Low-Cost Telemetry for Mass Market Demand Response

Market Study and Alternatives for Lower Telemetry Costs

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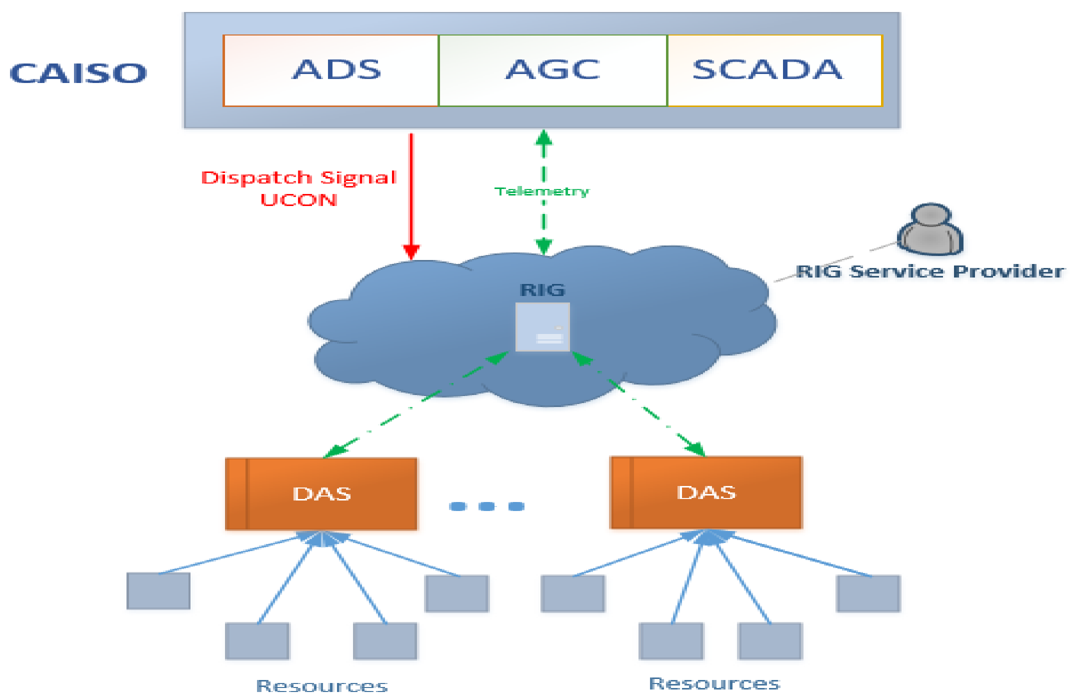

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Technical Update, March 2019

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ABSTRACT

The study clarifies telemetry requirements and proposes lower-cost telemetry alternatives for demand response (DR) participation in wholesale markets. The objective of the research is to identify and demonstrate lower-cost approaches more compatible with mass market DR (e.g., residential and small commercial customer) cost points.

The report begins by summarizing regional market telemetry requirements for demand response participation across six regional wholesale markets. Telemetry requirements are summarized for the California Independent System Operator (California ISO), the Electric Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midwest ISO (MISO), New York ISO (NYISO), and PJM, respectively. Findings are compared to identify precedence for relaxed requirements in wholesale market operations. A proposed approach is given for investigating relaxed telemetry requirements, considering market operator acceptability.

Technological approaches for lowering telemetry costs are identified, based on review of commercially available telemetry offerings and vendor interviews. One demonstrated implementation is described utilizing a remote intelligent gateway (RIG) communicating with a data aggregation server (DAS) for telemetry provision of multiple resources to the ISO. Other technological concepts for lowering telemetry costs are described, along with their respective benefits and challenges. This includes the concept of a virtual RIG, achievable through virtualization of telemetry hardware using software hosted on the public internet cloud. Additional ideas with the potential of lowering telemetry costs are recommended for future research and demonstration.

Industry practitioners may apply findings from this report to quickly clarify and compare telemetry requirement across six wholesale markets, and understand opportunities for lowering telemetry costs within a structured framework of established requirements. DR aggregators and telemetry providers may evaluate the proposed telemetry alternatives (e.g., virtual RIG concept) to guide development and demonstration towards advancing lower-cost telemetry solutions.

Keywords

Low-cost Telemetry
Mass Market Demand Response
Market Operator Telemetry Requirements
Data Aggregation Server
Virtual Remote Intelligent Gateway (RIG)
RIG in the Cloud

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1 INTRODUCTION

Overview

This report summarizes the findings from an investigation conducted in 2017 on market telemetry requirements and a subsequent investigation in 2018 to identify technological alternatives for lowering telemetry costs. The goal is to inform lower-cost alternatives compatible with mass-market cost points.

The market requirements investigation relied on interviewing grid operators and understanding their rationale for telemetry and the extent requirements have been relaxed and/or may be further relaxed. The investigation into technological alternatives also leveraged interviews from telemetry technology providers.

The overall project objective is to identify acceptably robust and cost-compatible telemetry options for aggregation of residential demand response (DR) resources. The project approach is to vet options with independent system operators (ISOs) like the California Independent System Operator (CAISO) on acceptability of alternative proposals.

Top-Down Approach

During 2017, EPRI conducted primary and secondary research to develop an understanding of regional market telemetry requirements for demand response participation. A top-down approach was executed to understand telemetry requirements originating from regional market systems. Findings were compared to identify any precedence for relaxed requirements.

In 2018, EPRI reviewed technological solutions commercially available for telemetry, and interviewed technology providers to better understand customer segments procuring telemetry solutions today. EPRI contacted qualified telemetry vendors listed on the CAISO website to discuss ways to lower telemetry costs for mass market loads (e.g., residential and small commercial customers) to participate in wholesale markets. Various ideas for lowering telemetry costs were identified to inform the research investigation and helped shape the project approach and recommendations for lower-cost telemetry demonstration.

Report Organization

The first chapter provides background and describes objectives of the investigation. Chapter 2 summarizes findings from EPRI's market study on telemetry requirements, and a proposed approach for investigating telemetry alternatives involving relaxed requirements within bounds of operator rationale and acceptability. The ultimate determination of acceptability is proposed through demonstration and study of relaxed requirements and review of the impact on accuracy, with feedback from operators on acceptability of results.

Subsequent chapters of this report detail individual ISO/RTO telemetry requirements based on referenced sources, such as phone interviews, published manuals, presentations, and other works. Chapters 3 through 8 detail telemetry requirements and references for CAISO, the Electric

Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midwest ISO (MISO), New York ISO (NYISO), and PJM, respectively. Draft requirements from the Southwest Power Pool (SPP) included in Chapter 9 are based on secondary research only through review of online documents.

Chapter 10 summarizes technological concepts for lowering telemetry costs, and describes one demonstrated method involving a data aggregation server (DAS) that aggregates multiple end-use assets into resources and relies on a remote intelligent gateway (RIG) for telemetry provision to the ISO. The chapter also identifies distinct conceptual alternatives with the potential of further lowering telemetry costs for consideration in future demonstrations. The chapter concludes with recommendations for demonstration and future work. Reviewed materials are documented in the final section.

2
SUMMARY OF MARKET STUDY FINDINGS

Background

During 2017, EPRI conducted primary and secondary research to develop an understanding of regional market telemetry requirements for demand response participation. A top-down approach was executed to understand telemetry requirements originating from regional market systems. Findings were compared to identify any precedence for relaxed requirements.

Secondary research was initially conducted by reviewing market requirements for telemetry and for metering available through online sources (such as public websites). Primary research consisted of interviews with regional grid and market operators to clarify regional telemetry requirements, discern differences between requirements, and consider potentially acceptable alternatives that may lower telemetry costs for mass market load participation. Interviews were conducted individually with each of the following organizations: CAISO, the Electric Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midwest ISO (MISO), New York ISO (NYISO), and PJM, respectively.

Telemetry Requirements

This section summarizes existing telemetry requirements and highlights instances where requirements have been relaxed in regional markets, to propose potential focus areas for investigating relaxed requirements that support a lower-cost telemetry alternative. Key findings from the market study are shown in Table 2-1, which provides a side-by-side comparison of existing independent system operator and regional transmission organization (ISO/RTO) telemetry requirements for DR. By comparing entries in the fifth and sixth rows of the table, the reader can discern differences between scanning intervals of the ISO/RTO in the column and required measurement sampling intervals. Where the requirement is slower for the latter indicates a relaxed requirement. This comparison indicates there is precedent among ISOs that have relaxed telemetry requirements. That is, many markets have products for which the measurement sampling interval required has been relaxed compared to the scanning interval. In particular, CAISO and ISO-NE requirements have been relaxed somewhat compared to NYISO, MISO, and ERCOT.

PJM has more extensively relaxed its telemetry requirement, by primarily requiring telemetry in its frequency regulation market and not necessarily requiring telemetry of DR resources in its other markets for which DR resources are eligible to participate. In particular, PJM does not require telemetry from DR resources providing synchronous reserve (i.e., spinning reserve). This represents the most extensive case of relaxation. PJM has shared that the process to relaxation required studies on the accuracy impact of not requiring telemetry from DR resources providing synchronous (sync) reserve. PJM also noted that its grid configuration may be more meshed than in other regions.

Significant cost drivers for DR telemetry are shown in red text under the second column of Table 2-1. They include requirements for measurement sampling interval; real load data source; primary and backup circuit; and authentication and data encryption. These significant cost drivers are identified based on the following rationale:

1. Relaxing measure sampling requirements from seconds to minutes enables lower-cost telemetry gateways. Consequently, requirements allowing slower measurement sampling intervals may lower overall telemetry costs.
2. By allowing statistical sampling in lieu of requiring every end-point device to be measured to provide real load data, costs can be reduced. The extreme case of relaxation of this dimension of requirement is to not require telemetering any device for DR to participate in a select market product or service (such as PJM's case for DR providing synchronous reserve).
3. Whether a primary link and backup communication link are required at all and the level of service required (such as speed and availability) can be a source of relaxation and lowering of telemetry costs (for example, PJM does not require a backup communication circuit).
4. Requirements for authentication and data encryption can drive up telemetry costs as well. For example, a requirement to issue certificates (for authentication) to each device or asset in a network can drive up telemetry costs.

