Computer Networks 57 (2013) 825–845

Contents lists available at SciVerse ScienceDirect

Computer Networks

journal homepage: www.elsevier.com/locate/comnet

Review Article

A comprehensive review of the application characteristics and traffic requirements of a smart grid communications network

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ARTICLE INFO

Article history:
Received 1 March 2012
Received in revised form 21 September 2012
Accepted 5 November 2012
Available online 10 November 2012

Keywords:
Smart grid
Communication technologies
Applications
Traffic requirements
Communication architecture

ABSTRACT

A robust communication infrastructure is the touchstone of a smart grid that differentiates it from the conventional electrical grid by transforming it into an intelligent and adaptive energy delivery network. To cope with the rising penetration of renewable energy sources and expected widespread adoption of electric vehicles, the future smart grid needs to implement efficient monitoring and control technologies to improve its operational efficiency. However, the legacy communication infrastructures in the existing grid are quite insufficient, if not incapable of meeting the diverse communication requirements of the smart grid. Therefore, utilities from all over the world are now facing the key challenge of finding the most appropriate technology that can satisfy their future communication needs. In order to properly assess the vast landscape of available communication technologies, architectures and protocols, it is very important to acquire detailed knowledge about the current and prospective applications of the smart grid. With a view to addressing this critical issue, this paper offers an in depth review on the application characteristics and traffic requirements of several emerging smart grid applications and highlights some of the key research challenges present in this arena.

1. Introduction

Since its inception, the basic structure of today's electricity grid has remained unchanged. For decades, the electrical grid has been a strictly hierarchical system where electric power flows unidirectionally from generation plants towards the consumer loads as shown in Fig. 1. Due to absence of appropriate communication infrastructures in the distribution domain, the existing grid is effectively operating in an open-loop manner where the control center has no or limited real-time information about the dynamic change in load and operating conditions of the system [1]. This poor visibility and lack of situational awareness coupled with the aging infrastructures have made the grid more susceptible to frequent disturbances which often turn into major blackouts and brownouts due to cascading failures [2].

On the other hand, rising awareness about the adverse effects of climate change has prompted the governments of the world to reduce their greenhouse gas emissions by promoting renewable energy sources like solar and wind power. According to t report published by the Clean Energy Council of Australia [3], a record US$243 billion was

Abbreviations: AMI, Advanced Metering Infrastructure; AMR, Automatic Meter Reading; ANSI, American National Standards Institute; DAP, Data Aggregation Point; DER, Distributed Energy Resource; DR, Demand Response; ESI, Energy Services Interface; EV, Electric Vehicles; FAN, Field Area Network; GOOSE, Generic Object Oriented Substation Event; HAN, Home Area Network; HV, High Voltage; IEC, International Electrotechnical Commission; IED, Intelligent Electronic Device; IEEE, Institute of Electrical and Electronics Engineers; IP, Internet Protocol; M2M, Machine to Machine; MDMS, Meter Data Management System; MU, Merging Unit; NAN, Neighborhood Area Network; P&C, Protection and Control; PMU, Phasor Measurement Unit; QoS, Quality of Service; SMV, Sampled Measured Value; SOC, State of Charge; WAMS, Wide Area Measurement System; WiMAX, Wireless Interoperability for Microwave Access; WLAN, Wireless Local Area Network; WMN, Workforce Mobile Network.

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1389-1286/$ - see front matter
http://dx.doi.org/10.1016/j.comnet.2012.11.002

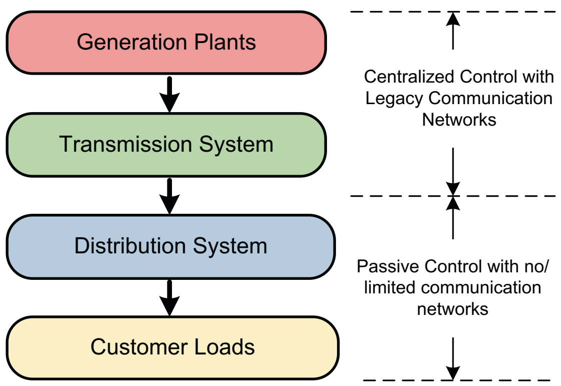

Fig. 1. The existing electricity grid with unidirectional power flow.

invested in the global renewable energy sector in 2010 up by 30% than the year before. In Australia, the number of household solar panels has grown more than 35 times in the past 3 years. In addition, the Electric Vehicles (EVs) are being considered as one of the promising solutions to reduce carbon emission and the dependence on fossil fuel. With the increasing adoption and use of EVs, they are expected to become a major load to the grid in near future. For example, according to a recent study by the Australian Energy Market Commission [4], EV sales are projected to be around 20% of total sales by 2020 and growing up to 45% by 2030 considering a moderate up take. This will impose an additional peak demand of 8.2% (1900 MW) on the Australian national grid.

Since most of the renewable energy resources are connected to the distribution domain of the grid, their widescale integration with the existing grid reverses the traditional direction of power flow. Moreover, the EVs may also act as storage devices and feed power back to the grid to smooth out the natural intermittency of renewable energy sources which strengthens the case for a bidirectional energy flow in the grid [5]. Hence, to enable bidirectional energy flow as well as to integrate large-scale renewable energy generators, the existing grid needs advanced monitoring and control technologies to stabilize its operating parameters (e.g., voltage, current and frequency) by optimally balancing its load-supply profile.

On the backdrop of the aforementioned challenges, the concept of the next generation of electricity grid, known as the 'smart grid' has been emerged that addresses all the shortcoming of the existing grid. According to the, the U.S. department of energy [2], one of the major advocates of the concept, the 'smart grid' is a distributed and automated energy delivery network that provides two-way flow of electricity and information and enables near-instantaneous balance of supply and demand by incorporating the benefits of distributed computing and communications. Hence a robust communication infrastructure is the key enabler for a smart grid that differentiates it from the conventional grid.

Nevertheless, finding the best communication technology for a smart grid is not straight forward. The conventional telecommunication networks are optimized to support various multimedia applications such as voice over IP (VoIP), streaming media, and web browsing where each application traffic is mapped into a certain Quality of Service (QoS) class (e.g. voice, streaming, interactive, and background). The overall network traffic is modeled such that each QoS class is associated as a single common session comprised of many individual sessions. However, the communication pattern of smart grid is quite different. In the smart grid environment, the communication network has to support information exchange among a large number of smart meters, Intelligent Electronic Devices (IEDs), sensors and actors without or very limited human intervention. This form of communication is often known as the machine-to-machine (M2M) which is autonomous in nature and triggered either by time or event. Each of these applications has different characteristics in terms of packet arrival rate, burst size and latency based on their deployment scenario. For example, the latency requirement of a smart meter event and a substation event are quite different. Thus, the co-existence of protection, control, monitoring and reporting traffic in the same network poses the additional challenge of adaptive QoS differentiation in the smart grid communications network.

Although the smart grid implementation activities are still in early stage and the commercially available applications are limited to the revenue metering and non-realtime demand side management activities, the utilities also need to consider other prospective applications to a develop a future-proof network. Hence, the utilities from all over the world are facing the major challenge of finding the most appropriate technology that can satisfy their current and future communication needs. Therefore, it is very important to acquire detail knowledge about the potential applications and characterize their traffic requirements in order to properly asses the available communication technologies, architectures and protocols.

With this motivation in mind, in this paper we provide a detailed study on the application characteristics and traffic requirements of emerging smart grid applications. The rest of the paper is organized as follows. Section 2 reviews the recent IEEE 2030-2011 standard for smart grid interoperability to develop an understanding of the smart grid communication architecture and identify its key components. Section 3 describes the application characteristics and traffic requirements of some of the key smart grid applications, namely automatic meter reading, demand response, electric vehicles, substation automation, Distributed Energy Resources (DERs)/microgrids, wide area measurement and distribution supervision. Section 4 summarizes the key performance requirements of these applications and highlights some of the key research challenges to meet these requirements. Finally, Section 5 concludes the paper.

2. Architecture of smart grid communications network

In order to study the applications of the smart grid, it is important to develop an understanding of its architecture first. Although it is very difficult to reach into a consensus about the architecture and scope of a highly cross-functional infrastructure like the smart grid, the IEEE 2030-2011 standard is being widely accepted as the industry's first guideline regarding its architecture and interoperability

[6]. The standard provides the smart grid interoperability reference model that uses a systems-level approach to provide guidance on interoperability among various components of communications, power systems, and information technology platforms in the smart grid. The communication technology perspective of the model provides a broad set of communication networks to interconnect the smart grid generation, transmission, and distribution and customer domains. Together they form an end-to-end smart grid communications network. A representative model of the end-to-end smart grid communications architecture based on the IEEE 2030 standard is provided in Fig. 2.

As seen in Fig. 2, the power generation and transmission domains are generally comprised of large substations that already have legacy communication infrastructures in place. A backbone network connects these substations with utility control center and 3rd party networks using mostly wired infrastructures such as digital subscriber line (DSL), fiber and cables. The power distribution domain contains substations, feeders and end-user loads over a vast geographic area. A wide area communications network connects these utility infrastructures with the utility control center to enable grid-wise monitoring and control applications. In addition, it provides the 'last mile' connectivity to the customer premises to enable end-user applications such as metering and billing, demand management and load control. A backhaul network connects it with the utility's backbone network.

The IEEE 2030 standard specifies a logical architecture for the smart grid communications network comprising of the following three subnetworks – (i) neighborhood area network for the customer premises, (ii) field area network for the utility infrastructures and (iii) workforce mobile network for the utility workforce as shown in Fig. 3. A brief description of these logical subnetworks is given in the following subsections.

2.1. Neighborhood Area Networks (NANs)

A NAN is the logical representation of an Advanced Metering Infrastructure (AMI) system that connects customer premises with the utility control center. The basic constituent of an NAN/AMI network is the smart meter that performs a variety of intelligent metering tasks such as consumption metering, power quality monitoring and optionally perform load control activities. A smart meter can also act as an Energy Services Interface (ESI) that allows the private networks, for example, the Home Area Network (HAN) to exchange information with the AMI system. It supports a number of advanced applications such as remote load control, monitoring and control of distributed energy resources and electric vehicles, in-home display of customer usage and reading of non-energy meters (e.g., water and gas). Fig. 4 illustrates the types of connectivity within a smart grid NAN. The end-points of a NAN can either be a standalone smart meter or a Data Aggregation Point (DAP) that collects data from/to a group of smart meters and then sends the aggregated information to the Meter Data Management System (MDMS) via a backbone network.

