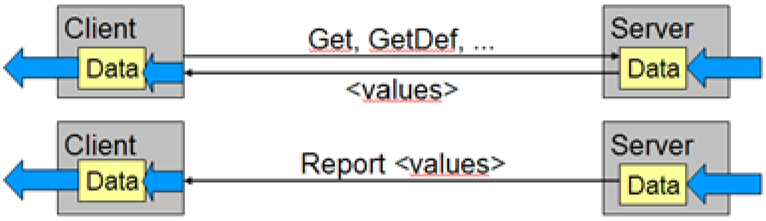


Figura 2.7 Flujo de información cliente-servidor. [5]

Las características de una comunicación Cliente / Servidor son:

- Conexión punto a punto.
- Usado típicamente para sistemas SCADA.
- Usado para aplicaciones que no requieras gran velocidad o tiempos pequeños de transmisión del mensaje.
- La comunicación es "Confirmada", es decir, el cliente recibe respuesta a sus peticiones.

2.2.9 Servicios en tiempo real [5]

Para una comunicación del tipo tiempo real o también llamada multicast, se definen dos nuevos roles: publicador y suscriptor. Un intercambio de información en multicast se produce entre una fuente publicadora del mensaje y uno o más receptores o suscriptores.

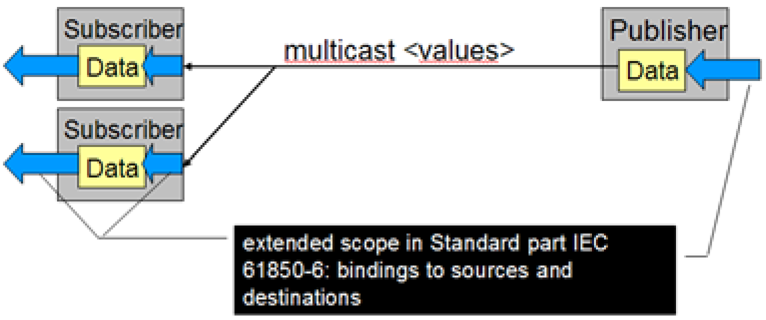


Figura 2.8 Flujo de información multicast [5]

La comunicación multicast se caracteriza por:

- Comunicación uno-a-muchos (MCAA)

- Utilizada para comunicación eficiente entre IEDs (GOOSE) y transmisión de Sampled Values desde transformadores de instrumentación.

- Usado en aplicaciones de tiempo real o críticas de tiempo.

- Comunicación no confirmada, es decir, el publicador no recibe respuesta de los suscriptores.

2.2.10 Mapeo específico de comunicación [5]

La definición de la sintaxis, la codificación de los mensajes y como se transportan sobre una red se denomina SCSM - Specific Communication Service Mapping -**Mapeo específico de servicios de comunicación**, donde se mapean los servicios abstractos a un protocolo de comunicación concreto.

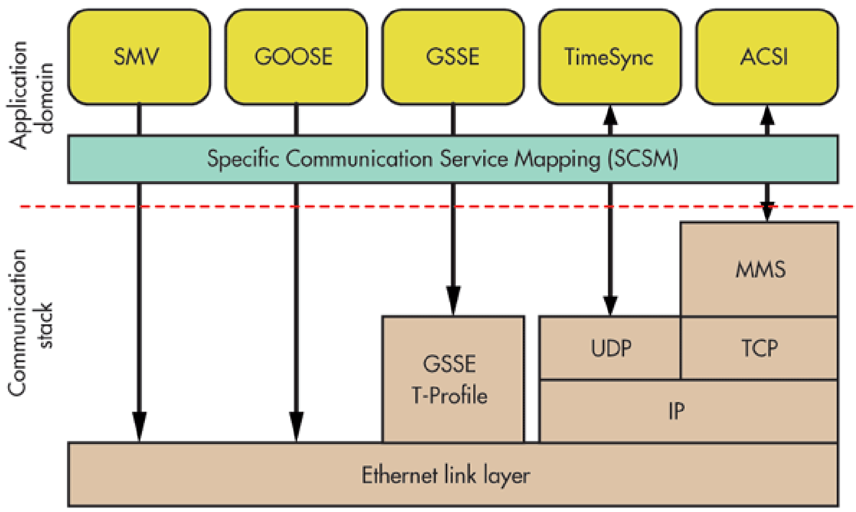


Figura 2.9 Mapeos de comunicaciones [5]

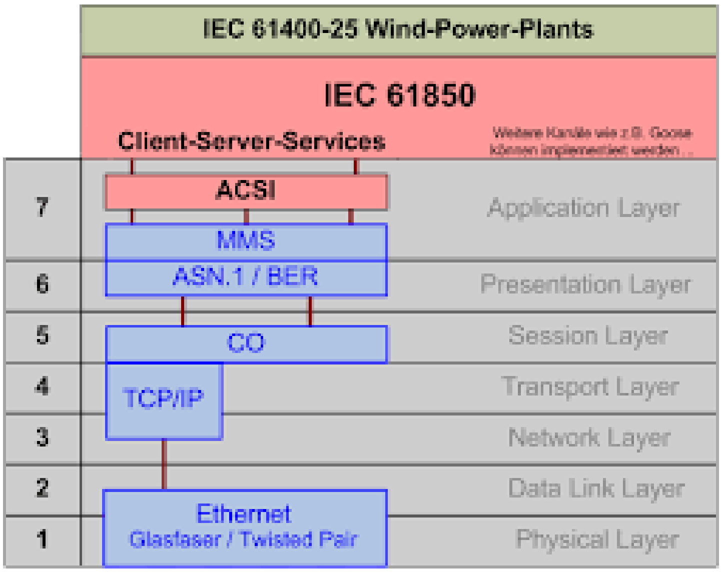


Figura 2.10 Mapeo cliente-servidor [5]

IEC 61850-8-1 específica el mapeo de los objetos y servicios de ACSI a MMS (ISO 9506) y paquetes de ISO/IEC 8802-3 (Ethernet).

Los servicios Cliente / Servidor de ACSI están mapeados al protocolo MMS. El MMS utiliza las reglas básicas de ASN.1 para codificar y descodificar los datos. En las capas de transporte y de red, se especifica un perfil TCP/IP.

Por otro lado, los servicios en tiempo real están mapeados directamente a los formatos de paquete de ISO/IEC 8802-3. Los mensajes de GOOSE se manejan directamente a la capa de Ethernet a fin de ser lo más rápidos posible, evitando tiempo extra de proceso que se supone conlleva pasar por las otras capas.

MMS - Manufacturing Message Specification (ISO 9506) es una norma que define servicios y una especificación de protocolo para operar sobre perfiles de comunicación que cumplan enteramente con OSI y TCP.

ISO/IEC 8802-3 es la norma que especifica los métodos de acceso y la capa física para redes Ethernet.

2.2.11 Estado actual de la norma [5]

Inicialmente el estándar IEC 61850 como fue concebido, era para la automatización de subestaciones y la telecomunicación entre sus dispositivos, en los diferentes niveles de control, siempre enfocado para la comunicación interna de la subestación; cuenta con 14 partes principales, provenientes de 10 capítulos. Estos 10 capítulos son los siguientes:

IEC 61850-1: Introducción y vista general.

IEC 61850-2: Glosario.

IEC 61850-3: Requerimientos generales.

IEC 61850-4: Sistema y administración del proyecto.

IEC 61850-5: Requerimientos de comunicación para las funciones y modelado de equipos.

IEC 61850-6: Lenguaje de descripción de la configuración para sistemas de automatización.

IEC 61850-7: Estructura básica de comunicación para la subestación y alimentadores.

IEC 61850-8: Servicios de comunicación específicos de mapeo (SCSM)- MMS.

IEC 61850-9: Servicios de comunicación específicos de mapeo (SCSM)- SV.

IEC 61850-10: Pruebas de conformidad.

2.3 Configuración de mensajería GOOSE en ARCTEQ [6]

Los relés ARCTEQ de la serie AQ200 pueden ser configurados y parametrizados desde computadoras utilizando el software AQtivate 200. El software utiliza una interfaz gráfica moderna amigable con el usuario. Los parámetros de los relés quedan almacenados en archivos de extensión ".aqs" los cuales guardan la configuración editable de los IEDs.

2.3.1 Software requerido

El relé proporciona un manual y software que puede ser descargado previo registro del equipo en la página del fabricante. La página donde se los puede encontrar es http://www.arcteq.fi/downloads/ en la figura de abajo se muestra la página revisada a la fecha 5/01/2017.

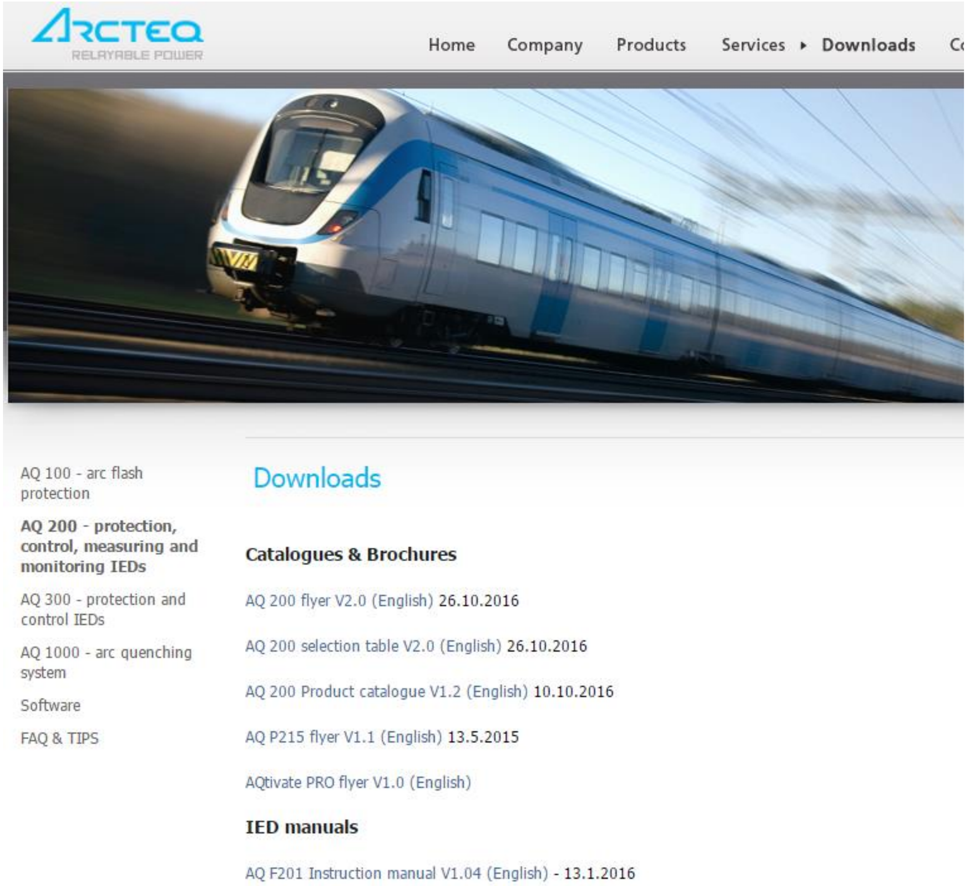


Figura 2.11 Pagina web descargas Arcteq

En la parte de la izquierda existen podemos ver los diferentes productos, seleccionamos el de nuestro interés. Luego de la instalación del producto es necesario, en caso de que el sistema operativo lo requiera, permitir la conexión del firewall para el programa. La versión de software usado actualmente es 1.3.2.16-g2f99673 solo disponible para Windows.

2.3.2 Conexión entre equipo y computadora

El equipo cuenta con puertos para conexión por fibra óptica y red Ethernet con 2 puertos RJ-45, cualquiera de los dos puede ser usado para configurar el equipo, sin embargo, el puerto posterior tiene limitaciones en caso de que se requiera actualizar el firmware del equipo o conexiones al SCADA.

2.3.3 Asignación de IP

Dentro de una red cada uno de los dispositivos conectados se le asigna un número que lo permite identificar de manera lógica y jerárquica. Dentro de una red se debe configurar IP, máscara de red, Puerta de acceso, una de las ventajas del relé es que acepta DHCP server, donde estos valores son asignados de manera automática.

2.3.3.1 Asignación de IP del relé

El usuario puede usar el HMI y navegar a través de *Comunicaciones →Conexiones.* En el menú que se despliega encontramos los tres parámetros descritos anteriormente. Todos los parámetros dentro del menú *Ethernet* son configurables para el usuario. En la parte de Serial se muestra información sobre la conexión que no será de uso para este manual.

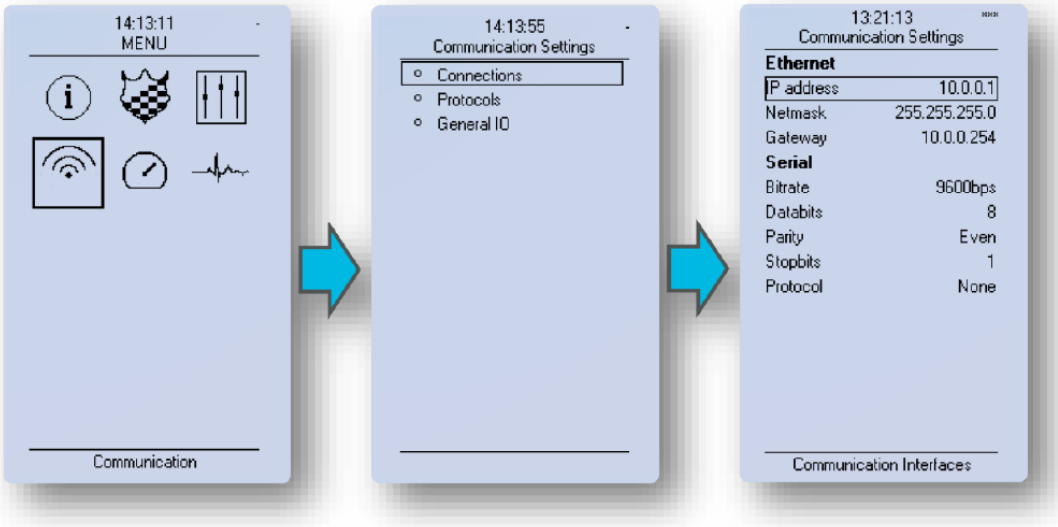


Figura 2.12 Interface HMI del ARCTEC

2.3.3.2 Asignación de IP al computador

Luego de obtener los valores de IP, máscara de red y gateway; configuramos los parámetros dentro del computador. Es posible configurar de dos maneras, la primera es que el sistema se asigne automáticamente estos valores, gracias a que el relé cuenta con DHCP server, y la segunda es ajustando los valores de manera manual.

2.3.3.3 Obtención Automática de parámetros

Dentro de Windows busque *configuración del adaptador* y diríjase a *propiedades de configuración local*. En el *protocolo de internet* 4 nos dirigimos a propiedades y configuramos tal como se muestra en la imagen inferior, es decir Obtener una dirección IP automáticamente y Obtener la dirección del servidor DNS automáticamente.

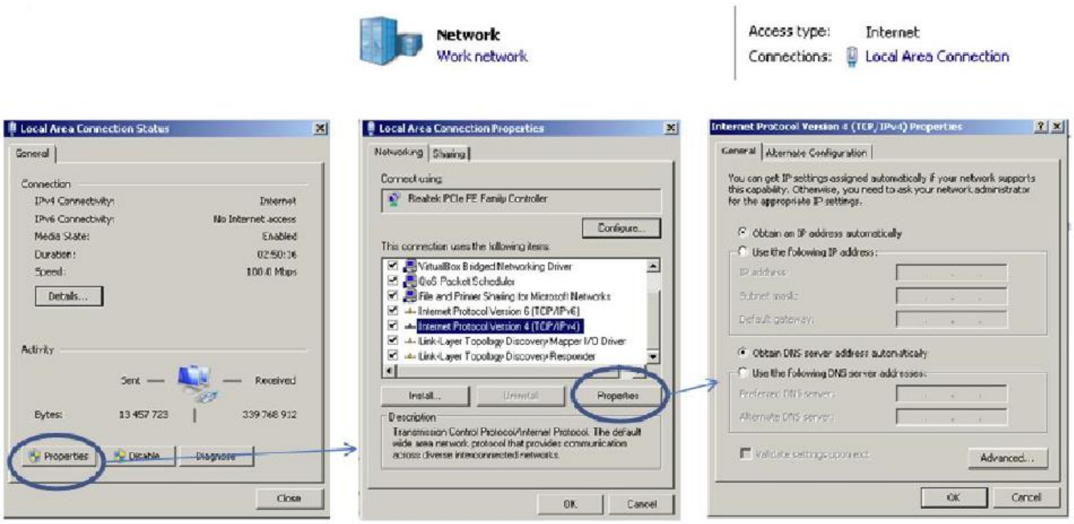


Figura 2.13 Configuración IP computador.

2.3.4 Conexión directa parámetros

En la misma ventana anterior asignamos en *Usa los siguientes valores* y en máscara de subred y Geatway colocamos los valores exactos obtenidos del equipo. En la dirección IP colocamos los 3 primeros valores y en el último valor colocamos el número que tenía más 3, para así evitar colisionar con otro elemento de la red.

El lector debe recordar que dentro de una red cada elemento tiene una Ip única que cambia desde el 1 hasta el 254 en su último valor. Ejemplo: 192.168.1.4 IED1, 192.168.1.5 IED 2, 192.168.1.9 PC1.

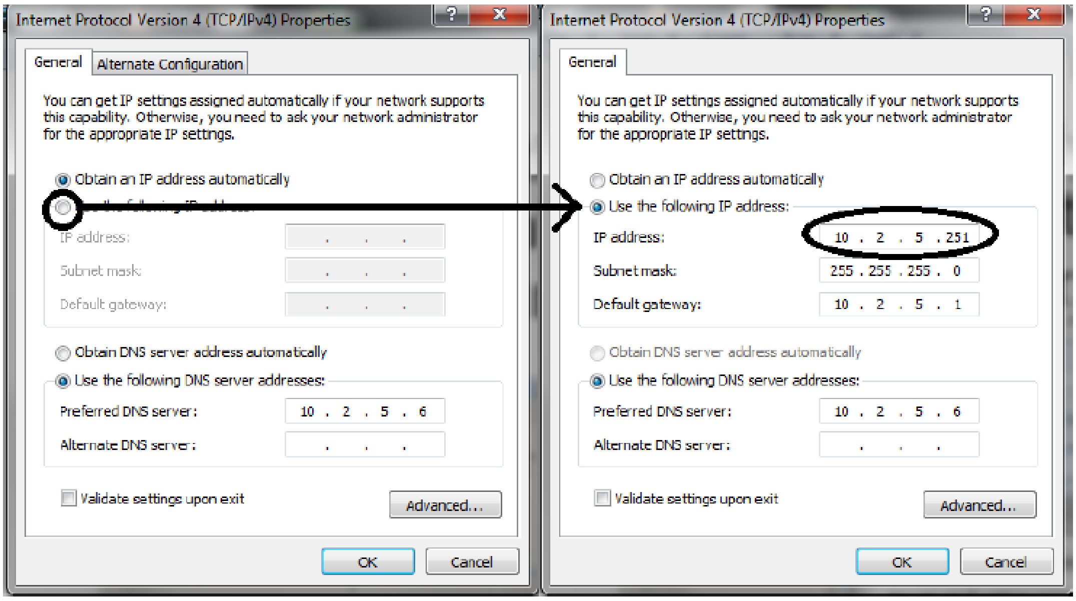


Figura 2.14 Asignación de IP al computador.

2.3.5 Conexión del Software con el relé

Hasta este momento ya se encuentra configurada la red, una prueba básica para saber si existe respuesta del cualquiera de los elementos de la red dentro de Windows es hacer un *Ping* a la dirección IP de cualquiera de los elementos.

Suponga que el relé tiene asignada la dirección IP 192.168.1.5 y queremos comprobar si se encuentra en la red, para ello abrimos el Símbolo del sistema (Inicio → Ejecutar → CMD) y en la consola de comandos escribimos Ping 192.168.1.5

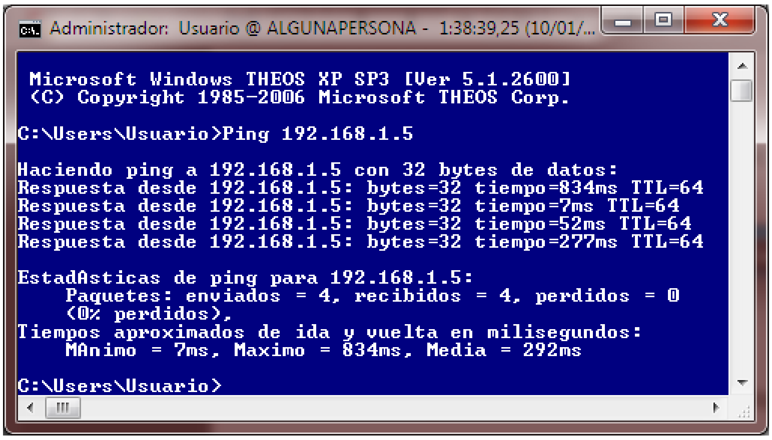


Figura 2.15 Ping al puerto.

El resultado muestra que todos los paquetes fueron recibidos de manera correcta, por lo que el equipo es visible para cualquiera de los elementos de la red.

Luego de todas las comprobaciones podemos abrir el Software del Relé, en la figura se muestra en entorno del programa.

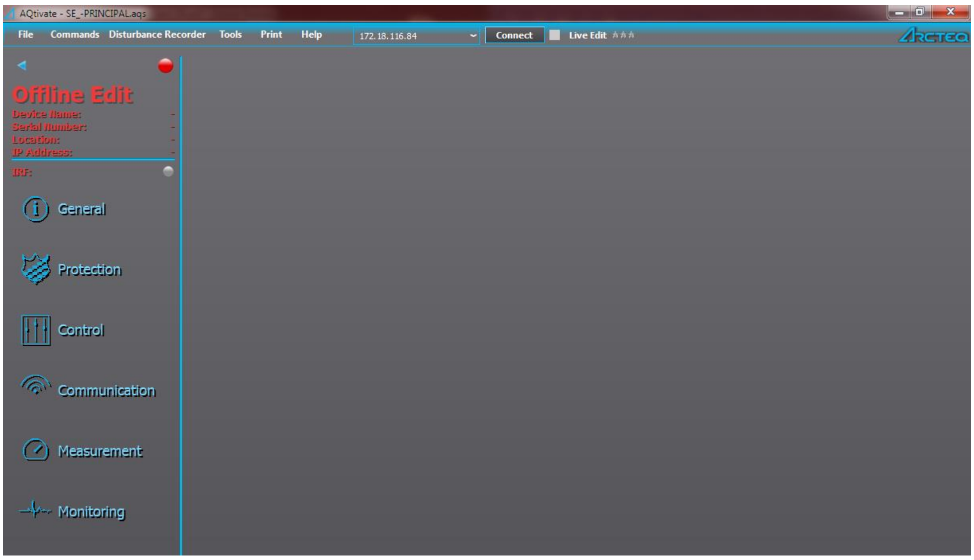


Figura 2.16 Vista general del entorno.

En la parte superior colocamos la dirección IP del Relé y damos clic en conectar. El sistema tiene una opción llamada *Live edit* la que permite editar los parámetros en vivo, mientras el equipo se encuentre en operación; en caso de que el usuario no habilite dicha opción, el relé descargará la configuración actual del relé para que el usuario realice los cambios y vuelva a cargar la información actualizada.

Solo una computadora puede estar conectada al relé a la vez.

2.3.6 Manejo de información del relé

El primer paso luego de conectarse al relé es descargar los datos de la información almacenada del mismo. Luego de realizar los cambios a la configuración se guardan los cambios realizados. Así mismo el usuario puede guardar un respaldo del archivo con la configuración para luego subirla.

2.3.6.1 Descargar información del relé

Para descargar la información del dispositivo, primero establezca comunicación con el disposito y dirigase *a Commands* → *Get aqs-file* (o presione Ctrl+g). Espere que el programa guarde el archivo.

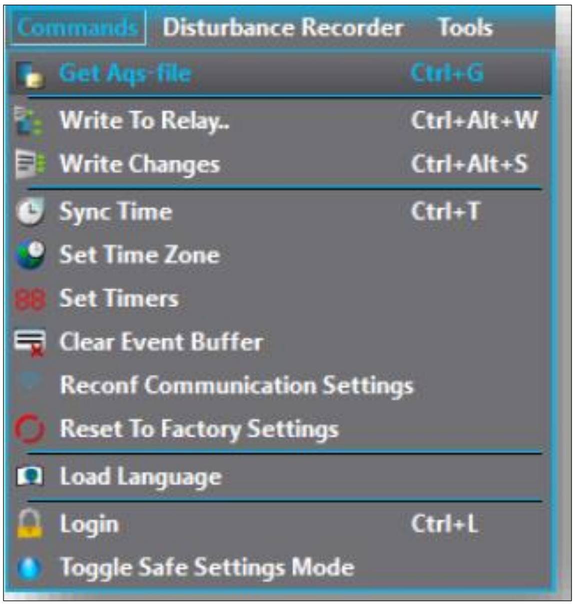


Figura 2.17 Menú disturbance recorder.

2.3.6.2 Subir Información del Relé

Para subir la información al dispositivo, primero establezca comunicación con el dispositivo y diríjase a *a Commands* → *Write to Relay*

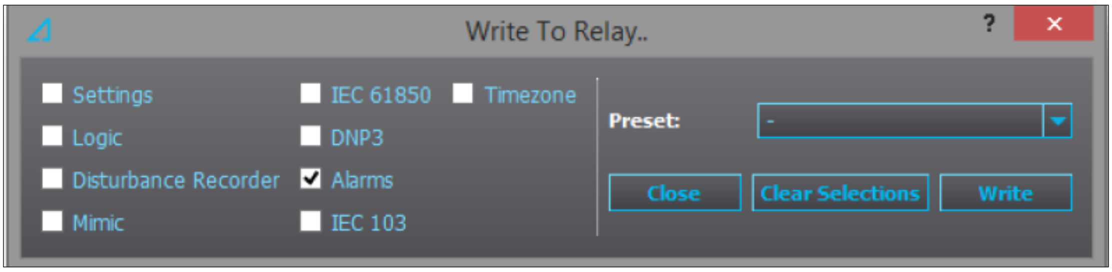


Figura 2.18 Menú guardar cambios al relé.

El usuario puede elegir la información que desea cambiar en la configuración actual del relé.

2.3.6.3 Guardar los cambios realizados

Para guardar los cambios realizados en el dispositivo, primero establezca comunicación con el dispositivo y diríjase a *a Commands* → *Write Changes*

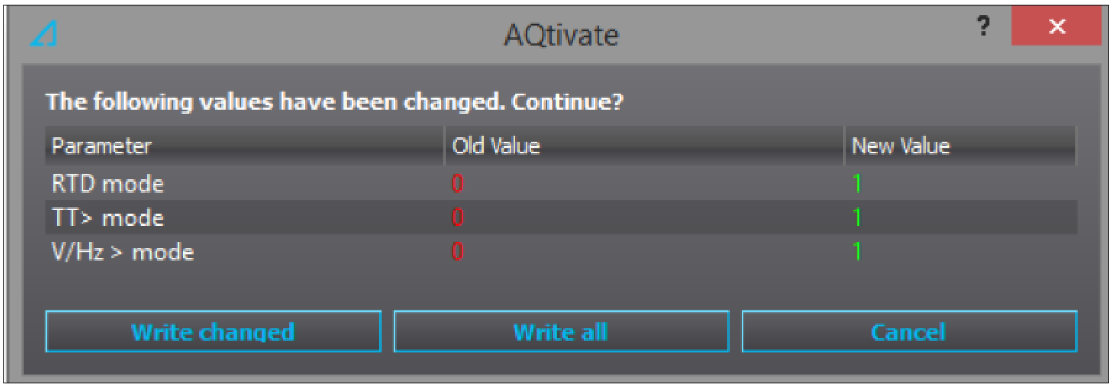


Figura 2.19 Menú guardar cambios.

En esta ventana se muestra cada cambio realizado con relación a la configuración anterior. El usuario puede decidir qué cambios escribir en el equipo.

2.3.7 Habilitando IEC61850

Para el relé se puede trabajar con el estándar IEC 61850 permitiendo los siguientes servicios:

- Dataset, pre-defined DataSets que pueden ser editaros con la herramienta dentro del programa.
- Bloques de control de informes.
- GOOSE
- Sincronización de tiempo.

Primero descargue la información del equipo, luego para activar el estándar IEC61850 en el dispositivo, vaya a *Communications* → *Protocols* → *IEC61850* y seleccione IEC61850 en *Enabled*. Finalmente guarde los cambios

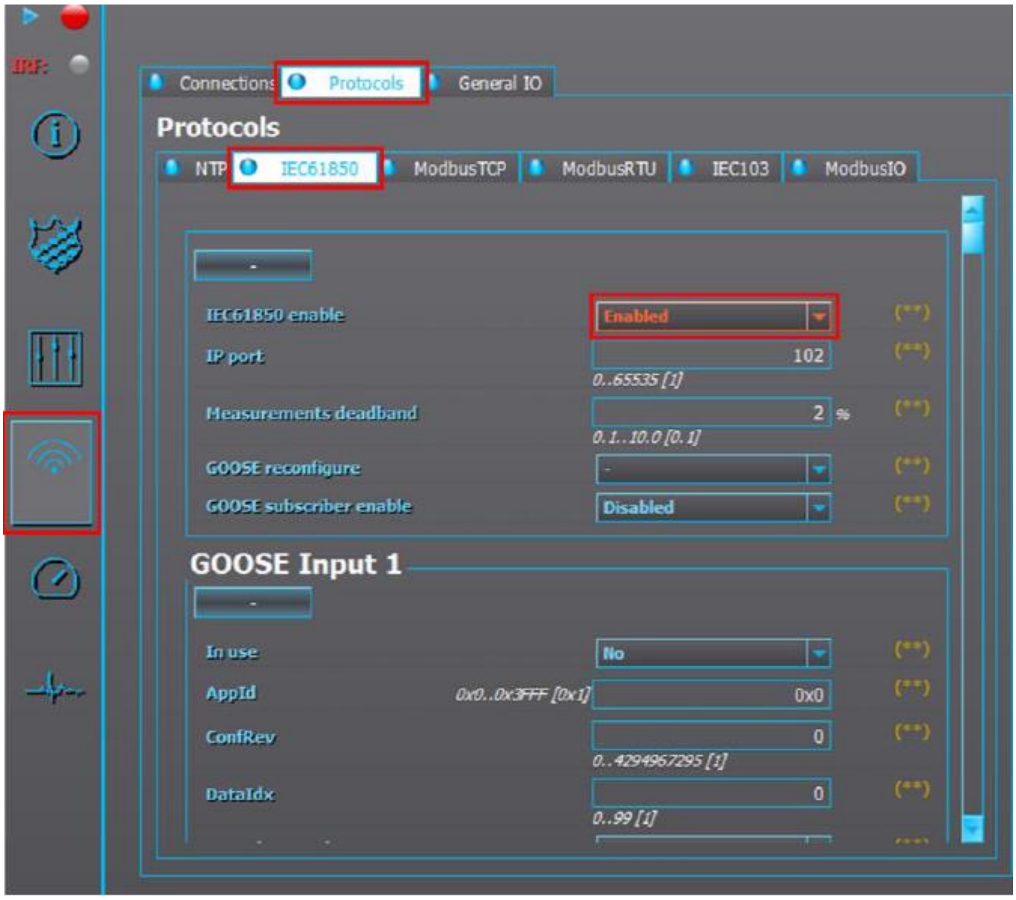


Figura 2.20 Habilitando IEC 61850

2.3.7.1 Editor IEC61850

El programa cuenta con un editor de IEC 61850, para poder acceder al mismo basta con presionar la tecla F8. Se desplegará un cuadro como el mostrado a continuación.