Table 2-1 summarizes telemetry requirements applicable to DR resources. The requirements, tabulated in Table 2-1, are divided into four categories: the measured or calculated values (Data Values); the temporal or geographic coverage of the values (Coverage); the network used to communicate the values to the ISO/RTO (Network); and cyber security aspects (Security). These four categories are consistently presented in subsequent chapters which detail telemetry requirements for CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP, respectively. As evident from the table entries, details of data acquisition are sometimes specified in terms of general quality characteristics rather than as detailed technical specifications.

Table 2-1
Side-by-side Comparison of Regional Telemetry Requirements

Category	Metric	Cost Driver for DR Telemetry?	CAISO Requirement	ISO-NE Requirement	NYISO Requirement	MISO Requirement	ERCOT Requirement	PJM Requirement
Data Values	Meter Accuracy (Settlements /Revenue-Quality Metering)	Possible	± 0.2%	± 0.5%	± 0.3%	± 0.3%	± 0.2% or 0.5%	± 0.3%
	Telemetry Accuracy (Load)	Possible	± 2%	± 2%	± 5%	± 3%	± 3%	± 2%
	Telemetry Accuracy (Behind-the-Meter Generation)	Possible	± 2%	± 2%	± 1%	± 3%	*	± 2%
	Telemetry Precision	Insignificant	~4.3 digits (15 bits + sign)	0.001 MW (~9.4 digits or 32-bits + sign)	*	0.001 MW	N/A (determined by QSE telemetry systems)	Sufficient to meet accuracy requirement
Coverage	Scanning Interval	Insignificant	4 sec	4 sec	6 sec	2 sec	2 sec	2 sec
	Measurement Sampling Interval**	Significant	4 sec (spin); 1 min (non-spin); 5 min (RT energy)	4 sec (regulation); 1 min (10-min spin, non-spin); 5 min (30-min non-spin, RT energy)	6 sec (regulation, 10-min spin, 10- min non-spin, 30-min non-spin)	2 sec (regulation); 10 sec (10-min spin; 10-min non-spin); 4-sec (RT energy)	2 sec (regulation, 10min spin, 30-min non-spin, RT energy)	2 sec (regulation)

Category	Metric	Cost Driver for DR Telemetry?	CAISO Requirement	ISO-NE Requirement	NYISO Requirement	MISO Requirement	ERCOT Requirement	PJM Requirement
	Real Load MW Data Source	Significant	Measured or calculated (statistically sampled)	Measured	Measured	Measured	Measured or calculated	Measured (regulation) or statistically sampled
Network	Primary Circuit	Significant	Full T1 (1.544 Mbs) or equivalent	Fractional T1	Full T1 (1.544 Mbs) or equivalent	MISO WAN for DRR-Type II; internet for all other resources	Full T1 (1.544 Mbs)	Internet speeds
	Backup Circuit	Significant	128 kb/s ISDN or equivalent	4G wireless or fractional T1 if wireless is not available at the site	Full T1 (1.544 Mbs) or equivalent	MISO WAN for DRR-Type II; internet for all other resources	Full T1 (1.544 Mbs)	N/A
	Connectivity Availability	(Bundled with network service level agreement)	99.70%	99.99% (per contract)	99.99%	99.995%	98% (end-to-end telemetry and network)	*
	Maximum Outage Duration	(Bundled with network service level agreement)	5 mins	N/A	15 mins	Defined by Control Room, but if critical, expect site to notify MISO and start investigating issue within an hour	5 mins (telemetry and network outage)	N/A

Category	Metric	Cost Driver for DR Telemetry?	CAISO Requirement	ISO-NE Requirement	NYISO Requirement	MISO Requirement	ERCOT Requirement	PJM Requirement
	Number of Outages	(Bundled with network service level agreement)	N/A	< 4.32 minutes/ month	4 plant maintenance outages per year	N/A	Primary and backup < 6	N/A
Security	Authentica-tion and Data Encryption	Significant	RSA >= 2048 bits with SHA256 RSA signature and AES-256 encryption	Yes	AES-128 encryption	Private WAN for DRR-Type II; internet for all other resources and certificate required for user account authentication before data download can begin	Three-level authentication	256-byte key TLS and PKI using an OATI-signed X.509 client certificate.

Notes:
* Parameter value not provided by organization.
** Measurement sampling interval for markets demand response may participate in.

Telemetry Cost Drivers and Focus Areas for Alternative Requirements

A proposal for a cheaper telemetry alternative considers the most significant cost drivers and possible relaxation in the following manner:

1. For measurement sampling interval, what is the extent of relaxation possible (e.g., from seconds to minutes enables considering cheaper non-SCADA technologies)?
2. For real load measurements, what is the proportion of devices required to be measured (e.g., all, a sampling, or none) and the resulting accuracy impact?
3. For the network circuit what is the level of requirement (public internet vs. private network versus no connection required)?
4. For authentication and data encryption, what is the level of security required (e.g., authentication of party and data encryption method)?

These focus areas for considering relaxation of telemetry requirements are illustrated in Figure 2-1. The figure identifies two telemetry paths for exchanging telemetry information with the CAISO. The first path represents direct telemetry between the ISO and resources. The second path illustrates telemetry delivered through Inter-Control Center Communications Protocol (ICCP) links between ISO and utility Energy Management Systems (EMS) systems. The figure labels the following focus areas for considering potential alternatives:

- Measurement sampling intervals dictate frequency of measurement (shown in the right of the figure in the area labeled “a”).
- Requirements for real load measurements drive the number of data exchange links (labeled “b” in the figure) to assets that comprise a resource; wherein statistical sampling lowers the number of links required for exchanging data with individual assets comprising the resource.
- Requirements for primary and backup circuits (labeled “c” in the figure) drive whether a circuit between the ISO and the resource or market participant is required at all and with redundancy, along with the service-level agreement needed with the communications network provider and resulting costs for the communication circuits.
- Requirements for authentication and data encryption over required communication links (labeled “d” in the figure) can also impact resulting costs and viable solutions.

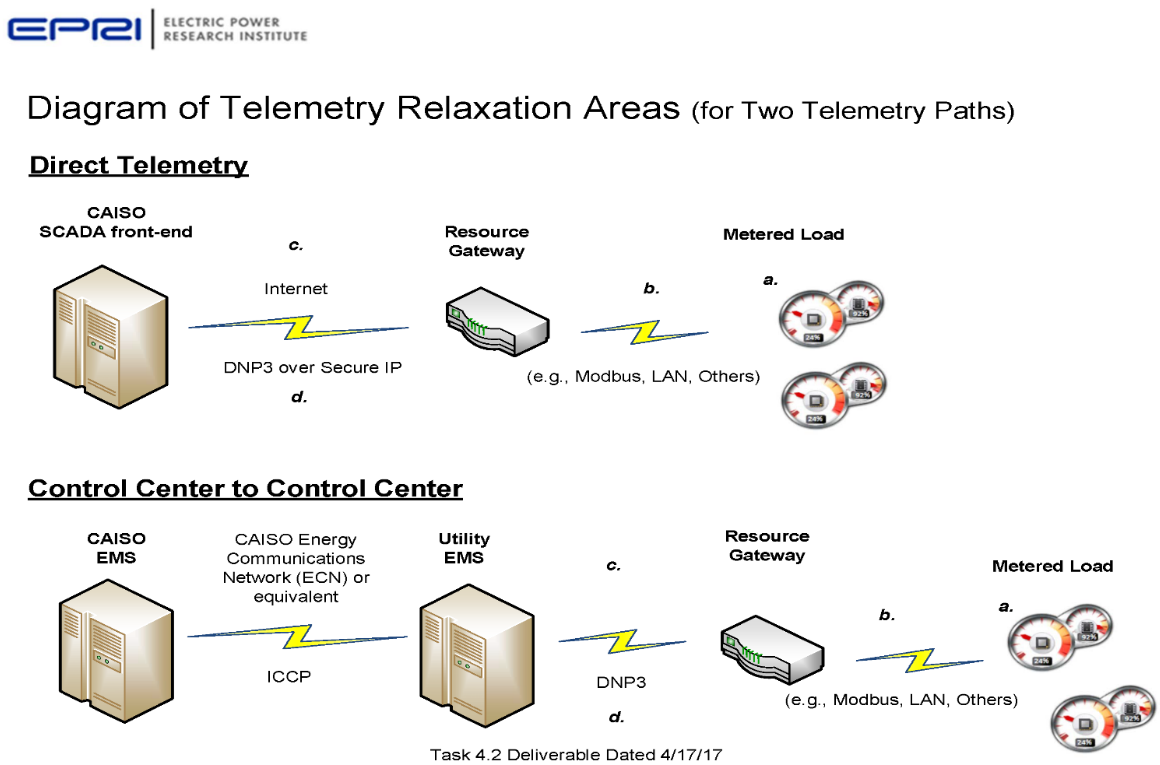

Figure 2-1
Diagram of Focus Areas for Relaxed Telemetry Requirements

Proposed Approach for Investigation of Telemetry Alternatives

Based on EPRI's interview of CAISO and other ISO/RTOs on existing telemetry requirements and acceptable alternatives, the following is proposed for inclusion in a market study to provide CAISO telemetry from residential DR aggregation.

