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Report on Consensus and Non-Consensus Smart Grid Metrics

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I.

INTRODUCTION

The Commission's Decision Adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla), Chapter 327, Statutes of 2009 (D.10-06-047) sets out the requirements for Smart Grid Deployment Plans (Deployment Plans) to be submitted by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (together, the IOUs). To help to evaluate the development of the smart grid in California, the Commission is also in the process of defining consensus metrics that will be included in these Deployment Plans. At the request of Commission staff, the IOUs have prepared this Report on Consensus and Non-Consensus Smart Grid Metrics. The IOUs have consulted with Environmental Defense Fund (EDF) on the environmental metrics proposed for further study and other sections, as appropriate.

These metrics are intended to measure some aspects of smart grid deployment, but will not be a substitute for the other requirements for Deployment Plans as set forth in D.10-06-047 and Senate Bill (SB) 17. This report contains a list of consensus metrics that the IOUs should use to help guide the first Deployment Plans to be filed by July 1, 2011. The Commission may also use these consensus metrics to help inform the initial report that it must file with the California Legislature pursuant to the requirements of SB 17.

While the consensus metrics that are ultimately adopted in this phase of the smart grid proceeding will be included in the IOUs' first Deployment Plans, these metrics may change to be more suitable for future Deployment Plans and updates. The exact nature of smart grid investments, projects and programs will be further defined in the future (and may in fact differ from current expectations). As such, future developments will require the Commission, the IOUs and other stakeholders to revisit the consensus metrics in this document..

1. Organization of the Report

As a threshold matter, the consensus metrics in this report reflect the efforts of the IOUs to determine what information is or could be feasible to collect by IOUs in the near term. This report also sets out a list of specific metrics or topics related to smart grid progress and performance that require further consideration before adoption. EDF contributed substantially to these areas for further consideration.

In addition, because SB 17 and the Commission define the term "smart grid" to include programs, projects, products and services that are directly utilized by utility customers as well as by utilities to serve those customers, the consensus metrics in this report significantly overlap with data that is already collected or reported under utility programs and projects governed by other CPUC proceedings and statutes, such as Advanced Metering Infrastructure, Demand Response, Renewable Portfolio Standard, Long Term Procurement Plan, Alternative Fuel Vehicles and General Rate Case proceedings.

The report is organized as follows:

- Section II – This section proposes guidelines for continued evaluation of smart grid metrics beyond the consensus list proposed in this document.
- Section III – This section contains a list of consensus metrics that the IOUs are able to collect today. This list is based on and responds to the Post-Workshop Discussion Draft (the Post-Workshop Draft) released by Commission Staff on September 3, 2010 and a series of public technical webinar sessions held from the week of October 4 through the week of October 11.
- Section IV – Consistent with the Post-Workshop Draft, the IOUs have also identified several areas where consensus has not been met following the public technical working sessions or where further research is still required to develop final metrics. Those areas are similar to those identified in the Post-Workshop Draft and include additional subject areas discussed in public webinar sessions. EDF contributed to the discussion of environmental metrics in this section.

2. Purpose and Use of Consensus Metrics

The IOUs believe that the consensus metrics proposed in Section III of this document serve two primary functions. First, the metrics will be an initial, preliminary source of information available to the Commission for use in meeting its obligation under Section 8367 of the Public Utilities Code to provide an initial annual report to the California Legislature about smart grid deployments in California.

Second, the consensus metrics will provide a useful starting point in initial development of the metrics section included in the IOUs' Smart Grid Deployment Plans. However, these consensus metrics should be considered preliminary and for initial guidance only. Once the IOUs' deployment plans are filed and approved by the Commission, and the future direction of smart grid investments, programs and projects becomes clearer, stakeholders should re-evaluate these metrics to ensure they are relevant and useful in measuring smart grid progress. Stakeholders may also add to or subtract from the list as the Commission, IOUs and other stakeholders enhance their ability to evaluate and apply certain concepts, such as the tracking of environmental benefits and other subject areas discussed in Section IV.

a) Consensus Metrics as a Tool for the Commission's Reporting Requirements under §8367

Public Utilities Code Section 8367 requires the Commission, by January 1, 2011 and by January 1 each year thereafter, to "report to the Governor and the Legislature on the commission's recommendations for a smart grid, the plans and deployment of smart grid technologies by the state's electrical corporations, and the costs and benefits to ratepayers."[1] The quantitative and qualitative information that each IOU will include in its Smart Grid Deployment Plan by July 1, 2011 should provide the Commission with the bulk of the information it will need to

[1] Pub. Util. Code § 8367

satisfy this reporting obligation. Metrics may complement this information in certain subject areas. Section III of this document provides analysis that links each consensus metric to the applicable policy goal from SB 17.

The Commission is also required under other laws, regulations and programs to report on a number of issues that are not included in the consensus smart grid metrics – including greenhouse gas emissions, the Renewable Portfolio Standard, energy efficiency, and the overall impact of energy on the environment (e.g. air quality and water conservation).[2] Additionally, while all of the consensus metrics proposed in this document relate generally to data collected or capable of being collected on certain utility operations and programs, such data may or may not be directly relevant to actual smart grid performance, even where included specifically to address the reporting requirements of Section 8367. For these reasons, the consensus metrics recommended here will need to be reviewed and updated as the quantitative and qualitative criteria and standards for the smart grid evolves over the next months and years.

b) Consensus Metrics as a Starting Point for Developing The Initial Smart Grid Deployment Plans, including Methods for Measuring Performance and Progress under Those Plans

The term "smart grid" covers a wide range of goals, programs and technologies that are in their formative phase and IOUs expect to gain a better understanding of smart grid capabilities and goals in upcoming years. For example, both SCE and PG&E will begin federally sponsored Smart Grid Demonstration and Investment Grant Projects in 2011. These projects will not begin yielding data for several years and the reported data will inform decisions in subsequent years. As such, efforts to develop smart grid metrics at this time are by

[2] SB 17, §8366

definition preliminary for many smart grid subject areas. Instead, quantitatively and qualitatively reporting preliminary expectations and periodic outcomes for certain technologies like energy storage and advanced transmission and distribution automation – as IOUs will do in Smart Grid Deployment Plans – may be the most effective means for evaluating these technologies in the near term.

