Decision 12-04-025 April 19, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System.	Rulemaking 08-12-009 (Filed December 18, 2008)

DECISION ADOPTING METRICS TO MEASURE THE SMART GRID DEPLOYMENTS OF PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY

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DECISION ADOPTING METRICS TO MEASURE THE SMART GRID DEPLOYMENTS OF PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY

1. Summary

This decision adopts consensus metrics to help measure the extent and effectiveness of Smart Grid investments made by Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company. These metrics are contained in Attachment A.

This decision declines to adopt metrics that apply to Southern California Gas Company at this time. Southern California Gas Company was not a respondent in this proceeding at the time that these metrics were developed and Senate Bill 17 (Padilla),[1] which has triggered this proceeding, applies principally to smart electric grids.

This decision also sets a schedule for the future review and revision of Smart Grid metrics. Specifically, this decision directs parties and Commission Staff to create four Technical Working Groups to address four topics: 1) updates or revisions to the metrics adopted herein, if needed; 2) the creation of metrics related to cyber-security; 3) the creation of metrics related to environmental benefits; and, 4) the creation of broad goals to focus all stakeholders toward a common vision.

As discussed below in greater detail, the purpose of establishing goals and metrics is to guide all stakeholders in a common policy direction as well as measure the performance of already deployed Smart Grid technologies.

The Technical Working Group on goals is tasked with proposing goals related to customers, the environment, the market, and utility operations. These goals will be considered later in this proceeding.

[1] Chapter 327, Statutes of 2009.

2. Procedural Background

Decision (D.) 10-06-047, which set Smart Grid Deployment Plan requirements, declined to adopt metrics, stating that there was an inadequate record to create useful metrics at the time that decision was made.[2]

Subsequently, Commission Staff led efforts to develop metrics. On July 30, 2010, a Joint Ruling was released seeking comment on a staff-proposed set of metrics.[3] The Joint Ruling included as an attachment a list of over 80 proposed metrics for discussion.

The Commission received comments on these potential metrics on August 17, 2010 from California Large Energy Consumers Association, the Environmental Defense Fund (EDF), the California Energy Storage Alliance (CESA), Southern California Edison Company (SCE), the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Pacific Gas and Electric Company (PG&E), the Greenlining Institute (Greenlining), Granite Key LLC (Granite Key), Ice Energy Inc. (Ice Energy), the Utility Consumers' Action Network, San Diego Gas & Electric Company (SDG&E), the California Independent System Operator (CAISO), Certichron Inc., and the Consumer Federation of California.

A workshop to consider the proposed metrics and comments was held on August 25-26, 2010. Based on the discussions at the workshop, Commission Staff agreed to develop a new set of proposed discussion draft metrics that would form the basis for metrics. Commission Staff distributed this discussion draft set of metrics to the service list in this proceeding on September 3, 2010. The discussion draft also directed PG&E, SCE and SDG&E to undertake an internal review of their processes to determine which proposed metrics are either

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[2] D.10-06-047 at 84.

[3] Assigned Commissioner and Administrative Law Judge's Joint Ruling, Rulemaking (R.) 08-12-009 (July 30, 2010) (Joint Ruling).

already being reported for other purposes, or could be easily collected and reported. Additionally, PG&E, SCE and SDG&E were directed to report on whether there were any metrics they were not currently collecting for which they could not easily collect the data for reporting purposes.

PG&E, SCE and SDG&E distributed a Joint Straw Proposal on Smart Grid Metrics (Straw Proposal) on September 24, 2010. This Straw Proposal presented metrics based on what can be currently reported to the Commission and what requires further discussion.

Commission Staff subsequently coordinated a series of “webinars” to discuss the attributes of the proposed metrics. Webinar #1 took place on October 8, 2010 and focused on customer and Advanced Metering Infrastructure (AMI) metrics. Webinar #2 took place on October 12, 2010 and focused on utility grid operations. Webinar #3 took place on October 13, 2010 and focused on cyber-security. Webinar #4 took place on October 15, 2010 and focused on environmental issues, electric vehicles and other issues not previously covered.

On October 22, 2010, PG&E, SCE and SDG&E distributed to the service list a “Report on Consensus and Non-Consensus Smart Grid Metrics” (Consensus Report). This Consensus Report identified 19 metrics that it considered consensus, based on the webinar process and additional discussions with parties.

The Consensus Report also listed a number of metrics that were identified as “Non-Consensus.” Additionally, the Consensus Report sought clarifications concerning a number of items, including the “base year” for taking the first measurement.

On December 29, 2010, the Administrative Law Judge (ALJ) issued an ALJ Ruling seeking comments on the Consensus Report. The ALJ Ruling included the Consensus Report as Attachment A.[4] The ALJ Ruling sought party

[4] Administrative Law Judge’s Ruling Seeking Comments on Proposed Interim Metrics to

comments on whether the metrics listed in the Consensus Report are appropriate and reasonable, whether the metrics are accurately listed as consensus or non-consensus, and whether the metrics accurately reflect the input of parties.[5] Additionally, the ALJ Ruling asked for comments on the appropriateness of creating "Technical Working Groups" to create metrics on cyber-security, and whether Technical Working Groups are needed for additional topics.[6] Finally, the ALJ Ruling sought comments on the appropriate reporting period for the metrics.[7]

Pursuant to the ALJ Ruling, opening comments were filed on January 24, 2011 by Granite Key and Aspect Labs (filing jointly Granite Key/Aspect Labs), Southern California Gas Company (SoCalGas), Greenlining, CAISO, Ice Energy, SDG&E, Alliance for Retail Energy Markets (AReM), PG&E, DRA, EDF, and SCE.

Reply comments were filed on February 14, 2011 by SDG&E, DRA, Demand Response and Smart Grid Coalition (DRSG),[8] SCE, California Energy Efficiency and Renewable Technologies (CEERT), EDF, CESA, and PG&E.

3. Consensus Metrics

The Consensus Report, which is Attachment A of the ALJ Ruling, identified nineteen consensus metrics to be measured as part of the initial Smart Grid Deployment Plans and reported annually as part of the Annual Reports, required

Measure Progress by Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas and Electric Company in Implementing a Smart Grid, R.08-12-009 (December 29, 2010) (ALJ Ruling).

5 ALJ Ruling at 2-3.

6 *Id.* at 3-4.

7 *Id.* at 4.

8 The Motion of Demand Response and Smart Grid Coalition for Party Status (February 14, 2011) was granted via an ALJ e-mail to the service list on February 16, 2011.

by D.10-06-047, to be filed with the Commission by October 1 of each year starting in 2012. The nineteen consensus metrics are as follows:

A. Customer/AMI Metrics

1. Number of advanced meter malfunctions where customer electric service is disrupted;
2. Load impact from Smart Grid-enabled, utility administered demand response programs (in total and by customer class);
3. Percentage of demand response enabled by Automated Demand Response and by individual Demand Response impact program;
4. The number of utility-owned advanced meters supporting consumer devices with Home Area Network (HAN) or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, customers in the California Alternative Rates for Energy (CARE) program and climate zone);
5. Number of customers that are on a time-variant or dynamic pricing tariff (by customer class, CARE, and climate zone);
6. Number of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) the functioning of a utility-administered HAN with registered consumer devices;
7. Number of utility-owned advanced meters replaced annually before the end of their expected useful life;
8. Number of advanced meter field tests performed at the request of customers pursuant to utility tariffs providing for such field tests; and
9. Number and percentage of customers with advanced meters using a utility-administered internet or a web-based portal to access energy usage information or to enroll in utility energy information programs.

B. Plug-in Electric Vehicles Metrics

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

C. Storage Metrics

Megawatt (MW) and Megawatt-hours of grid connected energy storage interconnected at the transmission and distribution system level.

D. Grid Operations Metrics

1. The system-wide and total number of minutes per year of sustained outage per customer served as reflected by the System Average Interruption Duration Index (s), Major Events included and excluded;
2. How often the system-wide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index, Major Events included and excluded;
3. The number of momentary outages per customer system-wide per year as reflected by the Momentary Average Interruption Frequency Index, Major Events included and excluded;
4. Number of customers per year and circuits per year experiencing greater than 12 sustained outages;
5. System load factor and load factor by customer class;
6. Number of and total nameplate capacity of customer-owned or operated, grid-connected distributed generation facilities;
7. Total annual electricity deliveries from customer-owned or operated, grid-connected distributed generation facilities; and
8. Number and percentage of distribution circuits equipped with automation or control equipment, including Supervisory Control and Data Acquisition systems.

3.1. Positions of Parties on Proposed Consensus Metrics

As the title of Attachment A, "Consensus Report," suggests, the comments of parties generally supported the metrics identified. Additionally, commenters recommended relatively minor edits to the metrics as listed, often to ensure clarity. This decision discusses and resolves these recommendations.

The CAISO requested that Customer/AMI Metric 4 be clarified to ensure that non-HAN methods of triggering demand response are also considered.[9] Additionally, the CAISO asked that the Commission ensure that there is coordination between the policies identified in the metrics and the goals outlined in the California Clean Energy Future Implementation Plan (Plan).[10] According to the CAISO, consistency between the Plan and Smart Grid metrics "will be an important step in ensuring that California's electric utilities and agencies carry out a coherent plan for building a smart electric system for California."[11]

Ice Energy argued that "metrics should be designed to measure not only the energy storage systems themselves but their grid-wide impacts."[12] Additionally, Ice Energy did not support the Consensus Report because the Consensus Report does not include a metric on thermal storage air conditioning. Ice Energy contended that thermal storage air conditioning is specifically listed in Senate Bill (SB) 17, and "it is essential to collect information through appropriately specific metrics about thermal storage air conditioning's usage, costs, benefits and impact on the grid."[13] Ice Energy proposed that the following metric be included in any final list of metrics: "The number and percentage of electricity customers and magnitude and percentage of total load served by thermal-storage air conditioning."[14]

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[9] California ISO Comments to ALJ Ruling at 2.

