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Data and Information Structure to Cope with Sharing and Allocation of PAC Functions

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SUMMARY

Free allocation of functions demands that the inputs of each function receive strategic treatment to lead to an effective functional optimization. When gathering PAC functions by categories, one notes that many of them share the same inputs, meaning that similar inputs shall be produced alike and not more than once. Bearing in mind that the inputs are data or information which can be shared by any function at any level of the operational hierarchy, it is worthwhile to have a Data and Information Structure (DIS) to cope with the challenges of providing an effective functional optimization. Brazilian SC B5 has just created a WG to deal with DIS.

The paper presents DIS concepts under the viewpoints of transforming data into information at the lowest possible level within the operational hierarchy. The lowest possible level arises spontaneously from the analysis of a reliable process for gathering and validating data, transforming valid data and producing valid information with high added value. As an inherent benefit, communication media alleviation stems from DIS implementation. In fact, seamless communication depends on DIS to cope with latency, availability and reliability requirements of each PAC function. The paper focuses on:

- A functional overview to explore the requirements of PAC functions;
- An analysis of measurement uniqueness to assure the coherence of all calculated quantities;
- A perspective for the application of new macro functions such as Synchrophasor Measurement and Asset Management Systems;
- A proposal of a strategic plan for DIS implementation both in cooperative or competitive environments.

KEYWORDS

Protection, Automation and Control (PAC). Data and Information Structure (DIS). Sharing and Allocation PAC Functions. IEC 61850 Standard. Common Information Model (CIM).

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DIS AND THE OPERATIONAL HIERARCHY

DIS Concepts

A Data and Information Structure (DIS) shall be conceived to fit and support all PAC functions and communication media required to the operation of a power system [1]. With the advent of IEC 61850 Standard and Common Information Model (CIM), DIS shall reinforce the systematic approach that allows the stations' secondary systems to interact with each other and, most of all, to interact with the Supervision and Control Systems (SCS=SCADA+EMS) of the control centers. DIS shall ease functional free allocation implementation along all levels of the operational hierarchy. Figure 1 shows the hierarchy and the relative requirements for data and information at each level:

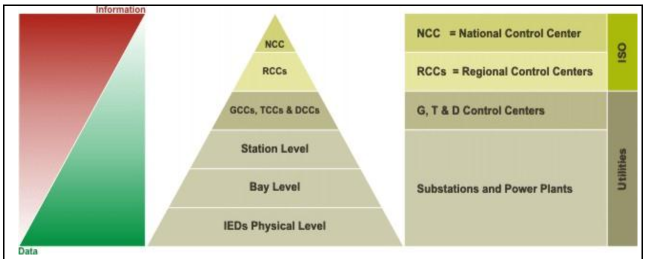

Figure 1 – Data and information relative requirements

DIS shall provide inputs to all kinds of algorithms and software required for dealing with the power system conditions, coping with PAC macro functions as per Fink and Carlsen Diagram. DIS shall fulfill the following requirements:

- Best benefit over cost ratio – transforming data into information **only once** at the lowest possible hierarchical level at minimum cost;
- Consistency – using data or information sets only after they have been validated and then have the same level of quality – the required quality level for the specific application;
- Coherence – applying the same data or information for all functions, for operator display and corporate broadcasting;
- Redundancy – using the inherent data abundance for validation and according to a quality level ranking (the best quality available data shall be used to create information; in the absence of the first ranked datum, the second one shall be considered);
- Reliability – extending the protection concepts of dependability and security to all functions;
- Cyber security – accomplishing the basic characteristics specified for the Global Energy Management System of regional and national control centers [2];
- Sharing – applying the same data or information (D+I) to single-owner functions (for example, component protection) and to multi-owner functions (for example, global and regional System Integrity Protection Schemes – SIPS);
- Selecting – heading to each function at each level exclusively the D+I needed to fulfill its input requirements, thus allowing D&I logging according to the attributions of each hierarchical level.

