PART 1 GENERAL

1.1 SUMMARY

.1 Provide labor, material, equipment, related services, and supervision required, including, but not limited to, manufacturing, fabrication, erection, and installation for electrical power monitoring and control equipment as required for the complete performance of the work, and as shown on the Drawings and as herein specified.

1.2 REFERENCES

.1 General: The publications listed below form a part of this Specification to the extent referenced. The publications are referred to in the text by the basic designation only. The edition/revision of the referenced publications shall be the latest date as of the date of the Contract Documents, unless otherwise specified.

.2 American National Standards Institute (ANSI):

.1 ANSI C12.20, "Electricity Meters - 0.2 and 0.5 Accuracy Classes – Part 5.5.4 Accuracy tests."

.2 ANSI / ISA – 61010-1, "Safety Requirements for Electrical Equipment for Measurement, Control, and Laboratory Use – Part 1: General Requirements."

.3 ANSI / ISA – 61010-2-030, "Safety Requirements for Electrical Equipment for Measurement, Control, and Laboratory Use - Part 2-030: Particular requirements for testing and measuring circuits."

.3 Canadian Standards Association (CSA):

.1 CAN/CSA C22.2 No. 61010-1, "Safety Requirements for Electrical Equipment for Measurement, Control, and Laboratory Use - Part 1: General Requirements."

.2 CAN/CSA C22.2 No. 61010-2-030, "Safety Requirements for Electrical Equipment for Electrical Equipment for Measurement, Control, and Laboratory Use - Part 2-030: Particular requirements for testing and measuring circuits."

.4 Federal Communications Commission (FCC):

.1 Title 47 CFR Part 15, Subpart B, "Radio Frequency Devices."

.5 Institute of Electrical and Electronics Engineers, Inc. (IEEE):

.1 ANSI/IEEE C37.90.1, "Surge Withstanding Capability (SWC) Tests for Protective Relays and Relay Systems."

.2 IEEE 802.3 – 2012, "Standard for Ethernet."

.3 IEEE 1815 - 2012, "Standard for Electrical Power Systems Communications –

Distributed Network Protocol (DNP3)."

.6 Industry Canada (IC) Standards, Interference Causing Equipment Standard (ICES):

.1 ICES 003, "Information Technology Equipment (ITE) - Limits and Methods of Measurement."

.7 Underwriters Laboratories, Inc. (UL):

.1 UL. 61010-1, "Safety Requirements for Electrical Equipment for Measurement, Control, and Laboratory Use - Part 1: General Requirements."

.2 UL 61010-2-030, "Safety Requirements for Electrical Equipment for Electrical Equipment for Measurement, Control, and Laboratory Use - Part 2-030: Particular requirements for testing and measuring circuits."

1.3 SUBMITTALS

.1 General: Submit the following in accordance with Conditions of the Contract and Division 01 - General Requirements.

.2 Product Data: Submit product data showing material proposed. Submit sufficient information to determine compliance with the Drawings and Specifications.

.3 Shop Drawings: Submit shop drawings for each product and accessory required. Include information not fully detailed in manufacturer's standard product data.

.4 Wiring Diagrams: Submit wiring diagrams detailing power, signal, and control systems, clearly differentiating between manufacturer-installed wiring and field-installed wiring, and between components provided by the manufacturer and those provided by others.

.5 Operation and Maintenance Data: Submit operation and maintenance data for electrical power monitoring and control equipment to include in operation and maintenance manuals specified in Division 01 - General Requirements.

1.4 QUALITY ASSURANCE

.1 Qualifications:

.1 Manufacturer Qualifications: Manufacturer shall be a firm engaged in the manufacture of electrical power monitoring and control equipment of types and sizes required, and whose products have been in satisfactory use in similar service for a minimum of five years.

.2 Installer Qualifications: Installer shall be a firm that shall have a minimum of five years of successful installation experience with projects utilizing electrical power monitoring and control equipment similar in type and scope to that required for this Project and shall be approved by the manufacturer.

.2 Regulatory Requirements: Comply with applicable requirements of the laws, codes, ordinances, and regulations of Federal, Provincial, and local authorities having

jurisdiction. Obtain necessary approvals from such authorities.

.3 Pre-Installation Conference: Prior to commencing the installation, meet at the Project site to review the material selections, installation procedures, and coordination with other trades. Pre-installation conference shall include, but shall not be limited to, the Contractor, the Installer, manufacturer's representatives, and any trade that requires coordination with the work. Date and time of the pre-installation conference shall be acceptable to the Owner and the Engineer.

.4 Single Source Responsibility: Obtain electrical power monitoring and control equipment and required accessories from a single source with resources to produce products of consistent quality in appearance and physical properties without delaying the work. Any materials which are not produced by the manufacturer shall be acceptable to and approved by the manufacturer.

1.5 DELIVERY, STORAGE, AND HANDLING

.1 Deliver materials to the Project site in supplier's or manufacturer's original wrappings and containers, labeled with supplier's or manufacturer's name, material or product brand name, and lot number, if any.

.2 Store materials in their original, undamaged packages and containers, inside a well-ventilated area protected from weather, moisture, soiling, extreme temperatures, and humidity.

1.6 WARRANTY

.1 The Compact Power and Energy Metering System shall be warranted by the vendor against manufacturing defects for a period of three (3) years.

PART 2 PRODUCTS

2.1 POWER QUALITY MONITOR WITH REVENUE METER ACCURACY ANALYSIS

.1 General Provisions:

.1 Setup parameters required by the System shall be stored in nonvolatile memory and retained in the event of a control power interruption.

.2 The System instrument may be applied in four-wire wye, three-wire wye, three-wire delta, direct delta, and single-phase systems.

.3 The System instrument shall be fully supported by the System software.

.2 Markings:

.1 The System instrument shall be CE marked.

.2 The System instrument shall be marked as compliant with the applicable UL standards.

