# Qualifying Capacity Methodology Manual Adopted 2017

## 1. Table of Contents



## 2. Introduction

This manual describes the current net qualifying capacity (NQC) counting rules of the California Public Utilities Commission (CPUC) and the methodology for implementing these rules. Each year, CPUC staff works with the California Energy Resources Conservation and Development Commission (Energy Commission) and California Independent System Operator (California ISO) to publish an NQC list which describes the amount of capacity that can be counted from each resource toward meeting Resource Adequacy (RA) requirements in the CPUC's RA program. The qualifying capacity (QC) of each resource is set by the methodologies described in this document. Then, if the QC is not fully deliverable to aggregate California ISO load, the QC is adjusted to its deliverable capacity resulting in the NQC. For the purposes of this report, the term 'resource' is used to refer to a generator that has a resource ID on the Master CAISO Control Area Generation Capability List (Generation Capability List)[1] or a demand response program which may or may not have a resource ID.

### 2.1. Guide to this Document

Sections 3 through 6 describe how resource classifications, deliverability, data conventions, outages and derates affect QC calculations. Sections 7 through 11 provide details on the specific calculation methodologies for each of the resource classifications.

## 3. Resource Classification

Each year, CPUC staff coordinates with California ISO and Energy Commission staff to group resources, by California ISO scheduling resource ID (CAISO ID), into the classifications described below. Classification is based on the dispatchability and technology type of the resource. Primary guidance comes from the most recent available Generation Capability Data List. Demand response resources are not listed on the Generation Capability List; these resources are addressed in Section 11.

First, resources are grouped and classified according to the "ISO Classification" column. Resources listed as wind are classified as wind, resources classified as photovoltaic or solar thermal are classified as solar. Resources listed as hydro are classified as hydro resources. Biomass, cogeneration, and geothermal facilities are also classified using the Generation Capability Data List. Then, resources are sub-classified by dispatchability, as described below.

---

1 http://www.caiso.com/Documents/MasterControlAreaGeneratingCapabilityList.xls.

Each year, Energy Division and California ISO publish a preliminary NQC list of all qualifying resources, including the proposed classification of each resource. Scheduling Coordinators (SCs) for individual resources may suggest changes to the classification of their resources. Stakeholders suggesting a change are to do so in the appropriate time frame and in the format specified each year when the California ISO and CPUC post the draft NQC list. Resources that are dispatchable by the SC or California ISO are classified as dispatchable generation. With the exception of wind and solar resources, dispatchable generation resources receive QC according to the methodology described in Section 7. This classification includes a variety of technologies: steam turbines; combustion turbines; combined cycle gas turbines; reciprocating engines; and dispatchable combined heat and power (CHP), biomass, dispatchable hydro and geothermal resources. Use limited resources may be classified as dispatchable.

Wind and solar facilities receive a QC based on the method explained in section 8. Non-dispatchable cogeneration and biomass facilities receive a QC based on the method explained in section 9 and non-dispatchable hydro and geothermal facilities receive a QC based on the method explained in section 10.

## 4. Deliverability

Deliverability is the ability of the output of a generating resource to be delivered to aggregate California ISO load. If a resource's QC exceeds its deliverable capacity as determined by California ISO Deliverability Assessments, its NQC is adjusted downwards to its deliverable capacity. In most cases, a resource is fully deliverable and there is no difference between QC and NQC. There are three other deliverability states a resource can have: interim deliverability, partial deliverability, or energy only deliverability.

California ISO assesses the deliverability of new and existing resources two to three times per year. A Deliverability Assessment is a required part of the Large Generator Interconnection Procedures (LGIP).[2] Existing resources retain priority for deliverability over new resources and existing deliverable resources are not expected[3] to lose deliverability rights unless the resource is unable to produce its deliverable capacity for at least three consecutive years. The deliverability study provides new resources with information to understand which network upgrades are necessary to achieve full deliverability.

The ability of the output from a new generation project and existing generation to be delivered to aggregate load within California ISO during a resource shortage condition is evaluated pursuant to the ISO's LGIP and the California ISO Deliverability Assessment Methodology posted on the California ISO's website.[4]

The California ISO Tariff defines a generation project's deliverability as full deliverability, partial deliverability, interim deliverability, or energy only deliverability. Full Capacity Deliverability Status and Energy-Only Deliverability Status are the most common deliverability statuses, and equate to either 100% or 0% deliverability, meaning the resource receives either 100% or 0% of their QC as NQC, respectively. Partial Deliverability Status equates to a resource-specific MW limit that is between 0 and 100% deliverable. Interim

---

[2] See Appendix U of the California ISO Tariff: http://www.caiso.com/2471/2471994c26350.pdf. See also: Section 5.1.3.4 of CAISO's Business Practice Manual for Reliability Requirements: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements.