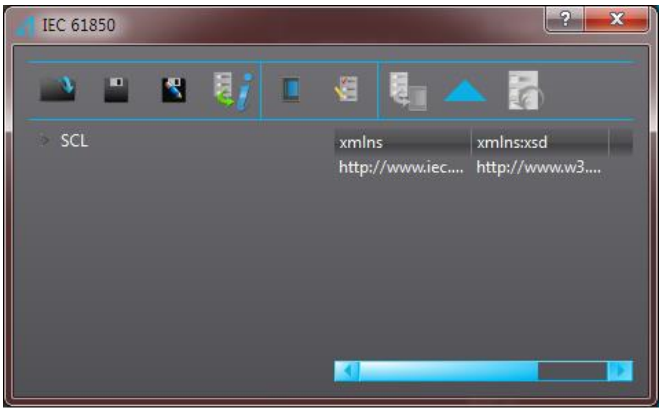


Figura 2.21 IEC 61850 editor

La descripción de cada botón se muestra a continuación.

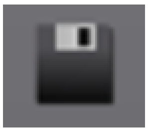
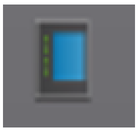
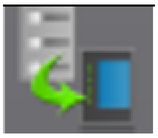
	Abir un Archivo CID	Usados para abrir un CID del disco duro.
	Guardar un archivo CID	Guarda la actual configuración CID al aqs (se debe volver a subir el aqs luego de esto)
	Guardar como CID	Guarda el archivo CID con un nombre específico.
	Exportar DataSet	Guarda el dataset en un archivo de tabla .txt que puede ser abierto por herramientas como excel
	Configuraciones	Abre la actual configuración
	Editar DataSet	Usado para editar el actual DataSet.
	Enviar al relé	Envía la actual configuración CID al relé
	Descargar CID del relé	Recibe el archivo con la configuración del CID actual.

Tabla 2 Menú del editor IEC 61850

2.3.7.2 Configurar IEC61850

Una vez abierta la herramienta de edición (se puede abrir presionado F8) nos encontraremos con una pantalla similar a la mostrada a continuación.

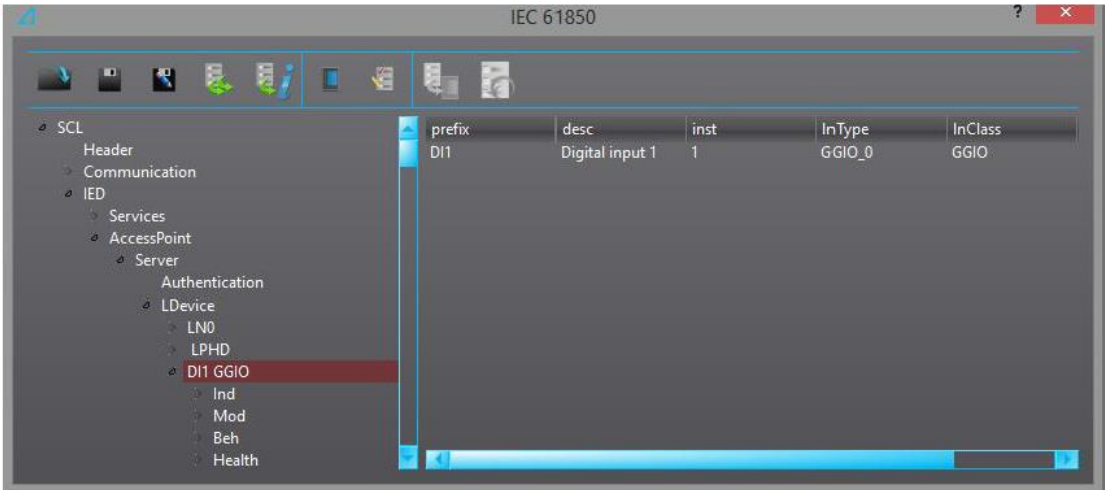


Figura 2.22 Configuración de DataSets.

2.3.7.3 Parámetros de comunicación

Esta es una parte vital para que funcione el sistema ya que aquí asignamos nuestro equipo a la red. La imagen inferior refiere a la configuración de los parámetros de comunicación. Los primeros 5 parámetros refieren al direccionamiento de la capa superior, estos son rara vez usados.

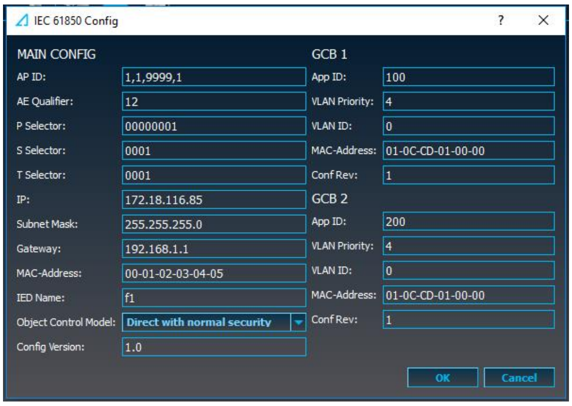


Figura 2.23 Configuración nombre de equipo en IEC 61850.

Los valores de IP con su máscara y gateway deben ser las mismas del sistema, la IP debe coincidir con la colocada en la sección de comunicación. La dirección MAC está dado por el fabricante y es única para cada dispositivo. El nombre del IED es el que se le asignará para reconocerlo en el entorno general, este nombre debe ser único en el sistema.

2.3.8 GOOSE Publisher

En la parte derecha se muestra 2 bloques de control GOOSE que pueden ser configurados. Estas son usadas para publicar en la red.

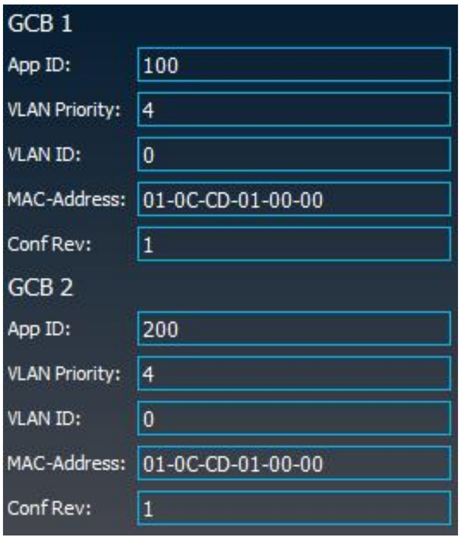


Figura 2.24 Ajuste del AppID del equipo.

El **App ID** es un valor hexadecimal y debe ser único en la red. Este valor es usado por el suscriptor para identificar el dato publicado. Existen 2 paquetes disponibles para el dispositivo GCB1 Y GCB2.

VLAN priority es utilizado para crear subredes en el sistema utilizando switches inteligentes donde se puede dar prioridad de envío a las señales de mayor importancia.

MAC-Address define la dirección física del multicast cuando se publican los mensajes GOOSE

Conf Rev. Puede ser usada como el número de versión del GOOSE dataset

2.3.9 DataSets y bloques de Control

Todo el tráfico comúnmente usado en IEC61850 está relacionado con DataSets. La configuración de los DataSets consiste en bloques de reportes ya sean URCB o BRCB.

URCB: Unbuffered report control block. Reporta solo cuando hay una suscripción al cliente.

BRCB: Buffered report control block. El servidor recolecta información y almacena incluso si no hay existe suscripción del cliente.

2.3.9.1 Editor de DataSets

Cuando se abre el editor de DataSets, se encontrará con 2 DataSets GOOSE 1 y GOOSE 2. En la serie aq200 es imposible añadir o disminuir más DataSets.

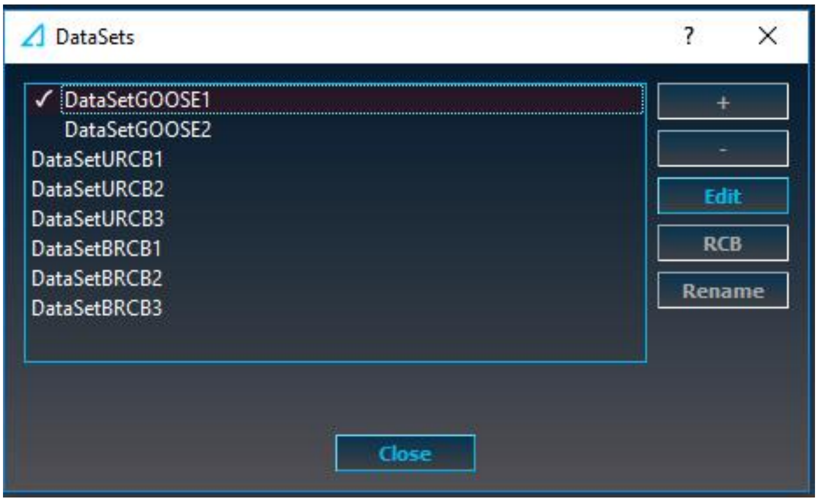


Figura 2.25 Editor de DataSets

Al seleccionar DataSet GOOSE1 para editarlo, se puede observar cuales son las señales o información que se emite en este arreglo de datos.

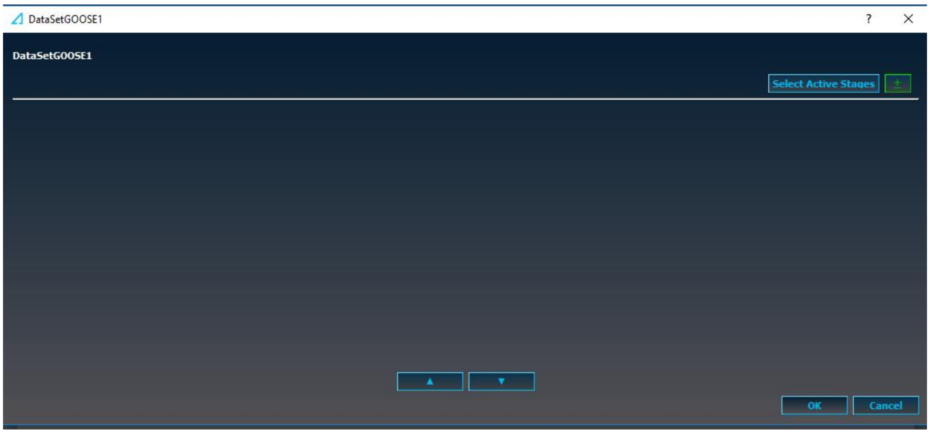


Figura 2.26 Agregar datos al DataSet

DataSetGOOSE1 y DataSetGOOSE 2 vienen vacíos como programación de fábrica. En la esquina superior derecha se encuentra el botón +- de tono verde. Dar click en este, da paso a la lista de señales o información ya configuradas para viajar a través de mensajería GOOSE.

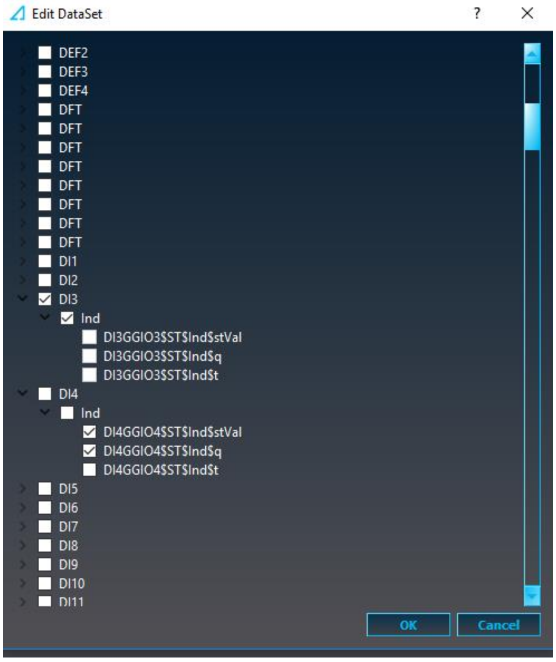


Figura 2.27 Habilitando elementos a publicar.

Cada señal tiene subniveles. Estos son los atributos de los objetos de datos. Es posible seleccionar solo un atributo en específico o también todos los atributos del dato al seleccionar el objeto de dato.

Por ejemplo, la imagen muestra la selección del objeto Entrada Digital 3 (DI3), esto asegura que los atributos del valor de la entrada (stVal), el tiempo (t) y la calidad de la señal (q) quedan automáticamente seleccionados. A diferencia de la Entrada Digital 4 (DI4), se seleccionaron solamente los atributos del valor del estado (stVal) y calidad de la señal (q).

A continuación, se muestran las señales ingresadas en el arreglo de datos.

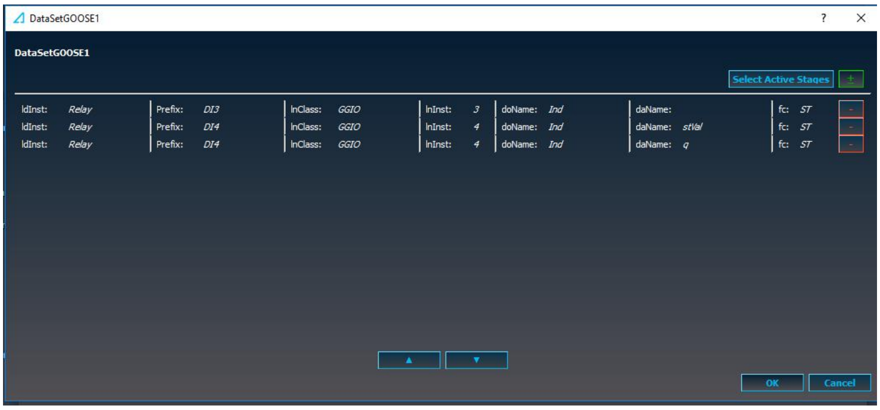


Figura 2.28 DataSets escogidos a ser publicados.

Es necesario recordar la posición del dato para poder acceder al mismo en el momento de suscribirse al DataSetGOOSE1. Es decir:

1. DI3
2. DI4 (stVal)
3. DI4 (q)

Una vez listo el DataSetGOOSE1, se procede a guardar cambios son enviados al relé.

2.3.10 GOOSE Subscriber

Para suscribirse al DataSetGoose1 que previamente se había configurado en la sección 3.6.1, en un segundo relé, nos dirigimos a Communication → Protocol → IEC61850 y se habilitan las opciones IEC61850 enable y también GOOSE subscriber enable.

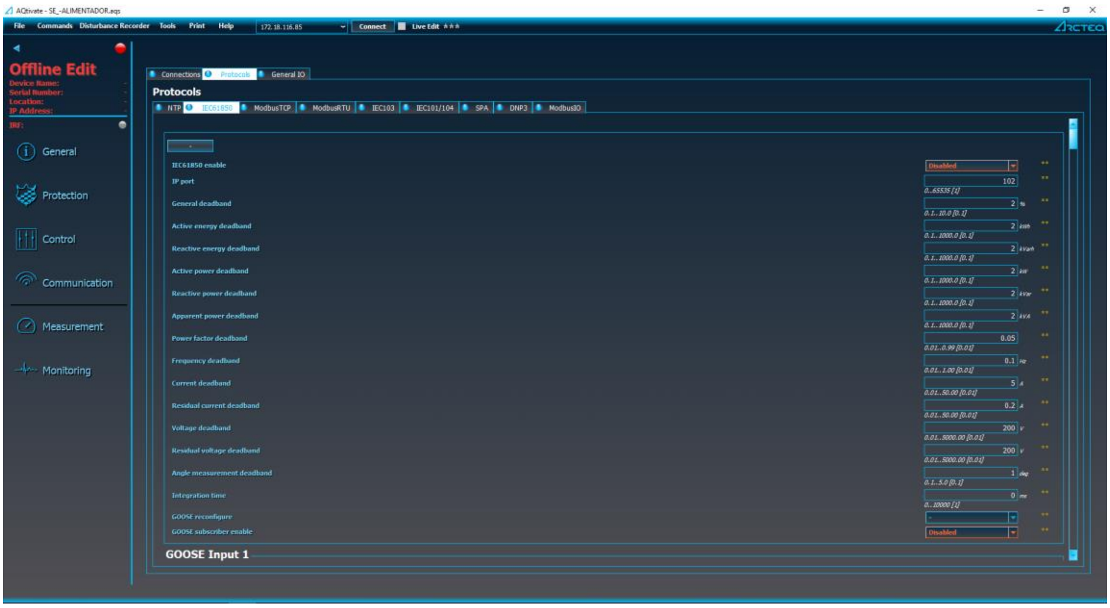


Figura 2.29 Habilitando GOOSE Subscriber

En la misma sección se encuentran los GOOSE Inputs. Es aquí donde se configura la recepción de los mensajes emitidos por el DataSetGOOSE1. En primera instancia debemos habilitar la opción “In use” para activar la entrada. En la opción de “AppId” se escribirá el encabezado del DataSetGOOSE1 (100) configurado en el primer relé, de esta manera se liga la entrada GOOSE1 del segundo relé, a los mensajes emitidos por el DataSetGOOSE1 del primer relé.

Por último, en la opción “DataIdx” se escribirá la posición del dato de interés perteneciente al arreglo de datos. En este caso se ha configurado para recibir el segundo dato “DI4 (stVal)”.

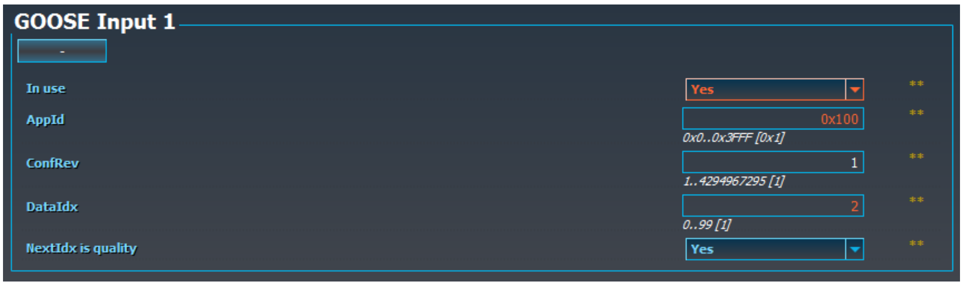


Figura 2.30 Asignación de entradas GOOSE

Luego de escribir los cambios realizados en el relé, la entrada GOOSE1 estará lista para utilizarse desde la matriz de entradas y salidas del relé en *Control* → *DeviceIO* → *GOOSE Matrix* y podrá ser asignada a cualquier salida o señal digital para uso del usuario. De esta manera se reafirma la interoperabilidad al configurar solo la mensajería más no el uso específico del mensaje.

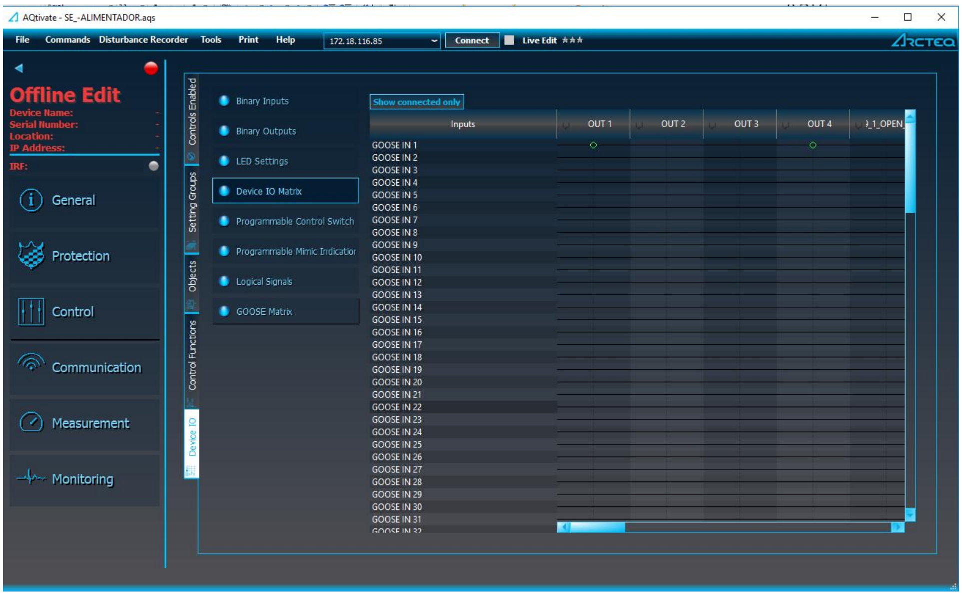


Figura 2.31 Matriz I/O de GOOSE

CAPÍTULO 3

3. ESCENARIOS PLANTEADOS

En este capítulo se plantearán 3 escenarios de protección y control. Estos van a ser desarrollados mediante los métodos convencionales y aplicando mensajería GOOSE con el fin de comparar los resultados de ambos métodos. El factor principal a ser analizado es el tiempo de operación de las funciones programadas.

Para comparar y analizar las ventajas de la aplicación de la norma en cada uno de los escenarios planteados, se utilizará la maleta de inyección Omicron CMC 356 con el objetivo de medir los tiempos de operación de los relés, configurándolos mediante el esquema tradicional y aplicando mensajería GOOSE.

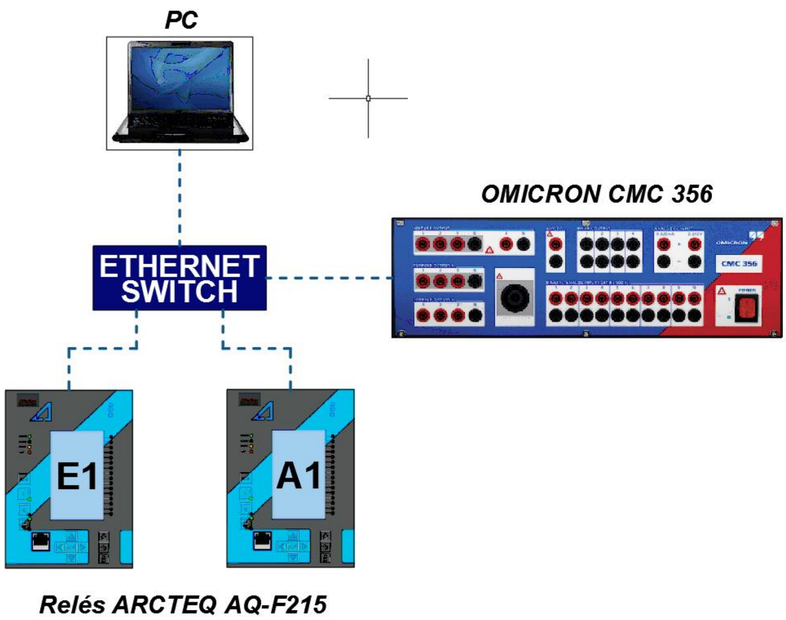


Figura 3.1 Topología de la red LAN

En la figura 3.1 se muestra las conexiones de la red LAN entre los equipos. Se puede apreciar que el equipo de inyección de corriente Omicron 356 también está conectado a la red. Esto es necesario puesto que el equipo es controlado por el operador desde la computadora utilizando su software Omicron Test Universe. Es posible realizar una conexión USB entre la maleta de inyección y el ordenador, dejando así a la CMC 356 fuera de la red LAN.

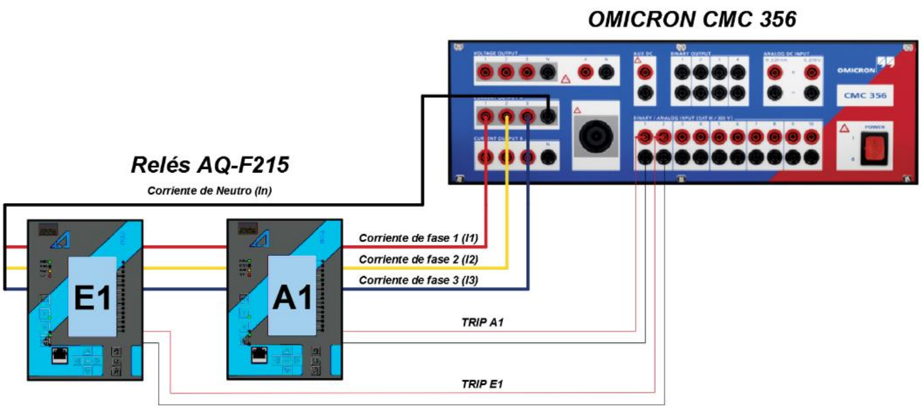


Figura 3.2 Conexiones para inyección de corriente

La figura 3.2 presenta el diagrama de conexiones para realizar la inyección de corriente y simular las fallas. Se conectarán los relés en serie para que reciban la misma corriente de falla. También se realizan las conexiones entre las salidas de TRIP de los relés y las entradas binarias de la CMC 356, de esa manera se pueden medir los tiempos de actuación de los relés.

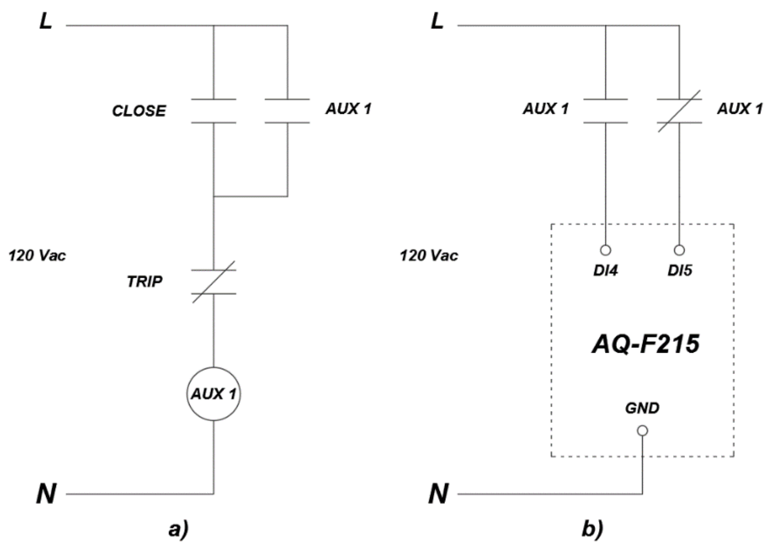


Figura 3.3 a) Circuito de encendido y apagado del relé auxiliar b) Asignación de entradas digitales para estado del disyuntor

La figura 3.3 a se muestra el circuito de encendido y apagado del relé auxiliar. Los contactos del relé auxiliar ayudarán a simular los contactos de estado del interruptor (52a y 52b). Los contactos CLOSE y TRIP son salidas del relé AQ-F215 programados para energizar y desenergizar el relé auxiliar. Se cambió la salida del TRIP por una normalmente cerrada para que sea aplicable en este control. Como se muestra en la figura 3.3 b si AQ-F215 envía la señal de cierre, se energizará el relé auxiliar AUX 1, dejándolo enclavado y la entrada digital 4 del relé de protección quedará recibiendo la señal de voltaje. Si se envía la señal de apertura, el contacto normalmente cerrado de TRIP desenergizará a AUX 1, de tal manera que ahora la entrada digital 5 es la que recibe la señal de voltaje en lugar de la 4. Las entradas digitales 4 y 5 serán programadas para recibir los estados de cerrado y abierto del disyuntor respectivamente.

3.1 Escenario 1: Breaker failure

El objetivo de este esquema de protección es reducir el tiempo de despeje de falla en caso de que los disyuntores de los alimentadores no operen. Supongamos una coordinación relé-relé en una configuración barra simple. El principio básico de la protección de respaldo es que, si en caso de que el interruptor aguas abajo (52-1) no logra despejar la falla (F1) debido a algún problema mecánico, el interruptor inmediatamente superior (52-0), luego de un tiempo de margen, deberá ser el encargado de despejarla.

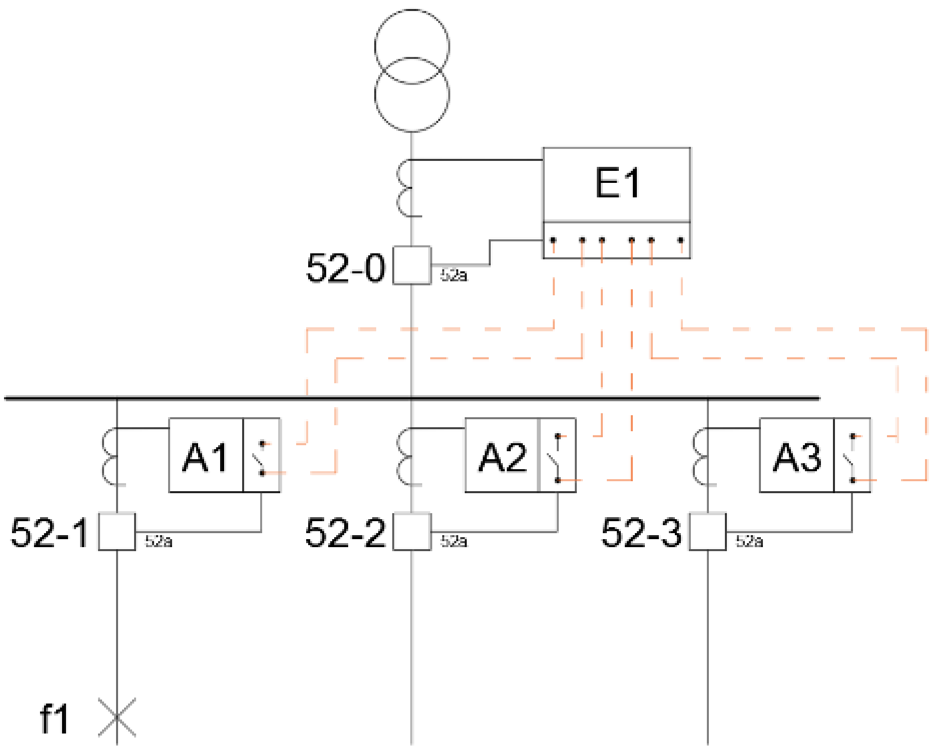


Figura 3.4 Sistema tradicional cableado para breaker failure

Un tiempo de margen usual para la coordinación relé-relé oscila entre 100 y 500 milisegundos para una corriente de falla. El tiempo de margen seleccionado para este escenario será de 300 milisegundos. Esto quiere decir que, en caso de que el disyuntor (52-1) no opere, luego del tiempo programado, operará el relé de protección de respaldo

(E1). Bajo esas condiciones se está obligando al sistema a soportar una corriente de falla durante 300ms.

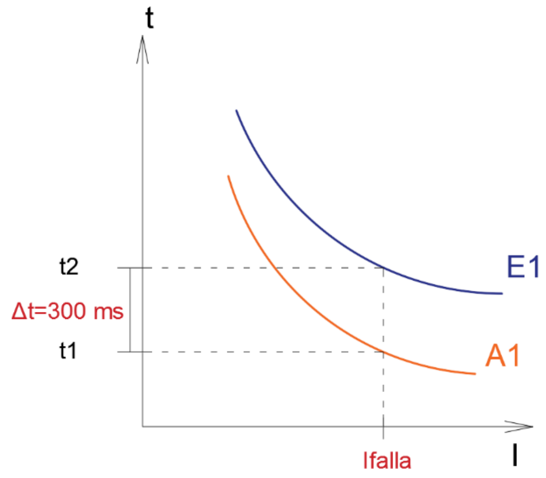


Figura 3.5 Coordinación de curvas de protección

Al utilizar la función “Breaker Failure”, el relé A1 monitorea la señal de estado del disyuntor en conjunto con su señal de TRIP. Cuando A1 sensa la sobrecorriente y envía la señal de disparo del disyuntor, espera el cambio de estado del mismo. En caso de no ocurrir el cambio de estado, se envía una señal al relé E1 para que dispare su breaker asociado sin tener que esperar los 300 ms de la coordinación relé-relé.