[10] *Id.* Note: *The California Clean Energy Future Implementation Plan* (September 2010) was jointly developed by this Commission, the California Air Resources Board, the California Environmental Protection Agency, the California Energy Commission (CEC) and the ISO. It is available here: http://www.cacleanenergyfuture.org/common/CCEF%20Implementation%20Plan_vFinal_2a.pdf.

[11] *Id.* at 3.

[12] Ice Energy Comments to ALJ Ruling at 1.

[13] *Id.* at 2-3.

[14] *Id.* at 2. Ice Energy notes that this metric was included the initial Staff metric list included in the Joint Ruling.

Greenlining proposed that Customer/AMI Metric 9 information be collected "by customer class, CARE enrollment and climate zone."[15] Greenlining argued that collecting this additional information would help in "understanding if any particular group of customers is taking advantage" of accessing information over the internet more than any other class of customers.[16] Additionally, Greenlining proposed that Customer/AMI Metrics 4, 5 and 9 include collection of data by zip code or census track. Greenlining stated that collecting information by zip code or census track would help in understanding which customers are using information and which customers are not. Further, Greenlining noted that "in order for Smart Grid to succeed, every community in California must contribute to its policy goals."[17]

DRA argued for the adoption of the consensus metrics, but advised that the metrics should be considered as preliminary and interim in nature.[18] In addition to its overall argument, DRA provided comments on specific metrics. Notably, DRA cautioned that Customer/AMI Metric 4 does not cover devices that are not registered with the utility, and suggested that this metric be reviewed as the HAN device marketplace evolves.[19]

On Customer/AMI Metric 6, DRA noted that there is no definition for the term "escalated complaint" and argued that all utilities should report on this metric using the same definition.[20] Further, DRA argued that this particular metric does not clearly state what type of complaint will be tracked and whether

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[15] Greenlining Comments to ALJ Ruling at 1.

[16] *Id.* at 1.

[17] *Id.* at 2.

[18] DRA Comments to ALJ Ruling at 2.

[19] *Id.* at 8.

[20] *Id.* at 8-9.

or not those complaints are resolved. DRA recommended that the metric be modified to track and classify the types of escalated complaints.[21]

Concerning Customer/AMI Metric 7, DRA asked that this metric be revised to state as follows: "The number of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually." Additionally, DRA requested that the reason for replacement be reported.[22]

On Customer/AMI Metric 8, DRA asked that the results of the field tests of the meters be reported, and offered proposed language as follows: "Number of advanced meters field tested at the request of customers pursuant to utility tariffs providing for such field tests that are measuring usage correctly or incorrectly."[23]

Finally, DRA requested that the costs of implementing and measuring these metrics be included as part of the metrics requirements.

AReM argued that the metrics should "focus primarily on measuring and evaluating utility performance" in the utility's role as the Utility Distribution Company (UDC). Specifically, AReM requested that the metrics "measure UDC performance and reject metrics that measure other utility functions."[24] Further, AReM noted that several metrics focus on bundled customer actions, which are unrelated to the actions of the utility as a UDC.[25]

EDF generally supported the proposed metrics but recommended that "metrics be further developed to fully measure the ways that utilities use smart grid deployments to comply with" SB 17.[26] Additionally, EDF proposed two new metrics related to measuring the environmental benefit of Smart Grid:

Demand Response Benefits: EDF argued that with an *ex post*

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[21] *Id.* at 9.

[22] *Id.*

[23] *Id.* at 9-10.

[24] AReM Comments to ALJ Ruling at 2.

[25] *Id.*

[26] EDF Comments to ALJ Ruling at 1-2.

analysis of the load impact of demand response, the utility could determine the fuel being displaced and thus the avoided greenhouse gas (GHG) and criteria pollutant emissions; and

Distributed Generation Benefits: EDF argued that by determining the total MWs of distributed generation in their service area and total distributed generation during peak times, utilities can calculate the type and amount of conventional fuel being displaced and the resulting GHG and criteria pollutant reduction.[27]

Finally, EDF noted that several proposed metrics provide information that, when matched to a generation-fuel profile of the utility at that time and date, can be used to quantify emission impacts.[28]

SCE argued that the metrics "are appropriate, reasonable, serve the public interest," and will provide the Commission with necessary information to prepare the Commission's annual report to the Legislature, and reflect the input of parties.[29] In its Reply Comments, SCE supported two of the modifications offered by DRA. Specifically, SCE supported the revisions to Customer/AMI 6 and 7.[30] SCE also argued that several suggestions made by DRA to Customer/AMI 6, 7 and 8 are more appropriate for discussion in a Technical Working Group.[31] Additionally, SCE noted that discussions around revisions offered by CAISO and Greenlining are also more appropriate for a Technical Working Group.[32] SCE agreed with DRA on the topic of storage metrics, noting that any new metrics on storage should wait for direction and further information from the on-going Order Instituting Rulemaking on storage.[33,34] SCE argued that the proposed metrics

27 *Id.* at 4.

28 *Id.* at 5.

29 SCE Comments to ALJ Ruling at 2.

30 SCE Reply Comments at 3.

31 *Id.* at 4.

32 *Id.* at 4-5.

33 *Id.* at 5.

34 *See* R.10.12-007.

offered by EDF are not "ready for adoption at this time."[35] SCE also proposed that consideration of the applicability of adopted metrics on gas companies "would be best accomplished in a separate forum dedicated to gas systems, as opposed to smart electricity systems."[36] Finally, SCE argued that AReM provided no support for its opposition to metrics and that SB 17 does not limit measurement to only the UDC function of the utility. SCE also argued that other issues raised by AReM are more appropriate for other Commission proceedings.[37]

PG&E stated that the "proposed interim metrics are a useful starting point" for development of the utilities' Smart Grid Deployment Plans, and that it agrees with SCE that the metrics will provide the Commission with sufficient information for the Commission's annual report to the Legislature.[38]

In Reply Comments, PG&E supported EDF's goal of creating metrics that "take into account the impact of various Smart Grid projects and programs on GHG emissions and other relevant environmental impacts."[39] PG&E, however, did not support EDF's proposed metrics. Instead, PG&E proposed that EDF work with other parties to develop a more comprehensive GHG emission metric, using concepts developed in other Commission proceedings.[40]

PG&E also opposed the inclusion of additional metrics on energy storage. PG&E argued that "it is premature" to adopt a metric for measuring performance for thermal air conditioning because "the utilities have no means of managing, operating or measuring the use or market penetration of the technology."[41]

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[35] SCE Reply Comments at 6.

[36] *Id.* at 6.

[37] *Id.* at 7

[38] PG&E Comments to ALJ Ruling at 1.

[39] PG&E Reply Comments to ALJ Ruling at 2.

[40] *Id.* at 3.

[41] *Id.* at 3-4.

Finally, PG&E did not support the proposal of Greenlining to collect data for Customer/AMI Metric 9 at a more granular level. PG&E cautioned that while the proposal "may have merit," it is currently unclear what the burden and cost would be to the utility to meet the proposal. PG&E offered to research the feasibility of Greenlining's proposal and stated it may propose a future revision to Customer/AMI Metric 9 if feasible along the line recommended by Greenling.[42]

SDG&E stated that it supports the metrics identified in the Consensus Report. Specifically, SDG&E argued that the "proposed set of metrics provide a useful starting point and a preliminary set of metrics to be included in the first Smart Grid Deployment Plan."[43]

In Reply Comments, SDG&E opposed the inclusion of four cyber-security metrics proposed by Granite Key and Aspect Labs. SDG&E instead argued that the Technical Working Group on cyber-security is the more appropriate forum for discussion of cyber-security metrics.[44] SDG&E also opposed the request of AReM to limit the smart grid metrics to only the UDC function of the utility.[45]

SoCalGas contended that the majority of the consensus metrics do not apply to gas companies. SoCalGas also argued that as a gas company, it is not required to file a Smart Grid Deployment Plan. SoCalGas argued further that the Commission should either adopt only those metrics that can be applied to the gas company or apply these metrics only on electric companies. SoCalGas identified Customer/AMI Metrics 1, 4, 6, 7, 8, and 9 as applicable to a gas company. Finally SoCalGas supported the position that these metrics be considered as "preliminary and for initial guidance only."[46]

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[42] *Id.* at 4-5.

[43] SDG&E Comments to ALJ Ruling at 2.

[44] SDG&E Reply Comments at 2.

[45] *Id.* at 4-5.

[46] SoCalGas Comments to ALJ Ruling at 3-5.

CEERT commented that the proposed consensus metrics "are still insufficient to track the deployment and implementation of California's Smart Grid."[47] CEERT supported EDF's proposed environmental metrics as well as the inclusion of a metric to measure thermal-storage air conditioning.[48]

The DRSG proposed that Customer/AMI Metric 9 be revised to include the number of customers who use an authorized third-party to provide access to information. Specifically, DRSG would revise Customer/AMI Metric 9 as follows: "Number and percentage of customers with advanced meters using a utility or authorized third-party administered internet or web-based portal to access energy usage information or a utility-authorized internet or web-based portal to enroll in utility energy information programs."[49] DRSG argued that adding this language supports the Commission's prior action in D.09-12-046 allowing customers to access their data through an authorized third-party.[50]

3.2. Discussion

No party opposed these metrics.

These metrics will provide the Commission, parties and the public with information that will allow for greater understanding of Smart Grid investments and provide a useful starting point in moving forward on the Smart Grid. Furthermore, these metrics will facilitate monitoring and measuring Smart Grid investments made by the utilities. The metrics will also assist the Commission in preparing its annual report on the Smart Grid, which is required by § 8367 of the Pub. Util. Code.

