SMART GRID INTEROPERABILITY PANEL

IEC 61850 Information Model Concepts and Updates for Distributed Energy Resources (DER) Use Cases and Functions

A white paper developed by the Smart Grid Interoperability Panel – October 2015

Acknowledgements

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About the Smart Grid Interoperability Panel

The Smart Grid Interoperability Panel (SGIP) is a consortium that securely accelerates and advances Grid Modernization through interoperability and the leadership talents of its members. SGIP is committed to improving individual quality of life by integrating energy resources securely, intelligently and efficiently. To learn more about SGIP, visit http://sgip.org/.

1. Introduction

1.1 Scope and Purpose

The scope and purpose of this report is to overview the hierarchical architecture of Distributed Energy Resources (DER)[1], describe the IEC 61850 information modeling concepts, apply the DER IEC 61850 information model data objects for each of the "Smart Inverter" functions as pertinent to the DER architecture, and illustrate a mapping of the IEC 61850 information model to IEEE 2030.5 (Smart Energy Profile 2.0 or SEP2) protocol.

In this document, the term "DER" refers to electric generation and storage devices which utilize inverters and to proxies (e.g., facility energy management systems or aggregators) that manage generation, storage, and controllable loads. DER systems are connected directly or indirectly (behind a facility meter) to a utility distribution system, even if sometimes they provide services to the transmission system. Although some broader definitions of DER include synchronous generators, this document restricts the term to devices and proxy systems that can perform "Smart Inverter" functions and can interact with utilities and third parties through communications.

1.2 Background

"Smart Inverter" or advanced DER functions have been developed over the last few years through collaborative efforts by the SGIP Priority Action Plan (PAP) 7, EPRI[2], IEC TC57 WG17, California's Smart Inverter Working Group (SIWG), IEEE 1547 revision working group, and other groups. The DER IEC 61850 information model has also been used as a source for developing mappings to other protocols, such as IEEE 1815 (DNP3) and IEEE 2030.5 (SEP 2).

IEEE 1815 mappings from IEC 61850-7-420 and IEC 61850-90-7 are found in the DNP Application Notes documents, including AN2013-001, Version 2013-01-14, "*DNP3 Profile for Advanced Photovoltaic Generation and Storage.*" Additional mapping for energy storage systems are being undertaken by the MESA Alliance[3]. DNP3 is expected to be used for direct utility SCADA monitoring and control of DER systems.

IEEE 2030.5 has also developed data objects that were based on the IEC 61850 information model. This SEP2 protocol is expected to be the default protocol for California's investor-owned utilities for indirect interactions with DER systems, facility energy management systems, and aggregators, where the utility is not directly monitoring and controlling the DER systems.

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[1] The SGIP DRGS previously published the Subgroup B White Paper "*Distributed Energy Resources (DER): Hierarchical Classification of Use Cases and the Process for Developing Information Exchange Requirements and Object Models*", 2014, which describes the DER hierarchical architecture in greater detail.

[2] Electric Power Research Institute, "*Common Functions for Smart Inverters, Version 3*", Product ID: 3002002233, February 2014

[3] http://mesastandards.org/

2. Hierarchical Architecture of DER Systems

2.1 Stakeholders in Managing DER Systems

Traditionally, utilities have owned most of their equipment, and have contractually had direct control over all generation, usually at the transmission level. The entire purpose of bulk generators is to provide power to the utility. However, with the advent of DER systems, utilities no longer have direct control over generation, but must coordinate with many different DER stakeholders with many different purposes in order to cope with generation sources now usually at the distribution level.

DER systems involve many different stakeholders, each of which has different purposes and business drivers. These business drivers can be in conflict with each other, and many are not directly focused on benefiting the utilities. Some of the DER capabilities benefit just one stakeholder, but in most situations, many of the DER capabilities can benefit multiple stakeholders often through tariff agreements or market pricing that balance the compensations across these stakeholders. Some the primary stakeholders are illustrated in Figure 1.

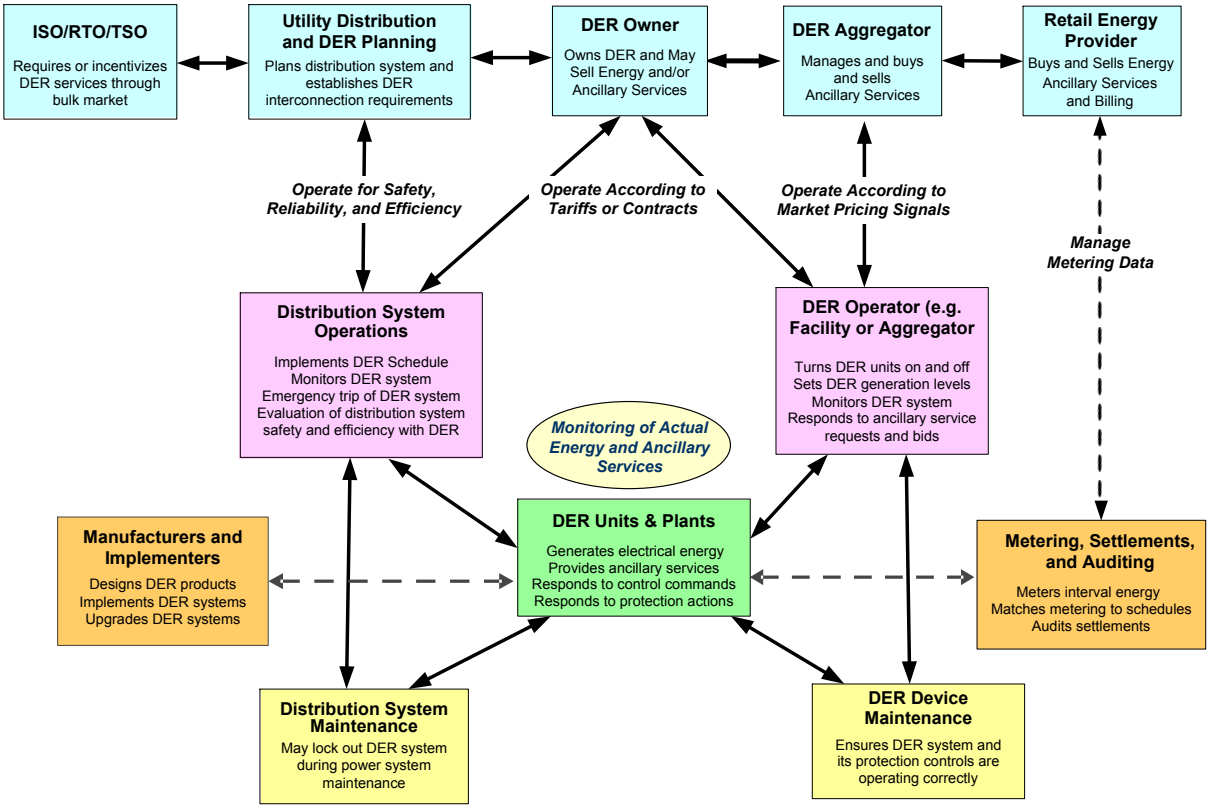

Figure 1: Variety of Stakeholders with Different Business Drivers Interacting with DER Systems

2.2 DER Hierarchical Levels and Interfaces

Almost all DER systems include inverters that convert DER primary mover power to become compatible with the grid standard of 60 Hz sine waves. These inverters are managed by software, and therefore are easily manipulated to change their characteristics. Other DER technologies, such as

energy storage, allow these systems to provide additional grid services. Over the past few years, these "smart" DER functions have been identified and their capabilities described in more detail, even though it is not always clear yet where they may be cost-effectively deployed and under what circumstances to deploy these capabilities.

Direct control by utilities is not feasible for the thousands if not millions of DER systems "in the field", so a hierarchical approach is necessary for utilities to interact with these widely dispersed DER systems. At the local level, DER systems must manage their own generation and storage activities autonomously, based on local conditions, pre-established settings, and DER owner preferences (*primary control*). However, DER systems are active participants in grid operations and must be coordinated with other DER systems and distribution grid devices. In addition, the distribution utilities must interact with regional transmission organizations (RTOs) and/or independent system operators (ISOs) for reliability and market purposes. In some regions, retail energy providers (REPs) or other energy service providers (ESPs) are responsible for managing groups of DER systems (*secondary control*).

This hierarchical approach can be described as hybrid combinations of five (5) levels across multiple domains, as illustrated in Figure 2, Five-Level Hierarchical DER System Architecture. This overview figure is expanded and described in more detail in the 2014 Subgroup B White Paper "*Distributed Energy Resources (DER): Hierarchical Classification of Use Cases and the Process for Developing Information Exchange Requirements and Object Models.*"

The Smart Grid Architecture Model (SGAM) shown in the gray background of the figure was originally developed by the European community under the M/490 effort. This model and the SGIP model are now actively being harmonized. For instance, the SGIP model now recognizes DER as a domain, although it has not finalized a new model diagram structure.

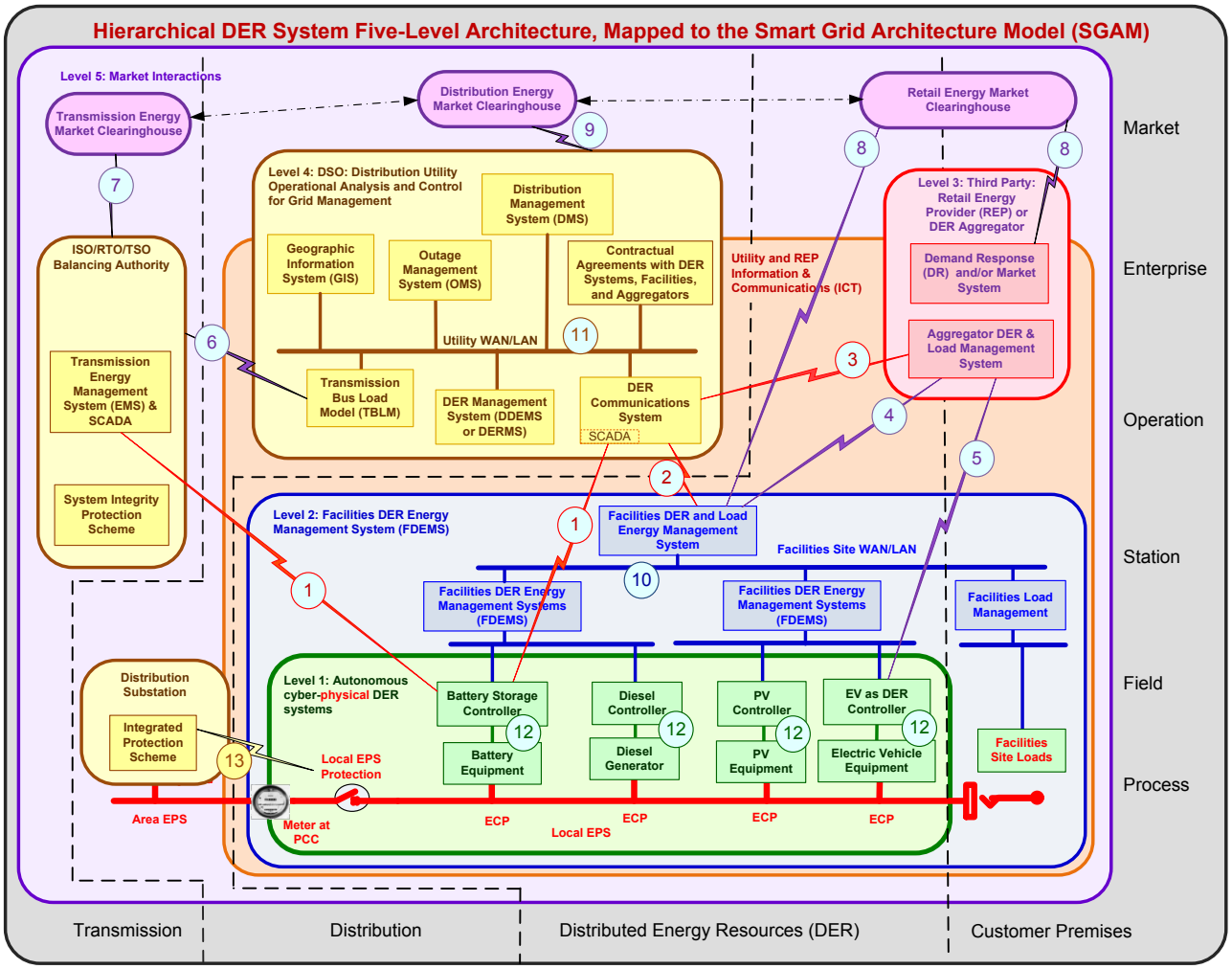

Figure 2: Five-Level Hierarchical DER System Architecture

1. **Level 1 DER Systems** (green in Figure 2.) is the lowest level and includes the actual cyber-physical DER systems themselves. These DER systems will be interconnected to local grids at Electrical Connection Points (ECPs) and to the utility grid through the Point of Common Coupling (PCC) (the ECP and the PCC may be the same if the DER is directly grid-connected). These DER systems will usually be operated autonomously. In other words, these DER systems will be running based on local conditions, such as photovoltaic systems operating when the sun is shining, wind turbines operating when the wind is blowing, electric vehicles charging when plugged in by the owner, and diesel generators operating when started up by the customer. This autonomous operation can be modified by DER owner preferences, pre-set parameter, and commands issued by utilities and aggregators.
2. **Level 2 Facility DER Management** (blue in Figure 2.) is the next higher level in which a facility DER management system (FDEMS) manages the operation of the Level 1 DER systems. This FDEMS may be managing one or two DER systems in a residential home, but more likely will be managing multiple DER systems in commercial and industrial sites, such as university

campuses and shopping malls. Utilities may also use a FDEMS to handle DER systems located at utility sites such as substations or power plant sites.

3. **Level 3 Third Parties: Retail Energy Provider or Aggregators** (red in Figure 2.) shows market-based aggregators and retail energy providers (REP) who request or even command DER systems (either through the facility's FDEMS or via aggregator-provided direct communication links) to take specific actions, such as turning on or off, setting or limiting output, providing ancillary services (e.g. volt-VAR control), and other grid management functions. Aggregator DER commands would likely be price-based either to minimize customer costs or in response to utility requirements for safety and reliability purposes. The combination of this level and level 2 may have varying scenarios, while still fundamentally providing the same services.
4. **Level 4 Utility Operational Grid Management** (yellow in Figure 2.) applies to utility applications that are needed to determine what requests or commands should be issued to which DER systems. Distribution System Operators (DSOs) must monitor the power system and assess if efficiency or reliability of the power system can be improved by having DER systems modify their operation. This utility assessment involves many utility control center systems, orchestrated by the Distribution Management System (DMS) and including the DER database and management systems (DERMS), Geographical Information Systems (GIS), Transmission Bus Load Model (TBLM), Outage Management Systems (OMS), and Demand Response (DR) systems. Transmission System Operators (TSOs), regional transmission operators (RTOs), or independent system operators (ISOs) may interact directly with larger DER systems, and/or may request services for the bulk power system from aggregated DER systems through the DSO or through the REP/Aggregators. Once the utility has determined that modified requests or commands should be issued, it will send these either directly to a DER system, indirectly through the FDEMS, or indirectly through the REP/Aggregator.
5. **Level 5 Market Operations** (purple in Figure 2.) is the highest level, and involves the larger utility environment where markets influence which DER systems will provide what services. The TSO markets are typically bid/offer transaction energy markets between individual DER owner/operators and the TSO. At the distribution level, the markets are not yet well formed and, over time as they evolve, may be based on individual contracts, special tariffs, demand response signalling, and/or bid/offer transaction energy markets.

Although in general DER systems will be part of a hierarchy, different scenarios will consist of different hierarchical levels and variations even within the same hierarchical level. For instance, small residential PV systems may not include sophisticated FDEMS, while large industrial and commercial sites could include multiple FDEMS and even multiple levels of FDEMS. Some DER systems will be managed by Retail Energy Providers through demand response programs, while others may be managed (not necessarily directly controlled) by aggregators and utilities through financial and operational contracts or tariffs with DER owners.

The management of DER systems involves multiple levels of information exchanges (see circled numbers in Figure 2):

- **Interface 1** – Direct DSO and/or TSO interactions with DER systems between Level 4 and Level 1. These direct DSO interactions usually imply that the DER system is under contract to be managed by the DSO, such as providing energy storage for smoothing fluctuations or

counteracting spikes and sags. The DSO generally uses its SCADA system for these interactions. Interaction latency requirements are typically a few seconds.

