APPENDIX C

California ISO Reliability Assessment in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318

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California ISO
Reliability Assessment in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318

June 14, 2012

California ISO
Shaping a Renewed Future

California ISO's Assembly Bill 1318 (AB1318) Reliability Studies

Executive Summary

This report is considered the final ISO reliability assessment report and is the documentation of studies described in the Draft Work Plan contained within the previous report (*aka Interim Report*) on "Assessment of Electrical System Reliability Needs in South Coast Air Basin and Recommendations on Meeting Those Needs"[1] that was posted on the State Air Resources Board (ARB or Board) on February 1, 2011. Assembly Bill 1318 (AB 1318, Wright, Chapter 206, Statutes of 2009)[2] requires the State Air Resources Board (ARB or Board), in *consultation* with the California Energy Commission (CEC), California Public Utilities Commission (CPUC), California Independent System Operator (ISO), and the State Water Resources Control Board (SWRCB), to prepare a report for the Governor and Legislature on or before July 1, 2010, that evaluates the electrical system reliability needs of the South Coast Air Basin (SCAB). The report is to include recommendations for meeting those reliability needs while ensuring compliance with state and federal laws. Specifically, given the current air quality permitting issues facing power plants under the South Coast Air Quality Management District's (SCAQMD or District) current program, the report is to include recommendations for ***long-term, sustainable permitting of additional needed capacity***. Due to short lead time for the report, the ARB and the state energy agencies (i.e., ISO, CPUC and CEC) agreed to submit an Interim Report, drawing from the existing grid reliability study results to date, while working toward a final report based on further detailed reliability assessments. The interim report served as Phase 1 in delivering the electric reliability and air permitting assessment envisioned in AB 1318. A final report (Phase 2 report) is now expected to be completed by summer of 2012. The ISO completed its reliability assessment related to AB 1318 for the L.A. Basin under its operational control as part of the ISO's 2011/2012 transmission planning process in December 2011. The study results related to reliability assessment for once-through cooled generation and AB 1318 were presented to the stakeholders at the third 2011/2012 transmission planning process meeting at the ISO on December 8, 2011. This report will be included in the ARB's final report, which will contain a section on ARB's discussion and estimates of air emission credits required for new generation[3] determined to be needed to meet applicable federal and regional electric reliability standards[4]. The ISO, as well as the Participating Transmission Owners (PTOs), are

[1] See posting on ARB website at (http://www.arb.ca.gov/energy/esr-sc/0215-workshop/ab_1318_draft_work_plan.pdf)
[2] See text of Assembly Bill 1318 in Appendix A
[3] New generators could include repowering or replacement of the existing once-through cooled generation in the L.A. Basin with acceptable cooling technology.
[4] Applicable national and regional electric reliability standards include standards from the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC) and the ISO.

required to comply with these grid reliability standards or face financial penalty if compliance violations are identified.

Scope of this Report

This report consists of the following:

- Reliability assessment results for local capacity requirements in the ISO's L.A. Basin and the need for new generation to meet applicable grid reliability standards. New generation is meant to be either repowering or replacement of the existing once-through cooled generation that was determined needed to maintain grid reliability for the local area. These studies were performed for 2021 time frame with four respective Renewable Portfolio Standards (RPS) portfolios: trajectory, environmentally constrained, ISO base case and lastly, time-constrained. The assumptions for these four RPS portfolios primarily come from the CPUC.

- Zonal and ISO Balancing Authority Area (BAA) loads and resources assessment. This assessment was performed to determine whether zonal or entire system's resources would be adequate to serve loads in the zonal areas (i.e., North of Path 26 (NP 26), or South of Path 26 (SP 26)) and entire ISO BAA. This assessment was performed for ten years in the future (i.e., 2021 time frame). This was performed for both a 1-in-10 year and a 1-in-2 year heat wave load projection.[5]

- Sensitivity assessment for the local capacity requirements in the L.A. Basin for the mid net load assumptions in which incremental uncommitted energy efficiency and combined heat and power were included. The reason that this assessment is a sensitivity assessment is because it includes demand side programs that are uncommitted and uncertain to materialize at this time. *This assessment was requested by the CPUC and CEC for informational purposes*.

Key Findings

- Local capacity requirements for the L.A. Basin area and Western L.A. Basin sub-area are provided in the table below. The Western L.A. Basin sub-area is part of the L.A. Basin local capacity requirements (LCR) area and its reliability need is the main driver of the generation need at the existing once-through cooled (OTC) generating sites. It is assumed the OTC generators, if determined to be needed, would be re-powered or replaced with acceptable cooling technology per the SWRCB's policy on OTC generating plants.

[5] Load projections were obtained from the latest available Commission-adopted demand forecast at the time of the studies (i.e., 2010 – 2020 demand forecast).

Nuclear generation, at the time of the ISO's study for assessment year 2021, was assumed to be in-service. The earliest compliance date for the nuclear generation is 12/31/2022 for the San Onofre Nuclear Generating Station (SONGS). The ISO plans to evaluate for nuclear generation backup plan as part of its 2012/2013 transmission planning process.

The study results are provided for four RPS portfolios: trajectory, environmental, ISO base, and time-constrained. The CPUC primarily provided these RPS portfolio assumptions. The ISO base case RPS portfolio is a variation of the CPUC's cost-constrained portfolio.

Table ES-1 – Summary of Local Capacity Requirements and New Generation Need #

LCR Area	Local Capacity Requirements (MW)				New Generation Need? # If Yes, Range of New Generation Need (MW)			
	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained
LA Basin (this area includes W. L.A. Basin sub-area below)	13,300	12,567	12,930	13,364	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896
Western LA Basin Sub-Area	7,797	7,564	7,517	7,397				

Notes for Table ES-1:
New generation need assumes existing generation would be retired and repowered or replaced with acceptable cooling technology.

- Zonal and ISO BAA's loads and resources assessments indicated that the operating margins for ISO BAA and SP26[6] zonal area would be marginally at 3% and about 8% for NP26[7] for a 1-in-10 year heat wave load forecast for 2021 time frame. For a 1-in-2 load forecast, it is projected that the operating margins for ISO BAA and the NP26 and SP26 zonal areas would be above 15%.