Data and Information (D&I) Issues

<u>Steady State and Dynamic D&I</u>

DIS can be split in steady state and dynamic D&I categories. Synchrophasor Measurement Systems D&I belong to both categories, as they are very accurate and time synchronized with great precision, thus being useful for various applications. Non-Conventional Instrument Transformers (NCIT) are expected to become common and to be found in most new stations in the near future, allowing that more D&I may be used for both steady state and dynamic functions.

<u>Control and Automation D&I</u>

Control functions provide circuit breaker and switch commands and the associated interlock logic.
Automation functions allow many tasks without the operator intervention, e.g., functions like on load tap changer, protection transfer, preparation and execution of station restoration. Some functions can be classified also as automation or control functions. Automation functions may be contained by black boxes to check the status data and to produce output information, e.g., the input data for automatic

reclosing (AR) are protection operation, AR able to operate, AR activated, AR selection, AR transfer and AR in test. If all are ok, the result will be “requested reclose”.

For breaker and switches commands, besides open and closed contacts that represent the primary equipment status, there may also be analog measures like transmission line voltage to improve the reliability of the command information. Table 1 exemplifies information generated by automation and control functions:

Table 1 – Example

Input	Functions	Information
Breaker and isolators open and close contacts status	Breaker closing command	Command conditions satisfied
Block relay status		Close command effected
Interlock condition satisfied		
Breaker and isolators open and close contacts status	Interlock	Interlock condition satisfied
Protection operation	Auto reclosing	Reclosing conditions satisfied
Reclosing activated		
Recloser able to reconnect		
Reclosing Selection		
Transfer of reclosing		
Reclosing in test		

The logic function can be generated by an Intelligent Electronic Device (IED) at the bay level or by the Information Creation Box (ICB) [1].

The level at which information is created depends on Grid Code, system architecture and SAS technology. Figure 2 shows the simplified diagram of the information created for a reclosing action when the input conditions are satisfied:

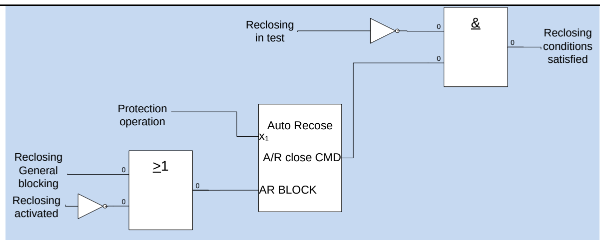

Figure 2 – Auto reclosing simplified diagram

<u>Fault and Disturbance D&I</u>

Fault and disturbance monitoring may gather digital fault recording (DFR), power quality (PQ) measurements, phasor measurement units (PMU), sequence of events recorders (SER) and SCS [3]. These systems find their primary use in specific applications, such as real-time system control or PQ studies, but they also produce information suitable for post-event fault and disturbance analysis.

Automatic analysis demands large amounts of data which are produced with distinct formats, sampling times, time spans and nomenclature. Proper data aggregation to allow for correct interpretation of the phenomena is a time consuming task, but it can be accomplished by software, enabling automated analysis functions to be performed. Automated analysis needs information from both dynamic and static data.

The functional requirements for future solutions in automated analysis are [3]:

- Intra-station analysis – detection and classification of disturbances, protection performance, performance of circuit breakers, single-ended fault location and fault clearing performance;
- Inter-station analysis – double-ended fault location, performance of communication and tele-protection, breaker opening/closing synchronization, double-ended fault clearing sequences;
- Utility-wide focus – topology verification and advanced state estimation, compensation for IEDs sparse allocation, analysis of system-wide switching sequences, cross-country faults and related fault clearing sequences, system-wide disturbances and related protection and clearing sequences, disturbance statistics and protection performance;
- Inter-utility focus – data from multiple utilities, impacts of faults in one utility on the neighboring utilities and propagation of system-wide disturbances.