- **Interface 2** – DSO interactions with FDEMS between Level 4 and Level 2. These interactions may be for the purpose of the DSO monitoring the aggregated generation and load, usually at the PCC, with the ability of the DSO to request ancillary services, such as reactive power support, frequency support, or limiting real power output at the PCC. The DSO could also request data on generation capabilities, load forecasts, and other longer term information. The DSO could also provide updated settings and schedules for specific advanced functions, such as volt-var control or frequency-watt control. It could also include pricing signals. These DSO-FDEMS interactions would probably not use the real-time SCADA system (due to concerns about the volumes of data and cyber security) and could be every few minutes, or hourly, weekly, or seasonally.
- **Interface 3** – DSO interactions with aggregators between Level 4 and Level 5. These interactions would be primarily for the DSO to monitor aggregated groups of DER systems that are under the aggregator's management. These groups of DER systems would be established by the DSO, such as all DER systems on a particular feeder or feeder segment, or all DER system capable of performing the volt-var function. The DSO could then issue commands (or requests, depending upon the contractual relationships) to specific groups of DER systems via the aggregator.
- **Interfaces 4 and 5** – Aggregator interactions with DER systems or FDEMS between Level 5 and Levels 3 and 4 (respectively). These interactions consist of monitoring and control (or requests) so that the aggregator has visibility of all DER or FDEMS under its management.
- **Interface 6** – DSO interactions with the TSO or ISO/RTO between Level 4 and Level 5. These interactions provide the TSO with the ability to request ancillary services from DER systems, FDEMS, and/or aggregators, usually by going through the DSO or any third party which can control aggregated DER systems. The TSO can also request forecasts, information on emergency situations, and other DER-related data.
- **Interfaces 7, 8, and 9** – Market interactions by the TSO, aggregators, FDEMS, and DSO (respectively) within Level 5. These interactions would be for sending and receiving market offers, bids, and/or pricing signals.
- **Interface 10** – DER management system interactions within Level 2 with multiple DER systems managed or coordinated by a FDEMS. Peer to peer interactions can also occur between DER controllers, such as between a PV controller and a battery storage controller. The FDEMS has a more global vision of all the DER systems under its control, and can allocate tasks to different DER systems, depending upon the facility operator's requests, load conditions within the facility, and possibly demand response pricing signals. It understands the overall capabilities of the DER systems under its management but may not have (or need) detailed data. FDEMS can issue direct commands but will primarily update the autonomous settings for each DER system. Interaction frequency may be seconds to minutes, hours, or even weeks.
- **Interface 11** – Internal DSO interactions among applications and systems involved with DER systems within Level 4. These interactions between applications provide the capability of the DSO to make decisions on operating the distribution system with DER systems.

- **Interface 12** – Autonomous DER behavior in which the controller responds to sensors that sense local conditions within Level 1. Controllers are focused on direct and rapid monitoring and control of the DER hardware. Common types of autonomous DER controls include managing one or more inverters, such as a small PV system, a battery storage system, or an electric vehicle service element (EVSE). In addition to basic control, this autonomous behavior can perform advanced "smart inverter" functions using one or more of the pre-set modes and/or schedules that respond to locally sensed conditions, such as voltage, frequency, and/or temperature. Responses could include anti-islanding ride-through protective actions, volt-var control, frequency-watt control, ramping from one setting to another per a schedule, soft-restart, and other functions that may be pre-set. Interaction latency requirements are typically milliseconds to seconds.
- **Interface 13** – Protection signals between substations and DER systems to permit the coordination of local and area protection schemes.

3. Information and Communication Concepts

3.1 Standardized Information Models for Interoperability

As can be seen from the number of interfaces in the DER hierarchical architecture, the amount and types of data being exchanged can be huge. If standards are not provided, then chaos could reign as different vendors and users implement different protocols with different definitions of the data being exchanged. This is equivalent to the tower of Babel, where everyone speaks different languages and therefore very few can understand what the others are saying (see Figure 3).

Figure 3: Pieter Brueghel the Elder - The Tower of Babel (Vienna) - Google Art Project

Similarly, using different communication protocols between different DER systems and different utilities or facilities would make interoperability impossible. The first step in providing interoperability is to define a standard information model. An information model is the standardized collection of data objects that have well-defined names and well-defined structures (ontology). This is the same as

an international group of people agreeing to speak English during meetings, using standard English words and standard English sentence structure.

In the power industry two main information models have been developed: IEC 61970/61968 (the Common Information Model – CIM) and IEC 61850. CIM is used primarily within utility control centers and back offices. IEC 61850 is used primarily with field equipment, such as in substations, although it is expanding to support interactions between utilities and field equipment. In particular, IEC 61850 has developed information models for DER systems for such interactions. These two information models are illustrated in Figure 4.

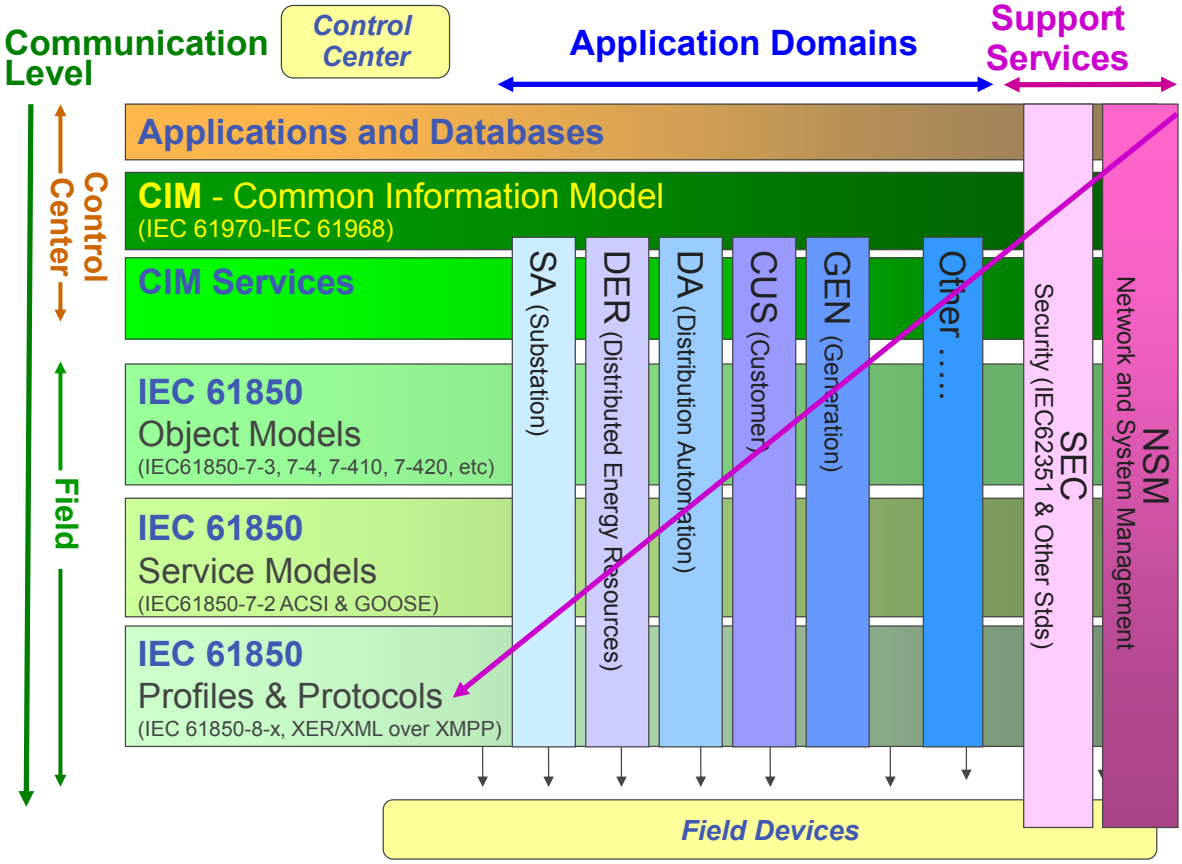

Figure 4: IEC 61850 information model and correlation with the Common Information Model (CIM)

The CIM was developed to allow application software to exchange information about an electrical network. It is currently maintained as a UML model and defines a common vocabulary and basic ontology (formal naming and definition of the types, properties, and interrelationships of the entities) for aspects of the electric power industry. The CIM models the network itself using the 'wires model'. This describes the basic components used to transport electricity. Additional parts of CIM have been developed to model transmission market interactions as well as the interactions between back office systems for metering applications.

The focus of this report, the IEC 61850 information model, is described in Section 3.2.

3.2 IEC 61850 as Information Model for Data Exchanges with Field Systems

In April 2004, the first meeting of the International Electrotechnical Commission (IEC) Technical Committee (TC) 57 Working Group (WG) 17 was held to start the development of communication requirements for monitoring and controlling DER systems with IEC 61850. Over the years many efforts provided input to first IEC 61850-7-420:2009 for the basic DER functions, and a couple of years later IEC 61850-90-7 for "smart DER" functions. Instrumental in this effort was EPRI[4], the IEEE 1547.3, Smart Grid Interoperability Panel (SGIP), and more recently the California's Smart Inverter Working Group (SIWG). The DER IEC 61850-7-420/90-7 information model has also been used as a source for developing mappings to other protocols, such as IEEE 1815 (DNP3) and IEEE 2030.5 (SEP 2)."

3.2.1 IEC 61850 Overview

IEC 61850 consists of three main components:

- An **abstract information model** in which each data item has a human-understandable name that uniquely identifies it, along with standardized formatting. These are the "nouns."
- An **abstract definition of communication services** that can be used to read and write data as well as metadata, issue control commands, receive alarms and events, and manage audit logs. These are the "verbs."
- **Communication protocols** that map the information model data and the services to the actual "bits and bytes" for transporting between interfaces. These are the instantiation of the abstract models to the real world. The current standardized protocols include the Manufacturing Messaging Specification (MMS) ASN.1 data structures, MMS services, GOOSE protocol, and more recently XML/XER over XMPP.

3.2.2 IEC 61850 Information Model Constructs

In the IEC 61850 information model, each piece of data has a human-readable text *name* that uniquely identifies it. IEC 61850 names have a hierarchical structure, similar to a file system, so that each point of data has an implied relationship with the others. IEC 61850 names consist of the hierarchy: *logical devices* which contain *logical nodes*, which contain *data objects*, which are structured according to *common data classes* which may contain several layers of *data attributes,* such as values, limits, quality codes and timestamps, and finally defined as *standard data types* such as integers, floating points, booleans, etc. This hierarchy of information model constructs is shown in Figure 5.

[4] Electric Power Research Institute, "*Common Functions for Smart Inverters, Version 3*", Product ID:3002002233, February 2014

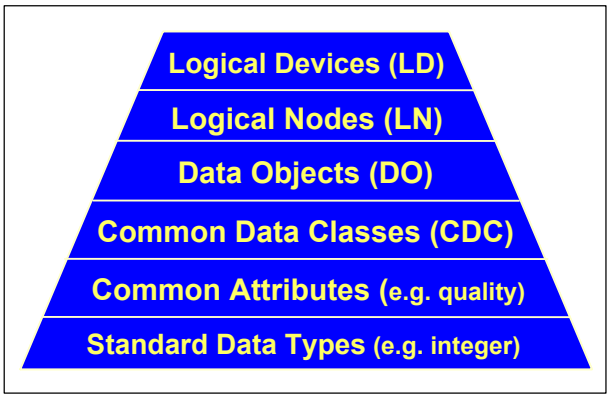

Figure 5: IEC 61850 Constructs

Which logical nodes are included in a particular logical device is determined by the architecture of the particular system. A logical node is a grouping of data associated with a particular electrical system function.

As seen in Figure 6, logical nodes are designated by four-character *class names*. If there is more than one logical node of the same class (performing the same function but on another part of the system) they are distinguished by one-or-two-character *instance numbers.* If a device implements a particular electrical system function, it must report and/or control the set of mandatory data objects associated with the corresponding logical node as specified by the IEC 61850-7-xxx set of standards.

Part of name	What it means	Example of an alternative
Logical Device Name	Chosen by the utility	Feeder3
Logical Node Prefix	-- not used in this example --	
Logical Node Class	Metering Measurement Unit	PDIS – Protection, Distance
Logical Node Instance	Feeder number 3	7
Data Name	Phase-to-Ground Voltages	PPV – Phase-to-phase volts
Data Attribute Name	Phase A	PhsB – Phase B Neut – Neutral
Data Attribute Name	Complex value after deadbanding	instMag – Instantaneous value
Data Attribute Name	Magnitude of the complex value	ang – angle in degrees
Data Attribute Name	Floating point value	i – integer value

Data Attribute Names – defined in a Common Data Class (CDC)

Bay12Unit2/MMXU3.PhV.phsA.cVal.mag.f

Figure 6: Naming rules in IEC 61850

3.2.3 IEC 61850 as an Electronic UML Model

IEC 61850 has recently been converted from paper to electronic form as a Uniform Modeling Language (UML) model. This permits direct extraction of the desired logical nodes and data objects into whatever format is desired, e.g. MMS ASN.1 or XML/XER. Figure 7 illustrates a portion of the UML model of IEC 61850-7-420.

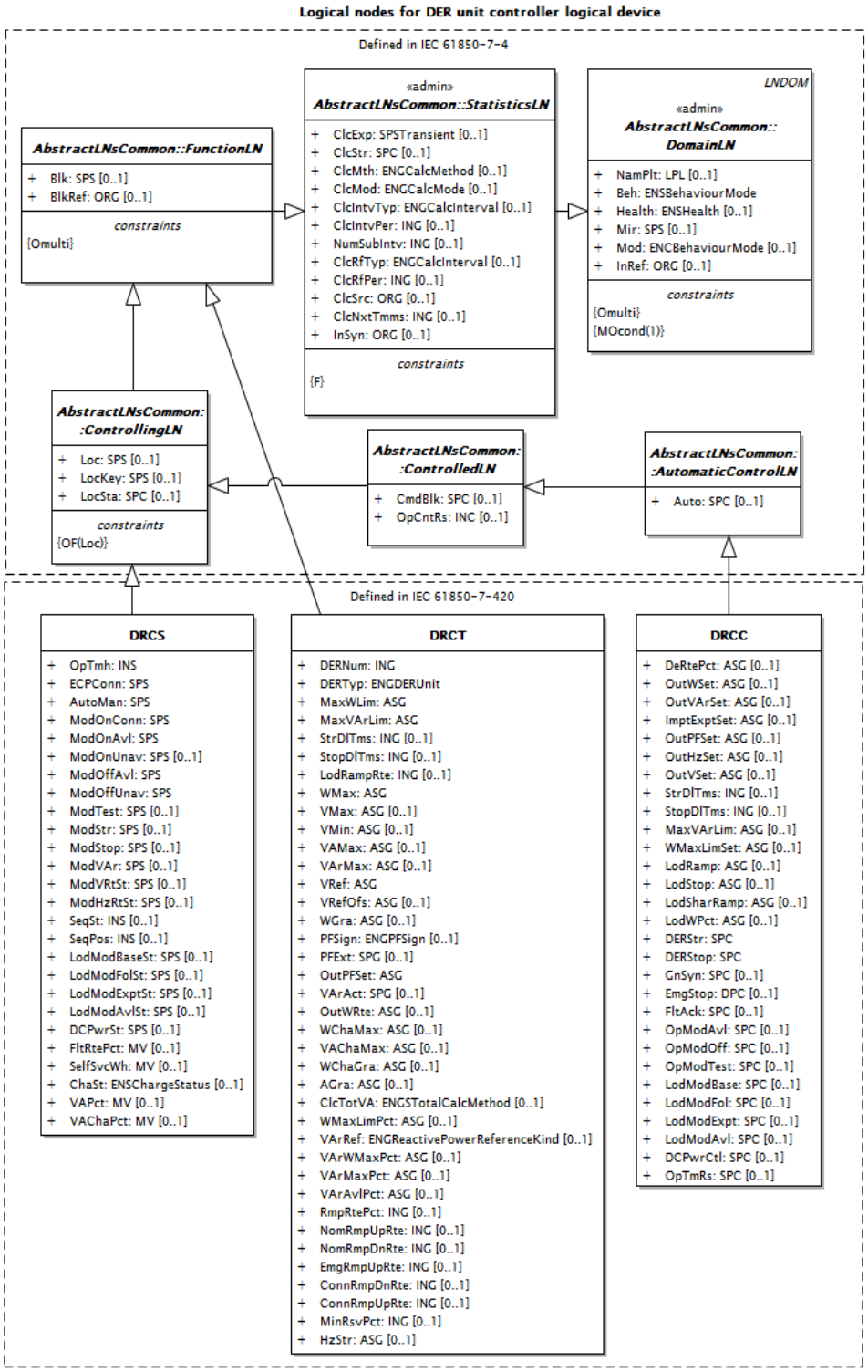

Figure 7: IEC 61850-7-420 as UML Model

3.2.4 IEC 61850-7-420 DER Logical Nodes

Figure 8 illustrates the primary IEC 61850-7-420 and IEC 61850-90-7 logical nodes used for DER systems, shown in red italic four-letter logical node acronyms. The blue logical nodes are in the base IEC 61850-7-4, consisting of logical nodes used in many different applications, such as substation automation, hydro plants, wind power plants, etc.

As can be seen, the large numbers of IEC 61850 DER logical nodes, each with multiple data objects, cover most of the DER communication requirements. However, new requirements from DER systems are still being found, and are being added to the information model.

