Smart Transmission Grid Applications and Their Supporting Infrastructure

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***Abstract*—In this paper we assume that time synchronized measurements will be ubiquitously available at all high-voltage substations at very high rates. We examine how this information can be utilized more effectively for real-time operation as well as for subsequent decision making. This new information available in real time is different, both in quality and in quantity, than the real-time measurements available today. The promise of new and improved applications to operate the power system more reliably and efficiently has been recognized but is still in conceptual stages. Also, the present system to handle this real-time data has been recognized to be inadequate but even conceptual designs of such infrastructure needed to store and communicate the data are in their infancy. In this paper, we first suggest the requirements for an information infrastructure to handle ubiquitous phasor measurements recognizing that the quantity and rate of data would make it impossible to store all the data centrally as done today. Then we discuss the new and improved applications, classified into two categories: one is the set of automatic wide-area controls and the other is the set of control center (EMS) functions with special attention to the state estimator. Finally, given that the availability of phasor measurements will grow over time, the path for smooth transition from present-day systems and applications to those discussed here is delineated.**

***Index Terms*—Information infrastructure, phasor measurement unit (PMU), power grid communications, real-time database, transmission grid applications, state estimation, wide-area control, wide-area protection.**

I. Information Infrastructure

A. Introduction

In recent years phasor measurements have received much attention. This ability to measure instantaneous values of voltages and currents with very accurate time stamping has become economical for widespread installation. Although the potential for using this data appear to be large, actual applications have been slow to emerge. The main thrust of this paper is that the infrastructure needed to gather, move, and process this data must also be installed at the same time as the new measurement units to be able to take advantage of them. We describe the infrastructure needed and in the process develop a new way to look at the handling of this new level of information.

We start with the premise that high-voltage substations today are measuring and gathering large amounts of data. This measured data are of two types: 1) change in the open or close status of any switch, and 2) analog variables, the most fine-grained measurements of which are the currents and voltages sampled over 100 times a second synchronized to an absolute time standard (the so-called synchronized phasor measurement). The amount of data being gathered at a substation today is so voluminous that most of it cannot be transmitted out of the substation at the rates at which they are gathered, and in actuality very little is transmitted today. In this paper we start with this substation data and look at how it can be organized locally for both local use as well as use for global applications.

Local use of this data at substations is mainly for protection and control. Protection requires fast sampling of data so that relays to switch out equipment can operate in milliseconds. The most common local control is voltage control which is generally slow. Some local calculations are made and stored separately for certain applications like digital fault recording (DFR), sequence of events (SOE), etc. A subset of all the substation data is also collected at the remote terminal unit (RTU) which makes it available to the control center over communication channels.

Next we look at the same data from the viewpoint of monitoring and operating the grid. We try to determine which data is needed where and for what purpose. At present, the only real-time data that exits the substation through the RTUs are collected at the control center where the Supervisory Control and Data Acquisition—Energy Management System (SCADA-EMS) can display and further analyze the data for the operator to take manual (supervisory) control actions. The only closed-loop control done at the control center is automatic generation control (AGC), although some European and Chinese systems have now incorporated automatic voltage control. If, however, the synchrophasor data increasingly available at the substations become available for broadcast, they can no longer be all collected centrally at the control center. Instead, the present-day control center functions and any new ones that can be anticipated must be thought out in terms of their data needs and the communication system has to be designed to transfer only the necessary data to the appropriate functions which may not all reside at a central control center.

Furthermore, the control center [say, of a balancing authority (BA)] has jurisdiction over, and hence observability of, only a small portion of the interconnection. The reliability coordinator (RC) of a region may have jurisdiction over several of these BA control centers, but there is no authority or control center which

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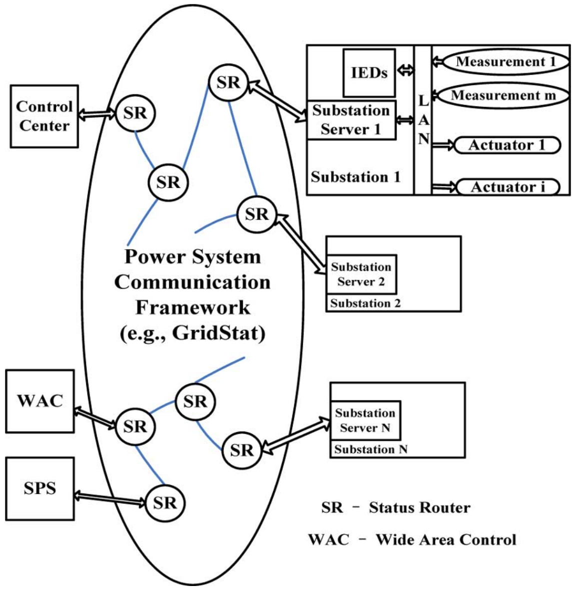

Fig. 1. Real-time information infrastructure for the electric power grid.

oversees in real time the whole Western or Eastern U.S.–Canada Interconnection. The Western Interconnection has about 40 BAs and four RCs and the Eastern Interconnection has about 100 BAs and 12 RCs. All of the BA and RC control centers need to coordinate with each other both at the same level and hierarchically.