When considering these scopes it becomes clear that a D&I structure is vital for integrating all this data and fulfilling all these requirements. Such need is corroborated by the fact that as SAS and communication technology evolves, PAC functions producing data for automated fault analysis shall be allocated to devices shared by other functions, using local and remote data. It is also vital that the results from automated analysis shall be used by areas other than PAC, as depicted by Figure 3.

SIPS D&I

SIPS aim to break chains of events that lead to blackouts, thus making a comprehensive use of a hierarchical DIS [4]. The higher is the SIPS level the higher is the number of involved utilities. Regional and Global SIPS inherently involve the ISO as a D&I provider for steady state conditions.

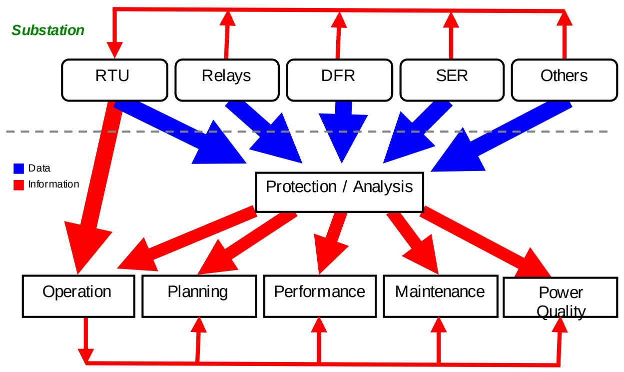

Figure 3 – Use of D&I by Different Teams

At first, data shall not reach SIPS. Only high added value info is adequate for SIPS application.
Steady state information is used for SIPS configuration, parameterization, adaptation, arming and disarming. They shall be created by SAS and Synchrophasor Measurement System (SMS), Control IEDs and EMS observing the measurement uniqueness concept. Sharing DIS among the involved utilities allows creating similar info by a single criterion, as well as avoiding duplicate tasks. Switch status shall be validated within the process of creating bay status information. When needed, switch secondary contact discrepancy cases shall be treated to privilege SIPS security or dependability.

Info for triggering and vetoing shall be created by SAS and SMS Protection IEDs. Latencies shall be minimized and time synchronization shall be used where required. A comprehensive disturbance register and analysis system shall work along with SIPS. DRAS shall supervise the whole SIPS, including the respective DIS (from raw data to the highest added value information). SIPS and its DIS shall be conceived embedded in WAMPACS, whenever they are available. DIS for SIPS shall benefit from the IEC 61850 capabilities. Asset Management allows SIPS to accurately preserve asset life cycle, preserving a given asset and considering the life cycle of the assets to be tripped.

Sequence of Events (SOE) D&I

IEDs provide a plethora of events that shall be logged and used according to each level attributions. SOE logs are used by operational, maintenance and *post mortem* analysis teams, but with different scopes and time requirements. The information concept is in used for SOE application in Brazil, regarding the operators at each hierarchical level. Station operators shall access all events originated by SAS – devices and systems within the station –, because they shall activate maintenance teams. At the GT&D control center (GT&DCC) level, the operators shall have access information on component protection and local SIPS events (data) to understand SIPS operation within the utility. At the regional control center level the operators shall also have access to the information on the component protection and local SIPS and on regional and global SIPS, to understand systemic SIPS operation.

The information on the component protection includes breaker open and close status, main 1 or main 2 protections tripping orders and blocking (ANSI 86) devices. The 86 devices nomenclature informs the kind of failure that will keep a component out of service, thus requiring that maintenance people to intervene. If main 1 or 2 protection trip, the time stamp of the internal function that operates in the first place will be the info time stamp. If more than one internal function operates, the time stamp of the last internal unit to reset will be the time stamp of the reset info. Figure 4 sums this philosophy, exemplifying for a transmission line. Table 2 depicts how SOE is dealt with in the Grid Code:

Revenue Measurement System (RMS) D&I

Brazilian RMS is based on independent CT, PT and IEDs. Such exclusive instrument transformers and exclusive IEDs configuration implies having two sets of direct measured quantities (V, I and f): one for RMS and another for all other steady state functions.