The Commission finds that the proposed metrics are reasonable, adopts the consensus metrics, and makes clarifying edits, as discussed below.[51]

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[47] CEERT Reply Comments at 3.

[48] *Id.* at 4.

[49] DRSG Comments to ALJ Ruling at 1.

[50] DRSG Reply Comments to ALJ Ruling at 2.

[51] The full list of metrics, including clarifying definitions, is included as Attachment A to

There is merit, however, to the issues raised by SoCalGas concerning the applicability of metrics to gas companies. As explained in D.11-07-056, the original scope of this proceeding, and the requirement to file a Deployment Plan pursuant to SB 17, are limited to electric utilities.[52] Additionally, the decision authorizing SoCalGas to install advanced gas meters is silent on the issue of whether SoCalGas should develop a Smart Grid Deployment Plan.[53] Based on these considerations, the Commission declines to apply these metrics to gas companies or gas consumption at this time.

3.2.1. Revisions to Customer/AMI Metrics

On Customer/AMI Metrics 1, 4, 5, 6, 7, 8, and 9, this decision makes minor revisions to those metrics to make the reporting consistent across measures. These revisions direct the utilities to report on the number and percentage of meter malfunctions and replacements, customers enrolled in particular tariff, complaints and HAN installations. These revisions ensure a consistency in reporting requirements and conform to the revised Customer/AMI Metric 9.

This decision also revises Customer/AMI Metric 2 to measure more specifically summer and winter peak reductions that are due to smart-grid-enabled, utility-administered demand response programs.

This decision revises Customer/AMI Metric 3 to add greater clarity to the reporting requirement.

On Customer/AMI Metric 4, the concerns expressed by the CAISO are well-taken. The means by which a customer uses a HAN device will ultimately be up to the customer. Indeed, we agree with DRA[54] that as the technology progresses

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this decision.

[52] Pub. Util. Code § 8364 (directing that "each electrical corporation shall develop and submit a smart grid deployment plan to the commission for approval.").

[53] D.10-04-027.

[54] DRA Comments at 8.

and other means of communicating with devices develop, this metric may take on less importance. Nevertheless, we expect that until that time comes, the vast majority of devices will be registered by the customer with the utility. This metric will therefore provide the Commission and other parties with an understanding of the prevalence of HAN-enabled devices, and how well the HAN is progressing across the service territory.

This decision does not adopt the request of Greenlining to require the inclusion of census track information for Customer/AMI Metrics 4, 5 and 9. Although this type of information may be useful in tracking the growth in technology across demographics, PG&E's argument persuades us that it is unclear whether it is it is feasible and cost-effective to collect the information at this time. However, we do not see a similar problem concerning customer class, CARE status, or climate zone. We direct PG&E, SCE and SDG&E to continue working with Greenlining in investigating the feasibility of including zip code or census track measurement as part of the information that they collect and report to the Commission. Any agreed-upon revision to this metric should be made in the time-frames for revision discussed below.

This decision adopts the request of Greenlining to revise Customer/AMI Metric 9 so as to report by customer class, CARE status and climate zone. The Commission agrees that this data may be useful to monitor the types of customers making use of this information.

Additionally, DRSG proposed a revision to Customer/AMI Metric 9 to require an enumeration of the customers who have authorized third parties to have access to the information. Since access to customer information provided by third parties is as important as access provided by the utilities, this decision modifies this metric as requested

On Customer/AMI Metric 6, this decision adopts the request of DRA to revise the definition of an "Escalated Complaint." This decision agrees that this definition should be consistent across the utilities, as that will allow the Commission, Staff, parties and the public to be able to compare utility reports on a meaningful basis. In reply comments, SCE offered a proposed definition.[55] This decision adopts this proposed definition offered by SCE. The language in Customer/AMI Metric 6 is not changed, but this decision revises the definition of "Escalated Complaint" as follows:

> Escalated Complaint: A complaint (written or telephonic) received by the utility's Consumer Affairs Department (or equivalent) regarding the AMI meter or program, or regarding device registration and communication issues.

DRA also requests that the information collected in Customer/AMI Metric 6 be tracked by the type of complaint. This decision finds this proposal reasonable. Customer/AMI Metric 6 should be organized according to the definition of escalated complaint. That is, complaints should be tracked by the following topics: AMI meters, AMI programs, device registration, and communication issues. To the extent that information is available, the reporting of this information can be divided by complaints about utility products, programs or devices and complaints about third-party products, programs or devices.[56]

As the utilities gain more experience with customer complaints associated with Smart Grid-enabled devices, we expect to be able to collect more detailed information on complaints. At this time, however, this decision declines to adopt DRA's full suggestion to track escalated complaints by more specific descriptions.

This decision also adopts DRA's proposed modification to Customer/AMI Metric 7. Additionally, this decision adopts DRA's suggestion that this metric

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[55] SCE Reply Comments at 4.

[56] The Commission does not expect the utilities to be the arbiter of customer complaints associated with third party devices and programs; rather, the purpose of this metric is to understand customer behavior and actions around third party devices and programs.

include the reason a meter is replaced. DRA argued persuasively that without including a reason for the replacement, this metric would hold less meaning. At a minimum, the reasons should include meter malfunction, meter installation error, or customer tampering; as the utility gains more experience with collecting and reporting on this metric, the reasons for replacement may be expanded. Customer/AMI Metric 7 is therefore revised to the following:

> The number and percentage of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually, with an explanation for the replacement.

3.2.2. No Revisions to Plug-in Electric Vehicle Metrics

There are no revisions to the proposed Plug-in Electric Vehicle Metric.

3.2.3. Revisions to Storage Metrics

The decision revises Storage Metric 1 to measure more accurately the amount of electricity released by a storage unit and reported by the transmission and distribution system.

Ice Energy's proposal to add a second metric to the Storage category is not adopted. As these metrics are designed to be preliminary and interim, the storage metric already identified is sufficient at this stage in Smart Grid development. While SB 17 identifies "thermal-storage air conditioning" as a Smart Grid technology, there is no specific direction to the Commission to include thermal-storage air conditioning as a separate category for measurement. As electric energy storage technologies begin to proliferate throughout the grid, the Commission expects further revisions in this category of metrics to begin measuring the variety of electric energy storage devices installed across the grid. Finally, this decision notes that a separate Commission proceeding is already on-going concerning electric energy storage.[57] The

[57] *See* R.10-12-007.

policies developed in that proceeding will likely have a great impact upon future smart grid storage metrics and this decision defers to that ongoing endeavor.

3.2.4. Revisions to Grid Operations Metrics

This decision revises Grid Operations Metrics 1, 2, 3, 4, and 5 to include a baseline year starting in July 2011 from which to start measuring. Additionally, this decision revises Grid Operations Metric 4 to require the reporting of the percentage of customers and circuits experiencing greater than 12 sustained outages. The data pertaining to "percentages" will allow the Commission to obtain information on the relative frequency of a particular issue.

3.2.5. Other Metrics

EDF's proposal to add two metrics under the Environmental category are not adopted at this time. As discussed below, development of metrics to measure any environmental benefits from Smart Grid implementation should be discussed in the context of a Technical Working Group. The metrics proposed by EDF deserve more attention and consideration than was possible in the record developed in this proceeding up to this point. The Commission expects the utilities, EDF and any other interested party to continue discussions around creating metrics that may be able to measure environmental benefits derived from Smart Grid implementation.

Finally, AReM requested that the Commission state that metrics only apply to the UDC company portion of operations, and that any benefits derived from Smart Grid should accrue to the appropriate entity. The Commission declines to make that determination at this time. AReM provides no suggested edits to the metrics to effectuate its changes and bases its supportive arguments on speculation on potential future benefits from Smart Grid. Thus, we cannot determine exactly what AReM requests. In addition, this decision also agrees with SCE's response that any discussion around the allocation of benefits should take place in the relevant proceedings where the benefits are produced, not here.[58] AReM is therefore free to reargue for cost and benefit allocation in those proceedings where benefits accrue; this Smart Grid proceeding is not the appropriate proceeding to discuss allocation of costs and benefits derived from Smart Grid investments because they are only rough estimates at this point.

4. Reporting of Metrics

There are two questions posed by the parties regarding the reporting period for metrics. The first involves the filing of the initial set of metrics, and the second involves the subsequent reporting of metrics with the Annual Report. The Commission will address both questions.

4.1. Positions of Parties

PG&E, SCE and DRA support setting the reporting date for the initial set of metrics of July 1, 2011.[59]

SCE requested that the Commission reconsider using June 30 as the end date for the yearly reporting period. SCE noted that many of their reporting schedules for information that serve as a basis for the Smart Grid metrics are collected annually and argued that having a different reporting period may increase reporting costs.[60]

PG&E also supported using December 31 of each year as the reporting period date, instead of June 30.[61]

DRA noted that the Commission decided to use June 30 as the reporting date to have more current information in the creation of the Commission's Smart Grid annual report, which is due to the Legislature every January 1.[62] DRA, however, stated that it is concerned about potential increased costs due to

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[58] SCE Reply Comments at 7.

[59] PG&E Comments at 3; SCE Comments at 3, 8-9; DRA Comments at 4-5.

[60] SCE Comments at 9.

[61] PG&E Comments at 3.