- A sensitivity analysis with incremental, uncommitted energy efficiency and combined heat and power programs included in the future load forecast per the

[6] SP26 is referred to as the area under ISO's operational control south of Path 26. Path 26 consists of three 500kV lines connecting Pacific Gas & Electric Co. (PG&E) and Southern California Edison (SCE)'s electric systems. SP26 zonal area includes service territories of SCE, San Diego Gas & Electric Company (SDG&E) and the Southern Cities Municipal Utilities (i.e., Cities of Anaheim, Azusa, Banning, Colton, Pasadena, Riverside, and Vernon)
[7] NP26 is referred to as north of Path 26. It consists primarily of PG&E and Silicon Valley Power within the ISO BAA.

request from the CPUC and CEC resulted in the reduction of the need for new generation in the L.A. Basin to about 56% - 58% of the need identified in Table ES-1 above. Please note that there is great uncertainty whether these uncommitted programs would fully be funded, developed and made available when needed in the future. The purpose of this exercise was to evaluate the sensitivity of the need for future new generation development had these state's policy on demand side programs were to fully develop for uncommitted energy efficiency and combined heat and power.

1. Background, Methodology and Assumptions

Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009) requires the California Air Resources Board (CARB), in consultation with the California Independent System Operators (ISO), California Energy Commission (CEC), California Public Utility Commission (CPUC) and the State Water Resources Control Board (SWRCB) to prepare a report for the governor and legislature that evaluates the electrical system's reliability needs within the South Coast Air Basin. The report is required to include recommendations regarding the most effective and efficient means of meeting reliability needs while ensuring compliance with state and federal law. In collaboration with the state agencies, in 2010, the ISO prepared an interim report: *Draft Work Plan on the Assessment of Electrical System Reliability Needs in South Coast Air Basin and Recommendations on Meeting those Needs*.[8] This report summarizes existing reliability studies for the ISO-controlled grid in the South Coast Air Basin and provides an overview of studies to be performed in the ISO's 2011-12 transmission planning cycle to meet AB 1318 objectives. The following discussion provides the details of the study scope.

For the AB 1318 study, CARB was interested in determining the maximum credible range of offsets rather than a single "most likely" range. An advantage of the maximum range approach is that it could be determined using *a priori* knowledge by strategically evaluating the ranges of assumptions and modeling conventions to provide potential maximum or minimum values, which would encompass the most likely range scenario. A most likely range would probably require more time to debate and reach consensus among various competing interest groups and might not result in a deliverable product for CARB by the end of 2011 time frame. Given the dynamics of renewable generation development, as well as the challenges of projecting the right number that demand side management would materialize in ten years, it was more logical to evaluate the maximum and minimum range of potential emission offsets at this time until further clarity of the Renewable Portfolio Standards (RPS) and demand side management development trend is known.

The analytic approach utilized power flow studies to determine thermal violations, and stability of the electric system was evaluated using transient and post-transient analyses. These studies were performed by applying the ISO's local capacity area requirements criteria.[9] The studies were also performed with the objective of finding a range of generation level, located at various existing once-through cooled generating sites in Los Angeles Basin (L.A. Basin), needed to meet local reliability requirements. The range refers to the minimum and maximum level of generation that would need to be either repowered or replaced with acceptable cooling technology other than once-through cooled (OTC) system. A long-term (2021) assessment was performed, using four RPS policy-driven power flow study cases that were developed in the ISO's 2011-2012 transmission planning process. With the capacity identified for either repowering or

[8] http://www.arb.ca.gov/energy/esr-sc/0215-workshop/ab_1318_draft_work_plan.pdf
[9] ISO, *2013-2015 Local Capacity Technical Analysis: Final Report and Study Results*, December 2010.

replacement generation in the LA Basin, supplemental analyses would be performed by the CARB staff, in conjunction with the CEC, to translate these generation capacities into emission offsets needed for development and permitting purposes.

Fig. 1 – Jurisdictional Area of South Coast Air Quality Management District (SCAQMD)

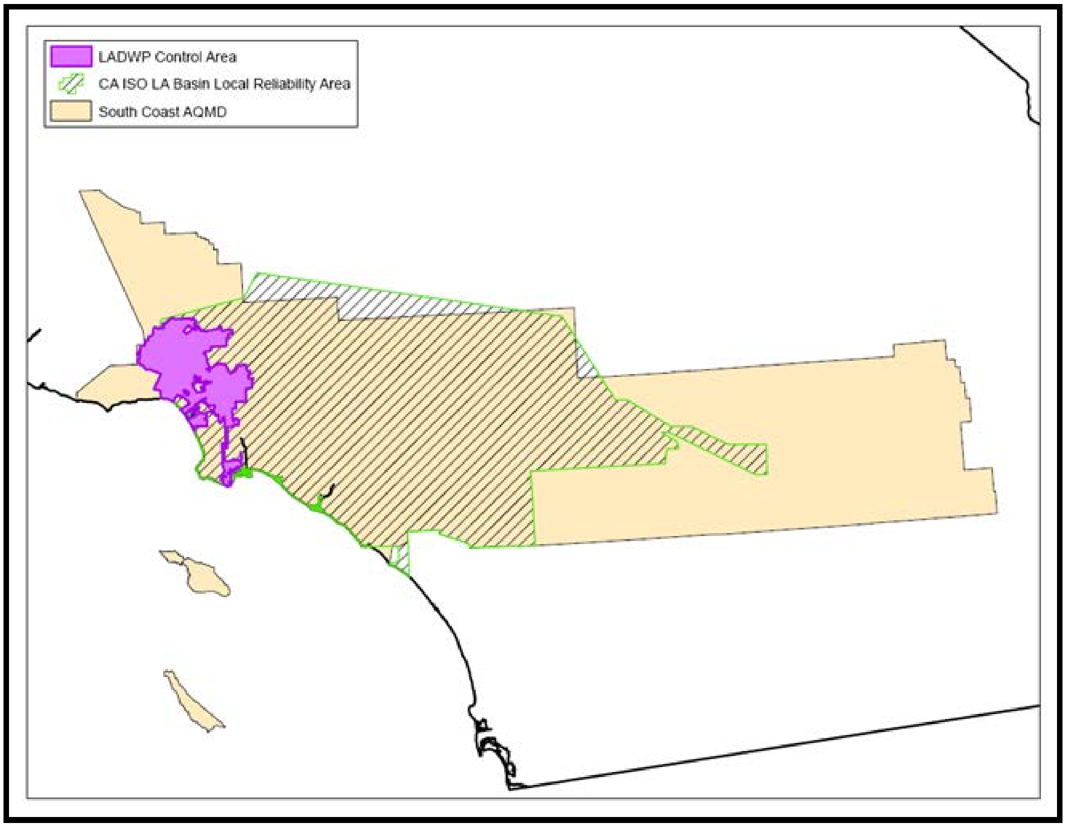
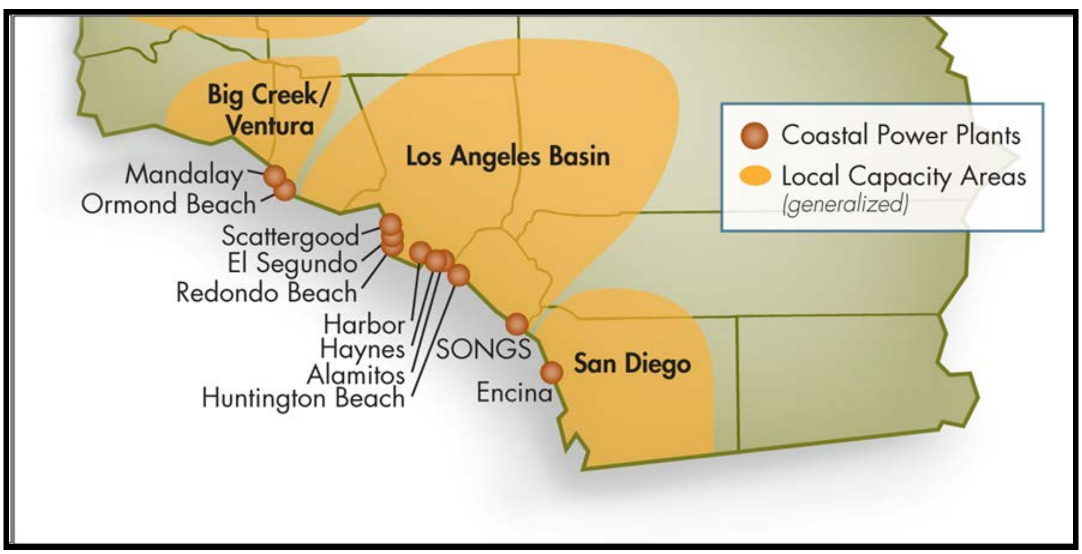