In this paper we examine the information needs at the above three levels: within the substation, between the substations and the BA control center, and between BA and RC control centers. We assume that the amount of synchronized data at fast sampling rates collected in a substation is too voluminous to centralize in one control center. So we speculate that any future design of the data architecture must be highly distributed thus also distributing the functionality of the present control centers (SCADA-EMS) and new functions/applications. We point out that in such a distributed architecture, the overview of the whole interconnection, which does not exist today, is only a natural extension.

B. Real-Time Information Infrastructure

As mentioned before, we assume that the latest technologies of computers and communications are available at high-voltage substations and up through the hierarchy. Fig. 1 shows such a generic communication architecture that connects all substations in an information network.

In Fig. 1 the communication infrastructure is shown as a two-level hierarchy. Each substation has its own high speed local area network (LAN) which ties all the measurements and local applications together. Each substation also has a server that connects to the higher level communication network through a router. Thus all applications those require data from more than one substation, i.e., applications that are not local, have to use this higher level network for gathering input and sending output.

This higher level network shown in Fig. 1 as a network of routers feeds all the wide-area applications. The most important and common application, of course, is the control center

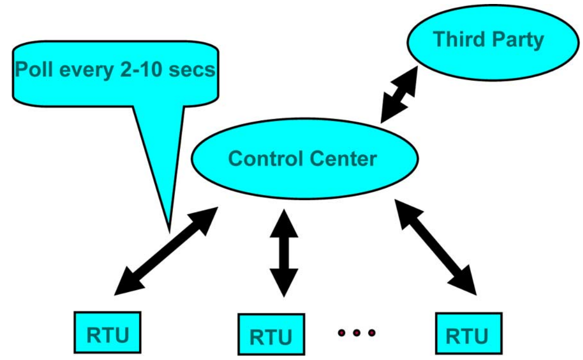

Fig. 2. The present-day SCADA configuration in which the substation data is gathered at the control center.

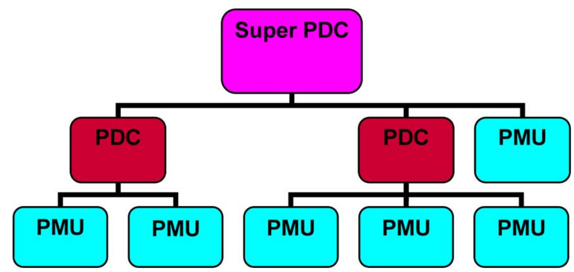

Fig. 3. The present-day PDCs that collects the data from PMUs.

(SCADA-EMS). At present, the SCADA gathers all the data by polling the remote terminal units (RTUs) at all the substations (Fig. 2). This gathering is done at a slow rate, about every 2–10 s. Moreover, the data at the RTU does not necessarily cover everything that is measured at the substation. In the system conceived in Fig. 1, the concept of the RTU has been replaced by the server-router that has access to all substation data through the substation LAN. It can easily be seen that the present day star communication with round-robin polling that centralizes all data from substations would be totally overwhelmed by the volume of data that is being collected at substations today. This would be true even if the present day microwave communication would be replaced with all high speed fiber. Thus, the star configuration is replaced with a network configuration in Fig. 1 and polling is replaced by a publisher-subscriber system that only moves data from substation to application and *vice versa* as needed.

In recent years a parallel communication configuration has been tried to gather the data from phasor measurement units (PMUs) shown in Fig. 3. This is also a star configuration that gathers all the PMU data from one company to one phasor data concentrator (PDC) and then the data from each PDC is further gathered at a super-PDC. This system is already overwhelmed with data even though the total number of PMUs in either of the large interconnections is significantly below 100. Obviously the PDC configuration will be useless when each substation may have over 100 phasor measurements.