On the other hand, all three IOUs are on schedule to complete the deployment of their advanced metering infrastructure (AMI) in the 2012 time frame. As a result, smart grid metrics that relate to deployment of AMI will be largely irrelevant by that time because the extent of AMI deployment will be part of the smart grid baseline, not a useful metric to report on an ongoing basis. However, metrics that relate to the benefits of AMI devices, including consumer interaction and load management, could continue to be relevant.

At the same time, D.10-06-047 set overarching goals for utilities to meet through their smart grid deployments – from enhancing customer choices and electricity markets with demand response and distributed generation to reducing the overall environmental footprint of electricity generating resources.[3] We recognize that these are long-term goals, and that big-picture environmental metrics may be difficult to define at this time. However, we note that these issues – which include greenhouse gas and criteria air pollutant emissions – are important in developing and evaluating the deployment plans and subsequent investments in accordance with the requirements of D.10-06-047 and SB 17.

Finally, while identifying and defining the right metrics is important, building the appropriate analytical framework to evaluate those metrics is equally critical. The current process of developing metrics in the context of the Smart Grid OIR has focused primarily on choosing and defining metrics based on data that IOUs currently collect in other CPUC programs or are capable of collecting

[3] D.10-06-047, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/119902.pdf

without significant additional expense. However, we recognize that the Commission, IOUs and stakeholders still need to spend significant time discussing how those metrics, once gathered, relate to, or have a unique causal relationship with, specific smart grid goals and policies. For example, assessing SAIDI, SAIFI and MAIFI as measures of reliability will require that future trends in these metrics be compared to an historical baseline. Similarly, properly attributing changes in these metrics to smart grid performance over time will require both devising an accurate measure of smart grid deployment (a challenge at this early stage) to correlate against changes in these outcome metrics, and controlling for other factors – like weather or infrastructure aging or changes in loads or demand – that may distort or provide misleading or inaccurate information regarding the benefits and costs of smart grid initiatives in a given year.

To address the challenges of developing metrics for early stage technologies and interpreting them once gathered, this document includes a discussion of non-consensus metrics and areas for further consideration in Section IV. That section, drawing in many cases on the content of the Post-Workshop Draft or the public technical working sessions of October 8 through October 15, describes several subject areas that require further deliberation before metrics can be developed. It also identifies issues to consider for each of those subject areas. Contributors to this report hope that by presenting both a list of presently viable consensus metrics, as well as a list of non-consensus metrics requiring further analysis and development, this document will satisfy the Commission's reporting obligations in the near term and lay the ground work for effective metrics development going forward.

c) Comments on Reporting Procedure

This report has intentionally omitted discussion of the baseline and reporting periods for the consensus metrics proposed in Section III. This is an important parameter of the metrics reporting process, and more direction is needed from the Commission about the intended reporting venue and period for each of these metrics. D.10-06-047 requires that metrics be reported as of June 30 of each year, but the first reporting of these metrics will be in the Smart Grid Deployment Plans to be submitted by July 1, 2011. A June 30 reporting date for these initial metric reports is therefore illogical. The IOUs propose that metrics reported in the first Smart Grid Deployment Plans be reported as of December 31, 2010 or consistent with existing reporting mechanisms as appropriate.

We would also request that the Commission revisit its decision to use a June 30 annualized date for metrics going forward. The IOUs are currently investigating whether any incremental expense would be incurred by reporting a metric as of June 30, if that is not the existing reporting date for a given piece of data or if a calendar year period is more relevant and feasible. IOUs will provide further data about existing reporting schedules on a metric-by-metric basis and they request flexibility from the Commission in setting reporting periods.

II.

PROCESS PROPOSAL RELATED TO NON-CONSENUS METRICS AND AREAS IDENTIFIED FOR FURTHER CONSIDERATION

After the public technical working sessions of October 8 through October 15, certain metrics and topics have been identified as being either non-consensus or for "further consideration" – meaning that, though they are important benefits or capabilities of the smart grid, the IOUs have determined that they are not feasible to measure or attribute reliably to smart grid deployment at this time. These areas, detailed in Section IV, include Advanced Automation and Measurement Technologies, Environmental Metrics, Customer/AMI, PEVs, Cyber Security and Energy Storage. As discussed in the webinar on October 15, 2010, over the upcoming months, EDF, PG&E, and SDG&E will work together to develop environmental metrics for consideration for inclusion in the July 2011 deployment plans.

Additionally, as IOUs make progress in defining the exact nature of their smart grid investments – in Smart Grid Deployment Plans and General Rate Cases or other applications – the Commission should direct further metric development in these areas. We ask that the Commission hold a workshop and/or return to the current informal process (with notice to parties) as more information about smart grid deployments emerges. As IOUs intend to report the consensus metrics proposed in this document in their first Smart Grid Deployment Plans to be submitted by July 1, 2011, we suggest that the Commission begin the process of re-evaluating the current list in advance of the October 2012 deadline for the first annual report following the initial Deployment Plan submission. During this process, the IOUs can share additional information with parties pertaining to data that can be collected and specific planned deployments. These workshops can help to identify specific metrics as they become feasible and further guide the IOUs as they make smart grid investments, while deployment plans will give parties greater clarity on evaluative data available.