Fig. 2 – L.A. Basin LCR Area with Respect to Other LCR Areas in Southern California



1.1 High End of Emission Offset Range

The purpose of this study is to identify the potential upper end of the offset range for non-nuclear thermal generation in the L.A. Basin under various 33 percent renewable generation RPS from the CPUC and OTC study scenarios utilizing the latest available CEC adopted demand forecast[10] at the time of the study. Offsets are both emission reduction credits (ERCs) and internal bank credits that would have to be surrendered for capacity that elected to use ***South Coast Air Quality Management District*** (SCAQMD) Rule 1304(a)(2). This approach was utilized due to the need to complete the evaluation of local capacity requirements for CARB at the end of 2011. Four high end scenarios were studied for the high net-load conditions[11] (i.e., CEC's adopted 1-in-10 year heat wave load without incremental energy efficiency or demand responses).

Study Combinations = [1 load level (high net load based on CPUC's forecast)* 4 RPS scenarios * 1 OTC generation study scenario[12]]

= 4 study cases

1.2 Low End of Emission Offset Range

The purpose of this study was to identify the lower end of the offset range if the CPUC and CEC's policy-driven demand side management measures (i.e., incremental energy efficiency, combined heat and power, demand response) were to materialize as projected. The CPUC and the CEC referred to this load level as the mid net load condition. In many cases, the values chosen are the opposite of those selected for the high end of the offset range scenario. One low end scenario was studied:

Study Combinations = 1 load level (mid net load[13])* 1 RPS (environmentally constrained portfolio) * 1 OTC generation study scenario

= 1 study case

Similar to the study described in the above section, in order to provide data inputs to CARB staff for estimates of emission offset needs, this study was performed for the environmentally constrained case to provide the lower end of the emission offset range.

1.3 Summary of Study Scope

The following is a summary of the study scope for AB 1318 reliability assessment for ISO-controlled electric grid within SCAQMD footprint:

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[10] Commission-adopted California Energy Demand 2010 – 2020 Forecast (http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html)

[11] High net load conditions include CEC's adopted 1-in-10 heat wave load projection without uncommitted energy efficiency, or combined heat and power (CHP) and demand response.

[12] Local capacity requirement scenario: This scenario will determine the minimum OTC generation need that enables the load serving entities to meet applicable national, regional and ISO reliability requirements.

[13] Mid net load scenario includes uncommitted incremental energy efficiency, demand response and combined heat and power.

- Reliability assessment of the LA Basin Local Capacity Requirements (LCR) area for four RPS portfolios at peak load conditions (high net load): the four portfolios are trajectory, environmentally constrained, ISO base case and time-constrained. The purpose of these studies was to identify whether there was a reliability need to repower the OTC plants, and if there was a need, what would be the OTC generation level needed for peak load conditions. Studies at peak load conditions establish local capacity requirements for upper bound conditions. These assessments utilized the official CEC-adopted demand forecast for 1-in-10 year heat wave load projection, which includes committed energy efficiency.
- Due to request from the state agencies (CARB, CEC and CPUC), the ISO also performed an LCR assessment for a mid net load condition utilizing the environmentally constrained RPS case. The ISO considers this study as a ***sensitivity*** study, and the results for this study would provide a lower bound generation requirement for CARB staff to use in translating to a lower bound emission offset requirements. For this study, the ISO utilized the assumptions of uncommitted incremental energy efficiency, modeled at specific load buses that were provided by the CPUC and the CEC. Because of the uncommitted nature of these programs as well as uncertainty whether these would materialize as the state agencies projected, the ISO considered this study request as sensitivity study.
- Transient stability assessment for on-peak and off-peak load conditions. For on-peak load conditions, the assessment was performed for the trajectory and environmentally constrained RPS portfolios. For the off-peak condition, the assessment was performed for the environmentally constrained portfolio to determine if this portfolio, with significantly more distributed generation modeled, would still meet the WECC transient stability reliability criteria. This assessment was performed to address concerns from various stakeholders whether the system, with less availability of existing steam units due to policy on once-through cooled generation, would still have adequate inertia to maintain system stability under critical contingencies.
- Loads and resource assessment for zonal (NP26 and SP26) and ISO balancing authority: the purpose of this assessment is to provide preliminary long-term view of resources vs. loads in the 2021 time frame under two load levels: 1-in-2 year and 1-in-10 year heat wave load conditions. For this assessment, the minimum level of generation requirement from the existing once-through cooled sites was included and assumed to be repowered in the future. In addition, net qualifying capacity values for future renewable generation and existing level of demand response were included in the loads and resources evaluation. Import levels were obtained from projected Maximum Import Capability (MIC) for ISO's load serving entities for 2021 time frame.