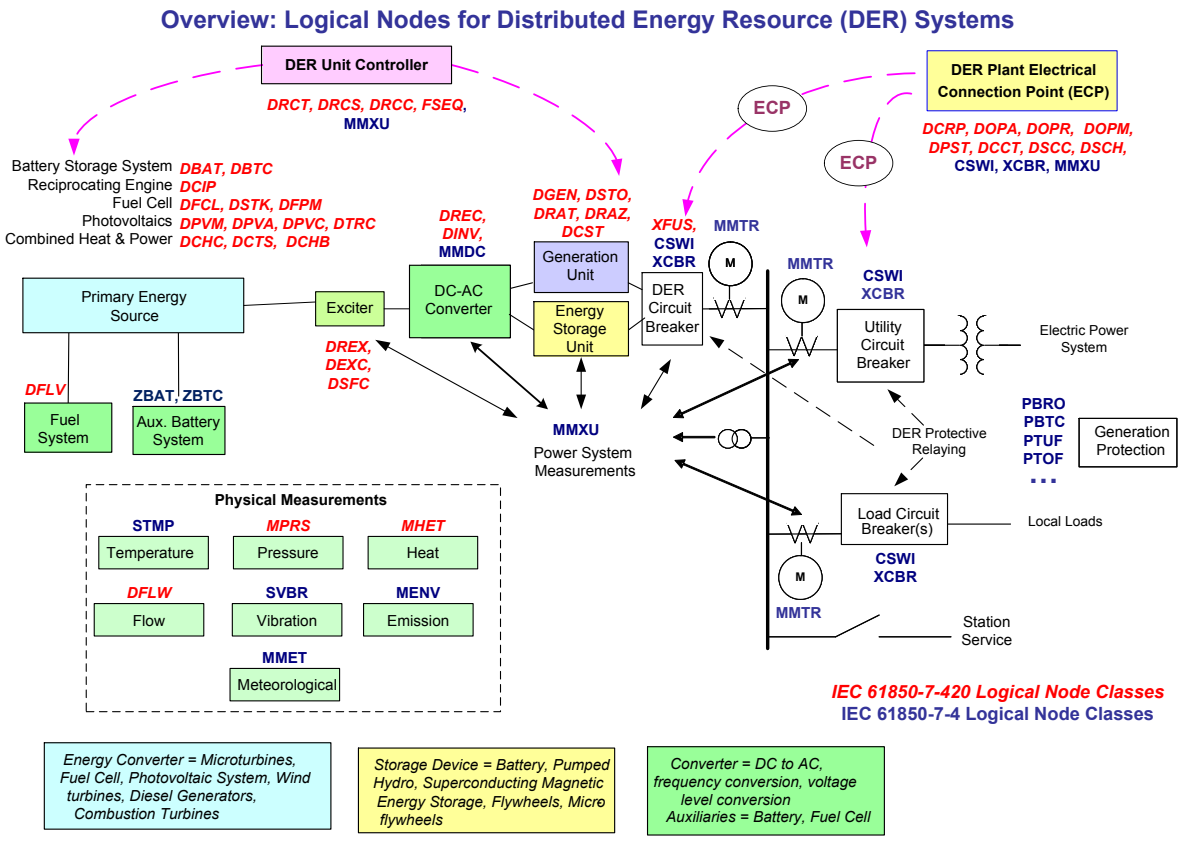

Figure 8: Conceptual organization of DER logical devices and logical nodes

3.3 Harmonization of Standards

3.3.1 Domains of CIM and IEC 61850

One of the benefits of focus on smart grid standardization efforts is that there are now many standards to support the smart grid interoperability vision (see Figure 14 and Figure 15). While there are standards yet to be developed, a majority of the standards needed already exist. Unfortunately, most were developed independently to address the integration of systems within a limited domain of application and so do not share a common model of the data or even a common modeling approach. As a result, every interface between systems that is not covered by the same standard requires a mapping or transformation from one standard's format to another in addition to the mapping from

proprietary formats to standard formats when a system interface does not support any standard at all.

For example, IEC 61850 and IEC 61970 are core standards in the smart grid domain (see Figure 9) and there are significant data exchanges involved between the IEC 61850 level and the IEC 61970 level, which require high compatibility between the two standards. However, due to different perspectives and independent evolution, IEC 61850 and IEC 61870 are not compatible with each other and data mappings between the standards have essentially been handled in an ad-hoc manner. CIM focuses on the organizational structures of different components within the smart grid, while IEC 61850 focuses on the structure of information exchanges between field devices and systems. This has led to significant issues on interoperability and data consistency in different implementations.

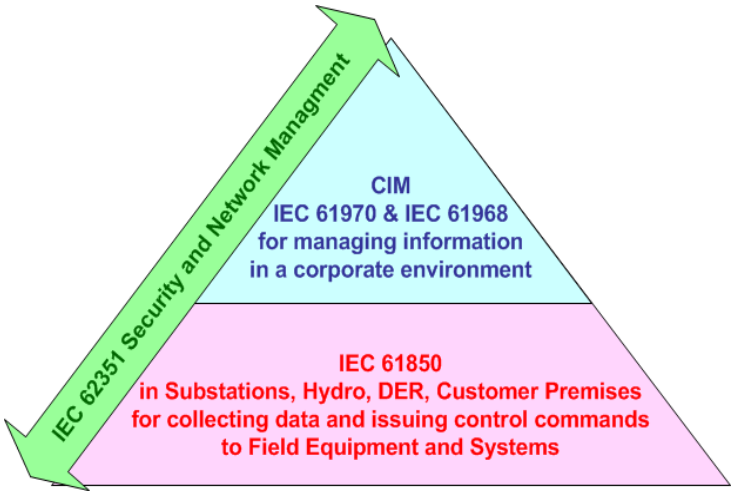

Figure 9: IEC TC57 Power Management Domains: CIM, 61850, and Cyber Security

3.3.2 IEC 62361-102: Interoperability in the Long Term – CIM and IEC 61850 Harmonization

The IEC TC57 WG19 therefore undertook the development of a CIM-61850 harmonization effort, IEC 62361-102: Interoperability in the Long Term – CIM and IEC 61850 Harmonization. The goal of IEC 62361-102 is to "align" the modelling where applicable and to precisely define a "mapping" between CIM and IEC 61850.

- Step 1: Use case analysis
  - Use cases that link control center applications and (initially) substation automation
- Step 2:
  - Identify overlap and duplication of CIM and 61850
  - What is missing in 61850 that is required by CIM
  - What is missing in CIM that is required by 61850

For example, IEC 61850 has a large set of data objects that could be mapped to CIM measurement types:

- IEC 61850 has over 1400 different data object names with very precise meanings, so this is a non-trivial effort.
- If the measurements associated with these data objects are to be used in CIM application calculations, then a precise mapping is needed
- Control Types are analogous to Measurement Types but apply to commands. IEC 61970-301 does not define a standard list of control types. It is recommended that CIM based standards should use selected IEC 61850 data object names as ControlType names

IEC 62361-102 is currently a Committee Draft (CD) with comments received April 2015. A CDV is expected to be released soon.

An example of a portion of the mapping is shown in Table 1.

Table 1: An example of IEC 62361 Measurement Type Mapping between 61850 and CIM

IEC 61850 Logical Node	IEC 61850 Data Object	IEC 61850 CDC	IEC 61850 Description	IEC 61970-301 or IEC 61970-452 Measurement Type	Subclass of CIM Measurement
MMXU	TotVA	MV	Total apparent power in a three phase circuit	ThreePhasePower	Analog
MMXU	TotW	MV	Total real power in a three phase circuit	ThreePhaseActivePower	Analog
MMXU	TotVAr	MV	Total reactive power in a three phase circuit	ThreePhaseReactivePower	Analog
MMXU	A	WYE	Phase currents	LineCurrent	Analog
MMXU	PhV	WYE	Phase to ground voltage	PhaseVoltage	Analog
MMXU	PPV	DEL	Phase to phase voltages (VL1,VL2, …)	LineToLineVoltage	Analog
PSDE	Ang	MV	Angle between voltage and current	Angle	Analog
MMTR	TotVAh	BCR	Apparent energy	ApparentEnergy	Accumulator
MMTR	TotVArh	BCR	Reactive energy	ReactiveEnergy	Accumulator
MMTR	TotWh	BCR	Real energy	ActiveEnergy	Accumulator
CSWI XCBR XSWI	Pos	DPC	Switch position [2bits= intermediate, open, closed, bad-state]	SwitchPosition	Discrete
Various	Loc	SPS	Local control behaviour	LocalOperation	Discrete
ATCC AVCO	Auto	SPC	Automatic/Manual operation	Automatic	Discrete
ATCC	TapPos	ISC	Tap position of power transformer or phase shifter	TapPosition	Analog
Various	Tmp	MV	Temperature	Temperature	Analog
Various	Pres	MV	Pressure	Pressure	Analog

3.4 IEEE 2030.5 (Smart Energy Profile 2.0)

The Smart Energy Profile 2 Application Protocol Standard (SEP2) was first published by the ZigBee Alliance and HomePlug Powerline Alliance in April 2013. Control of future versions of the protocol was subsequently transferred to the IEEE and the April 2013 version of the standard was then republished as IEEE 2030.5-2013 (IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard). SEP2 is based on the four-layer internet stack model which is shown by the four red rectangles labeled Link, Internet, Transport, and Application in Figure 10. The seven layers of the Open Systems Interconnection (OSI) model designated by the grey bars are only shown for comparison. The white rectangles show some of the specific protocols used at each layer of the internet stack with SEP2. What uniquely describes SEP2 is its application standard and the associated SEP2 XML Schema Definition (XSD) and SEP2 Web Application Descriptive language (WADL).

While SEP2 could be used by any smart energy device or even a utility computer used to control smart energy devices, this figure assumes that SEP2 is being used by a DER. The green bar at the top designates the functional requirements for the DER unit, such as a requirement to implement an autonomous volt-VAR function which is capable of accepting curve values from the utility by way of the internet. IEC 61850-90-7 describes such a function. The blue bar represents embedded software provided by the DER manufacturer to implement the actual function of measuring voltage and producing VAR in accordance with a supplied curve. The embedded software also includes the software that decides to get the curve data from the utility, validates the curve data when received, and activates the volt-VAR function when requested by the utility. For the purpose of this figure, it is assumed that generic software associated with standard communication protocols are considered to be part of the internet stack. The SEP2 standard provides some unique rules for how certain information should be used and conflicts resolved and this forms part of the design requirements for the embedded software.

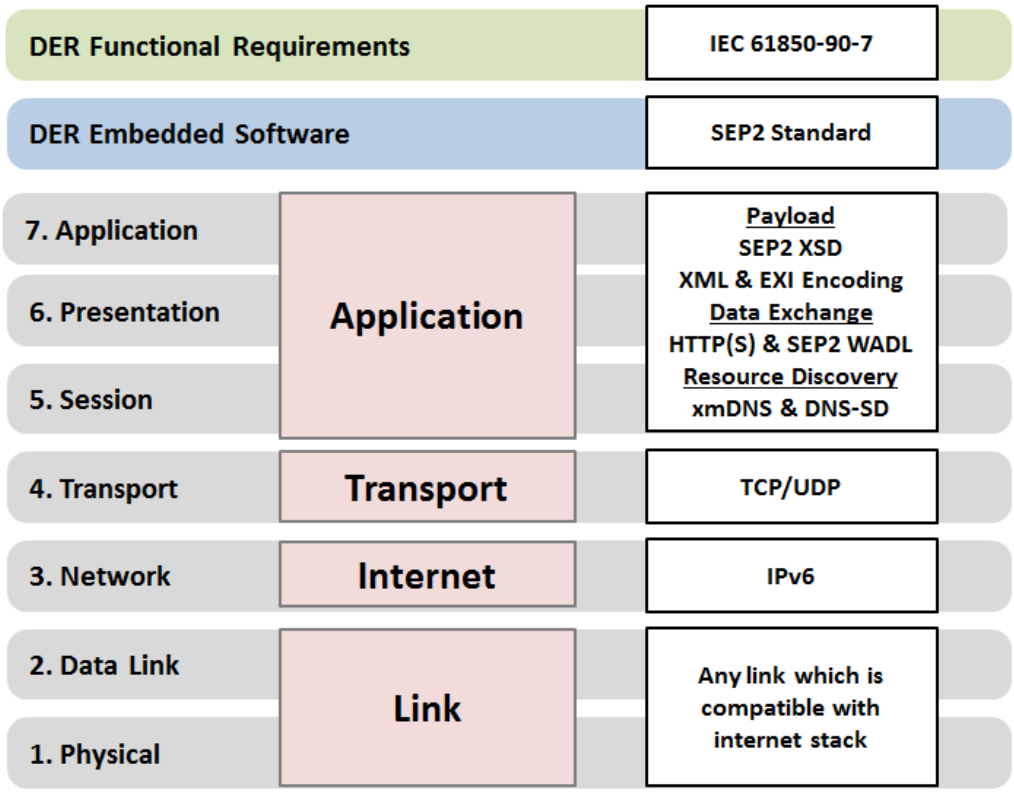

Figure 10: SEP2 Internet Stack

The SEP2 standard, WADL, and XSD are organized into 23 function sets divided into three areas: common resources, support resources, and smart energy resources. All function sets do not have to be implemented in every device and the requirements associated with a given function set may be mandatory or optional. Smart energy function sets include: DER, metering, demand response and load control, pricing, billing, and several others. The SEP2 XSD is based on the IEC 61968 common information model profile, mapping directly where possible, and using subsets and extensions where needed. The DER function set of the SEP2 XSD was developed based on the functional requirements of IEC/TR 61850-90-7, but it is not based on its associated object model. There is a UML model that completely describes the SEP2 object model and the standard itself includes many UML class diagrams, but these are provided only for informative purposes. The SEP2 XSD, which is written in XML, is the normative reference and it contains the definitions of the resources, attributes, and elements as well as their textual descriptions.

SEP2 is based on Representational State Transfer (REST) in which clients use HTTP methods to engage with servers which host resources. In SEP2 the distinction between a server and a client arises depending on whether a device exposes a resource (server) or interacts with the resource (client). The SEP2 WADL defines recommended URI structures to be used by the servers to identify and locate certain SEP2 resources and defines the use by clients of the HTTP methods of GET, POST, PUT, and DELETE associated with each resource. When a client polls a server using the HTTP GET method, the server responds with either an XML or EXI payload. The SEP2 standard requires a server to be capable supporting both XML and EXI. A client can implement both, but is only required to implement one. Devices that can act as both a client and a server would need to support both encoding

methods. SEP2 also provides an optional subscription mechanism that a client can use instead of polling the server for a resource using the HTTP GET method. This must be supported by the client and server devices and associated security protocols and firewalls.

An example of a DER using HTTP to request a specific instance of a DER control signal is shown in Figure 11. The DER uses the HTTP GET method based on the SEP2 WADL to request the XML payload for the DERControl located at a specific URI on the host server. The host server responds with the XML payload. The content of the payload is determined by the SEP2 XSD.

The DER requests a DER control signal

```
GET /derp/0/derc/1A3470 HTTP/1.1
Host: {hostname}
```

The server responds with an XML payload

```
HTTP/1.1 200 OK
Content-Type: application/sep+xml
Content-Length:{contentLength}

<DERControl  xmlns="http://zigbee.org/sep"
    href="/derp/0/derc/1A3470" subscribable="1">
   <mRID>02BE7A7E57</mRID>
   <description>Example DERControl</description>
   <creationTime>1383948000</creationTime>
   <EventStatus>
      <currentStatus>1</currentStatus>
      <dateTime>1383948000</dateTime>
      <potentiallySuperseded>false</potentiallySuperseded>
   </EventStatus>
   <interval>
      <duration>300</duration>
      <start>1383948000</start>
   </interval>
   <randomizeStart>10</randomizeStart>
   <DERControlBase>
       <opModFixedFlow>-5000</opModFixedFlow>
   </DERControlBase>
</DERControl>
```

Figure 11: DER Control service

A portion of a representative UML class diagram for the DERControl resource is shown in Figure 12. The diagram is consistent with the guidelines for UML class diagram and therefore the features and options will not be discussed here. The class attributes shown in red are the ones used in the XML example. Certain of the optional attributes indicated by [0..1] are not used in this XML example. All mandatory attributes are used. The red arrows in the UML diagram show inheritance and the black arrows show a direct connection between classes. In both cases the XML payload includes the elements from both. The SEP2 protocol does not decide which function sets and associated objects and attributes are to be used in the creation of XML payloads. This is part of the design of the DER embedded software.

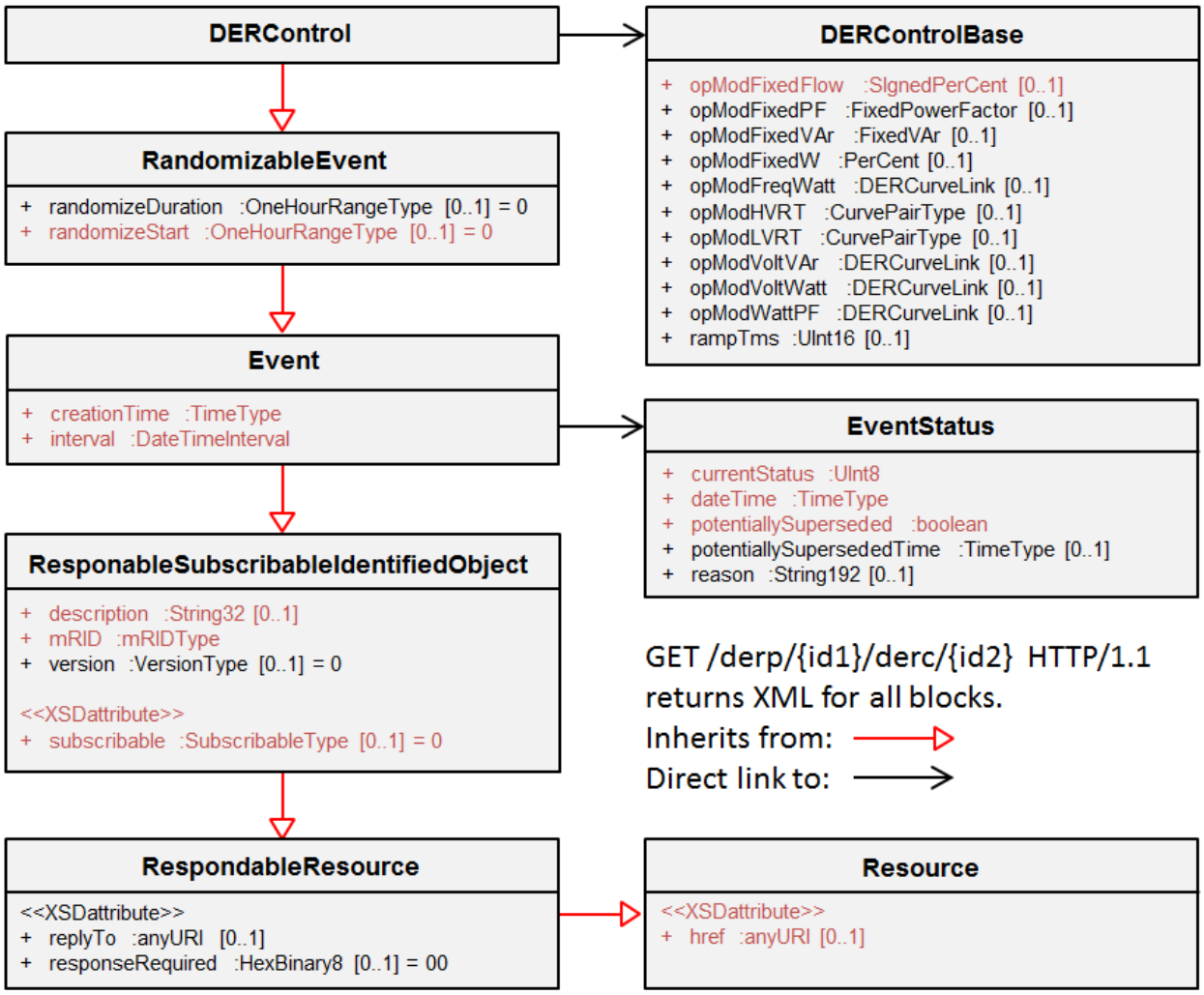

Figure 12: Example of SEP2 UML Class Diagram

Figure 13 shows the names of a few selected SEP2 objects associated with the DER devices. There are three major types of objects which are separated by columns: resources, lists, and links. In this table, resource means an addressable, single instance of an object, such as the single instance of a DERControl shown in the earlier example. The resources shown in black represent information about one specific DER device and the information is hosted on the server by that device. The resources shown in blue represent information placed on the DER host server by the utility to provide curve data or control signals. Those shown in red are used to locate the resources of a specific DER device on the host server. This table shows only a few resource objects to help understand the concept of operation.