The proposed configuration in Fig. 1 should be able to handle the higher demand for information movement. For example, a fast wide-area controller (WAC) or special protection scheme (SPS) may require a few synchrophasor inputs from a few different substations and may send out a few output (control) signals to different (again) substations. The routers can route this data directly from the substations to the controller instead of the

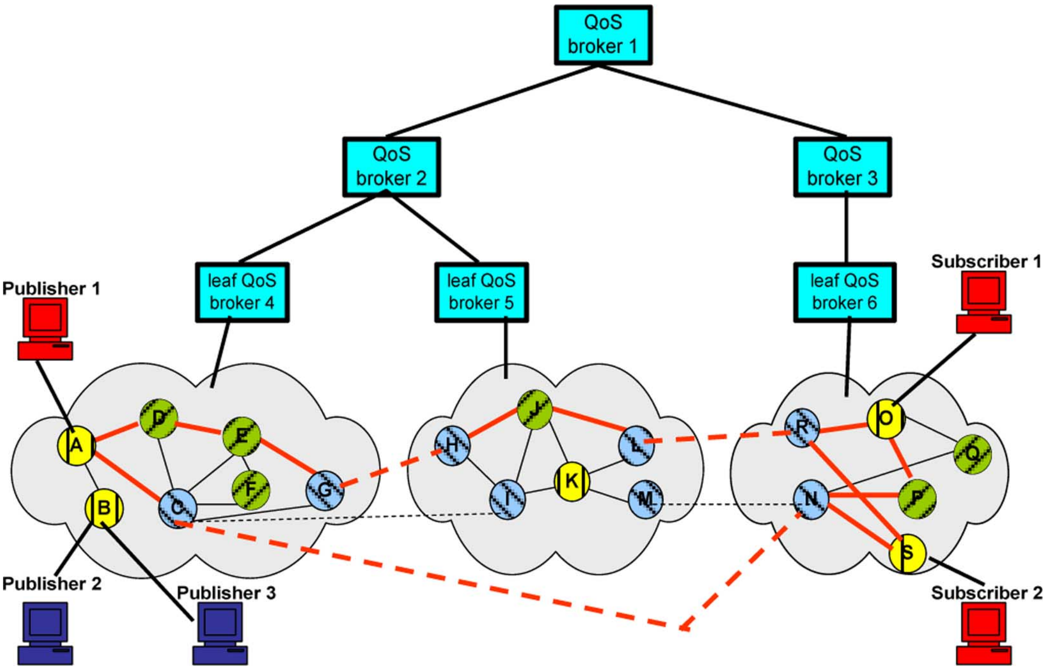

Fig. 4. The management of the router network, including some pathways between publishers and subscribers.

controller having to look for some central depository for this fast sampled data.

On the other hand, the control center requires data from all substations. Actually, the control center performs several functions which can be separated into three classes of applications:

1) monitoring of the system by the operator, which requires various displays (visualization) and alarms;
2) analysis of how vulnerable the grid is to contingencies which requires state estimation, contingency analysis and optimal power flow (EMS applications);
3) automatic controls like automatic generation control (AGC).

The slow AGC controller was developed to match the present day slow collection of data. It can be handled in its present form like any WAC/SPS showed in Fig. 1 but the new configuration provides many new opportunities for improving AGC.

The EMS applications today are geared to the present control center data rates. However, the newer configuration provides further opportunities to enhance these applications (discussed further below). Like the AGC, these applications can also be separated from the operator monitoring in terms of data requirements as long as the results are channeled to the operator.

The monitoring function is data intensive as the operator must be aware of all things, especially abnormal things, happening at all substations. However, the operator can only observe changes in data at slow rates compared to the sampling rate of measurements. Synchrophasors measure at rates up to 100 per second whereas the operator can only watch over seconds. The ability to take manual action (supervisory control) is even slower. Thus the data needs for monitoring at the control center is systemwide but at slower rates whereas for WAC/SPS the data needs are exactly reversed, fast sampled data but from few measurements. The networked configuration of Fig. 1 is ideally suited to handle such applications as long as they are separated as shown.

The network of routers in Fig. 1 is shown as being at one level with no hierarchies. Each substation will have at least one router and these will be connected in a network of high speed communication lines. If the transmission corridors between substations also have fiber optic cables, these may provide convenient channels although other channels may also be used. In addition, certain applications like the control center may not be at the same location as a substation and may have its own router(s).

A more detailed configuration is shown in Fig. 4. The routers may be grouped for management purposes and there may be a hierarchy of computers—shown as quality-of-service (QoS) brokers—that control the actual movement of the data. This grouping of routers can be done by jurisdiction, like control area or balancing authority area. However, we do not recommend that all the data from one area be channeled through one router—as it is done today through the area control center—because this will add significant latency to the communication paths. Instead, we assume that all routers in all areas will be at the same level and the QoS brokers will find the most efficient path as shown in Fig. 4.

This kind of router network does not preclude setting up functional hierarchies; that is, an RC control center can have higher level functions than that of the BA control centers, thus requiring different sets of information, but all these control centers can be supported by the same router network.