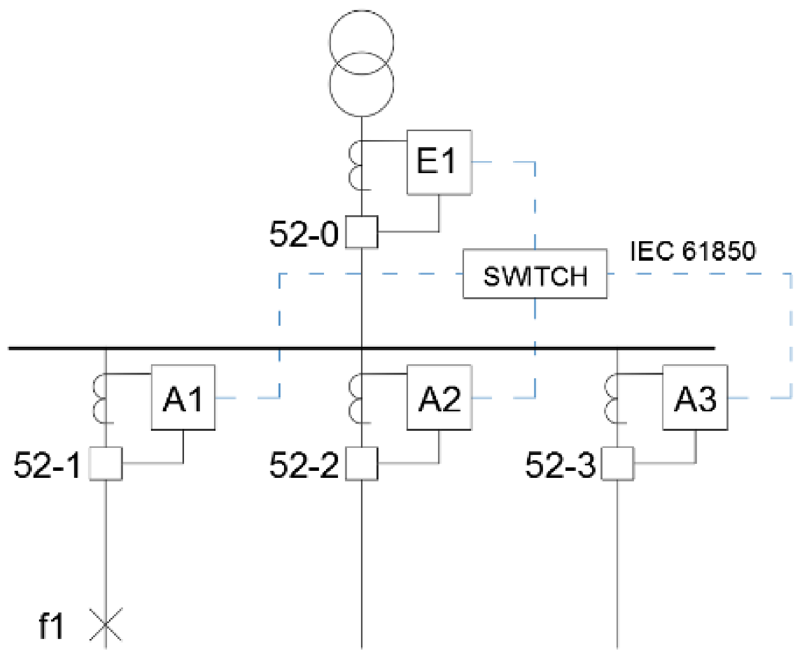


Figura 3.6 Sistema implementando IEC 61850 para breaker failure

Al aplicar mensajería GOOSE se espera obtener tiempos de respuesta mucho más cortos que en un sistema tradicional cableado puesto que no intervienen los tiempos de cierre de contactos de las salidas binarias de los relés. El tiempo de envío mediante mensajería GOOSE oscila entre 3 y 10 milisegundos mientras que en el sistema tradicional por accionamiento de contactos toma alrededor de 30 milisegundos. En la figura 3.6 se muestra como vería el sistema implementando IEC 61850.

En la primera situación se muestra la secuencia de operación para un despeje exitoso de la falla F1

Despeje exitoso de la falla (F1)

1) Falla F1 On
2) A1 Start y E1 Start.

$\downarrow$ Δt1

3) A1 TRIP
4) 52-1 Open
5) F1 OFF

Esta secuencia de despeje muestra la operación ideal para despejar una falla.

En el segundo escenario se muestra la secuencia de una operación sin éxito al ocurrir una falla (F1) en el alimentador 1 sin implementar la función de breaker failure.

Despeje fallido (F1) sin Breaker Failure

1) Falla F1 On
2) A1 Start y E1 Star.

$\downarrow$Δt1

3) A1 TRIP
4) 52-1 Failure

$\downarrow$Δt2=0.3 s

5) E1 TRIP
6) 52-0 Open
7) F1 Off
8) A1 Start OFF y E1 Start OFF

Al no estar habilitada la función breaker failure, se obliga a mantener una sobrecorriente durante 0.3 s después del TRIP del relé(A1). Extender el tiempo de una corriente de falla puede causar daños a los equipos de subestación, daños como: aislamiento y fundición de contactos.

En el siguiente escenario de muestra la secuencia de operación de un despeje fallido implementando la función de breaker failure.

Despeje fallido (F1) con Breaker Failure

1) Falla F1 On
2) A1 Start y E1 Star.

$\downarrow$ Δt1

3) A1 TRIP
4) 52-1 Failure

$\downarrow$ Δt2=0.03 s

5) E1 TRIP
6) 52-0 Open
7) F1 Off
8) A1 Start OFF y E1 Start OFF

En este escenario se puede apreciar que ya no es necesario esperar 0.3 s luego de que el breaker 52-1 no opera, es decir el tener esta función habilitada el tiempo de despeje se ve reducido significativamente.

3.1.1 Configuración escenario de CBFP sin GOOSE

Luego de establecer comunicación con el equipo y descargar su archivo, procedemos a hablilitar la protección CBFP, para ello nos dirigimos a *Control* → *Stage Activation* → *Supporting stages* → *CBFP mode* y colocamos en *Activated*.

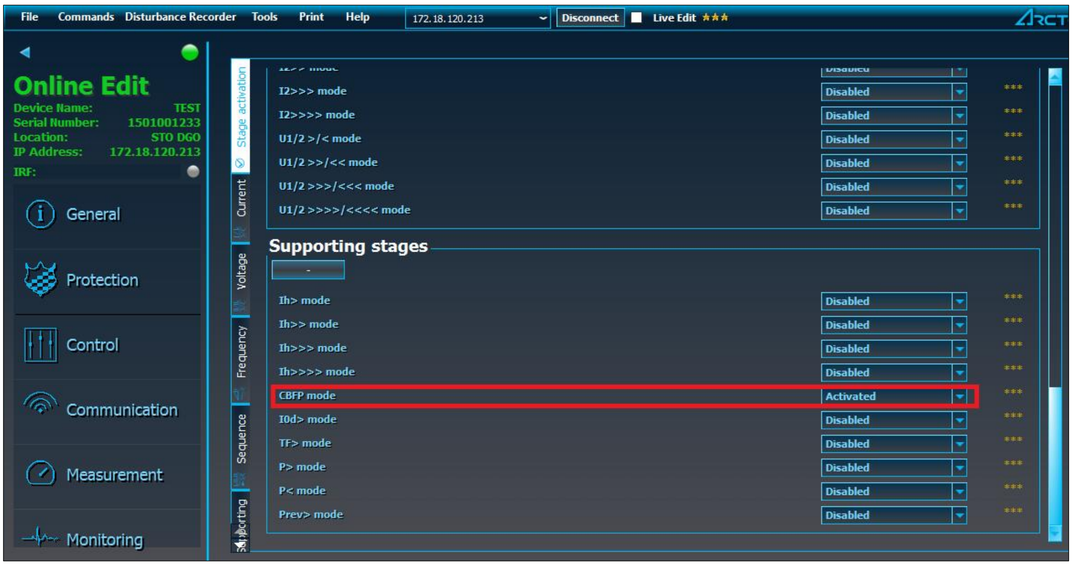


Figura 3.7 Habilitación de CBFP

Para configurar la protección CBF y nos dirigimos a *Protection→ supporting→ cbfp→ info* y establecemos la señal de monitoreo, Digital Input 4 (DI4), que es el estado del interruptor y la salida de monitoreo, OUT2, que es el TRIP de la protección de tiempo inverso.

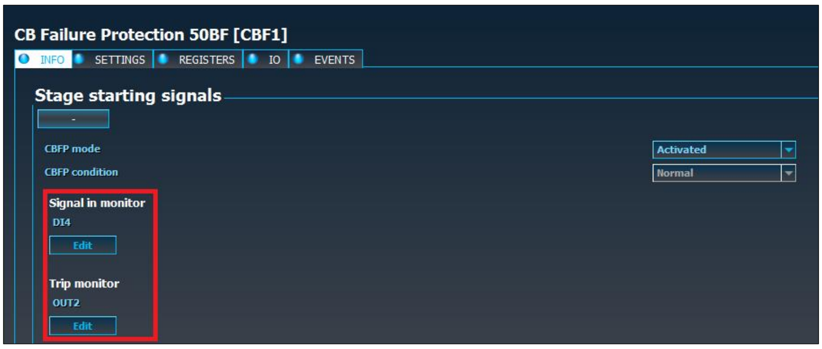


Figura 3.8 Asignación de señales y TRIP de monitoreo para CBFP

En la dirección *Protection→ Supporting→ CBFP→ Settings* establecemos del valor de *Signs and DO* como modo de operación. Esto quiere decir que para que se inicie la función de CBFP el relé espera que se cumplan ambas condiciones.

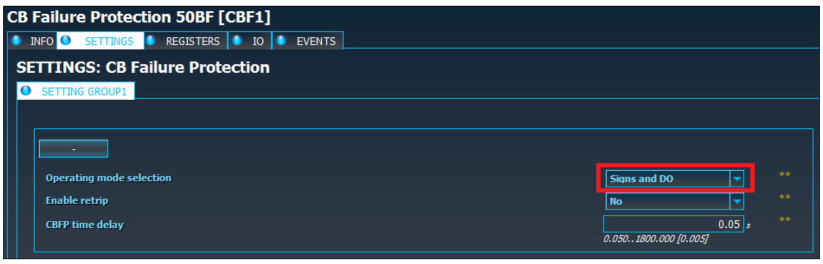


Figura 3.9 Establecimiento de modo de operación

Por último, en el relé A1, se debe asignar una salida física a la función, para ello en la dirección *Protection*→ *Supporting*→ *CBFP*→ *IO*→ *Direct Output Control* se le asignará la actuación en la salida 4 (OUT4).

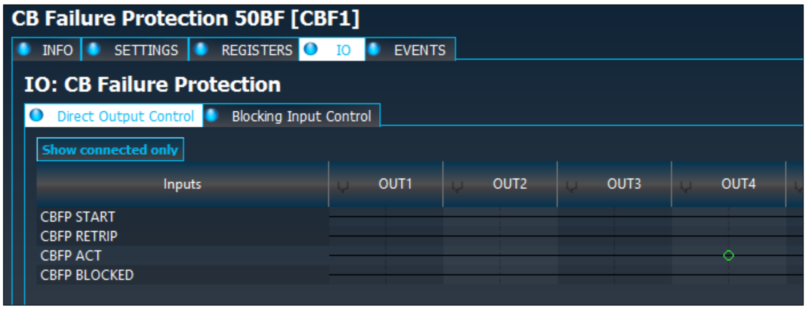


Figura 3.10 Configuración de I/O a estados de CBFP

El siguiente paso describe como asociar la señal binaria al TRIP del relé E1. En el relé en mención nos dirigimos a *Control*→ *Device IO*→ *Devide IO MAtrix.* Asignamos que la señal de entrada DI7, que es la que recibe el estado de CBFP, actúe sobre la salida OUT2, siendo esta el contacto configurado para abrir el disyuntor. De esta manera queda establecida una salida binaria para la actuación de CBFP en caso de que falle el interruptor asociado a A1.

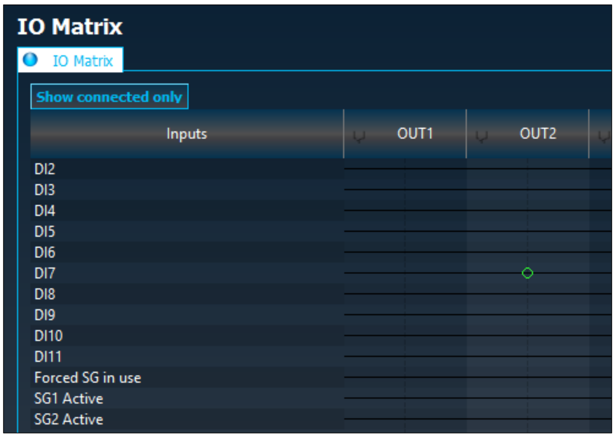


Figura 3.11 Asignación de salida a la entrada de estado de CBFP

3.1.2 Configuración de CBFP utilizando mensajería GOOSE

Una vez habilitado IEC 61850 en ambos relés, se configura el relé A1 para que publique las señales de estado de su interruptor y la señal de TRIP. Luego se ajusta E1 para que se suscriba a las señales publicadas. Procedemos a abrir la herramienta *Logic Editor* donde se realizará la siguiente lógica binaria.

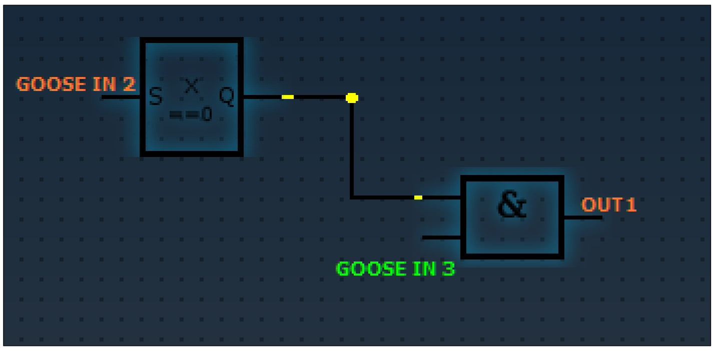


Figura 3.12 Lógica de enclavamientos

Se implementó la lógica de forma que la entrada GOOSE IN 2 recepta la señal de TRIP de A1 y GOOSE IN 3 la señal de estado cerrado del disyuntor asociado a A1. Se debe añadir un retardo de tiempo a la señal de TRIP con el fin de esperar la correcta apertura del interruptor. Este retardo varía según la característica del disyuntor. Para este ejemplo se ajustó a 33ms. Escoger un valor menor implica la actuación de CBFP antes de que el interruptor asignado a A1 despeje la falla a la mitad de una secuencia de despeje exitosa.

3.1.3 Resultados obtenidos

A continuación, se mostrarán los tiempos de actuación en caso de un despeje exitoso, un despeje fallido sin CBPF, despeje fallido con CBPF de la forma tradicional y despeje fallido aplicando mensajería GOOSE con CBFP. A continuación, se comparará el tiempo que tomaría despejar la falla sin CBFP.

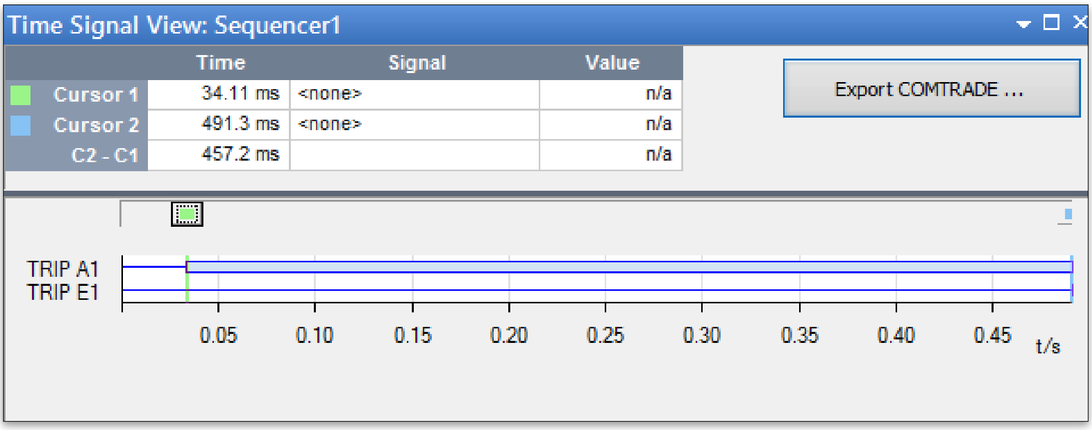


Figura 3.13 Tiempo de actuación sin implementación de CBFP

De la figura 3.13 se puede notar que A1 opera en 34.11 ms, que es el tiempo de operación dado por su curva TOC. El relé E1 opera después de 491.3 ms de sensar la falla. Se puede notar que la diferencia de tiempo (457.2 ms) está dado por el tiempo de margen de la coordinación relé-relé.

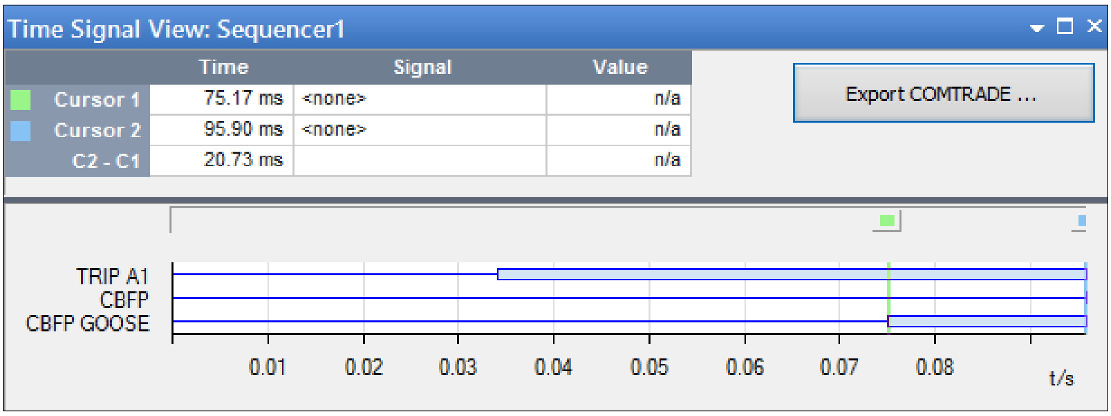


Figura 3.14 Comparación de tiempos entre métodos tradicional y GOOSE

En la figura 3.14 se muestran los tiempos de operación normal de A1 (TRIP A1), despeje fallido con CBPF de la forma tradicional (CBFP) y despeje fallido aplicando mensajería GOOSE con CBFP (CBFP GOOSE). Como se puede notar el implementar GOOSE representa una mejora en el tiempo de respuesta de 20.73 ms (CBFP GOOSE - CBFP) en comparación a usar cable de cobre.

En resumen, el no implementar la protección CBFP implica mantener la corriente de falla por 457.2 ms (TRIP E1 - TRIP A1), el implementarlo sin usar GOOSE la mantiene por 61.5 ms (TRIP A1 - CBFP) y usando GOOSE 41.1 ms (CBFP GOOSE – TRIP A1).

SEÑAL	t (ms)
TRIP A1	34.11
CBFP GOOSE	75.17
CBFP	95.90
TRIP E1	491.3

Tabla 3 Tiempos de actuación

Se demuestra que la mensajería GOOSE es más rápida en comparación a un sistema tradicional, además que no es necesario habilitar señales ni utilizar cables de cobre para poder comunicar estados. Finalmente se mostró que el ingeniero puede, a partir de señales de estado, crear una lógica digital que cumpla la función de CBFP sin que esta venga por defecto en el equipo.

3.2 Escenario 2: Protección de barra: REVERSE INTERLOCKING (RI)

El objetivo de este esquema de protección es reducir el tiempo de despeje de falla cuando esta ocurre en la barra y cuando los relés del alimentador no operen correctamente. Esto se logra mediante una protección de sobrecorriente instantánea en el relé principal restringida por la señal de arranque de los relés del alimentador. Es decir, a cada uno de los relés del alimentador (A1 y A2) se le habilitará una salida binaria de actuación con la señal de arranque y al relé principal (E1) una entrada digital donde monitorea estas señales.

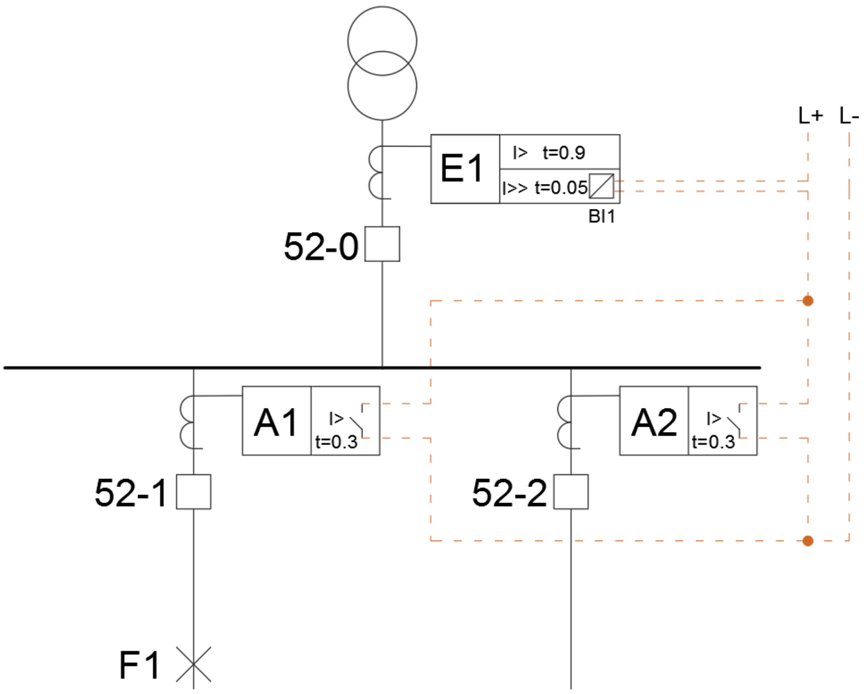


Figura 3.15 Sistema tradicional cableado para RI

Básicamente cuando la falla sea en el alimentador (A1 START ON), la característica de protección del relé E1 se comportará solo como una tiempo inversa, tal como se muestra en la figura 3.16 a. En cambio, cuando la falla ocurre en la barra (A1 START OFF), la característica de protección del relé E1 se comporta como una tiempo inversa más instantánea. Esto se muestra en la figura 3.16 b.

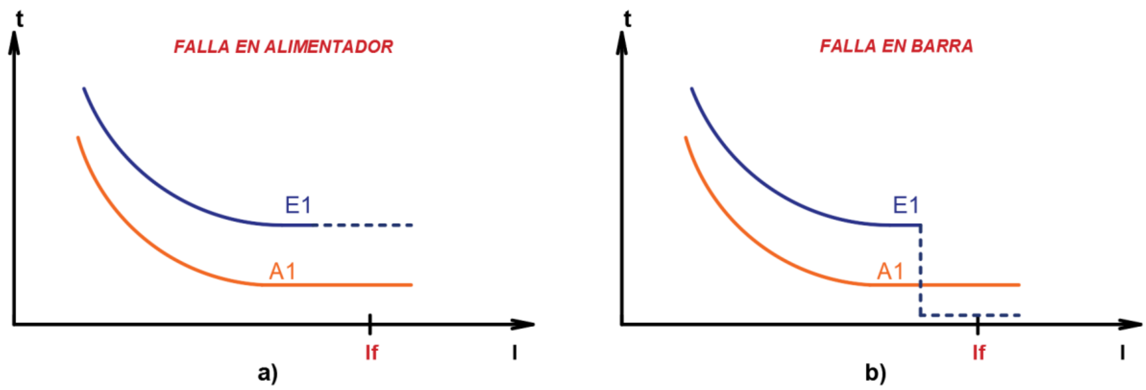


Figura 3.16 Característica de la protección de sobrecorriente

Los siguientes escenarios explican la importancia de su implementación cuando fallan los interruptores o los relés del alimentador. Se explicarán 4 situaciones para dar a conocer las ventajas de la mensajería GOOSE en RI. El primer escenario muestra la secuencia de operación para un despeje exitoso de la falla F1 con el interbloqueo habilitado.

Despeje exitoso de F1 con interbloqueo

1) Falla F1 ON.
2) A1 Start y E1 Start.
3) E1 I>> Disabled.

$\downarrow \Delta t = 0.3$ s

4) A1 TRIP.
5) 52-1 OPEN.
6) Falla F1 OFF.
7) A1 Start OFF y E1 Start OFF.

Este caso fue expuesto únicamente para mostrar el bloqueo y desbloqueo de E1 I>> durante una operación normal. En el siguiente escenario se muestra la secuencia de operación sin interbloqueo de un despeje fallido por causa del relé A1.

<u>Despeje fallido de F1 sin interbloqueo (A1 Failure)</u>

1) Falla F1 ON.
2) A1 Failure y E1 Start.

$\downarrow$Δt=0.9 s

3) E1 TRIP.
4) 52-0 OPEN.
5) Falla F1 OFF.
6) E1 Start OFF.

Debido a que no existe interbloqueos no se puede habilitar E1 I>> porque si no, en caso de cualquier falla, E1 despejaría siempre antes que los relés A1 y A2, yéndo en contra del principio de selectividad. Esto obliga a que, para tener una coordinación relé-relé exitosa, el tiempo de duración de falla se extienda hasta el tiempo configurado en el relé principal (0.9 s). El mantener la sobrecorriente durante mayor tiempo es perjudicial para los equipos, pudiendo ocasionar daños como afectación del aislamiento y fundición de contactos de los disyuntores. Ahora se mostrará la secuencia de operación para el mismo escenario anterior (F1+A1 Failure) utilizando el interbloqueo.

Despeje fallido de F1 con interbloqueo (A1 Failure)

1) Falla F1 ON.
2) A1 Failure y E1 Start.

$\downarrow \Delta t=0.05$ s

3) E1 TRIP.
4) 52-0 OPEN.
5) Falla F1 OFF.
6) E1 Start OFF.

Al fallar el relé A1, éste no da señal de arranque por lo que no existe restricción para E1 I>>, despejando la falla de manera instantánea. El tiempo de despeje de falla se ve reducido considerablemente en comparación al tiempo obtenido cuando no se hace uso del interbloqueo. Esto minimiza los daños descritos anteriormente. En caso de que ocurra una falla (F2) en la barra, al no existir la señal de bloqueo de los relés del alimentador, el tiempo de despeje estará dado por I>> (0.05 s) siendo mucho menor que solo teniendo I> (0.9 s). El próximo escenario muestra la secuencia de operación en caso de falla del interruptor 52-1.

<u>Despeje fallido de F1 con interbloqueo (52-1 Failure)</u>

1) Falla F1 ON.
2) A1 Start y E1 Start.
3) E1 I>> Disabled.

   Δt=0.3 s

4) A1 TRIP.
5) 52-1 Failure.

   Δt=0.6 s

6) E1 TRIP.
7) Falla F1 OFF.
8) A1 Start OFF y E1 Start OFF.
9) E1 I>> Enabled.

A diferencia del caso anterior el relé A1 no falla, por lo que la señal de bloqueo para E1 I>> es enviada y ya que el relé E1 sigue sensando la falla, cumple su tiempo y da la señal de actuación para su interruptor. Se puede notar que el tiempo de actuación sería igual que el caso de no existir interbloqueos ya que esta protección está dada para fallas en la barra o en él relé. Esta protección se complementaría con la función Breaker Failure explicada anteriormente en la sección 3.1

3.2.1 Configuración Reverse Interlocking

Para configurar reverse Interlocking primero habilitamos la señal instantánea de corriente en la dirección *Protection* → *Stages activation* → *Current stages* y habilitamos I>> como se muestra en la figura 3.16.

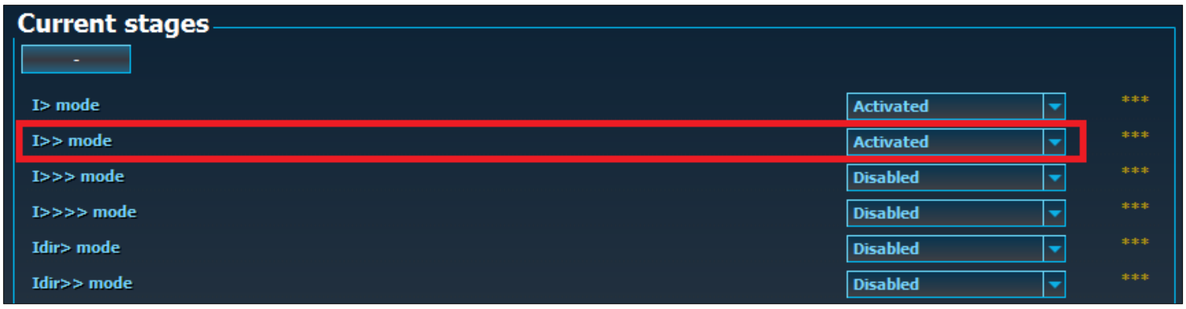


Figura 3.17 Habilitación de la protección instantánea

Luego se procede a configurar la coordinación de protección tanto como la I> y la I>>. En la ruta *Protection → Current → I> → Settings* seleccionamos los valores de Pick-up asignado (0.2) con una curva de tiempo definido (DT) sin retardo de tiempo como se muestra en la figura 3.17.

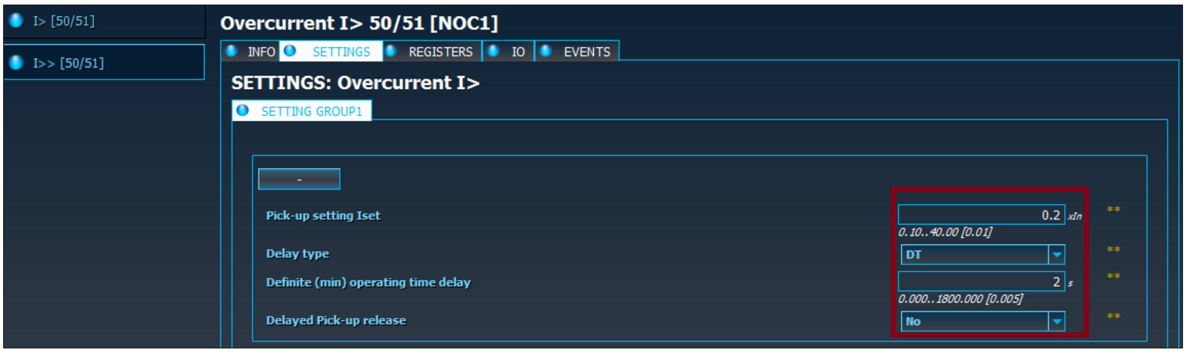


Figura 3.18 Configuración de la curva I>

En la figura 3.18 se muestra la configuración para la protección i>> con los valores asignados en la misma. La ruta es *Protection → Current → I>> → Settings*

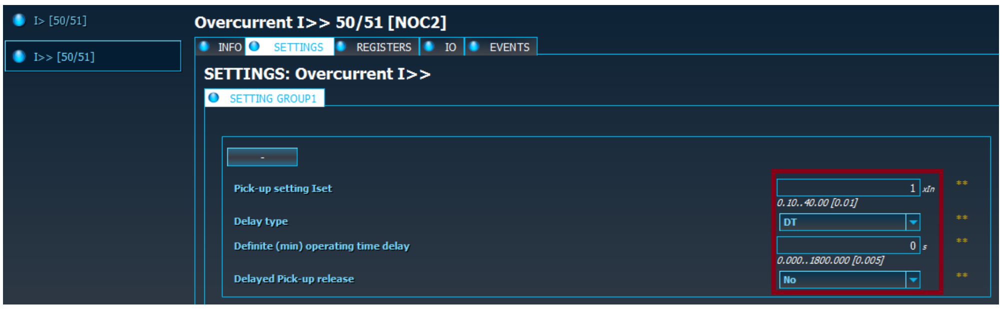


Figura 3.19 Configuración de la curva I>>

Finalmente se debe configurar la señal de bloqueo, en este punto es donde la señal puede venir por GOOSE o por señal cableada asignada a una entrada. La figura 3.19 muestra la configuración de bloqueo por DI7 que es la señal de arranque del relé A1. En caso de configurar por GOOSE se debe asignar que publique el estado de arranque y nos suscribimos esa señal como bloqueo.