- **Underlying approach**: Show operators that they are getting more from the proposed telemetry alternative, which trades accuracy for lower cost. For example, such a trade can bring operators telemetry data where none previously existed, and at lower cost by leveraging existing residential customer devices (e.g. smart meter, smart thermostat).
- **Underlying tradeoff**: Trade accuracy for cost savings through various techniques, including relaxing the measurement sampling interval and sampling a portion of devices in a resource aggregation.
- **Research question**: To what extent can accuracy from telemetered smaller resources (such as those rated less than 10 MW) be traded for cheaper telemetry and still give operators a sense of getting more (such as gaining visibility to twenty 9.99 MW resources)?
- **Proposed investigation**: Assess the impact on accuracy from reducing the measurement sampling interval from 1 minute to 5 minutes or slower for small load resources to provide non-spinning reserves. The selection of sampling rate proposed for a demonstration would accommodate the capabilities of measurement or instrumentation equipment employed at

target customer sites (such as smart meters and other deployed devices) that are compatible with the cost points of mass-market customers.

- **Proposed target**: Demonstrate at least 90% accuracy from sampling less than half of the devices within a resource aggregation over the period of a season. (This target has been vetted by CAISO.)

Remarks

This chapter summarizes telemetry requirements and a proposed approach for investigating telemetry alternatives involving relaxed requirements, considering operator rationale and acceptability. Subsequent chapters of this report detail individual ISO/RTO telemetry requirements based on referenced sources, as well as technological concepts for lowering telemetry costs. The ultimate determination of acceptability is informed by feedback from operators, which can be aided through demonstration.

3
CAISO DR TELEMETRY REQUIREMENTS

Background

The requirements for direct telemetry differ among Independent Systems Operators and Regional Transmission Organizations (ISOs/RTOs), and within a particular ISO/RTO the requirements may vary based on the size and/or type of a resource and the products that the resource supports. This section focuses on the CAISO's requirements and is mostly drawn from the latest versions of the relevant documents posted on the CAISO website at the time of investigation in 2017.

The telemetry requirements, tabulated in Table 3-1, are divided into four categories: the measured (or calculated) values (Data Values); the temporal or geographic coverage of the values (Coverage); the network used to communicate the values to the ISO/RTO (Network); and cyber security aspects (Security). The focus is on the requirements that are most applicable to DR resources.

NOTE: The table layout shown in Table 3-1 is used consistently in the subsequent chapters on the requirements of ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

Table 3-1
CAISO Requirements for Telemetry Data

Category	Metric	CAISO Requirements
Data Values	Meter Accuracy (Settlements/Revenue-Quality Metering)	± 0.2%[1]
	Telemetry Accuracy (Load)	± 2%
	Telemetry Accuracy (Behind-the-Meter Generation)	± 2%
	Precision	15 bits + sign[2]
Coverage	Scanning Interval	4 sec[3]
	Measurement Sampling Interval	4 sec (spin); 1 min (non-spin)[4]; 5 min (RT energy) [5]

[1] CAISO, *Business Practice Manual for Metering,* Version 15 (October 1, 2016), p. B-6.

[2] Display must show six digits with decimal points for the three least significant digits, per CAISO *Business Practice Manual for Metering,* Version 15 (October 1, 2016), p. B-14.

[3] CAISO, *Business Practice Manual for Direct Telemetry,* Version 10 (January 5, 2017), p. 22.

[4] CAISO, *Business Practice Manual for Direct Telemetry,* Version 10 (January 5, 2017), p. 21.

[5] CAISO, *Business Practice Manual for Direct Telemetry,* Version 10 (January 5, 2017), p. 21. For 5-minute sampling, "The per-location readings that make up the resource-level telemetry will be time-aligned within any PDR

Category	Metric	CAISO Requirements
	Real Load MW Data Source	Measured or calculated (statistically sampled); instantaneous power is measured over 1-minute interval[6]
Network	Primary Circuit	Full T1 (1.544 Mbs) or equivalent[7]
	Backup Circuit	128 kb/s ISDN or equivalent[8]
	Connectivity Availability	99.7%[9]
	Maximum Outage Duration	5 mins[10]
	Number of Outages	N/A
Security	Authentication and Data Encryption	RSA ≥ 2048 b with SHA256 RSA signature and AES-256 encryption[11]

Data Values

Settlement (revenue-quality) metering generally requires an accuracy of no less than ±0.2%. CAISO also allows ± 0.3% for metering systems that were installed prior to the CAISO's start of operations.[12] For control telemetry, CAISO allows ±2% accuracy. CAISO requires 15 bits of precision in the values (1 part in 32768, equivalent to about 30 ppm).

Data Coverage

CAISO's system scans for data in 4-second intervals, and resources providing spin must update the data at that frequency. Resources that provide non-spin only need to keep their data current to within 1 minute (although they nevertheless must provide the data in response to 4-second scans). Resources that provide real-time (RT) energy are required to keep their data current to within 5 minutes.

The Business Process Manual (BPM) for direct telemetry states that the real load reported by a resource may be either measured or calculated (such as by an EMS). With the approval of the

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resource to within a +/-30 second time accuracy compared to a resource-specific synchronization time. If and when a location's telemetry source drifts outside of this band, it will be the resource owner's responsibility to synchronize the telemetry source. In all cases, the resource-level telemetry points will be available within the remote intelligent gateway (RIG) for the CAISO's 4-second poll with no more than a 1-minute latency."

[6] CAISO, *Business Practice Manual for Metering,* Version 15 (October 1, 2016), p. B-11.

[7] CAISO, *Business Practice Manual for Direct Telemetry,* Version 10 (January 5, 2017), p. 18. An ISP-provided circuit is allowed for resources ≤ 10MW.

[8] CAISO, *Business Practice Manual for Direct Telemetry,* Version 10 (January 5, 2017), p. 19. An ISP-provided circuit is allowed for resources ≤ 10MW.

[9] CAISO, *New Remote Intelligent Gateway and Secure Socket Layer Validation Procedure,* Version 4.3 (December 16, 2015), p. 15.

[10] CAISO, *New Remote Intelligent Gateway and Secure Socket Layer Validation Procedure,* Version 4.3 (December 16, 2015), p. 15.

[11] CAISO, *Client Public/Private Key Instructions,* p.1.

[12] CAISO, *Business Practice Manual for Metering,* Version 15 (October 1, 2016), p. B-6.

CAISO, alternative methods for providing this value may be allowed. The BPM specifically says that real load "can also be derived by statistical sampling of a resource's underlying load."

Network

Data can either be provided via CAISO's contracted network (called "ECN") or via an Internet Service Provider (ISP). A full T1 circuit (1.544 Mbs) is required for the primary connection. Installation of a backup circuit is also required, and although another T1 circuit is recommended, a 128-kB/s ISDN line is an acceptable alternative. The latency of a T1 circuit is typically 10 milliseconds (ms) or less, while that of a DSL circuit (such as ISDN) may be from 10 ms to 70 ms.

The telemetry network is required to be available 99.7% of the time. Although this is would permit more than one day of outages each year, no single outage can exceed 5 minutes. Furthermore, the occurrence of outages is limited to "a reasonable number."[13]

Security

All devices must use Public Key Interchange (PKI) techniques for authentication with RSA keys of at least 2048 bits and SHA256 signatures. Data is to be encrypted using AES-256. As a reference, this level of encryption is what is equivalent to that recommended by the U.S. government for TOP SECRET documents and is somewhat stronger than that of OpenADR 2.0b (or the NYISO), which require only AES-128 encryption.

[13] This is self-contradictory. Allowing 99.7% availability means accepting more than 26 hours of outage/year, but more than 300 5-minute outages (not "a reasonable number") would be required to reach 26 hours in one year.

4

ISO-NE DR TELEMETRY REQUIREMENTS

Background

This section focuses on ISO-NE's requirements and is drawn from interviews with ISO-NE staff and the latest versions of the relevant documents posted on the ISO-NE website. Some of these requirements will not be in force until the adoption of the new FERC 745-compliant markets in June 2018. Table 4-1 presents the requirements.

Table 4-1
ISO-NE Requirements for Telemetry Data

Category	Metric	ISO-NE Requirements
Data Values	Meter Accuracy (Settlements/Revenue-Quality Metering)	± 0.5% for utility-grade meters (which are used for both billing and as the source for telemetry) [14,15]
	Telemetry Accuracy (Load)	± 2.0% for DR resources that do not have a utility-grade meter[16,17]
	Telemetry Accuracy (Behind-the-Meter Generation)	± 2.0%
	Precision	32-bits + sign (~9.4 digits) or 0.001 MW
Coverage	Scanning Interval	4 sec
	Measurement Sampling Interval	4 sec (regulation); 1 min (10-min spin, non-spin); 5 min (30-min non-spin, RT energy)[18,19]
	Real Load MW Data Source	Measured (ISO-NE used to allow statistical measurement for resources, but the resources have since retired)
Network	Primary Circuit	Fractional T1[20]
	Backup Circuit	4G wireless or fractional T1 if wireless is not available at the site[21]

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[14] ISO-NE, *Market Rule 1,* Appendix E1, Section 2.1.

[15] ISO-NE, *Market Rule 1,* Appendix E2, Section 2.1.

[16] ISO-NE, *Market Rule 1,* Appendix E1, Section 2.1.

[17] ISO-NE, *Market Rule 1,* Appendix E2, Section 2.1.

[18] ISO-NE, *ISO New England Operating Procedure No. 18: Metering and Telemetering Criteria (OP-18),* October 5, 2015, p. 5.

[19] ISO-NE, *ISO New England Inc. and New England Power Pool, Docket No. ER15-257-000, Market Rule 1 Changes to Integrate Price-Responsive Demand into Reserve Markets ("PRD Reserves Changes"),* FERC Filing, October 31, 2014, Section 2.1.

[20] ISO-NE by phone, February 24, 2017.