Resource	List	Link & ListLink
DeviceCapability		
DER	DERList	DERListLink
DERAvailability		DERAvailabilityLink
DERCapabilty		DERCapabiltyLink
DERSettings		DERSettingsLink
DERStatus		DERStatusLink
DERProgram	DERProgramList	DERProgramListLink
DERControl	DERControlList	DERControlListLink
DERCurve	DERCurveList	DERCurveListLink

Figure 13: Selected SEP2 objects

A list object is a special type of resource. It is a container for all of the instances of individual resources. For example, DERControlList represents a collection of all DERControl instances associated with a specific DERProgram. The HTTP GET method when used with a list object provides a query mechanism that returns an XML payload for selected instances of DERControl objects on the list. This is a way to create schedules for controlling the DER.

There are two variations of link object types. A basic link object contains the URI to a single instance of an associated resource object. For example, DERSettingsLink contains the URI for a specific instance of DERSettings. A listlink object contains the URI to a list object and also provides the number of object instances in the list.

The DeviceCapability object is the most basic SEP2 resource which is discovered on a host server by an entity using DNS-SD. It is the “master” resource. The URIs of the other resources can be found by sequentially drilling down to understand the structure of all of the resources on the host server. This is somewhat like drilling down from a website home page and then bookmarking the link for each page. The DeviceCapability object contains the DERProgramListLink object which includes the URI for one DERProgramList. The DERProgramList object contains many instances of DERProgram objects. Each DERProgram object contains one DERControlListLink object and one DERCurveListLink object. Each DERControlListLink object includes the URI for one DERControlList object. Each DERControlList object contains many instances of DERControl objects. The DER embedded software determines which instance of DERControl on the list to use at any time.

For additional guidance on using the SEP2 DER function see SAE J2847/3 Communication for Plug-in Vehicles as a Distributed Energy Resource. While J2847/3 is intended to be used to provide guidance for using SEP2 with electric vehicles with onboard inverters, most of the content is relevant to other DER devices that use SEP2.

3.5 Communication Protocols

3.5.1 Overview of Key Power Industry Communication Protocols

There are many communication protocols, some with their own "information models" but all with explicit definitions of the "bits and bytes" that must be exchanged between entities. Figure 14 and Figure 15 illustrate some of these communication protocols, including how they are designed with respect to communication reference models, namely the Open Standards Interconnect (OSI) 7-layer reference model and the Gridwise Architecture Council (GWAC) 8-layer stack.

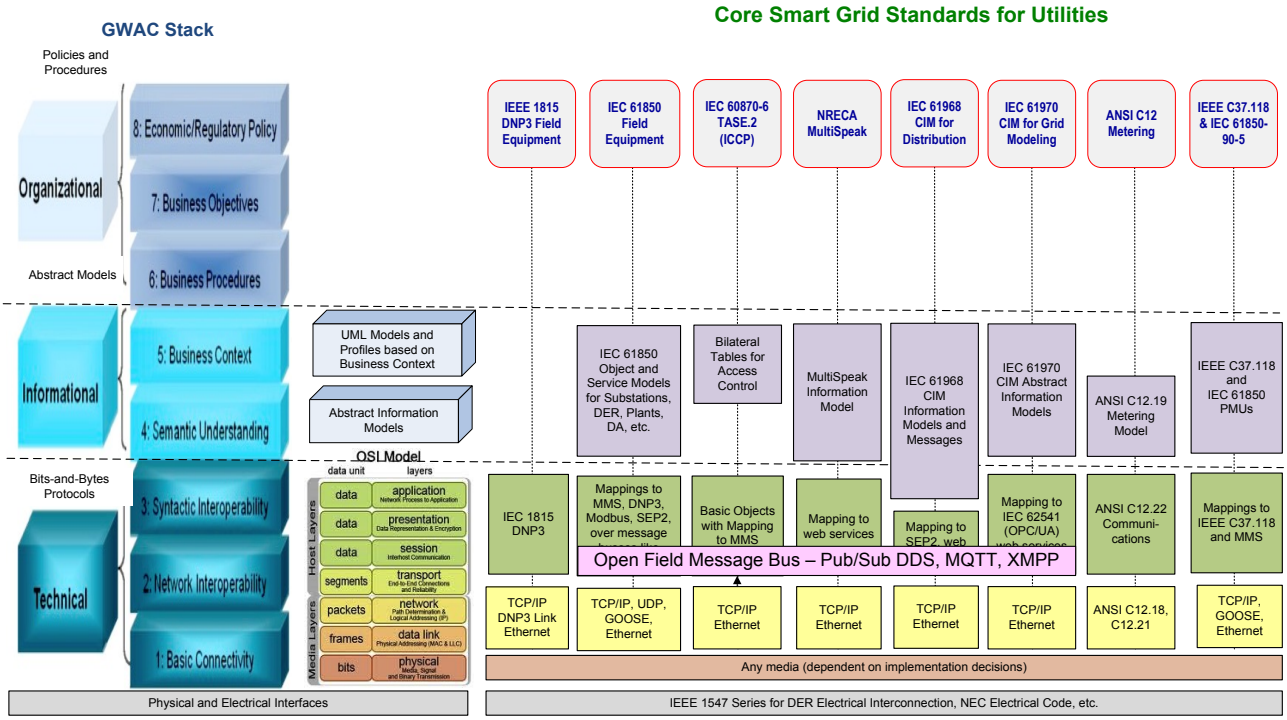

Figure 14: Core Smart Grid Standards used by Utilities

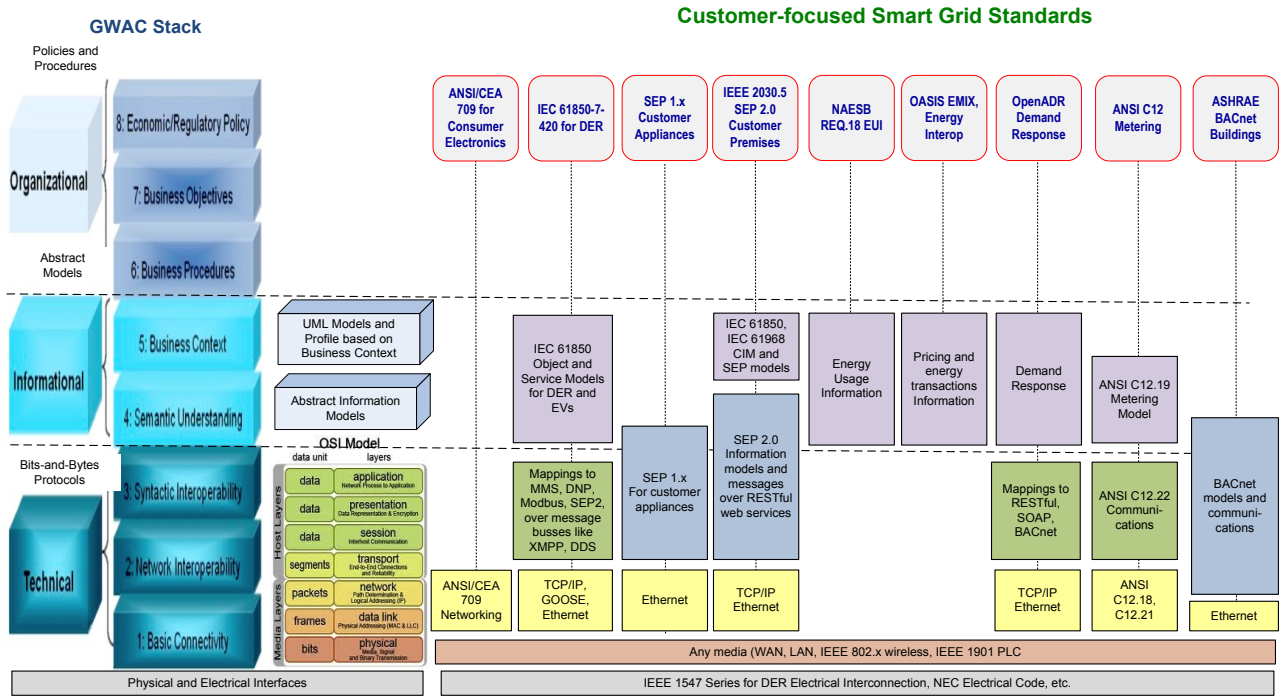

Figure 15: Customer-focused Smart Grid Standards

3.5.2 Example of Configurations with IEEE 2030.5 (SEP2) Protocol

An example of configurations with interactions with IEC 61850 as the information model and with IEEE 2030.5 (SEP2) and IEEE 1815 (DNP3) used as protocols, is shown in Figure 16 (numbered circles reflect interfaces described in Section 2.2). IEEE 2030.5 used IEC 61850 as the base for their objects, although they changed the names and structures to create their own information model. IEEE 1815 does not have an information model, but has developed some specific profiles that map selected IEC 61850 data objects to DNP3 data elements.

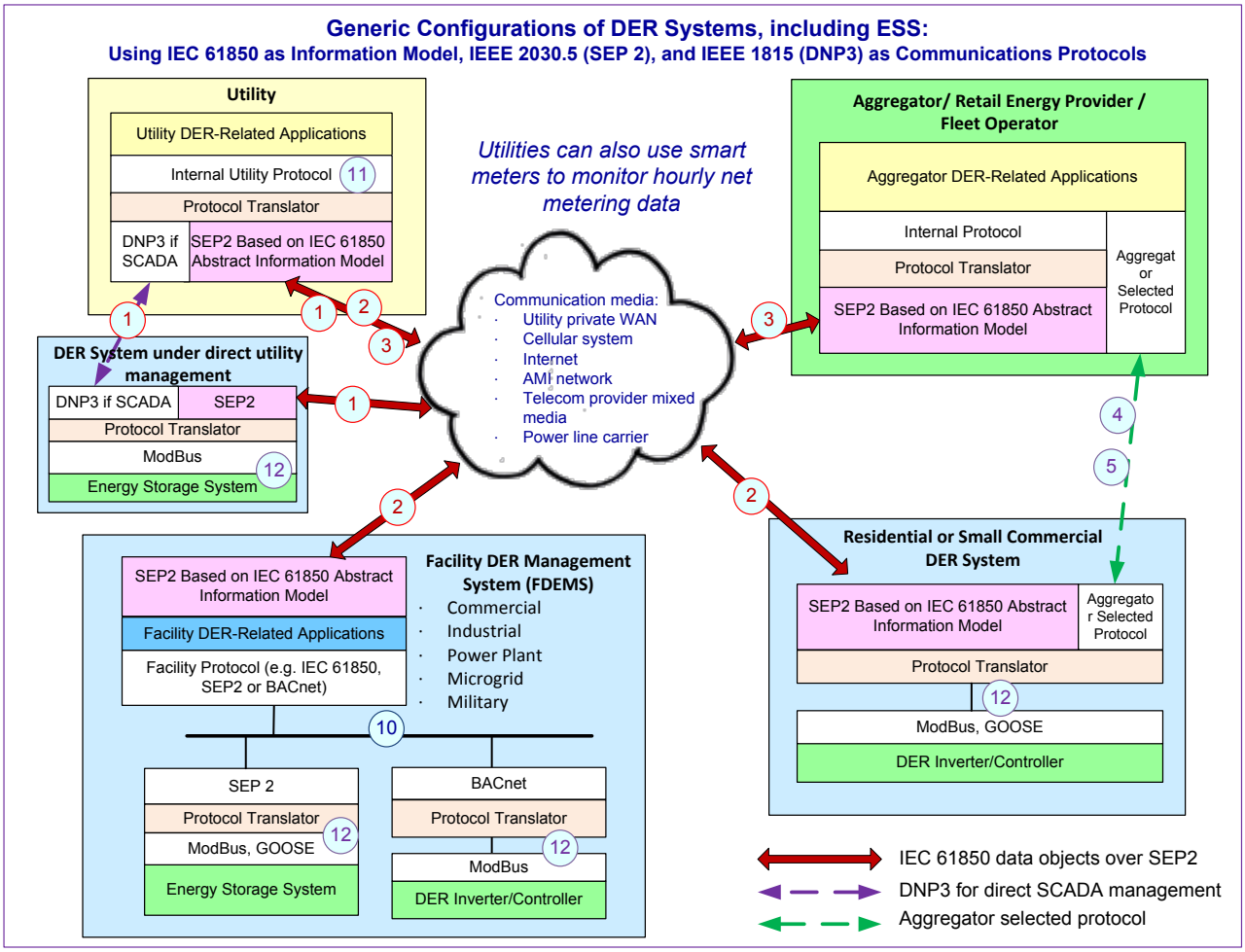

Figure 16: Example of IEC 61850 as information model while using SEP2 and DNP3 as protocols

4. "Smart Inverter" or Advanced DER Functions

4.1 Microgrid Interactive Use Cases from SGIP DRGS Subgroup C

These use cases define the requirements for information exchange between area Electric Power System (EPS) and advanced microgrids in the connected mode (see Table 2), while in some implementations third party microgrid managers may require similar information exchanges.

The requirements suggested in the interactive use cases imply high penetration of DERs and advanced microgrids in the distribution systems. Depending on the stage of advancement of the active distribution networks, some requirements will be mandatory, some will be optional, and some will be conditional. This division may change with the change of the development of the microgrids and their influence on the distribution operations. Also, depending on the sensitivity of the distribution operations to the specifics of the microgrid model, the representation of the model components may be more or less detailed.

In the use cases, an attempt was made to present the model components in consistency with the complexity of the operations of advanced microgrids. In some cases, the full adequacy of the model to the complexity of operation may not be needed. It depends on the effect of the simplification of the model on the loss of reliability, power quality, and economic efficiency. The use cases present the level of the model details, from which the simplification can be suggested depending on the specific condition. This issue can be a subject of further studies, such as the DRGS Subgroup C / PAP 24 Use Cases and the IEEE 2030.7 on microgrids (still under development).