[62] DRA Comments at 4.

reporting metrics as of June 30.[63]

4.2. Discussion

Utility smart grid annual reports are due to the Commission by October 1 of each year, starting on October 1, 2012. The purpose of the utility annual reports is to describe the current state of the utility's Smart Grid deployments and investments. As previously specified, the utility's annual report must include:

- A summary of the utility's deployment of Smart Grid technologies during the past year and its progress toward meeting its Smart Grid Deployment Plan;
- The costs and benefits of Smart Grid deployment to ratepayers during the past year; and
- Current initiatives for Smart Grid deployments and investments.[64]

Additionally, the utilities' annual report is the place where the utilities report on their performance using metrics adopted in this decision.

Finally, the utilities' annual report will serve as the basis for the Commission's annual report to the Governor and Legislature. The Commission is required by statute to prepare an annual smart grid report, which is due to the Governor and Legislature by January 1 of each year, beginning in 2011.[65] The purpose of the Commission's Annual Report is to "report … 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."[66]

In D.10-06-047, the Commission stated that information to be included in the utilities' Annual Report filings should be current as of July 1 of each year.[67]

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[63] *Id.* at 4-5.

[64] D.10-06-047 at 100.

[65] Pub. Util. Code Sec. 8367.

[66] *Id.*

[67] D.10-06-047 at 101.

The Commission reasoned that a reporting period of July 1 to June 30 for each year would provide "the most recently available information on the utilities' Smart Grid actions, and will allow the Commission to provide the Governor and Legislature the best available information."[68] Additionally, the decision explicitly denied SCE's request to use December 31 as the reporting period, noting that using a December 31 reporting period would result in "the Governor and Legislature … receiving a report using information that is over a year old."[69]

SCE and PG&E have not persuaded the Commission to revise the reporting period date for the metrics or the Annual Report. This decision reaffirms that using information collected on a calendar year basis and reported 12 months later is not in keeping with the intention of the statute, and it would prove less useful to the Commission, the Legislature, the Governor, parties, or the public. The Commission understands, however, that some information may only be available on a yearly basis, and may be costly to update during the year. SCE, PG&E and SDG&E should provide cost information on those metrics that require a costly mid-year adjustment. During the metrics review process, as discussed below, the utilities may request a change in the reporting period in those situations where it is costly to obtain the information. Nevertheless, until that time, the utilities should continue to report metrics as of July 1 to June 30 for each reporting year.

5. Metrics Review Process

The metrics that are adopted by today's decision are intended to be interim and preliminary, and are expected to be revised and edited over the coming years as advances in technology and infrastructure allow for greater understanding of the grid and consumer behavior. This section will set up a process for the initial review of the metrics.

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68 *Id.*

69 *Id.*

5.1. Positions of Parties

Concerning the revision of metrics, parties proposed several methods for routinely updating and revising metrics as technology advances. The commenters had much in common – all parties that provided comments on this topic of revising metrics agreed that there should be a yearly process for reviewing and revising the metrics.

SCE proposed a three step process for development of future Smart Grid metrics. SCE suggested that the process include both an informal and formal process, follow specific criteria, and fit within a defined time-line. SCE recommended that an informal Technical Working Group be convened as a starting point for review and revision of consensus metrics.[70] SCE also proposed that any new metrics be based on certain criteria: consistency with P.U. Code § 8360, consistency with content of the Smart Grid Deployment Plans, reasonable cost of measurement, and consistency across PG&E, SCE and SDG&E.[71] As for the timing of metric reviews, SCE recommended that the review of adopted metrics and the consideration of new metrics be deferred until the filing of their deployment plans on July 1, 2011. By waiting until after the deployment plans are filed, SCE states that the plans will help "determine (i) which subject matter should be prioritized by Technical Working Groups, and (ii) which Consensus Metrics require updating or revision."[72]

SCE also proposes that Technical Working Groups should be convened to revise the consensus metrics, where necessary, and develop other metrics.[73] These working groups can be convened on a yearly basis and recommend revisions and additions to the metrics in time for the yearly report.[74] SCE

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70 SCE Comments at 4-5.

71 *Id.* at 5-6.

72 *Id.* at 6-7.

73 *Id.* at 7.

74 *Id.*

proposed a preliminary schedule for the timing of these working group meetings tied to this annual reporting process.[75]

PG&E also supported an annual review and updating of the metrics. PG&E recommended that meetings be convened "for the purpose of periodically reviewing and updating the interim metrics."[76]

DRA stated that the "metrics should be reviewed on a regular basis, with revisions made as necessary."[77] DRA recommended that the Commission adopt a formal review process and allow for a public comment period before Commission adoption.[78] According to DRA, metrics should be "revisited prior to filing of the July 2012 deployment plans."[79] The Commission will be better informed about the plans and the process, and will have reviewed the initial deployment plans.[80]

The CAISO argued that "it is crucial that the metrics be reviewed on an ongoing basis."[81] The CAISO suggested that the Commission establish an annual review process "to ensure that the metrics remain tailored to the state's highest smart grid priorities."[82]

Granite Key/Aspect Labs supported the holding of a workshop "at a later date" to discuss any potential revisions to the metrics, as well as allow for a forum to discuss "areas of non-consensus."[83]

5.2. Commission Revisions of Metrics

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[75] *Id.*

[76] PG&E Comments at 2.

[77] DRA Comments at 3.

[78] *Id.*

[79] *Id.* at 4.

[80] *Id.*

[81] CAISO Comments at 2.

[82] *Id.*

[83] Granite Key/Aspect Labs Comments at 5.

The request for review and revision of adopted metrics is reasonable and we outline and describe a process below that will address the reports of Technical Working Groups and consider technical revisions to consensus metrics. This approach allows the Commission to gain experience with preparing annual reports and with reviewing metrics and revising them before establishing a rigid review process.

The ability for parties and Commission Staff to review and revise these metrics, where and when appropriate, is of great importance to ensure that the Commission and parties continue to make progress in renewing the grid's infrastructure. The Commission expects that these metrics will be updated, including adding new metrics and removing metrics that are no longer useful, over the course of the next several years. The request of an annual updating of metrics, however, seems overly ambitious. Rather than adopt a specific schedule for the updating of metrics, we commit to workshops and workshop reports that will lead to the adoption of revisions to metrics and to a process for updating metrics.

In order to facilitate the ability of parties to continue developing and revising these metrics, the Commission directs the creation of a Technical Working Group that is designed to focus on the development and review of metrics and measureable goals. This Technical Working Group should be composed of interested parties, including, at a minimum, representatives from PG&E, SCE and SDG&E, DRA, CAISO, CEC and Commission Staff. The Commission expects that additional representatives from consumer groups, end-users, third parties and other advocacy groups will participate. Additionally, the creation of this Technical Working Group does not mean parties cannot discuss proposed revisions outside of the working group process; however, in order for a metric to be considered as "consensus" it must go through the Technical Working Group process.

This Technical Working Group should review metrics by topics as listed in the consensus metrics; this will facilitate the review and creation of any new metrics by those interested in the specific topic areas. The Technical Working Groups should circulate their first report with recommended changes in the consensus metrics to the service list in this proceeding. In addition, the Commission will rely on its staff to bring proposed revisions to the Commission's attention.

To guide the work of the Technical Working Groups, the Commission adopts SCE's proposed criteria for guiding metric development. Specifically, any new metric developed during the working group process should be consistent with the Public Utilities Code, including § 8360, should be consistent across PG&E, SCE and SDG&E, and should be consistent with any metrics or policies in an approved Smart Grid Deployment Plan. Additionally, new metrics should not be too costly to implement or measure. Commission Staff will schedule workshops with this Technical Working Group.

6. Cyber-Security and the Environmental Metrics

Throughout the discussions over metrics, two specific topics were addressed repeatedly and deserve special attention: cyber-security and environmental protection. These two topics present special circumstances for the development of metrics because neither topic, albeit of critical policy significance, is subject to the straightforward quantification that would permit the construction of a simple metric.

As a consequence, the Commission directs, as described in more detail below, the creation of two additional Technical Working Groups to begin the discussion around developing consensus metrics on cyber-security and environmental benefits from Smart Grid deployments.

6.1. Positions of Parties

All parties that commented on this topic agreed that the creation of Technical Working Groups on cyber-security and environmental metrics was warranted.

SCE supported the creation of "an informal technical working group to address the development of future cyber-security metrics."[84] SCE also supported the creation of an inventory of utility cyber-security practices as proposed by Granite Key/Aspect Labs, as well as the need for parties to sign an appropriate non-disclosure agreement.[85]

SDG&E stated that a working group on "cyber security metrics would serve to promote stakeholders engagement and collaborative dialogues concerning this important matter."[86] SDG&E, however, cautioned that due to the sensitive nature of the topic a non-disclosure agreement may not be sufficient to protect the information.[87] SDG&E reiterated that "[t]he security of these systems and data are essential to avoiding disruptions in critical utility operations, as well as to prevent data tampering, fraud, and inappropriate disclosure of sensitive information."[88]

PG&E supported a Technical Working Group on cyber-security metrics, but cautioned that it "remains skeptical that cyber-security issues can be reduced to 'metrics'…"[89] PG&E, instead, viewed the Technical Working Group as a means to informally share information, "including the sharing of confidential and security sensitive information through appropriate non-disclosure protections and protocols."[90]

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[84] SCE Comments at 8.

[85] SCE Reply Comments at 9.

[86] SDG&E Comments at 3.

[87] SDG&E Reply Comments at 3.

[88] *Id.*

[89] PG&E Comments at 3.