[21] ISO-NE by phone, February 24, 2017.

Category	Metric	ISO-NE Requirements
	Connectivity Availability	99.99% (per contract)[22]
	Maximum Outage Duration	N/A
	Number of Outages	< 4.32 minutes/month (99.99% availability)[23]
Security	Authentication and Data Encryption	Yes[24]

Data Values

Settlement (revenue-quality) metering generally requires accuracy of at least ± 0.5%. Because generator control telemetry is also acquired from the same settlement quality meters, it is also generally at ± 0.5% accuracy.

For DR telemetry, ISO-NE allows resources to install non-utility-grade meters with a ±2% accuracy. ISO-NE requires 0.001 MW precision (32-bit plus sign) for telemetry.

Data Coverage

ISO-NE's system scans for data at 4-second intervals, and resources providing regulation must update their data at that frequency. Resources that provide 10-minute ancillary services also provide 1-minute data, while data from 30-minute non-spin and real-time (RT) energy resources is provided as 5-minute interval data.

Data sources are from measured values (although ISO-NE used to have statistical measurement for resources that have since retired). The 1-minute values can be instantaneous or averaged based on the collected energy interval data.

Network

Data must be provided via ISO-NE's contracted network at fractional T1 speeds. A backup circuit should use 4G wireless unless it is not available at the site, in which case fractional T1 is an acceptable alternative.

The telemetry network is required to be available ≥ 99.99% of the time (average outage of ≤ 4.32 minutes/month).

Security

Security is required for the network (details unavailable).

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[22] ISO-NE by phone, February 24, 2017.

[23] This is simply 99.99% availability expressed as outage duration.

[24] ISO-NE by phone, February 24, 2017.

5

NYISO DR TELEMETRY REQUIREMENTS

Background

This section summarizes NYISO's requirements and is drawn mostly from the latest versions of the relevant documents posted on the NYISO website. Table 5-1 presents the requirements.

Table 5-1
NYISO Requirements for Telemetry Data

Category	Metric	NYISO Requirements
Data Values	Meter Accuracy (Settlements/Revenue-Quality Metering)	± 0.3%[25]
	Telemetry Accuracy (Load)	± 5%[26]
	Telemetry Accuracy (Behind-the-Meter Generation)	± 1%[27]
	Precision	*
Coverage	Scanning Interval	6 sec
	Measurement Sampling Interval	6 sec (regulation, 10-min spin, 10-min non-spin, 30-min non-spin)
	Real Load MW Data Source	Measured
Network	Primary Circuit	Full T1 (1.544 Mbs) or equivalent
	Backup Circuit	Full T1 (1.544 Mbs) or equivalent
	Connectivity Availability	99.99%
	Maximum Outage Duration	15 mins
	Number of Outages	4 plant maintenance outages per year
Security	Authentication and Data Encryption	AES-128 encryption

* Parameter value not provided

Data Values

Settlement (revenue-quality) metering generally requires accuracy of ± 0.3%[28].

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[25] New York State Electric Meter Engineers' Committee, *Guide for Uniform Practices in Revenue Quality Metering,* Revision 4 (August 20, 2003), p. 3.

[26] NYISO, *Control Center Requirements Manual,* Manual 21, Version 3.0 (March 2014), p. A-1.

[27] NYISO by phone, March 1, 2017.

[28] New York State Electric Meter Engineers' Committee, *Guide for Uniform Practices in Revenue Quality Metering,* Revision 4 (August 20, 2003), p. 3.

For control telemetry, NYISO requires 5% accuracy (at the NYISO's or Transmission Operator's control room[29]).

Data Coverage

NYISO's system scans for data at 6-second intervals. All resources must update measurements at the same sampling frequency, whether providing frequency regulation and spinning reserve or non-spinning reserve (10-minute and 30-minute non-spin).

Network

A full T1 circuit (1.544 Mbs) is required for the primary connection to NYISO. Installation of a backup circuit is also required, and another T1 circuit (or equivalent) must be used, a 128-kB/s ISDN line is an acceptable alternative.

The telemetry network is required to be available 99.99% of the time. No single outage can exceed 15 minutes (not counting 4 plant maintenances that are allowed each year).

Security

Data is to be encrypted using AES-128.

[29] NYISO, *Control Center Requirements Manual,* Manual 21, Version 3 (March 28, 2014), p. A-1.

6
MISO DR TELEMETRY REQUIREMENTS

Background

This section focuses on MISO's requirements and is drawn mostly from the latest versions of the relevant documents posted on the MISO website. In MISO, *demand response* is defined as a *reduction* in consumption in response to an instruction (not an increase *or* reduction)[30]. Table 6-1 presents the requirements.

Some requirements for MISO DR telemetry differ according to the "type" of the DR resource. Two types are defined:

- **DRR-Type I** resources can supply a fixed, pre-specified quantity of energy (through physical load reduction) to the energy and operating reserve markets when instructed to do so.
- **DRR-Type II** resources can supply a continuous range of energy (through physical load reduction or behind-the-meter generation) to the energy and operating reserve markets and is capable of complying with set-point instructions.

Table 6-1
MISO Requirements for Telemetry Data

Category	Metric	MISO Requirements
Data Values	Meter Accuracy (Settlements/Revenue-Quality Metering)	± 0.3%[31]
	Telemetry Accuracy (Load)	± 3%
	Telemetry Accuracy (Behind-the-Meter Generation)	± 3%
	Precision	0.001 MW[32]
Coverage	Scanning Interval	2 sec
	Measurement Sampling Interval	2 sec (regulation); 10 sec (10-min spin; 10-min non-spin); 4 sec (RT energy)
	Real Load MW Data Source	Measured
Network	Primary Circuit	MISO WAN for DRR-Type II; internet for all other resources
	Backup Circuit	MISO WAN for DRR-Type II; internet for all other resources

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[30] MISO, *Demand Response Business Practices Manual,* BPM-026-r1 (June 1, 2016), p. 5. Despite this statement, DR can provide regulation, in which case both regulation up and regulation down are required.

[31] MISO, *Market Settlements Business Practices Manual,* BPM-005-r15 (June 30, 2016), p. 80.

[32] MISO, *Market Settlements Business Practices Manual,* BPM-005-r15 (June 30, 2016), p. 37.

Category	Metric	MISO Requirements
	Connectivity Availability	99.995%
	Maximum Outage Duration	Defined by Control Room, but if critical, expect site to notify MISO and start investigating issue within one hour[33]
	Number of Outages	N/A
Security	Authentication and Data Encryption	Private WAN for DRR-Type II; internet for all other resources, plus certificate required for user account authentication before data download can begin

Data Values

Settlement (revenue-quality) metering at MISO generally requires accuracy of ± 0.3% (unless local jurisdictions require greater accuracy).

Data Coverage

MISO's documented telemetry requirements specify 2 seconds to 12 seconds in various places. DR-Type II devices must provide 5-minute interval data, but only historically (up to five days following an event) rather than in real time. Sometimes, telemetry is described as coming through ICCP links, suggesting that in these cases, another control center is present between MISO and the DR resource.

Although MISO DR resources can consist of aggregations, no requirement seems to exist for the timeliness of the data reported for the individual resources that make up the aggregation. Also, no discussion of statistical sampling has been found.

Network

MISO's requirements for network communications specify 99.995% uptime. Higher-level protocol and requirements for data models (such as ICCP and XML) are specified. Furthermore, DR resources providing ancillary services must respond to (and help mitigate) frequency deviations (synthetic inertia or governor control).

Security

DRR-Type II resources use a private WAN to connect to MISO. All other resources use the internet, but require certificates for user account authentication before data download can begin.

[33] MISO phone conversation, April 3, 2017.

7
ERCOT DR TELEMETRY REQUIREMENTS

Background

This section focuses on ERCOT's requirements and is mostly drawn from the latest versions of the relevant documents posted on ERCOT's website.

An important principle to note is that "ERCOT does not do direct telemetry. All telemetered values are acquired from market participants."[34] Such communications with market participants are indirect, performed via ICCP.

Note also that ERCOT's requirements are flexible. Rather than state blanket requirements for all resources, requirements may vary based on the needs of their network model and state estimator. For example, loads on a continuous, non-branching circuit may be combined for telemetry purposes[35]. Table 7-1 summarizes ERCOT telemetry requirements.

Table 7-1
ERCOT Requirements for Telemetry Data

Category	Metric	ERCOT Requirements
Data Values	Meter Accuracy (Settlements/Revenue-Quality Metering)	± 0.2% or ± 0.5%[36]
	Telemetry Accuracy (Load)	± 3%[37]
	Telemetry Accuracy (Behind-the-Meter Generation)	*
	Precision	N/A (determined by QSE telemetry system)
Coverage	Scanning Interval	2 seconds
	Measurement Sampling Interval	2 seconds (regulation, 10-min spin, 30-min non-spin, RT Energy)
	Real Load MW Data Source	Measured or calculated
Network	Primary Circuit	Full T1 (1.544 Mbs)
	Backup Circuit	Full T1 (1.544 Mbs)
	Connectivity Availability	98%/month[38] (end-to-end telemetry and network)
	Maximum Outage Duration	5 mins (telemetry and network outage)

[34] ERCOT, *ERCOT ICCP Communication Handbook,* Version 3.08 (September, 2016), p. 43.
[35] ERCOT, *Telemetry Standards* (May 2, 2013), p. 3.
[36] ERCOT phone conversation, April 4, 2017.
[37] ERCOT, *Nodal Protocols* (May 1, 2017), p. 6-38.
[38] ERCOT, *Telemetry Standards* (May 2, 2013), p. 5.