.3 Standards Compliance:

.1 The System instrument shall comply to the following safety/construction standards:

.1 CAN/CSA C22.2 No. 61010-1.

.2 CAN/CSA C22.2 No. 61010-2-030.

.3 UL 61010-1.

.4 UL 61010-2-030.

.4 Current/Voltage Inputs:

.1 The PM instrument shall have no less than three (3) voltage inputs and four (4) current inputs.

.2 The PM instrument in its standard configuration shall be able to accept voltages up to 347 VLN / 600 VLL (UL) without using potential transformers.

.3 The PM instrument shall be able to withstand 3300 volts AC RMS for 2 seconds without damaging the device.

.4 The PM instrument shall support nominal current ratings of 1 ampere or 5 amperes, and an over current rating of 500 amperes for 1 second.

.5 Control Power:

1. The System instrument shall be able to accept a wide range of control power inputs the range of 90 V AC to 415 V AC +/- 10% (45 to 65 Hz), 90 V AC to 120 V AC +/- 10% (400 Hz) or 120 V DC to 300 V DC +/- 10% without need for a control power transformer.

2. The System instrument shall have the ability to sustain operation through a control power outage of 10 cycles, minimum, and ensure any events resulting in a control power outage will be captured.

.6 Mechanical:

.1 The instrument shall be available in multiple form factors for panel mounting with an integrated display, and for DIN rail mounting without a display or with a remotely mounted display.

.2 The panel mount meter and the remotely mounted display shall meet UL/NEMA Type 12 and IP54 installation criteria when properly installed.

.3 The power meter unit shall have removable connectors for voltage inputs, control power, communications, inputs, and outputs.

.7 Measured Values:

.1 The instrument shall provide at a minimum the following voltage values:

.1 Voltage L–L per-phase.

.2 Voltage L-L three-phase average.

.3 Voltage L–N per-phase.

.4 Voltage three-phase average.

.5 Voltage percent unbalanced.

.2 The instrument shall provide at a minimum the following current values:

.1 Current per phase.

.2 Current neutral (measured).

.3 Current three-phase average.

.4 Current percent unbalanced.

.3 The instrument shall provide at a minimum the following power values:

.1 Real power (per phase, three-phase total).

.2 Reactive power (per phase, three-phase total).

.3 Apparent power (per phase, three-phase total).

.4 Power factor - true (per phase, three-phase total).

.5 Power factor - displacement (per phase, three-phase total).

.4 The instrument shall provide at a minimum the following energy values:

.1 Accumulated energy (real kWh, reactive kVARh, apparent kVAh) (signed/absolute).

.2 Incremental energy (real kWh, reactive kVARh, apparent kVAh) (signed/absolute).

.3 Conditional energy (real kWh, reactive kVARh, apparent kVAh) (signed/absolute).

.4 Energy by quadrant (real kWh, reactive kVARh, apparent kVAh).

.5 The instrument shall be able to provide a minimum/maximum value for any measured parameter.

.6 The instrument shall be capable of deriving values for any combination of measured or calculated parameter, using the following arithmetic, trigonometric, and logic functions:

.1 Arithmetic functions; division, multiplication, addition, subtraction, power, absolute value, square root, average, maximum, minimum, RMS, sum, sum-of-squares, unary minus, integer ceiling, integer floor, modulus, exponent, PI.

.2 Trigonometric functions; COS, SIN, TAN, ARCCOS, ARCSIN, ARCTAN, LN, LOG10.

.3 Logic functions; =, =>, <=, <>, <, >, AND, OR, NOT, IF.

.4 Thermocouple linearization functions; Type J, Type K, Type R, Type RTD, Type T.

.5 Temperature conversion functions; C to F, F to C.

.8 Demand:

.1 The instrument shall be able to provide last completed interval demand, predicted demand, peak demand with date and time, and coincident demand values on multiple demand channels.

.2 The instrument shall be able to perform multiple accepted demand calculation methods, including, but not limited to, block, rolling block, and thermal demand with user-programmable demand period lengths.

.3 The instrument shall support the synchronization of the demand interval using a digital input, a command via communications, or internal clock.

.9 Accuracy:

.1 The instrument shall meet ANSI C12.20 accuracy Class 0.2.

.2 The instrument shall provide four-quadrant metering.

.10 Sampling:

.1 The instrument shall sample continuously at 256 samples per cycle.

.2 The instrument shall be able to perform sag/swell detection of voltage disturbances on a half-cycle basis, providing the duration of the disturbance, the minimum, maximum, and average value of the voltage for each phase during the

disturbance. Disturbances less than one cycle in duration can be detected.

.11 Memory:

.1 The instrument shall have at least 384 MB of non-volatile memory for configuration settings, log data, events, waveform captures, web pages and documents. A minimum of an additional 10 MB of memory shall be available for user programmable data logging.

.2 The instrument shall store critical internal and revenue data upon sudden power loss.

.3 The instrument shall retain all data and configuration in non-volatile memory for 15 years without control power.

.4 The instrument shall provide a real time clock (RTC) with battery backup that will provide ride-through of at least 7 years without control power once installed, 10 years in storage.

.5 The instrument shall have a field installable battery for real time clock ride-through that can be installed without need to remove the instrument from the installation.

.6 The instrument shall have a time-stamped event log with the following features:

.1 Shall support at least 500 events.

.2 The number of records in the log shall be programmable.

.3 Each event shall be recorded with the date and time of the event, the cause and effect of the event, and the priority of the event.

.4 Events relating to setpoint activity, relay operation, and self-diagnostics shall be recorded in the event log.

.5 Time stamps shall have a resolution of 1 millisecond.

.6 Time stamps can be synchronized to within +/- 1 millisecond between devices through the use of GPS (Global Positioning Satellites) serial input or IRIG-B digital input.