Table 2: Microgrid Interactive Use Cases

Subgroup C Use Case #	DER Use Cases	Description and Purpose of the Use Case	Communication Requirements	SCADA/EMS/DMS and DER/microgrid Functions
1	**Information Support for Coordination of EPS and Microgrid Load Shedding Schemes**	Determine the requirements for information exchange between the microgrid and EPS on contingencies	1. Possible emergency operating conditions of the EPS (Contingency/Security Analyses) 2. Aggregated performance of the microgrid load, DER, and other devices in response to emergency situations in EPS 3. Preventive measures for contingencies	Monitor EPS alarms, status, measurements through SCADA system Monitor DER (microgrid) alarms Monitor DER (microgrid) status Monitor DER (microgrid) measurements 1. EPS' EMS through TBLM and DMS submits to the µEMS the results of the EMS' Contingency Analysis in forms of frequency vs time and voltage at PCC vs time curves based on the last submitted load-to frequency and load –to-voltage dependencies aggregated at the transmission buses by the TBLM. 2. µEMS determines the reactions of the microgrid components to the submitted frequency and voltage at the PCC vs time curves and updates its aggregated at the PCC models of load-to voltage and frequency dependencies in the emergency ranges (real and reactive loads) in the forms of two or three dimensional curves (when the contingency analysis results in simultaneous changes of frequency and voltage, a three dimensional curve may be needed. These curves should be submitted back to the DMS for the update of the TBLM, if needed for another iteration of the contingency analyses. 2.1. In addition to the curves, the µEMS submits to the DMS the aggregated setup of the remedial actions schemes and DER protection (ride-through) under which the curves were derived. This information can be presented as a set of arrays (e.g., frequency setting – time delay- load/generation connected; voltage setting-time delay- load/generation connected; next array, etc.) 3. EPS' EMS through TBLM and DMS submits to the µEMS requests for changes in the setups of the remedial action schemes and/or DER protection, if needed. This information can be presented as a set of arrays (e.g., frequency setting – time delay- load/generation connected; voltage setting-time delay- load/generation connected; next array, etc.) 4. More details are available in [1] and [8]

Subgroup C Use Case #	DER Use Cases	Description and Purpose of the Use Case	Communication Requirements	SCADA/EMS/DMS and DER/microgrid Functions
2	**Coordination of Volt/var control in Connected Mode under Normal Operating Conditions**	Determine the requirements for information exchange between the microgrid and EPS on the EPS and microgrid volt/var control interactions	1. Provide the DSO/DMS with near-real time and short-term look-ahead aggregated at the PCC vars as a function of the PCC voltage under current microgrid volt/var control setups (ability to mitigate intermittency – based on contractual conditions) 2. Inform the DSO/DMS about the desired voltage range at PCC to support the chosen objective under different ambient and load conditions 3. Inform µGrid about the possible range of voltages at the PCC in a given timeframe 4. Provide the microgrid operator/µEMS with its requirements/ requests for the volt/var support of the EPS operations. 5. Provide the DSO/DMS with the impacts of the change of the volt/var control setup	1. µEMS (periodically or upon event) calculates the dynamically changing curves (point-pair arrays) with PCC vars vs. PCC voltage (IEC 61850 voltage-to-var dependencies DO using the CDC:CSG). Will use a deadband to determine if updated curves are needed 2. µEMS submits to DMS/DSO the desired PCC voltage range as min/max voltage and time interval 3. DMS/DSO informs µEMS about the possible PCC voltage range as min/max voltage and time interval 4. DMS/DSO submits its request or requirements (depending on the contractual agreement) on volt/var support of EPS operations in forms of 4.1. Time domain schedules of vars at PCC (the vars can be numerical values or available max/min requirements) 4.2. Time domain schedules of Power Factor at PCC (the PF can be numerical values or available max/min requirements) 4.3. Near real time var requirements for short time intervals (in case of near real time volt/var optimization performed by DMS) 4.4. Percentage of available/max kvars 5. If the DMS/DSO request/requirement is different from the submitted by the µEMS var curve (item 1), µEMS submits to DMS/DSO the impact of the change on the microgrid performance, e.g., as a schedule of change in demand at PCC. Other attributes of the microgrid operational model can be affected, e.g., the ability to mitigate the intermittency.

Subgroup C Use Case #	DER Use Cases	Description and Purpose of the Use Case	Communication Requirements	SCADA/EMS/DMS and DER/microgrid Functions
3	**Update aggregated at PCC real and reactive load-to-voltage dependencies under normal operating conditions**	Determine the requirements for information exchange between the microgrid and EPS on the load/generation dependencies on PPC voltage	1. Provide the DSO/DMS with the aggregated **short-term** real and reactive load-and-generation-to-voltage dependencies at the PCC 2. Provide the DSO/DMS with the aggregated l**ong-term** real and reactive load/generation-to-voltage dependencies at the PCC 3. Provide the microgrid operator/µEMS with EPS requests for change of the microgrid load/generation-to-voltage dependencies	µEMS (periodically or upon event) calculates the dynamically changing curves (point-pair arrays) with PCC Wats and vars vs. PCC voltage (IEC 61850 voltage-to-var dependencies DO using the CDC CSG). Will use a deadband to determine if updated curves are needed 1. For short-term Watt/var dependencies on PCC voltage 2. For long-term Watt/var dependencies on PCC voltage (CVR-factors) 3. The DSO may need a different load-to-voltage dependency than the one submitted by the µEMS. For instance, if the µEMS keeps constant voltage within the microgrid, it is playing against the DSO objective of conservation voltage reduction. In this case, the DSO may request a load-to-voltage dependency under which the microgrid's load reduces with PCC voltage reduction ("descending" dependency) - allow the voltage in the microgrid to decrease with PCC voltage reduction. It is unlikely that such request will be expressed in numerical values. It may be just a request not to play against load-reducing objective of voltage control.

Subgroup C Use Case #	DER Use Cases	Description and Purpose of the Use Case	Communication Requirements	SCADA/EMS/DMS and DER/microgrid Functions
4	**Updates of capability curves of the microgrid's reactive power sources**	Determine the requirements for information exchange on the microgrid capabilities of generating and absorbing reactive power	1. Microgrid maximum and minimum nominal capabilities as defined by the real power of a DER and the voltages at the DER terminals 2. Microgrid maximum and minimum operational capability as defined by other operational limits along the microgrid circuits (e.g., desired voltages for CVR) 3. DSO/DMS request for a change of volt/var control setups of the µGrid var sources to provide greater maximum and/or smaller minimum var capability 4. Impacts of the change of the volt/var control setup 5. Forecast of capabilities	The aggregated at the PCC reactive power capabilities of a microgrid are dependent in the real power of DERs, on loads, on voltages at the ECP (for nominal capability) and voltages at other critical buses within the microgrid (for operational capability). These conditions are changing in near real time and, therefore, create a large variety of combinations. Therefore, it may be difficult to prepare in advance a set of dependencies of the capabilities on the PCC voltage. Hence, the dependencies should be updated for each of the current time interval periodically or by exception. 1. µEMS (periodically or upon event) calculates the dynamically changing capability curves (point-pair arrays) with PCC nominal maximum and minimum vars capabilities vs PCC voltage. Will use a deadband to determine if updated curves are needed 2. µEMS (periodically or upon event) calculates the dynamically changing capability curves (point-pair arrays) with PCC operational maximum and minimum vars capabilities vs. PCC voltage. Will use a deadband to determine if updated curves are needed 3. The DSO may need a different var capability dependency than the one submitted by the µEMS. It is unlikely that such request will be expressed in numerical values. It may be just a request to provide maximum or minimum possible var capability. 4. If the DMS/DSO request/requirement is different from the submitted by the µEMS var capability curve, µEMS submits to DMS/DSO the impact of the change on the microgrid performance, e.g., as a loss of DER Watt generation. Other attributes of the microgrid operational model can be affected, e.g., increase in microgrid demand, reduction of customers power factor. (The capability can be expanded, if the voltages at the ECP are higher, which, in turn, may increase the real and reactive loads and reduce customers' power factor.

Subgroup C Use Case #	DER Use Cases	Description and Purpose of the Use Case	Communication Requirements	SCADA/EMS/DMS and DER/microgrid Functions
5	**Updating information on microgrid dispatchable load**	Determine the requirements for information exchange on the microgrid dispatchable load	1. Provide the DSO/DMS with the near-real-time information on real and reactive dispatchable load of the microgrid 2. Provide the microgrid operator/µEMS with the request for utilization of the dispatchable load of the microgrid according to the agreements between the involved parties 3. Provide the DSO/DMS the information on the impacts of the changes of the microgrid operating conditions, if such are required by the EPS to increase the amount of dispatchable load 4. Provide the DSO/DMS with the assessment of the degree of uncertainty of the dispatchable load	The dispatchable load aggregated at the PCC of a microgrid consists of the available changes of the real and reactive load and generation that can be controlled by the microgrid operator/ µEMS. The amount of the dispatchable load depends on a number of operational parameters within the microgrid, on the required duration of the use of the dispatchable load, and on the voltage at the PCC. The DSO/DMS needs to know the dispatchable loads of relevant microgrids and its attributes for the given time intervals to perform its load management functions. Most of the parameters affecting the dispatchable load are changing in near-real time. Hence, the µEMS should update the aggregated dispatchable load and its attributes periodically or by events and timely submit it to the DSO/DMS. The following attributes of the dispatchable load are suggested: • The controlling means (e.g., voltage reduction, ESS discharge, DR) • The amount (Watt, var) • The duration • Time of activation • Change during commitment (±%) • Price-level tolerance ($/kWh) • Probability of implementation (%) 1. In general, the amount of the dispatchable real and reactive load dependencies on the PCC voltage for each distinguished operating condition of the microgrid are non-monotonous functions and can be represented by two-dimensional arrays: Watt vs Volt and var vs Volt. 2. The request for the use of the dispatchable load can be submitted by the DSO/DMS to the µEMS in a form of a schedule in a time domain, which will also show the required duration of the use of the dispatchable load 3. µEMS submits to DMS/DSO the impact of the utilization of the dispatchable load on the microgrid performance in a form of a dependency of the price-level tolerance on the amount of the dispatchable load. 4. The assessment of the degree of uncertainty of the dispatchable load can be presented in a form of dependencies of the change during commitment and probability of implementation on the amount of the dispatchable load.

<table>
<tr><th>Subgroup C Use Case #</th><th>DER Use Cases</th><th>Description and Purpose of the Use Case</th><th>Communication Requirements</th><th>SCADA/EMS/DMS and DER/microgrid Functions</th></tr>
<tr><td>6</td><td>Updates of the information on overlaps of different load management means within microgrids</td><td>Determine the requirements for information exchange between the microgrid and EPS on the setups of the load management means and on the overlapping of loads connected to them</td><td>1. The conditions (settings) for activation of different load managements in the microgrid
2. The total amount of load connected to each group of the load management means
3. The amount of common load connected to each group of the load management means</td><td>The load management can be executed through several programs, such as:
• Dynamic pricing
• Volt/var control in distribution
• Demand response/direct load control
• Interruptible load/Load curtailment
• Remedial Actions
– Under-frequency load shedding
– Under-voltage load shedding
– Predictive/special load shedding
The same load can be included in different programs.
When the EPS' EMS and DMS implement load management by using more than one load management means, they need to know what load is left in the consecutive means after the previous means is executed.
An example of overlapping loads:
<table>
<tr><td colspan="2"></td><td colspan="3">UVLS groups</td></tr>
<tr><td colspan="2"></td><td>1</td><td>2</td><td>3</td></tr>
<tr><td>UFLS Groups,</td><td>Connected load, %</td><td>10</td><td>10</td><td>10</td></tr>
<tr><td>1</td><td>12</td><td>5</td><td>2</td><td>1</td></tr>
<tr><td>2</td><td>12</td><td>2</td><td>5</td><td>2</td></tr>
<tr><td>3</td><td>12</td><td>1</td><td>2</td><td>5</td></tr>
</table>
The following string for a DO can be suggested:
Name of load management system (UFLS); Name of group (Group 1); Total connected load (12%); Name of paired load management system (UVLS); Name of group (1); common load (5%); Name of group (2); common load (2%); Name of group (3); common load (1%).
It is assumed that the settings for the UFLS groups (Hz, Sec) are defined in another DO.</td></tr>
</table>

Subgroup C Use Case #	DER Use Cases	Description and Purpose of the Use Case	Communication Requirements	SCADA/EMS/DMS and DER/microgrid Functions
7	**Updating dependencies of the microgrid operational model on external conditions**	Determine the requirements for information exchange between the microgrid and EPS on dependencies on the weather, dynamic prices, and EPS request for ancillary services Determine the requirements for information exchange between the microgrid and EPS on Very Large Scale Event (VLSE)	The dependencies of the following microgrid parameters on the external factors should be exchanged between the µEMS and DMS/EMS: 1. µGrid natural real and reactive load 2. Real and reactive load-to-voltage sensitivities 3. DER/ESS real power generation 4. Microgrid reactive power generation/absorption 5. µGrid reactive power nominal and operational capability 6. µGrid dispatchable real and reactive power 7. Setups of the RAS and Ride-through functions 8. Preventive measures in response to warning about a VLSE 9. Updates on changes during the disaster 10. Commands, requests, and instructions to the µEMS issued by the EPS (DMS) before and during the VLSE, 11. Updates of the microgrid restorative state after the VLSE (connection state, disconnected load and generation, ability for black start, desired sequence of restoration, etc.)	1-7. To define the DO, the external conditions should be graded. Then, for each grade of the external condition, a component value (or an array of values) can be related. 8. Text messages 9. the same as 1-7 10. Text messages 11. Text messages

Subgroup C Use Case #	DER Use Cases	Description and Purpose of the Use Case	Communication Requirements	SCADA/EMS/DMS and DER/microgrid Functions
8	**Update aggregated at PCC real and reactive load-to-frequency and load-to-voltage dependencies in the emergency ranges**	Determine the requirements for information exchange between the microgrid and EPS on the dependencies of the operational models of microgrids on EPS frequency and PCC voltage under EPS emergencies	1. Dynamics of EPS frequency and PCC voltage during emergencies determined by EPS contingency analyses 2. Dependencies of the µGrid natural real and reactive load on frequency and voltage 3. Dependencies of DER/ESS real and reactive power generation on frequency and voltage 4. Updates of the setups of the RAS and Ride-through functions based on the frequency and voltage dynamics provided by the EPS and/or based on specific EPS requests. 5. Preventive measures requested by the EPS 6. Planned/expected preventive measures to be implemented by microgrid 7. Commands, requests, and instructions to the µEMS issued by the EPS (DMS) during the emergencies 8. Updates of the microgrid restorative state after the emergency	1. Arrays of frequency vs time and voltage vs time 2. Arrays of µGrid natural real and reactive load vs frequency and voltage 3. Arrays of DER/ESS real and reactive power generation vs frequency and voltage 4. DO for RAS and ride-through functions 5. Text messages and DO for RAS and ride-through 6. Text messages and DO for RAS and ride-through 7. Text messages and DO for RAS and ride-through 8. Text messages

4.2 Energy Storage Systems (ESS) Use Case Requirements for Smart DER Functions

Energy Storage Systems (ESSs) are increasingly deployed to provide many DER services to both customers and utilities. By their nature, ESSs are not net producers of energy, but can provide many energy services that support reliability, efficiency, and lower cost requirements. An overview is shown in Figure 17, while Table 3 provides more details.

Economic Drivers for Utilities Which Interface their SCADA to Energy Storage Systems with "Smart" DER Functions		Backgound								Direct Utility Interactions													Autonomous ESS Functions, Enabled by Utility														
		Capab.		Emergency						Utility Monitoring							Utility Controls						Frequency			Real Power					Q / PF				Voltage		
	Utility SCADA interface?	Preset: ESS nameplate data	Access: ESS Capabilities and Supported Modes	Preset: Voltage Ride-Through	Preset: Frequency Ride-Through	Mode: Dynamic reactive current support	Mode: Soft-Start Reconnection	Mode: Backup power	Mode: Provide black start support	Monitor: ESS identity	Monitor: Operational characteristics	Monitor: Short-term forecast	Monitor: Status & PCC measurement	Monitor: Remote commanded P / Q	Monitor: Aux meter measurement(s)	Monitor: Battery details (temps & cell voltages)	Control: Start / stop ESS	Control: Enable/disable modes	Control: Set Mode Parameters and Curves	Control: Schedule real power and modes	Control: AGC Reg Up and Down	Control: Permit reconnection	Control: Provide black start capability	Mode: AGC (utility sends Reg up and down commands)	Mode: Frequency smoothing (Autonomous response to frequency)	Mode: Frequency-watt (Emergency e.g. spinning reserve)	Mode: Limit ESS real power to max discharge rate	Mode: Limit ESS real power to min watts charge rate	Mode: Set real power charge / discharge rate	Mode: Load / generation following	Mode: Real power smoothing of spikes and sags	Mode: Limit reactive power	Mode: Set reactive power	Mode: Fixed power factor	Mode: Power factor correction	Mode: Volt-var control (autonomous)	Mode: Volt-watt control (autonomous)	Mode: Fast var support
Electric Supply																																					
Electric Energy Time Shift	Y	x	x	x	x					x	x	x	x	x	x		x	x	x	x		x					x	x	x									
Electric Supply Capacity	Y	x	x	x	x					x							x										x	x	x									
Ancillary services																																					
Load following	Y	x	x	x	x					x	x	x	x	x	x		x	x	x	x	x										x							
Area Regulation	Y	x	x	x	x		x		x	x	x	x	x	x	x		x	x	x	x	x	x	x		x							x	x	x	x			
Electric Supply Reserve Capacity	Y	x	x	x	x					x	x	x	x	x	x		x						x			x	x	x	x									
Voltage Support	Y	x	x	x	x	x	x			x	x	x	x	x	x		x																x	x	x	x	x	x	x
Grid System																																					
Transmission Support	Y	x	x	x	x					x		x												x	x	x							x	x	x	x			
Transmission Congestion Relief	Y	x	x	x	x					x		x															x	x	x	x								
Transmission & Distribution Upgrade Deferral	Y	x	x	x	x					x		x					x										x	x	x				x	x	x	x			
Substation On-site Power	Y	x	x	x	x	x	x		x	x		x					x	x	x	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x
End User / Utility Customer																																					
Time-of-Use (TOU) Energy Cost Management	N									x	x	x	x		x												x	x	x	x								
Demand Charge Management	N									x	x	x	x		x																							
Electric Service Reliability	N							x	x	x	x	x	x		x	x																						
Electric Service Power Quality	N									x	x	x	x		x	x																	x	x	x	x	x	x	x

Figure 17: Economic Drivers for Energy Storage System (ESS) with Smart DER functions