Category	Metric	ERCOT Requirements
	Number of Outages	Primary and backup > 6
Security	Authentication and Data Encryption	Three-level authentication

* Parameter value not provided

Data Values

Settlement (revenue-quality) metering generally requires accuracy of ± 0.2% or ± 0.5%. For control telemetry, Qualified Scheduling Entities (QSEs) must provide real-time data for reliability purposes that is accurate to within three percent.

Data Coverage

ERCOT receives real-time data as ICCP messages from QSE control systems. ERCOT's system scans for the data at 2-second intervals. All resources must update measurements at the same sampling frequency, whether providing frequency regulation and spinning reserve or non-spinning reserve and RT energy. The values sent to ERCOT may be calculated or directly measured.

Network

Data must be provided via ICCP over ERCOT's contracted network. Two full T1 circuits (1.544 Mbs) are required for the connection to the primary and backup control centers. The latency of a T1 circuit is typically 10 ms or less. However, the end-to-end communications in ERCOT may be orders of magnitude larger due to the market participants' telemetry systems.

The ERCOT-provided network provides 99.9999% overall availability. However, ERCOT's requirement for connectivity availability is expressed as the end-to-end availability of telemetry data, and not just network availability. This end-to-end telemetry from market participants is required to be available 98% of the time, measured monthly. Moreover, outages cannot exceed five minutes in duration.

Security

ERCOT requires three-level authentication for data security, the details of which were not provided.

8

PJM DR TELEMETRY REQUIREMENTS

Background

This section focuses on PJM's requirements and is drawn mostly from the latest versions of the relevant documents posted on the PJM website and from phone interview. Table 8-1 presents the requirements.

Table 8-1
PJM Requirements for Telemetry Data

Category	Metric	PJM Requirements
Data Values	Meter Accuracy (Settlements/Revenue-Quality Metering)	± 0.3%
	Telemetry Accuracy (Load)	± 2%
	Telemetry Accuracy (Behind-the-Meter Generation)	± 2%
	Precision	Sufficient to meet accuracy requirement[39]
Coverage	Scanning Interval	2 seconds[40]
	Measurement Sampling Interval	2 seconds (regulation)
	Real Load MW Data Source	Measured (regulation) or statistically sampled
Network	Primary Circuit	PJM*net* or Jetstream (ISP) at internet speeds[41]
	Backup Circuit	N/A
	Connectivity Availability	*
	Maximum Outage Duration	N/A
	Number of Outages	N/A
Security	Authentication and Data Encryption	256-byte key[42] TLS and PKI using an OATI-signed X.509 client certificate.[43]

* Parameter value not provided

[39] PJM Manual 01, *Control Center and Data Exchange Requirements,* Revision 33 (December 15, 2016), pp. 49-50.

[40] PJM Manual 01, *Control Center and Data Exchange Requirements,* Revision 33 (December 15, 2016), p. 27.

[41] PJM Conference Call, March 16, 2017.

[42] PJM, *Jetstream Guide: DNP SCADA over Internet with TLS Security,* November 20, 2013, *passim.*

[43] PJM, *Introduction to Jetstream,* November 14, 2013, pp. 3-4.

Data Values

Settlement (revenue-quality) metering generally requires accuracy of ± 0.3%. For control telemetry, PJM allows ± 2% accuracy.

Data Coverage

PJM's system scans for data at 2-second (for regulation) and 10-second intervals (for Watt and VAR, although this is not required for DR). Measured values are required for individual resources providing regulation. Proposals for statistical sampling may also be considered.

Network

Data can be provided either via PJM's contracted network (PJM*net*) or via an ISP (called "Jetstream"). PJM members get one PJM*net* link that can be used for either ICCP or DNP3. DR is usually implemented using DNP3 over Jetstream.

Security

Encryption gateways are required for Jetstream. A 256-byte key is used for Transport Layer Security (TLS) and authentication uses PKI with an OATI-signed X.509 client certificate.

Notes on Demand Response in PJM

- Unselected day-ahead (DA) bids may be modified prior to real-time energy market (RTEM) during the "Generation Rebidding Period".[44]
- All DR offers are capped at ~$1k.[45]
- DR is eligible to set DA energy market (DAEM) and RT energy market (RTEM) prices if selected as the marginal resource, but operators can dispatch DR out-of-merit (OOM) and out-of-service (OOS) if conditions warrant.[46]
- DR has an opportunity cost of $0.[47]
- Regulation (REG) resources must be able to receive an automatic generation control (AGC) signal. and the resource's MW output is to be communicated to PJM's control center "in a manner determined to be acceptable by PJM." [48]
- DR available for REG or synchronous reserve (SR) can be called for emergency or pre-emergency instead.[49]

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[44] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 19.

[45] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 25.

[46] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), pp. 51, 146.

[47] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 64.

[48] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 65.

[49] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), pp. 66, 95.

- DR participation is limited to 25% of the REG requirement[50] and 33% of the SR requirement[51] (10% to 20% if they are "batch load" [intermittent] resources).[52]
- Demand resources providing SR or DA Schedule Reserve (DASR) are required to provide metering information at no less than a one-minute scan surrounding a synchronized reserve event. Residential customers without one-minute metering may participate using a statistical sampling method.[53]
- Metering information for demand resources is not required to be sent to PJM in real time.[54]
- Load data for all SR events must be submitted two business days following the event day,[55] the next business day for DASR.[56]
- DR can provide REG and SR [57] but **not** non-sync reserve.[58]
- DR can receive capacity payments, energy payments, or both (depending on their offers).[59]
- Demand resources may be registered simultaneously as Economic Load Response Resources and Emergency or Pre-Emergency Load Response Resources.[60]
- Demand resources must be equipped with interval meters recording electrical usage at the Electric Distribution Company (EDC) account level. The interval of data collection must be sufficient to provide PJM with hourly, one-minute (for DASR), or real-time load data as applicable for a wholesale market. Residential direct-load control aggregates may have interval meters installed on a statistical sample of EDC accounts.[61]
- For load reduction that is not metered directly by PJM, curtailment service provides (CSPs) are responsible for forwarding the appropriate meter data to PJM within 60 days of the reduction. Participants submitting a settlement for an energy payment must use data provided by the load meter, when load reduction complies with a synchronized reserve event or regulation assignment[62].
- If on-site generation is used solely to enable a participant to provide demand reductions, then the CSP may provide qualified meter generation output data, upon approval by PJM, from the on-site generation for each hour of the event day instead of actual load metered data.[63]

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[50] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 69.
[51] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 94.
[52] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), pp. 94-95.
[53] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), pp. 94, 169.
[54] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), pp. 94, 169.
[55] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 94.
[56] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 169.
[57] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 160.
[58] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 101.
[59] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 129.
[60] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 137.
[61] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 148.
[62] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 148.
[63] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 148.

- Aggregation is allowed to meet the 100-kW minimum for day-ahead scheduling reserve (DASR) [30-minute], REG and SR [10-minute].[64] "Appropriate" telemetry must be provided for the aggregated resource.[65]
- DASR participation requires a valid DAEM offer.[66]

[64] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 160.
[65] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 169.
[66] PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017), p. 170.

9
SPP DR TELEMETRY REQUIREMENTS

Background

This section focuses on SPP's requirements and is drawn mostly from the latest versions of the relevant documents posted on the SPP website. In SPP, a "demand response resource" is defined as one that can *reduce* the withdrawal of energy from the transmission grid when directed by SPP."[67] Unlike in California, behind-the-meter generation typically can qualify as DR in SPP.

The SPP requirements could also be considered to be moot. SPP reports that "since March 14, 2014, no load-reduction demand response activity has occurred in the Integrated Marketplace"[68] (in essence, since the launch date of its market). Table 9-1 summarizes identified requirements.

Table 9-1
SPP Requirements for Telemetry Data

Category	Metric	SPP Requirements
Data Values	Meter Accuracy (Settlements/Revenue-Quality Metering)	± 0.2% (power factor 1.0); ± 0.3% (power factor 0.5)[69]
	Telemetry Accuracy (Load)	*
	Telemetry Accuracy (Behind-the-Meter Generation)	*
	Precision	0.001 MW[70]
Coverage	Scanning Interval	2 sec (regulation)[71]; 10 sec (reserves)[72]
	Measurement Sampling Interval	*
	Real Load MW Data Source	*
Network	Primary Circuit	*
	Backup Circuit	*
	Connectivity Availability	*
	Maximum Outage Duration	*
	Number of Outages	*
Security	Authentication and Data Encryption	*

* Parameter value yet to be identified

[67] SPP, *Market Protocols for SPP Integrated Marketplace,* Revision 42 (November 23, 2016), p. 31. Despite this statement, DR can provide regulation, in which case both regulation up and regulation down are required.

[68] SPP Compliance Filing, FERC Docket No. ER12-1179-024 (May 24, 2016), p. 4.

[69] SPP, *Market Protocols for SPP Integrated Marketplace,* Revision 42 (November 23, 2016), p. 726.

[70] SPP, *Market Protocols for SPP Integrated Marketplace,* Revision 42 (November 23, 2016), p. 219.

[71] SPP, *Market Protocols for SPP Integrated Marketplace,* Revision 42 (November 23, 2016), p. 105.

[72] SPP, *Market Protocols for SPP Integrated Marketplace,* Revision 42 (November 23, 2016), p. 123.

Data Values

Settlement (revenue-quality) metering generally requires accuracy no worse than 0.2% at a power factor of 1.0 or 0.3% at a power factor of 0.5. Precision of data values is to 0.001 MW.

Data Coverage

SPP's telemetry is described as coming through ICCP links, suggesting that in these cases, another control center is present between SPP and the DR resource. SPP's system scans for data at 2-second for regulation and 10-seconds for reserves.

Although SPP DR resources can consist of aggregations, no requirement seems to exist for the timeliness of the data reported for the individual resources that make up the aggregation. Also, no discussion of statistical sampling has been found.