2.2. Field Area Networks (FANs)

The FAN is responsible for facilitating information exchange between the utility control center and the distribution substation and feeder equipments for various monitoring, control and protection applications.

The distribution substations convert the High Voltage (HV) electricity into a low voltage one as required by the homes and businesses. In addition to voltage transformation, they also isolate faults and are used as a point of voltage regulation. In a smart grid environment, they will be equipped with advanced monitoring and control equipments such as remote terminal units (RTUs), Phasor Measurement Units (PMUs) and IEDs to perform various substation automation functions.

The distribution feeders include transmission lines, cable poles and tower to provide electricity connection to the customer premises. They also act as the point of common coupling for the DER/microgrids that are connected with the distribution side of the grid. In the smart grid, there would be a number of sensor and actor networks

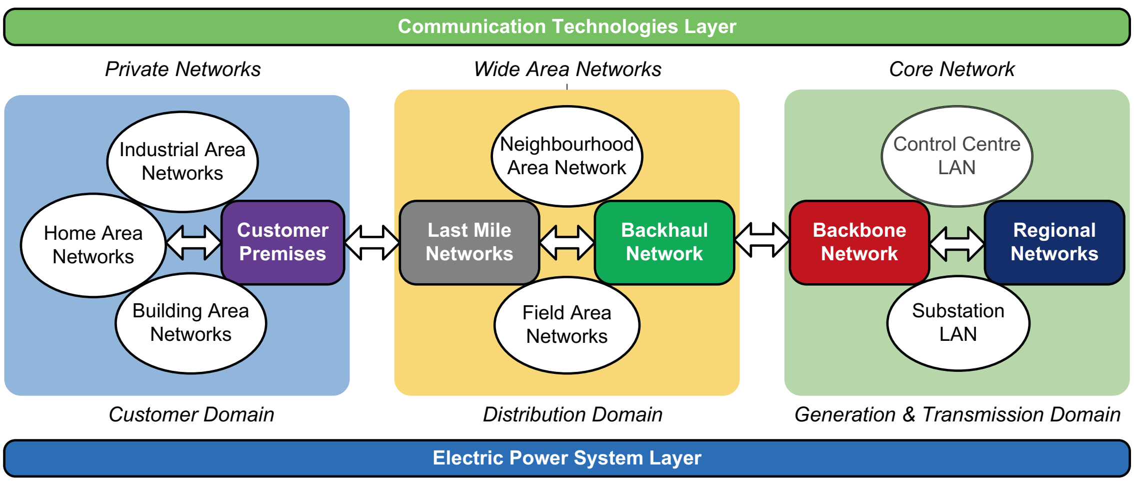

Fig. 2. End-to-end smart grid communications architecture based on the IEEE 2030 standard.

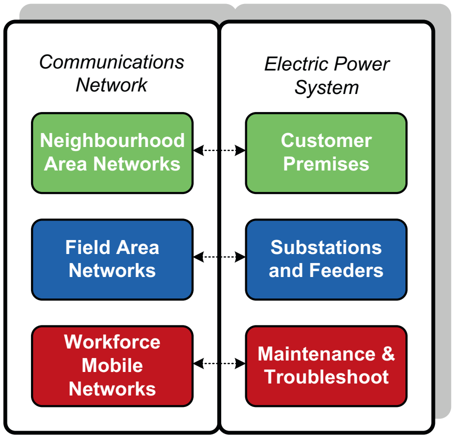

Fig. 3. Logical architecture of the smart grid communications network.

overlaid along the distribution feeders for distribution supervision and monitoring applications.

2.3. Workforce Mobile Networks (WMNs)

The WMN is used by the utility's workforce to provide dispatch, maintenance, and normal day-to-day operations. Typical requirements of a WMN include broadband connectivity to employees, including virtual private network (VPN), VoIP, and geographic information system (GIS) based applications for logistics or asset management. Moreover, in-vehicle applications and fleet telematics such as location-based services (LBSs) with global positioning system (GPS) based tracking and navigation, and automatic vehicle locating (AVL) are also expected to be integrated with the WMN system [7].

The WMN should be able to access both NAN and FAN via the wide area network to collect customer and equipment information and status. The communication requirements of a WMN are similar to that of standard telecommunication services such as voice, video, and internet applications. However, wide coverage and mobility support are typically required for many of its applications.

3. Applications of the smart grid communications network

Based on the two logical networks of the smart grid communications network – the NAN and the FAN, plethora of applications with different requirements and features are expected to emerge. However, to keep the scope of this paper limited, we shall discuss only a selected set of applications that have drawn significant attention from the smart grid research and standardization communities. In the rest of this section, we shall discuss the characteristics and requirements of these applications from communications network point of view based on the contemporary information and standards in their respective fields.

3.1. Automatic meter reading

Automatic Meter Reading (AMR) refers to a technique that uses communication systems to collect meter readings as well as events and alarms data from the meters. It is the most basic and simplest smart grid application. Several published standards are already available in this field. Of them, the ANSI C12.1-2008, IEEE 1377 and IEC 61968-9 are the prominent ones [8–10]. Both the ANSI C12.19 and IEEE 1377 standards provide specifications for the communication syntax for data exchange between the end device and the utility server using binary codes and extensible markup language (XML) contents. However, the scope of the IEC 61968-9 standard is more general and covers various aspects of AMR communications such as meter reading, meter connect/disconnect, meter data management, outage detection, prepaid metering and so on. Based on the IEC 61968-9 standard, some of the major AMR communications scenarios are listed below.

- *Meter reading*. The smart meters may send meter readings according to a schedule defined by the MDMS. In addition, both the customer and the MDMS may request meter readings on demand for billing inquiries, outage extent verification, and verification of restoration.

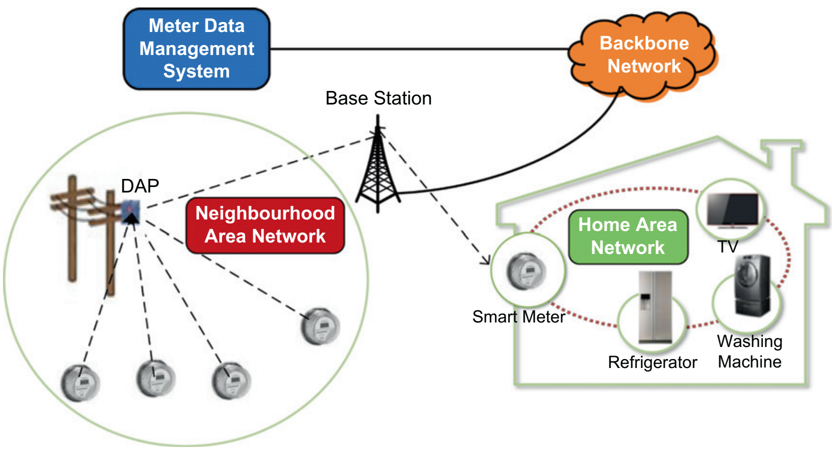

Fig. 4. Types of connectivity within a smart grid neighborhood area network.

- *Meter events and alarms.* The smart meters may report various meter health events and alarms to notify hardware, configuration or connection issues. Example of such communication includes diagnostic alarms, tamper alarms, or other unusual conditions. In addition, the meters can take part in periodic software and firmware upgrade activities.
- *Grid events and alarms*. The smart meters may collect information related to grid events such as momentary outage, sustained outage, low or high voltage, and high distortion and send report to the MDMS as an event or alarm. This information could be used for outage analysis, maintenance scheduling or capacity planning.
- *Others*. The smart meters may support other advanced applications such as receiving pricing information, supporting prepaid services, supporting customer switch between energy suppliers and so on.

An industry-led initiative known as the Open Automatic Data Exchange (OpenADE) provides functional and technical guidance based on the IEC 61968-9 standard for messaging and data exchange between the AMR entities during authorization and transfer of Customer consumption information [11].

Typically an AMR system has to support a large number of devices since it has to collect measurements from each residential and commercial meter within its coverage. For example, according to a report from the national institute of standards and technology (NIST) of the United States, the meter density is 100, 800 and 2000 per Km^2 for rural, urban and suburban areas respectively [12]. In the event of a wide-spread power outage, the affected meters are required to send a "last gasp" alarm to the control center. Since the meters are expected to operate without battery backup and rely on the charge stored in a capacitor to send this alarm, it needs to be sent out within a few 100 ms [13]. Hence, providing network access to a large number of devices within a short interval is an important requirement for the AMR applications.

On the other hand, the AMR applications have a very small data rate, for example, a typical meter reading report is 100–200 bytes according to the message format specified in [11]. This requires a very high signaling overhead per packet due to the signaling messages associated with establishing the network connectivity. Moreover, the protocol overhead associated with each packet is also very high. For example, a 100 byte meter reading payload might be associated with a 40 byte IPv6 (IP version 6) header and 20 byte TCP (Transmission Control Protocol) header which yields a protocol overhead of 60%. Hence, increasing data transmission efficiency by minimizing signaling and protocol overheads is another key requirement for the AMR applications [13].

3.2. Demand response

Demand Response (DR) enables the utility operator to optimally balance between power generation and consumption either by offering dynamic pricing or by implementing various load control programs. The dynamic pricing programs are intended to reduce energy consumption during peak hours by encouraging customer through various incentives to limit their energy usage or shift them to other periods.

In DR applications, the primary role of communication technologies is to convey the price information to the smart meter/ESI of the customer premises in the form of a price signal. The customer upon receiving the price signals takes necessary steps to regulate his or her energy consumption. Currently several dynamic pricing programs exists in the market [14]. For example,

- *Time-of-use (TOU)* – The day is divided into contiguous blocks of hours with varying price with the highest price for the on-peak block.
- *Real time pricing (RTP)* – The price may vary hourly and is tied to the real market cost of delivering electricity.
- *Critical peak pricing (CPP)* – Same as TOU, except that it is only applied on a relatively small number of "event" days.
- *Peak time rebates (PTRs)* – Customers receive electricity bill rebates for not using power (during peak periods).

A more advanced role is to perform the remote load control (RLC) programs where the response of the household appliances to price signals is automated with the help of the M2M communication and intelligent appliance control techniques. For example, a thermostat can be programmed by a remote server to increase set-point temperature in response to a critical peak pricing event signal. For RLC programs, the loads can be classified into the following three categories based on their ability to be regulated.