2. Reliability Study Results

In this section, the following study results are reported:

- Reliability assessment of the LCR for the L.A. Basin Area – the purpose of this study is to determine the amount of local generation requirements by 2021 time frame under four RPS portfolios, including whether there is a reliability need for generation at the existing OTC plants, and if there is, what level of generation is needed. It is assumed that the OTC generation will comply with the SWRCB's Policy on OTC plants, either by repowering or replacement with acceptable cooling technology if they're determined to be needed for local reliability and renewable integration purposes.

- Transient stability assessment for on-peak and off-peak load conditions – for on-peak load conditions, the assessment was performed for the CPUC's trajectory and environmentally constrained RPS portfolios. For the off-peak load conditions, the assessment was performed for the environmentally constrained portfolio to determine if this portfolio, with significantly more distributed generation that does not provide the inertia as the existing OTC synchronous machines, would still meet the WECC transient stability reliability criteria. Inertia is defined as the kinetic energy stored in the rotating parts of the synchronous generating machines that are important in helping to maintain system stability under critical contingency conditions. For large steam generating units, or combined cycle power plants, inertia values are large that help maintaining grid stability under large disturbance, whereas small distributed generation (DG), such as photovoltaic (PV) solar generation does not have inertia. The assessment was performed to determine whether system stability would still be maintained with the level of DG penetration as modeled in the CPUC's environmentally constrained portfolio. For details on the levels of DG penetration for the CPUC's environmentally constrained portfolio, please refer to the ISO 2011/2012 Transmission Plan[14].

- Loads and resources assessment for ISO's zonal area (NP26 or SP26) and balancing authority area (BAA) – this assessment provides long-term look at the future generation scenario and its ability to serve loads in the 2021 time frame under two load levels, 1-in-2 and 1-in-10 heat wave demand projections. The demand forecast was obtained from latest available Commission-adopted forecast from the CEC. At the time of evaluation, the latest available Commission-approved demand forecast was the 2010-2020 California Energy Demand forecast[15]. This evaluation is similar to the ISO's annual summer assessment, but is different in which the evaluation was performed for long-term horizon (2021 time frame).

[14] The ISO 2011/2012 Transmission Plan is posted on the ISO website at *http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf*.

[15] The CEC's California Energy Demand Commission-adopted forecast (2010 – 2020) can be obtained from *http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html*.

2.2.1 New Generation and Major Transmission Projects Assumed in the Studies

The starting power flow cases were obtained from the policy-driven study cases for the four RPS portfolios: trajectory, environmentally constrained, ISO base case and time-constrained. These RPS portfolios were provided by the CPUC for meeting 33% RPS target in 2021. Three of these RPS portfolios were directly provided by the CPUC, and the fourth study case, ISO base case, is a variation of the CPUC's cost constrained portfolio. These study cases were then modified further to include a 1-in-10 heat wave load projection (from the CEC) for the LCR areas under evaluation. Utilizing the same study process from the annual LCR studies, the Southern California electric system under ISO's operational control was modeled with a 1-in-10 year heat wave load projections.

Because the OTC study cases utilized the policy-driven (i.e., RPS) study cases, they have the same input assumptions of the renewable generation, new conventional generation and major transmission projects. Please refer to the ISO's final report for the 2011-2012 Transmission Plan for the details on the new generation (renewable and conventional) and major transmission project assumptions.

2.2.2 Summary of Study Results

In this section, the following study results are summarized:

- LCR assessment for the LA Basin area;
- Transient stability assessment for the four RPS portfolios at peak load conditions and for environmentally constrained portfolio at off-peak load conditions (*these study scenarios were evaluated per discussion and agreement with the state energy agencies and CARB)*;
- Preliminary supply and demand outlook assessment for 2021 time frame for the trajectory RPS portfolio for a 1-in-10 and 1-in-2 year heat wave load projections.

2.2.1 Local Capacity Requirement (LCR) Study Results for ISO's LA Basin LCR Area

For this assessment, the Diablo Canyon and San Onofre Nuclear Generating Station were assumed to be in service per discussion and agreement with the state energy agencies and CARB during ISO's 2011-2012 transmission planning process. In regards to the nuclear generating plants, the SWRCB has a separate but parallel process for review of the nuclear power plant for compliance with the Policy on OTC generating plants. This evaluation process, overseen by the SWRCB's Review Committee, requires special studies to be performed by an independent third party to evaluate various compliance options for alternative cooling technology and associated costs. The special studies report is required to be submitted to the SWRCB by October 1, 2013. The ISO, in its 2012-2013 transmission planning process, plans to evaluate impact on grid reliability with the absence of the nuclear generation for the 10-year out horizon. A reliability assessment performed for a tenth year in the future is considered a long-term assessment in the ISO transmission planning process[16].

To determine the level of generation requirements, including generation at the existing OTC plants, for the L.A. Basin in 2021, an LCR study was performed for the four RPS portfolios. The following areas and sub-areas were examined for generation requirements:

- Overall L.A. Basin;
- Western L.A. Basin;
- Ellis sub-area; and
- El Nido sub-area.

The Western L.A. Basin and Ellis sub-area drive the need for generation at the existing OTC plants. The Ellis sub-area needs these generating units to mitigate a voltage collapse concern. The Western L.A. area needs these generating units to mitigate an overloading concern. The overall L.A. Basin generation needs incorporate the generation requirements identified for the Western L.A. Basin, Ellis and El Nido sub-areas and the remaining generation need in the area. A range of generation needs at the existing OTC plants was identified for the most effective and least effective locations. The reason for this approach was because of the uncertainty in generation re-development in which there was no firm plan to which locations that the re-powering or replacement units would finally take place.