.7 Minimum event recording response time shall be 1/2 cycle (8.3 ms 60 hertz, 10 ms 50 hertz) for high speed events and 1 second for other events.

.8 The priority of setpoint events shall be programmable.

.7 The instrument shall be able to log any parameter in the meter, including, but not limited to, minimum/maximum and waveforms.

.8 The instrument shall be capable of supporting a minimum of 50 independent data

logs that support the following configuration options:

.1 Recording method of Fill and Hold or First In First Out (FIFO).

.2 Selection of up to 16 parameters per log.

.3 Log data on an event or based on internal clock.

.4 Ability to automatically fill gaps in data logs with a value of zero (0) or leave blank.

.12 Alarming:

.1 The instrument shall have the ability to support a minimum of 65 setpoint driven alarms evaluated once per second or once every ½ cycle, user configurable.

.2 The instrument shall have the ability to support disturbance alarms for detecting voltage and current dips and swells on all monitored phases.

.3 The instrument shall be able to generate an E-mail on an alarm condition.

.4 The instrument shall have millisecond time stamp resolution on alarm entries.

.5 The instrument shall be able to adjust alarm setpoints based on the alarm quantity (alarm setpoint learning).

.1 The user shall be able to enable the instrument to learn the characteristics of normal operation of metered values and select alarm setpoints based on this data.

.2 The quantities to be learned shall be user selectable, including, but not limited to, standard speed alarms, high speed alarms, and disturbance alarms.

.3 The user shall be able to configure this feature using one of two modes:

.1 Manual: Once the learning is completed, the recommended values shall be stored for review and manual installation.

.2 Automatic: Once the learning is completed, the recommended values shall be automatically installed and operational.

.4 The learning period shall be user configurable from 1 to 365 days to ensure system stability prior to determining the recommended setpoints.

.6 The instrument shall support consecutive high speed alarm conditions which shall trigger on a cycle-by-cycle basis with no delay time between events (i.e., no need for a rearming delay time between events).

.7 The instrument shall be able to operate relays on alarm conditions.

.8 The instrument shall be able to initiate data log captures on alarm conditions.

.9 The instrument shall be able to control digital output relays using pulse mode or latch mode operation, for control and alarm purposes.

.10 The instrument shall be able to combine any logical combination of any number of available setpoint conditions to control any internal or external function or event.

.13 Communications:

.1 The instrument shall be capable of supporting the following physical, communications methods simultaneously and independently:

.1 Ethernet (dual-port, single network).

.1 10/100 Base-TX (port 1).

.2 10/100 Base-TX (port 2).

.2 Ethernet switch.

.1 10/100 Base-TX (port 1).

.2 10/100 Base-TX (port 2).

.3 Ethernet switch with RSTP (Rapid Spanning Tree Protocol).

.1 10/100 Base-TX (port 1).

.2 10/100 Base-TX (port 2).

.4 Serial.

.1 RS-485.

.2 The instrument shall support multiple concurrent Ethernet communication protocols over an Ethernet network at any one time:

.1 IEC61850.

.2 DNP 3.0 TCP/IP.

.3 Modbus TCP/IP.

.4 Modbus TCP/IP mastering of Ethernet devices.

.5 ION TCP/IP.

.6 Ethernet to serial line gateway.

.7 FTP (file transfer).

.8 HTTP (web interface).

.9 NTP / SNTP (time synchronization).

.10 SMTP (E-mail).

.11 SNMP (network management with traps).

.12 MV-90 compatibility

.3 The instrument shall support any one of the following serial communications protocols on any one serial port at any one time:

.1 Modbus:

.1 Modbus RTU.

.2 Modbus mastering of Serial RS-485 slaves.

.2 DNP 3.0.

.3 ION.

.4 MV-90 compatibility.

.4 The instrument shall be able to support at least 32 concurrent Modbus TCP/IP connections.

.5 The instrument shall have a Modbus TCP/IP gateway to provide a network connection to Modbus serial devices connected to a serial port on the instrument.

.6 The instrument shall have the ability to read from and write to Modbus devices connected to a serial port on the instrument and on a common local area Ethernet network.

.7 The instrument shall serve web pages with the following capabilities to:

.1 Provide real-time and historical data views in both tabular and graphical formats.

.2 Provide a histogram of harmonic data through the 63rd harmonic.

.3 Provide an ITIC (CBEMA) and a SEMI E10 summary of voltage disturbances.

.4 Provide a NEMA motor derating curve.

.5 Provide a phasor diagram representation of the electrical connections to the meter.

.6 Provide a summary of EN 50160 power quality data along with a pass / fail analysis.

.7 Provide a graphical trend for voltage, average current, frequency and power demand along with a forecast of the next 4 points.

.8 Support the ability to provide technical documents and drawings in PDF format.

.9 Support user defined web pages containing data from the host meter as well as data from Modbus devices connected to a serial port on the instrument and on a common local area Ethernet network.

.8 The instruments shall have two (2) Ethernet ports that support the following functions:

.1 Automatically E-mail alarm notifications or scheduled system status updates. E-mail messages sent by the PM instruments shall be able to be received like any ordinary E-mail message.

.2 Ability to push historical logs through the Ethernet communication port to a remote server based on a user defined schedule or an event.

.3 Built in web pages in the PM instruments shall enable access to real-time values and basic power quality information using a current standard web browser. Basic configuration of the PM instruments shall also be able to be performed through the browser.

.9 The instruments shall automatically provide E-mail notifications for alarms and system status updates based on user configuration.

.10 The instrument shall have the ability to push historical logs through the Ethernet communication port to a remote server based on a user defined schedule or an event.

.11 The instrument shall provide an IEC 61850 compliant communications interface with the following features:

.1 Four (4) concurrent client connections.

.2 File based setup via FTP.

.3 Network time sync via NTP.

.4 Configurable reports, including, but not limited to, selectable dataset member and configurable dead band values.