[3] The exception to this rule is reduction in deliverability caused by any degradations of the transmission system which are not repaired promptly, for example due to fires or other force majeure events.

[4] http://www.caiso.com/23d7/23d7e41c14580.pdf.

Deliverability Status means the resource is either fully or partially deliverable, but only temporarily and contingent on other developments such as other generators that will consume deliverability or other transmission that will create additional deliverability. Either a power line is under construction or another resource is under construction that affects the resource's final deliverability status. A finding of deliverability does not ensure that a resource will not experience congestion, especially during non-peak periods, but the status is important for RA purposes.

Not all new resources use the LGIP. Some resources connected to the transmission system with nameplate capacity 20 MW or less use the Small Generator Interconnection Procedure (SGIP). The SGIP does not include a Deliverability Assessment and resources that use SGIP have an NQC equal to zero.[5] Other small resources that are connected to the distribution system may use a Small Generator Interconnection Agreement (SGIA) with the distribution system owner.[6] These SGIAs include deliverability assessments which are accepted by California ISO. Therefore, these resources can be deliverable up to 100% their QC.

## 5. Data Conventions

This section lists certain conventions used by CPUC staff in calculating the QC of non-dispatchable generating facilities:

- Effective load carrying capability (ELCC) is used to determine the QC for wind, PV and solar thermal facilities whether they are dispatchable or non-dispatchable. Nameplate capacity is

---

[5] See Appendix S to the California ISO Tariff: http://www.caiso.com/2471/247198fe24690.pdf.

[6] SGIA interconnections use the Wholesale Distribution Access Tariff (WDAT).

multiplied by a monthly ELCC value generated through the adopted modeling process to generate the QC value.

- Historical production data is used to determine QC values for non-dispatchable hydro and geothermal resources. Production data is represented by "Actual Settlement Quality Meter Data" and equals the total hourly settled MWh quantity produced by the resource and injected into the CAISO-controlled grid. These data are obtained by the CPUC on an hour and unit specific basis via subpoena to California ISO.
- A combination of settlement data and bidding and scheduling data is used to calculate QC values for pre-dispatch cogeneration and biomass facilities. This information is also received by the CPUC from the California ISO via a subpoena. This represents the actual MW amount for that resource as scheduled or bid into the California ISO day ahead market. If there is no scheduled MW amount available, the settlement data for that hour is used. These data are obtained on an hour specific and unit specific basis.
- New, non-dispatchable resources produce energy in advance of officially reaching a Commercial Operation Date (COD). Data created before the resource reaches a COD is called "test data" and is discarded for the QC calculation. CPUC staff only utilizes historical production data beginning on the date a resource (or phase of a resource) reaches COD.
- A resource that reaches COD by the 15$^{th}$ day of a particular month or before will receive a QC calculated from historical production data from the first month it is online. A resource that reaches COD on the 16$^{th}$ (or later) will have QC calculated from historical production data beginning in the following month.
- If facilities (either hydro, geothermal, etc.) have less than three years of historical production data (based on COD), the QC value is a composite of calculations based on historical production/bidding data for phases that have reached COD and technology factors attributed to the remaining phases or time periods before the resource reached COD. Production data is used for calculations for months that have sufficient settlement or scheduled MW data available (more than 15 days of production),

while monthly technology factors are used for the remainder of the three years. For example, a resource that reached COD in July 2015 would receive a 2017 QC based on six months of actual production data and 30 months of values generated from technology factors.

## 6. Outages and QC Calculation

Pursuant to D.15-06-063, neither forced nor planned outages affect the QC of a generating resource, whatever the generating type. Thus this section was removed.