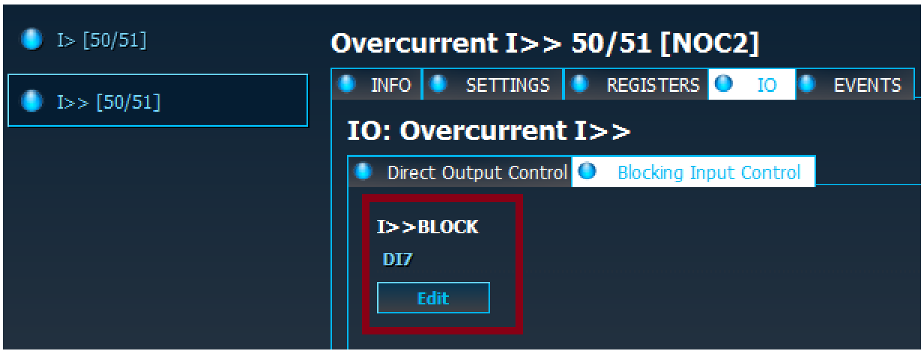


Figura 3.20 Configurar bloqueo de señal para I>>

3.2.2 Resultados obtenidos

Se realizó una prueba de tal manera que se pueda medir los tiempos para transferir los mensajes de un relé a otro utilizando su salida binaria y entradas digitales para compararlas con los mensajes transferidos mediante mensajería GOOSE. Se envió la señal de arranque (START) de un relé a otro. Se programó el relé receptor para que al sensar la señal de arranque emitida, accione uno de sus contactos y así poder medir el tiempo con la maleta Omicron CMC 356. Los resultados obtenidos se muestran en la siguiente tabla 4

	CONTACT	GOOSE	NO GOOSE	NO GOOSE-GOOSE
1	23	26,8	60,9	34,1
2	20,2	26,3	46	19,7
3	19	22	**177**	155
4	24	26	41	15
5	21,3	28,8	32,9	4,1
6	24,3	29,9	**75,2**	45,3
7	20,6	26,4	57,5	31,1
8	23,7	27,5	36,2	8,7
9	22,9	25,1	40,1	15
10	20,1	26,7	71,8	45,1
11	21,2	26,3	**71,5**	45,2
12	22,9	27,7	52,6	24,9
13	22,2	28,2	**73,3**	45,1
14	20,8	27,8	63,1	35,3
15	21,9	27,6	32,7	5,1
16	19,5	24,4	**78,9**	54,5
17	18,7	24,4	44,4	20
18	21	24,3	34,6	10,3
19	19,1	22	56,1	34,1
20	22,6	28,7	58,1	29,4
PROM	**21,4**	**26,3**	**60,2**	**33,9**

Tabla 4 Tiempos (ms) de actuación con y sin GOOSE

Contact	21,4
GOOSE	26,3
No GOOSE	60,2
No GOOSE - GOOSE	33,9
GOOSE - Contact	4,9
No GOOSE -Contact	38,8

Tabla 5 Comparación de tiempos de tiempos de actuación

La tabla 4 muestra 20 pruebas realizadas. En la primera columna están los tiempos de cierre de los contactos del relé. La segunda columna muestra el tiempo de transferencia de mensaje mediante mensajería GOOSE más el tiempo de cierra del contacto del relé receptor. La tercera columna muestra el tiempo de transferencia del mensaje mediante salidas físicas más el tiempo de cierra del contacto del relé receptor. La cuarta columna muestra la diferencia entre la tercera y segunda columna, es decir la ventajosa diferencia en tiempos de la mensajería GOOSE.

En promedio el tiempo de cierre del contacto del relé es de 21,45 ms. La diferencia entre la columna dos y uno representa el tiempo de envío de mensaje implementando GOOSE (4,9 ms). La diferencia entre la tercera y la primera columna representa el tiempo que tomaría en enviar la señal por el método tradicional (38,8). La diferencia entre elegir implementar mensajería GOOSE frente a un sistema tradicional implica una reducción promedio de tiempo de 33,9 ms.

Otra de las desventajas de usar salidas físicas, que al ser un elemento electromecánico se ve afectado por la antigüedad y uso resultando mala operación por desgaste, fundición de contactos, contactos pegados. La columna tres de la tabla 4 los casos en rojo muestran los valores críticos de los tiempos de operación mediante salidas físicas. Esto es prueba de que, para un mismo escenario, la trasferencia de mensaje del modo convencional puede tener un comportamiento muy variable.

En la figura 3.21 enseña la prueba de la característica de protección contra sobrecorriente para una falla en la barra. En este caso el relé A1 no ve la falla, por lo que no publica la señal de arranque, dejando que E1 habilite la protección instantánea. La figura 3.22 muestra los 12 puntos probados para fallas trifásicas junto a su magnitud de corriente y tiempos de operación. Demostrando que todos actuaron dentro de su rango de tiempo de operación.

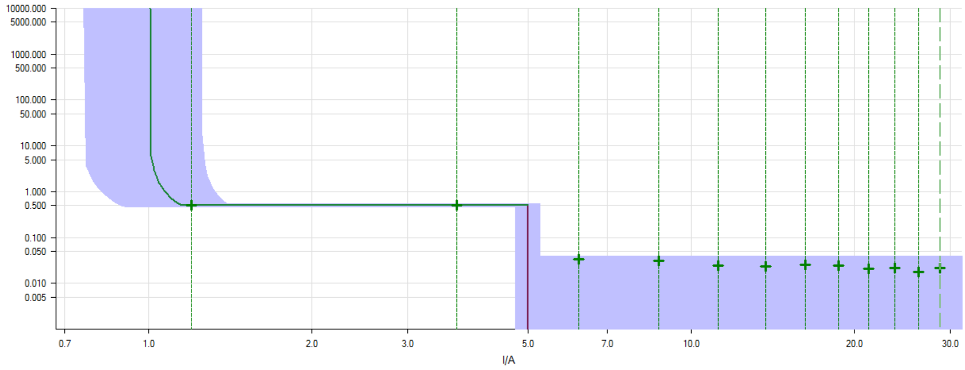


Figura 3.21 Pruebas de la característica de protección contra sobrecorriente en falla de barra

State	Type	Relative To	Factor	Magnitude	Angle	tnom	tmin	tmax	tact
✓	L1-L2-L3	(---)	n/a	1.200 A	n/a	500.0 ms	460.0 ms	No trip	510.9 ms
✓	L1-L2-L3	(---)	n/a	3.700 A	n/a	500.0 ms	460.0 ms	540.0 ms	499.7 ms
✓	L1-L2-L3	(---)	n/a	6.200 A	n/a	0.000 s	0.000 s	40.00 ms	33.80 ms
✓	L1-L2-L3	(---)	n/a	8.700 A	n/a	0.000 s	0.000 s	40.00 ms	31.30 ms
✓	L1-L2-L3	(---)	n/a	11.20 A	n/a	0.000 s	0.000 s	40.00 ms	24.30 ms
✓	L1-L2-L3	(---)	n/a	13.70 A	n/a	0.000 s	0.000 s	40.00 ms	23.70 ms
✓	L1-L2-L3	(---)	n/a	16.20 A	n/a	0.000 s	0.000 s	40.00 ms	25.50 ms
✓	L1-L2-L3	(---)	n/a	18.70 A	n/a	0.000 s	0.000 s	40.00 ms	24.30 ms
✓	L1-L2-L3	(---)	n/a	21.20 A	n/a	0.000 s	0.000 s	40.00 ms	20.60 ms
✓	L1-L2-L3	(---)	n/a	23.70 A	n/a	0.000 s	0.000 s	40.00 ms	21.60 ms
✓	L1-L2-L3	(---)	n/a	26.20 A	n/a	0.000 s	0.000 s	40.00 ms	17.90 ms
✓	L1-L2-L3	(---)	n/a	28.70 A	n/a	0.000 s	0.000 s	40.00 ms	21.60 ms

Figura 3.22 Puntos probados de la característica de protección sobrecorriente en falla de barra

Si la falla ocurre en el alimentador, el relé A1 si publicaría la señal de arranque, y el relé E1 al estar suscrito a ésta, deshabilita la protección instantánea. En la figura 3.23 se aprecia como para corrientes mayores a 5 amperios el relé hace caso omiso a la protección instantánea. La figura 3.24 muestra las magnitudes de las sobrecorrientes trifásicas inyectadas junto a los tiempos de actuación del relé.

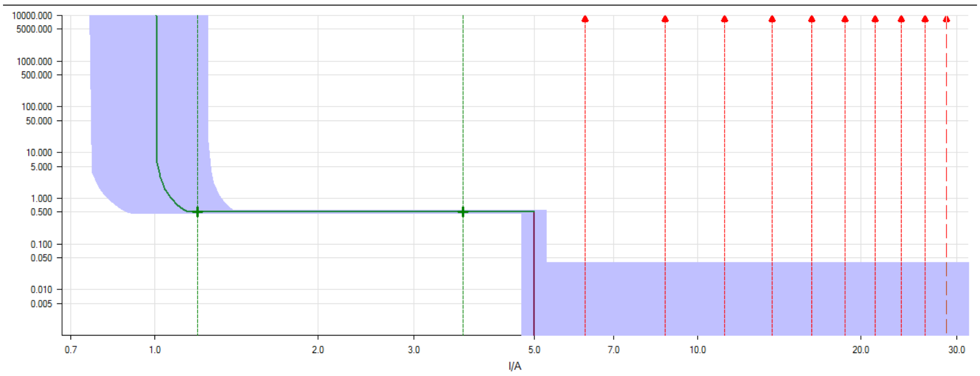


Figura 3.23 Pruebas de la característica de protección contra sobrecorriente en falla de alimentadora

State	Type	Relative To	Factor	Magnitude	Angle	tnom	tmin	tmax	tact
✓	L1-L2-L3	(---)	n/a	1.200 A	n/a	500.0 ms	460.0 ms	No trip	508.5 ms
✓	L1-L2-L3	(---)	n/a	3.700 A	n/a	500.0 ms	460.0 ms	540.0 ms	500.5 ms
✗	L1-L2-L3	(---)	n/a	6.200 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	8.700 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	11.20 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	13.70 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	16.20 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	18.70 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	21.20 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	23.70 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	26.20 A	n/a	0.000 s	0.000 s	40.00 ms	No trip
✗	L1-L2-L3	(---)	n/a	28.70 A	n/a	0.000 s	0.000 s	40.00 ms	No trip

Figura 3.24 Puntos probados de la característica de protección sobrecorriente en falla de alimentadora

3.3 Escenario 3: Transferencia de barra Main-Tie-Main (M-T-M).

La trasferencia de barra Main-Tie-Main es normalmente usado en las subestaciones para aumentar la confiabilidad del sistema. En un sistema típico de configuración de transferencia de barra automática es la trasferencia de barra por voltaje residual. El implementar esta de trasferencia automática de barra es utilizado para minimizar el efecto de los apagones por culpa de las fuentes. Al abrir el breaker normalmente cerrado del lado de la fuente y luego reenergizando la barra que se queda sin energía al cerrar el breaker de enlace de barra normalmente abierto. Luego de que el voltaje de la barra que decayó sea menor a un nivel ajustado. Este método es llamado, trasferencia de barra por voltaje residual y es muy común en la trasferencia automática de barra.

La trasferencia de barra Main-Tie-Main puede ser aplicado utilizando dos relés de protección con mensajería GOOSE del estándar IEC 61850, el relé de protección uno será el master que implementa la lógica de transferencia automática de barra y provee protección para el circuito principal uno. El relé de protección controla el breaker de protección de la bahía uno y el de enlace. El relé de protección uno también provee de protección contra corrientes de fase y neutro. El relé de protección 2 provee de protección contra sobre corrientes y control de transferencia para la bahía 2. La figura 3.25 muestra la configuración típica.

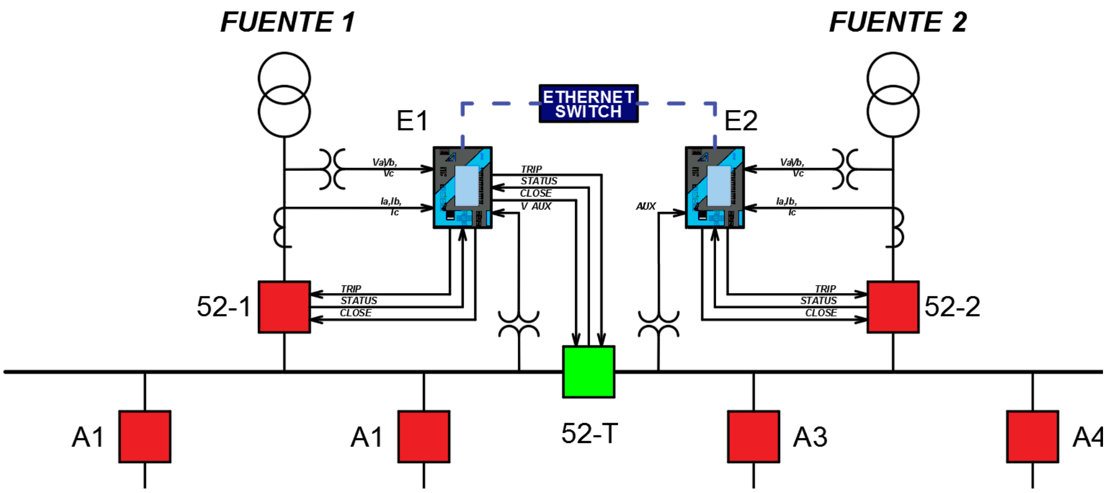


Figura 3.25 Esquema de transferencia utilizando dos relés de protección con IEC 61850

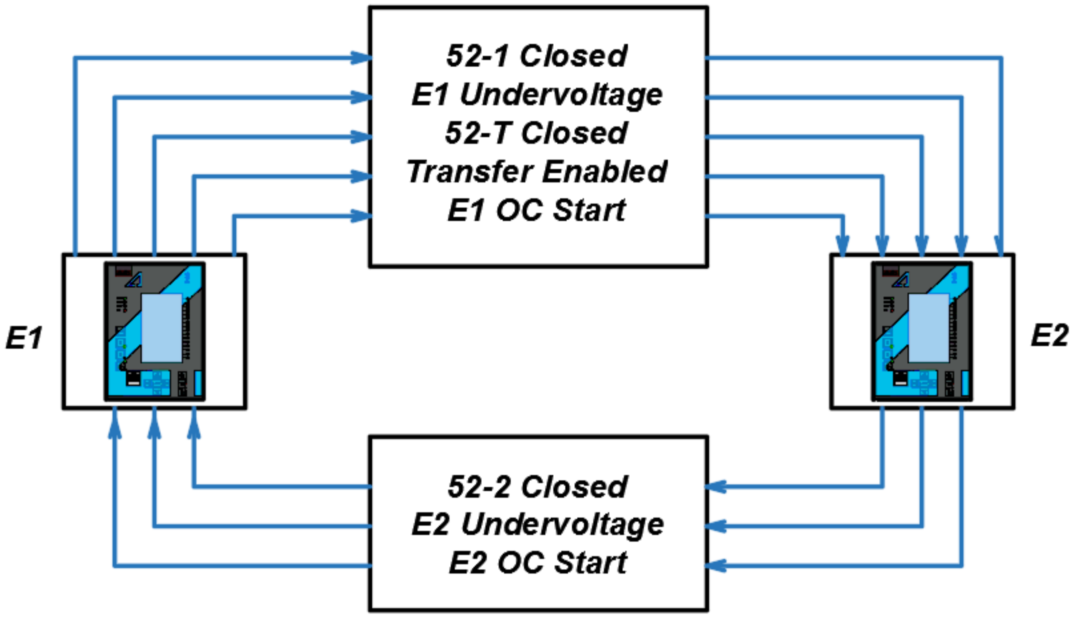


Figura 3.26 *Mensajes GOOSE intercambiados por los relés*

La figura 3.26 muestra los mensajes GOOSE que son intercambiados por los dispositivos electrónicos inteligentes basados en el estándar IEC 61850 que en el pasado era implementado por cableado de cobre.

Las tablas 6 y 7 detalla el orden de las señales a publicar, el encabezado y las señales a suscribirse. Todas estas señales serán necesarias para la implementación de la función y serán enviadas en el orden mostrado.

Relé	E1		
Publica		AppID	100
Orden	Condiciones	Descripción	Digital input asignadas
0	UV1	Under voltage	
1	52-1 CLOSED	Switch status	DI4
2	52-1 OPENED	Switch status	DI5
3	52-T CLOSED	Switch status	DI6
4	52-T OPENED	Switch status	DI7
5	TRANSFER ENABLED	Switch status	
6	NOC1	Over Current	DI8
Suscribe		AppID	101
Orden	Condiciones	Descripción	GOOSE IN
0	UV1	E2 Under Voltage	1
1	52-2 CLOSED	Switch status	2
2	52-2 OPENED	Switch status	3
3	NOC1	E2 Over Current	4

Tabla 6 Configuración GOOSE para E1

Relé	E2		
Publica		AppID	101
Orden	Condiciones	Descripción	Digital input asignadas
0	UV1	Under voltage	
1	52-2 CLOSED	Switch status	DI4
2	52-2 OPENED	Switch status	DI5
3	NOC1	Over Current	
Suscribe		AppID	101
Orden	Condiciones	Descripción	GOOSE IN
0	UV1	E1 Under Voltage	1
1	52-1 CLOSED	Switch status	2
2	52-1 OPENED	Switch status	3
3	52-T CLOSED	Switch status	4
4	52-T OPENED	Switch status	5
5	TRANSFER ENABLED	Switch status	6
6	NOC1	E1 Over Current	7

Tabla 7 Configuración GOOSE para E2

Se procede a realizar una lógica digital que pueda hacer la función de transferencia de barra por caída de voltaje. La figura 3.27 muestra la lógica programable que se implementa en el relé E2 para realizar dicha función. Logical Output 1,2,3 representa el estado cerrado de los interruptores 52-1,2 y el estado abierto del 52-T. El Logical Output 4 es la condición de que existe un bajo voltaje en la fuente 2 y no en la fuente 1. Las señales lógicas 1,2,3 junto a una verificación de que los relés E1 y E2 no ven sobrecorrientes, son las condiciones mínimas para poder ejecutar la transferencia de barras. Estas condiciones junto a la de existencia de un bajo voltaje (Logical Output 4) condicionan la apertura del disyuntor 52-2. Una vez que el relé E1 verifica que el disyuntor 52-2 está abierto, envía la orden de cierre del 52-T.

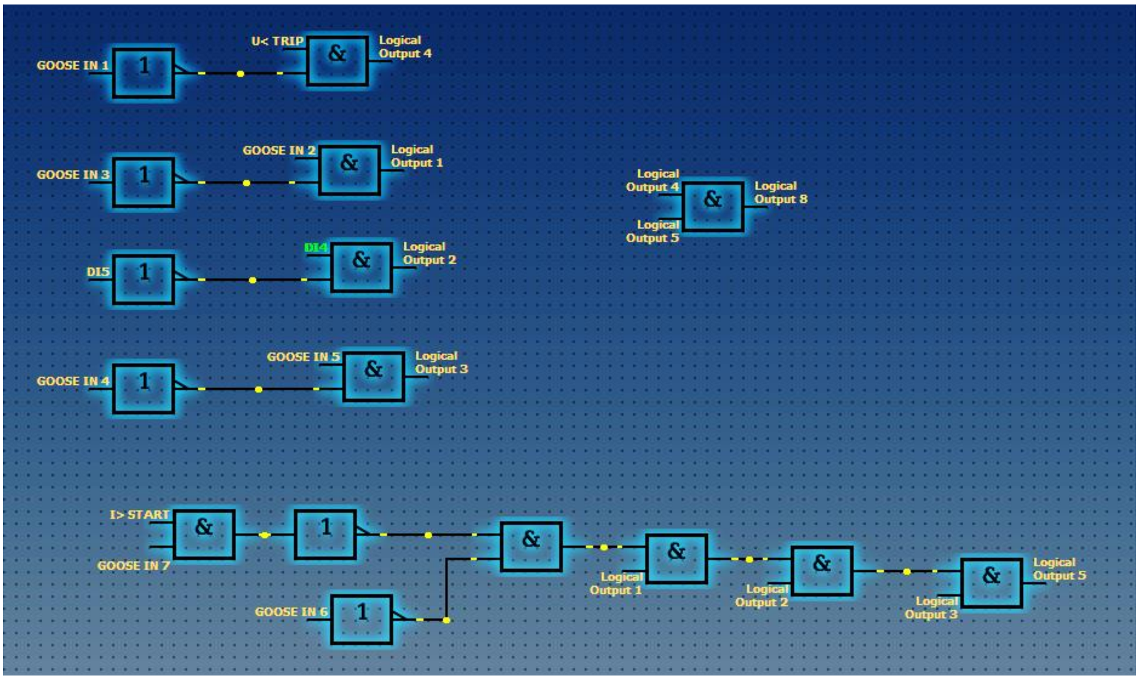


Figura 3.27 ***Lógica programable para el relé E2***

Debido a que el modelo organizado de datos del estándar IEC 61850 no define las señales lógicas propias de cada relé como un mensaje transferible mediante mensajería GOOSE, se replican las condiciones que habilitan la transferencia de barra y apertura del 52-2 en la lógica del relé E1. Continuando con la secuencia de bajo voltaje para la fuente 2. Para verificar que el interruptor 52-2 ha abierto, se utiliza una función *Latch* y una comparación con la posición del 52-2 (Logical Output 2). Una vez que se cumplen todas estas condiciones, se da la señal de cierre del 52-T (Logical Output 7). La señal *Latch* será reseteada una vez que se haya cumplido la condición de que ambos disyuntores, 52-T y 52-2, hayan operado correctamente. De igual manera se programó el relé E1 para el caso de bajo voltaje en la fuente 1.

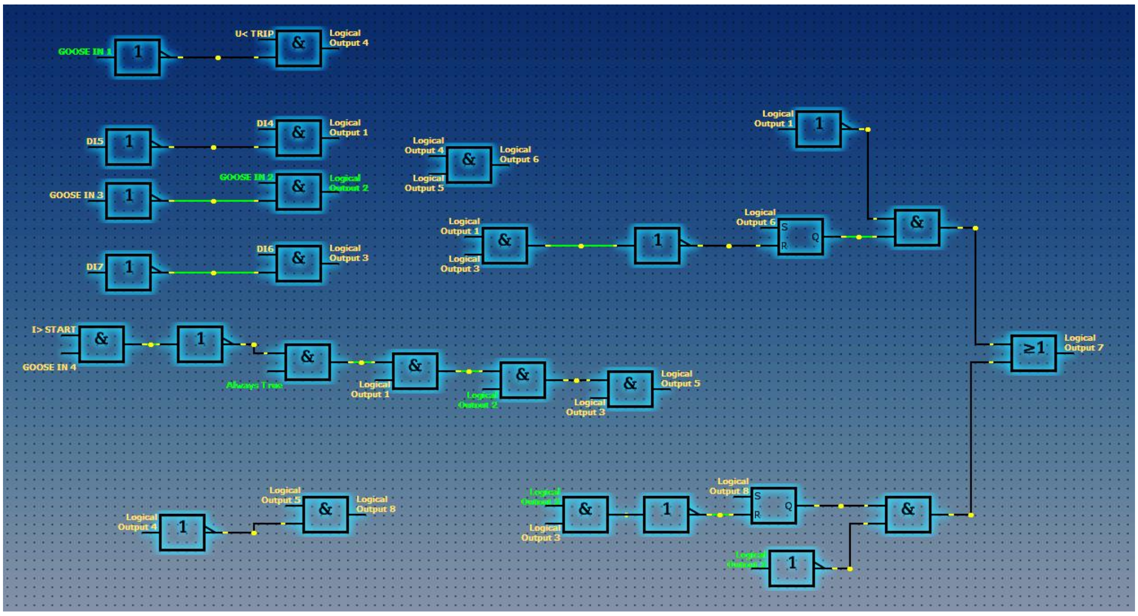


Figura 3.28 ***Lógica programable para el relé E1***

3.3.1 Resultados obtenidos

Las ventajas de utilizar dos relés de protección y comunicación GOOSE para una trasferencia de barra son:

- Significante reducción del cableado comparado con los esquemas tradicionales de trasferencia de barra.
- Transmitir y recibir estatus digitales entre relés de protección a través de un puerto Ethernet.
- El uso de funciones controladoras de lógica programables como temporizadores que proveen al relé, de tal manera que se de flexibilidad a un sistema de trasferencia de barra que mejor se acople a la aplicación.
- Funciones de switch selector de estados trasferencia prendida, apagada o automático, estas pueden ser cableados o implementados por botones del relé de protección, eliminando componentes y costos de instalación.
- Esquemas de alarmas cuando ambos relés de protección se encuentren fuera de línea o cuando no se estén comunicando
- Reconfiguración del esquema sin gastos de tiempo o cableado adicional
- Habilidad de fácilmente duplicar para sistemas de MTM adicionales al simplemente cambiar los nombres de los dispositivos usados.

CONCLUSIONES Y RECOMENDACIONES

Para los escenarios de protección planteados, se notó una mejora implementando mensajería GOOSE del estándar IEC 61850 para los tiempos de actuación frente a los esquemas tradicionales, al no utilizar elementos electromecánicos.

Se reduce considerablemente el cableado de control de una subestación al no tener que utilizar tantas entradas y salidas físicas. Al reducir estas limitaciones, se amplía las posibilidades de crear nuevos esquemas de protección, más complejos y selectivos, diseñados a la necesidad más específica del caso.

El estándar IEC 61850 ofrece la facilidad de implementación en subestaciones preexistentes. Se ofrece la posibilidad de reconfigurar las protecciones a medida que el sistema de protecciones cambie.

El implementar escenarios utilizando el estándar IEC 61850 reduce considerablemente el equipamiento frente a los esquemas tradicionales que requerían tableros específicos para llevar todo el cableado de la protección hasta el mismo.

Para este proyecto solo se han mostrado los beneficios que implica la mensajería GOOSE en 3 esquemas, sin embargo, es posible utilizar los conceptos y ejemplos explicados para una infinidad de escenarios personalizados.

Este trabajo sirve como referencia para estudiantes y profesionales que quieran adentrarse en el mundo de las comunicaciones para las protecciones eléctricas y de forma más directa, que requieran configurar mensajería GOOSE en relés ARCTEQ.

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Case Study: Design and Implementation of IEC 61850 From Multiple Vendors at CFE La Venta II

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of Modern EHV Power Systems, September 2007,
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***Abstract*—The IEC 61850 standard provides methods of developing best engineering practices for substation protection, integration, control, monitoring, metering, and testing. Comisión Federal de Electricidad (CFE) chose to build their newest integrated transmission protection and control network with IEC 61850 and evaluated the technology for possible future inclusion into their design standards.**

The primary IEDs chosen for protection were selected from the devices that have been approved by the customer and that also support IEC 61850. For the La Venta II project, the primary focus was to include IEC 61850 devices from as many vendors as possible rather than using traditional design criteria. In addition to the primary protection and control equipment, the customer invited all vendors to submit IEDs to be connected to the network to demonstrate their ability to communicate IEC 61850. Additional IEDs were added in an auxiliary bay because the design constraints required that the core of the network be useful and effective; it is not a demonstration control system but a pilot project to gain experience with the new standard.

This system integrated 24 devices from 9 different product platforms provided by 6 different vendors. The implementation was completed in four months and included newly released products from some vendors, involved staging device communications over the Internet, and relied on contributions from engineers in seven time zones. IEC 61850 is a very large standard with seven different protocols within it. End users implement different combinations of the protocols and the different features they provide. Therefore, it is important that end users not only specify that they want to use IEC 61850, but also what parts of the standard they want to use and, more importantly, how they want the system to perform. Throughout the implementation of this project, it became apparent that implementation details left to the discretion of the vendors and not dictated by the standard needed to be documented as requirements to attain the required system functionality. The following is a sample of these details:

- **Quantity of client/server associations to the device**
- **Quantity of peer-to-peer messages the device will publish or transmit**
- **Quantity of peer-to-peer messages the device will subscribe to or receive**
- **Number of characters allowed in the device name**
- **Run-time device diagnostics**
- **Configuration of the device via SCL (substation configuration language) XML files instead of settings**

I. Background

CFE is a government-owned utility that generates, transmits, and distributes energy to over 80 million people in Mexico. With 174 generation plants (46,672 MW), over 45,000 km of transmission lines, 135,238 MVAs of transformation, and 8 to 9 percent annual growth, CFE is one of the electric giants of Latin America.

CFE has been operating transmission substations remotely for more than 25 years and has developed a well-written specification that focuses on network topology, functionality, and device characteristics. This specification is known as SICLE (Spanish acronym for Information System for Substation Local and Remote Control).

In the early 1990s CFE migrated its specification to use DNP3 and then in 2000 moved to Ethernet as the network to be used at the substation level. At that time CFE was looking closely at UCA2 as an option but decided to wait until the new IEC 61850 standard was finished in order to avoid multiple migrations in a short period of time.

CFE has always been interested in new technologies that allow them to reduce engineering and commissioning time as well as overall project costs. CFE was interested in IEC 61850 because of interoperability and interchangeability.

After the release of the standard, CFE made several attempts to gather, at one table, all manufacturers that supported IEC 61850 in order to make a pilot project. CFE's goal was to prove interoperability with products from multiple vendors, but most of the manufacturers suggested that they preferred to build IEC 61850 systems consisting of only their own products. The opportunity finally came with the La Venta II project. La Venta II is an eight-phase wind farm that will generate close to 3 GWh by 2014, becoming the biggest wind farm in Mexico and Central America.

The bid for the first stage of the project was won by IBERINCO (IBERDROLA Ingeniería y Construcción), a well-known engineering firm and one of a handful with real-life IEC 61850 experience. IBERINCO built some of the first substations in Spain with IEC 61850. IBERINCO committed to deliver La Venta II as an IEC 61850 substation.

II. Scope

The La Venta II substation is part of the associated transmission network to Wind Farm La Venta II and in the first stage will be a 34.5/230 kV step-up substation. One hundred wind generators in groups of 20 will be connected to the 34.5 kV bus. In 230 kV, a main bus/auxiliary bus arrangement will connect the wind farm to the national grid. The one-line diagram of the 230 kV side is displayed in Fig. 1.

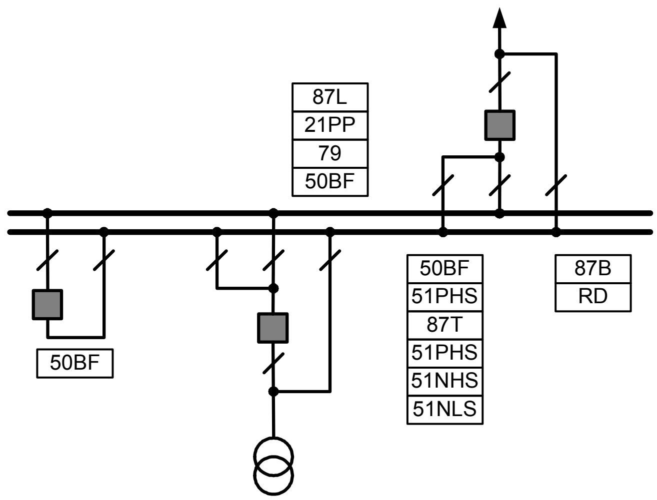

Fig. 1. La Venta II substation protection requirements

CFE defined the following requirements for the system to be developed:

1. Include only protection devices that are in LAPEM 5L (list of approved protection devices to use in electrical substations) because this will be an operative substation.
2. Include as many vendors as possible in order to prove interoperability between protection and control devices.
3. Comply with functionality of CFE protection specification.
4. Comply with functionality of CFE SICLE specification that already calls for Ethernet but not IEC 61850.
5. Consider interchangeability of main IEDs at the communications interface. Add redundant IEDs in parallel and demonstrate their functionality in the network.
6. Connect IEC 61850 bay control and protection devices to the Ethernet; allow no data concentrators for local operation.
7. Perform bay control interlocks between bays using GOOSE messages.
8. Communicate with two master stations using redundant SCADA gateways with DNP3 and Conitel 2020.
9. Provide two local HMIs.
10. Utilize traditional wiring and GOOSE for protection functions in order to test performance and reliability between the two options.

III. Implementation

La Venta II integrates devices from SEL, ZIV, Siemens, GE, RuggedCom, and Team ARTECHE. Other vendors were invited to participate but either did not have IEC 61850 available or were not approved. IBERINCO provided overall project management as well as the rules for logical devices, logical nodes, controls, and data mapping. IBERINCO also was responsible for defining HMI and gateway databases. CFE defined master station databases. ZIV provided HMI application and integration, one gateway to DNP3, one bay control, and on-site training. SEL provided protection and control devices, designed and built the panels, staged the system for testing, trained CFE, and provided on-site support for commissioning. Other vendors provided support during testing and on-site commissioning of their devices.

IV. Protection System

As mentioned before, all protection devices were required to be in LAPEM 5L, and all protection schemes were required to meet CFE protection specifications. Tables I–V list the requirements and how they were met for this project.