Area Definition for the overall L.A. Basin

The transmission tie lines into the L.A. Basin are:

1. San Onofre-San Luis Rey #1, #2, and #3 230 kV lines;
2. San Onofre-Talega 230 kV line;
3. San Onofre-Capistrano 230 kV line;
4. Lugo-Mira Loma #2 & #3 500 kV lines;
5. Lugo-Rancho Vista #1 500 kV line;
6. Sylmar-Eagle Rock 230 kV line;
7. Sylmar-Gould 230 kV line;
8. Vincent-Mesa Cal #1 and #2 230 kV lines;
9. Vincent-Rio Hondo #1 and #2 230 kV lines;
10. Devers-Red Bluff #1 and #2 500 kV lines;
11. Mirage-Coachella valley 230 kV line;

[16] It is noted that the compliance dates for the San Onofre and Diablo Canyon nuclear plants are scheduled for 2022 and 2024, respectively, per the SWRCB's Policy on OTC plants.

12. Mirage-Ramon 230 kV line; and
13. Mirage-Julian Hinds 230 kV line.

The following substations form the boundary surrounding of the L.A. Basin area:

1. San Onofre is in, San Luis Rey is out;
2. San Onofre is in, Talega is out;
3. San Onofre is in, Capistrano is out;
4. Mira Loma is in, Lugo is out;
5. Rancho Vista is in, Lugo is out;
6. Eagle Rock is in, Sylmar is out;
7. Gould is in, Sylmar is out;
8. Mesa Cal is in, Vincent is out;
9. Rio Hondo is in, Vincent is out;
10. Devers is in, Red Bluff is out;
11. Mirage is in, Coachella Valley is out;
12. Mirage is in, Ramon is out; and
13. Mirage is in, Julian Hinds is out.

The total 2021 substation load (i.e., bus bar level load) within the defined area is 22,686 MW. Each portfolio has different line losses. The following table is the summary for L.A. Basin loads and resources summary for all four RPS portfolios.

Table 1 - Load and resources summary for the L.A. Basin LCR area

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Total 1-in-10 load and losses	22,867	22,838	22,872	22,862
Generation				
Existing NQC* (2012)	12,083 MW			
Existing Capacity at OTC Plants (2012)	5,166 MW			
Distributed Generation	339 MW	1,519 MW	271 MW	687 MW

Note: *NQC: Net Qualifying Capacity (MW)

Critical Contingency Analysis Summary

<u>Overall L.A, Basin Area</u>

The most critical contingency for the overall LA Basin for all four portfolios is an overlapping N-1/T-1 contingency of Chino-Mira Loma East #3 500 kV line and Mira Loma West 500/230 kV bank #2. The limiting element is Mira Loma West 500/230 kV bank #1 (24-hour rating)[17]. This constraint establishes the LCR values for the four RPS portfolios in the table below:

Table 2: LCR for overall L.A. Basin for the most constrained contingency

RPS Portfolio	LCR (MW)
Trajectory	13,300
Environmental	12,567
Base	12,930
Time	13,364

Mira Loma West 500/230 kV bank #1 has a higher 1-hour emergency rating. This emergency rating can be utilized by assuming up to 600 MW of either load curtailment or load transfer within 1 hour (to be implemented so that the 24-hour rating can be used after the one-hour rating has reached its time limit). If this mitigation is feasible, the next worst contingency for the overall LA Basin area is the outage of Sylmar S-Gould 230 kV line and Lugo-Victorville 500 kV line. The limiting element is the Eagle Rock-Sylmar S 230 kV line. This next constraint establishes LCR values for the four RPS portfolios as noted in the table below.

Table 3: LCR for overall L.A. Basin for the next constraint

Portfolio	LCR (MW)
Trajectory	10,743
Environmental	11,246
Base	11,010
Time	12,165

<u>Generation Effectiveness Factors</u>

The following table shows generating units that have at least 5 percent effectiveness on mitigating the Eagle Rock-Sylmar 230 kV line for the overall L.A. Basin LCR area. The

[17] An initial higher one-hour rating is used after the contingency. If the contingency is still not cleared after an hour, and the overloading concern still persists, a lower 24-hour rating will have to be used to avoid potential thermal damage to the transformer. Please see further discussion above for mitigation measures.

reason that the generation effectiveness factor for the next constraint is shown is because the mitigation for the first constraint (i.e., load transfer via capital project or SPS for controlled load curtailment to relieve Mira Loma transformer's loading concerns under a double-element contingency condition at peak load) is considered a "low hanging fruit" transmission mitigation which could be implemented if determined to still be needed in future updated studies.

Table 4: Units with at least 5 percent effectiveness on mitigation of identified 230 kV line constraints for the overall L.A. Basin LCR area

Generator	**Effectiveness Factor (%)**
PASADNA1 13.8 #1	24
PASADNA2 13.8 #1	24
BRODWYSC 13.8 #1	24
MALBRG3G 13.8 #S3	15
MALBRG2G 13.8 #C2	15
Generator	**Effectiveness Factor (%)**
MALBRG1G 13.8 #C1	15
CHEVGEN1 13.8 #1	13
CHEVGEN2 13.8 #2	13
MOBGEN1 13.8 #1	13
MOBGEN2 13.8 #1	13
LA FRESA 66.0 #10	13
NRG ELS7 18.0 #7	13
NRG ELG5 18.0 #5	13
NRG ELG6 18.0 #6	13
ARCO 5G 13.8 #5	12
ARCO 1G 13.8 #1	12
ARCO 2G 13.8 #2	12
ARCO 3G 13.8 #3	12
ARCO 4G 13.8 #4	12
ARCO 6G 13.8 #6	12
LBEACH34 13.8 #3	12
LBEACH34 13.8 #4	12
LBEACH12 13.8 #2	12
LBEACH12 13.8 #1	12
HARBOR G 13.8 #1	12
HARBOR G 13.8 #HP	12
CARBGEN1 13.8 #1	12
HINSON 66.0 #1	12
THUMSGEN 13.8 #1	12