[90] *Id.*

DRA also supported the creation of working group on cyber-security. DRA recommended, however, that the group be called a "Cyber Security Technical Review Group" to "emphasize that the review group would not be advising PG&E, SCE and SDG&E on cyber security measures."[91] Specifically, DRA stated that this group "would collectively formulate and review metrics that will assist in informing the Commission and interested parties on the success or failure of cyber security specifically related to Smart Grid deployment."[92] Further, DRA argued that the purpose of the Technical Review Group is to "develop cyber security metrics that do not compromise the utilities' security."[93] Finally, DRA argued that the group should be considered confidential as participants may discuss confidential materials relating to cyber-security policies of the utility.[94]

SoCalGas stated that they have participated in the previous discussions on cyber-security metrics, and that a Technical Working Group on cyber-security "would be helpful in continuing the discussion among parties on these issues."[95]

Granite Key/Aspect Labs also supported the creation of a Technical Working Group on cyber-security metrics. Granite Key/Aspect Labs proposed that the working group "should perform an inventory of practices a utility already does in regards to grid and cyber-security."[96] Additionally, the working group should "allow for an informal sharing of information about utilities' cyber-security policies and protocols" in order to help inform participants in creating metrics.[97] Finally, Granite Key/Aspect Labs identified an initial list of 19 questions designed "to gather information about the current state of utilities' cyber-security practices"

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[91] DRA Comments at 6.

[92] *Id.*

[93] *Id.*

[94] *Id.* at 6-7.

[95] SoCalGas Comments at 6.

[96] Granite Key/Aspect Labs Comments at 2.

[97] *Id.* at 2.

that will help inform the conversation.[98]

6.2. Discussion of Cyber-security and Environmental Metrics

There is substantial agreement among parties concerning the path forward on these issues. The parties agree that the creation of a Technical Working Group to begin discussing and creating metrics on cyber-security would be beneficial. Additionally, as discussed above, there is also substantial agreement that a Technical Working Group should also be created to address the creation of metrics associated with potential environmental benefits from Smart Grid deployment.

Based on the consensual arguments of the parties, the Commission will create a Technical Working Group to develop cyber-security metrics for Smart Grid and a second Technical Working Group to develop environmental metrics.

On cyber-security, the Commission agrees with the parties that cyber-security is an important attribute of any Smart Grid deployment. Furthermore, the Commission has a responsibility to the customers of PG&E, SCE and SDG&E that any investments and deployments approved by the Commission contain a high-level of security and safety assurances. These metrics should provide a means to measure the effectiveness of a utility's cyber-security policies and protocols as it applies to existing and new Smart Grid deployments.

The creation of a Technical Working Group to recommend metrics on cyber-security is reasonable. These metrics, when adopted by the Commission, should be applied consistently across the three Investor-owned Utilities and should be reported, to the greatest possible extent feasible and consistent with

[98] *Id.* at 3-4.

[99] The Commission understands that there may be sensitive data that cannot be

security goals, publicly.[99] Finally, any consensus metrics that are developed in this process should be included in the Technical Working Group's report.

This decision also finds the proposal of Granite Key/Aspect Labs for structuring the initial Technical Working Group meetings a constructive suggestion for facilitating initial discussions and have added it as Appendix B to this decision. The Technical Working Group's initial efforts should undertake an inventory of what cyber-security information the utilities are already collecting, what information on cyber-security the utilities are already providing to the Commission, and other state and Federal agencies, and what cyber-security practices are currently in use by the utilities.[100] Once an inventory is done, the Technical Working Group should begin considering the creation of metrics based on this inventory that can be applied to PG&E, SCE and SDG&E.

The Commission therefore directs its Staff to initiate this Technical Working Group, and to make careful and appropriate use of the initial list of questions proposed by Granite Key/Aspect Labs and included as Attachment B to this decision as a starting point for discussion. The utilities will not be required to disclose cyber-security gaps and vulnerabilities, cryptographic and software protective measures, or other similar items in the workshop setting. Finally, the Technical Working Group should consider and create, to the extent necessary, a non-disclosure agreement for all participants to ensure the ability of all parties to discuss and collaborate freely and openly.

In D.10-06-047, the Commission required the utilities' Smart Grid Deployment Plans to include a section on Grid and Cyber-Security. As the Commission explained:

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reported publicly; in that case, metrics can be filed under seal, and be provided to Commission Staff, DRA and those who have signed the appropriate non-disclosure agreement.

[100] The full list of items is available at Attachment B.

> The Commission and the public have good cause to be concerned and a right to expect that the electric grid will remain secure with the deployment of Smart Grid technology.[101]

This Technical Working Group should be a forum for the Commission, utilities and interested parties to begin discussing policies and protocols that the Commission may adopt to ensure the security of the grid as Smart Grid is deployed. Additionally, this should also be a forum to discuss any policies that the Commission may need to adopt to address potential cyber-security issues with legacy equipment.

The Commission expects to continue participating in national efforts on cyber-security, and will expect the utilities to use any agreed-upon standard or protocol that is developed in that process. The Commission is also aware that investment in and deployment of Smart Grid technology and infrastructure in California is ahead of most of the United States; it is, therefore, incumbent upon the Commission to ensure that these deployments contain an appropriate level of cyber-security, and to ensure cyber-security is a fundamental practice for Smart Grid deployments. In addition, the Commission will rely on Energy Division staff to bring proposed revisions to the Commission's attention.

Concerning the development of environmental metrics, the Commission directs the creation of a separate Technical Working Group to develop metrics to measure the environmental benefits that can be attributed to Smart Grid deployments. The Commission appreciates the efforts already made by the utilities and EDF to begin this discussion. The Commission directs Commission Staff to initiate this Working Group, and begin discussions on this topic. Commission Staff should consult with the utilities, EDF, and other interested participants in the preparation of the first meeting and work towards a report that will be filed in this proceeding.

[101] D.10-06-047 at 58.

EDF, in its comments, identified an initial set of potential environmental metrics associated with Demand Response and Distributed Generation.[102] The Commission also agrees with EDF's observation that as Smart Grid deployments increase, it may become possible to measure additional environmental benefits that can be attributed to Smart Grid deployments. This Technical Working Group should be forum for this discussion.

Any consensus metrics that are developed in this process should be included in the report of this Technical Working Group. In addition, the Commission will rely on Energy Division staff to bring proposed revisions to the Commission's attention.

7. Goals to Complement Metrics

As part of the Commission's review of metrics, the Commission will examine whether the specification of goals offers a better way of directing progress towards the Smart Grid than simply specifying metrics.

Consider, for example, our metric concerning plug-in electrical vehicles: "the number of customers enrolled in time-variant electric vehicle tariffs." This metric offers a good way of measuring how electrical vehicles are able to use the new Smart Grid. It does not, however, set a vision shared by the utilities and the regulator for what the Smart Grid should or could accomplish for California. A goal akin to California's renewable portfolio standard, in contrast, creates a target and a direction for all involved.

For the Smart Grid, the development of a series of goals may offer a good way of developing a vision of the Smart Grid. The Commission plans to investigate this issue as part of the Technical Working Group's efforts.

Since 2008, the Commission has issued a number of decisions to guide the utilities toward a smarter grid. Specifically, the Commission opened this Rulemaking to guide policy in California's development of a Smart Grid system.

[102] EDF Comments at 4.

The Commission has since issued decisions to establish privacy rules, set requirements for utility deployment plans, and guide the utilities to enable third-party access. The utilities have been equally active in responding to our proceedings, including filing their 10-year deployment plans in 2011.

As the Commission and utilities advance in the deployment of a Smart Gird, a Technical Working Group chartered to create broad goals can create a common vision for all involved. Preliminarily, the Commission would like to investigate whether to adopt goals for the following areas:

1. Customer goal – where do we want the customer to be in 2020?
2. Environmental goal – how will upgrading the grid benefit the environment (*i.e.*, a reduction in GHG) by 2020? What should be the principal environmental goal?
3. Market goal – how does a Smart Market behave (*i.e.*, an increase in renewable distributed generation) by 2020?
4. Utility goal – are there utility operational goals or customer satisfaction goals that should be a focus of a utility's Smart Grid efforts?

Consider, for example, a potential Smart Grid customer goal: 50 percent of a utility's customers using an online account. This may be a legitimate Smart Grid goal because the usefulness of the Smart Grid depends on customers utilizing the data provided to them in their decision-making. If it remains the case that a customer is only able to get this information if the customer either uses a utility "my account" system and/or a third-party portal that gives the same type of information, then it may be reasonable to set as a goal that by 2020 50% of each utility's customer base will be using some form of online access their consumption information.

Goals not only focus us on a common vision, but also provide the policy makers, the utilities and consumer advocates yet another reason to continue to encourage a smarter grid.

The Technical Working Group on goals should commence its work within 45 days of the issuance of this decision and begin the process of creating such goals. This report should be filed and served in this proceeding by November 1, 2012.

8. Summary and Conclusion

This decision adopts 19 consensus metrics to measure progress on implementing a Smart Grid.

In addition, the decision creates four Technical Working Groups to revise consensus metrics, to develop cyber-security metrics, to develop environmental measures and to develop four Smart Grid goals. The reports developed by the Technical Working Groups will be used by the Energy Division in its review of metrics. The report of the Technical Working Group on goals will be filed and served in this proceeding by November 1, 2012. We anticipate a Commission decision in this proceeding adopting goals and subsequent consideration of additional metrics by the Commission in other venues.

9. Comments on Proposed Decision

The proposed decision of Commissioner Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 9, 2012, by AReM, CEERT, DRA, SDG&E, CAISO, PG&E, SCE, Greenlining and EDF, and reply comments were filed on April 16, 2012 by PG&E, SCE, DRA, SDG&E.

In general, the comments sought clarifications and modifications of the metrics and further details concerning the functioning and charter of the proposed technical working groups. We discuss the comments and our responses in this section.

SCE argues that the "Commission should not mandate that the California utilities disclose sensitive cyber-security information and vulnerabilities to anyone but the Commission itself."[103] In addition, SCE seeks clarifications to metrics 2, 4, 5, and 9. SCE also seeks modifications to the storage metric and the distributed generation metrics to remove contradictory definitions that create confusion.