C. Substation Information Architecture

Although the basic configurations of high-voltage substations—breaker-and-a-half and ring bus schemes, etc.—have not changed much over the years, the monitoring and control equipment have undergone a sea change in recent years. The main change is that this equipment is all microprocessor based allowing for digital collection and storing of all data. The signals, both for monitoring and for control are digital and the communication within the substation is done by LAN. The communication protocol is now standardized with the 61850 standard. In addition, all measurements and controls can be time stamped with high accuracy by using a GPS signal.

As a result the amount of data that can be collected and stored in a substation is enormous. The bulk of this is just the measurements gathered at very high sampling rates but also includes calculated data from digital fault recorders (DFR), sequence of event (SOE) recorders and other intelligent devices. In addition, all control signals—mostly opening and closing of breakers by protection devices but also analog signals like SVC control—can also be recorded.

Most of this substation real-time information is used for local control within the substation but some of it can be used for wide-area control. At present, the only pathway for this real-time data to get out of the substation is through the RTU and this is very limited. What has been proposed and assumed in this paper is a much faster communication gateway than the RTUs. Even then, the amount of information going out of the substation has to be judiciously selected for its utility as the fastest communication routers will still have limits that cannot move all data generated at the substation.

Obviously, the availability of this large amount of real-time data from each substation, time stamped at high sampling rates, warrants the rethinking of wide-area monitoring and control applications. In general, we can assume that the availability of this information will allow us to control the grid more precisely closer to its limits with higher reliability. However, the development of these applications is dependent on the availability of this data, which has to wait for the faster communication infrastructure.

In the meantime, these applications can be conceived and their information requirements determined. Moreover, the computational capability in each substation is now such that some of this data can be preprocessed a lot more than what is done today. For example, much of the bad data checking that is done today by the state estimator at the control center can be done better at the local substation level.

For example, the limitations in the data collection and communication have limited our measurements to one phase only at the system level (at the control center). But at the substation all three phases are measured and with the enhanced ability to move information, all three phases can be made available for wide-area monitoring and control. This has the advantage of picking up unbalanced situations whether that be slight operational unbalances or extreme cases of open or short circuits. Of course, the single phase models used today in the SCADA-EMS must be replaced with three-phase models.

D. Distributed Database Structure

The real-time database today resides at the control center SCADA system. The structure is usually proprietary to the SCADA vendor but the collection of the data is done through communication channels—usually slow microwave—to the substation RTUs, which are polled by the SCADA every few seconds. The real-time database may also include data that has been calculated from the raw measurements.

The amount of real-time data collected at a substation has always been much larger than what is available at the RTU. The proposed system assumes a much expanded set of data available at the gateway server at the substation. This data itself would be so large that consolidating all the real-time data from all the substations at a single site would be impossible (and unnecessary). The concept of the publisher–subscriber communication system presupposes a distributed database, in this case the substation data being kept at the substation server itself. The total real-time data base is then the collection of all the distributed sets of data. As usual, there will be calculated data from the real-time values that will be part of the database but may reside anywhere in the system. Sometimes duplicates of the same data may be kept in more than one site for backup and efficiency purposes.

Management of a distributed database is very different from managing a single database at one site. This will require middleware that can not only keep track of where all the data resides but also move them at the right time to where the data is needed for the right applications. Such middleware does not exist at present for the power grid but has been used in other distributed databases with communication systems. A middleware concept for power grid communications named Gridstat has been proposed.

E. Static Database Issues

Real-time data refers to measurement data (and some data that is calculated directly from the measurement data). Static data refers to the data that describes the system equipment—impedances of lines and transformers, connectivity of the breakers within substations, etc. This data is also voluminous but not subject to change rapidly like real-time data, thus the name "static" data. This data is needed for all the displays and all the EMS applications. (However, this data does change over a longer time as new equipment is installed and connectivity is changed, and keeping up this database has been a major problem for the industry.)

Today the static database resides in the control center SCADA-EMS. A standard structure for this database has been adopted, known as the common information model (CIM). For the new communication structure proposed here, there are two issues with the design of this static database.

The static database used today in the SCADA-EMS has no relationship with the data models being used at the substations themselves. The use of static data models at the substations is relatively new. Some attempts are now being made to standardize these data models at the substation and some coordination with the CIM standard is also part of the standard development. The new seamless connection between the substation data and the system operation will work only if the same static data is used at the substations as at the control centers. This again points to a distributed database even for the static data.

Another issue is whether to use single-phase or three-phase modeling. Obviously, the model within the substation has to be three phase, and there is no particular technical difficulty in extending this modeling to the whole system (except for the tradition of using single phase representation in the state estimator and other EMS applications). In this paper, we assume that this is the case although translating the three-phase data at the substation to a single-phase representation for the whole grid is quite feasible.