## 7. Dispatchable Generation

Dispatchable generation resources besides solar and wind resources receive NQC values based on their available capacity,[7] subject to the checks described in Section 4, Deliverability. The SC of the resource submits a proposed QC value to the California ISO, along with a reference to the resource's most recent maximum power plant output (PMax) test[8] that is in California ISO's master file. This information is submitted to the California ISO in a standard format.[9] The California ISO then checks the submitted value for consistency with the resource's PMax and deliverability status. If the proposed QC value is less than or equal to the PMax and the maximum deliverable capacity, it is accepted as the NQC value. If not, the PMax or maximum deliverable amount is accepted as the NQC value. The SC may coordinate with California ISO to update the

---

[7] See also, Section 5 of CAISO's Business Practice Manual for Reliability Requirements: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements.

[8] California ISO coordinates with SCs for resources to schedule PMax tests at a time selected by the SC. Generally, SCs select the timing of a PMax test to demonstrate output of the resource at or near its maximum possible output.

[9] See http://www.caiso.com/Documents/NetQualifyingCapacityRequestForm.xls.

PMax test or supply other information as requested by California ISO in order to determine an acceptable change to NQC and update the NQC at any time.

## 8. Wind, PV, and Solar Thermal

The QC of wind, PV, and solar thermal facilities is based on effective load carrying capability (ELCC) modeling under an approach adopted in D.17-06-027. As outlined in Appendix A of the decision, monthly ELCC values are determined according to the following seven step process:

1. Conduct a Monthly Loss of Load Expectation (LOLE) or Loss of Load Hours (LOLH) study. Choose a metric to target (LOLE or LOLH) and a reliability level for each month that represents the desired level of reliability that planners are attempting to have. Conduct an hourly reliability simulation representative of each month of the year with projected loads and expected resources that results in the desired monthly reliability level in each month. If results are either more or less reliable than desired, capacity or load is to be added or subtracted until each month's reliability results are in the desired range.

2. Conduct a Monthly Portfolio ELCC study. Remove all wind and solar electric generation facilities inside the CAISO aggregated region. Add or remove Perfect Capacity or load in each month individually until the resulting reliability level is back to the desired range. The amount of Perfect Capacity in MW (or load in MW) added is equal to the Portfolio ELCC of all wind and solar generators.

3. Perform ELCC modeling on each category individually
    a. Add back wind generators and leave solar generators removed. Add blocks of load or take away blocks of Perfect Capacity iteratively from each month until reliability levels are within the desired range each month. The result is the standalone ELCC of

solar generators. Record the monthly levels of Perfect Capacity modeled.

b. Perform Step A in reverse by adding back solar generators and removing wind generators. Remove blocks of Perfect Capacity iteratively from each month. Remove Perfect Capacity until the reliability level again falls within the desired range in each month. The result is the standalone ELCC of wind generators. Record the monthly levels of Perfect Capacity or added load modeled.

4. Add the standalone ELCC of wind and solar generators, and compare the total to the Portfolio ELCC calculated earlier. The difference (either positive or negative) is the diversity adjustment. (The diversity adjustment will be negative when the standalone ELCC values total greater than the Portfolio ELCC, and are the result of modeling a category of generator while another category of generators in the Portfolio ELCC was present, and some of the reliability contribution it imparts is applied as diversity. In that case, diversity must be removed.)
   Allocate the diversity adjustment to either wind or solar generators by prorating to the proportion of wind and solar standalone ELCC in each month.

5. Energy Division backs out the effect of BTM Solar on the overall RPS supply side solar ELCC. Energy Division staff compares the ELCC of solar generators without BTM PV in the fleet (taken from the March 2016 RA ELCC proposal) to the ELCC of solar with BTM PV included from this February 2017 RA proposal. That difference represents the amount of Perfect Capacity that is equivalent to the additional supply side solar added since March 2016 as well as all BTM PV installed that has until now not been included in modeling. Prorating the additional Perfect Capacity to the portion of the new solar that is BTM PV will represent the added Perfect Capacity for the BTM PV, and when removed represents just the Perfect Capacity needed for the incremental new supply side solar added.

6. Take the ELCC MW values that are the result of the modeling for each month, and divide them by the total nameplate installed MW of that technology, and the resulting monthly percentage values represent the ELCC percentages that are applied to the nameplate MW values of each individual generating facility to create the Qualifying Capacity of the generator. (Calpine proposes a methodology that allocates ELCC value individually to generators based on historical generation data)

7. Any further steps to create locational factors to break up wind and solar further into location or sub technology specific factors would follow from this point, and thus would be added as steps 7 and on. Future Monthly ELCC studies would require restarting the sequence of studies from Step 1.