CARBGEN2 13.8 #1	12
HARBOR 230.0 #F1	12
BRIGEN 13.8 #1	11
CTRPKGEN 13.8 #1	11
SIGGEN 13.8 #D1	11
ALMITOSW 66.0 #D3	10
ALAMT1 G 18.0 #1	9
ALAMT2 G 18.0 #2	9
ALAMT3 G 18.0 #3	9
HILLGEN 13.8 #D1	9
EME WCG1 13.8 #1	9
EME WCG3 13.8 #1	9
EME WCG4 13.8 #1	9
EME WCG5 13.8 #1	9
EME WCG2 13.8 #1	9
ELLIS 66.0 #12	8
ELLIS 66.0 #11	8
HUNT1 G 13.8 #1	8
HUNT2 G 13.8 #2	8
BARRE 66.0 #11	8
BARRE 66.0 #10	8
BARPKGEN 13.8 #1	7
SANTIAGO 66.0 #1	7
COYGEN 13.8 #1	7
ANAHEIMG 13.8 #1	6
S.ONOFR2 22.0 #2	5
S.ONOFR3 22.0 #3	5
CHINO 66.0 #E1	5
DELGEN 13.8 #1	5
DELGEN 13.8 #1	5
SANIGEN 13.8 #D1	5
CIMGEN 13.8 #D1	5
SIMPSON 13.8 #D1	5

Generation at the Existing OTC Generating Sites Determined To Be Needed for the Overall L.A. Basin LCR Area

The need for generation at the existing OTC generating sites in the overall L.A. Basin LCR area is established specifically by the Western L.A. Basin and Ellis sub-area. The following table establishes the range of generation capacity requirements at the existing OTC generating sites, assuming that they would be re-developed with acceptable cooling technology in the future, across all four RPS portfolios to mitigate identified reliability issues in the area. Lower ranges of generation requirements correspond to more effective locations. The capacity for generation need at the existing OTC generating sites is counted toward the total LCR need for the overall L.A. Basin. The summary of generation need at the existing OTC generating sites is provided in the following table.

Table 5: Range of generation requirements at the existing OTC generating sites for the overall L.A. Basin under four different RPS portfolios

Portfolio	Range of Generation Need at Existing OTC Generating Plants* (MW)
Trajectory	2,370 – 3,741
Environmental	1,870 – 2,884
Base	2,424 – 3,834
Time	2,460 – 3,896

Notes: *Assuming generation re-development with acceptable cooling technology

Western L.A. Basin area

The most critical contingency for the Western L.A. Basin area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overloading concern for the remaining Serrano-Villa Park 230 kV line. This constraint establishes the LCR values for the four RPS portfolios as listed in the table below. These values are under the assumptions of generation re-development at more effective locations. Please refer to Table 7 for the effectiveness factors for various generation locations in the Western L.A. Basin area to mitigate reliability concerns. If the generation redevelopment occurs at a less effective location, then it would affect LCR value shown in the table below. Less effective generation locations would drive up the LCR need.

Table 6: LCR Need for the Western L.A. Basin Area

Portfolio	LCR (MW)
Trajectory	7,797
Environmentally Constrained	7,584
ISO Base case	7,517
Time Constrained	7,397

Generation Effectiveness Factors

The following table lists generating units that have at least 5 percent effectiveness on mitigating Serrano-Villa Park 230 kV line overloading concerns under identified N-1-1 contingency. This constraint establishes the LCR need for the Western L.A. Basin area.

Table 7: Units with at least 5% effectiveness for mitigating Western LA Basin sub-area constraint

Generator	Effectiveness Factor (%)	
BARPKGEN 13.8 #1	32	<-- More Effective Units
BARRE 66.0 #11	32	
BARRE 66.0 #10	32	
ANAHEIMG 13.8 #1	32	
ALAMT5 G 20.0 #5	24	
ALAMT6 G 20.0 #6	24	
ALAMT3 G 18.0 #3	24	
ALAMT4 G 18.0 #4	24	
ALAMT1 G 18.0 #1	23	
ALAMT2 G 18.0 #2	23	
ALMITOSW 66.0 #D3	23	
ALMITOSW 66.0 #D2	23	
ALMITOSW 66.0 #D1	23	
ALAMT7 G 16.0 #R7	23	
HUNT1 G 13.8 #1	23	
HUNT2 G 13.8 #2	23	
ORCOGEN 13.8 #1	23	
ELLIS 66.0 #12	23	
ELLIS 66.0 #11	23	
ELLIS 66.0 #10	23	
SANTIAGO 66.0 #1	17	
COYGEN 13.8 #1	17	
LITEHIPE 66.0 #10	16	
BRIGEN 13.8 #1	16	
LBEACH5G 13.8 #R5	16	
LBEACH6G 13.8 #R6	16	
LBEACH7G 13.8 #R7	16	
HARBOR 230.0 #F1	16	
HARBOR G 13.8 #1	15	
HARBOR G 13.8 #HP	15	
HINSON 66.0 #D8	15	
HINSON 66.0 #D7	15	
HINSON 66.0 #D6	15	
HINSON 66.0 #D4	15	
HINSON 66.0 #D3	15	
HINSON 66.0 #D1	15	
CARBGEN1 13.8 #1	15	

Generator	Effectiveness Factor (%)
SERRFGEN 13.8 #D1	15
THUMSGEN 13.8 #1	15
CARBGEN2 13.8 #1	15
HINSON 66.0 #1	15
LBEACH12 13.8 #2	15
LBEACH34 13.8 #3	15
LBEACH8G 13.8 #R8	15
LBEACH9G 13.8 #R9	15
LBEACH34 13.8 #4	15
LBEACH12 13.8 #1	15
ARCO 1G 13.8 #1	15
ARCO 2G 13.8 #2	15
ARCO 3G 13.8 #3	15
ARCO 4G 13.8 #4	15
ARCO 5G 13.8 #5	15
ARCO 6G 13.8 #6	15
CENTER 66.0 #D1	15
SIGGEN 13.8 #D1	15
CTRPKGEN 13.8 #1	15
LCIENEGA 66.0 #D1	14
VENICE 13.8 #1	14
MOBGEN1 13.8 #1	14
OUTFALL1 13.8 #1	14
OUTFALL2 13.8 #1	14
PALOGEN 13.8 #D1	14
REDON1 G 13.8 #R1	14
REDON2 G 13.8 #R2	14
REDON3 G 13.8 #R3	14
REDON4 G 13.8 #R4	14
LA FRESA 66.0 #10	14
LA FRESA 66.0 #D9	14
LA FRESA 66.0 #D8	14
LA FRESA 66.0 #D7	14
MOBGEN2 13.8 #1	14
CHEVGEN1 13.8 #1	14
CHEVGEN2 13.8 #2	14
ELSEG4 G 18.0 #4	14
ELSEG3 G 18.0 #3	14
REDON5 G 18.0 #5	14