The SCE requests are reasonable and clarify technical aspects of the metrics. We have incorporated the changes proposed by SCE into the text of the decision and into Attachment A.

AReM criticizes the metrics on several grounds. AReM argues that "the proposed consensus metrics are utility-centric and do nothing to facilitate third-party participation in markets."[104] AReM contends that the "PD conflates issues of how to appropriately allocate the benefits to various customers with how to count benefits for purposes of determining the effectiveness of the utilities' programs."[105] AReM also argues that "the technical working groups must not be allowed to dictate what is brought before the Commission."[106]

In response to AReM, we note that these consensus metrics are a first step, and additional metrics may emerge from the workshop process. Concerning benefits, the Commission remains focused on insuring that the benefits produced by Smart Grid investments exceed costs – we do not intend to allocate benefits at this time. Finally, we assure AReM that the technical working groups will not dictate what is brought before the Commission because they cannot. What is brought before the Commission must flow through the checks and balances of Commission procedure, which aims to ensure that all voices are heard.

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[103] SCE Comments on PD at 3.

[104] AReM Comments on PD at 2.

[105] *Id.* at 4.

[106] *Id.* at 5

CAISO makes several recommendations for modification of the metrics. Concerning Customer/AMI Metric 5, the CAISO recommends that "metric no. 5 be reported by type of time-variant or dynamic pricing tariff so that the Commission and other interested parties can gain a better understanding of how progress towards this metric is being achieved."[107] Concerning Grid Operations Metric no. 7, the CAISO asks for greater reporting detail, requesting "reporting by month and ISO sub-Load Aggregation Point."[108] In addition, CAISO asks the Commission "to clarify that the Commission's engagement with these issues going forward will not be limited to evaluating the IOUs' annual smart grid reports."[109] Finally, CAISO asks that the Commission provide more detail on the future of the working groups and that "the final decision explicitly address the question of how long the Commission intends for the update/revisions working group to remain active."[110]

In response, we have amended Customer/AMI Metric 5 and Grid Operations Metric 7. We further assure the CAISO that the Commission will be actively monitoring Smart Grid developments. We note that the reports of the utilities will be a key input to the Commission's annual report to the legislature on the Smart Grid. Finally, concerning the future of the working groups, it is premature to determine the future for updates and revisions at this time. We anticipate that the working groups will provide a recommendation to the Commission concerning what their experience with revisions and new metrics indicates is a prudent way to proceed.

PG&E argues that "the consensus Smart Grid metrics should be adopted, but the Commission should clarify the limitations on the use and relevance of the

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[107] CAISO Comments.

[108] *Id.* at 4.

[109] *Id.*

[110] *Id.* at 5.

metrics."[111] Furthermore, PG&E opposes the creation of a technical working group to develop goals as potentially conflicting with the proceedings reviewing Smart Grid deployment plans. PG&E also argues that the cyber-security working group should not be tied to the proposal of Granite Key/Aspect Labs, and asks that the environmental and metric revision technical working groups be combined "for administrative efficiency and reduced staffing burden."[112]

In response, we remind PG&E that Commission staff has led the development of the metrics, and understands their use and limitations. Concerning PG&E's working group proposals, we have clarified that the workshop on cybersecurity will not be tied to Granite Key/Aspect Labs proposal and that Appendix B is meant only to facilitate initial discussions. We, however, decline to consolidate the technical and environmental working groups because at this time we believe that the use of two groups will permit efficient and selective participation, and the Commission staff can merge them should they determine that merging them promotes efficient operation. Finally, we retain the technical working group concerned with goals, and note that it will report back to this proceeding to enable consideration of the goals by the Commission. This will ensure that there is no conflict between the work of this proceeding and that of the proceedings considering the Smart Grid development plans.

SDG&E makes comments on several of the metrics in Appendix A to their comments. In general, these comments point out areas of contradictions and ambiguities.[113] SDG&E also asks for changes to the consensus metrics "due to regulatory updates."[114] Finally, SDG&E urges the Commission to proceed with caution in developing goals for the Smart Grid and recommends "dialogue

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111 PG&E Comments on PD at 2.

112 *Id.* at 6.

113 SDG&E Comments on PD at 1.

114 *Id.* at 2.

among the Commission, the IOUs and other interested stakeholders in order to understand the key concerns of each party."[115]

In response to SDG&E, we have made clarifications to the metrics and revised them to reflect changes due to regulatory updates. Concerning the development of goals, we stress that the working group will propose goals for consideration by the Commission in this proceeding; it is not chartered to create goals.

Greenlining asks the Commission to "adopt Greenlining's proposal to report by customer class, CARE enrollment, and climate zone."[116] Greenlining argues that "it should be pursued unless pursuit is affirmatively demonstrated to be unworkable."[117]

In response, we have altered this decision to reflect Greenlining's new proposal. This proposal includes only data that should be readily accessible the utilities and not costly to provide. If, however, the costs of providing this data are large, the utilities may bring new facts to the attention of the Commission through a petition to modify.

EDF "supports the PD's approach to development of environmental metrics."[118] EDF asks further that "the Commission require the environmental technical working group to examine metrics that represent the broad scope of environmental benefits."[119]

In response, we anticipate that the work of the environmental working group will examine metrics that represent the broad scope of environmental benefits.

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[115] *Id.* at 2.

[116] Greenlining Comments on PD at 1.

[117] *Id.* at 2.

[118] EDF Comments on PD at 2.

[119] *Id.* at 3.

DRA recommends a revision to Customer/AMI Metric 8 to ensure "the results of the field tests of the meters be reported."[120] DRA argues that "the cyber-security technical working group should be limited to discussing consensus metrics"[121] and "cautions against using that group as a forum for formulation of cyber-security policies and protocols."[122]

In response, we agree with DRA that the results of the meter tests should be reported, and we now use SCE's proposed language to ensure that there is no ambiguity on this matter. Regarding cyber-security, the technical working group on metrics is not a forum for adopting cyber-security policies. If the Commission determines that specific policies should be adopted, we will use the appropriate procedural vehicle for creating a record that supports Commission decisionmaking.

CEERT recommends the Commission act on two of EDF's proposed metrics at this time. In addition, CEERT states that "the preliminary goal areas should be amplified to assist discussion at the technical working group."[123]

In response, we confirm that environmental metrics still require more work, and the technical working group is the best setting to resolve these issues. In addition, we welcome CEERT's efforts to provide examples of issues that the working group on goals can consider, but we decline to constrain the work of that technical working group at this time.

10. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Timothy J. Sullivan is the assigned ALJ in this proceeding.

[120] DRA Comments on PD at 2.

[121] *Id.*

[122] *Id.* at 3.

[123] CEERT Comments on PD at 5.

Findings of Fact

1. The "Report on Consensus and Non-Consensus Smart Grid Metrics," which is Attachment A to the December 29, 2010 ALJ Ruling in this proceeding, contains 19 consensus metrics.

2. The 19 consensus metrics contained in the "Report on Consensus and Non-Consensus Smart Grid Metrics" serve as a reasonable basis on from which to develop Smart Grid Metrics because they cover the major areas of concern identified SB 17 (Chapter 327, Statutes of 2009).

3. The 19 consensus metrics and definitions, as amended for clarity and contained in Attachment A, are reasonable initial metrics for assessing progress in implementing a Smart Grid because tracking changes in these metrics will provide a measure of the extent of progress achieved by a utility.

4. The 19 consensus metrics will assist the Commission in preparing its annual report on the Smart Grid because they provide information needed to create this report.

5. The 19 consensus metrics are not relevant for measuring SoCalGas's deployment of its new metering infrastructure because this gas metering structure is technically very different from that deployed by electric corporations.

6. The initial scope of this proceeding did not apply to SoCalGas because it was limited to electrical corporations.

7. It is not reasonable to require that SoCalGas provide information to the Commission pursuant to the 19 consensus metrics that apply to electric systems because of the differences in their new metering infrastructure and because they did not have judicial notice.

8. It is reasonable to modify consensus metrics 1, 4, 5, 6, 7, 8 and 9 pertaining to Customer/AMI Metrics to ensure consistency of reporting across companies and across measures because such consistency will both increase the utility of the measures and decrease confusion in reporting.

9. It is reasonable to modify consensus metric 3 pertaining to Customer/AMI Metrics to add clarity to the reporting metric because such clarity improves the accuracy of this measure.

10. It is reasonable to revise Storage Metric 1 to measure more accurately the amount of electricity released by a storage unit and reported by the transmission and distribution system because accuracy is an important element of any metric.

11. It is reasonable to set a baseline year starting July 1, 2011 from which to begin the measurement of grid operations Metrics 1, 2, 3, 4, and 5 because a common baseline will enable comparisons across time and across companies.

12. It is reasonable to revise Grid Operations Metric 4 to require the reporting of the percentage of customers and circuits experiencing greater than 12 sustained outages in addition to the raw number because this figure will provide context on the extent of the outage.

13. It is reasonable to continue to investigate the feasibility and cost-effectiveness of requiring the inclusion of census track information for Metrics 4, 5 and 9 pertaining to the Customer/AMI metrics because such information permits the Commission to determine whether the benefits such information provides warrants the cost of acquisition.

14. It is not reasonable at this time to require utilities to report Customer/AMI Metric 9 by customer class, CARE status, and climate zone because the Commission has not investigated the costs of such a requirement.

15. It is reasonable to require that PG&E, SCE, and SDG&E continue to research the costs and feasibility of matching customers who access their information online with customer class, CARE enrollment status, and climate zone because that information will enable the Commission to determine a reasonable course of action.

16. Because of the importance of third-party access to customer information is still in its infancy, it is reasonable to adopt the revisions to Customer/AMI Metric 9

proposed by DRSG at this time because these revisions will enable the Commission to track third-party access.