F. Historical Database

The real-time database as described above is large and distributed. This data accumulates at a very fast rate. Obviously several hours of this data is needed for operational purposes, for example, to produce different records like for billing. But the computers used for operational purposes cannot keep accumulating and storing this data for ever.

Storage of this historical data is a separate subject in itself as the applications for this data can be quite varied. In any case, a separate historical database will have to designed and implemented that can be used to transfer the data from the real-time database. This database will obviously be many magnitudes greater than the real-time database but its use will not be time critical as in real-time operations. However, this historical database should have a standardized structure for the same reason as the other databases described above, that is, exchange of data between different jurisdictions.

One critical application of this historical database is the post-mortem of large disturbances. We already know the great difficulty facing engineers when they try to reconstruct how a blackout occurs. A standardized historical database across an interconnection would enable such analysis to be done in hours rather than months, and more accurately.

There are, of course, many other mundane uses of historical data especially in forecasting loads and planning new generation, transmission, and distribution systems.

II. Applications

A. Introduction

The availability of synchronized phasor measurements has given rise to the possibility of two categories of new and improved applications.

One category has been broadly referred to as wide-area control. It is in the same family as all existing automatic control and protection, which are mostly local, that is, the actuating signal source and the control signal destination are in the same substation. Synchronized measurements and fast communication now make it possible for such control to be wide-area or regional. Special and unique examples of such wide-area control already exist and are called special protection schemes. The increasing availability of phasor measurements will make the development of more wide-area controls easier. Some example possibilities are provided below.

The other category is the enhanced control center functions. The main functions of the control center—SCADA, state estimator, contingency analysis, etc.—are for the system operator to monitor the power system and make operational changes, either using supervisory control or by telephone, to ensure the reliable and efficient operation of the system. The availability of phasor measurements at faster rates can improve these functions. For example, a faster and more accurate state estimator can both be a replacement for SCADA data and be able to provide better input to contingency analysis and other downstream EMS functions. Such a state estimator is described below.

B. Wide-Area Control

The proposed control concepts described here are all wide-area controls. Although local controls continue to be improved using newer technologies, the conceptual functionality of these local controls will remain the same. The wide-area controls presented here will often take care of the local controllers but the main objective is to improve the overall stability of the power system. The concepts are presented in the order of increasing complexity, also implying that the ones presented first would be easier to implement.

1) Frequency Control: Frequency is controlled by balancing load with generation. The primary governor control at the generators is local while the secondary AGC control that adjusts the governor setpoints is areawide. The primary control is continuous whereas the secondary control is discrete usually using 2–4-s sampling.

Given that all generators in a region are no longer owned by the same organization, this areawide AGC control has become more decentralized. Ancillary markets for regulation capacity have developed to handle this service. The Federal Energy Regulatory Commission (FERC) ancillary service regulations do allow third-party AGC but a new communication-computation-control scheme needs to be developed before this can occur in any large scale. As this control is quite slow (2–4-s sampling), feasibility of control is not a problem. The more complex communication scheme required is also not a problem; although a meshed communication network is required rather than the present star network, the bandwidth requirement remains modest. However, such a network introduces other modes of failures like signal delays and the control have to be robust enough to handle them.

2) Regional Voltage Control: Voltage control in North America has always been local, although Europe and China are trying some regional control schemes. FERC recognizes voltage-VAR control as an ancillary service but it has been difficult to develop any auction markets for this service. Control schemes for regional voltage control would be useful in North America as voltage collapse has played a prominent part in all recent blackouts. This type of control, like frequency control, is relatively slow, and so the feasibility of the control and communication is not an issue. The main hurdle has been the selection of input and output variables of the controller that can handle all the varied operating conditions that the power system endures. Thus, this challenge is a classical one of developing a practical robust controller.

3) Small Signal Stability Control: Small signal instability occurs when a system perturbation, even a small one, excites a natural oscillatory mode of the power system. These oscillations are slow, usually under 1 Hz. The main method used today to guard against small signal instability is the off-line tuning of power system stabilizers (PSSs). These PSSs are local controllers on the generators. Thus local controllers are used to mitigate system oscillation modes, a procedure that works well for local oscillation modes but not inter-area modes.

Phasor measurements have already been shown to be very helpful in tracking the oscillation modes and their damping in near real time. New controllers need to be developed that can use systemwide inputs (not necessarily more inputs per controller but input signals from further away). Such remote signal inputs will obviously require a more flexible communication mesh network.

Another control concept is to adaptively change the PSS setpoints according to the power system operating conditions. This would be analogous to the AGC control by introducing a secondary control scheme that would periodically adjust the setpoints of the local PSS controllers as the system changes. The challenge here is that the calculation of PSS setpoints requires large analytical calculations, which are today done offline but will have to be done online in this case. The speed of calculation is not a major concern, as changing the setpoints can be done quite infrequently, probably in minutes.