Generator	Effectiveness Factor (%)	
REDON7 G 20.0 #7	14	
REDON8 G 20.0 #8	14	
REDON6 G 18.0 #6	14	
NRG ELG5 18.0 #5	14	
NRG ELG6 18.0 #6	14	
NRG ELS7 18.0 #7	14	
FEDGEN 13.8 #1	12	
REFUSE 13.8 #D1	12	
MALBRG3G 13.8 #S3	12	
MALBRG2G 13.8 #C2	12	
MALBRG1G 13.8 #C1	12	
MESA CAL 66.0 #D7	11	
BRODWYSC 13.8 #1	10	
PASADNA1 13.8 #1	9	
PASADNA2 13.8 #1	9	
OLINDA 66.0 #1	7	
EME WCG1 13.8 #1	7	
EME WCG3 13.8 #1	7	
EME WCG4 13.8 #1	7	
EME WCG5 13.8 #1	7	
EME WCG2 13.8 #1	7	<-- Least effective units

<u>Generation Need at the Existing OTC Generating Sites in the Western L.A. Basin area</u>

The following lists the level of generation capacity requirements at the existing OTC generating plants to mitigate the reliability concern on the Serrano-Villa Park 230 kV line for the four RPS portfolios. A range of values are provided: lower number corresponds to generation re-development at more effective sites; higher number corresponds to generation re-development at less effective sites.

Table 8: Range of generation requirements at the existing OTC generating plants in the Western L.A. Basin

Portfolio	Range of Generation Need at Existing OTC Plants (MW)
Trajectory	2,370 – 3,741
Environmentally Constrained	1,870 – 2,884
ISO Base case	2,424 – 3,834

Time Constrained	2,460 – 3,896

<u>Ellis Sub-area</u>

The most critical contingency for the Ellis sub-area is the loss of the Barre-Ellis 230 kV line followed by the loss of the Santiago-San Onofre #1 & #2 230 kV lines. This contingency would have caused voltage collapse condition at peak loads.

This constraint establishes the LCR numbers for the four RPS portfolios as summarized in the table below.

Table 9: LCR for the Ellis sub-area

Portfolio	LCR (MW)
Trajectory	531
Environmental	597
Base	511
Time	556

<u>Generation Effectiveness Factors</u>

The generators inside the subarea have the same effectiveness factors.

<u>Needed Generation at the Existing OTC Generating Sites</u>

To mitigate voltage collapse issues in this subarea, about 450 MW of generation at the existing OTC generating site is required in all four portfolios. It is assumed that these generating units would be re-developed with acceptable cooling technology.

<u>El Nido Sub-area</u>

The most critical contingency for this LCR area is an N-2 outage of the La Fresa-Redondo #1 and #2 230 kV lines. The limiting element is the La Fresa-Hinson 230 kV line. This constraint establishes the LCR need for the four RPS portfolios, as listed in the table below.

Table 10: LCR for the El Nido sub-area

Portfolio	LCR (MW)
Trajectory	619
Environmental	585
Base	568
Time	620

<u>Generation Effectiveness Factors</u>

All generators inside this sub-area have the same effectiveness factors.

<u>Generation Need at the Existing OTC Generating Plant</u>

It was determined that the generation at the existing OTC generating site is not needed to mitigate identified reliability concerns (i.e., line overloading) in the El Nido sub-area.

2.2.3 Summary of Local Capacity Requirements and Generation Need at the Existing OTC Plants by Respective RPS Portfolios for a 1-in-10 Heat Wave Load Projections (High Net Load Scenario)

The following four tables provide the summary for the local capacity requirements by respective LCR area and sub-areas under four different RPS portfolios. In addition, the generation need at the existing OTC generating plants is also provided. It is assumed that this generation would be re-developed with acceptable cooling technology. The summary tables also list the most critical contingencies and limiting transmission elements.

Table 11: Trajectory RPS Portfolio — LCR and Generation Need (at the Existing OTC Plants) in the L.A. Basin area

RPS Portfolio	Area	LCR			Generation Need (at the Existing OTC Plants)? (MW)	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Trajectory	Overall LA Basin	12,961	339	13,300	Yes (2,370 – 3,741)	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV Bank #2
		10,404	339	10,743	Yes (2,370 – 3,741)	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500 kV line
	Western LA Basin	7,529	268	7,797	Yes (2,370 – 3,741)	Serrano-Villa PK #1	Serrano-Lewis #1, then Serrano-Villa PK #2 (N-1-1)
	Ellis	472	59	531	Yes (450)	Voltage Collapse	Barre-Ellis 230 kV line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	614	5	619	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 12: Environmentally constrained RPS portfolio — LCR and Generation Need (at the Existing OTC Plants) in the L.A. Basin area

Portfolio	Area	LCR			Generation Need (at the Existing OTC Plants)? (MW)	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Environmentally Constrained	Overall LA Basin	11,048	1,519	12,567	Yes (1,870 – 2,884)	Mira Loma West 500/230 bank #1 (24-Hr rating)	Chino-Mira Loma East #3 23 0kV line + Mira Loma West 500/230 kV bank #2
		9,727	1,519	11,246	Yes (1,870 – 2,884)	Eagle Rock-Sylmar S 230 kV line	Sylmar S - Gould 230 kV line + Lugo - Victorville 500 kV line
	Western LA Basin	6,695	869	7,584	Yes (1,870 – 2,884)	Serrano-Villa PK #1	Serrano-Lewis #1, then Serrano-Villa PK #2 (N-1-1)
	Ellis	473	124	597	Yes (450)	Voltage Collapse	Barre-Ellis 230kV Line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	494	91	585	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 13: ISO Base case RPS portfolio — LCR and Generation Need (at the Existing OTC Plants) in the L.A. Basin area

