California Energy Commission

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California Public Utilities Commission

Recommendations for Utility Communications with Distributed Energy Resources (DER) Systems with Smart Inverters

Smart Inverter Working Group Phase 2 Recommendations

Draft v9

February 28, 2015

Contents

Figures

Tables

1. Introduction

1.1 Background to SIWG Phase 2

In the January 2014 recommendations to the CPUC on Rule 21, the Smart Inverter Working Group (SIWG) described a three phase approach to the updating of Rule 21. Phase 1 defined seven autonomous functions (approved by the CPUC on December 18, 2014). Phase 2 described the need for communications, "*During Proposed Phase 2, the SIWG will define and propose an implementation plan for communication capabilities and standards for inverters. Some parts of the Proposed Phase 2 implementation plan are defined [in the SIWG recommendations document], in order to set out a broad road map. For example, basic communications requirements draw on existing communications standards, such as Internet specifications and the IEC 61850 communications standards for DER systems. Future SIWG discussions will adapt and refine communications standards to California-specific needs in a structure similar to that set out for Proposed Phase 1: definition of the standards, a transitional permissive period, collection and publication of operational data, and CPUC consideration of mandatory standards.*"

As stated in the May 13, 2014 Scoping Ruling of Commissioner Picker, "*Next Steps for Improving Interconnections with Distributed Energy Resources: The Working Group Report also recommended a second phase to focus on communications between the grid operator and distributed energy resource, and a third phase to identify and address additional advanced inverter functionalities. The Working Group should file and serve a proposed description of issues ready for Commission resolution and a proposed schedule for these issues no later than July 18, 2014.*"

The SIWG filed those issues and continued to work on the Phase 2 issues via weekly calls and additional subgroup calls. A workshop to discuss many of the issues was held at the CPUC on October 24, 2014, covering data exchange requirements, the selection of a protocol, and cyber security requirements.

Over the next months, decisions were made on initial recommendations for these and other communication issues, classifying them in one of the following categories:

- Recommended to be included in Rule 21
- Recommended to be included in each utility's "[Utility][1] Generation Interconnection Handbook" on requirements and options
- Recommended to be included in a single "California IEEE 2030.5 Implementation Guide"
- Recommended to be decided by mutual utility-DER owner/operator agreements on a utility basis or an installation basis

[1] [Utility] will be replaced by the name of the utility

- Recommended to be left up to vendor or market decisions

1.2 Utility Principles

The utilities identified the following principles in developing their communication requirements:

1) Our goal is to establish communications between the utility and external smart inverters and aggregator systems, and not define internal utility systems communications which are out of scope for Rule 21.
2) Where DER systems may have a “material impact” on the power system, utilities will create the necessary communication infrastructure for real-time monitoring and control.
3) While SEP 2.0 / IEEE 2030.5 is our default protocol, there is potential under mutual utility/3rd party agreement that alternative protocols may be used.
4) Utility communication requirements are just a subset of what any DER implementation may consider, so DER implementations may add other “value added” functionality as long as they are not in conflict with the set of requirements as defined by the default protocol.
5) For external system interactions, utilities want a single default mandatory communications profile that addresses all communications layers to ensure interoperability across California.
6) A common test harness and 3rd party certification processes are preferred for validating implementations. The utilities do not want to be in the device/protocol validation business for DER.
7) Utilities want the communication requirements for all Phase 1 and Phase 3 DER use cases identified, including the functional requirements for DER management (including administrative actions), as well as the non-functional/performance requirements.
8) Utilities recognize that communications with DER systems under Rule 21 are not intended for sub-second interactions and protection.
9) This is a technical specification only, other issues such as regulatory support and tariff issues are assumed to be handled outside of this specification and should not drive decisions
10) The utilities expect that technology both in DER systems and communications technology will continue to evolve and future revisions of our default protocol may be needed.
11) The primary use of DER performance data coming from inverters at this time is initially to improve planning models and generation/load forecasts. However it is

understood that this purpose will evolve over time, possibly to provide more near-real-time operational support.

2. SIWG Phase 2 Recommendations for Communication Aspects to be Included in Rule 21

2.1 Overview of Scope of Recommendations

The scope of the SIWG Phase 2 recommendations comprises the communications requirements between (see red lightning bolts indicating Wide Area Networks in Figure 1):

1. Utilities and individual DER Systems
2. Utilities and Facility DER Energy Management Systems (FDEMS) which manage DER systems within a facility, plant, and/or microgrid
3. Utilities and Retail Energy Providers (REP) / Aggregators / Fleet Operators which manage and operate DER systems at various facilities