4) Voltage Stability Control: Voltage instability occurs when a change in the power system causes an operating condition that is deficient in reactive power support. Guarding against such instability requires the anticipation of such contingencies that can cause voltage instability and taking preventive action. New preventive control schemes are needed that can also include SPSs that could isolate those areas with var deficiencies.

This is not a stability control in the traditional sense that responds to a disturbance. This is an action plan to ensure that the system operating condition does not stray into an area where a perturbation can cause voltage instability. This calculation requires good contingency analysis which in turn requires a good real-time model (state estimator) as discussed in the next section.

5) Transient Stability Control: The development of such a control scheme is by far the most difficult because a disturbance that can cause instability can only be controlled if a significant amount of computation (analysis) and communication can be accomplished very rapidly. This concept is approached in three increasingly difficult levels:

— the first is to use offline studies to manually adjust protective schemes, which would operate only if the disturbance occurs;
— the second is to automatically adjust these protective schemes with online calculations;
— the third is to directly operate the control actions after the disturbance occurs.

a) "Soft-wired" SPSs: A step advance in this direction will be to generalize SPSs to control transient stability. These SPSs today are developed from the results of voluminous offline studies and are implemented with a "hard-wired" communication system. Thus, the system values and statuses monitored and the breakers controlled cannot be modified. What is proposed here is the development of a generalized communication system that can enable the implementation of new SPS by software modification. Although many phasor measurements and a comprehensive communication scheme will be required in this type of control, the computation requirements will be modest as the control schemes are largely defined offline.

b) Online setting of special protection schemes: A step forward will be to develop methods to control transient stability but with less dependence on offline studies and more use of online computation. The main idea here is to use more real-time data to determine what control is needed. What is proposed here is the development of soft-computing techniques using pattern recognition, neural networks, expert systems, etc., to process the real-time data to decide the best control action. Of course, much offline training of the software may still be required offline, but the expectation is that the control action would be much more efficient than those purely decided offline.

c) Real-time control of transient stability: The objective here is to develop a global control for transient stability (with no offline assists). For this to be feasible, the computation needed to determine the disturbance scenario and then computing the necessary controls for stabilization, has to be in the same time frame as today's protection schemes (milliseconds). Whether this is indeed possible with today's technology is not known. However, the goal here would be to determine what kind of communication–computation structure will be needed to make this feasible.

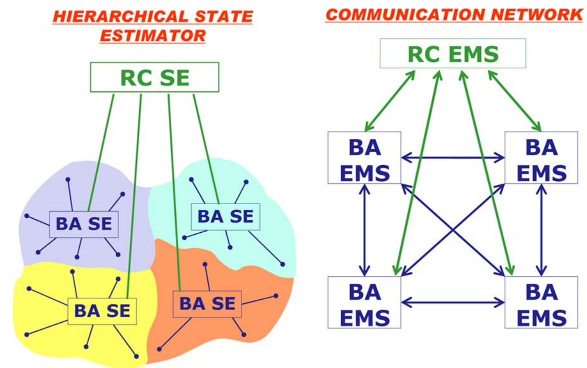

Fig. 5. The present-day SE configuration and its communication system.

C. Real-Time Modeling (State Estimation)

The state estimator (SE) today runs at the control center EMS using the data from the SCADA real-time data and the static database. There are two levels of SEs running today—at the BA level and at the RC level. The BA SCADA gets the real-time data from the RTUs and uses that for its SE; it also passes on the same real-time data to the ISO level for its SE. This hierarchical SE configuration is shown in Fig. 5.

To achieve this the BA control centers have to have communication connections to the RC control center, as shown. Often the BAs also have communications between themselves to exchange real-time data so that each BA SE can construct its own external model. The RC may also exchange such data with neighboring RCs. (It should be noted that many papers assume that the control centers exchange state estimated data for this purpose but this is not the case. So far, only SCADA data is exchanged and moreover, this data is usually not time stamped.)