- *Interruptible loads*. These loads can be interrupted during the peak period and shifted to another period. Example of such loads includes – water pump, dryer, and dishwasher. However, these loads will again come to the grid when the waiting period is over. For instance, the load from a water pumping system can easily be shed for as long as water is available in the tanks. However, after the load shedding, it has to fill up its tanks again causing a rebound of the load to the grid [15]. These loads require a simple load control signal to interrupt and re-schedule the process.
- *Reducible loads*. These loads can be reduced to a lower level for a certain amount of time. For example, during the peak hour the thermostat of refrigerators or air-conditioners can be set at a higher temperature which will reduce the overall load. These loads need periodic interaction with the remote DR server during the load regulation time.
- *Partially-interruptible loads*. These loads can be partially interrupted over the peak period by limiting the run-time cycle. For example, a 50% cycling would result in 30 min of run-time per hour. Example of such loads includes – air-conditioner, electric heater, washing machine, and electric cookers. These loads require two load control signals to start and end the limited cycle mode.

For DR applications, the Open Automated Demand Response (OpenADR) is the pioneering standard that provides specifications and guidance for automation of DR programs

[16]. Unlike the load control programs, the response in OpenADR system is determined by the customer. The OpenADR system conveys the price and event signals to the end-user's energy management system to trigger pre-programmed actions set by the customer. The standard defines following three entities for DR system:

- *Utility*. Configures and manages the DR programs. It is assisted by a utility information system that sends the real-time pricing and event information to the DR server and coordinates DR programs and dynamic pricing by using consumption details of each participant.
- *DR Automation Server (DRAS)*. Dispatches the information from the utility to the clients and also collect status reports.
- *Participant*. The end user(s) that participate in the DR programs. It is assisted by a DRAS client that communicates with the DRAS, receive price signals and event notification, execute the DR program and send status report to the DRAS.

An example of the OpenADR specified DR program is the General Event Based Programs (GEBPs) where each participant performs DR based on price and event notifications. Fig. 5 shows the DR automation architecture for the case of a DR event according to OpenADR standard.

When the utility initiates a DR event, the utility information system sends the event information to the DRAS. The DRAS conveys the event message to the DRAS Client in the participant's site via the communication network. A reply message is sent by the DRAS Client informing about its participation in the event. If participates, it sends the system load status to the DRAS. The participants are notified of an upcoming event at the *Issue Time*. The time period between the *Event Start Time* and the *Event End Time* is known as the "ACTIVE" state and the time period from the Issue Time till the Start Time is known as "PENDING" state of the DR event. The "IDLE" periods are the times before the Issue Time and after the End Time. The state transition diagram of a generic demand response event is given in Fig. 6.

In the current standardization efforts, the RLC programs for DR purposes are generally associated with the smart metering specifications as in Refs. [8–10]. Nevertheless, a more detailed specification is provided by the Australian Standard 4755 (AS4755) for direct load control of Priority Appliances such as air conditioners, pool pumps and water heaters [17]. As shown in Fig. 7, the AS4755 compliant demand response enabled devices is equipped with four control wires where load control signals are applied from an AS4755 compliant controller device. The controller device uses a communication link to receive load control information from the load control server in the utility control center.

Among the DR applications, communication requirement varies according to the type of the load and the DR method used. For price based programs, communication requirement is low since an event notification followed by an acknowledgment message is enough for each application session. A more intense message exchange is required for the load control programs. Among them, the communication requirements for the interruptible loads are smaller since a few load control signals are sufficient to interrupt and resume the load for a certain period of time. For reducible and partially-interruptible loads, the communication requirement will be higher since they need frequent control message exchanges during the load regulation period.

The overall communication load from the DR applications depends on a range of factors such as – operator's policy, system loading, wholesale energy price, weather condition and so on. Moreover, many of these factors are inter-related. For example, in a hot summer day, the electricity demand can increase significantly along with the wholesale energy price. Hence, the underlying communication network should be robust enough to cope with such scenarios. On the other hand, most of the price based DR programs are based on publisher/subscriber mechanism where a remote server sends price signal to the subscribed nodes using multicast techniques. Although the transmission of the price information is generally delay tolerant, they require reliable communication and therefore, very sensitive to packet loss. Hence, an important requirement for the DR applications is to ensure reliable multicast/broadcast services.

3.3. Electric vehicles

EVs are the motor vehicles with rechargeable battery packs that can be charged from the distribution feeder. While most of the EVs are expected to be charged at home,

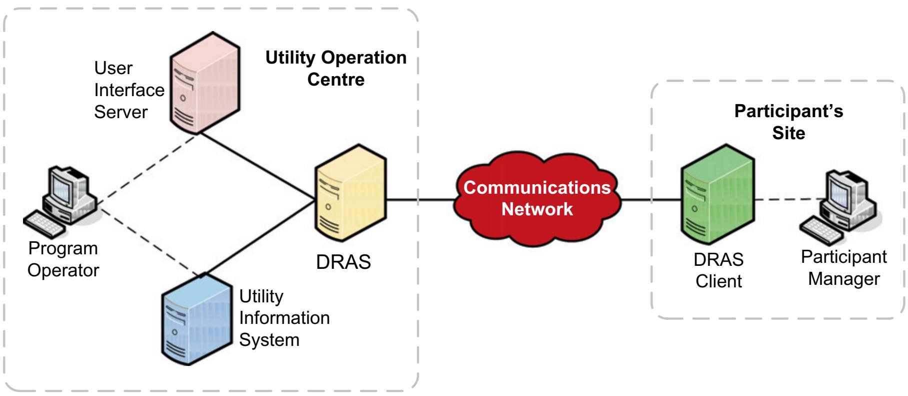

Fig. 5. Demand response automation architecture based on the OpenADR specifications [16].

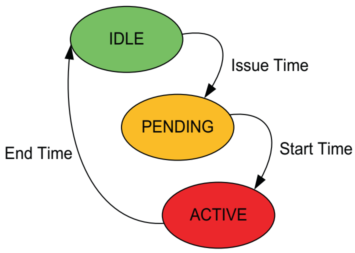

Fig. 6. State transition diagram of a generic demand response event according to OpenADR specifications [16].

there will also be public charging stations established in the public or corporate car parks. The charging of EVs at home can be either managed or unmanaged. According to the analysis presented in [18], EVs are assumed to come back home and plugged into the charging system according to a normal probability distribution function with the mean occurring at 6 p.m. and the variance of 1 h. In case of the unmanaged charging, it may cause a daily charging peak around that time. Since this period coincides with the normal evening peak of the grid, it would further aggravate the existing peak power shortage problem. Moreover, high concentrations of charging requests within a small time period may cause severe overloading in the distribution circuit which may lead to increased line loss and damage to utility assets and customer equipments [19–21].

To mitigate the above problem, the concept of 'smart charging' has been proposed in several literatures that enables controlled charging of the EVs using the bidirectional communication capabilities of smart grid [22–24]. A simple illustration of the smart EV charging concept is provided in Fig. 8.

The key instrument behind the 'smart charging' concepts is a centralized charging controller that is responsible for coordinating each energy transfer session in real-time to accommodate the time-varying nature of both the total available energy and the number of EVs being charged. To accomplish this, the charging controller needs to perform switching of the EV chargers and receive battery state-of-charge (SOC) status from the EVs using the communication infrastructures of the smart grid. From the communications network's perspective, the ZigBee Smart Energy profile 2.0 (Draft) has provided a detail guideline for such applications in the smart grid [25]. Based on this, the message exchanges during an EV charging session is depicted in Fig. 9.

According to the application model in Fig. 9, each charging contains of a number of fixed messages for initialization, vehicle authentication, energy transfer authorization and metering purposes. In addition, EV uses the SOC message to periodically update its charging status. Thus, the communication load (in bytes) for the ith charging session in the system can be given by:

$$l_i = l_{\text{Fixed}} + l_{\text{Variable}} = l_{\text{Fixed}} + n_i * l_{\text{soc}} \qquad (1)$$

where l_{Fixed} denotes the number of bytes for fixed messages, l_{Variable} denotes the number of bytes for variable messages, n denotes the number of SOC messages and l_{soc} denotes the length of each SOC message in bytes. Since the SOC messages are periodic, the value of n depends on the duration of the charging session. The longer is the charging time, the more SOC messages are needed to be exchanged. Thus, charging time plays a key role in determining the total communication load of the EV charging application.

The charging time of a particular EV mainly depends on three conditions – the size of the battery, the type of the charger used and the residual energy level. At present, most of the commercially available EVs have a battery capacity ranging from 16 to 54 kW with 16 kW being the most affordable and available one [26]. For EV charging, the SAE J1772 standard specifies three levels of charging listed in Table 1 [27]. The higher is the charging level, the faster is the charging process.

While Levels-1 and 2 type chargers are expected to be used in the households, Level-3 will be used mostly in commercial and public charging stations. Within each charging level, the actual charging time is determined by the rating of the power outlet used. For example, assuming a constant charging rate, the total charging time is 3 h for a 240 V/10 A power outlet while it is 6 h for a 240 V/20 A power outlet.

It should be noted that the battery charging profiles can be highly influenced by the charging control methods adopted by the utility. Since EVs remain parked for a longer period of time and their schedule of usage (trips) are often planned earlier, they provide a higher degree of load shifting ability in comparison to that of the other electrical loads. Hence, an essential part of the 'smart charging' concepts is the integrated DR programs to keep the overall load within the amount of provisioned energy [28]. Hence, while allocating energy to an EV charging session, the charging controller needs to consider not only the electrical loading of the associated transformer/utility equipments but also available energy for EV charging loads.

From the DR's point of view, the EVs can be assumed as partially-interruptible loads whose charging cycle can be reduced during peak periods. Instead of strict admission control (i.e. either reject or accept), the EV charging controller can allow the intended vehicles to be partially

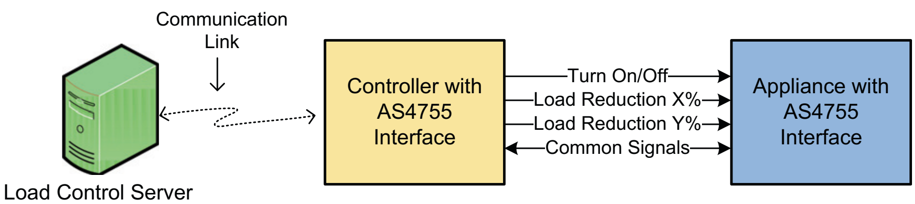

Fig. 7. Direct load control application using AS4755 compliant load control system [17].