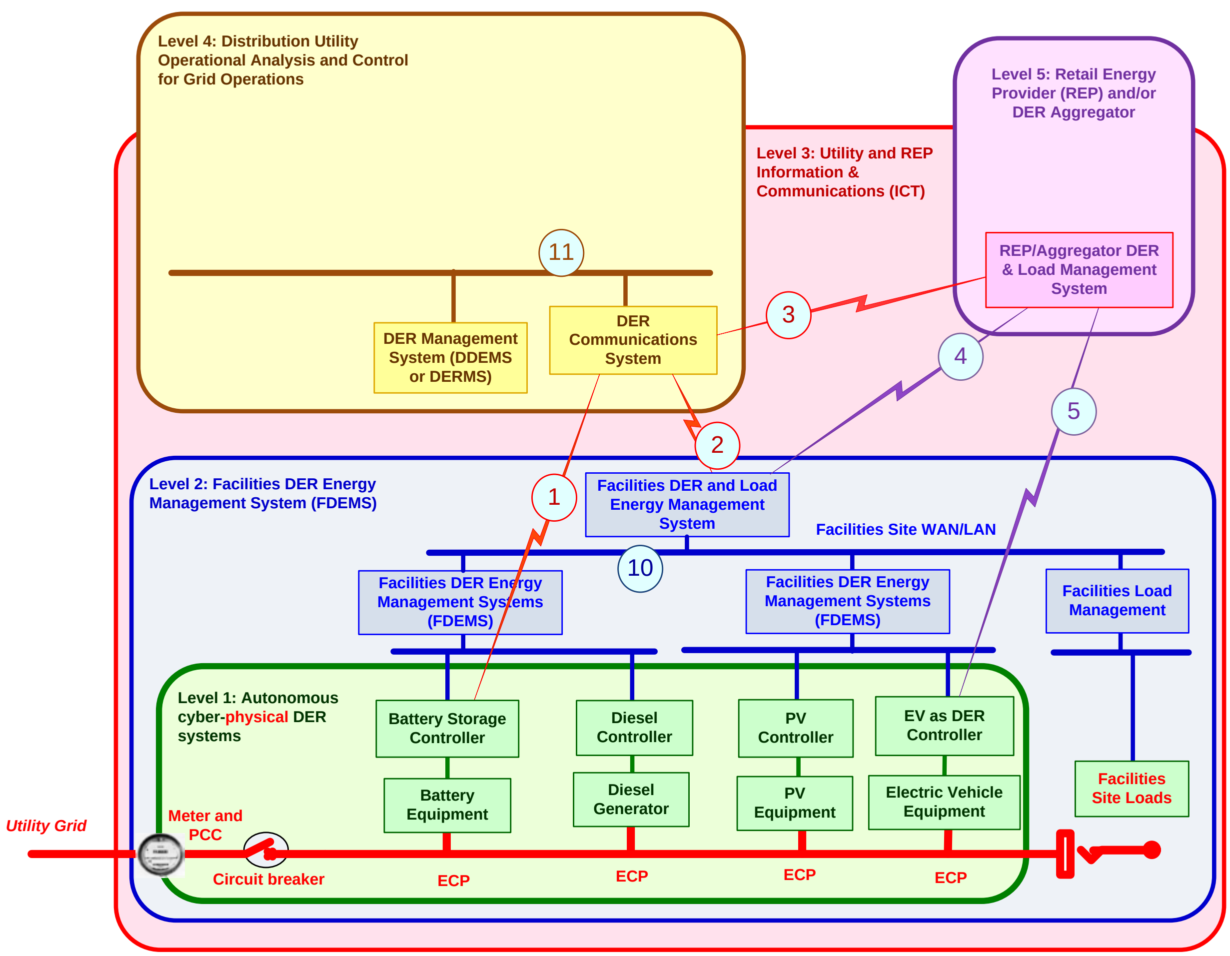

Figure 1: Communications between Utilities and individual DER systems, FDEMS, and REPS

Other communications are indicated by the brown utility LAN (11), the purple REP/Aggregator lightning bolts (4, 5) and the blue facility LANs (10), but these are out of scope for Rule 21.

At a high level, communications include the following aspects:

- Data "profiles" of the data to be exchanged for monitoring and control, including the complete specification at all communication stack levels.
- Data object models that define abstract data constructs and services
- Application level protocols and services mapped from the data object models, including encoding protocols
- Transport level protocols
- Communication media or telecommunication provider services
- Cyber security requirements

These communication aspects are identified in Figure 2. The status of general agreement by the SIWG is indicated (green denotes general agreement), although there is not necessarily complete agreement. The expectation of which communication aspects will be covered in Rule 21 (and which will not) is also indicated.