It is expected that the availability of large amounts of phasor measurements will significantly change the nature of SEs. Let us assume that enough phasor measurements will be available at all substations that voltage angles at all substations will be measured. In that case a mini-SE can be run within each substation to estimate all complex voltages and all currents out at each substation. Because there are enough redundant measurements

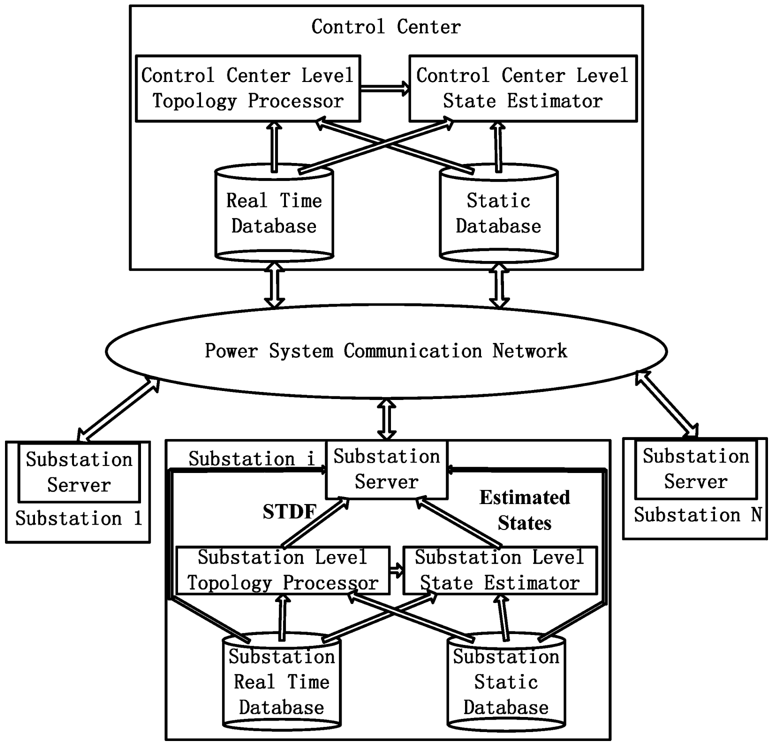

Fig. 6. Decentralized modeling system and database.

within a substation these voltages and currents can be very accurate. In addition, bad data, including switch statuses, can be identified and corrected right at the substation. This processed data would be very different in character than the raw measurement data that is fed to the control center SE today. Because this data includes voltage angles, some have referred to this as state measurement (precluding the need for an SE altogether).

In reality, the state estimate for the network will have to be more than just a collection of the complex voltages from the substations. Because there are always some noise and errors in the data, a central SE will have to reconcile (get the best fit) from all the measurements received. A major advantage of obtaining complex measurements of voltages and currents is that the estimator equations will be linear and the estimation will not require iterations like the present estimator. The structure of such a two-level SE is shown in Fig. 6.

This SE at the BA level can be updated quite often—maybe in seconds (rather than minutes today)—and because all the measurements are time stamped, the time skew of the measurements will always be known resulting in much more accurate SE results. The guaranteed speed and accuracy of the results would allow the operator displays to use SE results rather than raw SCADA data as is done today. It will also be possible to exchange these SE results with neighboring BAs or up to the next level RC.

The exchange of SE results among BAs will be a major step forward in the control of the grid. The errors in the external model today are a major problem in the accuracy of the contingency analysis results. Thus the BA operator today is usually unaware of what contingencies in the external model are dangerous to the internal system but accurate real-time models of the external system that can be obtained by exchanging SE results can extend the observability of the operator to the far reaches of the interconnected grid.

Similarly, the SE at the RC, especially if the RC is overseeing many BAs, can be made more accurate if it uses SE results from each BA rather than the raw SCADA data. Because the latter is used today the SE results at the RC can be significantly different than the BA SE results, which lead to difficult coordination between the RC and its BAs.

All the downstream applications of contingency analysis—steady-state, voltage, and dynamic—plus the optimal power flow are dependent on the accuracy of the SE results. The new technologies discussed here that can make the SE much more accurate will make the grid more reliable with better contingency analysis. As the optimal power flow is often used for setting nodal prices, accuracy here also has an impact on better market resolutions.

In addition, if the SE can be updated every few seconds, the state estimated results can replace the SCADA data normally presented to the operator on substation displays. The main advantage of the SE results over the raw SCADA data is that the SE results are filtered so that all bad data and anomalies have been eliminated thus providing the operator with a more accurate picture of the system.

Finally, a major advantage of such a distributed SE is that partial state estimates of a few substations or a geographic region can be calculated very rapidly (in milliseconds) and can be made available to various kinds of controllers as discussed in the last section.

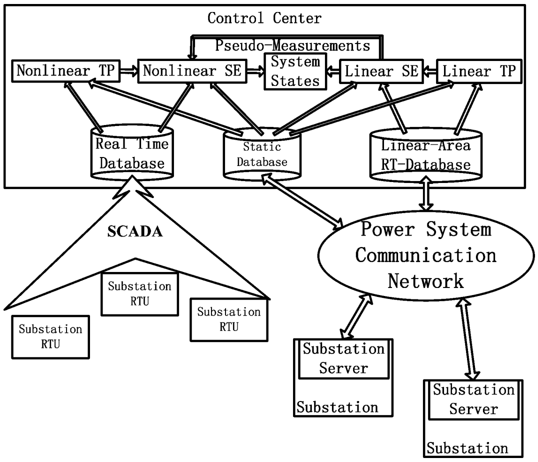

Fig. 7. Transitional real-time modeling system and database.