.5 Support four (4) buffered reports and twenty (20) unbuffered reports (one (1) buffered and five (5) unbuffered per client).

.6 Map up to 16 analog and/or 16 digital calculated values for reporting in IEC 61850.

.14 I/O Options:

.1 The instrument shall be capable of having 27 digital inputs capable of one (1) millisecond timing resolution.

.2 The instrument shall have a Form A digital output that shall support pulse output operation for kWh total, kWh imported, kWh exported, kVARh total, kVARh imported, kVARh exported, and kVAh values.

.3 The instrument shall be capable of supporting up to four (4) field installable option modules to expand digital and analog I/O capabilities without need for additional control power sources.

.4 The instrument shall be capable of having up to eight (8) Form C relays which shall be isolated for up to 3200 volts AC (2 seconds), with reinforced isolation rated for 300 V. Overvoltage Category II. The relays shall support maximum current of eight (8) amperes continuous for 250VAC or five (5) amperes continuous for 24 volts DC for 20,000 cycles (resistive load)

.5 The instrument shall be capable of having up to sixteen (16) Analog inputs which shall be isolated and support inputs of four (4) to twenty (20) milliamps or zero (0) to twenty-four (24 volts) volts DC.

.6 The instrument shall be capable of having up to eight (8) Analog outputs of four (4) to twenty (20) milliamps or zero (0) to ten (10) volts DC range

.7 The instrument shall be capable of providing consumption and rate of usage information with user defined units of measure from pulse inputs to support metering of utilities such as water, air, gas, electricity and steam (WAGES).

.15 Display:

.1 The instrument shall have two (2) graphical color display options: an integral display and a remote mounted display.

.1 The panel mounted instrument shall have an integral backlit color graphical LCD display.

.2 The DIN rail mounted instrument shall have a remotely mounted 320 x 240 pixel backlit color graphical LCD display.

.3 The remote display shall be fully powered by and capable of communicating with the instrument.

.4 The remotely mounted display shall be able to be located up 100 meters from the instrument and be powered through a standard Cat5/5e unshielded

twisted pair cable.

.5 The displays shall be suitable for NEMA / UL type 12 (IP 54) enclosures.

.6 The remotely mounted display shall perform and function in the same manner as the integrated display.

.2 The instrument shall be capable of presenting all real-time parameters on the instrument's display.

.3 The instrument shall have a user-programmable custom display that shall be capable of displaying up to six (6) quantities on a single screen.

.4 The instrument shall be capable of displaying advanced graphical representations of metering information, including, but not limited to, harmonic histograms, phasor diagrams, and bar graphs.

.5 The instrument shall be able to display measurements in either IEC or IEEE formats.

.6 The PM instrument shall be able to present the following display screens:

.1 Numeric: Display one (1) parameter , one (1) parameter with timestamp, two (2) parameters, three (3) parameters, three (3) parameters with timestamp, or four (4) parameters at a time.

.2 Event Log: Display recent events written to the instrument's event log, including, but not limited to, diagnostic events.

.3 Nameplate: Display information in a tabular format (default nameplates shall show Owner, and meter details).

.4 Bar: Display up to three (3) real time numeric parameters along with their upper and lower extremes.

.5 Histogram: Display harmonics content in histogram format, including, but not limited to, 2nd to 63rd harmonic, THD (total, even, odd); ability to select and display magnitude and angle for individual harmonics

.6 Phasor: Display current and voltage phase information in a phasor diagram format, including tabular display of magnitudes and angles.

.7 Inputs and Outputs: Display digital input and output status, and analog input and output values.

.8 Alarm: Display a listing of active and historical alarms and events.

.16 Field Configuration: The instrument shall be configurable as follows:

.1 Provide voltage input scale, voltage mode (wye, delta, single-phase), current input scale, auxiliary input and output scales, and communications setup

parameters that shall be configurable from the instrument's display, or via web pages.

.2 Basic parameters described above, plus additional setpoint and data log setup parameters may be programmed via the communications port using a PC.

.3 Custom configuration of operating parameters shall be possible through a graphical, flexible programming language.

.4 The configuration of the device shall be done using programmable modules. The modules shall be linked together in an arbitrary manner to create arbitrary functionality. Some example module types include, but shall not be limited to, minimum, maximum, setpoint, digital input, and digital output.

.5 Programming through a computer shall be secured by user ID and password.

.6 Programming through the instrument's display shall be secured by password.

.7 Programmability shall be sectioned such that when the meter is sealed it shall still be configurable to an extent that does not affect the accumulation of revenue metering related data.

.17 Power Quality:

.1 Without the use of separate software, the instrument shall be able to measure power quality statistically in accordance with IEC 61000-4-30, Class S.

.4 Without using separate software, the PM instrument shall determine statistical indicators of power quality parameters that shall include, but shall not be limited to dips and swells, harmonics, and frequency, in accordance with the EN 50160 standard.

.5 Without the use of separate software, the instrument shall make available the statistical indicators of power quality provided by EN50160 on the instrument's display, or via communications protocols such as Modbus RTU, Modbus TCP/IP, or via web pages.

.6 The instrument shall be capable of monitoring the value of any statistical indicator of power quality (present, predicted, average, or otherwise manipulated value) with an absolute or relative setpoint. When such setpoint is exceeded, an alert shall be issued via E-mail or pager, or control shall be enabled via a local interface to mitigation equipment or control systems through relays and analog or digital outputs.

.7 The instrument shall support symmetrical components.

.18 Waveform Capture:

.1 The instrument shall be able to perform 256 samples per cycle waveform

recording.

.2 The instrument shall have twenty-one (21) programmable oscillographic waveform recorders. Each waveform recorder shall have the following features:

.1 Able to record a digitized representation of any phase voltage or current signal with no dead time between such recordings, and the ability to trigger multiple such recordings in continuous succession, and at different resolutions simultaneously.