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III.

LIST OF CONSENSUS METRICS

Below is the list of consensus metrics that the IOUs propose for preliminary use in development of initial Smart Grid Deployment Plans as of the conclusion of the series of technical working group discussions. Areas that may not be covered by the list below that require further consideration before formally adopting metrics are addressed in Section IV.

A. Customer / AMI Metrics

1. Number of advanced meter malfunctions where customer electric service is disrupted

CPUC Staff Recommended Policy Goal Supported:	To measure improvements in grid reliability at the customer level and to measure the ability of the smart grid to avoid and identify outages. § 8360(a)
Definitions:	**Advanced Meter:** A meter that measures interval data and enables two-way communication between utilities and the meters located at customer premises. Includes AMI meters, or smart meters approved by the CPUC under the AMI deployment programs. Excludes RTEM and legacy meters (electro-mechanical and non-AMI) **Meter Malfunction**: Malfunction that caused a smart meter to become inoperable. Includes AMI meters with integrated service switch. Excludes AMI meters without service switch, RTEM, and legacy meters. **Service Disruption**: Outages caused by faulty AMI meters. Excludes outages caused by service panel or weather head issues or house fires, outages caused by AMI meters without service switch, RTEM or legacy meters, AMI meters installed with service switch open by mistake, and AMI meter replacements.
Applicable Data Sources Already Reported:	SDG&E: Smart Meter Program Quarterly Reports PG&E: Not currently reported

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	SCE: Not currently reported
Reporting Start Date:	July 2011 through AMI deployment completion date (IOUs expect meter malfunctions that disrupt electric service to be insignificant upon completion of AMI deployment)
Comments and Explanation of Changes:	Includes only advanced meter malfunctions that result in loss of power, which may be insignificant and not relevant to overall effectiveness of smart meter performance for purposes of energy and outage management, especially following completion of deployment. Does not include malfunctions that do not result in service disruptions (e.g., usage measurement malfunctions).

2. Load impact from smart grid-enabled, utility administered demand response (DR) programs (in total and by customer class, to the extent available)

CPUC Staff Recommended Policy Goal Supported:	To measure the achievement of energy efficiency and demand response goals as listed in § 454.5 and §454.55 -- § 8366(d)
Definitions:	**Smart Grid-Enabled DR Programs:** DR programs that rely upon two-way communications, including meters that allow for HAN or internet enabled access of interval meter data and/or notifications Includes: PTR (CARE and non-CARE DR impacts, to the extent available), CPP, PCT, TOU, A/C Cycling, Excludes: Energy information tools such as IHDs, web presentment, budget assistant, and third party data access. **Load Impact**: DR MW reductions will be determined, measured by ex post load impact analysis, coincident with each utility's system peak (adjusted to account for the DR load reduction). **Customer Class**: A group of customers with similar characteristics that have similar rate schedules or structures for electric service. For the purposes of this metric, customer classes shall be defined by existing tariff structures. For each utility, the customer classes shall be as follows: *for SCE:* (1) Residential, (2) C&I < 200 kW, (3) C&I > 200 kW, (4) Agriculture and Pumping. *for PG&E:* (1) Residential, (2) non-Residential < 200 kW, (3) non-Residential > 200 kW, (4) Other. *for SDG&E*: (1) Residential, (2) C&I < 500 kW, (3) C&I > 500 kW, (4) Other.
Applicable Data Sources Already Reported:	PG&E and SCE: AMI Annual Energy Savings Report PG&E, SCE, and SDG&E: Annual demand response load impact reports
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	This metric will not measure achievement of energy efficiency goals or energy conservation. The metric was changed from "AMI enabled" to "Smart Grid enabled" to better accommodate all future DR programs that may be enabled by the smart grid, not just those enabled by AMI.

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3. Percentage of demand response enabled by AutoDR (Automated Demand Response) by individual DR impact program

CPUC Staff Recommended Policy Goal Supported:	The smart grid seeks to promote the use of demand response and is tied to §8366(d) and §8360(d).
Definitions:	**AutoDR**: Demand Response that is enabled through a variety of technologies that are automatically activated upon receiving a DR event or price trigger from the DR provider. Examples of technologies include energy management systems and software, wired and wireless controls, thermostats and enabled appliances. For purposes of this metric, AutoDR is limited to utility administered programs for business customers. **Percentage**: Verified kW load reductions (engineering analysis) available for DR, divided by total DR portfolio kW. **Enabled:** Event triggered DR programs
Applicable Data Sources Already Reported:	Annual Load Impact Report
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	None

4. The number of utility-owned advanced meters with consumer devices with Home Area Network (HAN) or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE, and climate zone, to extent available)