Table 3: Smart DER Information and Functions to Meet ESS Use Case Requirements

ESS Use Cases	Smart DER Functions to Meet Use Case Requirements
Category 1 — Electric Supply	
1. Electric Energy Time-shift	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Set actual real power charging and discharging • Limit maximum real power output at ECP or other point • Load and generation following: counteract load and generation changes at the PCC • Schedule actual or maximum real power output, charging, or modes
2. Electric Supply Capacity	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide (long term) forecast of real power output/charging schedules at the PCC (characterized by annual hours of operation, frequency of operation, and duration of operation for each use)
Category 2 — Ancillary Services	
3. Load Following	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Load and generation following: counteract load and generation changes at the PCC
4. Area Regulation	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Set actual real power charging and discharging • Frequency-watt: Emergency counteract high/low frequency by changing watt output • Frequency smoothing: Smooth frequency variations by rapidly changing watt output • Participate in Automatic Generation Control (AGC) • Provide operational reserves • Default and emergency ramp rates as well as high and low limits for charging and discharging • Volt-VAR control: Counteract voltage variations by changing VAR output • Volt-watt: Counteract voltage variations by changing watt output • Watt-power factor function: change power factor based on watt output • "Soft-start" reconnection by ramping and/or random time within a window • Schedule actual or maximum real power output, charging, or modes
5. Electric Supply Reserve Capacity	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Provide "spinning", supplemental, and backup reserves • Provide black start capability

ESS Use Cases	Smart DER Functions to Meet Use Case Requirements
6. Voltage Support	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Volt-VAR control: Counteract voltage variations by changing var output • Volt-watt: Counteract voltage variations by changing watt output • Fast var support: Respond rapidly to voltage spikes and sags • Watt-power factor function: change power factor based on watt output • Schedule voltage support functions
Category 3 — Grid System	
7. Transmission Support	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Volt-VAR control: Counteract voltage variations by changing var output • Volt-watt: Counteract voltage variations by changing watt output • Fast var support: Respond rapidly to voltage spikes and sags • Schedule voltage support functions • Set actual real power charging and discharging • Frequency smoothing: Smooth frequency variations by rapidly changing watt output • Frequency-watt: Emergency counteract high/low frequency by changing watt output • "Soft-start" reconnection by ramping and/or random time within a window
8. Transmission Congestion Relief	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Set actual real power charging and discharging • Limit maximum real power output at ECP or other point • Load and generation following: counteract load and generation changes at the PCC • Schedule actual or maximum real power output, charging, or modes
9. Transmission & Distribution (T&D) Upgrade Deferral	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide (long term) forecast of real power output/charging schedules at the PCC (characterized by annual hours of operation, frequency of operation, and duration of operation for each use)
10. Substation On-site Power	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Provide black start capability

ESS Use Cases	Smart DER Functions to Meet Use Case Requirements
Category 4 — End User/Utility Customer	
11. Time-of-use (TOU) Energy Cost Management	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Set actual real power charging and discharging • Limit maximum real power output at ECP or other point • Load and generation following: counteract load and generation changes at the PCC • Schedule actual or maximum real power output, charging, or modes
12. Demand Charge Management	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Set actual real power charging and discharging • Limit maximum real power output at ECP or other point • Load and generation following: counteract load and generation changes at the PCC • Schedule actual or maximum real power output, charging, or modes
13. Electric Service Reliability	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • "Soft-start" reconnection by ramping and/or random time within a window • Provide backup power
14. Electric Service Power Quality	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Volt-VAR control: Counteract voltage variations by changing VAR output • Volt-watt: Counteract voltage variations by changing watt output • Fast var support: Respond rapidly to voltage spikes and sags • Watt-power factor function: change power factor based on watt output • Schedule voltage support functions
Category 5 — Renewables Integration	
15. Renewables Energy Time-shift	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Set actual real power charging and discharging • Limit maximum real power output at ECP or other point • Load and generation following: counteract load and generation changes at the PCC • Schedule actual or maximum real power output, charging, or modes

ESS Use Cases	Smart DER Functions to Meet Use Case Requirements
16. Renewables Capacity Firming	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Load and generation following: counteract load and generation changes at the PCC • Schedule load and generation following
17. Wind Generation Grid Integration	• Provide DER nameplate information, and operational characteristics at initial interconnection and upon changes • Provide status, measurements, and (short term) forecast of real and reactive power output/charging • Load and generation following: counteract load and generation changes at the PCC • Schedule load and generation following

4.3 Smart Inverter Working Group (SIWG) Phase 1 and 3 Functions and Use Cases

The SIWG, initiated through a joint agreement between the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), has developed a list of smart inverter functions, as well as a few use cases that identify different purposes for using those functions. These are listed in the SIWG Phase 1 and Phase 3[5] tables.

DER systems can implement certain basic functions, such as ride-through and volt-VAR control, but external energy management systems need to determine what values to supply for the functions, and when to use these functions. These external energy management systems may be local (FDEMS), or may be part of utility analysis of operational requirements. In turn, these energy management systems have inputs from the power system, from the DER systems, from DER owner-operators, and from market signals.

This list is combined in Table 4. That table contains the following columns:

- A number associated with the function. (*Note: since this table expands the original set of Phase 3 functions, the numbers are not linear at this time. That may change as this document is reviewed.)*
- The name of the function
- A brief description of the function

[5] The Phase 3 tables are still occasionally being updated to reflect additional concepts and uses

- Communication requirements, including whether the function is normally autonomous, what local sensors or communications are needed, and what "Information and Communications Technology (ICT) may be needed for monitoring, for updates to settings and for issuing control commands
- Reference to the EPRI Report "*Common Functions for Smart Inverters, Version 3, 3002002233*"[6]
- IEC 61850 Information Model data objects for each function. The 4-letter all-capitals acronym is the logical node, usually followed by specific data objects. **Bold** indicates that the data object is not yet in the IEC 61850 standard but has been submitted for inclusion.
- Corresponding IEC 2030.5 (SEP 2) data objects

[6] See http://www.epri.com/search/Pages/results.aspx?k=Common%20Functions%20for%20Smart%20Inverters

Table 4: SIWG Phase 1 and Phase 3 Functions and Information Support

#	DER Functions	Description and Purpose of the Function	Communication Requirements	EPRI Common Functions v3	IEC 61850 Information Model	IEEE 2030.5 (SEP2)
	4.3.1 Phase 1 Autonomous DER Functions					
P1a	**Support anti-islanding**: trip off under extended anomalous conditions	Support anti-islanding to trip off under extended anomalous conditions, coordinated with the ride-through functions	*Autonomous*	Not addressed	• MMXU.V – Voltage measurement • MMXU.Hz – Frequency measurement • PTUV and PTOV – Voltage protection • PTUF and PTOF – Frequency protection • XFUS – Fuse • CSWI – Circuit switch • XCBR – Circuit breaker	Communication not required. Expected behavior for Utility-Interactive Inverter. If Ride Through function is not activated IEEE 1547 default or site settings would govern.
P1b	**High/Low Voltage Ride-Through**: Provide ride-through of low/high voltage excursions beyond normal limits	Provide ride-through of low/high voltage excursions beyond normal limits	*Autonomous* *Local: Monitor voltage at ECP or PCC* *ICT: DER receives updated ride-through settings*	EPRI 14 Low/High Voltage Ride-Through	• MMXU.V – Voltage measurement • FMAR – Voltage vs. time array • DGSM.InCrv – Active curve • DGSM.ModEna.ModTyp.CurveModeKind - **enum = 9.10** – HLVRT curve • **DOPM.OpModVRt** – Mode of operation – voltage ride-through enable/disable • DRCC.StrDlTms – nominal time before starting or restarting • DOPR.ECPNomVLev - Nominal voltage level at ECP.including maximum and minimum • **DRCT.ConnRmpUpRte** - Soft-start reconnection ramp up rate. Ramp rate as percentage of current rather than power. • RDGS.LoVRtSt - When equals to TRUE low voltage ride-through incident is occurring	<u>Activate Function</u> DERControl: opModLVRT:[links to curves} opModHVRT:{links to curves} <u>Load Curves</u> DERCurve: curveType=4 (LVRT) CurveData:{x-y) DERCurve: curveType=5 (HVRT) CurveData:{x-y)

#	DER Functions	Description and Purpose of the Function	Communication Requirements	EPRI Common Functions v3	IEC 61850 Information Model	IEEE 2030.5 (SEP2)
P1c	**High/Low Frequency Ride-Through**: Provide ride-through of low/high frequency excursions beyond normal limits	Provide ride-through of low/high frequency excursions beyond normal limits	*Autonomous* *Local: Monitor frequency at ECP* *ICT: DER receives updated ride-through settings*	EPRI-15 Low/High Frequency Ride-Through	• MMXU.Hz – Frequency measurement • FMAR– Frequency vs. time array • DGSM.InCrv – Active curve identification • DGSM.ModEna.ModTyp.CurveModeKind - **enum = 11.12** – HLFRT curve **DOPM.OpModFrt** – Mode of operation – frequency ride-through enable/disable • DRCC.StrDlTms – nominal time before starting or restarting • DOPR.ECPNomHz - Nominal frequency level at ECP.including maximum and minimum • **DRCT.ConnRmpUpRte** - Soft-start reconnection ramp up rate. Ramp rate as percentage of current rather than power.	Not in SEP2 V1.0 –easy to add as with VRT, e.g. <u>Activate Function</u> DERControl: opModLFRT:[links to curves} opModHFRT:{links to curves} <u>Load Curves</u> DERCurve: curveType=6 (LFRT) CurveData:{x-y) DERCurve: curveType=7 (HFRT) CurveData:{x-y)
P1d	**Volt-Var Control**: Provide volt/var control through dynamic reactive power injection	Provide volt/var control through dynamic reactive power injection through autonomous responses to local voltage measurements	*Autonomous* *Local: Monitor voltage at ECP or PCC* *ICT: DER receives updated volt-var settings*	EPRI-9 Intelligent Volt-VAR Function	• MMXU.V – Voltage measurement • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the volt-var array curves: with DeptRef set either to percent available vars (% of LN ZINV VArAval) or percent max vars (% of LN DRCT VArMax) • **DOPM.OpModVVAr** – Mode of operation – volt-var control enable/disable	<u>Activate Function</u> DERControl: opModVoltVAr:[link to curve} <u>Load Curves</u> DERCurve: curveType=0 (Volt-VAr) CurveData:{x-y)

#	DER Functions	Description and Purpose of the Function	Communication Requirements	EPRI Common Functions v3	IEC 61850 Information Model	IEEE 2030.5 (SEP2)
P1e	**Ramping:** Define default and emergency ramp rates as well as high and low limits	Define default and emergency ramp rates as well as high and low limits	*Autonomous* *ICT: DER receives updated ramping settings*	EPRI-2 Basic Device Settings and Limits Default real power ramp rate = WGra	• DRCT.WGra - Default ramp rate for changes in active power: percentage of WMax • **DRCT.NomRmpUp** - Nominal ramp up rate if separate up and down ramp rates are required. Ramp rate as percentage of current rather than power. • **DRCT.NomRmpDn** - Nominal ramp down rate if separate up and down ramp rates are required. Ramp rate as percentage of current rather than power. • **DRCT.EmgRmpUpRte** - Emergency ramp up rate. Ramp rate as percentage of current rather than power. • **DRCT.ConnRmpDnRte** - Disconnection ramp down rate (non-emergency). Ramp rate as percentage of current rather than power. • **DRCT.ConnRmpUpRte** - Soft-start reconnection ramp up rate. Ramp rate as percentage of current rather than power. • DRCT.RmpRtePct - Setpoint for maximum ramp rate as percentage of nominal maximum ramp rate • DRCT.WChaGra - Setpoint for maximum charging ramp rate: percentage of WChaMax	Default Ramp Rate for Real Power DERSettings: setGradW (SHOULD BE READ ONLY VALUE - ERROR IN SEP2 DESIGN) For setpoint modes DERControl: rampTms: seconds (APPLIES TO ALL MODES ACTIVATED) For Curve Functions DERCurve: rampDecTms:seconds rampIncTms:seconds rampPT1Tms:seconds
P1f	**Fixed Power Factor:** Provide reactive power by a fixed power factor	Provide reactive power by a fixed power factor	*Autonomous* *ICT: DER receives updated fixed power settings*	EPRI-8 Fixed Power Factor Function	• DRCC.OutPFSet - Setpoint for maintaining fixed power factor • **DOPM**.OpModConsPF - Mode for power factor setting enable/disable	Activate Function DERControl: opModFixedPF: FixedPowerFactor

#	DER Functions	Description and Purpose of the Function	Communication Requirements	EPRI Common Functions v3	IEC 61850 Information Model	IEEE 2030.5 (SEP2)
P1g	**Soft-Start Reconnection:** Reconnect by "soft-start" methods (e.g., ramping and/or random time within a window)	Reconnect by "soft-start" methods (e.g. ramping and/or random time within a window)	*Autonomous* *ICT: DER receives updated soft-start ramping settings*		• DRCC.StrDlTms – nominal time before starting or restarting • **DRCT.ConnRmpUpRte** - Soft-start reconnection ramp up rate. Ramp rate as percentage of current rather than power.	
	4.3.2 Monitoring					
2	**Monitor DER Alarms**: Provide emergency alarms and information	The DER system (and aggregations of DER systems, such as virtual power plants) provides alarms and supporting emergency information via the FDEMS to the utility. This function is feasible only if the ICT infrastructure is available.	*ICT*: DER system provides alarms and emergency information to utility and/or REP	EPRI-24 Event Logging	• Status changes deemed alarms from all DOs • Logging report	

3a	**Monitor DER Status**: Provide status on current energy and ancillary services	The DER system (and aggregations of DER systems, such as virtual power plants interacting with the market system, or microgrids interacting with the EPS) provides current status, power system measurements, and other real-time data (possibly aggregated via the FDEMS) to the utility, in order to support real-time and short-term analysis applications. This function is feasible only if the ICT infrastructure is available. Additional characterizations of the DER system and its local EPS are expected to be provided during the interconnection process. Revenue metering data is provided via alternate means.	*ICT*: DER system provides status values to utility and/or REP	EPRI-23 Status Monitoring Points	• DGEN.GenOpSt – Generation operational state • DPST.ECPConn - PCC or ECP Connection Status • DPST.ECPConn - DER Connection Status • ZINV. GriModSt - Inverter status • DRCS for basic operations.DGSM for advanced - Active modes • **DRCS**.**OpModVRtSt** Voltage ride-through status • **DRCS.OpModHzRtSt**- Frequency ride-through status • **DOPM.OpModLimW** – Mode for limit maximum real power function - enable/disable • **DOPM.OpModHzW** – Mode of operation – frequency-watt enable/disable • **DOPM.OpModVW** – Mode of operation – voltage-watt enable/disable • **DOPM.OpModVA** – Mode of operation – voltage-amps enable/disable • **DOPM.OpModWPF** – Mode of operation – watts-PF enable/disable • **DOPM.OpModTmpVAr** – Mode of operation – temperature-var control enable/disable • **DOPM.OpModAGC** – Mode for AGC – enable/disable • **DOPM**.**OpModAGCReg**– Mode for AGC regulation – enable/disable • DOPM.OpModConsW – Mode for constant watts at ECP – enable/disable • DOPM.OpModExIm – Mode for constant export/import at PCC – enable/disable • **DOPM.OpModTVr** – Mode of operation – temperature-var control enable/disable • DOPM.**OpModAGC** – Mode for AGC – enable/disable • DOPM.**OpModReg**– Mode for AGC regulation – enable/disable • DOPM.**OpModReg**– Mode for AGC regulation – enable/disable • DOPM.OpModConsVAr - Mode of operation – constant vars	<u>DER Resource Objects</u> DERSettings: DERRatings: DERAvailability: DERStatus: PowerStatus: (See SEP2 for listing of parameters included in each object) Metering Function can also be used.