.2 Enabled and triggered manually or through internal operating conditions, including, but not limited to, periodic timer or setpoint activity.

.3 Half-cycle triggering shall be supported for waveform recorders.

.4 The number of records (depth) of each data recorder, and the overflow conditions (stop-when-full or circular) shall be programmable.

.3 The instrument shall be able to record continuously to capture long duration waveforms. The duration of the waveform capture shall be limited by memory alone.

.4 The instrument shall be able to determine (with a level of confidence) whether a disturbance event occurred upstream or downstream of the meter (disturbance direction detection).

.19 High-Speed Data Logging:

.1 The instrument shall be capable of recording high-speed data captures containing one (1) cycle RMS data updated every half (1/2) cycle.

.2 The instrument shall be able to record seconds of high-speed data per data capture.

.3 The instrument shall be able to initiate a high-speed data capture based on a setpoint condition, user programmed logical condition, or command received via communication.

.4 The instrument shall be capable of capturing high-speed logs concurrently with a waveform capture.

.20 Advanced Features:

.1 The instrument firmware shall be field upgradeable.

.2 Onboard meter clock shall be able to be paced by a choice of sources, including, but not limited to, GPS, Ethernet network (NTP/SNTP), power line, or internal clock.

.3 The Instrument shall have multi-level security which shall support customized access for up to 16 users.

.4 The instrument shall have revenue security capabilities, including, but not limited to, the following:

.1 Password protected, no hardware lock, or

.2 Password protected and hardware locked, or

.3 The following data shall be protected from alteration when locked:

.1 kWh and kVARh (import, export, net, and total).

.2 kVAh (total).

.3 kW, kVAR, kVA demand (block and sliding window).

.4 kWh, kVARh, kVAh pulse outputs.

.5 The instrument shall have selective conformal coating of its internal circuitry for increased isolation and to increase robustness of installations exposed to high degrees of humidity.

.6 The instrument shall have provisions for creating periodic or non-periodic schedules for up to two (2) years. These schedules shall be used to perform the following functions:

.1 Time of use (TOU).

.2 Demand control.

.3 Load scheduling.

.4 Logging.

.5 Periodic resetting.

.7 The instrument shall provide a physical lock switch that will preserve all meteorological configuration values to ensure accurate and consistent energy metering.

.8 The instrument shall provide the ability to secure its meteorological lock switch as well as all voltage and current inputs with tamper detectable wire seals.

.9 The instrument shall have multiple tariffs and time-of-use (TOU) functionality to store and monitor up to twenty (20) years of seasonal rate schedules. The TOU feature shall allow four (4) seasons, four (4) day types (each one capable of at least eight (8) switch times, with a resolution of one (1) minute). The TOU feature shall support four (4) rate tariffs, and at least twelve (12) holidays per

year, and shall allow periodic self-read capability.

.10 The instrument shall support trending and forecasting of real-time data values with visualization via device generated web pages.

2.2 POWER MANAGEMENT SOFTWARE - GENERAL

.1 The Power Management Software (PMS) platform shall facilitate applications in the broad categories of (a) energy performance, (b) power availability, quality and reliability, and (c) sustainability performance. At a high level, the feature-set shall provide functions in:

.1 Real-time monitoring.

.2 Alarming and event management.

.3 Energy cost analysis.

.4 Energy, power, and sustainability data analytics and visualization.

.2 The software platform shall be certified for use as a part of an ISO50001 program and verifiably support compliance. In addition, the functionality shall support ongoing ISO50001 programs per the following areas of Section 4 of the ISO standard:

.1 Energy review.

.2 Energy baseline.

.3 Energy performance indicators.

.4 Monitoring, measurement, and analysis.

.5 Input to management review.

.3 The PMS shall verifiably support compliance with EN 16247-1 for energy audits.

.4 The PMS shall include Modular, licensable optional applications to expand the basic functionalities of the core platform.

2.3 POWER MANAGEMENT SOFTWARE – REAL TIME MONITORING

.1 The Power Management Software (PMS) shall provide a graphical monitoring and analysis application for power users that provide a rich set of tools for energy analysis, Power Quality analysis, power system monitoring and control.

.2 The graphical monitoring and analysis application shall be able to create a comprehensive set of linked hierarchical graphical diagrams showing all devices and their associated device specific diagrams in the power monitoring network.

.3 The graphical monitoring and analysis application shall support custom graphics/images and provide the ability to create graphical diagrams of the Power Monitoring system, including electrical one-line diagrams, facility maps, plan views, floor layouts, equipment representations, and mimic displays.

.4 The graphical monitoring and analysis application shall be capable of writing to device registers for applications such as resetting, triggering, toggling, switching, manual waveform capture, controlling remote devices and equipment, including breakers.

.5 The graphical monitoring and analysis application shall allow application and HMI design engineers to create custom diagrams with linkages to device registers even if the devices are offline / disabled.

.6 Web-enabled real-time tables: The system shall have the following capabilities for interactive side-by-side visualization of real-time measurements:

.1 Display a tabular view to compare device readings from multiple meters in the power monitoring network quickly.

.2 Permit users to create, modify, view and share table views through a browser without the need for a separate software application.

.3 Have built-in functions that allow users to easily and instantly filter out measurements when viewing a table.

.4 Support both physical and virtual devices defined in the system.

.5 Support exporting real time tabular data into Excel formats.

.6 Power monitoring trending: The PMS shall include graphical charts for real-time trending of power usage (kW, Volt, Amp, and kWh) or any measurement supported by metered equipment such as generators and MV/LV switchgear. These trends shall include the capability to:

.1 Trend up to 14 measurements on the same chart (limit may be increased if desired).

.2 Customize attributes such as color, line thickness, overlays, display name, and display units for each data series.

.3 View the trend using an auto-scaling or manual chart axis.

.4 Adjust the desired time viewing window for the trend.

.5 Inspect the trend by zooming and panning to focus in on key areas of the trend.