Table I
230 kV Line Protection Panel

Description	Function	Device
Bay Control	Local Control and Data Acquisition	ZIV-6MCV
Main Distance Protection Directional Overcurrent	21/67	SEL-421
Main Line Current Differential Directional Overcurrent	87L/67	GE-L90
Breaker Failure/Synchronism Check	50 BF/25/27	SEL-451
Reclosing	79	SEL-279H *

* No relays approved by CFE for this function support IEC 61850.

Table II
230 kV Transformer Protection Panel

Description	Function	Device
Bay Control	Local Control and Data Acquisition	GE-F650
Main Transformer Protection	87	GE-T60
High Side Overcurrent Protection	50/51 HS	GE-F60
Breaker Failure/Synchronism Check	50 BF/25/27	SEL-451
Low Side Overcurrent Protection	50/51 LS	Siemens 7SJ62
Neutral Overcurrent Protection	50/51 N	Siemens 7SJ61
Tertiary Overcurrent Protection	50/51 TZ	GE-F35

Table III
230 kV Tie Breaker Protection Panel

Description	Function	Device
Bay Control	Local Control and Data Acquisition	SEL-451-4
Breaker Failure/Synchronism Check	50 BF/25/27	SEL-451

Table IV
230 kV Bus Differential Protection Panel

Description	Function	Device
Bus Differential	87B	SEL-487B

TABLE V
AUXILIARY BAY PANEL

Description	Function	Device
Backup Bay Control	Local Control and Data Acquisition	ARTECHE-BC
Backup Line Current Differential Backup Distance Protection	21/87L	SEL-311L
Backup Transformer Protection	87	SEL-387E

Additional panels for metering and DFR (digital fault recorder) were part of the scope but not integrated in IEC 61850.

V. INTEGRATED COMMUNICATIONS SYSTEM

A. *New Substation Technology: Bay Control, SCADA Gateway, and IEC 61850*

In addition to using the new IEC 61850 standard, this design incorporates a few products that CFE has not used before. All of the protective relays had to be independently approved for use by CFE on their system regardless of their support of IEC 61850 protocols. The final design relies heavily on several relays that CFE previously approved and used in other integration systems using other protocols that now also support IEC 61850. Other IEDs, such as the bay control units, were approved by CFE for use on this system. Fig. 2 illustrates the front-panel HMI on the bay control unit used in the 230 kV tie breaker protection panel.

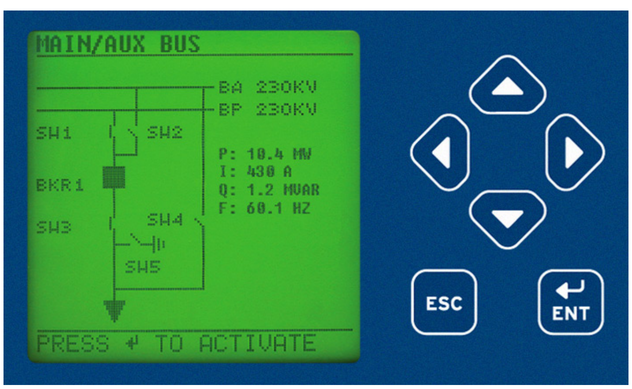

Fig. 2. Front-panel HMI on the bay control unit used in the 230 kV tie breaker protection panel

The communications integration team worked with every IED from multiple vendors to understand and implement the IEDs, each with different IEC 61850 capabilities, into the communications architecture.

New work is being done by the IEC Technical Committee (TC) Working Group (WG) 57 to extend use of the protocols within the IEC 61850 standard to outside the substation. Presently they are not used outside the substation, and the designs still rely on traditional and in-service SCADA protocols. CFE needed to support existing DNP3 links as well as the bit-oriented Conitel 2020 protocol. A rugged computer was deployed as a gateway to act as a client, collect and concentrate data from the IEDs via IEC 61850 protocols, convert these data into SCADA protocols, and serve them to the existing SCADA consoles. Therefore, in addition to acting as a protocol gateway, the rugged computer is a data concentrator and a client/server. Fig. 3 illustrates an example SCADA console similar to the ones in the project. The data collected via IEC 61850 protocols are converted into DNP3 and Conitel 2020 and transferred over established SCADA links. The operators are unaware of the fact that the substation protocols are different than previous designs that used DNP3 and other protocols in the substation.

Fig. 3. Typical SCADA console user unaffected by choice of protocol within the substation

The major impact of using IEC 61850 in this project and then converting it into traditional and legacy protocols is the dramatic increase in complexity of the new IEC 61850 protocols. Because some of the new IEC 61850 protocols are more functional they have more features and attributes that do not exist in other protocols like DNP3 and Conitel 2020. Therefore, it is difficult to convert simple DNP3 messages to perform actions that are more elaborate in the IEC 61850 protocols. One such example is commanded control. IEC 61850 protocols require six or more attributes to be set before an IED will act on it. The simple DNP3 command structure requires only two. Therefore, there is not a one-to-one correspondence of necessary protocol attributes to complete client/server transactions. This eliminates the opportunity to automatically map configuration between the protocols and creates the need for much manual configuration of the protocol translation. This translation effort became the most time consuming part of the system integration activity. Additionally, commands and other message transactions via IEC 61850 methods benefit from object-oriented data structures; however, some of these data structures include data types that are not available within the other protocol methods. Therefore, not only must missing data attributes somehow be created, existing data attributes often must be converted from one type to another.

B. *New Software Automatically Creates Communications Settings and Configuration*

New IEC 61850 configuration methods work in conjunction with previously existing IED application configuration software to create and set relays and other IEDs to perform logic, interlocks, and protection. The best practice method mentioned in the standard relies on the creation of a configured IED description (CID) file, which uses SCL to describe all of the IEC 61850 protocol configurations, and is then downloaded directly into the IED. When the IED starts up, it finds the CID file and performs self-configuration. This file is locally or remotely transferred into the IED without impacting any other functionality in the IED. Because this configuration is an IEC 61850 communications configuration file only, there is no opportunity to inadvertently impact protection or automation settings. Therefore, the communication is configured, tested, and commissioned without impacting the other applications within the IED. Furthermore, this CID file is also retrieved directly from memory within the IED to definitively verify what configuration is being used by the IED.

Because the IEC 61850 standard does not specify a single way to perform configuration, several vendors chose to add IEC 61850 configuration as settings among the existing protection and automation settings within their IED. For these IEDs, the protection-settings software is used to create and download all the settings into the IED. Care must be taken to preserve, test, and commission all affected, or possibly affected, settings. The upper portion of Fig. 4 illustrates the relationship between IEC 61850 configurations via designs saved as files to be distributed using traditional file transfer means, like FTP, and directly loaded into local or remote IEDs. The lower portion of Fig. 4 illustrates protection and automation settings being created and the IED being set with a separate, special-purpose software application.

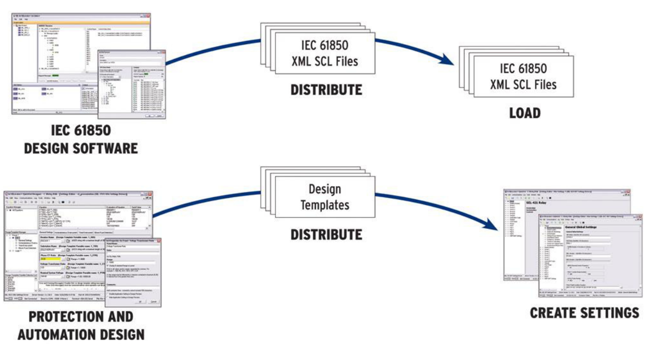

Fig. 4. File configuration of IEC 61850 and protection and automation settings configuration

For those IEDs that support the necessary SCL files, configuration software from any vendor should be able to view data descriptions within the SCL files that represent the system needs and IED capabilities. This allows the designer to visualize and logically connect data among IEDs from any vendor.

Using the methods described in the standard, IEC 61850 configuration software allows the designer to create data groups and reporting methods that identify what data are sent, to whom they are sent, when they are sent, and under what conditions.

Once the IEC 61850 configuration software imports files representing the capabilities of IEDs, designers make use of these capabilities to exchange data among the IEDs. After the configuration files or settings are installed in the IEDs, they report data to SCADA gateways, engineering workstations, sequential events recorders (SERs), etc., as well as to each other. Once an IED is configured to receive data from another IED via the IEC 61850 protocol GOOSE, the IED has access to that information as a logical status with the value of a binary one or zero. To the IED, this is now the same as a binary status received any other way, such as the mirror of the state of a bit in another relay via a peer-to-peer serial protocol, a commanded change of state via a SCADA command, a front-panel operator command, a remote engineering console command, or a local hardwire contact input.

In Fig. 5, the window in front illustrates combining several IED digital logic variables into a graphical Boolean expression. These digital logic variables are used freely without restriction based on their source, e.g., hardwire input contacts, GOOSE, serial peer-to-peer, or front-panel or remote command. The window behind illustrates the association of contents of received GOOSE messages to digital logic variables in an IED. In this case, Logic Bits RB01 through RB03 are received from other IEDs via GOOSE messages and then combined. RB04 and RB05 are received from another IED via a GOOSE message and then combined with RB06, which can be updated from any of the possible data sources.

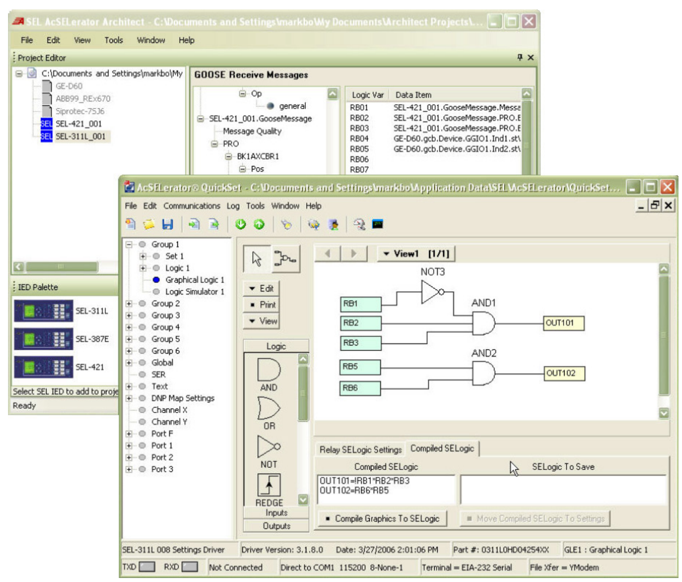

Fig. 5. Mapping of GOOSE contents to IED logic variables and use of these variables within a graphical logic editor

VI. System Architecture

The design called for the devices to be directly connected to the Ethernet LAN, and no data concentration was to be allowed for data exchange among the IEDs, local HMIs, and protocol gateways. Vendors submitted product designs that performed direct transmission and receipt of IEC 61850 protocols. As mentioned previously, data concentration was initially allowed only for the SCADA gateway function that converted IEC 61850 protocols into DNP3 and Conitel 2020. In the end, the HMIs were served via a data concentrator and did not communicate via the IEC 61850 protocols.

The substation LAN is configured in a ring topology with Ethernet switches installed in each cabinet. Because of the short distances and the fact that all the IEDs are inside one cabinet, the bay IEDs are connected to the switch using copper cables. Longer switch-to-switch connections between bays are accomplished via fiber optics that support the ring topology as seen in Fig. 6. This topology provides redundant ring communications at the switch level; however, IED connections within the same bay cabinet do not warrant redundant communications at the IED level based on past experience. Also, the use of internal switches within the IEDs connected in a ring is not allowed because it dramatically decreases reliability and increases complexity for the sole purpose of overcoming a cable failure.

Two local computers provide the operation HMI to the user for local control and visualization. Redundant SCADA protocol gateways provide the interface to the SCADA master in DNP3 and Conitel 2020.

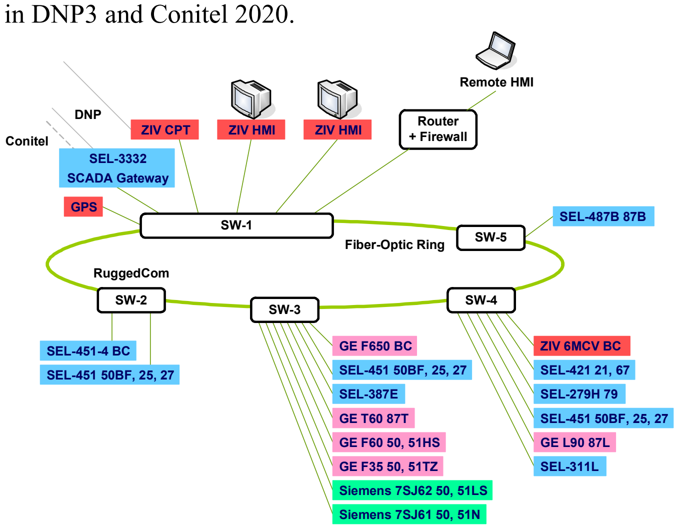

Fig. 6. Various connections to the substation fiber-optic Ethernet ring

As mentioned, each bay panel has its own Ethernet switch, regardless of the number of IEDs. This was done for several reasons: robust communications, ease of field installation, and ease of future maintenance. IEDs connected in a star fashion with the switches connected in a fiber-optic ring provide the most reliable and dependable substation LAN. Because each panel has its own switch, none of the bay communications cabling needed to be disrupted or retested between factory acceptance testing (FAT) and field installation. Each panel was complete and tested during the FAT. Once delivered on-site, the switches were reconnected in a ring, and the network was quickly reconfigured, regardless of their eventual distance from one another. Future Ethernet troubleshooting and maintenance has been simplified by inclusion of a switch in each bay instead of multidrop connections between IEDs or long-distance cable runs to a distant switch.

VII. Communications Implementation Considerations

The IEC 61850 standard requires timestamp resolution to the microsecond. Therefore, the recommended best practice for time synchronization remains IRIG-B because it is the only method that provides this accuracy. SNTP (simple network time protocol) can be used but will not provide the accuracy for some applications. Future changes to the IEC 61850 standard may recommend a method over Ethernet once one is available. The IEEE is working on a standard, referred to as IEEE 1588, that may provide microsecond time-synchronization accuracy over Ethernet. However, until then, some vendors suggest that customers use SNTP, which is convenient because it travels over Ethernet and does not require a second connection like IRIG-B. The accuracy of SNTP is at best several milliseconds and varies as the network traffic varies. CFE agreed to implement time synchronization via SNTP or IRIG-B because of different implementations among all the vendors. CFE asked that the vendors provide useful descriptive naming of the IEC 61850 data and groups, such as logical node names, and avoid generic names. However, many of the vendors used generic naming. These generic names are conformant with the standard; however, they are not very useful to the end user and are actually counterproductive to creating the SCL and self-description. By using generic naming, the vendors eliminate the ability to perform automatic configuration and require the integrator to refer to documentation to see which generic IEC 61850 value represents the needed phase voltage or breaker position.

As shown in Fig. 6, each IED must serve data to six clients, perhaps simultaneously. These six include the two dual-primary redundant HMIs, two dual-primary redundant protocol gateways, one local engineering access connection, and one remote engineering access connection. For each client connection, the design called for separate binary-state data set buffered reports and measurement data set unbuffered reports.

A. *Match Existing Device Naming Methods*

CFE planned to continue using the naming convention developed within their organization. All of the databases that receive substation data—protocol gateway, engineering, SCADA, HMI, and documentation—use the name of the source IED. The CFE naming convention requires 12 characters, XXX YYYYY ZZZZ. These 12 characters represent the aggregate name, where XXX identifies the substation (e.g., LVD), YYYYY is the breaker identifier associated with the device (e.g., 97010), and ZZZZ identifies the IED function (e.g., MCAD, the acronym for bay control). This combines to be LVD97010MCAD and represents the bay control for tie breaker 97010 in station LVD.

Some vendors do not support 12 characters in their IED description within their IEC 61850 configuration. Though this is not defined by the standard, it has been common for many years via many protocols to provide enough characters for end users to uniquely name each IED based on their established internal naming conventions, and it became a problematic "local issue." Local issue is the term used within the standard to refer to important implementation details that are not addressed by the standard and must be resolved locally—within the implementation of the IED. However, because many of the local issues result in differences that impact integration among vendors' IEDs, the connotation has come to mean issues local to the substation where the integrator must make things work. Because character length is a local issue, out of scope of the standard, IEDs were included that do not support CFE's naming convention. Discovering this local issue so late in the project resulted in a tremendous amount of rework and testing because each element in each database that referred to data from these IEDs had to be changed to the shorter name and retested. Furthermore, CFE was not able to maintain their established naming convention.

B. *Logical Devices, Functions*

CFE, like other customers, would like the opportunity to replace IEDs from one vendor with those of another vendor that perform the same function and would like to have each IED support the same communications interface capabilities. This is a useful consideration, but even though communications via IEC 61850 protocols can be standardized, they can only be standardized to the features that overlap within every product (the lowest common denominator). Also, keep in mind that even though IEC 61850 IEDs communicate similarly, they do not perform protection or automation the same, and the standard does not specify how they perform these functions. To allow interchangeability at the communications level for this project, IEC 61850 logical devices within the IEDs were defined for each required function. Only the specified logical nodes were allowed to exist inside each logical device. Examples of the logical devices include:

- CTRL1 for bay control – LVD97010MCADCTRL1
- PRO for main protection – LVD97010MCADPRO
- MET for metering – LVD97010MCADMET

The left view in Fig. 7 illustrates browser software finding several IEDs (physical devices) on the network, including the physical device bay control LVD97010MCAD. The right view shows the detail within the MCAD that exposes each logical device and the logical nodes inside the CTRL1 logical device.

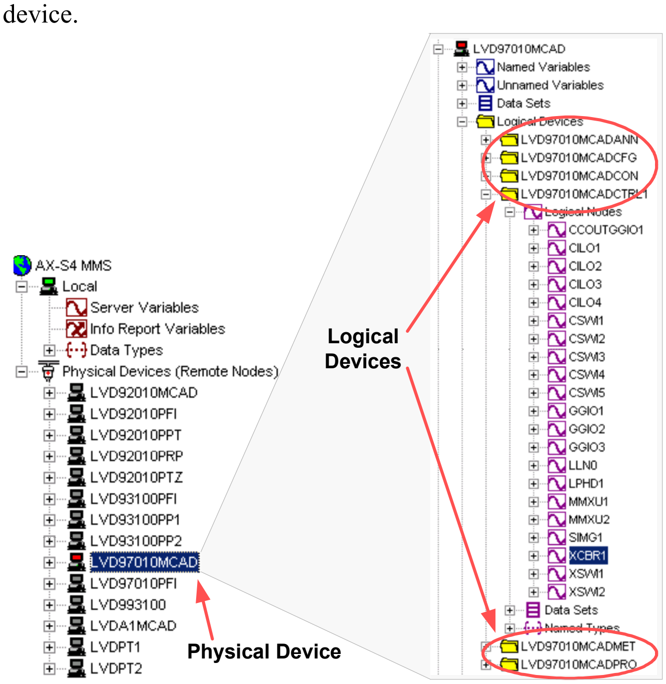

Fig. 7. Browsing on physical devices, logical devices, and logical nodes

C. *IED Data Sets*

Inside each logical device, only the logical nodes required for the project were allowed to be communicated within the data sets. This was accomplished by some vendors through the use of configurable data sets that were easily modified to support this. Also, several default logical devices and nodes were left in the IED in case of future needs, but they were not reported in the data sets developed for the in-service design. CFE requested data sets for binary data states (estados), analog measurements (medidas), and GOOSE bits (GOOSE) as summarized in Table VI.

TABLE VI
DATA SETS

Name	Association	Report Type
Estados	Binary Status	Buffered
Medidas	Measurements	Unbuffered
GOOSE	GOOSE Bits	GOOSE Messages

The contents of the digital state and measurement data sets are illustrated in Fig. 8.

Fig. 8. Required IED data sets and their contents

D. New IEC 61850 Data Objects

Based on previous design experience, IBERINCO had recommended the use of new data objects not yet a part of the standard. IBERINCO had already submitted a proposal to be added to the standard so that all users could benefit from their future use. Even though they were not yet a formal part of the standard, some vendors were able to implement them because the IEC 61850 standard defines the methods necessary to extend the logical nodes and data objects to include new and unanticipated contents.

One such data object is the open and close order activation information, or ACT. This is a status that represents that the IED received a control action command. The control switch logical node, CSWI, was extended to include both an open order ACT (CSWI\OpOpnOr) and a close order ACT (CSWI\OpClsOr).

E. Controls Filtered by Origin

The project design also required control functionality where the status was mandatory within the standard, but the function was left undefined. Origin category (orCat) and other features became local issues not expected by the vendors and required additional development during the project. It was determined to use orCat to filter the controls based on what the client sent them, or the "control origin category." This control origin, the originator category, is illustrated in Fig. 9 in this excerpt from the standard. As can be seen, the standard does not address the behavior or use of this attribute.

CFE requested that the IEDs accept or deny control execution based on the source of control that is the orCat attribute for circuit breakers, control switches, and sectionalizer switches. In this way, the IEDs are configured to accept or deny control commands by comparing the origin to the present state of permission for that client. Addressing it as a local issue, the integration design team defined its behavior to satisfy CFE's requirements. As designed, an IED can be set for remote control only and act on only commands with the origin associated with a remote SCADA client and deny local HMI commands. Conversely, when the IED is expected to perform in local mode, it can filter out all remote SCADA commands based on their origin and accept only commands from a local HMI. This filtering is useful to assure that the communications are configured correctly on a trusted network. However, it should not be considered a method to satisfy cybersecurity requirements because the origin is simply a setting and is not authenticated in any way. The IEC 62351 standard is under development and when complete will provide cybersecurity methods for IEC 61850 substations.

Logical node implementations for breakers, control switches, and sectionalizer switches are filtered as listed below:

- Breaker – XCBR\POS\origin
- Control switch – CSWI\POS\origin
- Sectionalizer switch – XSWI\POS\origin

6.8 Originator

Originator type shall be as defined in Table 7.

Table 7 – Originator

Originator Type Definition			
Attribute Name	**Attribute Type**	**Value/Value Range**	**M/O/C**
orCat	ENUMERATED	not-supported | bay-control | station-control | remote-control | automatic-bay | automatic-station | automatic-remote | maintenance | process	M
orIdent	OCTET STRING64		M

Originator shall contain information related to the originator of the last change of the data attribute representing the value of a controllable data.

orCat: The originator category shall specify the category of the originator that caused a change of a value. An explanation of the values for orCat is given in Table 8.

Table 8 – Values for orCat

Value	Explanation
not-supported	orCat is not supported
bay-control	Control operation issued from an operator using a client located at bay level
station-control	Control operation issued from an operator using a client located at station level
remote-control	Control operation from a remote operater outside the substation (for example network control center)
automatic-bay	Control operation issued from an automatic function at bay level
automatic-station	Control operation issued from an automatic function at station level
automatic-remote	Control operation issued from a automatic function outside of the substation
maintenance	Control operation issued from a maintenance/service tool
process	Status change occurred without control action (for example external trip of a circuit breaker or failure inside the breaker)

Fig. 9. Excerpt from IEC 61850 standard defining the originator type and orCat values

VIII. Major Communications Integration Project Challenges

A. Local Issues Undefined by the Standard

By and large, the complications encountered in this project resulted from local issues left unresolved by the standard. Many of these local issues cannot, and will not, be addressed by the standard but are essential to a successful implementation. Through this process, the communications integration team documented a list from these local issues and the chosen solutions as a guideform specification to aid other users of the standard. The most arduous task was actually representing specific CFE data requirements within the noncustomer specific international standard methods of IEC 61850.

The previously mentioned request to support CFE-specific IED names and logical device names was not unusual. However, it was unexpected by a few vendors. The primary IED vendor anticipated these requests because of years of experience supporting UCA2, which uses all of the same messaging specifications and data transfer methods. Thus, the flexibility of configuration of IEDs from this vendor's IEDs easily supported CFE's desires. However, several of the IEDs from other vendors did not. In some instances product development provided the solution; in others, the final design was modified to match the IED capabilities.

B. Unnecessary and Unexpected Use of Generic Data References

The choice of several vendors to use generic data references instead of specific naming for commonly used information was a surprise. Though not mandatory, it was definitely expected that vendors would provide logical node and data object names that reflected the source and purpose of the data.

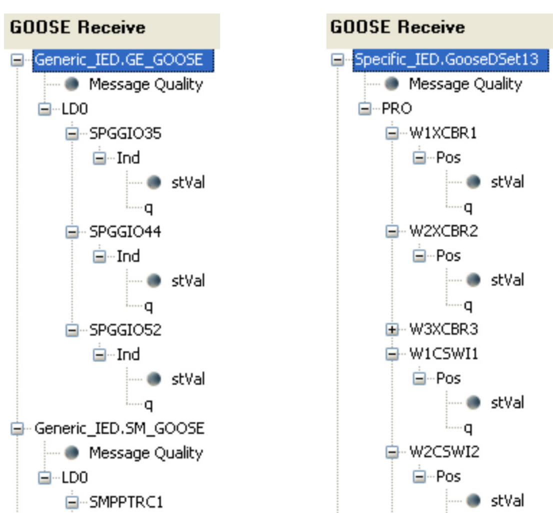

Fig. 10. Specific naming versus generic naming for a switch status

Fig. 10 illustrates an example of specific naming versus generic naming for a switch status. In the generic example on the left, the contents of a data set published in a GOOSE message represent the position of an apparatus as a generic data object (indicator, Ind) associated with a generic logical node (single point generic process input/output, SPGGIO35). The more descriptive example on the right shows the contents of a data set where each of three windings are associated with a separate circuit breaker. Winding one circuit breaker logical node is W1XCBR1, and the position is identified as Pos rather than a generic indication. Therefore, with a little experience, it can be observed that W1XCBR1.Pos.stVal refers to the value of the position of the circuit breaker associated with winding one. It is not possible from the generic description to know what SPGGIO35.Ind.stVal refers to.

Without specific naming within the IED, separate documentation must be used to identify what the generic data objects represent. This eliminates the possibility of self-description and automatic configuration. Generic naming is defined in the standard for use when data that cannot be anticipated, such as results of customer and/or site-specific logic, are incorporated in a system. This feature should be used sparingly to improve self-description but is a useful method to incorporate data at the time of installation that would otherwise be unavailable. If these data are common to other applications, they may become mapped to new or existing logical nodes as the products evolve.

The fact that devices from nine different product developments from six different vendors were combined for the first time in any project was also a difficult challenge, but this would be true regardless of the protocol chosen. Engineers that participated in the engineering of this project were located across seven time zones (United States, Mexico, Spain, Germany). Several communications tests were staged over the Internet between remotely located engineers and products so that work could begin before all products were collected at the site of the FAT. It quickly became evident that the vendors were in different stages of completeness of their IEC 61850 implementations. Some development continued until the beginning of the FAT, which in some cases allowed the vendors to incorporate some of CFE's local issue requests.

Time was also a concern because delivery was initially required four months after the contract award for the team to design, build, and test all the protection panels and integration systems. This, in concert with the fact that some IEDs were the result of product development completed during the design stage, resulted in a lot of integration rework during the FAT.

IX. Factory Acceptance Test

Overall, the FAT took six weeks. SEL, IBERINCO, and ZIV were involved in the total length of the testing. Siemens and GE were involved in the configuration and testing of their devices. The process started with initial network setup, switch configuration, and initial communications tests. This part of the process went quickly but also brought to attention the following issues:

1. Some manufacturers were not able to meet some of the IEC 61850 requirements for the project. Below is a list of limitations found during this process:
    a. Physical device name limited to eight characters. This made IBERINCO redefine the database naming and meant reconfiguration of databases for all the clients.

b. Logical device name was not configurable. This limited the overall goal of device interchangeability.

c. No mapping flexibility meant that the IED did not allow for mapping any desired IED digital value to a specific data object in a logical node. Therefore, the team used more generic nodes than what was expected in the design stage.

d. Some IEDs did not support the six clients required by the project.

Most of these limitations exist because of IED limitations and were not possible to overcome, requiring the design team to change databases and naming conventions for the devices with limitations.

2. After these problems were addressed, HMIs and SCADA gateways were reconfigured in order to start functional testing. During this second part of testing, new issues were discovered:

   a. Report control block names were not configurable for some of the IEDs.

   b. Writing to report control block named components OptFlds and TrgOps was a challenge because values defined in the design stage were not accepted by all the IEDs.

   c. Double point indication for breakers and sectionalizers caused problems when mapped to DNP3 and Conitel 2020.

   d. Some IEDs did not support the origin attribute to report back to the HMI. The HMI uses orCat to discriminate from which level the control was executed and to log the control origin.

   e. IEDs must use orCat as a filter to allow controls from different control levels.

      i. Local

      ii. HMI

      iii. Control center

3. After status, measurements, and controls were tested, GOOSE messages for interlocks were tested. The following two issues were addressed:

   a. Control block reference (CBR) cannot exceed 32 characters for some IEDs. CBR is configured by adding the physical name, logical name, logical node, and data set. Because of the naming convention used, this limitation was exceeded most of the time in several IEDs, and the customer was not able to use the CBR that they originally chose.

   b. Configuration software from some vendors will import SCL files from other vendors but will not respect all the configuration parameters. As a result, the device is not allowed to subscribe to the GOOSE messages from the other devices.

   After these issues were addressed, the testing of interlocks between bay controls was fast and easy, showing the real advantages of GOOSE.

4. Confirming the successful use of GOOSE messages for protection was the last part of the FAT. CFE wanted to perform detailed testing in order to gain confidence in the new technology.

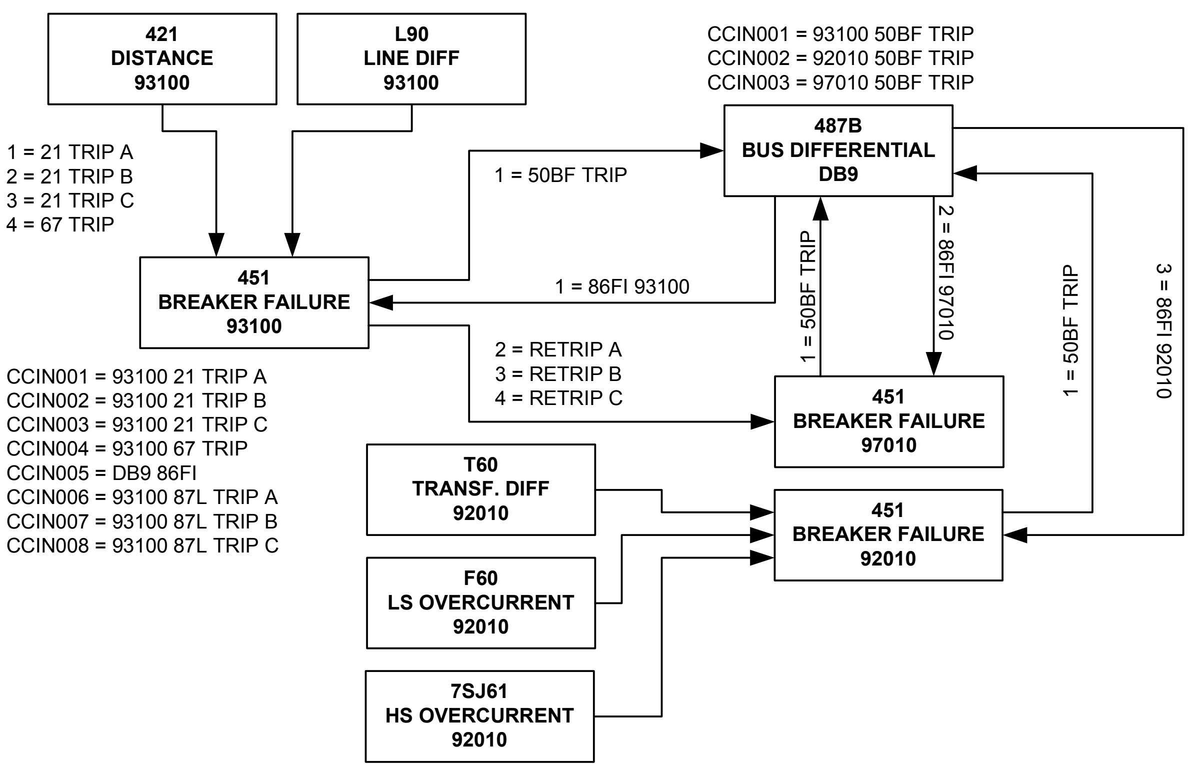

Fig. 11. Breaker failure protection scheme using GOOSE

The complete breaker failure protection scheme was implemented using both traditional wiring and GOOSE. The operation sequence of the breaker failure scheme is presented below. Fig. 11 illustrates the process.

a. Trip of protection relay—the relay detects the fault, operates, and at the same time, sends a GOOSE message to the breaker failure relay.
b. Retrip of breaker failure relay—breaker failure relay receives the GOOSE message and sends the retrip signal to the associated breaker.
c. Trip of breaker failure protection—in the case when a breaker failure timer expires, a breaker failure trip GOOSE message is sent to the bus differential relay to start the bus isolation.
d. Bus differential relay receives the GOOSE message, identifies feeders connected to the bus with the breaker failure, and sends a GOOSE message to trip the required breakers through their associated breaker failure scheme.