3b	**Monitor DER Output**: Provide measurements on current energy and ancillary services	The DER system (and aggregations of DER systems, such as virtual power plants) provides current status, power system measurements, and other real-time data (possibly aggregated via the FDEMS) to the utility, in order to support real-time and short-term analysis applications. This function is feasible only if the ICT infrastructure is available. (Revenue metering data is provided via alternate means.)	*ICT*: DER system provides measurement values to utility and/or REP		• MMXU.W (or TotW) • MMXU.Var (or TotVAr) • MMXU.PF (or TotPF) • MMXU.Hz • MMXU.VA (or TotVA) • MMXU.A • MMXU.PPV • DRCT.MaxWLim - De-rated real power • DRCT.MaxVArLim - Maximum vars limit • DRCT.VArAval - Available vars without affecting watts • Characterizations and statistical information (e.g. latest value (instantaneous).maximum.minimum.average. mean (may be the same as average).median.mode.percentile.total (count or cumulative))	Metering Function Set
3c	**Monitor DER Metered Output**: Provide measurements on current energy and ancillary services	The DER system (and aggregations of DER systems, such as virtual power plants) provides current status, power system measurements, and other real-time data (possibly aggregated via the FDEMS) to the utility, in order to support real-time and short-term analysis applications. This function is feasible only if the ICT infrastructure is available. (Revenue metering data is provided via alternate means.)	*ICT*: DER system provides metered values to utility and/or REP		• MMTR.TotWh - Wh. accumulated AC watt-hours • MMTR.TotVAh - VAh.accumulated VA-hours • MMTR.TotVArh - VArh.accumulated Var-hours	Metering Function Set

	4.3.3 Real Power Functions					
4	**Limit Maximum Real Power:** Limit maximum real power output at an ECP or the PCC upon a direct command from the utility	The utility issues a direct command to limit the maximum real power output at the ECP or PCC. The reason might be that unusual or emergency conditions are causing reverse flow into the feeder's substation or because the total DER real power output on the feeder is greater than some percentage of total load. The command might be an absolute watt value or might be a percentage of DER output. This function is feasible only if the ICT infrastructure is available. It might also be used to ensure fairness across many DER systems.	*Autonomous* *Local: Monitor real power output at PCC* *ICT*: Utility issues a command to limit the real power output at the ECP or PCC	EPRI-4 Maximum Generation Limit EPRI-19 Peak Power Limiting (FDEMS Capability, not DER function)	• MMXU.W (or TotW) – Actual watt output • DRCT.WMaxLimPct – Percent of reference active power watts as maximum allowed watts output (e.g. at ECP) • DOPM.**OpModLimW** – Mode for limit maximum real power function - enable/disable • DRCT**.WMaxLim**- Max real power output (e.g. if combinations of DER types at an ECP and/or at PCC)	Utility Needs DERSettings: setMaxW: (value in watts) Activate Function DERControl: opModFixedW: percent of setMaxW Reference is ECP
5	**Set Real Power:** Set actual real power output at the ECP or PCC	The utility either presets or issues a direct command to set the actual real power output at the ECP or PCC (constant export/import if load changes; constant watts if no load). The reason might be to establish a base or known generation level without the need for constant monitoring. This is the approach often used today with synchronous generators. This function is feasible only if the ICT infrastructure is available. Meter reads could provide 15-minute energy by the end of the day could provide production information for operational planning.	*Autonomous* *Local: Monitor real power output at PCC.* *ICT: utility issues a command to modify the real power output at the ECP or PCC including for charging or discharging storage systems*	EPRI-5 Battery Storage Direct Charge/ Discharge Management (Only use discharge)	• DRCC.OutWSet – Output target power setpoint • DRCC.ImptExptSet – Setpoint for maintaining constant import/export power at ECP (or PCC) • DOPM.OpModConsW – Mode for constant watts at ECP – enable/disable • DOPM.OpModExIm – Mode for constant export/import at PCC or at storage ECP – enable/disable	Utility Needs DERSettings: setMaxDischargeRate: (value in Watts) Activate Function DERControl: opModFixedFlow: percent of setMaxDischargeRate (>=0) Reference is ECP

6	**Command DER to Connect or Disconnect:** Support direct command to disconnect or reconnect	The DER system performs a disconnect or reconnect at the ECP or PCC. Time windows are established for different DER systems to respond randomly within that window to the disconnect and reconnect commands. This function is feasible only if the ICT infrastructure is available.	*ICT*: Utility or FDEMS issues disconnect or reconnect command	EPRI-3 Connect-Disconnect	• DRCC.DERStop – Stop DER if not using circuit breaker • DRCC.DERStr – Start DER if not using circuit breaker • DRCC.EmgStop - Remote emergency stop • CSWI.Pos – Close/open circuit breaker switch if using circuit breaker • DOPM.WinTms – If using time window with random start time • DOPM.RvrtTms – If DER can revert to reconnecting after specified time • **DRCT.ConnRmpUpRte** - Soft-start reconnection ramp up rate. Ramp rate as percentage of current rather than power.	<u>State of Connection</u> DERSettings: setGenConnect: T/F and also in DERStatus: genConnectStatus: T/F No explicit DERControl provided by SEP2 for this purpose. POOR DESIGN – utility could overwrite value of setGenConnect in server and expect DER to check to see that its resource value has been changed.

	4.3.4 Phase 3 Autonomous DER Functions					
7	**Frequency-Watt:** Counteract frequency excursions beyond normal limits by decreasing or increasing real power	The DER system reduces real power to counteract frequency excursions beyond normal limits (and vice versa if additional generation or storage is available), particularly for microgrids. Hysteresis can be used as the frequency returns within the normal range to avoid abrupt changes by groups of DER systems.	*Autonomous* *Local: Monitor voltage anomalies* *ICT: Utility updates frequency response settings*	EPRI-11 Frequency-Watt Function	• MMXU.Hz –Frequency measurement • DRCT.WGra - Default ramp rate for changes in active power: percentage of WMax • FWHZ.HzStr - Delta frequency between stop frequency and nominal grid frequency • FWHZ.HzStop - Delta frequency between stop frequency and nominal grid frequency • FWHZ.HzStopWGra - The maximum rate at which the output may be increased after releasing the frozen value of snap shot function. This is represented in terms of % WMax per minute • FWHZ.HysEna – Enable hysteresis Use of curves • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the frequency-watt array curves: with DeptRef set to percent of available watts • **DOPM.OpModHzW** – Mode of operation – frequency-watt enable/disable	Activate Function DERControl: opModFreqWatt: [link to curve} Load Curves DERCurve: curveType=1 (Freq-Watt) CurveData:{x-y)
8	**Voltage-Watt:** Modify real power output autonomously in response to local voltage variations	The DER system monitors the local (or feeder) voltage and modifies real power output in order to damp voltage deviations. Settings are coordinated between the utility and DER operator. Hysteresis and delayed responses could be used to ensure overreactions or hunting do not occur.	*Autonomous* *Local: Monitor voltage* *ICT: Utility modifies the real power output settings*	EPRI-10 Volt-Watt Function	• MMXU.V –Voltage measurement • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the voltage-watt array curves: with DeptRef set to percent of available watts • **DOPM.OpModVW** – Mode of operation – voltage-watt enable/disable	Activate Function DERControl: opModVoltWatt: [link to curve} Load Curves DERCurve: curveType=3 (Volt-Watt) CurveData:{x-y)

9	**Dynamic Reactive Current Support:** Counteract voltage excursions beyond normal limits by providing dynamic reactive current support	The DER system counteracts voltage anomalies (spikes or sags) through "dynamic reactive current support". The DER system supports the grid during short periods of abnormally high or low voltage levels by feeding reactive current to the grid until the voltage either returns within its normal range, or the DER system ramps down, or the DER system is required to disconnect.	*Autonomous* *Local: Monitor voltage anomalies* *ICT: Utility updates dynamic current settings*	EPRI-16 Dynamic Reactive Current Support	• RDGS.ArGraMod - Mode of reactive current characteristic • RDGS.ArGraSag - Gradient for reactive current during a voltage sag • RDGS.ArGraSwl - Gradient for reactive current during a voltage swell • RDGS.DelV - Delta voltage • RDGS.DbVMin - Lower limit.voltage dead band • RDGS.DbVMax - Upper limit.voltage dead band • RDGS.VAv - Moving average voltage • RDGS.FilTms - Filter time window for calculating moving average voltage • RDGS.HoldTmms - Hold time (in milliseconds) • RDGS.HysBlkZnV - Hysteresis voltage • RDGS.BlkZnV - Block zone voltage • RDGS.BlkZnTmms - Block zone time (in milliseconds) • DRCT.VRef - Reference voltage for functions using grid voltage as input • MMXU.V –Voltage measurement Use of curves • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the voltage-amps array curves: with DeptRef set to percent of available amps • **DOPM.OpModVA** – Mode of operation – voltage-amps enable/disable	**Not Implemented**

10	**Watt- Power Factor:** Power factor is shifted based on real power output	The power factor is not fixed but changes with the power level. It might be slightly capacitive at very low output power levels and becoming slightly inductive at high power levels.	*Autonomous* *Local: Monitor real power output* *ICT: Utility updates power factor settings*		• MMXU.W –Watts measurement • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the watts-PF array curves: with DeptRef set to percent of available PF • **DOPM.OpModWPF –** Mode of operation – watts-PF enable/disable	Activate Function DERControl: opModWattPF: [link to curve} Load Curves DERCurve: curveType=2 (Watt-PF) CurveData:{x-y)
11	**Smooth Frequency Deviations:** Smooth minor frequency deviations by rapidly modifying real power output to these deviations	The DER system modifies real power output rapidly to counter minor frequency deviations. The frequency-watt settings define the percentage of real-power output to modify for different degrees of frequency deviations on a second or even sub-second basis	*Autonomous* *Local: Monitor frequency* *ICT: Utility updates the frequency-watt settings*	EPRI-11 Frequency-Watt Function	• MMXU.Hz –Frequency measurement • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the frequency-watt array curves: with DeptRef set to percent of available watts • **DOPM.OpModHzW** – Mode of operation – frequency-watt enable/disable **Note**: the same data objects are used as for Frequency-Watt.but the settings used are different. So there may need to be a separate enable/disable	Activate Function DERControl: opModFreqWatt: [link to curve} Load Curves DERCurve: curveType=1 (Freq-Watt) CurveData:{x-y) Curve point selection different than for Frequency-Watt (7)
12	**Imitate capacitor bank triggers:** Provide reactive power through autonomous responses to weather, current, or time-of-day	In addition to volt-var control, the DER system implements temperature-var curves that define the reactive power for different ambient temperatures, similar to use of feeder capacitors for improving the voltage profile. Curves could also be defined for current-var and for time-of-day-var.	*Autonomous* *Local: Monitor weather conditions* *ICT: Utility updates xx-var curves*	EPRI-13 Price or Temperature Functions	• MMXU.V – Voltage measurement • MMET.EnvTmp - Temperature of environment [°C] • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the temperature-var array curves: with DeptRef set either to percent available vars (% of LN ZINV VArAval) or percent max vars (% of LN DRCT VArMax) • **DOPM.OpModTmpVAr** – Mode of operation – temperature-var control enable/disable	No Explicit Function for autonomous Temp-VAr
13	**Short Circuit Current Limit:** DER must have short circuit limits	DER should limit their short circuit current to no more than 1.2 p.u. This is useful for utilities in order to perform short circuit impact studies.	*Autonomous*		Internal to DER	Internal to DER

	4.3.5 Ancillary Services					
14	**Provide black start capabilities**	The DER system operates as a microgrid (possibly just itself) and supports additional loads being added, so long as they are within its generation capabilities. This function is feasible only if the ICT infrastructure is available.	*ICT: Utility issues "black start mode" command*	No Explicit Function.	• DRCC.DERStr – Start DER if not using circuit breaker • CSWI.Pos – Close circuit breaker switch if using circuit breaker	SEP2 does not provide a command for inverter to switch to V/F mode.
n	**Participate in AGC:** Support frequency regulation by automatic generation control (AGC) commands	The DER system (or aggregations of DER systems) implements modification of real-power output based on AGC signals on a multi-second basis. This function is feasible only if the ICT infrastructure is available.	*ICT: Utility issues AGC commands to modify real power output*	EPRI-5 Battery Storage – Charge/Discharge Management (also EPRI-7)	• DRCC.OutWSet – Set real power value • DGEN.GnRL - Raises or lowers the generation level by steps: Raise = True.Lower = False • DOPM.**OpModAGC** – Mode for AGC – enable/disable	<u>Utility Needs</u> DERSettings: setMaxDischargeRate: (value in Watts) setMaxChargeRate: (value in Watts) <u>Activate Function</u> DERControl: opModFixedFlow: signed percent of setMaxDischargeRate (>=0) or setMaxChargeRate (<0) The actual AGC signal would be converted into the percent set point value by DER controller before encoding into SEP2.
16	**Provide "spinning" or operational reserve as bid into market**	The DER system provides emergency real power upon command at short notice (seconds or minutes), either through increasing generation or discharging storage devices. This function would be in response to market bids for providing this reserve. This function is feasible only if the ICT infrastructure is available.	*ICT: Utility issues command for emergency reserve*	EPRI-5 Battery Storage – Charge/Discharge Management	• DRCC.OutWSet – Set real power value • **DOPM**.**OpModReg**– Mode for AGC regulation – enable/disable	<u>Utility Needs</u> DERSettings: setMaxDischargeRate: (value in Watts) <u>Activate Function</u> DERControl: opModFixedFlow: signed percent of setMaxDischargeRate (>=0)

17	**Reactive Power Support during non-generating times:** Support the grid with reactive power during non-generating times	DERs support the grid with reactive power (VARs) when there is no primary energy (i.e. solar irradiance). This can be used by utilities to reduce the stress in the system in areas with high motor load (A/C) during peak times	*ICT: Utility or REP*	EPRI-9 Intelligent Volt-VAR Function	• DOPM.OpModConsVAr - Mode of operation – constant vars • DRCT.VArMaxPct - Reactive power in percent of VArMax	<u>Activate Function</u> DERControl: opModVoltVAr:[link to curve} <u>Load Curves</u> DERCurve: curveType=0 (Volt-VAr) CurveData:{x-y)
18	**Single phase power control on multi-phase units:** Control power output independently in each phase	Multi-phase DER inverters/converters can have ability to control phase independently. This will be useful to balanced distribution circuits.	*ICT: Utility or REP*		• MMXU.W - Phase to ground/phase to neutral real powers P for each phase • DRCC.OutWSet – Set real power value for each phase	No capability in SEP2
19	**Fast VAr Support for voltage mitigations:** DER fast VAR support 0.7PF to mitigate voltage deviations	DER can provide VAR support when the voltage goes out of normal range. Provide 0.7PF leading when voltage is between 88% and 50%. Provide 0.7 PF when the voltage is between 105% and 110%. This will provide grid support during voltage events (such as FIDVR events)	*Autonomous* *Local: Monitor voltage at ECP or PCC* *ICT: DER receives updated fast VAr support volt-var settings*	EPRI-9 Intelligent Volt-VAR Function	• MMXU.V – Voltage measurement • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the volt-var array curves: with DeptRef set to either percent available vars (% of LN ZINV VArAval) or percent max vars (% of LN DRCT VArMax) • **DOPM.OpModVVAr** – Mode of operation – fast Var support enable/disable ***Note**: the settings are different than for volt-var control.but otherwise the same data objects are used*	<u>Activate Function</u> DERControl: opModVoltVAr:[link to curve} <u>Load Curves</u> DERCurve: curveType=0 (Volt-VAr) CurveData:{x-y) Multiple curves can be stored and the utility selects.
20	**Provide Backup Power:** Provide backup power after disconnecting from grid	The DER system, including energy storage and electric vehicles, has the ability to provide real power when the site is disconnected from grid power. The reason is for providing backup power to the facility and possibly black start capabilities.	*Autonomous* *Local: Monitor voltage, frequency, and connected load*		• MMXU.V –Voltage measurement • MMXU.Hz –Frequency measurement • DOPM.OpModExIm – Mode for constant export/import at PCC – enable/disable ***Note**: Local EPS is disconnected from the Area EPS at the PCC*	SEP2 does not have a command to go from NEC 705 (UII) to NEC 702 (V/F). DER can be designed to allow this mode.

21a	**Monitor Energy Storage System:** Monitor additional status and measurement data from energy storage systems	In addition to the status and measurement data monitored for distributed generation systems, monitor storage-specific real-time and near-real-time data from single or aggregations of energy storage devices	*ICT: Energy storage system provides status and measurement values to utility and/or REP*	EPRI-23 Status Monitoring Points	• DBAT.BatSt - Battery system status • DBAT.BatTestRsl - Battery test results • DBAT.BatVHi - Battery voltage high or overcharged • DBAT.BatVLo - Battery voltage low or undercharged • DBAT.V - External battery voltage • DBAT.VChgRte - Rate of output battery voltage change • DBAT.SocAhr - State of charge (SOC) (Ah-based) • DBAT.IntnBatV - Internal battery voltage • DBAT.ADrn - Battery drain current • DBAT.IntnBatA - Internal battery current • DBAT.IntnBatTmp - Internal battery temperature • DBAT.BatOn - Turn on battery • DBAT.BatTest - Start battery test • DBAT.BatTyp - Type of battery • DBAT.AhrRtg - Amp-hour capacity rating • DBAT.MinAhrRtg - Minimum resting amp-hour capacity rating allowed • DBAT.BatVNom - Maximum battery discharge current • DBAT.BatSerCnt - Number of cells in series • DBAT.BatParCnt - Number of cells in parallel • DBAT.DschCrv - Discharge curve • DBAT.DschTm - Discharge curve by time • DBAT.DschRte - Self discharge rate • DBAT.MaxBatA - Nominal voltage of battery • DBAT.MaxBatV - Maximum battery charge voltage • DBAT.HiBatVAlm - High battery voltage alarm level • DBAT.LoBatVAlm - Low battery voltage alarm level	Resources with storage status DERSettings: setMaxChargeRate setMaxDischargeRate setStorConnect DERCapability: rtgAh rtgMaxChargeRate rtgMaxDischargeRate rtgWh DERAvailability: availabilityDuration maxChargeDuration reserveChargePercent reservePercent DERStatus: stateOfChargeStatus PowerStatus: estimatedChargeRemaining minimumChargingDuration targetStateOfCharge timeChargeIsNeeded

21b	**Set Storage Charge Rate:** Set energy storage charge rate	DER storage systems set charge rates (default 10% minute) so that they do not provoke inrush in local utilities	*Autonomous* *ICT: Utility or REP*	EPRI-5 Battery Storage – Charge/Discharge Management (also EPRI-7)	• DBTC.BatChaSt - Battery charger charging mode status • DBTC.BatChaTyp - Type of battery charger • DBTC.ChaV - Charging voltage • DBTC.ChaA - Charging current • DBTC.ChaCrv - Charge curve • DBTC.ChaCrvTm - Charge curve as time schedule • DBTC.RechaRte - Recharge rate including maximum rate (discharge rates are same as DER) • DBTC.BatChaPwr - Battery charging power required • DBTC.BatChaMod - Battery charger mode setting • DBTC.ChaTms - Charging time since last off/reset	**To control the charging to a target rate:** Utility Needs DERSettings: setMaxChargeRate: (value in Watts) Activate Function DERControl: opModFixedFlow: signed percent of setMaxChargeRate (<0) **To only set max rate if charging occurs:** overwrite value in host server of DERSettings: setMaxChargeRate POOR DESIGN – utility could overwrite value in server and expect DER to check to see that its resource value has been changed. But DER might not check its own posted resource value.