CPUC Staff Recommended Policy Goal Supported:	Some of the benefits of the smart grid are linked to customer usage of its capabilities, and this metric seeks to measure customer use of smart grid and advanced meter capabilities. Tied to §8360(f), (h) (i) and §8366(a).
Definitions:	<u>**Consumer Devices**</u>: Smart grid-enabled tools used by consumers that communicate with the utility-owned meter or other gateway. Includes HAN devices (e.g., In-Home Displays, Programmable Communicating Thermostats, PC USB devices); devices owned by the consumer, utility or third party; devices that are included as part of a utility program; devices that are not included in part of a utility program. Excludes PC-software applications, internet portal applications (e.g., bill forecast, bill-to-date, SCE's budget assistant tool, PG&E/SDG&E's tier alerts, presentment of interval data), plug-in electric vehicles (PEV), energy efficiency (EE) and solar-related devices, and A/C cycling devices. <u>**Register**</u>: The act or process of pairing a consumer device to a HAN. Used to ensure that devices are communicating with the intended recipient (e.g., AMI meter). Registering a device is a control to prevent cyber security issues. <u>Considerations:</u> • All devices that communicate with the utility's HAN will need to be registered with the utility, regardless of where or how the device was purchased, or the ownership of such device. In addition, all devices that are part of a utility program will need to be registered with the utility. • This metric is likely a cumulative metric and will therefore increase over time. That is, once a meter has a device registered to it, the customer is unlikely to de-register the device, even if the device is no longer in use. <u>**Customer Class**</u>**:** Same definition as Metric 4. A group of customers with similar characteristics that have similar rate schedules or structures for electric service. For the purposes of this metric, customer classes shall be: *for SCE:* (1) Residential, (2) C&I < 200 kW, (3) C&I > 200 kW, (4)

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	Agriculture and Pumping. *for PG&E:* (1) Residential, (2) non-Residential < 200 kW, (3) non-Residential > 200 kW, (4) Other. *for SDG&E*: (1) Residential, (2) C&I < 500 kW, (3) C&I > 500 kW, (4) Other. **CARE**: California Alternate Rates for Energy (CARE) program. CARE offers income-qualified customers a discount of 20% or more off their monthly electric bill. **Climate Zone**: An area that is distinguished by its climate so that utility customers within the territory have similar heating and cooling needs.
Applicable Data Sources Already Reported:	None
Reporting Start Date:	Dependent on wide commercial availability of utility HAN and comparable consumer devices, which is expected no earlier than 2012 to 2013
Comments and Explanation of Changes:	Consumer device capabilities have been postponed due to a delay in the adoption of the Smart Energy Profile 2.0 HAN national standard and uncertainty regarding commercial availability beyond that date. Currently, the IOUs expect this capability may become available in the 2012 to 2013 timeframe or later. Thus, this metric will be relevant and reported as part of future smart grid Annual Reports. This metric will only include devices that are registered with the utility's HAN. Devices that connected with a different gateway are excluded. Also, devices that are connected to an energy management system, but not registered with the utility, are excluded (even though the energy management system may be registered with the utility). Change to the metric wording requested since all devices will need to be registered with the utility. A commissioned or enrolled device will be a subset of the registered devices. Utilities will be registering[4] devices, which involves authentication and authorizing a HAN device to exchange secure information with the HAN. However, utilities will not be commissioning[5] devices, as commissioning a device allows for an exchange of a limited amount of information, but may not provide appropriate cyber security. Program

[4] Registration is defined as "The process by which a Commissioned HAN device is authorized to communicate on a logical network. This involves the exchange of security credentials… The registration process is required for the exchange of secure information…" Definition per the UCAIug Home Area Network System Requirements Specification, Draft v1.95, OpenHAN Task Force, and referred to in NISTIR 7628 Guidelines for Smart Grid Cyber Security, Vol. 2, Privacy and the Smart Grid, issued in August 2010.

[5] Commissioning is defined as "The process by which a HAN device obtains access to a specific physical network and allows the device to be discovered on that network." Admission to the network allows the HAN device to communicate with peer devices and receive public broadcast information, but the information is not secured.

[6] Enrollment is defined as "The process by which a Consumer enrolls a HAN device in a Service Provider's program (e.g. demand response, energy management, pre-pay, PEV programs, distributed generation programs, pricing, messaging, etc.) and gives certain rights to the Service Provider to communicate with their HAN device."

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	enrollments[6] are provided in metric 2 "Load impact from smart grid-enabled, utility administered demand response (DR) programs (in total and by customer class, to the extent available)", and metric 5 "Number of customers that are on a time-variant or dynamic pricing tariff (by customer class, CARE, and climate zone, to the extent available)" SCE does not currently have the capability to track devices by CARE/non-CARE and climate zone. SCE would need to add this functionality to its data warehouse system in order to provide this data.

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5. Number of customers that are on a time-variant or dynamic pricing tariff (by customer class, CARE, and climate zone, to the extent available)

CPUC Staff Recommended Policy Goal Supported:	Some of the benefits of the smart grid are linked to customer usage of its capabilities, and this metric seeks to measure customer use of smart grid and advanced meter capabilities. §§8360(f), (h) (i) and §8366(a)
Definitions:	**Time Variant or Dynamic Pricing Tariff:** A rate in which prices can be adjusted on short notice (typically an hour or day ahead) as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. Includes customers on CPP, TOU, RTP rates, customers enrolled in PTR notifications, and customers on separately metered PEV rates. Excludes A/C cycling programs, PCT programs, and customers with a PEV that are not on an EV time variant rates. **Customer Class:** Same as Metric 4. A group of customers with similar characteristics that have similar rate schedules or structures for electric service. For the purposes of this metric, customer classes shall be defined by existing tariff structures. For each utility, the customer classes shall be as follows: *for SCE:* (1) Residential, (2) C&I < 200 kW, (3) C&I > 200 kW, (4) Agriculture and Pumping. *for PG&E:* (1) Residential, (2) non-Residential < 200 kW, (3) non-Residential > 200 kW, (4) Other. *for SDG&E*: (1) Residential, (2) C&I < 500 kW, (3) C&I > 500 kW, (4) Other. **CARE:** Same as Metric 7. Number of customers enrolled in the California Alternate Rates for Energy (CARE) program. CARE offers income-qualified customers a discount of 20% or more off their monthly electric bill. **Climate Zone:** Same as Metric 7. An area that is distinguished by its climate so that utility customers within the territory have similar heating and cooling needs.
Applicable Data Sources Already Reported:	Monthly DR reports (all utilities), PG&E and SCE AMI Annual Energy Savings Reports
Reporting Start Date:	July 2011

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Comments and Explanation of Changes:	Change requested to the metric as not all customers will opt-into time variant or dynamic pricing tariffs, for example, SCE residential customers will be defaulted onto the PTR program, and will have the option to opt-into other time variant or dynamic pricing tariffs. Excludes customers currently enrolled in TOU, CPP, and RTP tariffs. That is, customers enrolled in dynamic tariffs pre-AMI are excluded.