17. It is reasonable to revise the definition of "Escalated Complaint" and to ensure that the definition is consistent across utilities because these revisions eliminate ambiguities that undermine the accuracy of a measure.

18. It is reasonable to require the information collected in Customer/AMI Metric 6 to be tracked by the complaint topics: AMI meters, AMI programs, device registration, and communications issues. To the extent that information is available, it is reasonable to count separately complaints concerning utility products and those pertaining to third-party products, programs or devices. These requirements are reasonable because they improve the accuracy of these measures and permit comparisons across utilities.

19. It is reasonable to require Customer/AMI Metric 7 to include a reason for the replacement of a meter because this information is critical to the Commission's understanding of this program.

20. It is not reasonable at this time to adopt a metric pertaining to thermal storage air condition because the Commission is currently investigating policies pertaining to storage in R.10-12-007.

21. It is reasonable to await direction and guidance on storage metrics from the Commission rulemaking pertaining to storage, R.10-12-007, because that proceeding is undertaking a systematic view of storage policy.

22. It is reasonable to defer the development of environmental metrics to a Technical Working Groups initiated by this proceeding because the Commission lacks information needed to adopt such measures at this time.

23. It is reasonable to establish July 1, 2011 as the benchmark date for metrics because a common starting point improves the comparability of collected data.

24. Because of the need to file an annual report with the Governor and the Legislature by January 1 of each year, it is reasonable to set July 1 to June 30 as the year for reporting purposes. Reliance on a January 1 to December 31 reporting year would result in the provision of dated information in the annual report.

25. The establishment of "goals" for the Smart Grid may offer a more productive and more reasonable approach to directing progress towards the Smart Grid because this approach has proved effective in other areas of energy policy.

26. It is reasonable to revise the metrics from time to time because of the changing nature of Smart Grid technologies and services.

27. It is reasonable to create a Technical Working Group to consider the revision of metrics or the adoption of additional metrics because a working group provides a good forum for addressing such a technical topic.

28. It is reasonable that the Technical Working Groups insure that any new metric developed during the working group process should be consistent with the Pub. Util. Code and with policies approved in the Commission's review of the Smart Grid Deployment Plans. In addition, new metrics should be consistent across PG&E, SCE and SDG&E. These requirements are reasonable because they ensure consistency with the Pub. Util. Code and add to the comparability of the metrics across companies.

29. It is reasonable to require PG&E, SCE, SDG&E, DRA, and Commission Staff to begin consideration of revisions to adopted metrics after the adoption of this decision through Technical Working Groups because of the rapid pace of change in this area. It is reasonable to permit other parties to participate in these discussions because of the valuable insights that they may provide.

30. It is reasonable to create a Technical Working Group to develop cyber-security metrics because a technical working group is the best forum for consideration of such a technical topic.

31. It is reasonable to require that the initial Technical Working Group meetings pertaining to cyber-security undertake an inventory of the cyber-security information that the utilities are already collecting, what information on cyber-security the utilities are providing to the Commission and to other state and Federal agencies, and current cyber-security practices in use by the utilities because such information can educate the Commission on the current state of network security. It is reasonable to keep this information confidential, and if filed with the Commission, it is reasonable to keep it under seal without time limit unless the Commission determines that the release of this data is in the public interest because information on security could be exploited.

32. It is reasonable to create a Technical Working Group to address issues pertaining to the development of environmental metrics because of the technical nature of these issues.

33. It is reasonable to create a Technical Working Group to develop Smart Grid goals pertaining to customers, to the environment, to energy markets, and to utility operations because such a forum can permit the consideration of multiple technical factors simultaneously.

34. It is reasonable to require that the Technical Working Group considering goals file and serve a report by November 1, 2012 in this proceeding because this will permit timely consideration of this matter by the Commission.

Conclusions of Law

1. The 19 consensus metrics as modified and contained in Attachment A are consistent with California statutes pertaining to the Smart Grid.

2. Pursuant to § 8367 of the Pub. Util. Code, the Commission must prepare and provide an annual report to the Governor and to the Legislature containing information on the status of the Smart Grid.

3. Since the statutory provisions pertaining to the provision of an annual report to the Governor and the Legislature on the status of the Smart Grid do not apply to SoCalGas, it is not necessary to develop metrics pertaining to deployment of its metering infrastructure at this time.

4. Setting a baseline year starting on July 1, 2011 from which to begin the measurement of grid metrics is consistent with the statutes pertaining to the Smart Grid.

5. The creation of Technical Working Groups to revise metrics and to establish goals for deploying the Smart Grid, to develop metrics pertaining to cyber-security, and to develop metrics for assessing environmental improvement is consistent with statutes pertaining to the Smart Grid.

6. To facilitate the development of comprehensive Smart Grid Deployment plans, the Technical Working Group considering goals should file and serve its report in this proceeding by November 1, 2012.

O R D E R

IT IS ORDERED that:

1. The Consensus Metrics and definitions contained in Attachment A to this decision are adopted.

2. Pacific Gas and Electric Company, Southern California Electric Company and San Diego Gas & Electric Company shall include information pertaining to these metrics defined in Attachment A in their reports filed pursuant to ordering paragraphs 15 of Decision 10-06-047.

3. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company shall participate in four Technical Working Groups formed by representatives of the Commission to review the consensus metrics, to develop cyber-security metrics, to develop environmental metrics and to propose Smart Grid goals. The representatives of the Commission may invite others as needed to participate in a Technical Working Group. The Technical Working Group developing goals shall file and serve its report by November 1, 2012 in this proceeding.

4. Rulemaking 08-12-009 remains open.

This order is effective today.

Dated April 19, 2012, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

ATTACHMENT A

Metrics

A. Customer / AMI Metrics

1. **Number of advanced meter malfunctions where customer electric service is disrupted, and the percentage this number represents of the total of installed advanced meters.**

   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:

   <u>Advanced Meter</u>: A meter that measures interval data and enables two-way communication between utilities and the meters located at customer premises.

   Includes Advanced Meters, or smart meters approved by the CPUC under the Advanced Metering Infrastructure deployment programs.

   Excludes RTEM and legacy meters (electro-mechanical and non-AMI).

   <u>Percentage:</u> Percentage is defined as [(the number of advanced meter malfunctions where customer service is disrupted) divided by (the number of advanced meters installed)], with the resulting number multiplied by 100.

   <u>Meter Malfunction</u>: Malfunction that caused an Advanced Meter to become inoperable. If a meter included a tamper detection feature, then the reporting should report separately meter malfunctions due to tampering from other malfunctions.

   Includes Advanced Meters with integrated service switch.

   Excludes Advanced Meters without service switch, RTEM, and legacy meters.

   <u>Service Disruption</u>: Outages caused by faulty Advanced Meters.

Excludes outages caused by service panel or weather head issues or house fires, outages caused by Advanced Meters without service switch, RTEM or legacy meters, Advanced Meters installed with service switch open by mistake, and Advanced Meter replacements.

Applicable Data Sources Already Reported:

SDG&E: Smart Meter Program Quarterly Reports

PG&E: Not currently reported

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: Includes only Advanced Meter malfunctions that result in loss of power, which may be insignificant and not relevant to overall effectiveness of Advanced 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 in MW of peak load reduction from the summer peak and from winter peak due to smart grid-enabled, utility administered demand response (DR) programs (in total and by customer class).**

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:

<u>Smart Grid-Enabled Demand Response Programs</u>: Demand Response programs that rely upon two-way communications, including Advanced Meters that allow for Home Area Network or internet enabled access of interval meter data and/or notifications

<u>Includes</u>: PTR (CARE and non-CARE Demand Response (DR) impacts, to the extent available), CPP, PCT, TOU, A/C Cycling,

Excludes: Energy information tools such as In-Home Displays, web presentment, budget assistant, and third-party data access.

Load Impact: Demand Response MW reductions will be determined, measured by ex post load impact analysis, coincident with each utility's system peak (adjusted to account for the Demand Response 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: This metric will not measure achievement of energy efficiency goals or energy conservation.

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

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 Demand Response event or price trigger from the Demand Response 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.

<u>Percentage</u>: Verified kW load reductions (engineering analysis) available for Demand Response, divided by total Demand Response portfolio kW, with the resulting number multiplied by 100.

<u>Enabled</u>: Event triggered Demand Response programs

Applicable Data Sources Already Reported: Annual Load Impact Report

Reporting Start Date: July 2011

Comments: None

4. **The number and percentage 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 status, and climate zone).**

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 Advanced Meter or other gateway.

Includes Home Area Network 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.

Percentage: Percentage is defined as [(the number of advanced meters with consumer devices with HAN or comparable consumer energy devices registered with the utility) divided by (the number of advanced meters installed for the group of concern)], with the resulting number multiplied by 100.

Register: The act or process of pairing a consumer device to a Home Area Network. Used to ensure that devices are communicating with the intended recipient (*e.g.*, Advanced Meter). Registering a device is a control to prevent cyber-security and privacy issues.

Considerations:

- All devices that communicate with the utility's Home Area Network 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 an Advanced 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.

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, customer classes shall be:

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: 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 Home Area Network and comparable consumer devices, which is expected no earlier than 2012 to 2013.

Comments: Widespread availability of Consumer Device capabilities have been delayed 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. Pursuant to D. 11-07-056, the IOUs were required to file a HAN Implementation Plan by November 29, 2011. Those plans are currently under review by the Commission. D.11-07-056 envisioned a plan to allow up to 5,000 customer-owned Customer Devices to be able to connect their Advanced Meters. The IOUs plans allow for limited roll-out using SEP 1.0/1.X. IOUs expect widespread availability of Consumer Devices using the SEP 2.0 standard may become available in the 2013 to 2014 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 Advanced Meter. Devices that connect 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).