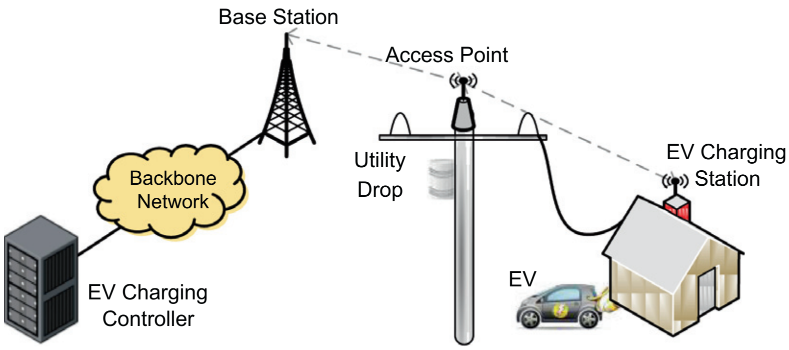

Fig. 8. Illustration of smart EV charging using the smart grid communications network.

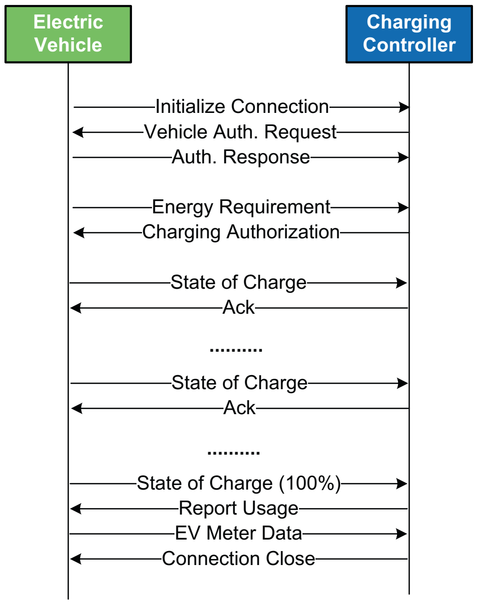

Fig. 9. Application message exchanges during a smart EV charging session [25].

Table 1
EV charging levels according to the SAE J1772 standard [27].

Level	Type	Power level (kW)
Level-1	120 VAC	1.2–2.0
Level-2	Low: 208–240 VAC	2.8–3.8
	High: 208–240 VAC	6–15
Level-3	208–240 VAC	>15–96
	600 VDC	>15–240

charged based on priority and fairness. For example, the EV charging controller may allow the emergency vehicles (e.g., ambulance, police cars, etc.) to be charged fully and provide prioritized charging to those vehicles whose battery charge have been dropped below a certain threshold.

In order to calculate the total communications load (in bytes) of an EV charging system, we consider the admission control model described in [29] where the authors have introduced the concept of activity factor in order to facilitate partial charging of the contending vehicles. Let us assume that the EV charging requests follow a Poisson arrival process with arrival rate λ and the charging duration (i.e. service time) is exponentially distributed with mean μ. Thus, the traffic intensity, ρ of the system is given by:

$$\rho = \frac{\lambda}{\mu}\beta \tag{2}$$

where β is the ratio of battery to be charged which depends on the residual charging level. Using the Erlang-B formula of the teletraffic theory, we can calculate the blocking probability of the system in terms of the maximum number of acceptable vehicles (M) using the following equation:

$$B = \frac{\frac{\rho^M}{M!}}{\sum_{i=0}^{M}\frac{\rho^i}{i!}} \tag{3}$$

Using Eqs. (2) and (3), we now can find the total energy requirement of the system by:

$$\begin{aligned} E_{\text{Total}} &= \text{Avg. System Load} \\ &\quad \times \text{Probability of Succsessful Access} \\ &= \rho(1-B) \end{aligned} \tag{4}$$

If the activity factor is α (where $0 \leqslant \alpha \leqslant 1$), then the energy budget of the system is given by:

$$E_{\text{Budget}} = \alpha\rho(1-B) \tag{5}$$

From Eq. (5), we can see that the energy budget of the system can be tuned by the parameter α given that the maximum number of allowed EVs remains fixed. Now, the number of SOC messages for a particular vehicle i throughout the charging session is given by:

$$n_i = \frac{\alpha\beta_i T_i}{t_{\text{soc}}} \tag{6}$$

where T is the time required to reach full battery charge and t_{soc} is the energy scheduling interval. Note that the SOC reporting interval depends on the utility's choice and may vary between 5 and 30 min. Thus, the overall communication load of an EV charging system can be calculated by using Eqs. (1) and (6):

$$L_{\text{Total}} = M * l_{\text{Fixed}} + \sum_{i=1}^{M}\frac{\alpha\beta_i T_i}{t_{\text{soc}}} l_{\text{soc}} \tag{7}$$

From Eq. (7), we see that the total communications load of the EV charging system is tightly coupled with the available energy of the system which is represented in Eq. (7) by the activity factor α.

The SOC update messages are very critical for the EV charging applications since the charging controller relays on this information to adjust the charging rates. Moreover, they are very delay sensitive since the charger will remain idle and energy will not be transferred (hence, wasted) until it receives energy allocation information against the SOC update message as shown in Fig. 9. Hence, fast and reliable message transfer is the key requirement for the EV applications. In addition, the SOC update messages from different vehicles should be scheduled in such a way that they are distributed over the entire scheduling interval. Otherwise, if all the vehicles send SOC update messages simultaneously, it may create congestion in the underlying communication network.

In addition, the EVs have been proposed to be used as distributed storage devices to absorb excess energy from the renewable energy sources. They are also expected to be used in vehicle-to-grid (V2G) mode to feed power back to the grid to smooth out the natural intermittency of renewable energy sources [5]. Thus, an entire ecosystem of dynamic energy transactions between the EVs and the grid is envisaged to be built which may involve rigorous information exchange at wide range of conditions including fixed and mobile scenarios.

Another important future requirement could be to allow roaming of the EVs among different utility networks. In that case, energy management functionalities would be controlled by the visited utility network and metering and billing functionalities would be carried out by the home utility network. This requires reliable and secure communication path between the two networks to enable real-time information exchange.

3.4. Substation automation

Substation automation refers to the monitoring, protection and control functions performed on substation and feeder equipments. In the substation automation domain, the IEC 61850 and DNP3/IEE1815 are the most widely adopted protocols [30,31]. While the DNP3 (Distributed Network Protocol, version 3) standard only provides communication specifications for low-bandwidth monitoring and control operations, the IEC 61850 standard covers almost all aspects of SAS including real-time, high bandwidth protection and control applications. Therefore, IEC 61850 is gradually becoming the dominant protocol in this field.

3.4.1. Overview of the IEC 61850 standard

The IEC 61850 standard is based on interoperable Intelligent Electronic Devices (IEDs) that interacts with each other, either within a substation (e.g. protection signals to circuit breakers) or on feeders (e.g. automated reclosers and switches along a feeder responding to isolate a fault). Although IEDs of several types and functionalities are defined in the IEC 61850 standard, the most common types include the breaker/switch IED, Merging Unit (MU) IED, and protection and control (P&C) IED [32]. The P&C IED is responsible for supervising the protection and control operations of its serving bay unit. The breaker/switch IED continuously monitors the state and conditions of the corresponding switchgears/circuit breakers, send status information to the P&C IEDs and receives trip/close command from the P&C IEDs. The MU IED collects the analog voltage and current signals from field CT and PT, converts them into digital format and then transmits to the P&C IEDs in the form of sampled analog values (SMVs).

The IEC 61850 communication architecture is comprised of three hierarchical levels – station, bay and process as shown in Fig. 10. The process level includes various switchyard equipments such as CT/PT, I/O devices, sensors and actuators. Bay level P&C IEDs and the station level contains the Human to Machine Interface (HMI) devices, station controller computers, etc. The standard defines two separate Ethernet subnetworks (called 'Buses') to facilitate QoS implementations. While the process bus handles the delay sensitive communication between P&C IEDs and switchyard devices such as breaker and switch IEDs, the station bus handles communication among different bay and with the station controller as well as communication with the external networks.

3.4.2. IEC 61850 communication services and application types

The IEC 61850 protocol is designed to run over standard communication networks based on the Ethernet and the IP standards. To differentiate among various applications and to prioritize their traffic flows, the standard defines five types of communication services:

1. Abstract Communication Service Interface (ACSI)
2. Generic Object Oriented Substation Event (GOOSE)
3. Generic Substation Status Event (GSSE)
4. Sampled Measured Value multicast (SMV)
5. Time Synchronization (TS)

The ACSI services include querying device status, setting parameters and reporting and logging. All ACSI services are requested by the clients and responded by servers. The message exchange inside an ACSI application is similar to that of a FTP session where the application starts with a mutual handshaking followed by data exchange and connection termination.

GOOSE and GSSE services, together often called as Generic Substation Events (GSEs), are used to exchange event and status information (e.g., a binary change of state or an analog value crossing the reporting threshold) in real-time. While the GOOSE message may include several data types like analog, binary, and integer values, the GSSE message is limited to support only a fixed structure of binary event status data. The GOOSE messages use multicast services that allow simultaneous delivery of the same message to multiple IEDs. The IEC 61850 standard also specifies a retransmission scheme to achieve a highly dependable level of GOOSE message delivery [33]. The messages are sent immediately at the time of an event and then repeated with an increasing time interval from $T_{\min}$ to $T_{\max}$ as shown in Fig. 11. The retransmission time gradually increases from $T_{\min}$ and eventually settles at

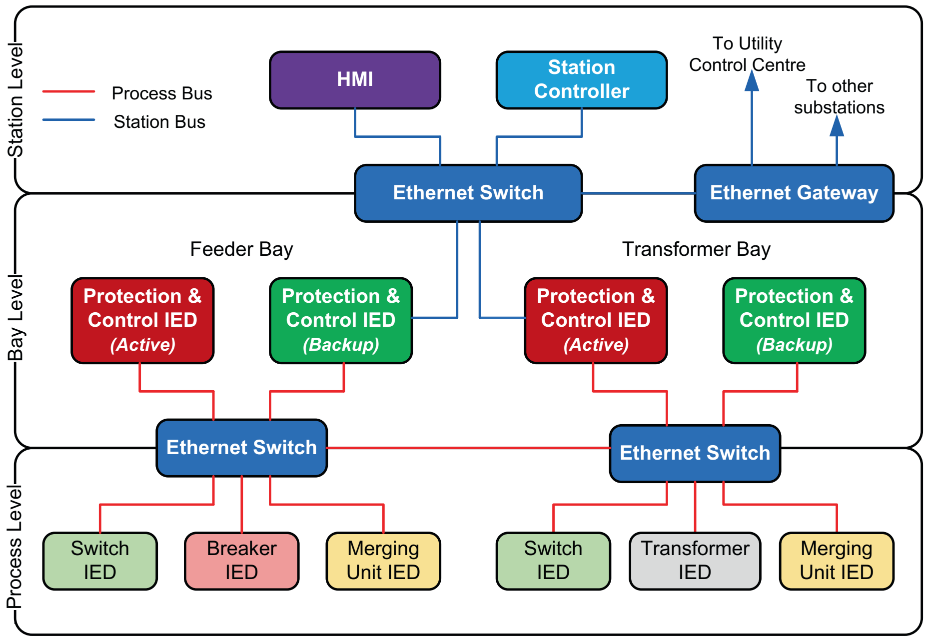

Fig. 10. Architecture of an IEC 61850 based substation automation system.