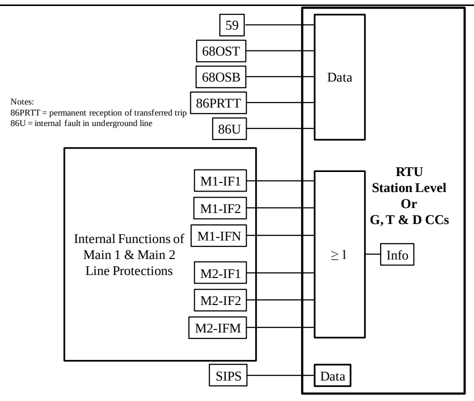

Figure 4 – E.G.: Transmission Line SOE

Table 2 – SOE application in Brazil

Teams	Levels	Attributions	Scope	Time Frame
Operators	Station (local or remote)	- Event acknowledgement - Station maneuvers - Maintenance activation	- Station SOE data	ASAP
	G, T & D Control Centers	- Event acknowledgement - Local SIPS maneuvers - Local SIPS maintenance activation	- Information on component protection - Local SIPS data	
	Regional Control Centers	- Event acknowledgement - All SIPS maneuvers - All SIPS maintenance activation	- Information on component protection - All SIPS data	
	National Control Center	- None	-	-
Maintenance	All	- Off line	- Full SOE data	By request
Post Mortem Analysis	Office	- Off line	- Full SOE data	By request

Lack of measurement uniqueness poses problems when relevant events observed by RMS are not mirrored by the historian in the control centers, as it is the case with violations of voltage limits. RMS may show that there was a voltage limit violation in a given busbar which was measured by SAS as a smaller value. For the operators, voltage remained within its limits, as shown by SAS, but electric energy trading personnel have indication of limit violation, thus having to get to a common point with operational personnel and then warning the regulatory agency about the exceptional condition [1].

There are great expectations on the deliverables of CIGRÉ WG B5.41 – Investigation of Possibilities to Improve Metering Systems for Billing Purposes in Stations, so RMS and SAS shall be integrated in terms of measurement uniqueness.

Adaption D&I

External information (EI) shall be provided to exchange setting groups, so adapting protection to the power system prevailing state. EI may stem from the bay level, from other station, from GT&DCCs and from RCCs, so info shall flow up, down and horizontally along the hierarchy. Extra attention shall be paid when creating and feeding external information into protection IEDs, because there is a risk of introducing new failure modes, thus demanding the implementation of recovery mechanisms.

EI shall be granted with very high added value. EI may have many tuning purposes: speed, sensitivity, topology, security, dependability, etc. It shall be created and carefully validated, regardless of the involved hierarchical levels. EI shall be created bearing in mind some issues such as: latencies, steady state and dynamic aspects. Dynamic aspects are tricky: the steady state adaption concept may be adversely affected by the dynamics imposed by a slow disturbance, for instance. Redundancy and voting/vetoing techniques may be used to create and validate EI, assuring security and dependabilily.

There shall be supervision and logging along the EI creation path. If some operational condition does not allow the EI complete creation, e.g., a communication failure, the adaption process must assure that the valid setting group is the one that best suites the security and dependability.

Data-Base D&I

Besides communication, a DIS needs interoperability and integration. To exchange static data among the different DIS levels and approaches, the standards shall be improved to consider the basic issues of each DIS level. Today, static data are freely managed in different levels by distinct staffs. Thus, some work is redone and there may be problems with the static data quality that are manually updated in the DIS upper levels. In some cases the lower DIS levels cannot supply all static data needed by DIS upper levels.