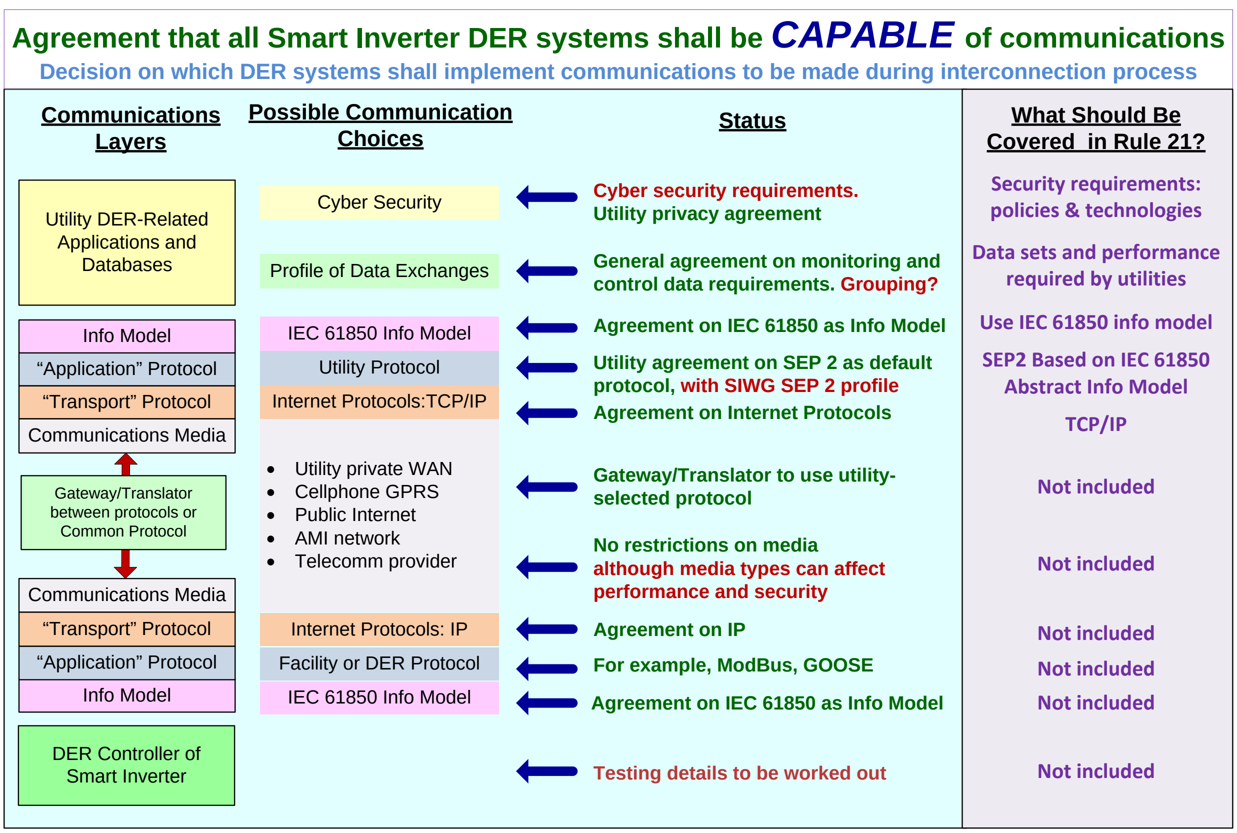

Figure 2: Status and expected coverage in Rule 21 for communication aspects

These agreements include:

1. **Communications capability**: DER systems with smart inverters shall be capable of communications although the implementation of those communication capabilities is a deployment decision and/or an upgrade decision.
2. **Utility data monitoring and control requirements**: The utilities have determined what data will be required at a minimum for the Phase 1 functions and selected Phase 3 functions, based on Use Cases, internal discussions, and discussions during the SIWG calls with the SunSpec Alliance which has worked with DER manufacturers and others on determining what data exchanges are supported by most smart inverter-based DER systems. Performance requirements have been outlined.
3. **IEC 61850 abstract information model**: The IEC 61850 abstract information model has been selected as providing the basis for the communications required for the Phase 1 functions and Phase 3 functions. Specifically IEC 61850-7-420 provides abstract information models for general data exchanges with DER systems, while IEC 61850-90-7 provides specific object models for the Phase 1 and Phase 3 functions.
4. **Utility protocol**: The utilities have determined that IEEE 2030.5 (also known as the Smart Energy Profile 2.0 (SEP 2)), is the default protocol which must be supported by individual DER systems, by facility DER energy management systems (FDEMS), and by aggregators of DER systems in order to communicate with the utility in support of smart inverter-defined functionality. The DER objects in IEEE 2030.5 were derived from the IEC 61850 abstract information model, and meet most if not all SIWG data requirements. See Figure 3 for an illustration of the use of IEEE 2030.5.
5. **Internet protocols**: The Internet protocols TCP/IP will be used.
6. **Communications media**: No restrictions or constraints are expected to be placed on the communications media so long as they can meet the utility performance and security requirements. Expected media types include cellphone channels, AMI networks, private utility networks, and the Internet. Telecommunications providers may also supply communication channels which are combinations of different media.
7. **Cyber security requirements**: Utilities are expected to identify cyber security requirements based in part on IEEE 2030.5 cyber security specifications and in part on utility security policies and procedures. These cyber security requirements are expected to include appropriately configured firewalls, role-based access control mechanisms, authentication and integrity of all messages, ability to provide confidentiality for some messages, key management requirements, communications channel performance requirements and monitoring, time synchronization across all systems, security monitoring, and audit logs of all significant alarms and events.