T_{max}. The repetition with T_{max} continues forever, until a new event occurs and the repetition rate starts again with T_{min} [34]. Each message contains a TTL field after which the message is discarded by the receiver.

The SMV services are used to transfer sampled analog signals and status information from the MU IEDs via the process bus. The TS service is used to broadcast the system clock information to the IEDs to ensure measurement accuracy. The two most popular methods for time synchronization in SAS include the GPS and the IEEE 1588 Precision Time Protocol (PTP).

Since the raw data samples and GOOSE messages are time critical, they are directly mapped to the low-level Ethernet layer to reduce protocol overhead. The GSSE message uses its own protocol mapping called the GSSE T-profile. The TS service use broadcast communication using the UDP/IP transport layer. The rest of the ACSI services use the typical TCP/IP transport layer. The communication stacks mapping of the IEC 61850 services with the OSI (Open Systems Interconnect) layer is shown in Fig. 12.

Moreover, the standard classifies application message types based on the delay requirements of the above five services. Table 2 lists the IEC 61850 message types and their transfer time requirements.

3.4.3. Communication requirements

The IEC 61850 standard specifies the structure for application protocol data unit (APDU). Each APDU consists of one or more application protocol data unit (ASDU) with 6 bytes of header for each ASDU. The ASDU contains the data set (e.g., sampled values, status indication, ACSI data objects, etc.) based on their associated service types [35].

In order to calculate the communication traffic of a substation automation system, at first we need to identify the corresponding IEDs by examining the single line diagram of the substation. For example, let us consider the case of a small distribution substation whose single line diagram is given in Fig. 13.

From the single line diagram, we can see that the substation has two transformer bays and four feeder bays. Each transformer bay contains a Load Break Switch (LBS) and each feeder bay contains a Circuit Breaker (CB). Thus, the total SAS should at least have six MU IEDs (for 6 bays), twelve P&C IEDs (1 + 1 redundancy) assuming that the LBS and CB communicates via their respective MU IEDs. To calculate the traffic load for different SAS applications, we assume the following parameters:

- *Sampled data*. Each APDU generated by the MU IED of the transformer bay contains two ASDUs as it contains two data sets of voltage and current and the feeder bay contains only a single ASDU. Each data set consists of 8 sampled values (8 bytes each) and other status information adding up 32 bytes. Thus the total ASDU size is 96 bytes for this case [36]. Using the APDU structure in [35], the APDU size for sampled data in the transformer MU IED is 198 bytes (2 ASDUs with 2×6 bytes of header) and for feeder MU IED yields 102 bytes (1 ASDU with 6 bytes of header).
- *Protection and control*. APDU size for Type-1 message (trip signal) is 50 bytes, Type-2 message (interlocking) is 150 bytes and Type-3 message (e.g., status indication, control, etc.) is 200 bytes [36].
- *File transfer*. A 1 Mb file is transferred from each IEDs to the station controller in every 1 h.

Assuming a sampling rate of 1440 Hz for analog data, 250 Hz for medium speed messages and 10 Hz for low speed messages according to Ref. [37], the traffic load of each individual application is listed in Table 3.

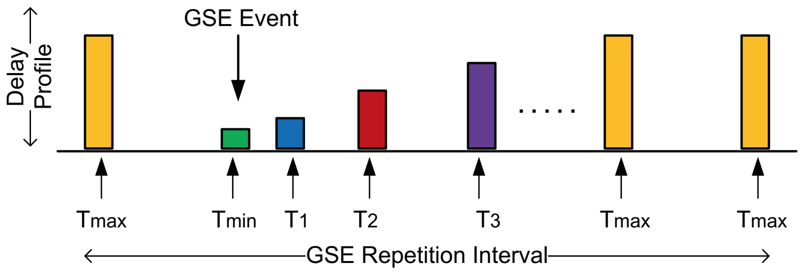

Fig. 11. Repetition pattern of GSE messages.

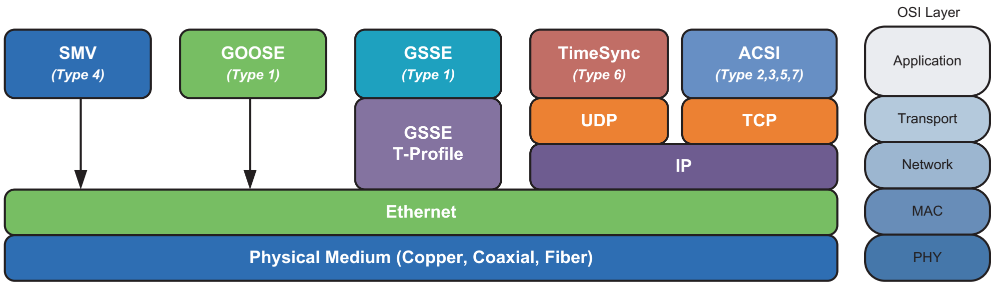

Fig. 12. Communication stack mapping for the IEC 61850 messages.

Table 2
IEC 61850 message types and transfer time requirements.

Message type	Application	Services	Transfer time requirement (ms)
1A	Fast message (trip)	GOOSE, GSSE	3–100
1B	Fast message (other)		20–100
2	Medium speed	ACSI	100
3	Low speed		500
4	Raw data	SMV	3–10
5	File transfer	ACSI	⩾1000
6	Time synchronization	TS	(Accuracy)

The substation automation applications are strictly delay sensitive since they act as the triggering points for the underlying protection and control systems. Many of the time critical messages in substation automation applications contain a Time-To-Live (TTL) fields which implies that the message will lose its relevance if not delivered within the specified time. For example, the trip/close commands needs to be delivered to the respective IEDs within 1/4th cycle time (4 ms for 60 Hz system, 5 ms for 50 Hz system) to perform the required actions. Hence, the IEC 61850 standard defines a strict transfer time requirements for the SAS applications as listed in Table 2.

It is envisaged that in the future smart grid, the domain of substation automation functions will be extended out of the generation and transmission substations to the entire distribution grid [38]. Since the distribution side of the grid covers a vast geographic area, it will be covered by several communication technologies which require the IEC 61850 messages to traverse through both wired and wireless links. Hence, end-to-end QoS guarantee in terms of latency and reliability are the key communication requirements here.

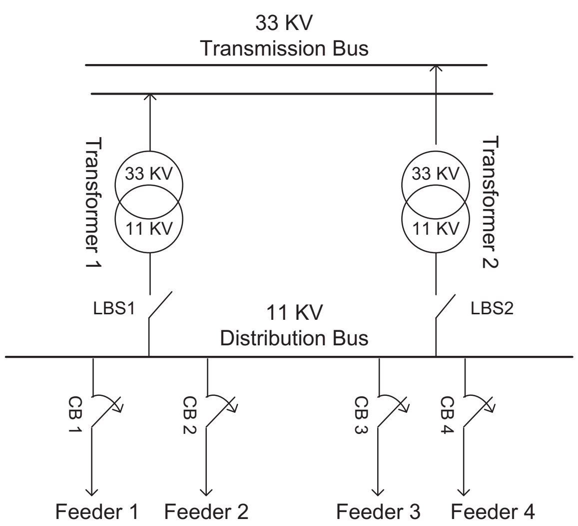

Fig. 13. Single line diagram of a small distribution substation.

3.5. DER/microgrid

Distributed Energy Resources (DERs) are small sources of power generation and/or storage that are connected to the distribution grid. The DER can be from both renewable and non-renewable sources and can either be a distributed generation (DG) source or a distributed storage (DS) source or both. The examples of DER include solar panels, wind turbine, combustion turbine, fuel cells and battery storage systems, etc.

Microgrid is a small local electric power system having one or more DER units and loads. During normal operation, it is connected to the grid and operates in a synchronized mode. However, in case of any fault or maintenance event, it can operate autonomously in an island mode and capable of supporting its own load [39]. Microgrids can be of two types based on their purpose – utility microgrids which serve parts of the utility and industrial/commercial microgrids which only serve customer facilities as shown in Fig. 14. In a microgrid, loads and energy sources can be disconnected from and reconnected to the main grid with minimal disruption to the local loads. This offers potential benefits of using microgrids such as reducing system load by intentionally islanding the microgrids and providing un-interrupted power supply during maintenance activities [40].

Several standards are available for the DER/microgrid operation. From the IEEE standards association, the IEEE 1547 series of standard provides specifications and guidelines for DER/microgrid operation. Among them, the IEEE 1547.2-2008 standard provides specifications for interconnecting DERs and the IEEE 1547.3-2008 provides guidelines for monitoring, information exchange and control of DERs [41,42]. The latest standard of the IEEE 1547 series, the IEEE 1547.4-2011 provides specific guideline for microgrid operation in island mode [43]. On the other hand, the IEC technical committee defines the IEC 61850-7-420 extension to incorporate different parts of DER/microgrid system in the IEC 61850 standard [44].

3.5.1. Energy management

Although the DER/microgrid systems normally reside in the distribution system and managed by the customers, the energy transfer from them must be scheduled and coordinated by the utility operation center. To facilitate this, the IEEE 1547.3-2007 standard provides a model for monitoring, information exchange and control for the DER system. A simplified reference diagram for DER/microgrid management model according to IEEE 1547.3-2007 standard is provided in Fig. 15.

The standard defines a set of external stakeholders – the area electric power system (AEPS) operator, DER operator, DER aggregator, DER maintainer with whom the DER system needs to exchange information with. The overall DER system forms a microgrid having one or more DER units, loads and least one DER controller. A brief description of the key entities of the DER MIC system is provided below.

- *Area electric power system operator*. The regional utility operator that is responsible for the operations of the electric power system (EPS) with which the DER is interconnected through the PCC.
- *DER operator*. Monitor, supervise and control the DER unit via local or remote communication links.
- *DER controller*. The DERC is responsible for monitoring and control of the DER unit. The DERC is equipped with a communication interface to exchange information with the DER operator.
- *DER unit*. The power generation entity for the DER system, e.g. solar panel, wind turbine, etc.
- *Load*. A point of delivery for end-user electrical consumption in the power system. The load is usually made up of a combination of appliances (e.g., heating, ventilation, and air conditioning; refrigerators, etc.) and fed through a single point.