III. Transition to the New Architecture

A. Introduction

Most of the applications presented above, as well as the supporting information software, are dependent on transitioning to the architecture shown in Fig. 1. This architecture assumes a significant infusion of new measurements (synchrophasors), communications and control devices (FACTS). It is not going to happen overnight, but will have to phased in over many years both because of the costs involved as well as the fact that the system has to be fully operational during the transition. Thus the transition has to be planned carefully, i.e., while certain parts of the transmission grid is upgraded, these new information handling and applications can be tested and implemented on these parts, and the rest of the grid can be cut over as it is upgraded.

An example of the architecture in this transitional state is shown in Fig. 7 for the SE. In this case, the real-time data from the updated substations has already been filtered by substation level SEs and then sent to the control center over the updated communication network, whereas the traditional substations still send their real-time data through the substation RTUs over the existing SCADA communication system. At the control center, the two parts have to be combined using an updated SE algorithm shown schematically in the figure.

Following is a summary roadmap to the smart transmission grid. Because every application is dependent on a complex set of different developments coming together, a systematic planned approach is needed.

B. Phasor Measurements

So far phasor measurement units have been installed in an ad hoc way with no particular applications in mind. A systematic goal may be to make observable regions with phasor measurements. First only a few substations could be made observable, then their neighboring substations can be added, and so on. Moreover, it would be reasonable to start with the highest voltage substations, because they will be the easiest to retrofit as they are usually the newest and because they will have the most impact on any application. The feasibility of installing so many phasor measurements—tens of thousands rather than tens—is fully dependent on the fact that all new measuring, recording, and control equipment in the substation are microprocessor based and capable of synchronizing through a GPS signal.

C. Communications

The development of the communication system can follow the syncrophasor implementation at substations. As more phasor measurements are installed at a substation, a digital LAN within the substation will be needed to handle its collection and handling as well as a gateway server as shown conceptually in Fig. 1. A managed meshed network, like that shown in Fig. 4, is needed to connect all these updated substations and other application servers. This multilevel communication system will require significant software (middleware) development.

D. Controls

The most useful applications for smart operation of the transmission system are fast wide-area controls. To implement these we will need fast controllers, i.e., FACTS devices. Except for FACTS, we are limited to the opening and closing of circuit breakers for our only fast controls and such digital control is quite limited in scope. Because of their expense, the number and type of FACTS controllers will have to be carefully selected (at least until their prices come down) but this would be easier to do once the measurements and communication parameters are known.

E. Databases

With thousands of phasor measurements updating 30, 60, or 120 times per second, centralizing the real-time database is not feasible. Thus the database has to be a distributed one, also depending on the communication system to move data where it is needed. This means that the applications will also be distributed, which in turn, implies that our static database is also distributed. The design and development of this database will be a significant undertaking (somewhat similar in scope as the design of the communications system).

F. Simulation and Design of Applications

Although it is clear that such an infrastructure can support better automatic controls and better operator tools, the actual tools and controls are yet to be developed. The development of these applications will require significant R&D. In fact the tools required for this development are woefully inadequate and will have to be developed first.

Take for example the simulation tools that are used for planning today: power flow and transient analysis. The models used in these simulations are simple; a bus-branch model that does not have any description of the substation details and hence no way to model the fine-grained control systems within a substation like protection. Thus the representation of actual measurements and breaker openings by even local protection is not feasible. In addition, the models are single phase balanced systems, whereas actual protection and control schemes operate more for unbalanced faulted systems. To design a fast wide-area controller that uses PMU inputs we will need to represent it in a time simulation of the grid where the time granularity of the simulation must match the time granularity of the controller.

Such simulation tools with the time granularity and the models are not available at this time.

IV. Conclusion

The smart grid of the future is generally characterized by more sensors, more communication, more computation, and more control, but a comprehensive conceptual architecture is seldom presented. We assume a certain generic configuration of more sensors, more communication, more computers, and more control, from which we try to lay out the total information picture. From that we speculate as to how the present applications can be enhanced and new applications be developed that will make the operation of the grid more secure and reliable. Finally, we lay out a systematic plan of how we can transition from the present grid to the smart grid. The component technologies are all known but putting them together into a coherent whole and transitioning from the present technologies to the new is a significant (and expensive) undertaking. The technical feasibility, however, is not in doubt, and the cost of not undertaking this journey is significantly higher than the investment needed.

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