## 9. Cogeneration and Biomass Resources

Pursuant to D.15-06-063, a new classification was created for qualifying facilities that were QF cogeneration. Many of these facilities were in the process of migrating to contracts that allow for utility predispatch and are called utility predispatch facilities (UPF). This 'predispatch' classification was adjusted in D. 16-06-045 and expanded to apply to all cogeneration and biomass facilities that are able to schedule in the day ahead market but are not fully dispatchable. If a cogeneration or biomass facility is dispatchable, it may request a QC value based on Pmax.

These decisions adopted a QC methodology which relies on bidding and scheduling history rather than settlement data. Beginning for the 2017 RA compliance year, CPUC staff took settlement data, bidding data and scheduling data for all biomass and cogeneration resources and, in hours where the resource was self-scheduled or bid into the day ahead market, the greater of the self-scheduled or day ahead market bid was used instead of the same resource's settlement data for that hour. In hours where the scheduling MW data was nonexistent for a particular resource (the resource did not submit a MW schedule amount) or bidding and scheduling data were missing, the settlement data for that hour was used.

A month specific average of the maximum of bidding/self-scheduling/production during the RA Measurement Hours (Table 1) is created to generate the QC for each resource.

| | |
|---|---|
| Jan–Mar, Nov and Dec: | HE17 - HE21[10] (4:00 p.m. - 9:00 p.m.) |
| Apr–Oct: | HE14 - HE18 (1:00 p.m. - 6:00 p.m.) |

**Table 1: RA Measurement Hours**

Technology factors are created for each resource type. New, non-dispatchable resources with less than three years of historical production data for any month receive a QC for months without data based on multiplying the resource's PMax by the applicable technology factor (Equation 1).

$$MonthlyQC_{Resource} = NDC_{Resource} * \frac{\sum_{ExistingNon-Dispatchable\,Resources} MonthlyQC}{\sum_{ExistingNon-Dispatchable\,Resources} NDC}$$

**Equation 1. QC for Non-Dispatchable Resources with no Available Data**

## 10. Hydro and Geothermal Resources

Non-dispatchable hydro and geothermal resources receive monthly QC values based on a three-year rolling average of production during the specified hours in Table 1**Error! Reference source not found.**. Production for these

---

10 HE indicates "hour ending", or the 60 minutes that end at the numbered hour, in 24 hour time. For example, HE17 indicates the 60 minutes beginning at 16:00 (i.e. 4:00 p.m.) and ending at 16:59.

facilities is calculated from settlement quality meter data only. The three most recent years of available data are used. For example, 2018 QC is calculated based on 2014-2016 data.

Each monthly value is calculated as an average of the production during the specified hours (Equation 2). The 36 monthly average values are calculated as:

$$Average_{Month}(MW) = \frac{\sum_{Month} Production(MWh)}{\sum_{Month} Hours(h)}$$

**Equation 2. Monthly Average Production for Non-Dispatchable Hydro and Geothermal Resources**

Then, the monthly values are averaged together for all (up to three) years of available data to calculate the final QC for each month (Equation 3).

$$FinalQC_{Month} = \frac{1}{\{NumberOfYearsOfData_{Month}\}} * \sum_{AllYearsOfData} Average_{Month}$$

**Equation 3. Final QC of Non-Dispatchable Hydro and Geothermal Resources**

Technology factors are also created for each resource type. New, non-dispatchable resources with less than three years of historical production data for any month receive QC for missing months based on multiplying the resource's PMax by the applicable technology factor (Equation 4).

$$MonthlyQC_{Resource} = NDC_{Resource} * \frac{\sum_{ExistingNon-Dispatchable\,Resources} MonthlyQC}{\sum_{ExistingNon-Dispatchable\,Resources} NDC}$$

**Equation 4. QC for Non-Dispatchable Resources with no Available Data**

## 11. Demand Response (DR)

In D.09-06-028, CPUC directed that the QC of DR resources be based on the Load Impact Protocols (LIPs) adopted by D.08-04-050.[11] However, the LIPs provide far more detailed information than 12 monthly QC values. The discussion of the LIPs in this manual does not in any way impact the requirements of any previous decision in the DR proceedings or any other uses of the LIPs besides QC calculations.