Network

No network requirements have been identified. Higher-level protocol and requirements for data models (such as ICCP and XML) are specified. Furthermore, DR resources providing ancillary services must respond to (and help mitigate) frequency.

10
METHODS TO LOWER TELEMETRY COSTS

Background

In collaboration with the California Independent System Operator (CAISO), EPRI worked with a demand response aggregator (OhmConnect) and a qualified RIG provider (SEL) to demonstrate a lower cost telemetry alternative supportive of mass market demand response.

By utilizing a data aggregation server (DAS), multiple proxy demand resources (PDRs) can be represented by one remote intelligent gateway (RIG). The DAS aggregates individual end-use assets (e.g., smart meter and other metered load) into multiple proxy demand resources (PDRs). The DAS exchanges resource data with one remote intelligent gateway (RIG). The RIG in turn provides telemetered values for each resource to the CAISO system.

This chapter investigates ways to further lower telemetry costs, by considering alternative deployments of the RIG to support multiple DAS servers, including the potential for software-based RIG implementations that would allow virtualization and utilization of RIG implementations in a cloud environment. Alternatives are described along with benefits and challenges. The chapter discusses issues associated with meeting CAISO requirements and may not generally apply to other regional market operator systems.

Overview of RIG Deployment

A RIG has been demonstrated as a hardware box physically located at the DR aggregator's location. The RIG is connected to a Data Aggregator Server (DAS) and communicates with the CAISO EMS SCADA system. Figure 10-1 represents these components, wherein the RIG is connected to the network at the DR Aggregator's location.

The DAS can aggregate data from multiple resources. Each resource may be connected to multiple assets or data points. The RIG receives data input from the DAS. Within some constraints, new assets can be aggregated into a resource defined by the DAS. However, every time a new resource is added to the RIG, it has to be validated with the ISO.

The DAS sends input data, which is read by the RIG and stored in a local data cache. When the ISO requests data from the RIG, the RIG selects the most recent data from the cache and sends it to the ISO using the appropriate protocol and transport/connection (e.g. DNP3 over TCP).

The RIG must meet security and reliability standards defined by ISO to ensure reliable communication, prompt response times, and data integrity.

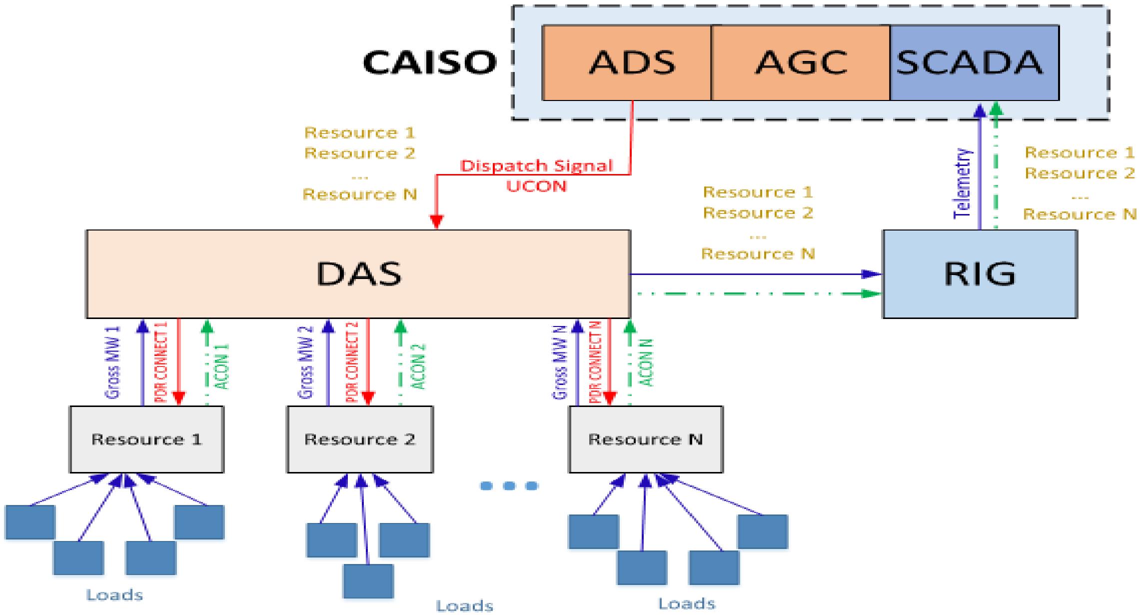

Figure 10-1
RIG Deployment with Data Aggregation Server

Limitations

The demonstrated RIG and DAS setup allows one RIG to represent multiple resources, lowering telemetry costs by sharing one RIG with multiple resources. However, other limiting factors remain unaddressed that contribute to telemetry costs involved in new resource registration, specialized configuration of hardware, connection to ISO, and certification with ISO. For example:

- Every time a new resource needs to be added by the aggregator, the aggregator needs to undergo a validation procedure, which can be time consuming and resource intensive.
- The CAISO process is generally new to DR aggregators and requires expertise to define and create a complete telemetry solution.
- The current hardware RIG setup also poses location constraints. Although the ISO does not require all PDR resources that are connected to the RIG to be in the same sub-region, communications is needed to the local RIG. Additionally, the RIG will need to be physically mounted or installed and maintained by the DR aggregator.

Due to the above-mentioned limitations, it has been challenging for smaller organizations to deploy RIGs at their locations. To overcome these challenges, the RIG functionality could be reduced to a software implementation that runs on a cloud-based service. This may also contribute to reducing the overall costs involved for resource telemetry.

Virtualization of RIG

By implementing the RIG functionality in software, and by working with the ISO to enable this implementation in a generic, repeatable manner, RIG implementation costs can be reduced. This also opens up the possibility of many different deployment/implementation options in the industry. For example, DAS providers could either serve as RIG service providers or use the services of another RIG service provider.

Key Functions of a Virtualized RIG

Figure 10-2 illustrates the concept of virtualizing the RIG. The key functions of a RIG, from a software implementation perspective, include:

1. Accept information from one or more DAS systems:
   - The DAS sends data asynchronously, at time scales it has available, to the RIG. Some data may be provided on different timescales than other data, depending on the nature of the data source.
   - The data can be provided over the public internet, provided appropriate security and reliability concerns are addressed. The current EPRI demonstration implementation sends this data as secure FTP, but other secure methods could be implemented.
2. Localized caching of data:
   - The data provided by DAS is cached in the RIG.
   - When the ISO system requests data from the RIG, the RIG is required to provide the most recent data maintained in the cache.
3. Respond to data requests from the ISO:
   - The ISO system requests the RIG to send the most recent data as desired, typically every few seconds. The time interval and data requested depend on the assets being monitored.
   - The virtual RIG must convert the data using a real-time protocol such as Distributed Network Protocol, Version 3 (DNP3) and communicate to ISO over TCP/IP using secure methods such as Secure Socket Layer (SSL) for encryption, to meet the standards.[73]
   - The data must be provided within a defined performance band.

[73] This RIG could also use services like Dispersive Technology to provide highly reliable and secure methods for communication.

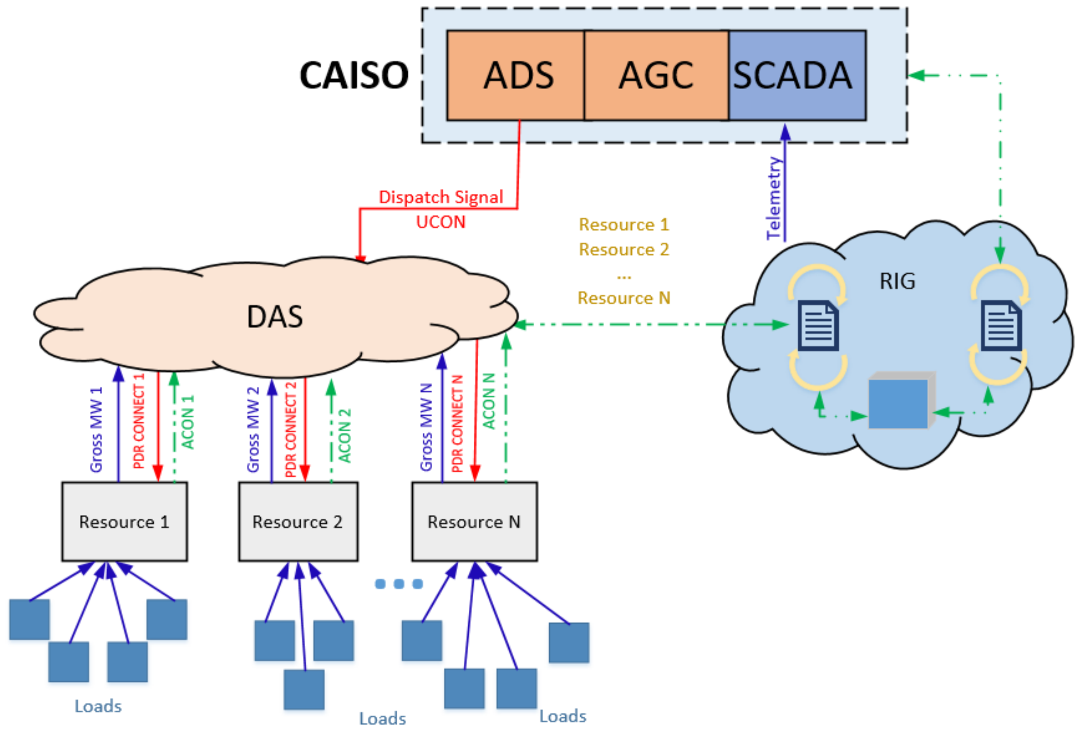

Figure 10-2
Conceptual Diagram of Virtualized RIG in the Cloud

Concerns in Realizing the Virtual RIG Concept

Implementing a virtualized software-based RIG in the cloud introduces some new concerns and possible limitations. For example, issues include:

1. Responsibility: With a software-based virtual RIG, a number of business configurations are possible. A key difference between these configurations is the organization that is responsible for maintaining the RIG environment. This difference is a key attribute that impacts how low-cost the RIG configuration can be. If, for example, the RIG can be managed by an organization that specializes in managing the RIG and has the experience and processes to manage certification with the ISO as new DAS and resources are added, then the overall costs to the participants might be decreased.
2. Location: Typically RIGs for sizable resources are required to be located in the same sub-region as the resources. This is important for reliability and control. Once the RIG is virtualized, it may not be in the same geographical location as the resources. If implemented in the cloud, the location of the RIG could be anywhere, including outside of ISO service area, or even in a different state or country. There are ways to force the virtual RIG to be sited in the same geographical location as the data aggregator, but additional costs may be involved. If the virtual RIG location is not restricted to a region, the costs can be significantly reduced. This approach would require approval of the ISO.
3. Reliability: The entire telemetry system, including the RIG needs to be reliable and resilient. This may require additional redundancy or more complex configurations to meet suitable

reliability expectations from resources. For example, additional communications redundancy or tools may be critical to improve reliability.