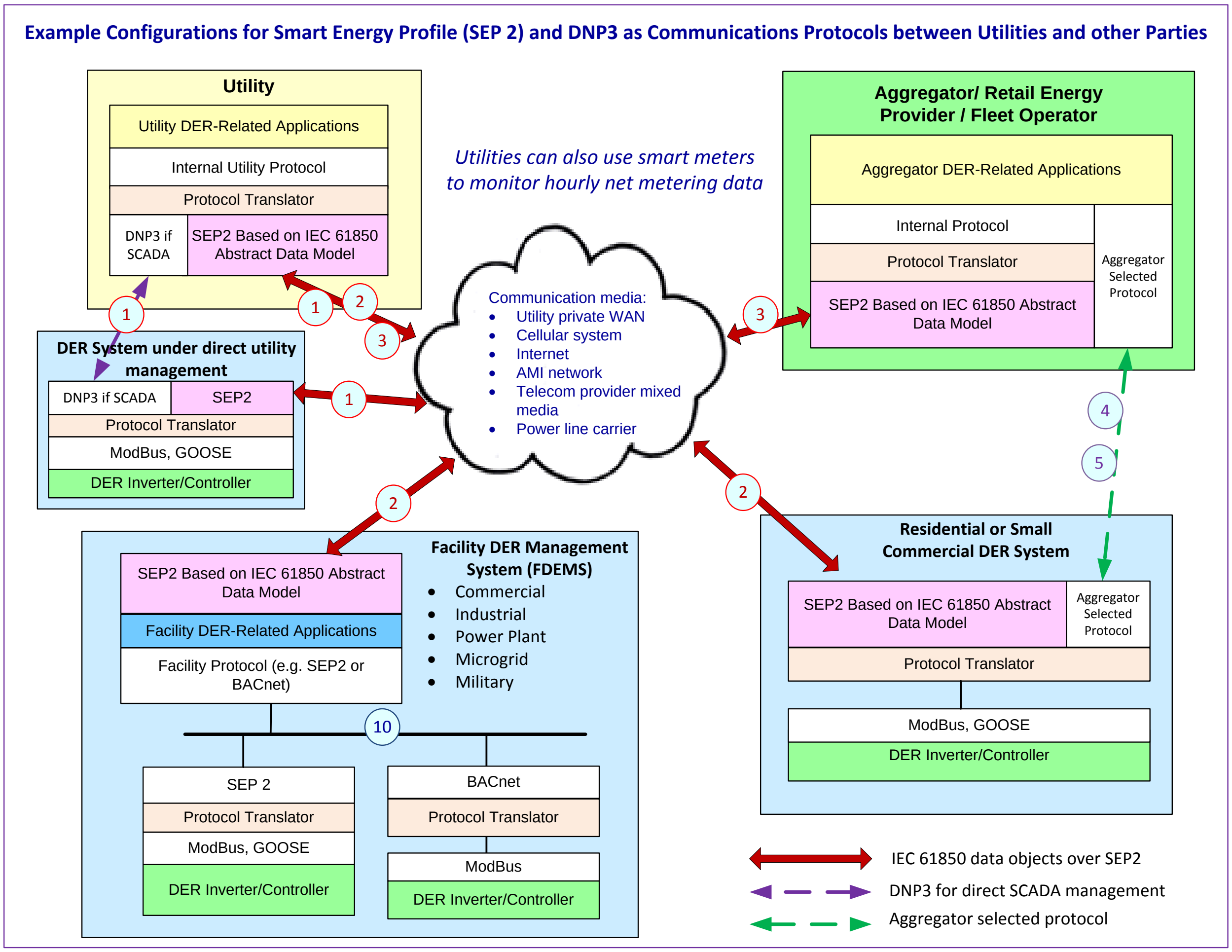

Figure 3: Conceptual Implementation of IEEE 2030.5 (SEP2) Communications with DER.

2.2 SIWG Recommendations for Communication Requirements to be Included in Rule 21

The SIWG recommends that the following communication requirements are included in Rule 21:

1. All inverter-based DER systems shall be capable of communications
2. The scope of the SIWG Phase 2 shall be the communications requirements between (1) Utilities and individual DER Systems, (2) Utilities and Facility DER Energy Management Systems (FDEMS) which manage DER systems within a facility, plant, and/or microgrid, and (3) Utilities and Retail Energy Providers (REP) / Aggregators / Fleet Operators which manage and operate DER systems at various facilities.
3. Each utility shall include sections in their individual "[Utility] Generation Interconnection Handbook" providing complete details and guidelines for the implementation of communications with DER systems.

4. Each utility handbook shall make reference to a common “California IEEE 2030.5 Implementation Guide” that will be developed and maintained collectively by the California IOU’s. This implementation guide shall provide detailed communication requirements and implementation guidelines that ensure consistent interoperability of DER systems with all of the IOU’s. This guide may be updated periodically to support advances in technology or updates in tariffs and other California DER rules.
5. The data exchange requirements shall be defined in “DER Data Exchange Requirements” document that shall be referenced by each utility’s Generation Interconnection Handbook as the minimal that must be available to be compliant with Rule 21 (see example of minimal data exchange requirements in Section 3). Additional types of data may be exchanged by mutual agreement between the utility and DER operator/owner.
6. The DER system software shall be updateable via communications either remotely or at the customer site. The update protocol may be vendor specific.
7. The Transport Level protocol shall be TCP/IP.
8. The default Application Level protocol shall be the IEEE 2030.5. The details of the IEEE 2030.5 profile are defined in the California IEEE 2030.5 Implementation Guide.
9. Other Application Level protocols may be used by mutual agreement, including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850.
10. Utility Generation Handbooks and the Protocol-Specific documents shall include cyber security and privacy requirements..
11. Generic device communications registration management requirements shall be defined in each Utility Generation Implementation Handbook, including how to register individual DERs, Facility DER Energy Management Systems, and Aggregators.

2.3 SIWG Communication Requirements Recommended to Be Included in each Utility’s “Generation Interconnection Handbook”

The SIWG recommends that the following topics are included in each utility’s “[Utility] Generation Interconnection Handbook” that will be maintained by each utility Although each utility will develop and maintain their own Handbook, it is also recommended that coordination among the utilities ensure that these separate requirements are not contradictory:

1. Date and version of the [Utility] Generation Interconnection Handbook
2. Registration and enrollment processes for each utility’s communication network
3. Categorizations of DER systems, such as by type of DER system, type of DER owner/operator, size of DER, location of DER within the utility grid, types of Groups for aggregated information, etc. These categorizations can be referred to when identifying certain requirements which may have different options.