The LIPs must be followed by the entity (typically the IOU) requesting that the DR program be eligible for meeting RA Requirements. That entity must work with Energy Division staff to provide the LIP information described below for the DR resource to receive QC values. The following table summarizes the use of LIPs for QC demonstration. Event based resources (i.e. AC cycling) are DR programs that only operate when a specific event is called, while non-event based resources (i.e. Time-Of-Use rates or permanent load shifting) operate each day, regardless of whether or not a DR event is "called". Page and section references in this table refer to Attachment A to D.08-04-050.

The monthly QC of a DR resource is the average expected (*ex ante*) load impact measured over certain measurement hours. The measurement hours are:

| RA Compliance Year | Hours | |
|---|---|---|
| 2011 | Hour Ending (HE) 15 to HE 18<br>(2:00 p.m. to 6:00 p.m.) | |
| 2012 and beyond, except for programs that have a different, fixed operational period set by CPUC decision. | Jan–Mar, Nov and Dec: | HE 17 to HE 21<br>(4:00 p.m. - 9:00 p.m.) |
| | Apr–Oct: | HE 14 to HE 18<br>(1:00 p.m. - 6:00 p.m.) |

**Table 2. Measurement Hours for DR**

---

[11] The LIPs are detailed in Appendix A to D.08-04-050; http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/81979.PDF.

The hourly estimates for each of these hours from the LIP data are averaged together. These hourly estimates must be provided according to protocols 17, 21, 22, and 23. Other protocols described in this table are required for supporting data and report formatting.

| Resource Type | Load Impact Protocols Required |
|---|---|
| **Event Based Resources.**<br>Example IOU programs:<br>CPP<br>CBP<br>DBP<br>AC Cycling<br>OBMC | <u>**Ex Post for Event Based Resources**</u><br>Protocol 7 requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table.<br><br>Protocol 8 requires reporting for the average across all participants notified on a average event day over the evaluation period. Only the hourly load drop across participants notified on an average event day is required; no need to provide the following details:<br>• Each day on which an event was called;<br>• The average event day over the evaluation period<br>• For the average across all participants notified on each day on which an event was called;<br>• For the total of all participants notified on each day on which an event was called.<br><br>Protocol 10 requires regression based methods (read section 4.2.2, pg 60 for an overview of regression analysis). Any suppliers choosing not to use regression as described in Protocol 10 *must* file an evaluation plan (Protocols 1-3) well in advance of the QC demonstration deadline.[12]<br><br><u>**Ex Ante for Event Based Resources**</u><br>Protocol 17 requires that ex ante estimates should be informed by ex post whenever possible.<br><br>Protocol 21 requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table.<br><br>Protocol 22 requires the use of 1-in-2 weather year for the monthly system peak day. The 1-in-10 weather year, typical event day, or an average weekday for each month are not needed for QC calculation.<br><br>Protocol 23 requires ex ante estimates be based on regression methodologies (read section 6.2, pg 98 for guidance).<br><br><u>**Portfolio Impacts, if Required**</u> |

[12] The deadline is typically April 1.

| | |
|---|---|
| | Protocol 24 describes methodology for estimating the impacts of multiple DR programs within a portfolio. All DR resources whose participants also participate in other DR programs (potentially operated by other entities) must follow Protocol 24; such resources should also submit an evaluation plan (Protocols 1-3).<br><br>**<u>Sampling if Required</u>**<br>Protocol 25 requires certain procedures to ensure that sampling bias is minimized. Protocol 25 is not anticipated to be required for most DR resources using LIPs only to demonstrate QC; DR resources with a small number of participating customers should provide data from *all* participants, obviating the need for sampling methodologies. For resources with enough participants to adopt a sampling methodology, an evaluation plan (Protocols 1-3) is required well in advance of the QC demonstration deadline.<br><br>**<u>Reporting Protocols</u>**<br>Protocol 26 lists certain sections that should be included in the evaluation reports. These reports may be limited in scope, as described above. |