The DER controller performs monitoring and control function as well as collaborates with stakeholders and site equipments using a communication interface. Some loads may be integrated with the facility's energy management system to optimize their operation. In that case, the DER controller collaborates with the energy management system in order to co-ordinate the energy management functions. The DER controller also monitors various points of interconnections such as the point of DER connection, point of load connection and the point of common coupling to ensure the proper functioning of the system. The standard describes several example usage scenarios for DER management such as DER dispatch, scheduling and maintenance.

A DER energy transfer session can be either initiated by the utility operator to increase supply during peak condition or by the customer to sell the energy produced during normal grid operation as an independent power producer (IPP). A sample information exchange model for DER dispatch operation is provided in Fig. 16.

Table 3
Traffic mix for the substation automation system in Fig. 13.

Application	Message type	IED type	Total IEDs	Packet size (Bytes)	Sampling rate (Hz)	Data rate (Kbps)
Protection	1	P&C	6	50	1	2.34
Sampled data	4	MU (trans.)	2	198	1440	4455.00
		MU (feeder)	4	102	1440	4590.00
Interlocks	2	P&C, MU	12	150	250	3515.63
Control	3	P&C, MU	12	200	10	187.50
File transfer	5	MU	12	1 Mb	1/h	3.41
Total traffic volume						12.75 Mbps

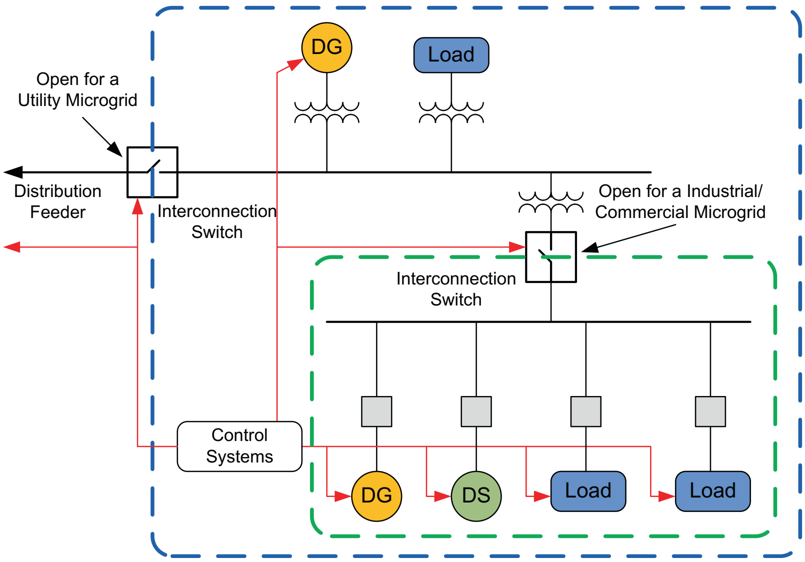

Fig. 14. Diagram of a networked microgrid [39].

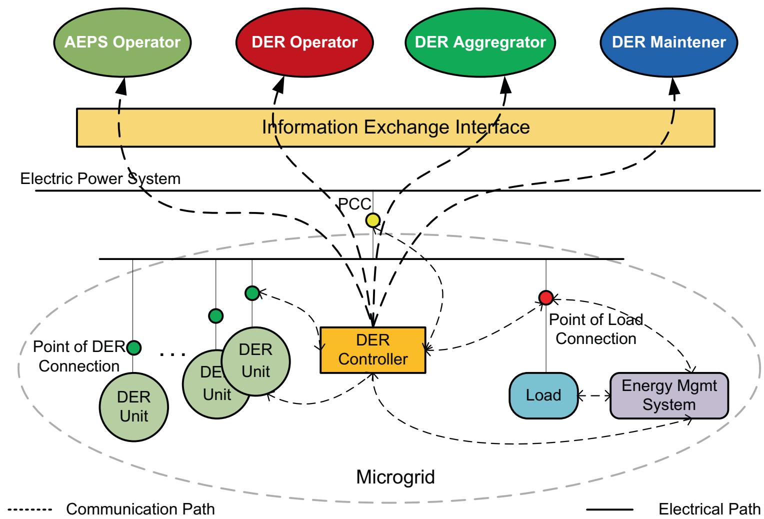

Fig. 15. DER/microgrid management model according to the IEEE 1547.3-2007 standard [42].

3.5.2. Monitoring and control

For seamless operation, the DER/microgrid controller needs to frequently exchange various operating parameters with the utility control center in real-time [44]. The communication requirements of a DER/microgrid controller include the following.

- Management of the interconnection points between the DER units and the power systems they connect to, including local power systems, switches and circuit breakers, and protection.
- Monitoring and controlling the DER units and the associated the energy conversion systems, such as reciprocating engines (e.g. diesel engines), fuel cells, photovoltaic systems, and combined heat and power systems.
- Monitoring and controlling the individual generators, excitation systems, inverters/converters and auxiliary systems, such as interval meters, fuel systems, and batteries.
- Monitoring the physical characteristics of equipment, such as temperature, pressure, heat, vibration, flow, emissions, and meteorological information.

A representative model of a DER/microgrid monitoring and control system based on the IEC 61850-7-420 standard is illustrated in Fig. 17.

The information flows from a DER/microgrid system can be of two types – (i) energy management information and (ii) monitoring and control information. According to the smart grid communication architecture, the energy

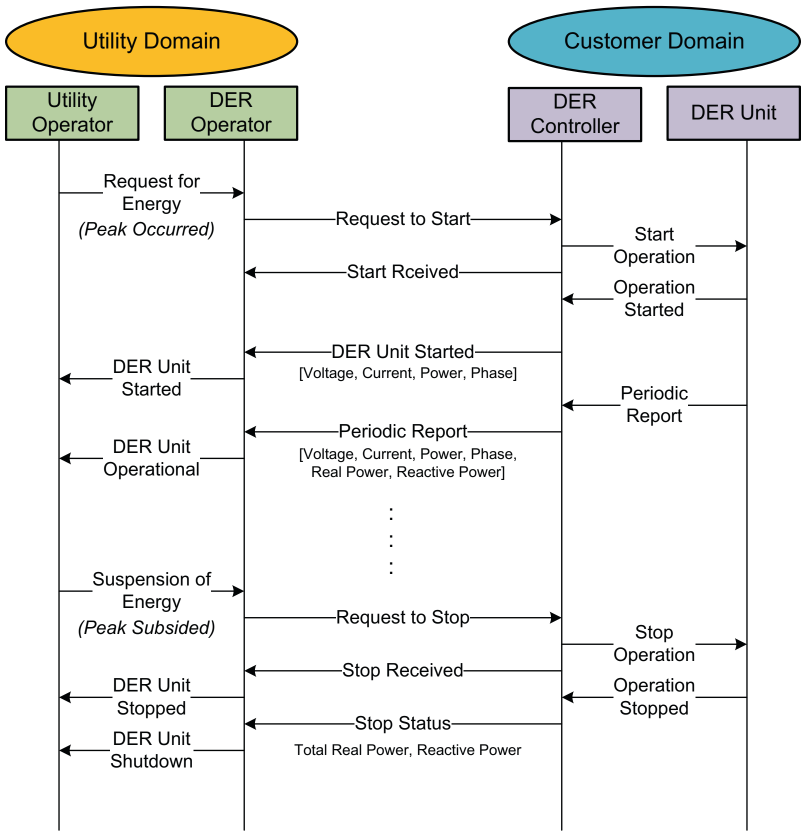

Fig. 16. Message exchanges during a DER dispatch session according to the IEEE 1547.3 standard [42].

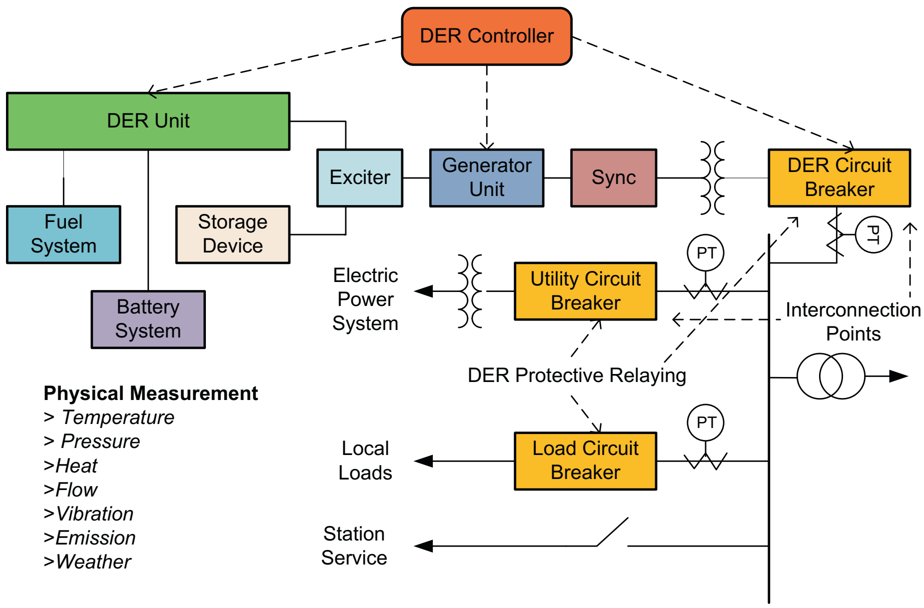

Fig. 17. A DER/microgrid monitoring and control system based on the IEC 61850-7-420 standard [44].

management traffic will be carried by the NAN since the energy transfer is controlled by the owner of the DER unit. In contrast, the monitoring and control traffic will be carried by the FAN since it will be used by the utility control center. Nevertheless, in practice both logical NAN and FAN will be using a single physical network. Hence, strict

QoS control mechanisms are required to efficiently handle the reporting, monitoring, control and protection traffic with different QoS requirements in the same network.

3.6. Wide area measurement

Wide Area Measurement System (WAMS) refers to an advanced sensing and measurement system that continuously monitors the health of the power grid. In a WAMS, the system state and power quality information are obtained from the state measurement modules based on the Phasor Measurement Units (PMUs). Unlike conventional measurement systems, the PMUs provide accurate system state measurements in real-time utilizing GPS to provide time-stamp for each measurement [45]. Due to the precise synchronization of the measurements, the utility control center can obtain high resolution phase information which enables them to initiate proper response within seconds, to protect a whole wide-area network from black-out events [46]. The PMUs were traditionally installed on the generation and transmission domains (high voltage level) because of the conventional top-down direction of the power flow. However, in a smart grid, the PMUs are also expected to be deployed at the distribution domain (medium and low voltage levels) to enable real-time monitoring of the overall power system [47,48].