.6 Provide drill-down detail for the highlighted trend data point to help identify root causes of concern.

.7 Trend measurements with different units on the same chart using two different axes.

.8 Provide calculated values of minimum, maximum, and average values for a trend.

.9 Configure a target threshold line for comparison against actual measurements.

.10 Configure up to two target bands with visual indicators to identify when a measurement is outside specified limits.

.11 Display real-time data and/or historical data per data series, with optional back-filling of the real-time data using historical data.

.12 Export trend data to .CSV/Excel format.

.13 Access trend data from a web browser or mobile environment.

.14 Save specified trends in a library for later use.

.15 Share trends with other users or restrict use.

.16 Simultaneously view multiple trend charts, or alternatively maximize a selected trend to display it in full screen mode.

2.4 POWER MANAGEMENT SOFTWARE – ALARM AND EVENT ANALYSIS AND NOTIFICATION

.1 The Power Management Software (PMS) shall provide alarm and event annunciation features that include the following:

.1 An alarm viewer that provides a summary of the active alarms shall be provided. The viewer shall:

.1 Be visible in any screen when logged into the web interface of the system.

.2 Display the total number of unacknowledged alarms, and the breakdown of how many of those alarms are high priority, medium priority and low priority.

.3 Provide an audible alarm and a simple means for muting the alarm.

.4 Allow a simple mechanism to acknowledge alarms for users with appropriate user privileges.

.5 Allow a mechanism to sort and group alarms.

.6 Allow a mechanism to set configurable alarm thresholds, for example, high, medium, and low.

.7 Allow a mechanism to create user defined alarm views that fit user defined criteria.

.8 Provide an active alarms view to show alarms currently in the active state.

.9 Indicate if a given power quality alarm has an associated waveform capture. It will also provide a link that will open the graphical homepage screen for the device that triggered the alarm.

.2 The PMS shall provide an alarm notification system.

.1 The alarm evaluation and notification system shall ensure that appropriate staff members are notified of power system events. The system shall collect data, evaluate alarm conditions, and annunciate the alarms to specified users through email or SMS text messages.

.2 The alarm evaluation and notification system shall include:

.1 An alarm evaluation engine.

.2 An alarm notification/annunciation engine that supports annunciation through email and SMS text message.

.3 Flexible alarm scheduling capabilities.

.4 Web-based configuration tools for notification configuration, log viewing, and filtering.

.5 The ability to control alarm flooding by intelligent aggregation through alarm filtering and consolidation.

.6 Message delivery mechanisms such as:

.1 Electronic mail (Email)

.2 Text messaging for cell phones (GSM Modem)

.3 Short messaging peer-to-peer protocol (SMPP)

.4 Simple Network Paging Protocol (SNPP)

.5 Simple Network Management Protocol (SNMP)

.6 Traditional dial-up Pager (TAP)

2.5 POWER MANAGEMENT SOFTWARE – DATA ANALYTICS AND VISUALIZATION

.1 The Power Management Software (PMS) shall provide web-enabled dashboards.

.1 The system shall have a web client interface that presents interactive auto-updating dashboard views that may contain water, air, gas, electric, and steam (WAGES) energy summary data, historical data trends, images, and content from any accessible URL address.

.2 Users shall be able to create, modify, view, and share their dashboards (including graphics, labels, scaling, measurements, date ranges, etc.) using only a browser and without a separate software application.

.3 Users shall be able to create with configurable drag and drop gadgets to show the following data:

.1 Images from any web-based content

.2 Energy consumption

.3 Energy cost

.4 Energy comparison

.5 Energy savings

.6 Emissions

.7 Trends

.4 The system shall facilitate kiosk displays by assigning individual dashboards to slideshows to run in unattended mode, scrolling through designated dashboards at a configurable time interval.

.5 The system shall permit users to create, save, and share an unlimited number of dashboards and slideshows.

.2 The system shall provide a web-enabled reporting platform.

.1 The system shall provide a web-enabled reporting tool to view historical data in pre-formatted or user-defined report templates.
.2 The system shall support reporting on all supported physical devices and virtual (or calculated) meters as defined in the device hierarchy.
.3 Users shall be able to create, modify, view and share their reports in the web reports interface.
.4 The reporting tool shall provide standard pre-formatted report templates for:

.1 Energy cost

.2 Load profile

.3 System-wide interactive power quality with CBEMA/ITIC evaluation.

.4 EN50160 compliance

.5 EN50160 Edition 4 compliance

.6 Harmonics compliance (IEEE519-1992)

.7 IEC61000-4-30

.8 100 ms. power quality

.9 Energy Usage: period-over-period, by shift, single and multi-device comparison

.10 Tabular, trend and multi-trend

.11 Alarm and event history

.12 System configuration

.13 Hourly usage report

.14 Single and multi-device usage reports

.5 The reporting tool shall support exporting to the following output formats: .HTML, .PDF, .TIFF, .Excel, and .XML.

.6 The reporting tool shall be capable of subscriptions to facilitate automatic distribution of reports according to a configurable schedule by saving to network locations, email, or print.

.7 The system shall support the ability to trigger the generation and delivery of a pre-configured report based on pre-specified event criteria. The system shall be capable of configuring event monitoring detection filters criteria.

.8 The reporting tool shall have a framework to support:

.1 Simple customizations to reports such as colors, image inclusions, turning report sections on/off, and logo changes without programming.

.2 Additional more complex report customization through a programming kit.

.9 The reporting tool shall be capable of subscriptions to facilitate automatic distribution of reports according to a configurable schedule by saving to network locations, email, or print.

2.6 POWER MANAGEMENT SOFTWARE – TECHNICAL INFRASTRUCTURE

.1 The Power Management Software (PMS) shall provide the following operating system and browser support:

.1 All associated core components of the PMS software operate as Windows operating system services.

.2 The web client interface shall support multiple browsers.