| | |
|---|---|
| **Non-Event Based Resource.**<br>Example IOU programs:<br>TOU<br>RTP<br>SLRP<br>PLS | **<u>Ex Post for Non-Event Based Resources</u>**<br>Protocol 14 (same as Protocol 7) requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table.<br><br>Protocol 15 requires reporting for the monthly system peak day.<br><br>Protocol 16 requires regression based methods (read section 5.2, pg 84 for guidance). Any suppliers choosing not to use regression as described in Protocol 10 *must* file an evaluation plan (Protocols 1-3) well in advance of the QC demonstration deadline.<br><br>**<u>Ex Ante for Non-Event Based Resources</u>**<br>Protocol 17 requires ex ante estimates should be informed by ex post whenever possible.<br><br>Protocol 21 requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table.<br><br>Protocol 22 requires the use of 1-in-2 weather year for the monthly system peak day. The 1-in-10 weather year, average weekday, or typical event day are not needed for QC calculation.<br><br>Protocol 23 requires ex ante estimates be based on regression methodologies (read section 6.2, pg 98 for guidance).<br><br>**<u>Portfolio Impacts, if Required</u>**<br>Protocol 24 describes methodology for estimating the impacts of multiple DR programs within a portfolio. All DR resources whose participants also participate in other DR programs (potentially operated by other entities) must follow Protocol 24; such resources should also submit an evaluation plan (Protocols 1-3).<br><br>**<u>Sampling if Required</u>**<br>Protocol 25 requires certain procedures to ensure that sampling bias is minimized. Protocol 25 is not anticipated to be required for most DR resources using LIPs only to demonstrate QC; DR resources with a small number of participating customers should provide data from *all* participants, obviating the need for sampling methodologies. For resources with enough participants to adopt a sampling methodology, an evaluation plan (Protocols 1-3) is required well in advance of the QC demonstration deadline.<br><br>**<u>Evaluation Reporting</u>**<br>Protocol 26 lists certain sections that should be included in the evaluation reports. These reports may be limited in scope, as described above. |

**Table 3. Required LIPs**

As noted above, in order to translate the detailed LIP information into monthly QC values, QC is measured using the average expected (*ex ante*) load impact during the appropriate measurement hours shown in Table 2. CPUC staff takes the hourly estimates provided[13] according to the LIPs and averages the estimates over the relevant hours.

In order for DR programs to receive local capacity credit for RA, the load impact must be broken down by local areas. However, this breakdown is not required for all months – it is only required for August. Further, for compliance purposes, the CPUC aggregates PG&E's "other" local areas: Fresno, Humboldt, North Coast/North Bay, Sierra, and Stockton. These areas do not need to be broken out individually. For August, average expected (*ex ante*) load impact must be provided by local area as follows, for each DR program:

| SDG&E | SCE | PG&E |
|---|---|---|
| San Diego | Big Creek/Ventura | Greater Bay Area |
| System (no local area) | LA Basin | Other PG&E local areas |
| | System (no local area) | System (no local area) |
| Program Total | Program Total | Program Total |

**Table 4. Local Area Breakdown for DR Resources.**

For each program, the sum of system and local capacities should equal the program total capacity. Table 4 is not intended to be a format, but simply a description of the data required. If a program operates in multiple IOU territories, expected load impacts for all relevant local areas should be included.

Previously, CPUC staff sourced T&D line loss data from each utility's most recent adopted General Rate Case. D.15-06-063 changed the source of data to the line loss data from the most recent LTPP scenarios and assumptions update.

[13] If assumptions underlying the LIP estimates for a particular program are unreasonable, CPUC staff accordingly adjusts the load impacts.

CPUC staff will "gross-up" the DR QC for avoided line losses. A single loss rate for each service area is calculated according to Equation 5. Total Line Loss Factor

$$LossRate = 3\% + DistributionLossRate$$

**Equation 5. Total Line Loss Factor**

Finally, the QC of DR is calculated by grossing up by the loss rate.

$$FinalQCofDR = \frac{\sum_{MeasurementHours} AverageExAnteLoadImpact}{\{NumberOfMeasurementHours\}} * \left(\frac{1}{1 - LossRate}\right)$$

**Equation 6. Final QC of DR**

## 12. Acronym List

| **Acronym** | **Definition** |
|---|---|
| CAISO ID | California ISO Scheduling Resource ID |
| California ISO | California Independent System Operator |
| CEC | California Energy Resources Conservation and Development Commission |
| CPUC | California Public Utilities Commission |
| HE | Hour Ending |
| IOU | Investor Owned Utility |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| LGIP | Large Generator Interconnection Procedures |
| LIP | Load Impact Protocol |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NQC | Net Qualifying Capacity |
| PMax | Maximum Power Plant Output |
| QC | Qualifying Capacity |
| RA | Resource Adequacy |
| SC | Scheduling Coordinator |
| SGIA | Small Generator Interconnection Agreement |
| SGIP | Small Generator Interconnection Procedures |
| SLIC | Scheduling and Logging for ISO of California |