4. Security: As more telemetry data is placed on the public Internet, high quality security protocols will need to be followed to achieve data accuracy. Addressing security issues such as physical access to the server that hosts the RIG, electronic access control, secure communications (SSL, DNP3, Virtual Private Network, etc.), and encryption of data in transit are highly critical to maintain the security of the RIG.
5. Performance: Telemetry data must be provided to the ISO within a particular performance band, which may be difficult in some cases when using the public Internet. The required performance may vary depending on the size of resources monitored and grid services targeted for provision, whereas performance requirements may be less of an issue for individual assets that comprise the resources.
6. Certification: If a single RIG provider can be certified to support multiple DAS's, telemetry costs may be decreased. The process of certification of the RIG supporting multiple DAS and its connection to ISO would likely differ from current standard processes. This remains a research question to be explored.

Business Configuration Options

With a virtual RIG, the components of an end-to-end telemetry system could be configured in different ways. Although the ISO ultimately determinates requirements for different configurations, in general a single virtual RIG could support multiple data aggregation systems.

The ideal configuration depends on the evolving needs of the various business participants. Each configuration affects certain ISO requirements and places various responsibility on different business participants. Although other configurations are possible, a few sample configurations are discussed below for consideration. These include the following.

1. Third-party hosting of existing RIG hardware for a single DAS
2. Aggregator integrating software-based RIG with existing DAS in cloud
3. Third-party hosting of software-based RIG for multiple DAS

1: Host RIG Hardware at a Third-party Location

Figure 10-3 describes a partial-cloud solution. In this configuration, the RIG service provider is a third-party (not the aggregator) who hosts the RIG hardware, which can receive data input from the aggregator via the cloud and then send output to the ISO in the traditional way. This relieves the need for the DAS provider to have a detailed understanding of the ISO requirements, as RIG expertise is provided by a third-party.

This could be implemented as a separate RIG hardware device per DAS, though it may be possible for a hardware RIG to support multiple DAS's.

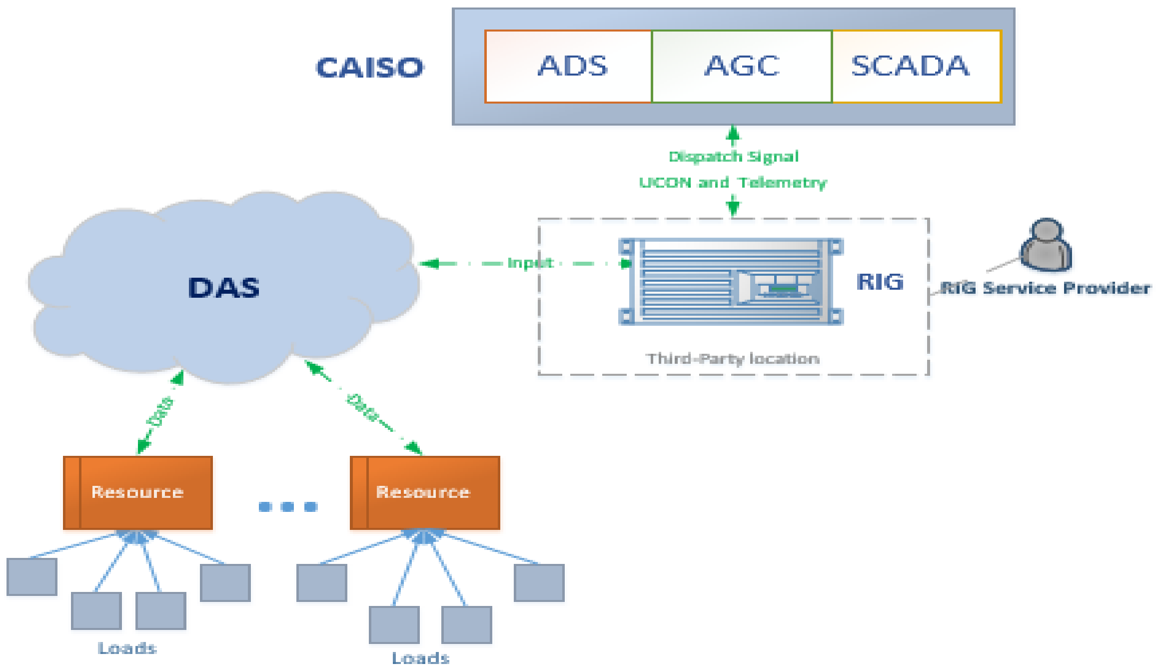

Figure 10-3
Hardware RIG Hosted at a Third-Party Location

Responsibility:

- The RIG service provider would be responsible for hosting, maintaining, and validating the hardware RIG.

Benefits:

- Simplifies certification process with ISO, as the certification follows the usual pattern, and is provided by a 3rd party with expertise in this area.
- Addition of resources would be made easy.
- By maintaining the hardware-based RIG, the RIG provider may be able to better manage the physical location and security of the equipment. The RIG provider may also better assure that the hardware is performing as expected and would have technical expertise to troubleshoot the configuration and equipment.

Challenges:

- Certification may still be required as new resources are added.

2: Virtual RIG Hosted by Aggregator

For this proposed option, the Virtual RIG software can be made available to the DAS provider, who can integrate it with the DAS or otherwise co-locate the software with the DAS functionality. This is illustrated in Figure 10-4.

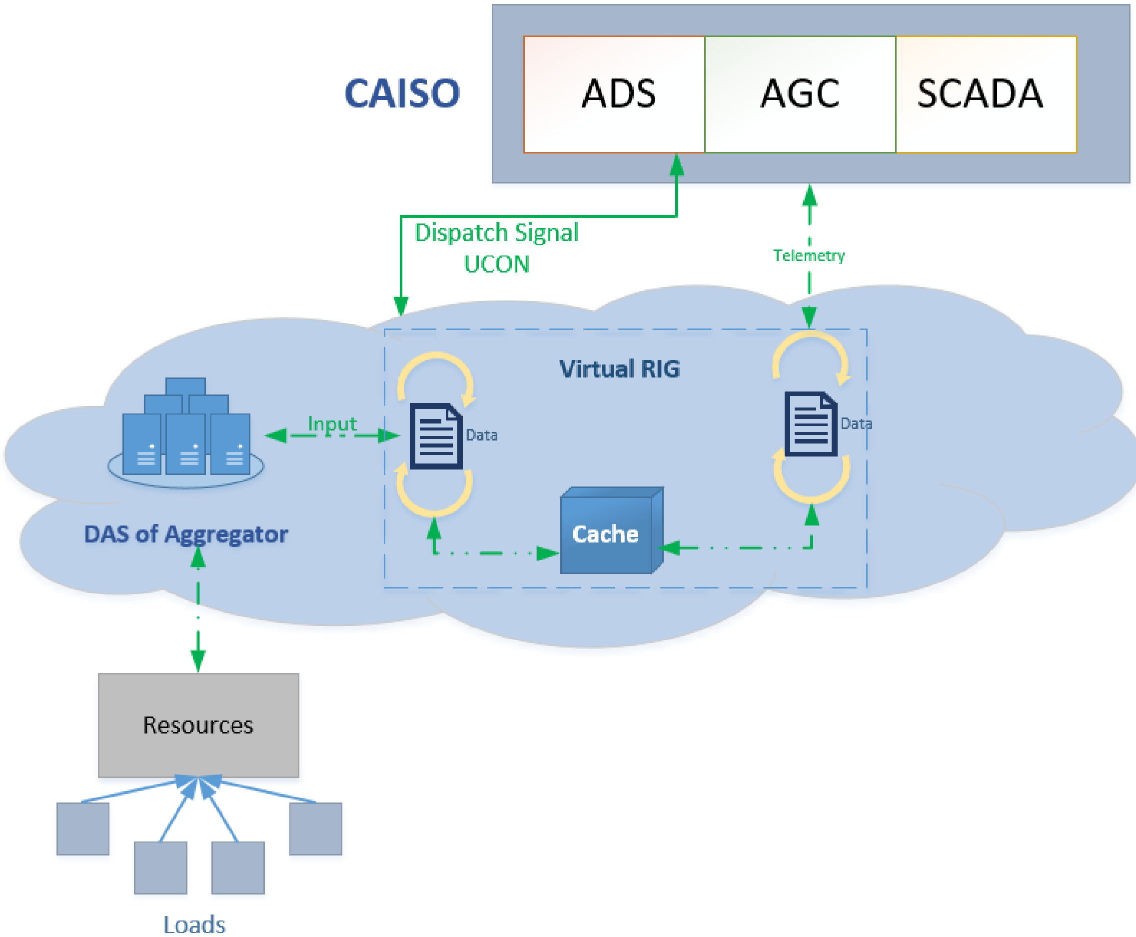

Figure 10-4
Software-based RIG Integrated with DAS in the Cloud

Responsibility:

- The aggregator provider will be completely responsible for deploying, maintaining, and validating the software/virtualized RIG.