4. A separate “DER Data Exchange Requirements” document containing the minimum data exchange requirements (monitoring, settings, control) as agreed among the California utilities shall be referenced in each Handbook, based on the example data exchange items shown in Section 3.
5. Reference to the appropriate “California IEEE 2030.5 Implementation Guide” which provides detailed specifications for implementing IEEE 2030.5-based communications.
6. Additional optional parameters and messages to the shared California IEEE 2030.5 implementation guidelines. These options must be specified in a non-contradictory manner to avoid one utility’s IEEE 2030.5 requirement from being incompatible with another utility’s requirement
7. Additional communication profiles that may be permitted upon mutual agreement (e.g. IEEE 1815 (DNP3) for real-time interactions and IEC 61850)
8. Performance requirements, including periodicity of data exchanges, latency of data requests-responses, sizes of data files, error management, and cyber security impacts on data latency
9. Cyber security requirements for communications, including Authentication, Authorization, Accountability, and Data Integrity shall be included at a minimum. Other cyber security requirements, such as confidentiality shall be supported but may be enabled only when needed. References to relevant cyber security standards shall be included.
10. Cyber security management requirements outside the protocol cyber security, including key management, certificate authorities, and cyber security management procedures
11. Cyber security-related passwords and cryptographic keys shall be secured from unauthorized access
12. Privacy policies shall clearly define what types of data shall be not available publicly, including individual data elements, utility aggregations of customer data, and third party aggregations of data
13. Testing and certification requirements (with references to the IEEE 2030.5 Implementation Guidelines for IEEE 2030.5 testing and certification.)

2.4 SIWG Communication Requirements Recommended to Be Included in a Single “California IEEE 2030.5 Implementation Guide”

The SIWG recommends that the following topics are included in a single “California IEEE 2030.5 Implementation Guide” that has been agreed to and will be maintained by the utilities:

1. Date and version of the California IEEE 2030.5 Implementation Guide
2. The default data schemas for the data exchange requirements defined in the “DER Data Exchange Requirements” document.

3. Any specific configuration requirements for individual DER systems, facility energy management systems, and/or aggregators
4. Any additions or modifications to the minimal data exchange requirements that may be required for different types of implementations.
5. The default IEEE 2030.5 profile, including:
    a. An interpretation of all data elements and objects
    b. IEEE 2030.5 services for retrieving data, setting data values, and notifications
    c. IEEE 2030.5 services for updating Groups of DERs
    d. IEEE 2030.5 cyber security technologies and procedures
    e. IEEE 2030.5 optional fields, values and commands such that they do not conflict with the base interoperability standard.
6. References to other documents as necessary for details on compliance or as useful as guidelines
7. Testing and certification requirements with references to facilities certified for performing such testing, such as the IEEE 2030.5 CSEP – Testing Certification Program and the SunSpec Alliance on ModBus Gateway to IEEE 2030.5
8. Identification of additional abstract IEC 61850 information model objects which could be translated to IEEE 2030.5 for additional functions.

2.5 SIWG Communication Requirements Recommended to Be Decided by Mutual Utility-DER Operator Agreements

The following issues are recommended to be decided by mutual utility-DER operator agreements which may vary by utility and/or by installation:

1. Whether communications are to be established between the utility and (directly or indirectly) the DER system For instance, the larger DER systems already require communications, but the protocol and types of data to be exchanged may be updated.
2. Which DER systems are allocated to which Groups for purposes of aggregation. The method for updating these allocations dynamically is provided in the protocol-specific Implementation Guides.
3. Which protocol to be used (e.g. the default IEEE 2030.5, a real-time protocol such as IEEE 1815/DNP3, or another protocol)
4. What optional data may be exchanged
5. What options in the IEEE 2030.5 protocol may be used
6. Which cyber security options may be used in addition to those defined in the California IEEE 2030.5 Implementation Guide or could be needed for securing other protocols

2.6 SIWG Communication Requirements Recommended to Be Left Up to Vendor or Market Decisions

At a minimum the following issues are recommended to be left up to "industry", vendor, and/or general market decisions, although many additional issues are expected to be industry decisions:

1. The development of "gateways" that translate from other protocols to the utility communication protocols
2. The communication technologies used by the DER system between its communication module and the "gateway" to the utility
3. The communications media used between the "gateways" and the utility, so long as it does not pose a performance or security issue for the utility
4. Any other issues not covered in Rule 21 or the Utility Generation Interconnection Handbook

3. Examples of Utility Data Monitoring and Control Requirements

3.1 Smart Inverter Use Cases as Basis for Data Requirements

The utilities reviewed the Phase 1 and Phase 3 functions as Use Cases to determine their data requirements. These are summarized below, along with indications of the importance to utilities (H, M, L):

- Real Power DER Functions
  - Real power output at the PCC is limited to a maximum value by the DER owner/operator. This information must be provided to the utility. (H)
  - The utility limits the maximum real power output at the PCC by a command to the DER system, the facility energy management system, or the aggregator who manages the DER system. (H)
  - The utility sets the actual real power output at the PCC if permitted by tariff agreements. (M)
  - The utility schedules the actual real power output or limits the maximum real power output at the PCC for specific time periods. (H)
  - The utility sets the voltage-watt parameters for the DER system to modify its real power output autonomously in response to local voltage variations. (H)
  - The utility sets or schedules the storage of energy for later delivery, indicating time to start charging, charging rate and/or "charge-by" time. (Applicable for energy storage; NA for PV systems)
- Reactive Power DER Functions
  - The utility sets a fixed power factor parameter for the DER system (having a fixed power factor is a Phase 1 capability; updating the power factor is a Phase 3 capability). (H)
  - The utility sets the curves for volt-var control for the DER system to provide dynamic reactive power injection through autonomous responses to local voltage measurements (volt-var control is a Phase 1 function; updating the volt-var curves is a Phase 3 capability). (H)
  - The utility provides and/or updates the temperature/current/time-of-day var curves for the DER system to provide reactive power through autonomous responses to temperature, current, or time-of-day. (H for temperature)
- Frequency Support DER Functions
  - Utility uses DER systems for frequency regulation by setting the curves for the DER systems to autonomously and rapidly modify real power output to counter minor frequency deviations. The utility can enable/disable the function. (H)
  - Utility uses DER systems for frequency regulation by issuing automatic generation control (AGC) commands. (M)