21c	**Set Storage "Charge-by" parameters:** Set energy storage charge-by parameters	Set the parameters for permitting the storage system to change charging rates so long as the requested state of charge is reached by the "charge-by" time. Multiple settings in the charge curve may be possible so that, say, 50% SOC is reached in 30 minutes, while 100% SOC is reached in 5 hours	*Autonomous* *ICT: Utility or REP*	EPRI-7 Battery Storage – Coordinated Charge/Discharge Management	• **DBTC.SocTgt –** Target state of charge • DBTC.ChaCrvTm - Charge curve as time schedule	PowerStatus: timeChargeIsNeeded targetStateOfCharge These would normally be set at the DER without using SEP2. These are status parameters. If some entity overwrites the values in the host server for these resource and the DER checks to see that its values have been changed and allows the change, this is a way to update the values. This is POOR design practice.
22	**Storage Frequency-Watt:** Ability to vary active power during frequency changes	Storage facilities can charge during over frequency and discharge during under frequency events. This can support the grid and support grid stabilization.	*Autonomous* *ICT: Utility or REP*	EPRI-11 Frequency-Watt Function	• MMXU.Hz –Frequency measurement • DGSM for curve-based commands WinTms.RmpTms.RvrtTms.and ModEna • FMAR to provide the frequency-watt array curves: with DeptRef set to percent of available watts • DOPM.OpModFW – Mode of operation – frequency-watt enable/disable ***Note**: This function is identical to the general F-W function except that negative watts are permitted, indicating charging instead of discharging.*	<u>Activate Function</u> DERControl: opModFreqWatt: [link to curve} <u>Load Curves</u> DERCurve: curveType=1 (Freq-Watt) CurveData:{x-y) This only requires curve settings that reflect the ability to swing from discharging to charging.

23	**Schedule Storage**: Set or schedule the storage of energy for later delivery, indicating time to start charging, charging rate and/or "charge-by" time	For a DER system that has storage capabilities, such as battery storage or a combined PV + storage system or a fleet of electric vehicles. Preset time-of-charge values can be established. Settings are coordinated between the utility and DER operator. Different scenarios could include: • Low load conditions at night are causing some renewable energy to be wasted, so charging energy storage DER systems at that time makes power system operations more efficient. • DER controller charges at the specified rate (less than or equal to the maximum charging rate) until the state-of-charge (SOC) reaches a specified level. • DER controller charges at the necessary rate in order to reach the specified SOC within the "charge-by" time.	*Autonomous* *ICT: Utility updates the storage settings and/or schedule*	EPRI-7 Battery Storage – Coordinated Charge-Discharge Management	• FSCH.SchdSt - State of this schedule: Not ready.Validated.Ready.Running • FSCH.SchdEntr - The current schedule entry of a running schedule. • FSCH.Valxx - Current value of the scheduled parameter as determined by the schedule. • FSCH.Validate - Validate transition request • FSCH.Enable - Enable transition request • FSCH.Edit - Edit transition request • FSCH.Disable - Disable transition request • FSCH.SchdPrio - The priority relation of this schedule.0n. with higher numbers superseding lower numbers. • FSCH.NumEntr - The number of schedule entries that are valid • FSCH.SchdIntv - The schedule interval duration in time entities as specified in the unit	Activate Function DERControl: opModFixedFlow: signed percent of setMaxChargeRate (<0) A sequence of DERControls can be provided. Each control includes a start time with optional ramp time between setpoint values and random time delay on start of ramp. If DER real power is not being controlled, it will optimize its own charging. Information for utility Used when actively controlling real power and also managing DER needs. DERSettings: setMaxChargeRate setMaxDischargeRate PowerStatus: targetStateOfCharge timeChargeIsNeeded energyRequestNow minimumChargingDuration DERAavailability availabilityDuration maxChargeDuration

24	**Flow Reservation :** Storage DER requests either charge or discharge	Storage DER requests either charge or discharge of defined amount of energy (kWh) starting at a defined time and completing by a defined time at a rate not exceeding a defined charge or discharge power level. Utility responds with an authorized energy transfer, start time, and maximum power level. The utility can update the response periodically to modulate the power flow during transfer, but cannot change from discharging to charging, or the reverse, without a new flow reservation request by the storage unit.	*ICT: Utility or REP*		***Note**: see Schedule Storage*	<u>DER Requests Energy</u> FlowReservationRequest: energyRequested powerRequested intervalRequested durationRequested <u>Utility Responds</u> FlowReservationResponse: energyAvailable powerAvailable interval.start interval.duration For a single request the utility can issue a sequence of responses to manage power flow – but cannot change from charging to discharging. Also DER can cancel the Request and provide a new Request.

	4.3.6 Scheduling and Forecasts					
25	**Schedule output at PCC**: Schedule actual or maximum real power output at specific times	The utility establishes (or pre-establishes) a schedule (e.g. on-peak & off-peak) of actual or maximum real power output levels at the ECP or PCC, possibly combining generation, storage, and load management. The reason might be to minimize output during low load conditions while allowing or requiring higher output during peak load time periods.	*Autonomous* *Local: Monitor real power output at ECP or PCC.* *ICT: Utility updates the schedule of actual or maximum real power values*	EPRI-4 Maximum Generation Limit EPRI-19 Peak Power Limiting (FDEMS Capability, not DER function EPRI—5/7 Charge/Discharge Management	• FSCH.SchdSt - State of this schedule: Not ready.Validated.Ready.Running • FSCH.SchdEntr - The current schedule entry of a running schedule. • FSCH.Valxx - Current value of the scheduled parameter as determined by the schedule. • FSCH.Validate - Validate transition request • FSCH.Enable - Enable transition request • FSCH.Edit - Edit transition request • FSCH.Disable - Disable transition request • FSCH.SchdPrio - The priority relation of this schedule.0.n.with higher numbers superseding lower numbers. • FSCH.NumEntr - The number of schedule entries that are valid • FSCH.SchdIntv - The schedule interval duration in time entities as specified in the unit	DERControl: opModFixedW opModFixedFlow A schedule of DERControls can be provided in advance. The DER would be designed to control power at the ECP. A facility FDEMS could control at PCC. SEP2 does not have a switch. This would be an installation parameter.
26	**Schedule DER Functions:** Schedule real power and ancillary service outputs	The DER system receives and follows schedules for real power settings, reactive settings, limits, modes (such as autonomous volt/var, frequency-watt), and other operational settings.	*Autonomous* *ICT: Utility, REP, or FDEMS issues schedules to DER system*	EPRI allow immediate commands and autonomous functions to be scheduled	***Note**: see Schedule output at PCC*	SEP2 allows DER controls to be scheduled for all functions
27	**FDEMS or Aggregator provides generation and storage schedules:** Provide schedules to utilities or others	The FDEMS or Aggregator provides schedules of expected generation and storage reflecting customer requirements, maintenance, local weather forecasts, etc. This function is feasible only if the ICT infrastructure is available.	*ICT: Provide scheduling information to Utility, REP, or FDEMS*	EPRI allow immediate commands and autonomous functions to be scheduled	***Note**: see Schedule output at PCC*	SEP2 allows DER controls to be scheduled for all functions

28	**FDEMS or Aggregator provides forecasts of available energy or ancillary services:** Scheduled, planned, or forecast of available energy and ancillary services	The FDEMS or Aggregator provides scheduled, planned, and/or forecast information for available energy and ancillary services over the next hours, days, weeks, etc., for input into planning applications. Separate DER generation from load behind the PCC. This function is feasible only if the ICT infrastructure is available.	*ICT: FDEMS provides information to utility and/or REP*		***Note**: Forecasts will use the same structure as schedules - see Schedule output at PCC*	SEP2 allows DER controls to be used to schedule future events.
29	**FDEMS or Aggregator provides micro-locational weather forecasts:** Provide real-time and forecast weather forecasts	The FDEMS or Aggregator provides micro-locational weather forecasts, such as: Ambient temperature, Wet bulb temperature, Cloud cover level, Humidity, Dew point, Micro-location diffuse insolation, Micro-location direct normal insolation, Daylight duration (time elapsed between sunrise and sunset), Micro-location total horizontal insolation, Micro-location horizontal wind direction, Micro-location horizontal wind speed, Micro-location vertical wind direction, Vertical wind speed, Micro-location wind gust speed, Barometric pressure, Rainfall, Micro-location density of snowfall, Micro-location temperature of snowfall, Micro-location snow cover, Micro-location snowfall, Water equivalent of snowfall	*ICT: FDEMS provides information to utility and/or REP*		• MMET.EnvTmp - Ambient temperature • MMET.WetBlbTmp - Wet bulb temperature • MMET.CloudCvr - Cloud cover level • MMET.EnvHum - Humidity • MMET.DewPt - Dew point • MMET.DffInsol - Diffuse insolation • MMET.DctInsol - Direct normal insolation • MMET.DlDur - Daylight duration (time elapsed between sunrise and sunset) • MMET.HorInsol - Total horizontal insolation • MMET.HorWdDir - Horizontal wind direction • MMET.HorWdSpd - Horizontal wind speed • MMET.VerWdDir - Vertical wind direction • MMET.VerWdSpd - Vertical wind speed • MMET.WdGustSpd - Wind gust speed • MMET.EnvPres - Barometric pressure • MMET.RnFll - Rainfall • MMET.SnwDen - Density of snowfall • MMET.SnwTmp - Temperature of snowfall • MMET.SnwCvr - Snow cover • MMET.SnwFll - Snowfall • MMET.SnwEq - Water equivalent of snowfall	SEP2 allows DER controls to be used to schedule future events.

	4.3.7 Registration, Maintenance, and Update					
30	**Provide DER Nameplate or As-Built information:** Provide operational characteristics at initial interconnection and upon changes	The DER system provides operational characteristics during initial Rule 21 screening, during implementation, or after its "discovery" and whenever changes are made to its operational status.	*Off-line or ICT*: (may be prior to installation) Provide DER and local EPS characteristics to utility *Information collected during the Interconnection process*	EPRI-23: Status Monitoring	• LPHD.DPL – DER system nameplate data • DOPM.ECPOpnAuth - Operational authority • DRAT.WRtg or MaxWRtg - Watt rating • DRAT.MaxVARtg - VA rating • DRAT.MaxVArRtg - Var rating • DRAT.ARtg - Amp rating • ZSMC.PFRtg - PF rating • DRAT.WhRtg - Energy storage capacity rating • DRAT.MaxWRtg (negative) or DBTC.RechaRte - Energy storage max charging rate • DRAT.WRtg or MaxWRtg - Energy storage max discharging rate ***Note: Implementations may need to add additional DER information that may be part of the interconnection process, such as detailed DER characteristics. contractual agreement rules for authorized control commands, characteristics of the local EPS if pertinent, and communication characteristics***	DERCapability: rtgA rtgAh rtgWh rtgMaxChargeRate rtgMaxDischargeRate rtgWh rtgVA rtgVAr rtgVArNeg rtgMinPF rtgMinPFNeg modesSupported DERSettings: setMaxChargeRate setMaxDischargeRate setMaxW setMaxVA setMaxVAr setMaxVArNeg setMinPF serMinPFNeg setGradW setVRef setVRefOfs setStorConnect setGenConnect

31	**Registration:** Initiate automated "discovery" of DER systems	The DER system supports its automated "discovery" as interconnected to a location on the power system and initiates the integration process. This function is feasible only if the ICT infrastructure is available. Otherwise, manual methods must be used.	*Off-line or ICT: Utility, REP, or FDEMS "discovers" a new or moved DER system*		• In LPHD.DPL: • LPHD.DPL - DER system manufacturer • LPHD.DPL - DER system model • LPHD.DPL - DER system hardware version • LPHD.DPL - DER system software version • LPHD.DPL - DER system serial number • LPHD.DPL - DER system type • LPHD.DPL - Location • LPHD.DPL - Altitude • LPHD.DPL - EPS name • LPHD.DPL - Owner • LPHD.DPL - Operator • LPHD.DPL - ECP ID (connection point)	SEP2 supports discovery and registration Abstract Device: DeviceInformationLink DeviceStatusLink RegistrationLink FunctionSetAssigmentListLinl SubscriptionListLink DeviceInformation: functionsImplemented mfDate MfModel MfSerNum mfHwVer swVer
32	**Initiate Periodic Tests:** Test DER functionality, performance, software patching and updates	Initial DER software installations and later updates are tested before deployment for functionality and for meeting regulatory and utility requirements, including safety. After deployment, testing validates the DER systems are operating correctly, safely, and securely.	*Off-line, local, or ICT*: (may be prior to installation or handled locally) Test DER software		No IEC 61850 data objects in the information model except as a generic GGIO object	Test initiated by DER and not by SEP2. DERStatus: inverterStatus=9 (test)

33	**Change State Between Local and Remote**: Change the state of the DER between local control and remote control	Change the state of the DER between local control and remote control. In local control there could also be a change between operational and "in maintenance".	*ICT*		DRCS.LocSta – Local or remote status of communications DRCC.LocSta – Local or remote control command	DER reverts from internal control to default behavior when there are no active DER controls. Change to FDEMS control from utility control based on design of DER and priority of conflicting DER Programs DERStatus: localControlModeStatus=0 (local) -1 (remote)
33	**DC Fault Test during startup:** Test the DC circuitry for fault conditions	DER tests its primary energy mover (DC solar PV modules) for fault conditions. This feature will try to alarm plant operators, owners, public that the DC side has a potential short that could lead to a fire hazard.	*Autonomous*		• Other than reporting status if any alarms occur, there are no IEC 61850 data objects needed	This is by design of DER DERStatus: inverterStatus

34	**DER Configuration Assessment:** the DER determines if the feeder's configuration has changed	The DER does an assessment of whether it is on a weak or strong feeder, and learns whether its configuration has changed. *From Nokhum: First, we need a definition of a strong and weak feeder – is it a high-impedance feeder, or small ampacity feeder. In the first case, if the DER is close to the substation even if the feeder is weak, the DER's performance will be still as it is on a strong feeder. Hence, I would recommend to talk about a strong or a weak point of the circuit. There may be two ways to distinguish whether the point of DER connection is changed from a strong to a weak point and vice versa: 1) EPS informs the DER controller about such change, which most likely will result in the change of the control setup, and 2) the DER control is smart enough to determine the sensitivity of its voltage at the ECP to the variations of its reactive power and, based on this, to change the settings of control.*	*ICT* *Information collected during the Interconnection process*		• Unclear at this time of what information exchanges are needed for this function	This is by design of DER and not a SEP2 message accept for status DERStatus: inverterStatus
	4.3.8 Scenarios for Decision-Making				•	•
35	**Operate within an islanded microgrid:** Operate within an islanded microgrid	After grid power is lost or disconnected, or upon command, the DER system enters into microgrid "mode" as either "leading" or "following" the microgrid frequency and voltage, while acting either as base generation or as load-matching, depending upon preset parameters.	*Autonomous* *ICT: Utility or FDEMS issues "microgrid mode" command*		• No IEC 61850 objects as yet for microgrid management	This depends on design of DER and role DER plays in microgrid. It could start as normal utility interactive inverter if a large DER provides V/F regulation. If it serves as V/F regulator for MG. There is no SEP2 function for mode changing the DER to be a V/F source.

36	**Provide low cost energy**	Utility, REP, or FDEMS determines which DER systems are to generate how much energy over what time period in order to minimize energy costs. Some DER systems, such as PV systems, would provide low cost energy autonomously, while storage systems would need to be managed.	*Autonomous for renewables* *ICT: Utility or REP issues real power output requirement to other DER systems*		• No IEC 61850 objects as yet for identifying low cost energy request	Utility could schedule or limit real power using existing SEP2 functions.
37	**Provide low emissions energy**	Utility, REP, or FDEMS determines which non-renewable DER systems are to generate how much energy in order to minimize emissions. Renewable DER systems would operate autonomously.	*Autonomous for renewables* *ICT: Utility or REP issues real power output level to other DER systems*		• No IEC 61850 objects as yet for identifying low emissions request	Utility could schedule or limit real power using existing SEP2 functions
38	**Provide renewable energy**	Utility, REP, or FDEMS selects which non-renewable DER systems are to generate how much energy in order to maximize the use of renewable energy. Renewable DER systems would operate autonomously.	*Autonomous for renewables* *ICT: Utility or REP issues real power output level to other DER systems*		• No IEC 61850 objects as yet for identifying renewable energy request	Utility could schedule or limit real power using existing SEP2 functions
	4.3.9 Market Interactions				•	•
39	**Respond to Real Power Pricing Signals:** Manage real power output based on demand response (DR) pricing signals	The DER system receives a demand response (DR) pricing signal from a utility or retail energy provider (REP) for a time period in the future and determines what real power to output at that time. This function is feasible only if the ICT infrastructure is available.	*ICT: Utility or REP issues DR pricing signal*	EPRI-6 Price-Based Charge/Discharge	• Work is taking place in the IEC to map OpenADR to CIM which may be mapped to IEC 61850	?????? SEP2 has pricing model which can work with charging and loads. Not integrated to generate internal DER Control signals

40	**Respond to Ancillary Services Pricing Signals:** Manage selected ancillary services based on demand response (DR) pricing signals	The DER system receives a DR pricing signal from a utility or retail energy provider (REP) for a time period in the future and determines what ancillary services to provide at that time. This function is feasible only if the ICT infrastructure is available.	*ICT: Utility or REP issues DR pricing signal*	EPRI-13 Price or Temperature Functions	• Work is taking place in the IEC to map OpenADR to CIM which may be mapped to IEC 61850	No SEP2 functions to autonomously activate DER Controls. An FDEMS could perform tasks and then use existing DER functions to operate DER
41	**Damping of Electromechanical Oscillations by PV systems:**	TBD	*Autonomous*		No IEC 61850 objects as yet for this function	No SEP2 functions