6. Number of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) or the functioning of a utility-administered Home Area Network with registered consumer devices

CPUC Staff Recommended Policy Goal Supported:	Linked to cost-effectiveness and provision of information to customers. §8360(a) (e) (h)
Definitions:	**Escalated Complaint:** Escalated customer complaints (written or telephone call) received by the utility's Consumer Affairs Department (or equivalent)regarding the AMI meter or program, or regarding device registration and communication issues. **Advanced Meter:** Same as Metric 2. A meter that enables two-way communication between utilities/customers with the advanced meter. **Consumer Device**: Same as Metric 7. Tools that (1) provide electricity energy information to customers or provides control over energy usage, and (2) provides such information and/or control via a Home Area Network Includes devices provided by a utility program and devices purchased by consumers. Excludes devices not registered with the utility and devices communicating with HANs provided by non-utilities. **Home Area Network**: A network of energy management devices, digital consumer electronics, signal-controlled or enabled appliances, and applications within a home environment that is on the home side of the electric meter. Includes HANs provided by a utility. Excludes HAN provided by non-utilities (e.g., customers, device manufacturers). Considerations: Complaints related to the interaction of consumer devices with HANs, is dependent on the availability of utility HAN consumer devices, which is expected in 2012 to 2013.
Applicable Data Sources Already Reported:	SDG&E: Smart Meter Program Quarterly Reports SCE: Not currently reported PG&E: Partial current reporting
Reporting Start	July 2011 for complaints related to advanced meters. 2012/2013 for

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Date:	complaints related to the interaction of consumer devices with HANs.
Comments and Explanation of Changes:	Change to the metric requested as complaints should include only escalated complaints received regarding the functioning or accuracy of advanced meters. This metric should also be combined with Metric A.10 and include all escalated complaints regarding the interaction of consumer devices with utility-administered HANs. Includes only escalated complaints. For SCE, these are complaints received by the Consumer Affairs department. This metric will include all escalated complaints related to consumer devices, including those complaints that were determined to be caused by the consumer device and not the utility HAN.

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7. Number of utility-owned advanced meters replaced annually before the end of their expected useful life

CPUC Staff Recommended Policy Goal Supported:	Linked to cost-effectiveness and provision of information to customers (§8360(a) (e) (h)).
Definitions:	**Advanced meters**: A meter that enables two-way communication between utilities/customers with the advanced meter. Includes AMI meters, or smart meters approved by the CPUC under the AMI deployment program. Excludes RTEM meters and legacy meters. **Replaced**: AMI meter that has been replaced due to a malfunction causing the AMI meter to become inoperable.
Applicable Data Sources Already Reported:	None
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	None

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8. Number of advanced meter field tests performed at the request of customers pursuant to utility tariffs providing for such field tests

CPUC Staff Recommended Policy Goal Supported:	Linked to cost-effectiveness and provision of information to customers (§8360(a) (e) (h)).
Definitions:	**Advanced meters**: A meter that enables two-way communication between utilities/customers with the advanced meter. Includes AMI meters, or smart meters approved by the CPUC under the AMI deployment program. Excludes RTEM meters, legacy meters, and AMI meters replaced when service panel is removed or upgraded, installed in wrong service type, customer changes rate (NEM,) requiring a new meter with a different program. **Field Test:** A test requested by a customer and conducted personnel at the customers premise to determine if a meter is measuring usage correctly. Includes customer-requested field tests performed by utilities. Excludes tests independently conducted (not customer-requested).
Applicable Data Sources Already Reported:	None
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	Per current tariff rules, utilities will perform one field test every six months at no charge at the customer's request. This metric should not include field test requests that are not performed by utilities.

9. Number and percentage of customers with advanced meters using a utility-administered internet or web-based portal to access energy usage information or to enroll in utility energy information programs

CPUC Staff Recommended Policy Goal Supported:	Linked to cost-effectiveness and provision of information to customers (§8360(a) (e) (h)).
Definitions:	**Customers**: Number of unique customers that (1) have interval usage data available to them, and (2) have accessed the energy usage information at least once during the preceding 12 months. **Internet or Other Web-Based Portal**: Includes mobile phone applications Excludes customers accessing energy usage information from non-utility portals or websites **Enrollments in Energy Information Programs**: Includes enrollments in Tier Alert / Budget Assistant programs, phone applications Excludes enrollments in dynamic pricing and customers calls **Energy Usage Information:** Includes interval usage data collected by the AMI meter, backhauled to utility back office systems, and presented on utility web sites. Excludes usage or other data presented on third-party websites or tools, near real-time usage data available or any other information that is not received /stored in the utility back office systems (i.e., information received directly from the HAN), and cumulative energy usage information.
Applicable Data Sources Already Reported:	None
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	Metric should measure unique customers using web based tools and other energy information programs available that will not require customers to access the Web. Examples of these programs include Tier Alert (PG&E and SDG&E) and Budget Assistant (SCE) programs. This metric excludes customers accessing usage information through non-utility portals, and also excludes customer accessing cumulative

	usage information. This metric was expanded to include customers enrolling in energy management programs to better capture the penetration of customers accessing their energy information in manners other than the utility portals.