.2 The PMS shall provide the following data management support:

.1 Microsoft SQL Server database engine per supported configurations.

.2 All network configuration settings relating to device routing and addressing, communication gateways, distributed I/O servers, and load-distributing application servers shall be stored in the PMS databases.

.3 Archiving, trimming, and on-demand or scheduled capabilities shall be supported.

.4 The capability to view historical data from archived databases shall be included.

.5 The PMS shall be capable of retrieving data from devices in the monitoring network and provide the following abilities:

.1 Interrogate and download logs of interval, waveform, and alarm data stored onboard metering devices and related circuit breaker trip units.

.2 Interrogate and download logs of interval data generated by the software system (software-based logging).

.3 Interrogate and download logs of alarm and event data generated by the software system (software-based alarming).

.4 Automatically re-arm the waveform recorders upon upload of information.

.5 Detect unknown measurement quantities provided by devices in the network, and automatically generate appropriate database references for those quantities without user intervention.

.3 The PMS system shall include an Administrative interface with the following management functions:

.1 Security: administer groups and user accounts with role based privileges.

.2 Database: initiate backup, archiving, and trimming tasks.

.3 Devices: Add or rename devices, map measurements, and communication settings.

.4 Connections: Configure connection schedules and manage modem connections.

.5 Events: View and manage software system events.

.4 The PMS system shall function without disruptions (including communications, logging, and alarming) and shall remain online during all system administration functions such as adding, modifying, or removing devices in the system;

creating, modifying, or removing graphical diagrams, dashboards, tables, and reports; creating, modifying, or removing application logic programs in the application logic engine.

.5 The PMS shall support the following device support and management features:

.1 The system shall include factory-tested native support for at least 75 electrical distribution devices (energy and power meters, protection relays, circuit breakers, PLCs, etc.).

.2 Native comprehensive device support shall include:

.1 Pre-engineered, interactive graphical display screens for viewing and analyzing real-time and historical device data.

.2 All registers pre-mapped to standard measurement names without additional mapping of internal device registers.

.3 Automatic upload of time-stamped onboard data logs, event strings, and waveform captures without additional configuration.

.4 Automatic time synchronization.

.3 The system shall support integration with other third party intelligent electronic devices (IEDs) not directly supported natively.

.4 The system shall support logical device definitions for user-friendly device and measurement names for inputs/outputs or channels on devices that represent a downstream device (in the case of PLCs and auxiliary inputs) or an individual circuit (in the case of multi-circuit devices). Bulk-import capability to create large numbers of logical devices without manual single-device configuration shall be supported.

.5 The system shall support the concept of hierarchies to organize devices structurally into various levels. Examples include Tenants/Racks/Circuits, PDUs/RPPs/Panels, or Buildings/Floors/Rooms. The system shall include the ability to:

.1 Aggregate data at any location in the hierarchy.

.2 Track hierarchy configuration changes over time.

.3 Allow administrators to update names in a given hierarchy at any time (even in the past) to ensure accurate reporting of associated data points (for example, report on energy consumption for a Tenant who has re-located, expanded, added, or removed circuits during the billing period).

.4 Export the hierarchy structure to Excel format.

.5 Bulk-import capability to create and edit large hierarchies without manual per-device setup.

.6 The system shall support extensibility in the following ways:

.1 Provide a graphical, object-oriented application logic engine to create system-wide logic modules with arithmetic, XML data import, PC-based alarming, and logging capabilities.

.2 The application logic engine shall have a comprehensive set of functions to create customized applications programs for functions such as weather or real-time price import, KPI calculations, energy units conversion, data aggregation, data normalization, data comparison, power loss calculations, power factor control, load shedding, etc.

.7 The PMS system shall support system integration in the following ways:

.1 Device-level Modbus interoperability.

.1 The system shall be capable of supporting Modbus communicating devices and be capable of functioning as a Modbus master to read/write registers in Modbus devices for monitoring and control applications.

.2 The system shall be capable of Modbus device definition (device drivers) creation to enable integration of third-party Modbus protocol devices.

.2 System-level OPC interoperability.

.1 The system shall be OPC DA 2.0.1 compliant (as per the OPC Foundation Compliance Testing process) for OPC Server and OPC Client data sharing applications amongst OPC compliant systems.

.2 The system shall provide default OPC Server tag mappings for all natively supported device types without the need to select, configure, or program the mapping of device registers to OPC tags.

.3 The system shall provide a flexible means to add or change OPC mappings and shall support the ability to add custom measurements.

.3 Data-level interoperability.

.1 The system shall support the Extract, Transform, and Load (ETL) data log file transfer mechanism to import and export data log files to integrate functions such as manual data entry, offline device data import, push data to the cloud, or to other systems.

.2 The system shall include a mapping application for specifying log data file import-export mappings and import schedules to facilitate import/export in formats such as .CSV, .XML, etc.

.4 Web application level integration.

.1 The system shall include:

.1 The capability to integrate other web applications into its web

interface through the use of pluggable web content widgets.

.2 The capability to supply content such as dashboards, reports, trends and diagrams to other external web applications through addressable URLs.

.5 Web services integration.

.1 The system shall include web services integration capabilities for machine-to-machine interactions with other application software systems with the following characteristics:

.1 Based on SOAP (Simple Object Access Protocol) protocol specification.

.2 Provide a Web Services Description Language (WSDL), machine-readable description.

.3 Allow access to real-time, historical (i.e., time stamped), and alarm/event type data.

.4 Provide the ability to acknowledge alarms by authenticated and authorized clients.

.5 Provide digest authentication functionality.

.6 Provide the ability to be enabled or disabled.

.8 The PMS shall support system configuration and advanced analysis tools in the following ways:

.1 The system shall include a monitoring and analysis application with a rich set of power tools for water, air, gas, electric, and steam (WAGES) energy analysis, power quality analysis, power system monitoring and control, and include the following capabilities:

.1 Auto-diagram creation capability to create a comprehensive set of linked hierarchical graphical diagrams showing devices and their associated device specific diagrams in the network.