In SCADA application the static data are: system topology, communication and telemetering components and their topology. Nowadays the ISO staff has to link together all the different types of SCADA data. Almost all data needed for SCADA and their correlation can be obtained at the station level. On the other hand, most of NAA data are provided by SCADA. But data like transmission line parameters shall stem from other sources and entered manually in the EMS or SCS software. In order to avoid duplicate work to manage static data, there are new ways to collect and update them for EMS. The idea is that utilities (the data owners) shall share the work with ISO. The utility sends new data releases to update ISOs database so ISO staff may validate data. Utility can use its data from ISO database. Thus, ISO and utilities shall use an automatic procedure supported by standards.

TRANSFORMING DATA INTO INFORMATION

Station Level – Boolean Algebra Versus Local State Estimator

Control center state estimation seeks to produce good information from raw station data. State Estimators (SEs) provide continuous sequences of the best estimates of the power system state, as so defined through the complex bus voltages, from a redundant set of analog quantities and topology info, all periodically obtained through SCADA, along with power system component parameters.

SE is a core application in EMS, for contingency analysis and emergency control, among other functions. Thus, this function has been the target for intense academic effort to overcome difficulties in identifying errors induced by bad analog data and topology errors. This effort has resulted in different approaches, all relying on the same general principle: bad data can be only identified by using redundant information. In other words, redundancy is a requirement for identifying bad data.

Conventional SEs rely on the assumption of balanced operating conditions, so limiting the model to a single-phase equivalent. Consequently, only one analog measurement per voltage level in each station is selected as SE input. Any error in this measurement or in the topology information will contribute to impair the SE performance. Consequently, better info on the positive sequence voltage in a bus and correct station topology info is a permanent objective. This exposes an opportunity for improving the quality of station variables by using the huge amount of data provided by modern SAS, which offer an increase in redundancy. The proper availability and location of instrument transformers lead to the availability of redundant data. All sources of a given quantity shall be handled according to their intrinsic accuracies to provide a better and more reliable estimate of the measurement info).

Today's ample station data availability, easy data handling by IEC 61850 based SAS architectures, the modest amount of data in a single station, as compared with data volume in a control center SE (even considering redundancies) and the potential benefits in the performance of a key function (SE) explain the interest illustrated above and make worthwhile further work on Local SE concept.

Station Level – DIS Analysis under IEC 61850 Standard Viewpoint

Data models provide well known and shared semantics for information. IEC 61850 comes up as a great solution for the exchange of information to accomplish DIS standardization. At the station level, IEC 61.850 based data acquisition at the IEDs is basically performed by:

- Physical activation of the binary inputs;
- Reception of GOOSE messages subscribed from publisher devices;
- Reception of sampled values and status subscribed from merging units or analog signals from instruments transformers.

Station level processing may include a local SCADA, depending on the architecture. Manufacturing Message Specification (MMS) protocol based information is available to flow upward along the hierarchy, for SCADA and EMS functionalities. Likewise, it may flow downward, being typically addressed for commands. The IED Model Implementation Conformance Statement document presents the data objects that help organizing DIS.

Data Model

IEC 61850 allows the full implementation of the Model Based Automation (MBA) concepts, as shown on Figure 5 below. In this architecture, an automation solution is divided in three layers:

- Physical Layer – at the process level, where automation signals are collected or injected on the primary equipment;
- Model Layer – where standard software blocks mirror the behavior of all devices from the Physical Layer, while serving as a gateway to and from upper layers;
- Application Layer – where data standard blocks and software implement the PAC functions.

This MBA architecture allows the abstraction of the Application Layer from the process physical aspects, offering advantages over hardware-oriented SAS, allowing location-free and multi-supplier interoperable solutions. IEC 61850 supports the implementation of MBA architecture for SAS by using standardized blocks of data and software classes known as Logical Nodes (LNs). At the Model Layer, specific LNs are available to model almost all kinds of power systems equipment, like circuit breakers (XCBR), current transformers (TCTR), power transformers (YPTR) etc. The use of these modules allows building a complete model of the primary system, so PAC functions can be deployed using real-time data conveyed by the models. Figure 6 shows the models used to convey info to and from the Physical Layer, while receiving and transmitting data to Application Layer (AL).