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B. Plug-in Electric Vehicle Metrics

1. Number of customers enrolled in time-variant electric vehicles tariffs

CPUC Staff Recommended Policy Goal Supported:	Provides a view into the usage of plug in electric vehicles; consistent with §8362(g)
Definitions:	**Time Variant Electric Vehicle Tariffs:** 1) for SCE: TOU-EV-1, TOU-EV-2, TOU-EV-3, TOU-EV-4, and TOU-D-TEV; 2) for PG&E: E9a and E9b; 3) for SDG&E: EV-TOU, EV-TOU-2, EV-TOU-3, EPEV-L, EPEV-M and EPEV-H.
Applicable Data Sources Already Reported:	None
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• As discussed by parties in the context of the Alternative Fuel Vehicle (AFV) OIR, utilities currently have limited ability to determine which customers have electric vehicles. As methods for acquiring this information are determined in that proceeding, this metric should be updated. • Metrics related to metering arrangements should be deferred until after PEV metering policy is set in AFV OIR.

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C. Storage Metrics

1. MW and MWh of grid connected energy storage interconnected at the transmission or distribution system level

CPUC Staff Recommended Policy Goal Supported:	Determine the number of units providing storage services to the network and their capability; § 8362(g)
Definitions:	None
Applicable Data Sources Already Reported:	None
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• Utilities may not have access to information about energy storage systems owned by independent power producers or customer-sited and owned systems.

D. Grid Operations Metrics

1. The system-wide total number of minutes per year of sustained outage per customer served as reflected by the System Average Interruption Duration Index (SAIDI), Major Events Included and Excluded

CPUC Staff Recommended Policy Goal Supported:	Meet reporting requirements of §8366(e) and the policy goal of § 8360(a)
Definitions:	IOUs will use information reported in Annual Reliability Reports to produced information required for this metric. Each IOU's Annual Reliability Report is available at: http://www.cpuc.ca.gov/PUC/energy/ElectricSR/Reliability/annualreports/
Applicable Data Sources Already Reported:	Annual Reliability Reports
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• Location- and circuit- level information is too detailed and variable over time to be included in metrics. Utilities have as many as 4,500 circuits. • New metrics are aimed at providing circuit-level information

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2. How often the system-wide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index (SAIFI), Major Events Included and Excluded

CPUC Staff Recommended Policy Goal Supported:	Meet reporting requirements of §8366(e) and the policy goal of § 8360(a)
Definitions:	IOUs will use information reported in Annual Reliability Reports to produced information required for this metric. Each IOU's Annual Reliability Report is available at: http://www.cpuc.ca.gov/PUC/energy/ElectricSR/Reliability/annualreports/
Applicable Data Sources Already Reported:	Annual Reliability Reports
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• Location- and circuit- level information is too detailed and variable over time to be included in metrics. Utilities have as many as 4,500 circuits. • New metrics are aimed at providing circuit-level information

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3. The number of momentary outages per customer system-wide per year as reflected by the Momentary Average Interruption Frequency Index (MAIFI), Major Events Included and Excluded

CPUC Staff Recommended Policy Goal Supported:	Meet reporting requirements of §8366(e) and the policy goal of § 8360(a)
Definitions:	IOUs will use information reported in Annual Reliability Reports to produced information required for this metric. Each IOU's Annual Reliability Report is available at: http://www.cpuc.ca.gov/PUC/energy/ElectricSR/Reliability/annualreports/
Applicable Data Sources Already Reported:	Annual Reliability Reports
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• Location- and circuit- level information is too detailed and variable over time to be included in metrics. Utilities have as many as 4,500 circuits. • New metrics are aimed at providing circuit-level information

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4. Number of customers per year and circuits per year experiencing greater than 12 sustained outages

CPUC Staff Recommended Policy Goal Supported:	Meet reporting requirements of §8366(e) and the policy goal of § 8360(a)
Definitions:	IOUs will use information reported in Annual Reliability Reports to produced information required for this metric. Each IOU's Annual Reliability Report is available at: http://www.cpuc.ca.gov/PUC/energy/ElectricSR/Reliability/annualreports/
Applicable Data Sources Already Reported:	Annual Reliability Reports
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• Location- and circuit- level information is too detailed and variable over time to be included in metrics. Utilities have as many as 4,500 circuits. • New metrics are aimed at providing circuit-level information

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5. System load factor and load factor by customer class

CPUC Staff Recommended Policy Goal Supported:	Meet reporting requirements of §8366(e) and the policy goal of § 8360(a)
Definitions:	**System** The distribution system owned and operated by a utility. **Load Factor** Calculated by dividing (1) average load (total energy divided by number of hours) during the year by (2) peak load during the year. In the case of Load Factor by customer class, the average and peak load during the year shall both be measured for that customer class (as opposed to the system). **Customer Class** A group of customers with similar characteristics that have similar rate schedules or structures for electric service. For the purposes of this metric, customer classes shall be defined by existing tariff structures. For each utility, the customer classes shall be as follows: *for SCE:* (1) Residential, (2) C&I < 200 kW, (3) C&I > 200 kW, (4) Agriculture and Pumping. *for PG&E:* (1) Residential, (2) non-Residential < 200 kW, (3) non-Residential > 200 kW, (4) Other. *for SDG&E*: (1) Residential, (2) C&I < 500 kW, (3) C&I > 500 kW, (4) Other.
Applicable Data Sources Already Reported:	Calculations for this metric will be based on data collected for the purpose of Annual Rate Group Load Studies. Some statistics from the Load Studies are used for analyses in the Phase II (Rate Design) of General Rate Case. SCE's Annual Load Profiles are available at: http://www.sce.com/AboutSCE/Regulatory/loadprofiles/ PG&E's Annual Load Profiles are available at: http://www.pge.com/nots/rates/instruction.shtml SDG&E's Annual Load Profiles are available at: http://www2.sdge.com/eic/dlp/dynamic.cfm
Reporting Start Date:	July 2011

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Comments and Explanation of Changes:	• Until advanced meters are fully deployed for residential, small commercial and industrial, and small agriculture customers, load factor will be calculated using estimates, rather than measured directly.