Fig. 12 shows an event report from the breaker failure relay 93100 for a retrip operation. IN101 represents the trip signal from the distance protection relay using a hardwired contact; CCIN001 represents the trip signal from the same relay using GOOSE. The time difference between hardwired and GOOSE is about 12 ms because of the time introduced by the physical output of the distance protection relay and the debounce timer of the breaker failure relay. Because of this delay, the retrip operation using GOOSE was 12 ms faster than the hardwired operation. This difference might be reduced using high-speed output contacts.

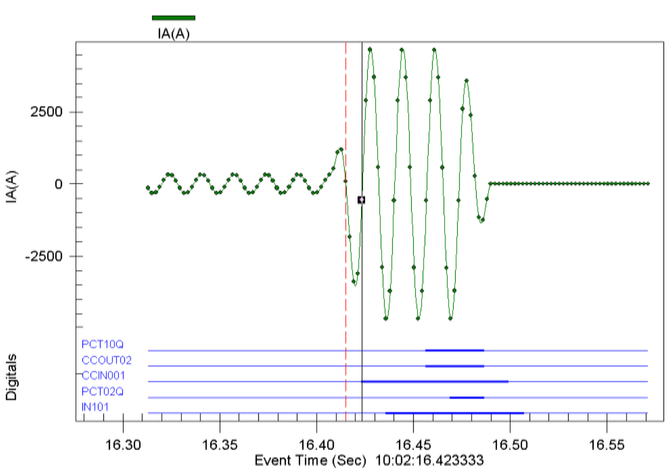

Fig. 12. An event report from the breaker failure relay 93100 for a retrip operation

Fig. 13 shows an event report for the breaker failure relay 97010. In this case the hardwired trip comes into IN103, and after about 200 ms, BFTR1 represents the output contact to the 86FI lockout relay that will distribute the trip to all breakers in the bus. The GOOSE trip comes into CCIN003, the same 200 ms apply, and another GOOSE (CCOUT001) is sent to the bus differential relay that determines which breakers to trip and sends another GOOSE message (CCIN005). Fig. 13 shows that the GOOSE scheme is 8 ms faster, without considering that the wiring scheme still has to go through the lockout relay.

Additional tests were performed, increasing traffic in the network and obtaining the same results. In this specific project, Ethernet switches with VLAN (virtual LAN) priority tagging and store-and-forward technology to avoid collisions were used in order to guarantee the results.

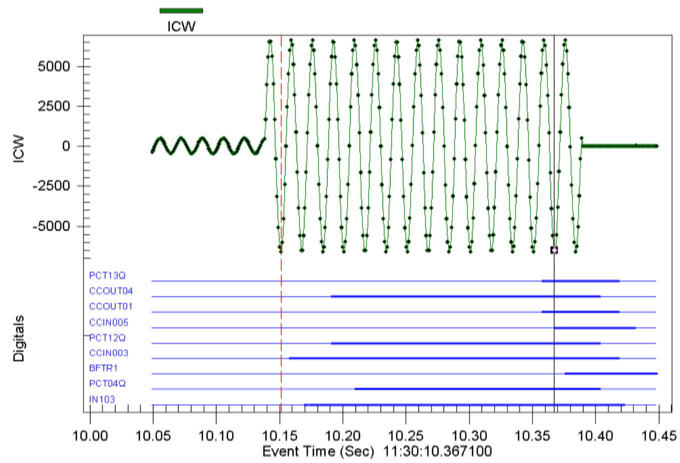

Fig. 13. An event report for breaker failure relay 97010

X. Lessons Learned

Much was learned during the project because it was the first to integrate so many different vendor IEDs into one system and prove interoperability. Success was possible because of the skills and years of experience of the design team working with the messaging and methods of the new standard. The vendor that supplied the bulk of the IEDs has been providing this technology for six years as UCA2 and recently upgraded their implementation to incorporate SCL. However, most of the lessons that can and should be taken from this paper are the resolution of local issues documented as a guideform specification. These local issues were not solved in the past because other IEC 61850 system designs were created with a handful of IEDs from the same vendor or perhaps two different vendors. The design team for this project offers the following list of lessons learned.

A. Design Stage

- Be aware of desired IED name length and restrictions within the IEDs.
- As early as possible, identify optional parts of the standard that you will require in order to increase the likelihood that each vendor will support them. Be prepared to compromise if your IED of choice does not support these requirements.
- Choose IEDs that support configuration flexibility so that any IED data available to the communications interface can be presented and so that logical devices and logical nodes can be extended to incorporate new and unanticipated data.
- Choose vendors that will support your requirements and desires to implement nonmandatory elements of

the standard as well as your selection of resolutions to local issues.

- Test new product communications as much as possible prior to the FAT.
- Use IRIG-B for better timestamp accuracy.
- Use substation-grade communications equipment.
- Use Ethernet switches that support VLAN and priority tagging.
- Preferably, use IEDs that support direct loading of SCL configuration files over devices that require proprietary software.
- Choose IEDs that support the required number of clients (recommend six).
- Choose IEDs that support the appropriate GOOSE parameters.
  - GOOSE subscriptions (recommend 24)
  - Logic variable associations for bay control (recommend 128)
  - Logic variable associations for protection (recommend 16 or 128, depending on application complexity)
  - GOOSE publications (recommend eight)

B. *Communications Interface Testing*

- Be prepared to understand and test communications at the manufacturing messaging specification (MMS) level.
- Be aware that, because of the anonymity of Ethernet, messages are interleaved from multiple sources.
  - This complicates troubleshooting and eliminates straightforward functional testing.
  - One must trust software test tools rather than hardware connections and diagnostics, such as LEDs, to provide communications information.
- Choose IEDs that respond to commands to identify what configuration file is loaded within the IED and in use.
- Choose IEDs that respond to commands to identify the status of their configured outgoing GOOSE message publications.
- Choose IEDs that respond to commands to identify the status of subscription to expected incoming GOOSE message.

C. *Functional Testing*

- Document everything.
- Keep your Ethernet analyzer recording at all times. You cannot troubleshoot what was not captured by an analyzer.
- Recognize that part of the simplicity and speed in using GOOSE is that permissive logic is done in the relay logic rather than auxiliary relays because so much information can be received quickly from many sources.

D. *Software*

At this time, not all vendors have IEC 61850 configuration software available. Some still edit files at the XML level. For this project, only three vendors had an IEC 61850 configuration tool available. Engineering software tools (SCL software) that can import ICD files from the different IEDs and create CID files for the IEDs, SCADA gateways, and HMIs will help to reduce configuration time as well as complexity.

Fig. 14. Construction of Wind Farm La Venta II

XI. Guideform Specification

In order to confirm that IEDs that support IEC 61850 are successfully integrated into a substation system, the following details also need to be met. Some of these details are not mandatory for IEC 61850 conformance but are necessary to satisfy integrated communications. Therefore, IEDs offered for inclusion in a system to satisfy this specification need to be IEC 61850 conformant and support the following itemized functionalities:

- Each IED shall support the appropriate protocols within the IEC 61850 standard.
  - Reporting, poll response, controls, and self-description shall be performed via MMS protocol.
  - Configuration shall be performed via XML-based SCL files.
  - Peer-to-peer messaging shall be performed via IEC 61850 GOOSE messages.
- Each IED shall have a native Ethernet port that supports each of the IEC 61850 protocols mentioned previously as well as essential engineering access connections over the same Ethernet port. Specifically,

each IED Ethernet port shall support, at a minimum, the following:

- IEC 61850 reporting via MMS
- IEC 61850 polling MMS
- IEC 61850 controls via MMS
- IEC 61850 self-description via MMS
- IEC 61850 GOOSE messaging
- IEC 61850 configurations via XML-based SCL files loaded directly into the IED (preferred)
- Engineering access via standard TCP/IP mechanisms
- Event report collection via standard TCP/IP mechanisms
- Non-IEC 61850 settings transfer via standard TCP/IP mechanisms (e.g., protection and logic settings)

In order to support varied future and additional installations, each IED shall also support a SCADA protocol in addition to IEC 61850 via the Ethernet port.

Each IED shall support the origin category (orCat) for controls and filter permission to execute a received command based on the command origin.

Each IED shall support the data object ACT to represent the open and close order activation information. This status represents that the IED received a control action command.

Each IED shall support a descriptive name of up to 16 characters in order to provide the ability for the end user to uniquely name the IEDs within their system based on new or established naming practices.

Each IED shall be capable of supporting six simultaneous client-server associations. This number is necessary to support the possible network requirement of two redundant SCADA gateway connections, two redundant HMI connections, and two redundant engineering access connections.

Each IED shall support six default preloaded buffered reports and six preloaded unbuffered reports. These reports shall be preconfigured and capable of being used without customization. However, the IED shall also support customization of the reports and data sets.

Each IED shall have the ability to freely rename data sets, logical devices, and logical nodes.

Each IED shall have the ability to add and remove logical nodes to and from each logical device.

Each IED shall use specific naming for commonly used information rather than generic data references.

Changes to data sets and reporting configuration shall be done via ease-of-use configuration software. The resulting SCL CID file shall be downloaded directly into the IED as described within the standard. This is necessary to confirm that future IEDs from multiple vendors can be used and configured with one software tool.

Each IED shall support remote loading of the CID file via Ethernet using standard TCP/IP mechanisms in order to accommodate engineers designing and technicians configuring IEDs remotely from each other because of geography and/or time.

It is of utmost importance that the IEDs support stations and applications with different data requirements, have the ability to accommodate data that were not recognized to be necessary until after contract award, and represent customer specific data and IED logic values as appropriate IEC 61850 logical nodes and data objects. Therefore, flexible configuration of data sets shall be required as well as the ability to create new logical devices, logical nodes, and their contents. To support this, it shall be possible to create different ICD (IED capability description) and CID files that map any and all available IED data for specific customer applications. In this way, unique data sets and customer specific names shall be supported. Modification of the IED IEC 61850 capabilities shall be done without hardware or firmware changes to the IED.

Each IED shall allow the user to query it directly and to verify which IEC 61850 configuration file is active within the IED. This function is necessary to confirm correct configuration and identify what behavior should be expected from the IED in order to perform effective commissioning and troubleshooting.

In order to perform effectively in the anticipated communications designs, the IEC 61850 GOOSE implementation in each IED shall support the following requirements:

- Each IED shall be capable of publishing eight unique GOOSE messages.
- Each IED shall be capable of subscribing to 24 unique GOOSE messages.
- Each IED shall be capable of monitoring GOOSE message quality.
- Each IED shall be capable of processing incoming data elements and their associated quality.
- Each IED shall be capable of monitoring message and data quality as permissives prior to use of the incoming data. At the time of configuration, the end user can choose to ignore the possibly corrupted data—if the data or message quality fails—to prevent an unwanted operation.
- Each IED shall be capable of creating a GOOSE data set that includes both Boolean values and non-Boolean data types, such as analog values.
- Each IED shall be capable of accepting and processing data sets from other IEDs that contain Boolean and non-Boolean data types even though IEDs need only map and use Boolean data types.
- Each IED shall support priority tagging of GOOSE messages for optimizing latency through Ethernet switches.
- Each IED shall support VLAN identifiers to facilitate segregation of GOOSE traffic on the Ethernet network.
- Each IED shall support a preloaded default GOOSE message for use without custom configuration.
- Each IED shall support custom editing of the data sets published in the GOOSE messages so the user can send what they choose.

- Changes to data sets, GOOSE parameters, GOOSE publication, and GOOSE subscription shall be done via ease-of-use configuration software. The resulting SCL CID file shall be downloaded directly into the IED as described within the standard. This file shall not be converted into settings and downloaded via the conventional settings process. This difference is documented specifically and necessarily to confirm that future IEDs from multiple vendors can be used and configured with one software tool.
- The configuration software from the IED vendor shall import CID, ICD, and substation communications description (SCD) files in order to learn the available GOOSE publications and data sets from other IEDs. The software will use this information to configure the IED to subscribe to other vendor IEDs and use the data being broadcast.
- Each IED, while in service, shall allow the user to query it to learn communications diagnostics as well as status and/or error codes of GOOSE messages being sent and received.

In order to effectively configure the IED for use within the network, the ease-of-use configuration software provided with the IED shall be capable of the following requirements:

- The software shall be capable of importing configuration information about other IEDs from ICD, CID, or SCD files.
- The software shall validate the imported information to confirm that it complies with IEC 61850 parameters.
- The software shall provide error messages describing problems detected in imported files.
- The software shall support naming IEDs with up to 16 characters.
- The software shall support review and editing of IED data sets and report parameters.
- The software shall support review and editing of data sets and GOOSE parameters.
- The software shall support the mapping of any available data into the data sets.
- The software shall support the association of data quality with data elements.
- The software shall support visible end-user warnings to prevent incorrect data set editing as well as warning when editing a data set that is already in use. In this fashion, the end user can be warned not to disrupt an existing configuration and/or create a data set too large for its intended purpose.
- The configuration software shall support creation of eight GOOSE publications.
- The configuration software shall present the user with all available GOOSE messages and support up to 24 subscriptions.
- The configuration software shall support assigning VLAN and priority tags to GOOSE messages.
- The configuration software shall present the user with the entire data set for each potential GOOSE subscription and allow the user to browse for necessary data.
- The configuration software shall present the user with the entire data set for each potential GOOSE subscription and allow the user to map data from the incoming data sets into the IED. When this is done, the software automatically subscribes to the associated GOOSE message.
- The configuration software shall allow the user to choose message and data validation on incoming GOOSE data set contents.
- The configuration software shall allow the user to directly load the SCL file into the IED, or export it for storage or remote loading.
- The configuration software shall allow importing and exporting of SCL files without modification of the private regions of the original.
- The configuration software shall create files in XML format that can be modified by XML editors and tools to help resolve conflicts or errors in badly formed files.

IEC 61850-5 identifies several specific performance requirements for applications operating in the IEC 61850 series environment. Unfortunately, the IEC 61850 standard defines speed criteria that cannot be exactly measured. Therefore, it is not presently possible to test and verify the transmit time performance classes as described in the standard. Instead, it is possible to measure the transfer time, which includes the transmit time plus the time to process and timestamp the transmitted data. This transfer time represents the performance of communications in actual use. Data element state changes are timestamped and logged as sequential events records (SER). In IEDs with clocks synchronized to the same time reference and that create accurate timestamps, SER are used to calculate transfer time. The transfer time is described as the difference in time between the timestamped SER in the initiating IED and the timestamped SER in the receiving IED. For each IED, the measured GOOSE transfer time shall be provided with a description of how it was measured.

IEC 61850-10 defines other metrics to be measured within devices and documented by the vendors so that end users can compare multiple vendors. For each IED, timestamping accuracy will be identified and documented by providing the two following measures:

- Maximum clock synchronization error, which indicates the accuracy of the IED to synchronize its clock to the time reference
- Maximum timestamp delay error, which indicates the accuracy of the IED to timestamp the data when the event occurs

Product reliability metrics are essential because of the nature of networked IEDs being used to design systems of interoperable devices working in a coordinated fashion. IEC 60870-4 Telecontrol Equipment and Systems Part 4: Performance Requirements documents methods to measure and calculate the following [1]:

- Reliability
- Availability
- Maintainability
- Security
- Data integrity
- Time parameters
- Overall accuracy

These and other device performance measures are essential information for predicting performance, functionality, and reliability of designs executed by networked IEDs. No specific performance benchmarks are expected to be met; however, verification and publication of actual performance measures is necessary to be conformant. Using these published performance measures, system integrators can predict the performance of the interconnected IEDs and, thus, the performance of the system. Furthermore, system integrators will be able to identify suitable devices for specific applications.

Reliability measures should include, but not be limited to, specific product reliability metrics and a description of how the metrics are calculated or measured. Metrics that are mandatory include:

- Specific device mean time between failure (MTBF)
- Product family MTBF
- Specific product mean time between removals (MTBR)
- Product family MTBR

Reliability data should be based on the actual incidence of field failures for a large population of installed units. If the provided figures are based on actual data, the approximate size of each installed population used as a basis for each value should be indicated.

If insufficient field data are available to provide a meaningful MTBF, base the predicted MTBF on the parts-count procedure defined in Military Handbook, MIL-HDBK-217F, December 1991 [2]. Manufacturing quality and design quality can yield significantly better MTBF than predicted by MIL-HDBK-217F. The parts-count procedure does establish a pessimistic MTBF to support a minimum system availability calculation.

XII. References

[1] *Telecontrol Equipment and Systems Part 4: Performance Requirements*, IEC Standard 60870-4.

[2] *Military Handbook: Reliability Prediction of Electronic Equipment*, MIL-HDBK-217F, Department of Defense, Washington DC, December 1991.

[3] D. Dolezilek, "IEC 61850: What You Need to Know About Functionality and Practical Implementation," presented at the Western Power Delivery Automation Conference, Spokane, WA, 2005.

XIII. Biographies

Victor Manuel Flores is chief of the automation department of CFE GRTSE. He is an electrical engineer from ITESM with 22 years of experience in CFE SCADA and automation systems. His experience also includes planning, design, implementation, commissioning, and testing of systems using DNP3, Harris 5000/6000, Conitel 2020, and Modbus®. He is a CFE-certified instructor and is actively involved in the CFE specifications group for SICLE, SIME, and the working group to adopt IEC 61850 in CFE.

Daniel Espinosa received his B.S. in electrical engineering from the Instituto Politécnico Nacional in 1998. He is a member of the Protection Specialists National Committee from CFE and is involved in several aspects of electric power protection and automation systems standardization and normalization in CFE. Since 1999 he has been responsible for preparing bid specifications for integrated systems for distribution substations and for 13.8 kV to 400 kV power lines in the CPTT in CFE.

Julian Alzate received his B.S. in electrical engineering and telecommunications at the Universidad Nacional de Colombia in 1998. Julian joined Schweitzer Engineering Laboratories, Inc. in 1999 as an integration and automation application engineer in the International Sales and Marketing Division. He provided technical support to international customers on integration and control applications and relay technical training. In 2003 he became Automation Engineering Manager for the SEL Mexico Division, where he was involved in preparation of technical bid responses and management of international projects. In 2005 Julian became the new technologies manager and is involved in the design, implementation, and management of projects in which new SEL technology is involved.

Dave Dolezilek is the technology director of Schweitzer Engineering Laboratories, Inc. He is an electrical engineer, BSEE Montana State University, with experience in electric power protection, integration, automation, communications, control, SCADA, and EMS. He has authored numerous technical papers and continues to research innovative technology affecting our industry. Dolezilek is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE working groups, and two International Electrotechnical Commission (IEC) technical committees tasked with global standardization and security of communications networks and systems in substations.

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Conference for Protective Relay Engineers.

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Case Study: IEC 61850 Application for a Transmission Substation in Ghana

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Meade Electric Company, Inc.

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Power and Energy Automation Conference, March 2013

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***Abstract*—One of the benefits of implementing IEC 61850 is minimizing or even eliminating the copper field wiring used to exchange protection and control data between intelligent electronic devices (IEDs) across a substation. Conversely, implementing IEC 61850 has introduced commissioning, testing, and maintenance complexity that can be alleviated with proper training, documentation, and testing plans.**

The design and implementation of the Kintampo, Ghana, transmission substation required redundant protection and control functions distributed among the IEDs and a robust communications network to implement IEC 61850 protocols. In order to maintain a high level of availability, the power supplies of the primary and backup protection devices are fed from two separate battery chargers that also feed dual trip coils for the 161 kV high-voltage ac breakers. The use of dual main protection schemes in both distance and differential protective relays and single-pole tripping and reclosing on the transmission line enhances the availability, stability, and reliability of the transmission system. Outdoor equipment mounted in enclosures near the breakers collects and reports breaker and motor-operated disconnect (MOD) alarms and statuses, as well as provides MOD and transmission line ground switch control.

The Kintampo substation has a robust and reliable substation automation system (SAS) that includes a human-machine interface (HMI) for local indication and control, a supervisory control and data acquisition (SCADA) server to provide status, metering, and control data to the local HMI and remote utility enterprise system, and a hardened Ethernet network of industrial-grade switches for reliable communications that can support critical, high-speed protection schemes.

The Ethernet network uses a ring topology with Rapid Spanning Tree Protocol (RSTP) and virtual local-area networks (VLANs) to provide network redundancy, reliability, data segregation, and traffic control. The SAS uses the Manufacturing Message Specification (MMS) and Generic Object-Oriented Substation Event (GOOSE) communications protocols from the IEC 61850 communications standard for data acquisition and control and for high-speed, peer-to-peer protection schemes.

This paper discusses several key aspects of the electrical design, protection and control, communications network design, testing, and commissioning of an IEC 61850-based substation.

I. Introduction

Ghana is undergoing major electrical upgrades affecting all aspects of the power system, from generation to transmission and distribution. The Kintampo substation will transmit and distribute 400 MW of power generated at the Bui power plant to hundreds of communities throughout Ghana. Two hundred and sixteen of these communities are being electrified for the first time as part of the Self-Help Electrification Program (SHEP). This paper documents the innovative use of international standard communication with modern Ethernet network designs to protect, control, and monitor the 161 kV/ 34.5 kV substation.

With the rapid growth and understanding of the IEC 61850 communications standard, the local utility required several of the protocols and methods defined within the standard to be implemented in this substation for several reasons. The primary reason was to minimize the copper connections between the field and the control house. This was effectively accomplished by using digital messaging over fiber cables to act as virtual wiring among networked intelligent electronic devices (IEDs). Substation wiring practices vary depending on the voltage level, although the number of wires (i.e., the total number of points being measured and controlled) is relatively constant between components. The wire length and number of data paths are significantly reduced by locating the protection and control equipment in the yard [1]. This reduces the amount of material and labor involved and also makes it much easier to verify the wiring correctness, resulting in significant time savings during installation.

Another important reason that a design based on networked IEDs was chosen was to take advantage of additional tangible and intangible benefits. These benefits are based largely on the fact that the IEDs create and contain well organized and accurate data about the IEDs and primary equipment. IEDs also have the processing, memory, and communications capabilities to convert the data into information about the health and performance of the power system. The ability of IEDs to test their own health, store sequence of events (SOE) reports, and provide asset details and firmware information on request makes previously tedious processes simpler and automatic. From a communications and configuration perspective, one of the greatest engineering benefits is the self-documenting capability of the IEC 61850 Substation Configuration Language (SCL) files stored directly in these IEDs. The encapsulation within an IED of a data model that universally describes each piece of substation data and its attributes is one of the greatest advantages this technology has to offer.

II. Protection and Control

The Kintampo substation is composed of two substation yards. One is a 161 kV transmission substation with four transmission lines, two step-down transformers, and nine circuit breakers arranged in a breaker-and-a-half scheme. The other is a 34.5 kV distribution substation consisting of two incoming feeds arranged in a main-tie-main scheme with eight feeders. The two stations are connected with underground cables and are several hundred meters apart. The one-line diagram for the transmission substation is shown in Fig. 1.

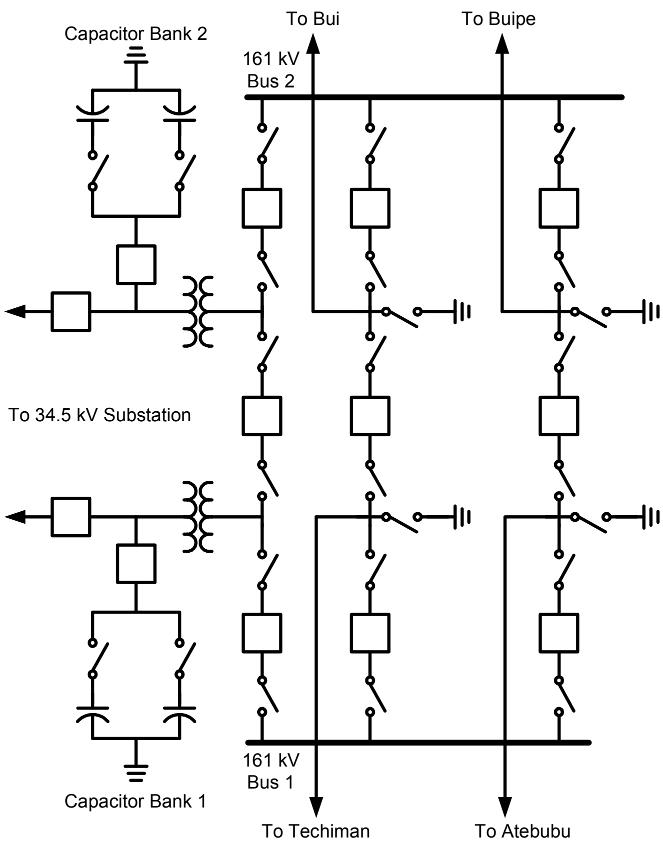

Fig. 1. Kintampo transmission substation one-line diagram.

The electrical arrangement in the transmission substation provides operational flexibility. When the transmission substation is normally operated with each circuit breaker closed, the loss of one transformer, transmission line, or 161 kV bus does not impact the distribution power flow. However, the design requires more complex protection and control schemes. Redundant protection is provided throughout the substation by using primary and backup protection IEDs. The IEDs are powered with separate dc circuits and backup battery systems. Each circuit breaker features single- and three-pole tripping capability with redundant trip coils for each phase. The primary IED trips Trip Coil 1 while the backup IED trips the circuit breaker via Trip Coil 2.

This paper focuses on the communications aspects of the system. The protection applications are out of scope but are generally consistent with traditional methods of accelerating protection applications by sharing information between IEDs. The sophisticated protection and control schemes at Kintampo depend on reliable and deterministic communications to constantly move data between IEDs. These data were formerly conveyed by hard-wiring a physical output of the source IED to a physical input of the destination IED using copper conductors. IED communications are accomplished via Generic Object-Oriented Substation Event (GOOSE) messages between the source IED and one or more destination IEDs. This requires careful configuration of GOOSE messages within the IEDs and information on where to deliver the messages within the Ethernet switches. GOOSE messages are multicast, meaning that they can be delivered to many IED receivers. However, without proper local-area network (LAN) configuration, multicast messages are sent to every single device in the system. These GOOSE messages support protection and control functions such as circuit breaker failure, GOOSE test mode, and reclose initiate. Perhaps most important is that this message exchange is constantly supervised by each receiving IED in order to immediately detect message delivery problems. If problems occur, the receiving IEDs revert to noncommunications-assisted logic and alert technicians to the problem.

A. *Breaker Failure Communications*

The dual primary IEDs controlling each transmission line circuit breaker and the transformer protection IED controlling the transformer circuit breaker also perform breaker failure protection. GOOSE messages transport indications of the change of state of Boolean data such as breaker status, analog values such as metering, and bit strings. The receiving IEDs then interpret and act on the indications that are immediately appropriate to their condition and other logic and inputs. In this way, GOOSE data are not direct trip commands but are rather indications of the remote statuses that are used in trip equations. Communication of information among various IEDs is needed in two stages of breaker failure protection: indication of breaker failure initiation and breaker failure trip indication from the source IED, transmitted to the appropriate relays. Also, in cases where single- and three-pole operations are both possible, indications for both operations are conveyed within the GOOSE message. In cases where the backup IED trips the circuit breaker prior to the primary IED asserting a trip, the backup sends either a single-pole breaker failure initiate or a three-pole breaker failure initiate, depending on the type of fault, to the primary relay.

Once the breaker failure initiate is received, the primary relay starts a 12-cycle timer. If the circuit breaker still has not interrupted the fault once the timer expires, the primary IED declares a breaker failure and sends a trip indication to the surrounding relays within a GOOSE message. The receiving IEDs act on this indication to trip their circuit breakers in order to isolate the faulted circuit breaker. In the Kintampo substation, both the primary and backup relays also receive breaker failure trip indications from the surrounding IEDs, including the relays protecting the 161 kV bus, the opposite transmission line, the adjacent transmission line, and the transformer.

B. GOOSE Test Mode Communications

In order to test or commission a relay without affecting the other IEDs within the substation, a GOOSE test mode latch bit was programmed into each relay. The latch is enabled with a pushbutton on the front panel of the relay or with a remote bit from the human-machine interface (HMI) and is included in the outgoing GOOSE message. When the latch is enabled, a user can test the relay protection elements and communication with other relays in the zone without causing any of the other circuit breakers to operate. The relay supervises the latched bit in its own logic and publishes the bit in its outgoing GOOSE publications. The receiving relays accept the test mode indication within the GOOSE message and are consequently programmed to block some functionality during testing to avoid inadvertent operation. For example, if the GOOSE test mode is enabled in one relay, the other relays in the zone receive indication of this via GOOSE test mode indication being set to true in the GOOSE message. Therefore, when the GOOSE test mode indication is used as a permissive to block logic, as shown in Fig. 2, data received from the tested relay are updated but not acted upon in the receiving IEDs. If breaker failure asserts from a relay that is in GOOSE breaker failure test mode, the other relays that would normally trip on a breaker failure condition will not operate. However, the other relays still receive a breaker failure and GOOSE test mode indication, which can be verified via the front-panel display. In order to provide isolation of individual protection functions, GOOSE test mode indications are created for each unique protection function to be tested.

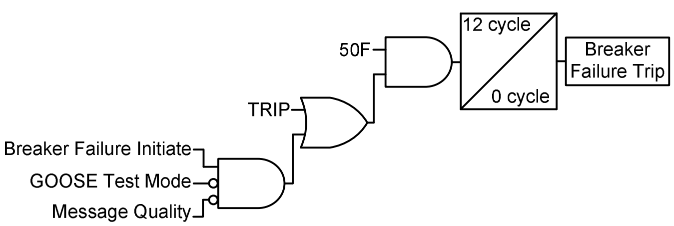

Fig. 2. Breaker failure trip logic.

C. Reclose Initiate Communications

For the transmission line protection in the substation, the Main 1 relay is used as the primary recloser, while the Main 2 relay is used as the backup recloser. Main 2 reclosing is enabled only when the Main 2 relay detects failure of communication from the Main 1 relay, which may mean that the Main 1 relay is out of service. However, due to the nondeterministic nature of Ethernet, failed GOOSE reception may indicate failed Ethernet cables or Ethernet switches as well as a failed relay. If the Main 1 relay is not failed but GOOSE reception from it is, both main relays can initiate reclosing. Failed GOOSE reception at one relay does not necessarily mean that other relays are not receiving the multicast GOOSE messages.

The overall reclosing design considers both single- and three-pole tripping conditions. Reclosing is initiated by both main relays for single-phase and multi-phase faults detected by the distance elements, pilot scheme, overcurrent elements, or line current differential. Reclosing is set for one shot for single pole followed by one shot for three pole. For a line-to-ground fault, the primary relay performs a single-pole trip and reclose. If the fault is still present after the single-pole reclose, the relay initiates three-pole tripping. The open time interval for the three-pole trip is 900 cycles (15 seconds). If the initial fault involved multiple phases, the relay initiates a three-pole trip and only attempts a single three-pole reclose if the fault is still present. After the reclose and if the fault is still present, the relay performs a three-pole trip and the recloser is driven to lockout.