A commissioned or enrolled device will be a subset of the registered devices.

Utilities will be registering[124] devices, which involves authentication and authorizing a HAN device to exchange secure information with the HAN. However, utilities will not be commissioning[125] devices, as commissioning a device allows for an exchange of a limited amount of information, but may not provide appropriate cyber-security protections. Program enrollments[126] are provided in Customer/AMI Metric 2 "Load impact in MW of peak load

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[124] 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 , Draft v1.95, Open HAN 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.

[125] 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.

[126] Enrollment is defined as "The process by which a Consumer enrolls a HAN device in

reduction from summer peak and from winter peak due to smart grid-enabled, utility administered demand response (DR) programs (in total and by customer class)," and Customer/AMI Metric 5 "Number and percentage of customers that are on a time-variant or dynamic pricing tariff (by type of tariff, by customer class, by CARE status, and by climate zone)."

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.

5. **Number and percentage of customers that are on a time-variant or dynamic pricing tariff (by type of tariff, by customer class, by CARE status, and by climate zone).**

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 rate.

Percentage: Percentage is defined as [(the number of customers that are on a time-variant or dynamic pricing tariff) divided by (the number of customers in the group of concern)], with the resulting number multiplied by 100.

Customer Class: A group of customers with similar characteristics that have similar rate schedules or structures for electric service. For the

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."

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: 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: 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:

PG&E, SCE, SDG&E-Monthly DR reports

PG&E and SCE-AMI Annual Energy Savings Reports

Reporting Start Date: July 2011

Comments: Excludes customers currently enrolled in TOU, CPP, and RTP tariffs; that is, customers enrolled in dynamic tariffs pre-AMI are excluded.

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

Policy Goal Supported: Linked to cost-effectiveness and provision of information to customers. § 8360(a) (e) (h).

Definitions:

Escalated Complaint: A complaint (written or telephonic) received by the utility's Consumer Affairs Department (or equivalent) regarding the Advanced Meter or program, or regarding device registration and communication issues.

Percentage: Percentage is defined as [(the number of escalated complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) the functioning of a utility-administered Home Area Network with registered consumer devices) divided by (the number of escalated complaints in total)], with the resulting number multiplied by 100.

Advanced Meter: A meter that measures interval data and enables two-way communication between utilities and the meters located at customer premises.

Includes Advanced Meters, or smart meters approved by the CPUC under the Advanced Metering Infrastructure deployment programs.

Excludes RTEM and legacy meters (electro-mechanical and non-AMI).

Consumer Device: Smart grid-enabled tools used by consumers that communicate with the utility-owned Advanced Meter or other gateway.

Includes Home Area Network 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 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 at a later date.

Applicable Data Sources Already Reported:

SDG&E: Smart Meter Program Quarterly Reports

SCE: Not currently reported

PG&E: Partial current reporting

Reporting Start Date: July 2011 for complaints related to Advanced Meters. 2013/2014 for complaints related to the interaction of consumer devices with HANs.

Comments: Complaints should include only Escalated Complaints received regarding the functioning or accuracy of Advanced Meters. This metric may also be combined with Customer/AMI Metric 9 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.

Metric to be reported by complaint type: AMI meters, AMI programs, device registration, and communication issues.

7. **The number and percentage of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually, with an explanation for the replacement.**

Policy Goal Supported: Linked to cost-effectiveness and provision of information to customers (§ 8360(a) (e) (h)).

Definitions:

<u>Advanced Meter</u>: A meter that measures interval data and enables two-way communication between utilities and the meters located at customer premises.

Includes Advanced Meters, or smart meters approved by the CPUC under the Advanced Metering Infrastructure deployment programs.

Excludes RTEM and legacy meters (electro-mechanical and non-AMI).

<u>Percentage:</u> Percentage is defined as [(the number of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually) divided by (the number of advanced meters installed)], with that resulting number multiplied by 100.

<u>Replaced</u>: Advanced Meter that is replaced due to a malfunction causing the Advanced Meter to become inoperable.

Applicable Data Sources Already Reported: None

Reporting Start Date: July 2011

Comments: Possible reasons for meter replacement: meter malfunction, meter installation error, or customer tampering.

8. **Number and percentage of advanced meters field tested at the request of customers pursuant to utility tariffs providing for such field tests, and the number of advanced meters tested measuring usage outside the Commission-mandated accuracy bands.**

Policy Goal Supported: Linked to cost-effectiveness and provision of information to customers (§ 8360(a) (e) (h)).

and the number of advanced meters tested
measuring usage outside of the Commission-mandated accuracy
bands.

Definitions:

<u>Advanced Meter</u>: A meter that measures interval data and enables two-way communication between utilities and the meters located at customer premises.

Includes Advanced Meters, or smart meters approved by the CPUC under the Advanced Metering Infrastructure deployment programs.

Excludes RTEM meters, legacy meters, and Advanced Meters replaced when service panel is removed or upgraded, installed in wrong service type, or customer changes rate (NEM,) requiring a new meter with a different program.

<u>Percentage:</u> Percentage is defined as [(the number of advanced meters field tested) divided by (the number of advanced meters installed)], with that resulting number multiplied by 100.

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: Per current tariff rules, utilities will perform one field test every six months at no charge at the customer's request. This metric does not include field test requests that are not performed by utilities.

9. **Number and percentage of customers using a utility web-based portal to access energy usage information or to enroll in utility energy information programs or who have authorized the utility to provide a third-party with energy usage data.**

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

<u>Energy Usage Information</u>:

Includes interval usage data collected by the Advanced 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: 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-authorized portals, and also excludes customer accessing cumulative usage information.

B. Plug-in Electric Vehicle Metrics

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

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-X, EPEV-Y and EPEV-Z.

Applicable Data Sources Already Reported: None

Reporting Start Date: July 2011

Comments: 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 Alternative Fueled Vehicles OIR (R.09-08-009).

C. Storage Metrics

1. **MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals.**

   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: 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 for each year starting on July 1, 2011 through the latest year that this information is available.**

   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: 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.

   Consideration should be given to creating new metrics aimed at providing circuit-level information.

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 for each year starting on July 1, 2011 through the latest year that this information is available.**

   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: 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.

Consideration should be given to creating new metrics aimed at providing circuit-level information.

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 for each year starting on July 1, 2011 through the latest year that this information is available.**

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: 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.

Consideration should be given to creating new metrics aimed at providing circuit-level information.

4. **Number and percentage of customers per year and circuits per year experiencing greater than 12 sustained outages for each year starting on July 1, 2011 through the latest year that this information is available.**

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/.

Percentage of customers experiencing greater than 12 sustained outages per year equals [(the number of customers experiencing greater than 12 sustained outages in a year) divided by (the total number of customers)] with the resulting number multiplied by 100.

Percentage of circuits experiencing greater than 12 sustained outages per year equals [(the number of circuits experiencing greater than 12 sustained outages in a year) divided by (the total number of circuits)] with the resulting number multiplied by 100.

Applicable Data Sources Already Reported: Annual Reliability Reports

Reporting Start Date: July 2011

Comments: 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.

Consideration should be given to creating new metrics aimed at providing circuit-level information.

5. **System load factor and load factor by customer class for each year starting on July 1, 2011 through the latest year that this information is available.**

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 a 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

Comments: 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.**

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: **Customer-owned or operated g**enerating systems that are enrolled with a utility in the Self Generation Incentive Program (SGIP) or the California Solar Initiative (CSI) or otherwise 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: Use programs and tariffs to define "distributed generation."

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

7. **Total electricity deliveries from customer-owned or operated, grid-connected distributed generation facilities, reported by month and my ISO sub-Load Aggregation Point.**

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: Use programs and tariffs to define "distributed generation."

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 remote control equipment, including Supervisory Control and Data Acquisition (SCADA) systems.**

Policy Goal Supported: Measure the extension/development of the smart grid.

Definitions

Percentage of distribution circuits equipped with automation or remote control equipment equals [(the number of distribution circuits equipped with automation or remote control equipment) divided by (the total number of distribution circuits)] with the resulting number multiplied by 100.

Applicable Data Sources Already Reported: None

Reporting Start Date: July 2011

Comments: 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.

(END OF ATTACHMENT A)

ATTACHMENT B

Initial Set of Cyber-Security Questions

What are utilities currently reporting to other agencies (cyber-security, privacy and breach notification)? What is a utility's obligation to report breaches or violations to the public or individuals?

What other groups/associations do utilities report cyber-security incidents to, i.e., other utilities, contractors, etc.?

How many cyber-security attacks does a utility average during a day/week/month/year?

How many cyber-security attacks result in an escalated response, or require additional action to repel?

How many security breaches have resulted in the dissemination of personal/customer information?

How often does a utility engage with an independent third-party to engage in penetration testing of their networks, such as AMI, operations, other mainframes, etc.?

How often does a utility engage with an independent third-party to perform a security audit?

How does a utility define a cyber attack, a security break, etc.?

What criteria does a utility use to determine the competence of an internal and/or third-party penetration tester and/or auditors?

What do utilities do when they have determined that Smart Grid components/systems/equipment are vulnerable to security breaches?

Who is responsible for the costs of fixing security breaches due to vulnerabilities in products?

What known security vulnerabilities in the Smart Grid deployment currently remain in a vulnerable state?

What cryptographic techniques/methods are used by utilities to protect the systems?

What automated testing tools/security software are used by the utilities to protect the systems

Do utilities require security certifications for the purchased systems/components?

Do utilities have permanent job positions for security/cryptography professionals?

Do utilities have mechanisms in place to check against publicly known security vulnerabilities?

Do utilities have mechanisms to automatically apply security patches?

(END OF ATTACHMENT B)