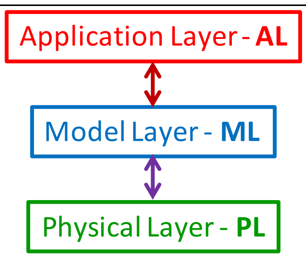

Figure 5 – Model Based Automation Architecture

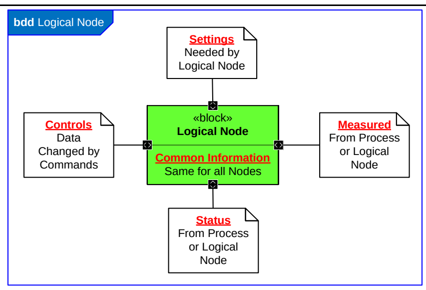

Figure 6 – Logical Node Structured Data

Concerning data, a LN can be seen as a software class, with structured data for settings, controls, measured and status information about a specific modeled behavior, as shown in Figure 7 as a UML package diagram for a Logical Node.

Settings and control data allow commands and behavior to be defined from UAL to select a desired behavior from the LN or its modeled process. Measured and status data allow monitored data to be collected and exchanged among LNs on the same layer or to and from upper layers. LNs are used at the Application Layer to build PAC functions. All major functions found on station and power system automation can be built by LNs, like differential protection (PDIF), Human Machine Interface (HMI), etc. An input-output (I/O) LN view and its connection to a process and other LN can be depicted as a package of four building blocks, as shown in Figure 7. These blocks unveil the possible roles a LN can play in a SAS, in conveying I/O data among other LN, while serving as a communication channel to the process and other automation layers for settings, controls, measured and status data [1].

Programmable logics and algebraic operators are available at the IEDs, also at SCADA servers, to create signal grouping and manage the corresponding info time stamps. The IEC 61850 data modeling helps to match information, although the standard is still focusing on station local applications, while other protocols are more popular in communication to control centers.

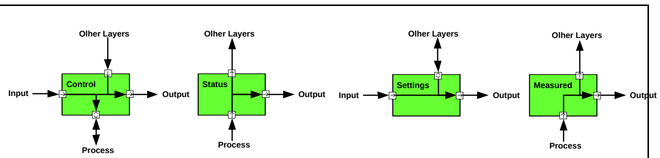

Figure 7 – Logical Node Input-Output Functions

Information Check

At higher levels, the electrical process is physically distant and information is the main input, its quality shall be checked. Other ways may be applied to achieve more reliable and higher added value info, e.g., developing an on-line monitoring specific application, designed for automatic detection of wrong status indications in SOE, out of range measurements, delayed time stamps, etc. IEC 61.850 based systems offer new areas for checking, like Station Configuration Description (SCD) files and data set matching, attributes, GOOSE quality bits, etc. Proprietary and third party tools can also be applied. A virtual tree can be accomplished, showing the logical composition of all info.

Information from legacy systems used to be based only on electrical activation of I/O, mostly status only information. DIS offers additional information, as illustrated in Figure 9 such as quality bits, timestamp etc.