Benefits:

- Possibly lower the costs for the DAS provider since the RIG can be virtually hosted on cloud, together with DAS.
- Ease of communication between the DAS and the RIG.
- Easier to implement security as both DAS and RIG will be hosted together.

Challenges:

- The aggregator provider will need to manage RIG validation certifications with the ISO, which may be inefficient due to limited expertise.

3: RIG Service for Multiple Data Aggregators (DAS)

This implementation combines aspects of the previous options. In this configuration, a RIG service provider would host a virtual RIG in the cloud which would communicate with multiple DAS providers, as illustrated in Figure 10-5. The RIG service provider would host and maintain the RIG on the public internet.

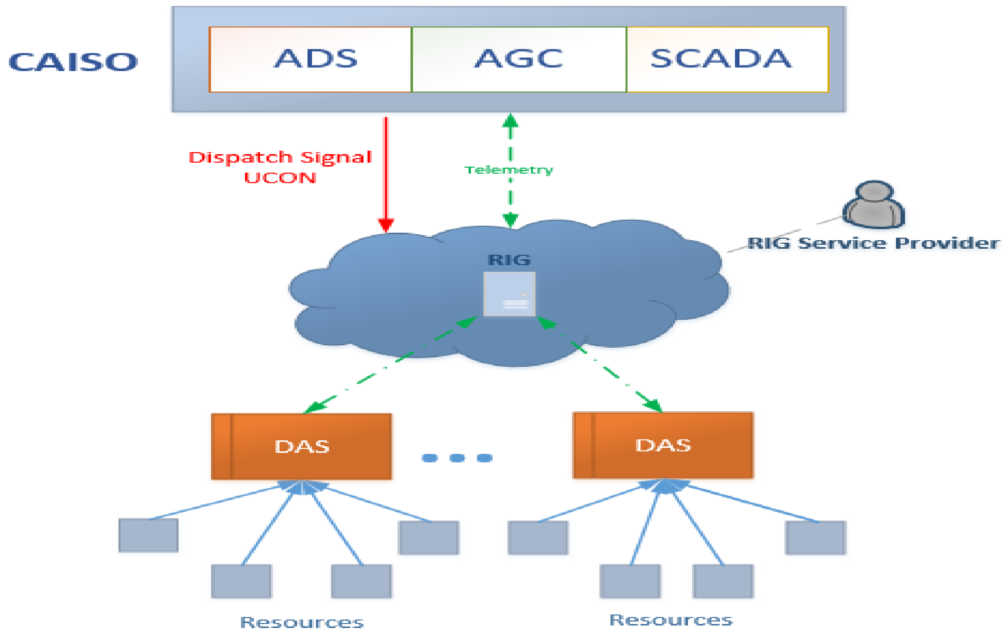

Figure 10-5
RIG Service for Multiple DAS Systems of Data Aggregators

Responsibility:

- The RIG service provider would be responsible for hosting, maintaining, validating the virtual RIG.

Benefits:

- A single RIG would be able to provide service to multiple data aggregation systems (DAS), improving economies of scale.
- Reduces costs involved for hosting individual RIGs per DAS.

Challenges:

- Need to establish secure communication methods between the RIG in the Cloud and the resources, as well as with the ISO.
- Advantages may be limited if there are restrictions regarding locating the RIG in the same sub-region as the resources.

Recommendation for Demonstration

A number of configurations of the DAS and RIG can be implemented to decrease telemetry costs. A key enabler of these opportunities is to have the RIG implemented in a software environment that allows a variety of deployment options and can be easily and repeatedly implemented in a way that is easy to certify with the ISO.

To explore this further, a software system demonstration can be prepared to illustrate the data flows and functionalities that would be necessary to implement a secure system, as well as identify issues and interface points that would need to be addressed in future research. To provide maximum generality, the software system demonstration could replicate the Option 3 described above. The demonstration would be designed to show the major components of a virtual RIG, and be used to identify key issues. The demonstration could consist of the following features:

- The DAS provides resource information to a secure FTP service in the cloud
- A simple Virtual RIG is implemented in a cloud-hosted server
- Resource data is requested by a simulated ISO emulator and provided using a simulated DNP3 protocol.

From this basic implementation, other options can be supported, as well as new deployment and implementation options explored. There are also aspects of the proposed implementation approaches that can be evaluated to further decrease overall telemetry costs involved in implementing and validating new telemetry alternatives. This is the subject of further work and future research.

Future Work to Lower Telemetry Costs

This chapter described technological alternatives with the potential of lowering telemetry costs for mass market demand response participation in markets. The described virtual RIG concept was devised to address the following ideas that surfaced during industry interviews[74] EPRI conducted during 2017-18 on ways to lower telemetry costs:

a) Eliminate need for site visit and travel to site for commissioning of RIG

b) Make telemetry system completely remotely manageable (e.g., remote firmware update)

c) Use public network infrastructure instead of private network infrastructure in more situations. (This would require encryption, authentication, and resiliency.)

Other ideas that surfaced from EPRI's interviews of qualified RIG vendors include:

d) Make RIG certification process easier

e) Support plug and play installation and commissioning of hardware box or software (e.g., streamline process by allowing DR participant to log-into website and put in the serial number of a box installed for telemetry)

f) Provide standards for load control (e.g., equipment put in using a standard, so next company can operate what was installed)

g) Provide more economical choices in securing RIG communications to CAISO.

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[74] Qualified RIG vendors listed on the CAISO website were interviewed for ideas on ways to lower telemetry costs for mass market loads (e.g., residential and small commercial customers) to participate in wholesale markets.

Many telemetry vendors described a labor-intensive effort to register new resources with the ISO for direct telemetry. To help demystify the new resource certification process for direct telemetry, EPRI produced a video that illustrates the procedure for validating a RIG with the California Independent System Operator (CAISO). The procedure involved point-to-point testing between the CAISO EMS system and a RIG configured to communicate with a DAS that aggregates assets into multiple resources, as depicted in Figure 10-1. The video may be reviewed to help familiarize and better prepare for validation testing with the ISO, towards saving some time and effort for those new to the CAISO process.

It may also be possible to simplify the RIG New Resource Implementation (NRI) procedures so that resource input/output point lists and certification can be established more quickly and efficiently. This is a subject for future research in collaboration with the ISO, towards lowering labor costs associated with meeting ISO telemetry requirements.

Simplifying and making the NRI process more efficient could hugely impact telemetry costs, along with having the RIG deployed in a way where it can be remotely managed (e.g., virtual RIG concept). Other suggested ways to lower telemetry costs include: supporting simple (e.g., plug and play) installation and commissioning of telemetry devices where end-use assets are located that are aggregated into resources; advancing standards for load control that enable monitoring and control devices to be interoperable across vendor platforms; and having more economical solutions in deploying secure communications between the RIG and CAISO. These and other ideas are subject to future investigation.

11
REVIEWED MATERIALS

1. CAISO, *Business Practice Manual for Metering,* Version 15 (October 1, 2016)
2. CAISO, *Business Practice Manual for Direct Telemetry*, Version 10 (January 5, 2017)
3. CAISO, *New Remote Intelligent Gateway and Secure Socket Layer Validation Procedure,* Version 4.3 (December 16, 2015)
4. CAISO, *Client Public/Private Key Instructions*
5. New York State Electric Meter Engineers' Committee, *Guide for Uniform Practices in Revenue Quality Metering,* Revision 4 (August 20, 2003)
6. NYISO, *Control Center Requirements Manual,* Version 3 (March 28, 2014)
7. ERCOT, *ERCOT ICCP Communication Handbook,* Version 3.08 (September, 2016)
8. ERCOT, *Telemetry Standards* (May 2, 2013)
9. ERCOT, *Nodal Protocols* (May 1, 2017),
10. New York State Electric Meter Engineers' Committee, *Guide for Uniform Practices in Revenue Quality Metering,* Revision 4 (August 20, 2003)
11. NYISO, *Control Center Requirements Manual,* Version 3 (March 28, 2014)
12. ISO-NE, *Market Rule 1*
13. ISO-NE, *ISO New England Operating Procedure No. 18: Metering and Telemetering Criteria (OP-18),* October 5, 2015
14. ISO-NE, *ISO New England Inc. and New England Power Pool, Docket No. ER15-257-000, Market Rule 1 Changes to Integrate Price-Responsive Demand into Reserve Markets ("PRD Reserves Changes"),* FERC Filing, October 31, 2014, Section 2.1
15. MISO, *Demand Response Business Practices Manual,* BPM-026-r1 (June 1, 2016)
16. MISO, *Market Settlements Business Practices Manual,* BPM-005-r15 (June 30, 2016)
17. PJM Manual 11, *Energy & Ancillary Services Market Operations,* Revision 86 (February 1, 2017)
18. PJM Manual 01, *Control Center and Data Exchange Requirements,* Revision 33 (December 15, 2016)
19. PJM, *Metering System and Communications Requirements,* presentation to Special MRC Session on DER, August 24, 2016
20. PJM Manual 14D, *Generator Operational Requirements,* Revision 40 (January 1, 2017)
21. PJM, *Introduction to Jetstream,* November 14, 2013
22. PJM, *Jetstream Guide: DNP SCADA over Internet with TLS Security,* November 20, 2013
23. SPP, *Market Protocols for SPP Integrated Marketplace,* Revision 42 (November 23, 2016)
24. SPP Compliance Filing, FERC Docket No. ER12-1179-024 (May 24, 2016)

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