- DER Response to Emergencies
  - Utility receives notification that a DER system disconnected from or reconnected to the utility grid. (H?)
  - Utility issues commands to the DER system to disconnect or reconnect. (M)
  - Utility updates the voltage ride-through curves (voltage ride-through is a Phase 1 function; updating the curves is a Phase 3 capability). (H)
  - Utility updates the frequency ride-through curves (frequency ride-through is a Phase 1 function; updating the curves is a Phase 3 capability). (H)
  - Utility receives notification that a facility or microgrid disconnected from or reconnected to the utility grid. (H)
  - Utility issues a command to disconnect or reconnect a microgrid from the utility grid. (L)
  - Utility requests that the DER system provide "spinning" or operational reserve
- Scheduling DER Output, Modes, and/or Functions
  - Utility provides schedules for real power settings, reactive settings, real power or reactive power limits, power factors, operational reserves, activating/deactivating modes, and other operational settings. Schedules may be for specific time periods or may repeat periodically, e.g. daily, weekly, or seasonally. Multiple schedules may be in effect so long as they do not conflict. Higher priority schedules preempt lower priority schedules. (H)
  - Utilities activate/deactivate schedules
  - Utility receives schedules from DER systems that forecast their net real power and storage schedules.

3.2 Example of Minimal Data Requirements for Direct Interactions with DER Systems and/or Facility DER Management Systems

Table 1 contains examples of the expected utility data monitoring and control requirements for direct interactions with DER systems. The "DER Data Exchange Requirements" document will provide the minimum data exchange requirements. Additional data exchanges are always allowed.

Table 1: Utility data monitoring and control requirements

Administrative Messaging Requirements	
Information in headers	
	Unique Plant or FDEMS ID
	Meter ID, Service Point ID, or other ECP ID
	Utility ID
	Timestamp of message and other header information
Nameplate and/or "as installed" base information of DER System (for each DER System registered with utility)	

	DER system manufacturer
	DER system model
	DER system version
	DER system serial number
	DER system type
	Location (lat long and/or street address)
Basic information of DER system or of facility or plant (FDEMS) (ratings are the installed ratings which are different from capabilities which may change or be forecast based on customer or market issues)	
	Operational authority (role)
	Watt rating
	VA rating
	Var rating
	Current rating
	PF rating
Monitoring Data Sets	
Monitored analog measurements, aggregated by the FDEMS to reflect the PCC	
	Watts
	VArs
	Power Factor
	Hz, Frequency
	VA, Apparent Power
	A, Phase Currents
	PPV, Phase Voltages
	TmpCab, Temperature (as applicable)
	{Type of data collection or aggregation, e.g. indication of whether instantaneous, average over period, max, min, first, last}
Monitored status, aggregated by the FDEMS for the PCC	
	DER Connection Status
	PCC or ECP Connection Status
	Inverter status
	De-rated real power due to inability to meet stated rating
	Available real power
	Available vars
	Status of limits (flags that get raised when a specified limit is reached)
	Active modes (flags that get raised when a control (mode) is enabled)
	Ride-through status (flags on instantaneous ride-through state; does not count R-T events)
Metered DER system values	
	Wh, Watt-hours, lifetime (or from reset time) accumulated AC energy

	VAh, VA-hours, lifetime (or from reset time) accumulated
	VArh, VArh, lifetime (or from reset time) accumulated
Notification of alarms	
	Binary alarm values (flags that get raised for specific types of alarms of a specific DER)
	Binary alarm values (flags that get raised for specific types of facility/plant alarms)
Sending Updates to Settings and/or Issuing Control Commands	
Voltage Ride-Through	
	Default L/HVRT curves and settings
	Custom L/HVRT curves and settings
	Voltage
	Duration
Frequency Ride-Through	
	Default L/HFRT curves and settings
	Custom L/HFRT curves and settings
	Frequency
	Duration
Dynamic Volt/VAr Control	
	Enable a specific curve
	V reference, V reference offset
	Tolerance
	Selected curve
	Curves
	Disable (default upon start-up)
	Custom Volt-Var Curves
Ramping	
	Default ramp rate
	Customized ramp rates
Power Factor	
	Value
Soft Start	
	Ramp Rate
	Time Delay
	Fixed
	Randomized within window
Connect/Disconnect Command	
Limit Real Power (both readable and settable at the PCC)	
Frequency-Watt	

	Default Frequency-Watt
	Custom Frequency-Watt
Volt-Watt	
	Enable/disable
	Collection of settings
Possible Future Functions (Optional)	
Dynamic Current Support	
	Enable/disable
	Collection of settings
Frequency Deviation Support	
	Enable/disable
	Collection of settings
Limit Reactive Power (both readable and settable at the PCC)	
Schedule output and/or modes at PCC (see pending IEC 61850-90-10)	
	Set schedules
	Start Time
	End Time
	Real Power
	Reactive Power
	Schedule of operations and modes
	Enable/disable specific schedule

3.3 Additional Information for Interactions with Aggregators

Utilities will require aggregators to supply the same data as in Table 1, but aggregated by Group. In particular, utilities will provide aggregators with Groups that contain lists of DER systems. Groups may contain other nested Groups. DER systems may be in multiple Groups. These Groups may reflect different organizations of DER systems, such as:

- Group of DER systems connected to a specific substation
- Group of DER systems connected to a specific feeder
- Group of DER systems connected to a specific feeder segment
- Group of PV-based DER systems
- Group of energy storage DER systems
- Group of DER systems capable of providing “operational reserves” within specific time periods
- Group of DER systems capable of providing black start services

- Group of DER systems capable of providing volt-var support
- Group of DER systems capable of providing frequency support

In addition to the Group data, Table 2 identifies the additional data information which is expected to be needed for interactions between utilities and aggregators.