6. Number of and total nameplate capacity of customer-owned or operated, grid-connected distributed generation facilities

CPUC Staff Recommended Policy Goal Supported:	State policy seeks to promote both distributed generation and the use of renewables. The ability to integrate these resources is an expected benefit of the smart grid. This is tied to §8366 (b) renewable and §8360(c) distributed generation.
Definitions:	**Distributed Generation Facilities** Generating systems that are (1) enrolled with a utility in the Self Generation Incentive Program (SGIP) or the California Solar Initiative (CSI) (2) part of each utility's respective Solar PV program or, (3) operating under a Feed In Tariff (FIT). **Electricity Deliveries From Grid-Connected, Customer Owned Or Operated Distributed Generation** All electricity purchased by a utility under a Net Surplus Compensation Tariff or under a Feed In Tariff (FIT), measured in KWh.
Applicable Data Sources Already Reported:	SGIP, CSI and FIT reports.
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• Use programs and tariffs to define "distributed generation" • Additional metric added to measure electricity deliveries as a proxy for "integration" • Information and estimates about production of distributed generation facilities that serve on-site customer load is produced annually by the CEC in their California Energy Demand Forecast

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7. Total annual electricity deliveries from customer-owned or operated, grid-connected distributed generation facilities

CPUC Staff Recommended Policy Goal Supported:	State policy seeks to promote both distributed generation and the use of renewables. The ability to integrate these resources is an expected benefit of the smart grid. This is tied to §8366 (b) renewable and §8360(c) distributed generation.
Definitions:	**Distributed Generation Facilities** Generating systems that are (1) enrolled with a utility in the Self Generation Incentive Program (SGIP) or the California Solar Initiative (CSI) (2) part of each utility's respective Solar PV program or, (3) operating under a Feed In Tariff (FIT). **Electricity Deliveries From Grid-Connected, Customer Owned Or Operated Distributed Generation** All electricity purchased by a utility under a Net Surplus Compensation Tariff or under a Feed In Tariff (FIT), measured in KWh.
Applicable Data Sources Already Reported:	SGIP, CSI and FIT reports.
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	• Use programs and tariffs to define "distributed generation" • Additional metric added to measure electricity deliveries as a proxy for "integration" • Information and estimates about production of distributed generation facilities that serve on-site customer load is produced annually by the CEC in their California Energy Demand Forecast

8. Number and percentage of distribution circuits equipped with automation or control equipment, including Supervisory Control and Data Acquisition (SCADA) systems

CPUC Staff Recommended Policy Goal Supported:	Measure the extension/development of the smart grid.
Definitions:	None
Applicable Data Sources Already Reported:	None
Reporting Start Date:	July 2011
Comments and Explanation of Changes:	All IOUs track SCADA installation while there are significant interpretation challenges associated with both automation equipment and total load associated with either SCADA or automation or control equipment.

IV.

NON-CONSENSUS METRICS AND AREAS FOR FURTHER CONSIDERATION

As discussed in Section II, the IOUs have identified subject areas for “further consideration” and have proposed a process for continued metrics development for these topics. This section also includes proposed metrics on which stakeholders and IOUs have not achieved consensus following the series of public working groups session held during October 8 through October 15.

Subject Area	Example Metric / Topic	Issues to Consider
Customer/AMI Metrics	• CPUC Staff Recommended Policy Goal Supported: Measured improvements in grid reliability at the customer level and to measure the ability of the smart grid to avoid and identify outages • Metric Discussed by Parties: Number customer reported outages	• Parties agreed to consider alternatives to this metric for inclusion in future metric reporting. • This metric is not directly related to smart grid performance or measuring grid reliability at the customer level because it will not measure improvements in ability of the smart grid to avoid outages, but in fact may distort actual outage management improvements attributable to new smart grid technologies that reduce outage duration or frequency, such as advanced meters and distribution automation. This metric is a rough, indirect measurement at best, and may be significantly affected by events beyond the utility’s control (e.g., storms). • As an alterative, the parties suggest that another measurement be developed concurrent with the wide-scale deployment of smart grid sensor technology. For example, the number of avoided outages due to smart grid technologies should be considered, to the extent that it is possible to develop and agree on a measurement protocol. In the near term, the IOUs recommend that the outages measures captured in SAIDI, SAIFI, and MAIFI be used to measure the smart grid’s impact on improvements in grid reliability. • Issues surrounding weather and how to isolate identification of outages by digital systems from those identified by customer reports should be further explored in the context of developing future metrics.