Bit(s)	IEC 61850-7-3		Bit-String	
	Attribute name	Attribute value	Value	Default
0-1	Validity	Good	0 0	0 0
		Invalid	0 1	
		Reserved	1 0	
		Questionable	1 1	
2	Overflow		TRUE	FALSE
3	OutofRange		TRUE	FALSE
4	BadReference		TRUE	FALSE
5	Oscillatory		TRUE	FALSE
6	Failure		TRUE	FALSE
7	OldData		TRUE	FALSE
8	Inconsistent		TRUE	FALSE
9	Inaccurate		TRUE	FALSE
10	Source	Process	0	0
		Substituted	1	
11	Test		TRUE	FALSE
12	OperatorBlocked		TRUE	FALSE

Table 1. IEC 61850 Detail Quality Bits

Figure 9 – Quality Bits

Evolution

The full integration of IEC 61850 in a system-wide hierarchical DIS, covering the full range of automation applications, from bay level at stations, to inter stations, inter-area and wide-area applications like SMS and SIPS needs further development to assure harmonization with existing SCADA standards like CIM and other power system protocols [1].

Common Information Model (CIM) Concepts

IEC TC 57 standard applications and devices inherently can interoperate with other systems, performing integrated functions in a cooperative and distributed way. CIM is a semantic model that provides a common understanding over systems and information exchange. The IEC TC 57 standards provide a general information model and message/file schemes for messages/files exchanged among systems. CIM provides a semantic layer in enterprise architecture. Another CIM standard is the CIM/XML applied to utilities' model exchanges. CIM and IEC 61850 need to fit together to provide interoperability and integration over all levels. This is a key matter to provide the exchange data and information from all DIS levels.

CIM and IEC 61850 have different scopes (bulk power system and secondary system, respectively), what leads to distinct models. Example: CIM deals with power system connectivity and IEC 61850 with station connectivity, as shown on Table 3:

Table 3 – CIM & IEC 61850 Approaches

CIM	IEC 61850
Detailed system wide description	Station design and modeling
Model exchange for high-level systems	Device configuration management
Power flow, state estimation, etc.	Protection and device control
Market operations	SCADA, protection & control data exchange
Planning and system design	

Control Center Level – DIS Analysis under CIM Viewpoint

CIM model applies to DIS at the control center level in order to enable:

- Common data exchange model for application integration;
- Definition of messages for exchange over an Enterprise System Bus (ESB);
- Power system model exchange between neighboring utilities and ISO/RTOs.

The CIM pattern of system integration has evolved to the use of services, making easier the implementation and reuse of services in other integrations. Examples:

- The integration of external systems to an EMS, such as outage scheduling management, allows the information exchange between the two environments and ensures that the functions that use external information may be run seamlessly in EMS. The use of information sent by EMS can enable an improvement of external systems' functions and, sometimes, their enforcement by sending the results to be displayed on the EMS interface;

- Many utilities are adopting CIM for enterprise integration. A relational database using CIM model is maintained as the unique repository of the network model for the whole company. This database shall generate information for operational area clients' EMS/OTS and provide steady state and dynamic cases for clients from planning areas, assuring data uniqueness;
- Very Large Power Grid Operators are working on a general interface that presents all info (EMS, historical data, market info and other info services) using a single interface based on CIM. The advantage of this project is more flexible exchange of such software from one vendor to another while keeping the same interface with users. This project is already going on in at least one ISO.

Soon, most EMS and energy market software will be built by services. This will ease the acquisition of software modules more appropriate to form the new EMS or energy market systems. CIM/XML allows power system models to be exchanged among neighboring utilities and ISO/RTOs. There is a family of standards that allows the exchange of static and dynamic models, schematic layouts and solved states, plus EMS static model updates. Nowadays there is EMS software that deals with CIM/XML. Some ISOs have adopted CIM/XML to exchange power system models among utilities.

APPLICATION OF NEW MACRO FUNCTIONS

Synchrophasor Measurement Systems (SMS)

SMS will generate and transmit a huge amount of synchrophasor data to the upper hierarchical levels. Table 4 shows some possible SMS applications and their data requirements [5].

This table shows that data requirement will strongly depend on the intended application – mainly regarding to the information needs. The ongoing revision of IEEE C37.118, among others changes, will introduce two different PMU classes (M for measuring and P for protection applications). Steady-state estimators need very accurate measuring data, but only a few samples per second.