Because the Main 2 relay can trip the circuit breaker without the primary relay asserting a trip, a reclose initiate indication is sent via GOOSE messaging from the Main 2 relay to the Main 1 relay. The Main 1 relay then initiates the appropriate reclosing sequence depending on whether the received indication is a single- or multi-phase reclose.

III. Existing Substation Wiring Versus New Practices

Substation wiring practices vary depending on the voltage level, equipment age, and associated apparatus technology. Traditionally, copper is the primary interface between components in the yard and a relay that is centrally located within a control house. Evaluation of traditional in-service installations finds that there are typically 44 conductors between the field and a relay in a control house. Normally, several multiconductor cables are used; separate cables are typically installed for breaker status (trip/close) and current transformer (CT) and potential transformer (PT) secondaries. Wiring runs are fairly long, spanning between 200 and 500 meters, as shown in Fig. 3.

Fig. 3. Copper conductors removed from cable trenches and replaced by digital messaging.

The horizontal data paths for information exchange between components, labeled "wires" in Fig. 4, represent pairs of copper wires conducting real-time state, binary, and analog measurement information. In this case, each data path includes a data source on the left and a data client on the right.

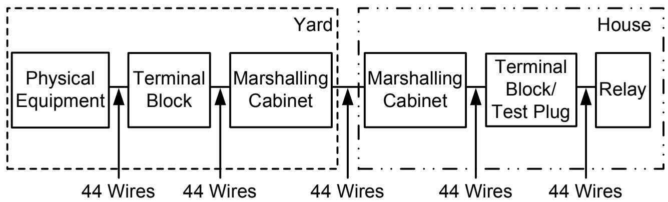

Fig. 4. Traditional wiring approach with relays in the control house.

Although the number of wires (i.e., the total number of points being measured and controlled) is relatively constant between components, the wire length and number of data paths are significantly reduced by locating the protection and control equipment in the yard, as shown in Fig. 5 [1]. This reduces the amount of material and labor involved and also makes it much easier to verify the wiring correctness, resulting in significant time savings during installation.

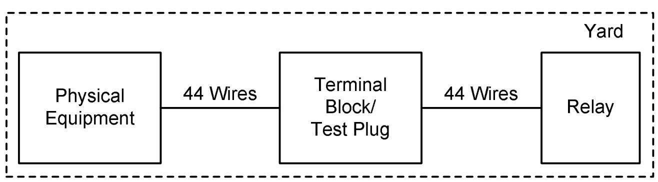

Fig. 5. Wiring approach for relays in the yard.

Locating microprocessor-based relays in the yard significantly improves overall functionality, reduces size, and simplifies internal cabinet wiring. However, care must be taken to select IEDs that are designed for the harsh environment of outdoor installation, as demonstrated by stringent environmental ratings and long manufacturer warranties.

Even without moving the relay to the yard, digital communication of digital I/O greatly simplifies installations. Over 50 percent of the wires within the data path from the yard to the house are associated with circuit breaker control signals. It is therefore advantageous to use a hybrid approach in which the CT and PT wiring is retained, but the control wiring is replaced with a fiber-optic-based I/O transceiver module and communications cable, as shown in Fig. 6.

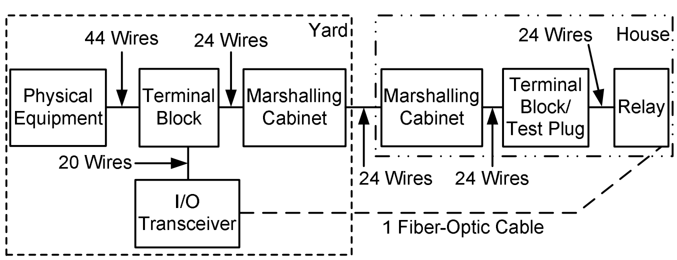

Fig. 6. Hybrid project showing the amount of copper wire replaced with fiber-optic-based I/O module technology.

The I/O module approach provides significant wire savings and introduces the ability to monitor the health of the data connection. This practice has been field-proven for more than a decade based on purpose-built digital communications standards created by standards-related organizations (SROs) and offered via a "reasonable and nondiscriminatory" license, such as MIRRORED BITS® communications. Also, protocols created by standards development organizations (SDOs), such as the IEEE and IEC, are useful. One of the two forms of standardized IEC 61850 GOOSE messages has been used in the field for over a decade, and other standards are in use, such as IEEE C37.94. As mentioned, devices use the connection health status to supervise the digital data path and differentiate between silence due to inactivity and silence due to a severed conductor. Reliability is improved because the number of unsupervised components, processes, apparatuses, and data paths is reduced. I/O modules minimize the number of unsupervised data paths between field sources and component data clients. This approach vastly improves the value of the data by confirming the availability and reliability of the methods by which they are collected and by alarming when a data path is broken. Finally, fiber-optic cables also offer galvanic isolation of the data paths between components.

Substation wiring reduction is accomplished in the Kintampo substation via the IEC 61850 real-time GOOSE protocol that is specifically optimized for reliable and timely data transmission. Its use is best understood by reviewing the digital I/O wiring reduction example. Fig. 6 illustrates a straightforward approach of using IEC 61850 GOOSE to digitize and transmit bidirectional information between equipment in the substation yard and the controller in the control house.

Based on user preference, other designs involve moving the entire relay out into the field kiosk, as shown in Fig. 7 [2]. This illustrates a simple way to communicate data between a relay installed in the field kiosk and a station controller installed in the control house.

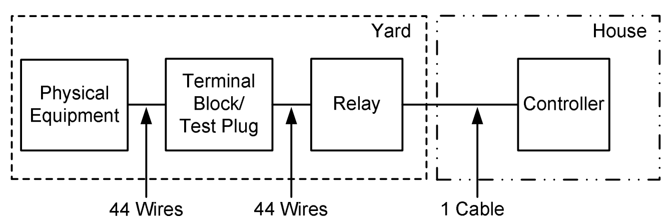

Fig. 7. Simplified diagram showing cable reduction potential with Ethernet-based virtual wiring technology.

While conceptually very simple, the design in Fig. 7 does not take full advantage of the Ethernet network capabilities. The Ethernet link between the relay and controller in the control house is installed as a dedicated, point-to-point interface.

A general interoperable standards-based approach with an Ethernet switch, LAN, and communications among several devices is shown in Fig. 8.

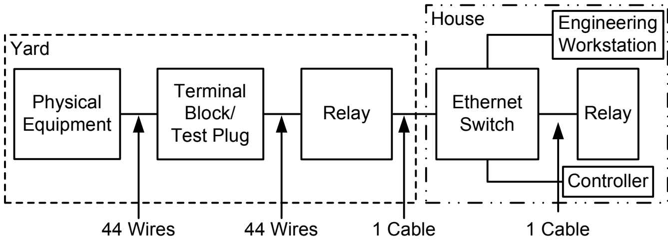

Fig. 8. Ethernet-based relay installation with an Ethernet switch.

IV. Motor-Operated Disconnect Switches and Circuit Breaker Alarm Field IEDs

The modern prefabricated field kiosks and modular control houses used for Kintampo follow the design separation shown in Fig. 6. Everything necessary for the yard application is preinstalled in a prefabricated field kiosk, and all items ordinarily installed in a site-built house are preinstalled in a prefabricated control building. This pre-engineered method greatly reduces overall project time.

This option was ultimately chosen for Kintampo because it simplifies the procurement and installation process dramatically and simplifies site preparation and commissioning. The system became a repeatable, pre-engineered, and pretested solution designed to user specifications in a way similar to primary equipment.

The user requirements were such that circuit breaker control was implemented using a control switch module with indication located in the control house hard-wired to the yard circuit breaker, as shown in Fig. 9.

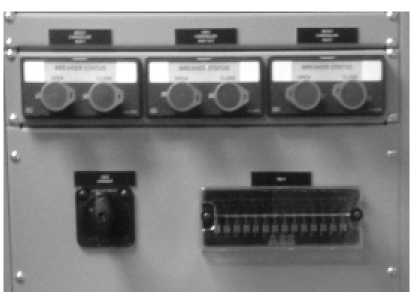

Fig. 9. Control switch module with indication located in the control house.

Circuit breaker alarms and the control and status of the motor-operated disconnects (MODs) are hard-wired to outdoor equipment mounted in enclosures and communicated via IEC 61850 messages over fiber-optic cable as indicated in Fig. 6 and illustrated in Fig. 10. This eliminated significant amounts of wiring between the yard and the control house. Circuit breaker alarms, including SF6 low pressure, control switch in remote, and trip coil monitoring, are reported to the HMI from the field kiosk IEDs using the IEC 61850 poll-and-response Manufacturing Message Specification (MMS) protocol.

Moreover, MOD control trip and close are implemented by wiring the control switch module output to an input on its associated breaker relay in the same panel. Once the input asserts, the relay in the control house sends a GOOSE message to the outdoor equipment to perform the appropriate action to trip or close and then sends the MOD status back to the HMI and relay. The relay then, in turn, provides an output contact to an input in the control module to provide indication.

Ground switches located near the transmission line circuit breakers have their open/close indication wired to the outdoor equipment. This information is also sent to the circuit breaker control logic inside the control house relays via GOOSE to prevent closing the circuit breaker once the ground switch is closed.

Fig. 10. Typical IED field kiosk installation.

V. Ethernet Design and Considerations

Ethernet has found a place in safety-critical industrial systems and mission-critical substation networks. Any discussion of Ethernet (which defines the physical and data link layers of the seven-layer Open Systems Interconnection [OSI] communications model) is incomplete without including network topologies and higher-layer protocols created by SROs and SDOs, such as the IEEE and IEC. In the power system industry, Ethernet is often identified with the IEC 61850 set of protocols, as well as IEEE C37.118 synchrophasor transmission and supervisory control and data acquisition-only (SCADA-only) protocols such as DNP3/IP and IEC 60870-5-104. Unlike the message path of serial direct messages, which follow the same path as the physical cabling between devices, Ethernet messages travel paths dictated by methods such as Rapid Spanning Tree Protocol (RSTP), which enables virtual data circuits through the Ethernet network. Ethernet networks, regardless of redundant cabling, always select a single active path for message transit among devices on the network. Therefore, the switch and cabling design should be done by designers aware of the implications of underlying Ethernet path design technology to make sure the paths are appropriate for the applications that require data exchange. Ethernet networks must be carefully engineered—not simply assembled.

Operational technology (OT) reliability is maximized by choosing IEDs with two Ethernet ports in failover mode connected to redundant switches. For power system OT, the most stringent applications require rapid and reliable message exchange among peers to perform teleprotection, interlocking, and high-speed automation. International standards for the reliability of teleprotection applications in power systems allow between 0 and 9 messages to be dropped in a 24-hour period of GOOSE exchanges, require that messages be delivered in less than 4 milliseconds 99.99 percent of the time, and require that the remaining 0.01 percent of exchanges experience a maximum transmit time of less than 10, 20, or 30 milliseconds, depending on the specific protection scheme [3]. Simply put, the message transit requirements are:

- Redundant message paths, in case the primary path fails.
- Low latency.

Designing for redundancy provides a secondary path after a segment or switch failure. Designing for low latency minimizes the number of switches the message must pass through while between devices.

Multicast messages within IEDs, such as IEC 61850 GOOSE messages, are sent to one or more IEDs to share data to accelerate teleprotection, interlocking, and high-speed automation. Best practices for configuring IEDs and switches for correct operation of GOOSE messages are discussed in Section VI, Subsection C. Virtual LAN (VLAN) segregation is important not only to manage the type and amount of traffic sent to each IED but also to manage the amount of traffic within the switches themselves. By keeping the traffic restricted to what is appropriate and necessary on each network segment, bandwidth saturation is less likely.

VI. Network Architecture

A. Network Topology

The LAN for Kintampo substation is designed to provide a reliable and deterministic platform for the substation communications-based protection schemes. The substation LAN is composed of a ring of substation-hardened industrial Ethernet switches. All of the IEDs have dual Ethernet ports operating in failover mode with two separate connections to two different switches. The IED connections are 100BASE-FX multimode fiber. A ring topology was chosen because, when combined with RSTP, this topology allows for network redundancy in the case of a connection or switch failure. Also, it is easy to understand, test, and install in the field. The IED count is sufficiently small, so that when connected in failover mode, this design matches or surpasses any other topology choice in regard to reliability and recovery. With this topology, no single failure in the network (or two or more failures in some cases) results in a loss of communication. Large rings experience long recovery times after a switch or link failure, so other topologies should be considered in different, larger systems. Fig. 11 displays a portion of the Kintampo network layout. When designing switch-to-switch connections, it is recommended to use connections of similar or equal latency so they behave similarly and traffic behavior does not radically change when network reconfiguration moves traffic from one segment to its redundant partner. The latency of each segment is determined by its speed (i.e., the speed that it moves messages, described as capacity) or bandwidth.

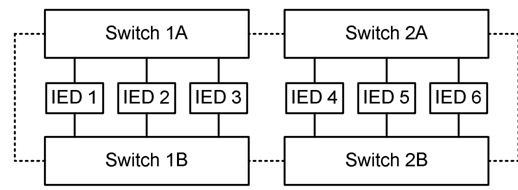

Fig. 11. Sample diagram of the network layout.

B. Designing RSTP

Special care should be taken when designing a network that uses RSTP for recovery in the event of a failure. Taking the time to configure the various RSTP settings ensures that the network recovers in the most optimum way in the event of a failure. One of the switches in the network acts as the root bridge or root switch to be the starting point for all network topology decisions. Because there does need to be a starting point, if the user does not choose, the switches choose among themselves to select one, and only one, root. Left to choose on their own, switches use the media access control (MAC) addresses to decide. Network engineers should choose a root switch so they definitively know the topology and are able to predict topology changes. Root switch designation can be assigned to a device by setting the bridge priority to a sufficiently low number.

The RSTP process recognizes the root as the logical focal point of the network, and all segments are identified based on their proximity to the root. RSTP minimizes the distance that messages must travel from all points on the network to the root. Therefore, all IEDs close to the root are close to each other, with fewer cables and switches for the messages to pass through. If the network is a star or hub-and-spoke topology, then the switch at the center should be made the root bridge. At Kintampo, no switch is more physically central than the other because they are connected in a ring, so the switch with the most IEDs connected to it was selected as the root bridge.

C. VLAN Design for GOOSE

The Ethernet switches at the Kintampo substation are configured with VLANs in order to segregate traffic on the network. Each IED network interface must process all Ethernet messages that it receives, including frequent IEC 61850 GOOSE messages, even if it is not the intended recipient. Because IEC 61850 GOOSE messages are multicast Ethernet traffic, Ethernet switches attempt to send them to every Ethernet interface in the system LAN. However, the Kintampo LAN switches are engineered to pass or deny the VLAN identifier (ID) of each GOOSE message based on which IED is connected to the switch ports. A unique VLAN was created for every IEC 61850 GOOSE message and the switches set accordingly, so that the message is only delivered to the devices that are configured to receive it. By restricting the VLANs on each switch port to GOOSE messages that are configured to be received by the IED on a particular port, all of the other GOOSE traffic is blocked. This minimizes the amount of traffic that each IED must process and, as a result, maximizes the performance of the IED Ethernet ports. This also reduces the likelihood of bandwidth saturation on any network segment by reducing unnecessary traffic. Each IED port on the switch was configured with the same native-port VLAN ID or port-based VLAN ID for all of the other non-GOOSE traffic.

The complete list of best engineering practices for using Ethernet virtual wiring via digital messages to replace copper conductors is quite extensive [3]. Designers using protection, control, and monitoring (PCM) IEDs and networks for Layer 2 multicast messages must adhere to the following rules for designing and configuring messages and network engineering parameters:

- Assign each GOOSE message a unique VLAN based on IEEE 802.1Q, referred to as a QVLAN.
- Assign each GOOSE message a unique IEC 15802-1 multicast MAC address.
- Assign each GOOSE message a unique application identifier (app ID).
- Assign a descriptive GOOSE identifier (GOOSE ID) rather than a generic ID in the IED to improve documentation and troubleshooting.
- Label GOOSE message payload contents with descriptive rather than generic names in the IED to improve documentation and troubleshooting.
- Carefully design payload size and contents to facilitate appropriate GOOSE application processing—mind the gap.
- Carefully choose IEDs that process incoming GOOSE messages appropriately fast for protection-class applications—mind the gap.
- Do not publish multicast messages on the network without QVLAN tags.
- Disable all unused PCM communications ports.
- Monitor GOOSE message attributes to derive the quality of the message.
- Use the GOOSE attributes of sequence number and state number to determine if all wanted messages reach the receiver.
- Monitor, record, and alarm failed quality of GOOSE messages.
- Provide GOOSE reports with configuration, status information, and statistics pertaining to GOOSE messages being published and subscribed to by the IED.
- Record and alarm failed quality of GOOSE messages for use in local and remote applications.
- Display status of GOOSE subscriptions and alert operators of failure.
- Configure each switch port to block the ingress of unwanted messages and allow wanted multicast messages via VLAN and MAC filtering. This reduces the multicast traffic through the network to only that which is required.
- Configure each switch port to block the egress of unwanted messages and allow wanted multicast messages via VLAN and MAC filtering. This prevents unwanted messages from reaching the IEDs.
- Use switches designed for rugged environments and Layer 2 multicast among PCM IEDs in a fixed address network.
- Do not allow dynamic reconfiguration; this leads to unknown network configurations.
- Use switches that provide real-time status of traffic behavior and network configuration.

VII. Substation Automation System

A. *Substation Automation System Components*

The substation automation system (SAS) at Kintampo includes an HMI to provide local indication and control of substation components and a remote terminal unit (RTU) to provide SCADA to the local HMI and the utility remote control center. The RTU performs data acquisition and control for the substation IEDs via the MMS communications protocol that is part of the IEC 61850 standard. The RTU provides remote SCADA via the IEC 60870-5-104 communications protocol. The Kintampo SAS has several unique features not common to a typical SAS, including hot-standby quadruple redundancy, highly customizable user access control, historical trending of metering data, and automatic event retrieval.

B. *Hot-Standby Redundancy*

Most SAS designs separate the RTU and the HMI into two different hardware platforms for redundancy purposes in the event that one of them fails. At Kintampo, the RTU and the HMI are housed within the same software package and located on the same hardware platform, but the software has built-in hot-standby quadruple redundancy. There are four substation-hardened computing platforms in the Kintampo SAS that are configured exactly the same. The four software instances constantly communicate their status to one another via a heartbeat signal over Transmission Control Protocol/Internet Protocol (TCP/IP). At any given time, only one of the four computing platforms is actively performing data acquisition and control. When the active one has a hardware or communications failure, the next one automatically starts up and begins where the first left off. In order to preserve consistency and coherency of data across all four computing platforms, the same communication that provides the heartbeat signal also transmits any changes in data to the other three inactive computing platforms. The software automatically ensures that all four computing platforms have the same configuration and data.

C. Access Control

The Kintampo substation is shared by two separate utilities: Ghana Grid Company Limited (GRIDCo) and Northern Electricity Distribution Company (NEDCo). GRIDCo operates the transmission portion of the substation, and NEDCo operates the distribution section. One of the user requirements is the ability to control access to the HMI with separate user accounts for each utility. The HMI and RTU software supports multiple users with unique credentials and access rights. The Kintampo substation has two control buildings, one for distribution and one for transmission, which require two separate touchscreen panels in either building. The touchscreen panel in the distribution control building is configured to automatically display the distribution portion of the HMI upon startup, and the touchscreen panel in the transmission control building is configured to automatically display the transmission portion of the HMI upon startup. When users log in to the HMI on either screen, they are asked to provide login credentials. Users of both utilities can view both sections of the HMI, but they are only able to perform operations on their section of the substation.

D. Trending

The HMI and RTU software supports historical trending of metering data and is configured to sample and store various metering quantities, including power, current, and voltage. These sampled data are stored on the substation computer and saved for 30 days. The historical data sets are circular first in, first out (FIFO) files. The sampling interval and retention period determine the size of the files. The HMI is configured with customizable graphs to view and compare the data that are stored in the historical data sets. Users can open multiple graphs simultaneously and edit the time periods that are displayed on the graphs. The trending data can also be imported from the data set files into Microsoft® Excel® for further analysis using a Microsoft Excel plug-in. These trending capabilities are a useful tool when trying to forecast load requirements and provide users with greater insight into the historical behavior of the system.

E. Automatic Event Retrieval

The SAS is equipped with software that performs automatic event record retrieval from substation IEDs. This software is housed on the same substation-hardened computing platform that contains the HMI and RTU. Protection event records are historical records of multiple data readings from multiple sensor measurements before, during, and after an event trigger, such as a fault on the power system. This software periodically connects via Telnet to all of the substation IEDs in a round-robin fashion at a user-configurable interval. The software archives event record files on the local storage of the substation computers and can also be configured to store event files on remote servers. Although the station is staffed, this automatic event retrieval software allows operators to go to the SAS and collect all the event records to send to the engineering department. In the future, this information collection can be automated and done remotely via this software application.

VIII. Factory Acceptance Test

A factory acceptance test was conducted in an office environment to provide the end users with equipment familiarity, testing, and training in a safe environment. Due to the size of this project and the number of protection and integration panels, a complete factory acceptance test was not appropriate. However, a smaller scale of the substation was replicated with a complete transmission bay including the remote end along with a transformer panel and two 34 kV panels. The end users witnessed the full testing of this replicated system, allowing the engineers and end users to test the system and make final adjustments before overseas shipping.

Circuit breaker simulators were used to simulate closing and tripping of circuit breakers and MODs and thoroughly test and verify all logic and communications.

IX. Conclusion

This paper discusses key aspects of the electrical design, protection and control, and communications network design at Kintampo. This paper demonstrates that the use of field kiosks does significantly lower the amount of wiring between the control house and the yard. Even interpanel wiring was greatly reduced by using IEC 61850 GOOSE messages for breaker failure initiate and tripping. The network design was chosen to provide network redundancy, reliability, and traffic control. The local HMI provides operators with local indication and control while providing remote access to SCADA operators.

As the acceptance of IEC 61850 communications by utilities grows, this type of large-scale project will grow as well. Just as with complete hard-wired projects, special engineering design must take place in the beginning stages of an IEC 61850 implementation project. In particular, the design of the network architecture is critical to make sure that the system can withstand single points of failure of network equipment and IEDs. Another challenge that remains is adequately training the operators who ultimately have to quickly respond to late-night emergencies. For example, the factory acceptance test has proven invaluable because it provided the engineers and operators training on the new technologies familiarity with the communications-assisted logic, LAN, and system performance and operation. A system solution that is repeatable, pre-engineered, pretested, and designed to specifications is extremely important because it provides the user with a standardized solution that can be implemented across the system, minimizing different designs.

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XI. Biographies

Charles E. Anderson is Vice President of Engineering for Meade Electric Company, Inc. He graduated with a BSEE from the University of Notre Dame in 1980 and holds master electrician licenses in seven states. Charles has experience in the design, construction, and commissioning of electrical power generation plants, high-voltage substations, and medium-voltage power distribution systems for both utility and industrial facilities.

Salim Zniber joined Schweitzer Engineering Laboratories, Inc. as a protection engineer in 2010. He has been involved in several projects for the engineering services division, which provides engineering services in protection, automation, and networking for utilities and industrial clients. Salim has worked on projects that include IEC 61850 and IEEE C37.118 engineering, design, and implementation. He holds a BSEE and MS in electrical engineering from the University of North Carolina in Charlotte.

Youssef Botza earned his BSEE from the University of North Carolina at Charlotte with honors and is currently employed as an engineering supervisor at Schweitzer Engineering Laboratories, Inc. He has several years of experience in power systems, providing protection and automation solutions and serving as a technical lead and project manager in the engineering services division. Youssef has been working on cutting-edge technology projects, specializing in IEC 61850 solutions. He is a registered professional engineer in the state of North Carolina and a member of the IEEE.

David Dolezilek received his BSEE from Montana State University and is a research and development technology director at Schweitzer Engineering Laboratories, Inc. He has experience in electric power protection, integration, automation, communication, control, SCADA, and EMS. He has authored numerous technical papers and continues to research innovative technology affecting the industry. David is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE working groups, and two International Electrotechnical Commission (IEC) technical committees tasked with the global standardization and security of communications networks and systems in substations.

Justin McDevitt joined Schweitzer Engineering Laboratories, Inc. as an associate automation engineer in 2010. He has been involved in several projects for the engineering services division, which provides SCADA and substation automation engineering systems and services for power system utilities and industrial clients. Justin is responsible for the development of automation, control and network systems, HMI design, communications processor settings, relay logic and communication, and commissioning. He has worked on several IEC 61850 substation automation projects with complex automation and protection communications schemes. He has a BS in computer engineering from the Georgia Institute of Technology.

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IEC 61850 – More Than Just GOOSE: A Case Study of Modernizing Substations in Namibia

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***Abstract*—The need for a unified approach to a substation communications standard that has been addressed by the IEC 61850 standard is well recognized by utilities and vendors alike. The introduction of new paradigms in the approach to substation communications, as well as the foundation provided by modern software development techniques to develop multifunctional devices, has resulted in a standard that is complex to digest and apply. Early adopters of the technology have implemented solutions that do not leverage the full capabilities of the standard and foundational technologies that it is built on. Many systems are poorly specified and often left to vendor turnkey implementation, which may not always be in line with the "spirit" of the standard.**

Applying IEC 61850 requires careful consideration of network design, data modeling of devices, data reporting for SCADA (supervisory control and data acquisition) and HMIs (human-machine interfaces), infrastructure management, system testing, and personnel training. This paper discusses the approach taken in the design of an IEC 61850-based substation solution for EHV (extra-high-voltage) and HV (high-voltage) applications in the Namibia power utility, NamPower.

I. Introduction

Modern electrical substation control rooms follow the trend of information technology data centers where everything is becoming virtualized. The days of dedicated metering, measurements, and control and protection systems are quickly fading. Dedicated physical devices have largely been replaced with modern IEDs (intelligent electronic devices), which are software-based logical devices. Dedicated disturbance recorders, breaker monitoring systems, battery monitors, and transformer monitoring systems are being integrated as yet another logical device in modern IEDs. The process of modernizing secondary equipment in substations has reached the point where even cabling is virtualized in the form of messages over high-speed Ethernet networks. Physical Ethernet networks are also virtualized to represent multiple logical networks.

Using IEDs to communicate with each other over high-speed networks has been the norm in the industrial automation sector for a number of years now. Implementation of field bus networks has brought intelligence down to the simplest of devices, such as actuators and proximity sensors. In a similar fashion to the migration from relay boards to programmable logic controllers, the migration from hard-wired plant interfaces to communications systems has changed the nature of automation systems in industrial applications. The modernization of the substation environment is, of course, similar in nature to what has happened in the industrial automation sector.

Intelligent devices provide a number of additional benefits that are both tangible and intangible. The ability of the devices to self-diagnose, store sequence of events, and provide asset details and firmware information on request makes previously tedious processes much simpler. From a communications perspective, however, one of the greatest engineering benefits is the self-documenting capability of these devices. The encapsulation of the data model within the device is one of the greatest advantages this technology has to offer.

II. Historical Background

The interfacing of substation control equipment has traditionally been hard-wired. Outputs from one device became the inputs to another device. In many cases, this was how different devices communicated with each other. The only devices that would typically implement a digital message communications standard were the RTUs (remote terminal units), which presented the hard-wired substation information to control centers using a proprietary or standardized SCADA (supervisory control and data acquisition) communications solution. Typical examples of these communications standards include DNP3, IEC 60870-5-101, and IEC 60870-5-104. There have also been numerous attempts at defining a communications interface for substation equipment. Examples include standards such as IEC 60870-5-103 for communicating with protective relays and IEC 60870-5-102 for metering devices. Vendor proprietary solutions have also addressed the need for solutions, such as LONBUS and PROFIBUS. Most of these standards are designed to work over point-to-point serial, EIA-232, or serial bus interfaces, such as EIA-485. The implementation of such communications solutions has typically been aimed at meeting the requirements for SCADA purposes.

III. Ethernet in the Substation

High-speed communications infrastructure in substations has been needed for a number of years. The evolution of numerical relays, intelligent meters, distance-to-fault locators, and disturbance recorders has made the need to communicate with these devices essential in order to extract the maximum possible benefit from the equipment.

Implementing switched Ethernet technology in the substation environment addresses the challenge of accessing data contained in various IEDs. The enabling factors of modern Ethernet networking technologies for substation applications include:

- High signaling rates: Ethernet supports signaling rates of 10, 100, 1000, or 10000 Mbps (megabits per second) with standard off-the-shelf equipment. The fastest alternatives used in the industrial sector operate at about 10 to 12 Mbps.
- Flexible architecture: Unlike traditional EIA-485 physical bus topologies, Ethernet switches provide a per-packet, circuit-switched mechanism for data flows within the switch. This makes the technology scalable in terms of capacity requirements. In addition, Ethernet switches can be connected together in a number of different topologies, providing further flexibility and scalability. Common switched Ethernet topologies include ring, star, double-star, tiered, and meshed networks.
- Cabling choices: The connection of devices to Ethernet switches and of Ethernet switches to each other is done using point-to-point connections. This provides for the choice of shielded copper cabling or fiber-optic cabling to meet this need. Copper Ethernet cabling uses a dedicated transmit and receive circuit with individual twisted pairs. Fiber-optic communications circuits by default normally consist of a dedicated transmit and receive fiber. This dual circuit provides full-duplex communications that increase the performance of Ethernet technologies.
- Priority tagging: A historical problem with Ethernet is its inability to provide the determinism required for industrial applications. This has been addressed with data priority tagging, per IEEE 802.1p and IEEE 802.1Q [1]. In conjunction with the circuit switching capability of Ethernet, priority tagging has effectively addressed the need for determinism in many applications.
- Cost per port: The cost of embedding Ethernet within devices is becoming cheaper because of the popularity of the technology across all industry sectors. Vendors of substation secondary equipment have provided Ethernet interfaces with their devices for years.
- Substation-grade Ethernet devices: IEC 61850 specifies that communications equipment meet the same requirements as protection and control IEDs.

In order to take advantage of Ethernet networks in the substation, the DNP Users Group developed a solution that allows DNP3 to take advantage of the benefits offered by TCP/IP (Transmission Control Protocol/Internet Protocol) for both local- and wide-area networks. However, DNP3 is largely used for SCADA purposes.

The EPRI (Electric Power Research Institute) UCA2 (Utility Communications Architecture) project proved that Ethernet technology can be used for SCADA communication and is also capable of meeting the communications requirements for other devices within the substation [2]. In fact, the project proved that the Ethernet communications infrastructure can reliably replace hard-wired communications interfaces between devices, including time-sensitive signaling related to tripping, provided the network is well designed.

The success of the UCA2 project spurred the development of the IEC 61850 standard, which is built on the findings of the project. Interdevice communication over Ethernet networks is described within the standard, which also places great emphasis on the data model that needs to be applied across all devices that wish to communicate using the standard. The primary purpose of the data model is to unambiguously define the representation of data elements present in a substation environment and the relationship between these data elements.

IV. Network Architecture

The design of the network architecture for NamPower projects comprises a switched Ethernet topology that uses a double-star backbone and edge switch design, as shown in Fig. 1. The design was selected because of its performance characteristics and inherent enhanced redundancy options. The design is also scalable and allows for extension without impacting system operation or otherwise compromising its redundancy. A redundant device connection to the network was not a requirement for the project, because this aspect is not conclusively addressed in the first edition of the IEC 61850 standard. In addition, various redundancy methods being standardized within IEC 61850 vary significantly in the IED and network architecture requirements. For this project, only the bus zone relays were connected redundantly to two separate switches.