Table 2: Additional information required for interactions with aggregators

Administrative Information for Aggregators	
Heading information for all messages	
	Unique Aggregator ID
	Utility ID
	Group ID for this message
	Timestamp of message and other header information
Aggregator information (may be handled off line)	
	Aggregator information
	Aggregator capabilities
	List of DER UUIDs for each group
Group information	
	Watt rating
	VA rating
	Var rating
	Current rating
	PF rating

3.4 Utility Performance Requirements for Interacting with Different Types of DER Systems

Utilities have identified the performance requirements for the high priority DER functions, as summarized in Table 3:

Table 3: Smart Inverter Use Cases

Use Case	Requirement	Type			Protocol
		Industrial	Aggregator	Residential	SEP2 Object
Real Power DER Functions					
Real power output at the PCC is limited to a maximum value by the DER owner/operator. This information must be provided to the utility.	Limit Power	Seconds	Minutes	Hourly / Day Ahead	SetMaxWatts DERcontrol Opmodfixw

Use Case	Requirement	Type			Protocol
		Industrial	Aggregator	Residential	SEP2 Object
The utility sets the voltage-watt parameters for the DER system to modify its real power output autonomously in response to local voltage variations.	Set Voltage / Watt Parameters	Seconds	Minutes	Hourly / Day Ahead	DERcontrol opmodvoltwatt
The utility sets or modifies ramp rates, or settings for inverters, that gradually raise or lower power output.	Set or Update Ramp Rates	Seconds	Minutes	Hourly / Day Ahead	DERCurve object rampDecTms rampIncTms
Reactive Power DER Functions					
The utility sets a fixed power factor parameter for the DER system (having a fixed power factor is a Phase 1 capability; updating the power factor is a Phase 3 capability).	Set Fixed Power Factor	Seconds	Minutes	Hourly / Day Ahead	opmodfixedpf
The utility sets the curves for volt-var control for the DER system to provide dynamic reactive power injection through autonomous responses to local voltage measurements (volt-var control is a Phase 1 function; updating the volt-var curves is a Phase 3 capability).	Set Volt Var control curve	Seconds	Minutes	Hourly / Day Ahead	opmodvoltvar Selection between multiple curves not supported
The utility provides and/or updates the var curves for the DER system to provide reactive power through autonomous responses	Update VAR curves	Seconds	Minutes	Hourly / Day Ahead	opmodvoltvar Only single curves supported
Frequency Support DER Functions					
Utility uses DER systems for frequency regulation by setting the curves for the DER systems to autonomously and rapidly modify real power output to counter minor frequency deviations. The utility can enable/disable the function.	Update, enable, disable frequency watt curves	Seconds	Minutes	Hourly / Day Ahead	opmodfreqwatt
DER Response to Emergencies					
Utility issues commands to the DER system to disconnect or reconnect.	Disconnect Reconnect	Seconds	Minutes	Hourly	setgenconnect

Use Case	Requirement	Type			Protocol
		Industrial	Aggregator	Residential	SEP2 Object
Utility updates the voltage ride-through curves to change the anti-islanding settings.	Update Voltage ride through curves	Seconds	Minutes	Hourly	opmodhvrt opmodlvrt
Utility updates the frequency ride-through curves to change the anti-islanding settings .	Update frequency ride through curves	Seconds	Minutes	Hourly	Not Supported
Scheduling DER Output, Modes, and/or Functions					
Utility provides full lifecycle control for schedules. Schedules may be for specific time periods or may repeat periodically, e.g. daily, weekly, seasonally. Multiple schedules may be in effect so long as they do not conflict. Higher priority schedules preempt lower priority schedules.	Add, update, delete schedules	Daily	Daily	Daily	DER programs
Registration					
Utility registers a DER system or facility after interconnection approval and installation	Registration	Hours	Hours	Hours	Registration - Out of band process
System Health and Monitoring					
Utility Monitors DER system operating status	Receive operating status	Seconds	Hourly	Hourly	DERinfo/DERstatus
Utility Monitors DER system operating capability, as opposed to name plate	Receive system operating capability	Seconds	Hourly	Hourly	DERcapability
Utility receives DER system metering information	Receive DER system metering information	Seconds	Hourly	Hourly	Meterreading/usagepoint

4. Cyber Security and Privacy Requirements

4.1 Cyber Security Requirements

General requirements for cyber security shall be covered in Rule 21. Specific cyber security requirements may be included in utility handbooks or auxiliary documents. Basic cyber security requirements include:

- Cyber security requirements shall be end-to-end, including across any intermediary systems.