.2 Ability to import custom graphics or images to create electrical one-line diagrams, facility maps, plan views, floor layouts, equipment representations, and mimic displays.

.3 Support for power quality analysis.

.1 Plot PQ events on an ITIC/CBMEA curve or SEMI F47 curve.

.2 Manual waveform capture.

.3 Visualization or analysis tools for sinusoidal electrical waveforms including waveform overlay, zooming, and calculations for RMS, peak, delta, harmonics spectrum bar charts, and phasor diagrams.

.2 Ability to write to device registers for applications such as resetting, triggering, toggling, switching, manual waveform capture, controlling remote devices and equipment, including breakers.

.3 Ability to develop custom graphics screens and application logic programs with the devices being offline or disabled to allow for project development in disconnected mode.

.9 The system communications infrastructure shall support the following:

.1 Multiple communications network topologies including Ethernet/TCP, serial RS-485/RS-232, and Modem dial-up connections.

.2 The capability to provide time-synchronization signals over an Ethernet network with 16ms accuracy or better.

.3 The capability to communicate simultaneously with multiple devices, including devices on different physical communications channels.

.4 Scalability to greater than a thousand devices.

.5 The ability to automatically retrieve logged data (interval data, event data, and waveform data) from natively supported devices without additional configuration.

.6 The ability to accept or reject duplicate data entries into the database.

.7 The ability to schedule connection times for specific time-periods to conserve bandwidth.

.8 The ability to automatically disconnect modem connections when all device data is database-synchronized (used to minimize long distance phone charges).

.9 Support for modem pooling and assignment of communication sites to specific modems for communications optimization.

2.7 MISCELLANEOUS COMPONENTS

.1 System Switches:

.1 8 Gigabit Ethernet ports.

.2 PoE support up to 124 watts

.3 Standard of Acceptance: Cisco Model 2960-cx

.4 Mount on wall of electrical room.

PART 3 EXECUTION

3.1 EXAMINATION

.1 Verification of Conditions: Examine areas and conditions under which the work is to be installed, and notify the Engineer in writing of any conditions detrimental to the proper and timely completion of the work. Do not proceed with the work until unsatisfactory conditions have been corrected.

.1 Beginning of the work shall indicate acceptance of the areas and conditions as satisfactory by the Contractor.

3.2 INSTALLATION

.1 Install electrical power monitoring and control equipment in accordance with reviewed product data, final shop drawings, manufacturer's written instructions and recommendations, and as indicated on the Drawings.

.2 Conduct tests in accordance with Section 26 05 00 – Common Work results – Electrical in accordance with manufacturer's recommendations.

.3 Perform simulated operation tests with metering, disconnected from permanent signal and other electrical sources.

.4 Verify correctness of connections, polarities of metering, disconnected from permanent signal and other electrical sources.

.5 Perform tests to obtain correct calibration.

.6 Do not dismantle meters and instruments.

.7 Install system monitors software on Owner supplied PC and confirm system is reading on meter information properly.

.8 All power supply and communications wiring connections must be performed in accordance with the guidelines set out in the product documentation.

.9 All current and voltage sensing connections to Compact Power and Energy Meters must be made using appropriately rated CT shorting blocks and PTs.

3.3 DEMONSTRATION

.1 Provide the services of a factory-authorized service representative of the manufacturer to provide start-up service and to demonstrate and train the Owner's personnel.

.1 Test and adjust controls and safeties. Replace damaged or malfunctioning controls and equipment.

.2 Train the Owner's maintenance personnel on procedures and schedules related to start-up and shutdown, troubleshooting, servicing, and preventive maintenance.

.3 Review data in operation and maintenance manuals with the Owner's personnel.

.4 Schedule training with the Owner, through the Departmental Representative, with at least seven day's advanced notice.

3.4 PROTECTION

.1 Provide final protection and maintain conditions in a manner acceptable to the Installer, that shall ensure that the electrical power monitoring and control equipment shall be without damage at time of Substantial Completion.

3.5 POWER MANAGEMENT SOFTWARE—TECHNICAL SUPPORT SERVICE PLAN

.1 The software vendor shall maintain global technical support centers, with sufficiently trained engineers to provide support escalations from the contractor, and efficient management of software faults/bugs.

.2 All Technical support cases should be tracked to ensure alignment within the context of a defined Service Level Agreement.

.3 The contractor shall the contractor shall furnish a support service plan, which provides the user of the Power Management Software with priority access to technical support.

.4 The support service plan shall have the endorsement of the software vendor, providing a priority escalation channel for the resolution of technical enquiries.

.5 The support service plan shall include version upgrade subscription (software assurance), providing access to all new releases for the duration of the Service Plan.

.6 The support service plan shall include:

.1 On-Demand Technical Support

.1 Priority access to a support engineer

.2 Live telephone support, response within four hours.

.3 Email, response within four hours.

.4 Priority escalation channel to Expert level resources for critical cases.

.5 Digital tools for remote connection/troubleshooting of the system.

.2 Meter System Validation:

.1 The software vendor shall possess tools to provide ongoing reporting on the validation of the metering equipment, confirming the data is accurate and repeatable.

.2 Validation reports shall be provided on required intervals to satisfy reporting requirements of ISO50001:4.6.1 (Monitoring, measurement and analysis).

.3 Proactive Maintenance Support:

.1 Scheduled remote maintenance activity related to the health of the power monitoring software and related system.

.2 Validation of system operation including: communication status of field devices, system event log review, database status (size and job logs), and Service operations of host server.

.3 Verification of system operation against user defined thresholds.

.4 Documented reporting of suggested maintenance routine.

.7 Support service plan to be included in the tendered project scope/price for a duration of 36 months after substantial completion.

END OF SECTION