The same occurs with wide-area monitoring applications, like voltage magnitude and angle or corridor stress conditions, as the respective data shall be processed at the control center level to situational awareness applications to support operator decisions. Some applications like dynamic-state estimators, wide-area or local dynamic monitoring and wide-area protection and control applications need good dynamic representation, with higher sample rates and reliable communications.

According to the IEEE Standard revision, probably each application will need a different PMU class, with specific communication requirements. How this data will be processed and integrated to EMS application is something that shall be addressed in the early stages of SMS specification work. The revision includes synchrophasor data transmission based on IEC 61850 to integrate SMS with other PAC applications.

Asset Management Systems (AMS)

An AMS aims to provide a set of coordinated activities and practices to manage the assets, including their performance optimization, risks and expenses over their life cycles. One key requirement for any AMS is the info management system that manages all D&I related to the assets. The info shall be collected, processed and delivered with the proper quality to support the decisions expected from the AMS, as specified, e.g., by British Standard PAS 55 [6], which is about to be converted to an ISO standard.

Table 4 – PMU Data Requirements

APPLICATION	PMU Location	PMU Data Rate (phasors/s)	PMU Data Latency	PMU Data Reliability
Wide-area dynamic disturbance recording	Inter-tie substations and power plants	10 – 60	Not critical	Critical (Local storage)
Wide-area real time monitoring	All major buses	1 – 10	1 – 5 s	Not critical
Synchronized state estimation	For full observability	1 – 10	1 – 5 s	Not critical
Phase angle Monitoring	Selected buses	1 – 10	1 – 5 s	Not critical
Real-Time System Oscillations Monitoring	Inter-tie Substations	10 – 60	1 – 5 s	Not critical
Wide-area protection and control system	Selected bus and lines	30 – 120	Few cycles (<150ms)	Critical (Redundant channels)

At station level, IEC 61850 is an opportunity to automate the acquisition of all required data for AMS. Physical asset information, including static data like geographic location, asset type, manufacturer, date of commissioning, settings, as well as dynamical data can now be modeled for almost all kinds of equipments and structures, allowing the automatic acquisition and updating by IEDs connected to these assets and real-time transmission to centralized AMS. These features allow the automation of updating asset data, with constant modifications and refurbishing of physical installations, a common difficulty faced by any AMS. In addition, the standardization of data modeling and communication brought by IEC 61850 allows the collection and transmission of asset related data in a non-proprietary and manufacturer independent way within a utility, easing their integration to the corporate AMS.

STRATEGIC PLAN FOR DIS IMPLEMENTATION

The deliverables of the Brazilian SC B5 WG on DIS will be a Technical Brochure (TB) and a Strategic Plan (SP). The SP for DIS implementation will consider major issues such as: responsibilities, costs (installation, maintenance, communication and updating), information as SCADA input, performance (steady state and dynamic), the proper time to start the implementation and how DIS shall be shared among the utilities and the ISO.

Responsibilities and DIS sharing are tricky issues because they depend on how the Brazilian electric energy industry model shall be interpreted. The feasible solution possibly lies somewhere between a DIS condominium and a DIS market. The market idea was provided by Prof. Dr. Alexander S. Berdin from JSC High Voltage Direct Current Power Transmission Research Institute (RU) when [1] was presented in the St. Petersburg (RU) Conference. The WG will achieve real progress only if all industry segments make themselves represented.

CONCLUSION

The proposed Data and Information Structure (DIS) for power system PAC and operation aims to benefit from IEC 61850 and CIM full capabilities and to support the future requirements of a multi-layer hierarchical country-wide power system control structure. DIS will provide the creation of high added value information from the lowest possible level of the operational hierarchy, alleviating communication media and offering better flexibility for implementing PAC macro-functions, mostly with functional free-allocation, thus improving their performances. As technological evolutions do not take place at the same time in a power system, deciding the most appropriate moment to start DIS implementation is effectively a tricky concern.

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