- The implementation of these cyber security requirements shall be validated before data exchanges are commenced with utilities.
- Cyber security requirements include Authentication, Authorization, Accountability, and Data Integrity at a minimum. Other cyber security requirements, such as confidentiality shall be supported but may be enabled only when needed.
- Stored cyber security data, such as cryptographic keys and passwords, shall be secured from unauthorized access, including in any intermediary systems between the utility and DER systems
- Privacy policies shall clearly define what types of data shall be not available publicly, including individual data elements and aggregations of data.

When the following cyber security questions are being answered by utilities, the responses should clarify what should be included in Rule 21, what should be handled by in the Utility Generation Interconnection Handbook, and what should be provided by other sources.

- What are the utility security policies for interacting with non-utility sites and equipment where the data to be exchange has operational impacts?
- What utility security procedures must be followed by such non-utility sites in order for operational data to be exchanged? In particular, how can new DER sites be "registered" and tested for security compliance?
- Are there different security requirements for different types of sites, e.g. small < 10 MW DER sites versus > 10 MW sites?
- Have these security policies and procedures been clearly established or are they still being worked on?
- Are there specific security technologies that must be used? Are there specific technologies that must not be used?
- Some security technologies are specific to different communication protocols - are there preferred protocols from a security perspective?
- Is there agreement that at least authentication and data integrity must be ensured?
- When should non-repudiation / accountability be ensured?
- When should confidentiality be ensured?
- How is key management expected to be handled? PKI? What Certificate Authorities can/must be used?
- Will Role-based Access Control (RBAC) be used to constrain the permitted actions?
- Are these cyber security requirements accepted by all California utilities or are there major differences?
- What other cyber security issues need to be resolved?

4.2 Privacy Requirements

Utilities can utilize the confidentiality provisions that already exist in Rule 21 and make any associated provisions within the Rule 21 tariff. One such provision would be to require aggregators to have privacy agreements with their customers. The agreement would say that the meter data, or solar output data, or whatever data is in question could be conveyed from the aggregator to the utility. Once the utility had the data the utility would abide by their own privacy rules and other applicable state, federal, and CPUC rules.

A. Appendix A: Definitions of Terms and Acronyms

Term	Definition
Aggregator	A legal organisation that consolidates or aggregates a number of individual customers and/or small generators into a coherent group of business players.
Area EPS	electric power system (EPS) that serves Local EPSs
CEC	California Energy Commission
Connected	Condition of the DER system during which it is electrically linked to an EPS through an ECP.
CPUC	California Public Utilities Commission
CVR	Conservation Voltage Reduction
DER	Distributed Energy Resource. Sources of electric power that are not directly connected to a bulk power transmission system. DER includes both generators and energy storage technologies, and sometimes may include controllable loads.
DOE	Department of Energy
ECP	Electrical Connection Point: point of electrical connection between the DER source of energy (generation or storage) and any electric power system (EPS)
EPRI	Electric Power Research Institute
EPS	Electric Power System: facilities that deliver electric power to a load
FDEMS	Facilities DER Energy Management Systems
ICT	Information and Communications Technologies
I-DER	For the purposes of this document, I-DER is defined as inverter-based Distributed Energy Resources
IEC	International Electrotechnical Commission
IEC 61850-7-420	Communication networks and systems for power utility automation - Part 7-420: Basic communication structure - Distributed energy resources logical nodes
IEC 61850-90-7	Communication networks and systems for power utility automation - Part 90-7: Object models for power converters in distributed energy resources (DER) systems
IEEE	Institute of Electrical and Electronic Engineers

Term	Definition
IEEE 1815	IEEE Standard for Electric Power Systems Communications—Distributed Network Protocol (DNP3)
IEEE 2030.5	IEEE Standard for Electric Power Systems Communications— IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard
Inverter	A machine, device, or system that changes direct-current power to alternating-current power.
ISO	Independent System Operator
ISO	International Standards Organization
Local EPS	An EPS contained entirely within a single premises or group of premises.
OIR	Order Instituting Rulemaking
P	Real power (measured in watts)
PCC	Point of Common Coupling, the point where a Local EPS is connected to an Area EPS.
PF	Power Factor (ratio between real power and apparent power), expressed as W/VA or as cos ϕ, the phase angle between the current and the voltage)
Q	Reactive power (measured in volt-ampere reactive or VArs)
REP	Retail Energy Provider
RTO	Regional Transmission Organization
SIWG	Smart Inverter Working Group
UL	Underwriters Laboratory
VAr or var	Volt-ampere reactive

B. Appendix B: Smart Inverter Working Group Participants

The following list includes all participants in the Smart Inverter Working Group through February 2015.

Table 4: List of SIWG Participants

Company	Full Name
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ABB	Roger White
ABB	Ronnie Pettersson
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AEI	Christopher Heinzer
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APS	Jimi Diaz
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APS America	Ryan Simpson
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California Energy Commission	Gabriel Taylor
California Energy Commission	John Mathias
California Energy Commission	Linda Kelly

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California Energy Commission	Rachel MacDonald
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Empower Micro Systems	Mika Nuotio
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Enphase Energy	Daniel Lewis

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LADWP	Matt Hone
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Matzinger-Keegan	Josh Barklow, PE
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Outback Power	Phil Undercuffler
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Pacific Gas and Electric	Caitlin Henig
Pacific Gas and Electric	Chase Sun
Pacific Gas and Electric	Dewey Day
Pacific Gas and Electric	Jason Yan
Pacific Gas and Electric	Phuoc Tran
Pacific Gas and Electric	Stacy Walter
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San Diego Gas & Electric	Mike Turner
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Sandia National Labs	Sig Gonzalez
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SMA	Brett Henning
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