	• Peak/off-peak price differential	• Parties agreed to consider alternatives to this metric in the context of developing further metrics. • Although certain parties expect the on-peak/off-peak price differential to decrease as smart grid technologies are deployed, electricity market prices are subject to significant factors outside of the utility's control. In fact, this ratio is impacted most by generation supply, rather than customer behavior or transmittal of energy and price information to customers. For example, the amount of generation (i.e., supply) bid into the CAISO market will have a significant impact to market prices, as will natural gas prices. In addition, other factors that may influence the on-peak/off-peak price differential in the future include the potential load increase resulting from plug-in electric vehicles and increases in the renewable portfolio standard. Such factors may significantly impact the price differential and obscure demand-side impacts affected by the utilities. To the extent that parties believe that this metric should be reported, consideration should be given to the appropriate reporting source for this data (i.e. CAISO).
	• Load impact from smart grid-enabled, utility administered demand response (DR) programs (in total and by customer class, to the extent available) • The number of utility-owned advanced meters with consumer devices with Home Area Network (HAN) or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE, and climate zone, to extent available) • Number of customers that are on a time-variant or dynamic pricing tariff (by customer class, CARE,	• Parties agreed that these metrics may be improved by providing more granular information on customer participation in smart grid programs, rates, and technologies. Thus, parties agreed to discuss the inclusion of such data in the context of developing future metrics. Examples of potential data granularity include, but are not limited to customer participation in smart grid programs by zip code or census track.

	and climate zone, to the extent available) • Number and percentage of customers with advanced meters using a utility-administered internet or web-based portal to access energy usage information or to enroll in utility energy information programs	
Advanced Automation and Measurement Technologies	• Power Quality Metric • Line Losses • Dynamic Line Rating • T&D Load Factors	• Early Stage Technologies – Many of these technologies are in there early stages and IOUs have not decided if or in what form they should be deployed. • "Widget Counting" – Stakeholders must give further thought to how to effectively measure smart grid deployment. Counting widgets seems to be the easiest solutions but the optimal level of a widget count is unclear. • Costs of Measurement Technologies – Exact measurement of lines losses at the distribution level would require deployment of additional advanced measurement technology. IOUs anticipate deploying many such technologies as part of smart grid investments in the future but they are not available today. • According to current utility practices, lines losses for specific elements on the transmission system may be estimated based on a variety of inputs. Information about the distribution system is scarcer. Deployment of advanced measurement technology as part of smart grid investments will enhance utilities' ability to collect this information. This information may be produced on an ad-hoc basis but is impractical to collect in the form of a metric.

Environmental Metrics	• Avoided GHG emissions due to smart grid-enabled line loss reductions in the transmission and distribution system. This could possibly be done with a modeling tool. • Avoided GHG emissions due to smart grid-enabled improvements in intermittent renewable integration that reduce the need for spinning reserves and other ancillary services. • Avoided GHG emissions from smart grid-enabled residential Auto-DR programs. • Avoided GHG emissions due to smart grid-enabled energy storage. Changes in NOx and hydrocarbon(HC) emissions (in place & time) • Changes in consumptive water use per unit of electricity generated • Cost of avoided GHG emissions ($ per ton of avoided global warming pollution with SG deployment compared against a non-SG baseline.) • Cost of delivered energy efficiency and demand response programs with and without SG deployment, such as improved cost-effectiveness and meeting program goals at lower than anticipated cost • Achieve RPS goals at lower than anticipated cost	• CPUC staff have proposed several metrics for further consideration that pertain to global warming pollution (and thus to evaluation with respect to the Global Warming Solutions Act (Assembly Bill 32). However, additional metrics warrant further consideration to plan for smart grid performance evaluation with respect to the environment overall, including urban and regional air quality, water conservation and pollution, and land use impacts. Evaluative metrics pertaining to the cost of achieving environmental goals also warrant further consideration • Stakeholders should explore several environmental performance metrics in follow-up technical working group with IOUs, EDF and other interested parties. • SB 17 requires the evaluation of smart grid environmental performance with respect to achieving the goals of the Renewable Portfolio Standard (RPS), Global Warming Solutions Act (AB32), demand response and energy efficiency, as well as California's environment overall (i.e. air quality and water). • While land use and water quality evaluations are appropriate, no metrics are proposed at this time due to lack of available data and analytical complexities involved in establishing causal relationships. • Initial steps for further consideration may include: (i) identifying what data are collected and reported by various state and local agencies, such as CARB and local air quality management agencies, and (ii) drawing from AB 32 policy, GHG emissions performance standard (EPS), and Long Term Procurement Plan CPUC decisions describing state-of-science and stakeholder views, as well as providing regulatory guidance about how to calculate performance in terms of GHG emissions

	due to SG deployment • Economic value of avoided transmission and distribution line losses	
Cyber Security	• Number and total number of minutes of outages attributable to grid and cyber attacks; • Number and percentage of customers whose data is compromised by a cyber-attack, and number and percentage of customers notified of a data breach (DRA suggested). • Number of attempted cyber-attacks on the utility, and the number of security breaches experienced by the utility	• Security and Disclosure – Much of this information may be sensitive and further thought must be given to disclosure protocols, jurisdictional boundaries and CPUC security process/procedures. • Following from discussions in workshops and in communications from staff, the IOUs propose deferring metrics related to cyber security to a more comprehensive discussion of cyber security policy. The disclosure of data about cyber security attacks raises issues related to security and liability that should be assess in a separate workshop or proceeding dedicated to the subject. • Recommend CPUC staff initiate a Cyber Security Technical Working Group with IOUs, DRA and other interested parties as appropriate to follow up on possible cyber security issues for California IOUs. Staff will discuss options for participation requirements with IOUs for interested parties (i.e., possible non-disclosure agreements, etc).
Plug-in Electric Vehicles	• Metering-related metrics • Smart charging	• Upon development of policies in the AFV rulemaking, new metrics may be developed related to an accurate PEV count, PEV load, and networked PEV charging facility count pending consideration of notice / requirements in the AFV proceeding.
Energy Storage	• The magnitude and percentage of total load served by advanced energy storage and peak-shaving technologies • MW and MWh of capacity of peak load-reducing energy storage installed	• Peak-shaving cannot be tracked as an isolated storage use and assigned a capacity.

(END OF ATTACHMENT A)