A complete WAMS system comprises of hundreds of PMUs deployed at various locations in the national or regional electrical grid. The PMUs are locally grouped and the measurements from them are first collected by a Phasor data concentrator (PDC) via the local communication network as shown in Fig. 18. The data is then routed to the central control network (CCN) located at the utility's core network via the backhaul communication networks [49]. The challenges of a smart grid communications network to provide reliable communication paths between the PMUs and PDC with in a strict delay bound (typically < 1 s) [50].

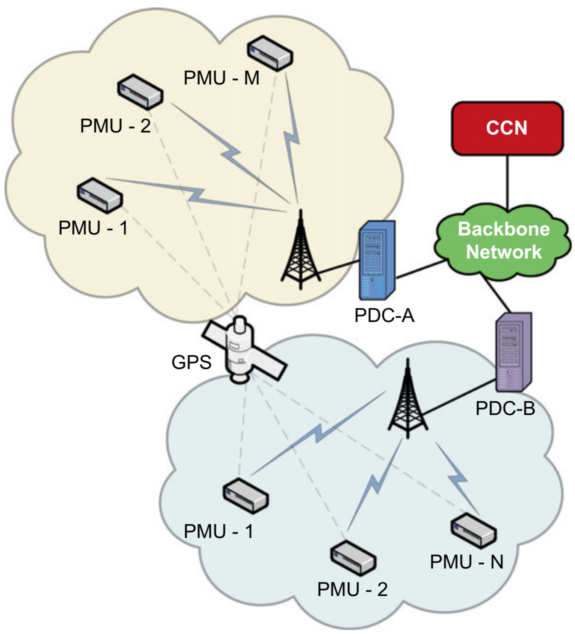

Fig. 18. Communication architecture of a wide area measurement system in the smart grid.

The IEEE C37.118-2005 standard provides the data communication specifications for the PMUs [51]. According to the standard, each PMU data packet contains a fixed 16 byte header followed by a variable length message body based on the number of Phasor readings. Table 4 shows the payload structure of a sample phasor data frame based on the IEEE C37.118-2005 standard.

Here, we assume that each PMU data frame is comprised of four Phasor readings (three phase voltages and current), two analog fields and one digital field. Considering the lower layer protocol overheads such as IP (20 bytes) and User datagram Protocol (UDP) (8 bytes), the total MAC PDU (protocol data unit) size becomes 76 bytes. The overall communications load of a PMU depends on the reporting frequency (F_s) of the system. The IEEE C37.118-2005 standard specifies reporting frequency of 10, 25 Hz and 10, 12, 15, 20, 30 Hz for a 50 Hz and 60 Hz based power systems respectively. The maximum communication delay between the PMU and the PDC should be such that a measurement is received before the next one is available. Hence, it can be expressed as the inverse of the reporting frequency.

Based on the payload size specified in Table 4, the application data rate of a PMU ranges from 6 Kbps to 24 Kbps for a reporting cycle of 10 Hz and 25 Hz respectively (under a 50 Hz power system). Apart from continuous measurement reports, generally the PMUs are co-located with microprocessor based Transient Fault Recorder (TFR). The TFR generate bulk statistical information about transient faults, voltage swings and trends, etc. and the data is transmitted hourly or daily. The daily data volume for a typical TFR may reach 100 MB [50].

Measurements from the PMUs are strictly delay-sensitive since they produce continuous high resolution measurements and a measurement will lose its significance if the data is not transferred before the next one is available. Moreover, continuous transmission of real-time measurements requires reliable communication along with guaranteed Quality of Service (QoS). Another issue

Table 4
Payload structure of a sample phasor data frame.

No.	Field	Size (Bytes)	Comments
1	SYNC	2	Synchronization byte
2	FRAME SIZE	2	Number of bytes in frame
3	ID CODE	2	PMU ID
4	SOC	4	Second of century time stamp
5	FRACSEC	4	Time fraction and quality flag
6	STAT	2	Bitmapped Flag
7	PHASORS	4×4[a]	No. of phasors
8	FREQ	2[a]	Frequency
9	DFREQ	2[a]	Rate of change of frequency
10	ANALOG	2×4[b]	2 Analog data
11	DIGITAL	1×2	1 Digital data (16 bit field)
12	CHK	2	Cyclic redundancy checks

[a] 16-Bit signed integer.
[b] 32-Bit floating-point.

is that since the PMUs produce synchronous measurements, if all of them try to send the data simultaneously there will be a sudden burst of communication load in the network which may severely degrade the network performance. Hence, PMU data transfer should be intelligently scheduled so that both the network load and application delay remain within a specified level.

3.7. Distribution supervision

The goal of distribution supervision is to provide increased visibility into the power distribution network in order to take proactive actions to prevent equipment failure and ensure public safety. Unlike sensing and measurement applications in substation and microgrid networks, which is related to certain infrastructure points in the distribution system, the scope of distribution supervision is more distributed that includes passive infrastructure like transmission lines, cables and branching points [50].

In the smart grid, it is expected that most of the overhead transmission lines will be equipped with adequate sensor and actor nodes for continuous monitoring and preventive measures. The underground transmission lines will also have sensors to monitor the thermal condition and corrosion of the burial conductors. Moreover, multimedia sensors might be used in some cases to detect line faults and monitor nearby environment to prevent contact with vegetation or animals [52]. In addition, wireless sensor networks will be used to monitor the weather conditions since the power generation from the renewable energy sources is highly influenced by them. For example, solar power is not available at night and wind power is heavily dependent on the wind direction in smaller wind farms. Solar panels require temperature, radiation and cloud sensors to forecast energy output in order to help the utility control center to manage the generation sources. Similarly, the wind turbines require temperature, pressure, humidity and wind orientation sensors to optimize the overall power generation [53].

For distribution supervision applications, the IEEE 1451 based 'smart sensor' is widely considered as the most preferred solution for its interoperability and flexible architecture. The IEEE 1451 standards defines a set of open, common, network-independent communication interfaces for connecting transducers (sensors or actuators) to microprocessors, instrumentation systems, and control/field networks [54]. The 'smart sensor' model has two separate network entities – Network Capable Application Processor (NCAP) and Transducer Interface Module (TIM) for sensor operation. The TIM consists of transducers (up to 255), signal conversion and processing electronics, and Transducer Electronic Data Sheets (TEDSs). The TEDS provide transducer ID (identification), measurement range, location, calibration and user information, and more. The NCAP can access the TIM through the Transducer Independent Interface (TII) and send the sensor information to the control network. The conceptual layout of the IEEE 1451 smart sensor model is shown in Fig. 19.

Since the DS system is spread across a vast geographic area, a wireless communication system is the appropriate for sensor applications. To facilitate wireless sensor application, the IEEE 1451.5 standard defines a wireless based transducer interface and TEDS. It also specifies radio-specific protocols for achieving this wireless interface. Wireless standards such as 802.11 (WiFi), 802.15.1 (Bluetooth), 802.15.4 (ZigBee), and 6LowPAN are adopted as the IEEE 1451.5 wireless interfaces [55].

For the above discussion, it is clear that the distribution supervision systems will be comprised of many IEEE 1451.5 based wireless sensor networks (WSNs) connected to the smart grid FAN. The coordinator node of these WSNs will act as the gateway between the WSN and the FAN. Nevertheless, the communication requirements for a particular distribution supervision system depend on its deployment scenarios, network architecture and communication protocols. For example, a simple illustration of overhead transmission line monitoring system based on a WSN is provided in Fig. 20.

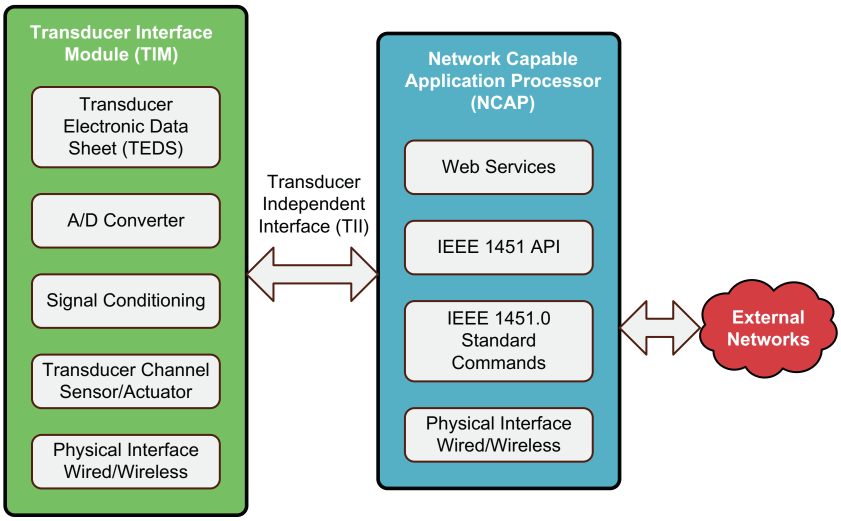

Fig. 19. The IEEE 1451 smart sensor model [54].

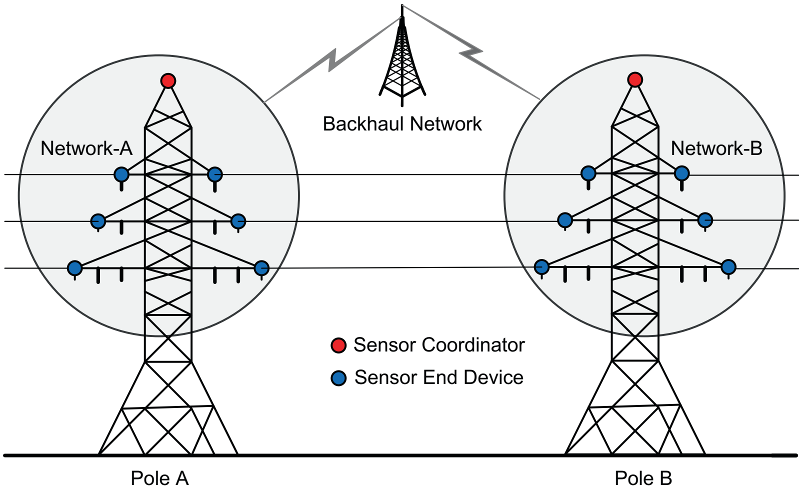

Fig. 20. Illustration of an overhead transmission line monitoring system in the smart grid.