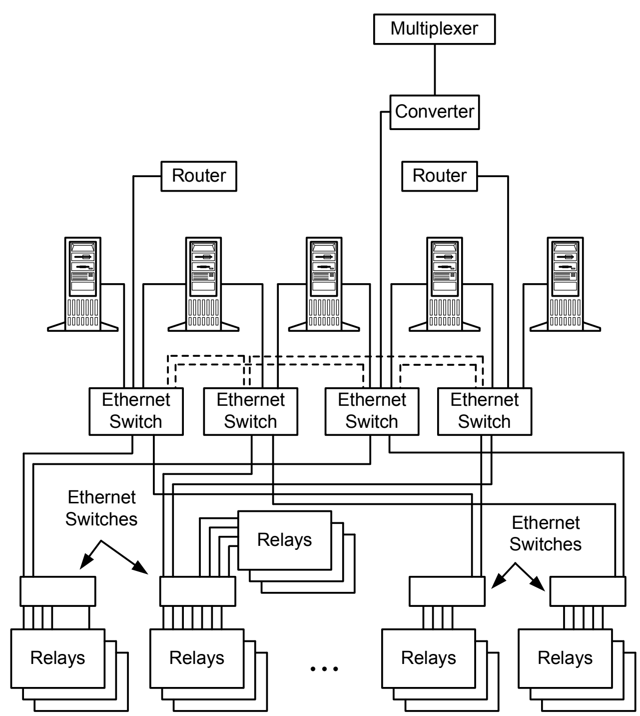

Fig. 1. NamPower network architecture example.

A major design requirement of the network was to allow for flexibility when applying future technologies to the substation without impacting the real-time performance requirements of the network. In order to facilitate this requirement, extensive use was made of VLANs (virtual local-area networks) and priority tagging for time-critical GOOSE (Generic Object-Oriented Substation Event) messaging. This design approach allows for the incorporation of enabling technologies, such as IP (Internet Protocol) telephony, to use the same network infrastructure without impacting the performance of the protection and control functionality.

V. Device Data Modeling

IEC 61850 places significant emphasis on data modeling. The standard builds up complex data structures from simpler data types in order to describe substation functions and equipment in a standardized way. Types of equipment, such as circuit breakers, transformers, tap changers, earth switches, and cooling systems, are described by the standard using object-oriented techniques. The IEC 61850 standardized naming convention is applied to the device application definition (known as a logical device) and individual application function descriptions (known as logical nodes). Logical nodes used to define the data models related to protection functions for instantaneous overcurrent also exist, including timed overcurrent, distance, and protection-related functions, such as autoreclosing.

The standard therefore defines a consistent way of describing the information related to a significant number of system functions and substation devices and equipment, but it is not feasible to define every possible logical node. In order to cater to unmodeled or generic substation information, we can use either a generic I/O logical node, known as a GGIO, or extend the standard by defining custom logical nodes and data types. The problem with GGIO logical nodes is that they have little or no semantic relationship to the information being described, and the definition of custom logical nodes cannot be realized on all products.

The process of defining a data model for a substation application requires flexibility within devices, allowing the data model to be defined within the device ICD (IED capability description) file and mapped accordingly to the internal data references of the device. Vendors supporting this level of flexibility within their products make the application of the end user substation model possible without confining the user to predefined models.

Per the guidelines of the standard, Fig. 2 shows the extension of the standard XCBR (circuit breaker) logical node for adding more data objects. This is then described using the IEC 61850 SCL (Substation Configuration Language) within the ICD file for the IED and mapped to the appropriate hard-wired inputs and outputs.

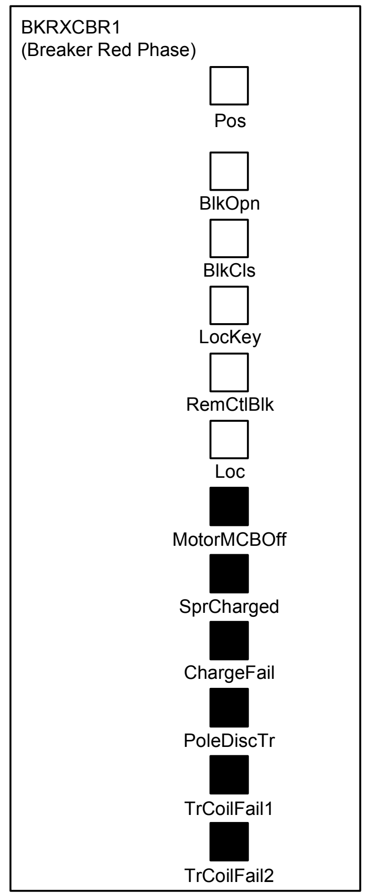

Fig. 2. Extended XCBR logical node.

Fig. 3 shows the use of multiple XCBR logical nodes (one for each phase) and the SIMG (gas insulation supervision) logical node within the same logical device in an IED with the corresponding mapping to a data set to be transported using GOOSE. Describing the model and signal mapping in a diagram greatly simplifies the configuration process and provides suitable documentation for later fault finding and troubleshooting.

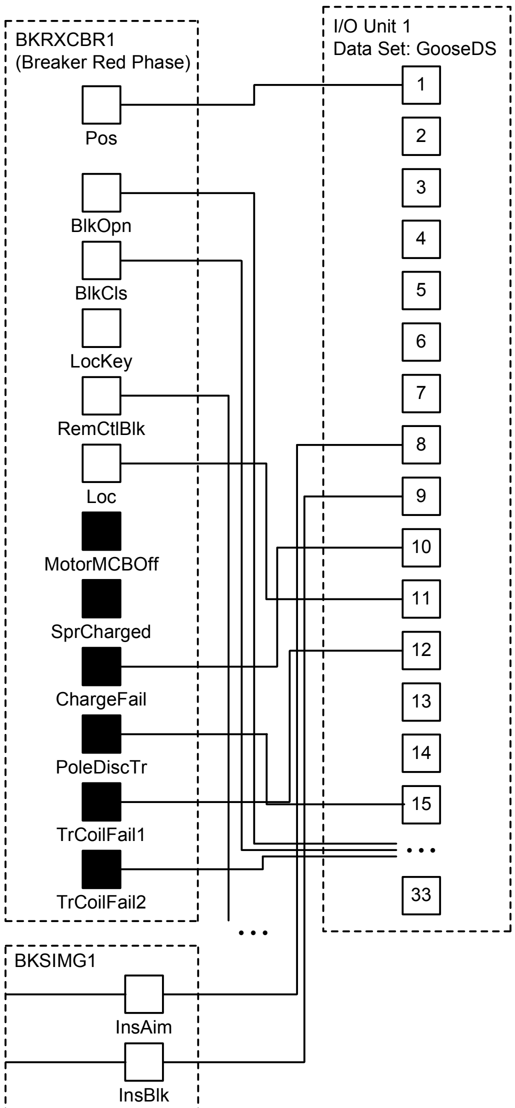

Fig. 3. XCBR and SIMG logical nodes with GOOSE data set.

Fig. 4 shows the definition of a new logical node that maps the signals contained within a substation yard junction box. Again, the definition was completed following the guidelines of IEC 61850-7-4 Appendix A.

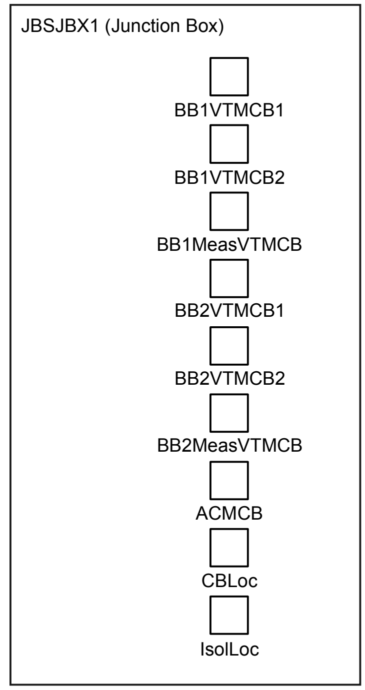

Fig. 4. Custom junction box logical node.

One of the more beneficial aspects of data modeling is that, once modeled, a system easily flows from concept to implementation. A complete model does not easily allow anything to slip through the cracks. It makes testing faster and easier, because the engineer already has a detailed overview to test against, whether it is a small part of the system or some section that comprises all key aspects of the system. It is always much easier to change a model than an implemented system. In other words, data modeling encourages engineers to plan properly.

VI. Substation Automation

In the past, if a protection signal from one device was needed in a distant device or in a device in a different building, wiring had to be installed, especially in the case of on-site modifications. This put limitations on device-to-device signaling and substation-wide automation.

For example, as illustrated in Fig. 5, if a signal was needed on multiple devices, either the sending device would need a contact per the receiving device or the contact itself would need to be multiplied or cascaded in order to be connected to all receiving devices. Either in series or in parallel, each of these solutions presents difficulties.

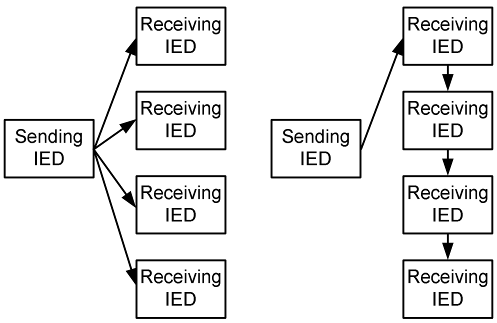

Fig. 5. Hard-wired interdevice signaling.

Devices connected via Ethernet networks allow all devices to be interconnected, sometimes spanning many kilometers. This connectivity provides almost unlimited device-to-device signaling. A single IEC 61850 GOOSE message transmission using multicast addressing allows concurrent reception by numerous devices on the same Ethernet subnetwork, shown in Fig. 6, while meeting the timing requirements for protection applications.

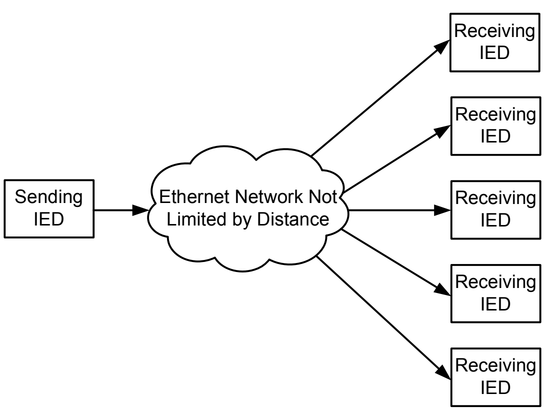

Fig. 6. Multicast messaging.

In addition, the flexibility provided by the standard for peer-to-peer signaling allows for substation-wide automation to provide functions and procedures that can eliminate human error. Automated switching procedures, such as live bus changeover and placing a feeder on transfer, can be implemented, allowing the IEDs to automatically and safely complete complex and dangerous switching procedures every time without error.

VII. System Management

A. Network Monitoring and Management

The Ethernet network is a crucial part of the overall system and needs to be monitored. Fortunately, monitoring and management technology for Ethernet networks has existed for many years. Many different forms of monitoring and management strategies and tools exist, such as SNMP (Simple Network Management Protocol). This allows for a clear, present overview of the system and how it is performing. These tools and technologies lead to simpler and faster maintenance, because the system can be monitored and tested while live. There is no need to shut down the system to perform tests. Furthermore, integration of the SNMP functionality into the gateways and HMIs (human-machine interfaces) allows network monitoring to be presented to control centers via SCADA.

B. Configuration Management

Configuration management always plays a major role in the successful implementation of any system. Because IEC 61850 stores its configuration in an open format (ICD, CID [configured IED description], and SCD [system configuration description] files use industry standard XML [Extensible Markup Language]), it is easy to integrate the configuration into existing configuration management systems already being used by engineers. Configuration information is thus readily and easily obtained. Many tools exist to take XML configuration files and perform configuration revision (also built into IEC 61850), alterations, storage, distribution, and many more functions used by engineers.

C. Documentation

Detailed and substantial documentation can easily be generated by combining all of the tools mentioned in Section VII, Subsection B. IEC 61850 can even store some documenting details inside the configurations itself. All of this documentation helps engineers understand, troubleshoot, and train on new systems.

VIII. Simulation and Testing

GOOSE messaging can make testing and simulation much easier than before. GOOSE tools give an engineer the ability to monitor or reproduce any GOOSE message. This can be done using a laptop (as shown in Fig. 7), turning it into a powerful simulation and monitoring tool.

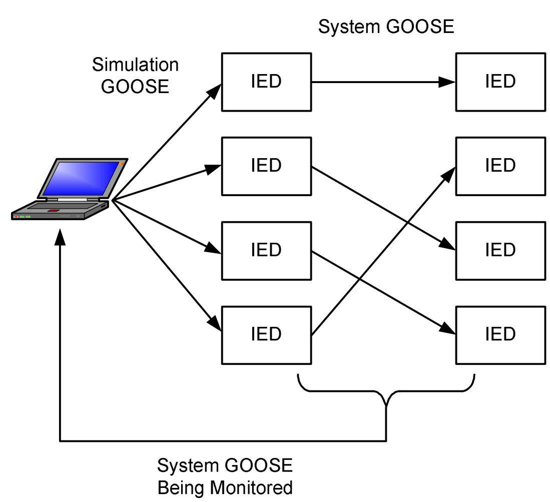

Fig. 7. Laptop sending simulation GOOSE messages and monitoring system GOOSE messages.

A laptop can be used to set up complicated automated testing by sending GOOSE messages to the system and monitoring the results via GOOSE messages or MMS (Manufacturing Message Specification) reports, depending on the particular system configuration. This helps tremendously with testing and engineering time, because there are no temporary wired signals to be set up and wired into the system. The other important advantage of virtual testing is that large substation-wide testing can be done, such as breaker fail trip, during a substation-wide automated feeder-on-transfer sequence.

IX. Implications

So what do all of these new technologies and concepts mean? As mentioned before, Ethernet networks have been around for years and used all over the world in many different forms because of their flexibility, reliability, and speed. Full-time monitoring of all communication is possible. This, coupled with GOOSE messaging, allows engineers to know when their wire is broken in advance rather than having to test for it. This monitoring is available for the relays to use; thus different steps can be put in place to allow for extra flexibility and safety.

IEC 61850 can provide time savings for project and system design, implementation, test, and documentation, all of which impact the bottom line—project cost. Flexible solutions allow for fast scalability of substations, fast integration with existing equipment, and easier adaptation for future applications. Therefore, we can do more with what we have rather than continuously purchasing more equipment.

One of the main implications of an IEC 61850 substation is information distribution. In the past, any signal that was needed by another bay or substation had to be hard-wired if it was to be protection-level secure. By using GOOSE messaging, this same connectivity is achieved via the Ethernet network. The additional benefit is that the same data are available for any relay on the same subnetwork to use without additional wiring. Deciding which applications need information is the only requirement. This capability brings with it an ease of adapting to change or providing solutions to problems that were unforeseen.

X. Concerns and Resolutions

Numerous concerns related to the IEC 61850 standard have been raised since the standard was published. Most of these concerns are either caused by false assumptions or a misunderstanding of the underlying technologies. Some of the concerns that were addressed during this project include:

- *Tripping times and general signaling between devices are significantly faster with hard wires than with GOOSE messaging.*
  This concern proved to be false, and repeated tests highlighted a consistently faster or at least equivalent signaling time achievable using GOOSE messaging. The GOOSE protocol message definition is such that the GOOSE application layer is transported directly using the Ethernet data link layer, thereby eliminating the need to process additional communications layers within the IED firmware.
- *Network congestion can cause delays in the delivery of GOOSE messages.*
  This concern is valid only when the features provided by Ethernet technologies are not fully leveraged. Ethernet provides a prioritization scheme and a traffic isolation mechanism by means of VLANs (as defined by IEEE 802.1Q). Hence, a correctly designed Ethernet network can effectively eliminate this perceived risk.
- *Many GOOSE messages on the network can overload the IED CPU (central processing unit) with unnecessary processing of GOOSE messages.*
  The IED filters GOOSE messages based on the destination multicast address, and further filtering is possible by the network switches using VLAN tags embedded within the Ethernet frame of the GOOSE message. Unique destination multicast addresses and carefully designed VLAN filtering are therefore essential on large networks.
- *The entire system fails when a network failure occurs.*
  A redundant network design is very effective in addressing this failure concern. Many utilities apply a redundancy philosophy that can also be extended to the substation-switched Ethernet network. This project made use of redundant backbone switches with redundant connections from the bay switches to the backbone switches. The bus zone IEDs also used the redundant connections in two separate network switches. Should the highly unlikely catastrophic condition arise where the substation network is rendered unavailable, the protection will still operate, because all instrument transformer inputs and trip coil outputs are wired directly to the protection IEDs.

- *What if the GOOSE message is not sent or is corrupted in transit?*
  GOOSE messages are constantly sent by transmitting IEDs and may contain the value of several signals, as defined by a data set. Any signal change within a data set speeds up transmission repetition of the GOOSE messages so that the risk of reception failure (because of a corrupt or lost message) is reduced. The reception of GOOSE messages is constantly monitored by associated IEDs, and failure of such reception of any GOOSE message must be suitably alarmed. In addition, a contingency plan must be made within the IED protection and automation logic to change behavior from communications-aided logic to noncommunications-aided logic when GOOSE reception fails.
- *How can I test the virtual wiring of GOOSE messages?*
  Physical I/O wiring was replaced with virtual wiring of GOOSE messages communicated between IEDs, but the resulting testable condition remains the same. Is the trip transmitted between IED 1 and IED 2? Does the interlock indicate and function as designed? These are all testable conditions via logic or actual physical operations in an IED. IEDs, test equipment, and software are capable of easily monitoring GOOSE messages, the resulting logic, or the indications resulting from the receipt of GOOSE data. The engineer tool set now includes more network monitoring equipment and software.

XI. Training

The issue of staff expertise with the new technology is often raised as an entrance barrier to IEC 61850 and networking technologies. Many utilities see the technology learning curve as being too high, thus making successful implementation risky.

There is definitely a different skill set required when implementing Ethernet networks and an IEC 61850-based solution. Switched Ethernet networking, data modeling, and new troubleshooting techniques present additional layers of complexity and introduce an additional learning curve to staff not familiar with these technologies.

However, dealing with technological innovations and the evolution of solutions is not new to the energy industry. Utility staff have had to familiarize themselves in the past with the migration from electromechanical to solid state and then to numerical relays. This includes understanding SCADA protocols and related communications issues, the increasing intelligence of multifunctional devices, and the natural blurring of previously clear lines of responsibility. Continuous professional development is a key success factor in any industry.

XII. Conclusion

Implementing a comprehensively engineered IEC 61850 solution is not a trivial task. Training is a primary issue that must be addressed, because the change in thinking is more revolutionary than evolutionary. Ethernet networks and multifunctional devices blur the distinctions between protection, control, measurements, metering, dc systems, transformer monitoring, disturbance recording, system testing, and most other aspects of the substation environment.

The long-term success of modern substation projects hinges on planning for current technologies and designing for the future. Building substation networks that scale and support devices, such as synchrophasors, merging units and other process bus components, and IP telephony, should be a core consideration of modern system designs. Further success factors include the application of IEC 61850 modeling techniques on a system-wide basis. All equipment vendors should provide flexible devices without compromising functionality.

Finally, the engineering time associated with modern projects should not be underestimated. The potential benefits of IEC 61850 technology in terms of reduced engineering and commissioning times can only be truly experienced once the correct levels of familiarity and experience with the standard and supporting technologies have been gained. However, once this has been achieved, benefits can be realized throughout all aspects of a project. In summary, such projects may not be simple, but they are achievable and certainly worthwhile.

XIII. References

[1] IEEE Standards for Local and Metropolitan Area Networks—Virtual Bridged Local Area Networks, IEEE Standard 802.1Q-2005.

[2] UCA2.0 Standard Document, Part 1, Electric Power Research Institute (EPRI), Palo Alto, CA. Available: http://my.epri.com.

XIV. Biographies

Dorran D. Bekker received his BSCE in 2007. After working at e-LEK Engineering as an application engineer for a year, he joined Consolidated Power Projects as a SCADA/automation engineer.

Peter Diamandis received his BSEE from the University of the Witwatersrand in Johannesburg, South Africa, in 1991. Currently, he is an independent consultant, formerly of Eskom, working for Trans-Africa Projects.

Tim Tibbals received his BS in electronics engineering from Gonzaga University in 1989. After graduation, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as an application engineer, performing system studies and relay testing. He has also worked as a development engineer and as part of the development team for many of the communications features and functions of SEL products. He subsequently worked as an application engineer for protection, integration, and automation products, assisting customers through product training, seminars, and phone support. He served as the automation services supervisor in the SEL systems and services division for several years before returning to the research and development division as a product engineer for automation and communications engineering products. He is currently a senior automation system engineer in the sales and customer service division.

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ABB review

The corporate technical journal

Special Report IEC 61850

Case studies

IEC 61850 at work

The goal of IEC 61850 is to facilitate interoperability of substation devices while simplifying engineering and maintenance. The examples described in this section present some of the standard's successes.

Retrofitting for the future

It is inevitable that as substations age, their parts will need to be replaced. The 380/220 kV air-insulated substation (AIS) located in the Alps in Sils, Switzerland was one such case. Its secondary infrastructure – ie, protection, control and metering – and parts of its primary equipment at the 380 kV level – ie, switchgear, power transformers and circuit breakers – had reached the end of their life cycles. The operator KHR (Kraftwerke Hinterrhein) thus turned to ABB for an economically feasible, standardized and forward-looking solution for one of the most important nodes of the Swiss transmission network. The answer: a substation automation retrofit using IEC 61850 technology.

Implementing the IEC 61850 standard enables availability of all necessary information – which supports extensions, replacements or upgrades of all or part of the substation automation system – and enables integration of products from different suppliers. It also ensures data consistency within the complete system and defines the

engineering processes, helping to keep data and data flow consistent for the whole substation. In this project, the horizontal bay-to-bay communication model GOOSE was used to considerably reduce the copper wiring between the bays. All information for interlocking between bays is now exchanged between the ABB Relion® 670 series IEDs on the IEC 61850 bus via GOOSE messages.

Although testing was a major part of the retrofit, the greater challenge was to avoid a shutdown during commissioning. Outage time of individual feeders had to be minimized and coordinated with the grid operator months in advance. The complete system was manufactured and delivered to the site where, except for the connection to the AIS interfaces, it was installed. Once the dedicated bay was commissioned, the new IEDs were connected to the primary equipment. The substation was configured to enable concurrent operation of the existing and new equipment during this transition phase.

After successfully retrofitting the 380 kV substation, the 220 kV part was integrated into the new control system. The existing IEDs were equipped with a new IEC 61850 communication interface, allowing communication with the new MicroSCADA control system and ensuring that both the 380 kV and 220 kV switchyards could be operated and monitored from the central control system. A hot standby system was put in place to provide backup should a failure occur.

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Challenges build partnerships

In 2006, ABB supplied a pioneering substation-automation project to the Brazilian government power transmission utility, Eletrosul. This utility is responsible for electrical transmission in the south of Brazil. The projects delivered were based on the IEC 61850 standard, with applications using messages between IEDs, GOOSE [1], redundant control units and featuring interoperability between systems from different vendors.

The first project consisted of three substations, “Atlântida 2”, “Gravataí 3” and “Osório 2”. These are 230 kV and 138 kV transmission substations. “Atlântida 2” uses 60 IEDs (14 with redundancy and 32 without) for protection, acquisition and control. These are mapped to 13,683 dynamic objects from a total of 28,786 objects available in the IED. About 3,300 of these were distributed to centers of higher hierarchy.

Redundant control

Redundant control was one of the special challenges of this project. This philosophy, used by Eletrosul for many years, uses two control terminals (for ABB’s projects this meant two REC670s). These have exactly the same functionality in terms of control logic, interlocking and automatisms for controlling a certain number of bays. Both units are active, but just one is monitored by the supervisory system. In case of unavailability of a terminal, the SCADA system switches to the other IED.

Based on this philosophy, Eletrosul clearly defines how a system should react, for example, in contingency situations. Briefly, the terminal managed by the supervisory system is monitored and executes remote commands. In case of interlocks, the two redundant terminals send signals to external bays. This affects the philosophy of treatment of these redundant signals by the receiving logic.

In this project, GOOSE was widely used both for monitoring the active terminal and for interlocks and automatic logics. This permitted a considerable saving of cables, as twice as many signals are generated and received in this philosophy versus a philosophy of simple control.

Interoperability

Eletrosul uses SAGE (an open-source energy-management system) as SCADA software. SAGE was developed by CEPEL, a Brazilian government research center. The MMS protocol defined in IEC 61850 was implemented in SAGE in 2006. The ABB project was thus a test of the standard’s interoperability. This test was passed successfully.

Results

Another request from Eletrosul was to minimize the number of hours required for the preparation of texts in the system database. For this, it encouraged the use of generic signs (GGIOs) to be minimized. Even so, in the control terminals that use many monitoring aspects not defined in the standard (mostly complex interlocks and automatic logic) the use of GGIOs is still very high. It is hoped that as the IEC 61850 standard evolves, more standard signs will be provided. In IED protection, it was found that the use of GGIOs was reduced because of the standard, and because ABB IEDs use standards for all protection functions.

The three substation projects fostered a spirit of partnership between Eletrosul and ABB, resulting in new projects being carried out together delivering the benefits of IEC 61850.

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Footnote
1 GOOSE: Generic Object Oriented Substation Event

Portuguese transmission substations

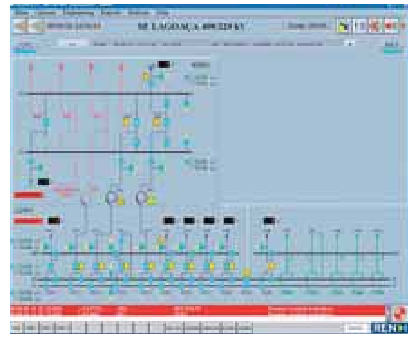
REN is the main Portuguese utility for electrical energy transmission. ABB supplied the utility's first IEC 61850 system, installing it at the 400/220 kV Lagoaça substation. The installation is responsible for some of the most important interconnection points with the Spanish grid on the 400 kV voltage level.

Of all the benefits of migrating substation automation systems to the new standard, the customer was especially focused on one in particular: standardizing the system architecture, ie, using the same network topology and overall arrangement independently of the supplier.

ABB brought much experience into this project that it had built up in previous deliveries to the customer. The previous platform may have been different, but marked an excellent starting point and permitted ABB to quickly identify the required solution.

The Lagoaça substation uses a system based on a decentralized Ethernet ring. The main products from ABB are:
– MicroSCADA Pro for local HMI, and automated sequences
– COM500i as Gateway, for communication with network control center
– IED's 670 for control and protection units
– REB 500 Systems for busbar protection

Third party products used were:
– Switches and routers from RUGGEDCOM
– Meinberg GPS servers for SNTP time synchronization
– Computers with no-moving parts running Windows XP Embedded platform
– KVM switches and fallback switches from Black-Box
– Industrial computers from Advantech, for remote access and engineering stations.
– RTU servers and local-event printing system from SYCOMP Germany (REN mandatory).



– Remote access via RX1000 routers from RUGGEDCOM

The adoption of IEC 61850 was clearly beneficial. It allows both customers and vendors to retain extensive functional freedom in their definitions and philosophies. It also assures independence from single suppliers as well as cost savings in both engineering and maintenance.

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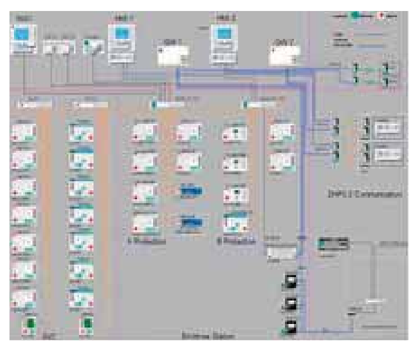
Wuskwatim transmission system

In order to strengthen the existing 230kV network, Manitoba Hydro main utility in Manitoba contracted with ABB for the design, engineering, supply and commissioning of Wuskwatim Transmission System Complex, comprising three new stations and expansion of four existing ones. The new stations featured distributed control, bay protection and a bay controller concept. The entire control and communication process used the IEC 61850 standard.

Protection devices were sourced from three different manufacturers. In fact the use of different suppliers was a requirement of the protection redundancy concept. Prior to IEC 61850 such integration would have been challenging if not impossible, especially for large systems due to inconsistency of data and engineering.

The IEC 61850 engineering approach and data structure using SCL language significantly facilitated the engineering of interfaces between different units. The descriptive power of the SCL language enabled part of the integration to occur without having access to all devices or bay level information.

Because design, manufacturing and testing of the two SA systems was completed in close colaboration between ABB and Manitoba Hydro, an attuned and future-proof system was delivered. The IEC 61850 standard made it possible to combine and integrate ABB, Siemens and Areva Protection IEDs within the SA and thus to fulfill safety requirements. The use of GOOSE



messages for bay-to-bay interlocking and intertrip reduced the amount of copper wiring required. The complete communication of the substations are now described and documented in SCD-files, which is of advantage for the future maintenance and extension of the stations that are now in service.

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The Star of Laufenburg shines

The 380 kV Laufenburg substation – one of the largest and most important in Europe – boosts several world premieres. Staying abreast of the development and extension of IEC 61850, its owners, the Swiss utility EGL AG, were the first to equip a high-voltage substation with an IEC 61850 automation system, doing so shortly after the release of the standard in 2004, and even opting for a multi-vendor solution. Two years on, the utility issued the very first open tender based on a SCD (substation configuration description) file, and most recently implemented the 9-2 process bus.

When built in 1967 at the inception of the European grid, the Laufenburg substation, with its key position in terms of interconnection and metering, was dubbed the "Star of Laufenburg". It was extended and upgraded from 1979 to 1981. From 2004 to 2009, EGL undertook the following refurbishment work:

– Step 1: retrofit of primary and secondary equipment
– Step 2: replacement of old station HMI
– Step 3: pilot project for IEC 61850-9-2

Step 1: Bay retrofit

Both primary and secondary equipment of the 17 feeders was replaced in a bay-by-bay manner, warranting an almost interruption-free retrofit. The migration was supported by a compact hybrid solution that connects the new gas-insulated switchgear (GIS) modules to the existing air-insulated switchgear (AIS) busbar using silicon bushings. The GIS modules comprising circuit breaker, disconnector, earthing switch and instrument transformers were pre-tested to enable short installation times. They offer maximum operational safety and high immunity to environmental conditions. They also require less space and simplify maintenance as replacement of a complete pole can be performed in less than 24 hours.

The future-proof secondary retrofit concept addressed the varying lifecycles of bay and station-level equipment. With the latter equipment being retained, ABB integrated its new IEC 61850 compliant bay control and protection IEDs (Intelligent Electronic Devices) to the third-party control system using a gateway converting IEC 61850 to IEC 60870-5-101. ABB also successfully integrated a third-party main protection device with an IEC 61850 interface. Consistency of bay data during the stepwise upgrade was supported by pre-configuring and pre-testing using an SCL-based tool.

Step 2: Station-level replacement

In 2007, ABB won an open tender for the replacement of the old station HMI (human-machine-interface). ABB installed a new IEC 61850 HMI fully re-using the engineering data from the SCD file generated for the bay retrofit.

Step 3: Introduction of process bus

The pilot installation contains a selection of products and systems ready for the IEC 61850 process bus. On the primary side, there is a combined and fully redundant CP-3 current and voltage sensor with merging units for protection and metering. On the secondary side, a REL670 line distance protection IED and a REB500 busbar protection system with three bay units are in operation. Metering is performed by an L+G energy meter. For supervision and easy access, a SAS using IEC 61850 station bus completes the pilot installation.

The pilot is running in parallel to the conventional control and protection system and enables collection of long-term real-life experience as well as comparison of behavior. Since its commissioning in 2009, the system has been in continuous operation.

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