An overhead transmission line monitoring system may contain several types of sensors such as accelerometers, magnetic field sensors, strain sensors, temperature sensors. All the sensors except the temperature sensor require two channels to collect data in the horizontal and vertical axes [56]. The communication load (in bits) for such applications can be expressed by:

$$\rho_i = \frac{n_{\mathrm{CH}} * f_{\mathrm{sample}}}{T_{\mathrm{report}}} \quad (8)$$

where n_{CH} is the number of sensing channels, f_{sample} is the number of data points per report and T_{report} is the reporting Interval. A summary of the communications loads for a typical overhead transmission line sensor network is provided in Table 5 according to [56]. Please note that here we've considered application layer loads only.

Since the traffic interarrival times are different for various sensor nodes, data aggregation techniques are required to aggregate data from several nodes to improve the network utilization and data transmission efficiency. However, data aggregation may introduce longer delays, to compensate which transmission rate might need to be increased.

4. Performance requirements and research challenges

In the previous section, different smart grid applications and their basic networking architectures and traffic characteristics has been discussed. It is quite evident from those discussions that any future smart grid communications network needs to support a wide range of traffic sources with significantly varying QoS requirements. In this section, we summarize some of the performance requirements of these applications and highlight some of the key research challenges in relation to them.

4.1. Performance requirements

In case of multimedia applications, while it is important to ensure proper QoS, an even more vital issue is how the end-user perceives and experiences the service. This has often been referred to as Quality of Experience (QoE) and although it is a subjective measure, in the end it determines how satisfied the user is [57]. For example, a user can tolerate up to a certain amount of performance degradation during a voice call while still having a fair degree of QoE at the end of that session. On the other hand, session-durations for smart grid M2M applications are generally brief and involve only a handful of message exchanges. However, most of these applications require highly reliable message delivery within a strict delay bound. Hence, their performance has to be measured in objective terms against a set of pre-defined QoS attributes (e.g., delay, jitter, and packet-loss).

Based on our discussions in Section 3, we can classify the key smart grid applications/traffic sources into following five categories.

- Protection traffic from the IEC 61850 compliant IEDs that can operate both at the substation and in distribution systems.
- Control traffic from the field devices (sensors/actors) offering services to substations, high and low voltage distribution networks.
- Monitoring applications such as the PMUs over a large distributed area covering the electricity distribution network.
- Metering and billing applications; mostly servicing residential and industrial premises through smart meters.
- Demand management traffic serving different applications such as EV charging, energy storage systems, and scheduling renewable energy sources.

Table 6 lists the typical response time for the above traffic classes according to the draft European Telecommunications Standards Institute (ETSI) technical report on M2M communication for the smart grid [50]. It indicates the range of delay variability of smart grid applications that needs to be catered by an integrated communications network.

Table 5
Example of transmission line sensor types and data requirements.

Type	Function	Data points (floats)	Data size[a] (bytes)	No. of channels	Sampling freq. (Hz)	Reporting interval (s)	Data rate (bps)
Accelerometers	Inclination	4	16	2	60	300	204.8
	Cable tilt	2	8	2	60	300	51.2
	Cable position	2	8	2	60	300	51.2
Magnetic field sensor	Magnetic field	4	16	2	10	1	10,240
	Current	1	4	2	10	1	640
	Power quality	4	16	2	10	1	10,240
Strain sensor	Extension and strain	2	8	2	60	300	51.2
Temp. sensor	Temperature	1	4	1	5	5	32
Total traffic volume							21 Kbps

[a] 1 Floating point data = 4 bytes.

Table 6
Typical response time for different application classes in the smart grid [50].

Application class	Typical maximum response time	Data burst size (range)
Protection	1–10 ms	Tens of bytes
Control	100 ms	Tens of bytes
Monitoring	1 s	Tens to hundreds of bytes
Metering/billing	Hours	Hundred of bytes
Reporting/software update	Days	KB to MB

Data traffic for the above applications can also be classified as periodic/deterministic, semi-periodic, random and event-based. In the conventional communication networks well defined resource allocation and QoS models exists to serve traffic such as voice, data, CBR (Constant Bit Rate) and VBR (Variable Bit Rate) coded video. However, besides periodic and semi-periodic traffic, event based traffic sources are hardly seen in these applications other than some specialized industrial sensor networks [58]. Delay requirements in such events could very short, as low as few milliseconds. For example, according to the IEEE 1646 standard, the delay requirement for protection events is 4 ms within a substation and 8–12 ms external to the substation [59]. Other event based traffic such as the ‘‘last gasp’’ alarms could be quite stringent since the alarm needs to be detected and transmitted within a shortest possible delay due to possible energy constraints after a power outage.

Table 7 summarizes the traffic characteristics and critical aspects of some of the key smart grid applications discussed in this paper.

4.2. Key research challenges

Whilst serving number of applications in a communications network with diverse QoS profiles itself is a challenging issue, there are several other challenges exist in a smart grid communications network. In this section, we shall briefly discuss only a few important research challenges to keep the scope of this paper limited. In addition, as a critical infrastructure the smart grid communications network is also vulnerable to various security attacks (e.g., intrusion and denial of service). However, this article is not considering the security issue.

4.2.1. Short data burst transmission from a large number of devices

To provide an efficient data transmission mechanism for short data burst transmissions from a large number of devices is a major challenge for the smart grid communications network. Contemporary 3G/4G communication networks have been designed to support moderate number of nodes per base-station but with high data rates. However, the smart grid communications network needs to serve a large number of nodes generating short bursts of data that requires frequent entry/re-entry in the network. Occasionally, the random access mechanism may experience avalanche of network entry requests/attempts caused by an event in the grid [13]. Such high random access loads are very difficult to handle as it could overwhelm any network by simply exhausting its signaling channels [60]. Leading M2M communication standardization committees including IEEE 802.16p and Long Term Evolution – Advanced (LTE-A) have already paid considerable attention to this critical issue and a number of solutions have been put forward by their associated task groups [61]. However, it is still an open research issue that needs further investigation.

4.2.2. Resource allocation and QoS control in a heterogeneous network

As seen from Fig. 2, the overall smart grid communications network is envisaged to be comprised of several communication technologies including wired, wireless and power line carrier (PLC) operating at different parts of the grid. To develop such a networking environment, researchers need to concentrate on heterogeneous network (Hetnet) architecture [62]. For example, in the HV segment of the grid, many protection and monitoring sensors will be installed that could be organized in a clustered

Table 7
Summary of traffic requirements for the key smart grid applications.

Application	Reference standards	Traffic characteristics	Critical aspects
AMR/AMI/DR	ANSI C12.19, IEEE 1377, IEC 61968-9, OpenADE, OpenADR	Delay tolerant Mostly periodic/event based Small burst size Multicast/broadcast	Large number of devices High overheads High random access loads Uplink biased
DER/microgrid/EV	IEEE 1547.x, IEC 61850-7-420	Delay sensitive Semi-periodic/event based Multicast/broadcast	Real-time communication High reliability Mobility (e.g., EV roaming)
Substation automation	IEC 61850, DNP3/IEE1815, IEEE 1646	Extremely delay sensitive No retransmission Event based Reliable multicast	Mission critical Explicit message expiry time End-to-end delay bound High reliability
Wide area monitoring	IEEE C37.118	Delay sensitive Periodic Limited retransmission	Continuous transmission Dedicated bandwidth High reliability
Distribution supervision	IEEE 1451.x	Delay sensitive/tolerant Periodic/event based/ random Low power consumption	Large number of devices Clustered sensor networks Data aggregation

manner depending on their spatial distribution and traffic requirements. For such case, clustered sensor networks could be developed based on the WPAN/WLAN (Wireless Personal Area Network/Wireless Local Area Network) based standards and then those clustered networks could be connected via a WiMAX (Wireless Interoperability for Microwave Access) or a BPL (Broadband over Power Line) based backhaul network.

Perhaps the most important challenge for such architecture is to provide end-to-end QoS for different classes of traffic which is the product of QoS values within each subnetwork. For example, consider the case of WiMAX–WLAN Hetnet architecture [63]. The WiMAX networks have an end-to-end QoS framework that provides guaranteed QoS via the logical service flows [64]. For QoS management among the service flows, the IEEE 802.16 standard has defined several scheduling classes but most of them involve high signaling overheads. On the other hand, the WLAN networks have a loosely coupled QoS framework based on the IEEE 802.11e standard that supports QoS only at the MAC layer [65]. Hence, to provide end-to-end QoS guarantee within the Hetnet, the WiMAX scheduling classes should be appropriately mapped with the WLAN access categories based on the specific M2M traffic requirements. Also, the combined QoS framework needs to be jointly optimized to reduce signaling overheads and radio resource usage.

In such paradigm, a policy based QoS manager can be used to optimally meet the end-to-end QoS requirements [66]. For example during a smart grid event, the QoS manager can restrict resource allocation to some of the delay-tolerant applications based on a set of admission control rules and re-allocate them to the event based applications to meet their newly generated QoS requirements. In such cases it is necessary to investigate both reactive and proactive resource allocation techniques based on the application characteristics and operating environment of the network [67].

Apart from the above issues, some of the other challenges include supporting operation of energy constrained communication environments, providing address space for a large number of devices, ensuring reliable communication regardless of operating conditions, and supporting uplink biased traffic [68–70].

5. Conclusion

In this paper, we have presented a comprehensive review of several key smart grid applications and their communication requirements. While we provided a general idea about the communication requirements of AMR, DR, DER/microgrid and EV charging applications, we generated illustrative data rate requirements for substation automation, wide area measurement and distribution supervision applications based on their relevant standards as well as described their QoS requirements in detail.

In Section 4 we have highlighted some of the major research challenges and possible research directions. Discussions show that the traffic models will include range of traffic sources which are periodic, random/aperiodic and event based. Periodic and random traffic sources can be modeled using conventional teletraffic models but the event based traffic model will be application and system specific. Moreover, event based traffic will be very demanding in terms of resource allocation techniques. As the global smart grid initiatives are accelerating, new smart grid applications will continue to emerge with the introduction of multi-serviced QoS enabled smart grid communication systems. Hence, the researchers must concentrate on the development of necessary network architectures and protocols to serve in a scalable and adaptable manner.

As a part of the continuing work, we are now developing several event based traffic models for the smart grid to evaluate the performance of communication networks. Also, the future research work will concentrate on the development of a cooperative Hetnet architecture for the smart grid.

Acknowledgments

This research was jointly supported by the Australian Research Council (ARC) and AUSGRID under the smart grid communications project.

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