Portfolio	Area	LCR			Generation Need (at the Existing OTC Plants)? (MW)	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
ISO Base case	Overall LA Basin	12,659	271	12,930	Yes (2,424 – 3,834)	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		10,739	271	11,010	Yes (2,424 – 3,834)	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230kV line + Lugo-Victorville 500 kV line
	Western LA Basin	7,325	192	7,517	Yes (2,424 – 3,834)	Serrano-Villa PK #1	Serrano - Lewis #1, then Serrano - Villa PK #2 (N-1-1)
	Ellis	472	39	511	Yes (450)	Voltage Collapse	Barre-Ellis 230kV Line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	544	94	568	No	La Fresa-Hinson 230 kV	La Fresa-Redondo #1 and #2 230 kV lines

Table 14: Time-constrained RPS portfolio — LCR and Generation Need (at the Existing OTC Plants) in the L.A. Basin area

Portfolio	Area	LCR			Generation Need (at the Existing OTC Plants)? (MW)	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Time-Constrained	Overall LA Basin	12,677	687	13,364	Yes (2,460 – 3,896)	Mira Loma West 500/230 bank #1 (24-Hr rating) **	Chino - Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		11,478	687	12,165	Yes (2,460 – 3,896)	Eagle Rock-Sylmar S 230 kV Line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500kV line
	Western LA Basin	6,954	443	7,397	Yes (2,460 – 3,896)	Serrano-Villa PK #1	Serrano-Lewis #1, then Serrano-Villa PK #2 (N-1-1)
	Ellis	495	61	556	Yes (450)	Voltage Collapse	Barre - Ellis 230 kV line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	589	31	620	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

2.2.4 Sensitivity LCR Assessment for Environmentally Constrained Portfolio with Additions of Incremental Uncommitted Energy Efficiency and Combined Heat and Power (i.e., Mid Net Load Scenario)

The State Energy Agencies (i.e., CPUC and CEC) have requested the ISO to perform ***sensitivity*** reliability assessments with the assumptions of incremental uncommitted energy efficiency (EE) and combined heat and power (CHP). It is noted that ISO's local capacity requirement study methodology requires the use of a 1-in-10 heat wave load projections based on the CEC's Commission-adopted demand forecast. The ISO considers studies that include *incremental uncommitted* demand side management assumptions as ***sensitivity*** studies and should not be used for long-term capacity procurement process due to the uncertainty whether these programs would be procured by the Load Serving Entities (LSEs) and be made available as dependable resources when needed in the long term. In the annual local capacity need assessment, the ISO uses the CEC's Commission-adopted demand forecast for the load assumptions, which include *committed* energy efficiency.

Table 15: State energy agencies' provided assumptions on *incremental uncommitted* EE & CHP

Load Serving Entities	2021 Incremental Uncommitted EE (MW)	2021 Incremental Uncommitted CHP (MW)
SCE	2,461	209
SDG&E	496	14

The following presents a series of ***sensitivity*** study results with incremental uncommitted EE and/or additional CHP modeled for SCE and SDG&E. The study results are provided step by step to provide information regarding the incremental impacts of EE, CHP and the Del Amo-Ellis 230 kV loop-in project, respectively.

1. Table 16 provides a summary of study results with *incremental uncommitted* EE only and without the Del Amo – Ellis 230kV loop-in project[18].

    - *LA Basin's total LCR:*

        - For this study, the ISO dispatched base-load generation in San Diego LCR area[19] to adequately mitigate a voltage instability concern under an N-1-1 contingency condition (i.e., Sunrise Powerlink and Southwest Powerlink). This minimum level of generation need in San Diego for this *sensitivity* study was modeled to ensure that we would not underestimate the generation need in the LA Basin LCR area.

    - *Western LA Basin's new local generation requirements:*

        - The Western LA Basin LCR need was determined by dispatching adequate generation to mitigate thermal loading constraint on the Serrano – Villa Park #1 230kV line under an N-1-1 contingency of the Serrano – Lewis #1, followed by the Serrano – Villa Park #2 230kV line. The Western LA Basin OTC generation range in Table 16 refers to the need of new local generation which could be met by repowering of the existing once-through cooled generation with acceptable cooling technology. For this study, if new local generation is needed to maintain local reliability, the capacity of the existing OTC generation was modeled as proxy for new generation capacity. The range of new generation need varies from more effective to less effective locations. San Onofre nuclear generating units were assumed to be on-line in the studies.

[18] The Del Amo – Ellis 230kV loop-in of Barre substation project was accelerated for summer 2012 due to extended outage of the San Onofre nuclear generation. This project brings Del Amo – Ellis 230kV line into Barre Substation, creating Del Amo – Barre and second Barre – Ellis 230kV lines.

[19] The total generation within San Diego LCR area for this sensitivity study is approximately 1,900 MW.

Table 16: Summary of sensitivity assessment with incremental uncommitted EE

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (Mw)	Total (MW)	New Gen. Required ?^	Constraint	Contingency
Environmentally Constrained (Mid Net Load Condition)	Western LA	5,847	869	6,716	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	LA Basin Overall	7,135	1,519	8,654	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range	868 - 1,437 MW plus SONGS					New generation need ranges from most effective to less effective locations
	Ellis**	434	124	558	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	327	91	418	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering)

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA

** In addition to generation requirements, two 79 MVAR shunt capacitors (Johanna & Santiago) and 140 MVAR at HB were modeled to mitigate voltage collapse concern to maintain load. If Santiago N-2 SPS is used (drop Santiago load), then no new unit is needed (i.e., no OTC repowering), but two shunt caps are still needed.

2. Table 17 provides a summary of study results with *incremental uncommitted* EE and CHP. With the additional *uncommitted* CHP modeled for the LA Basin as well as for the San Diego LCR area, the need for new local generation requirements in the Western LA Basin LCR area is lower than the study scenario in Table 16. However, the total LCR needs in the larger LA Basin increase slightly, due to the lower effectiveness of the additional *uncommitted* CHP.

Table 17: Summary of sensitivity assessment with *incremental uncommitted* EE and CHP

Portfolios	Area	LCR Non-D.G. (MW)	D.G. (Mw)	Total (MW)	New Gen. Required ?^	Constraint	Contingency
Environmentally Constrained (Mid Net Load Condition)	Western LA	5,895	869	6,764	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	LA Basin Overall	7,203	1,519	8,722	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range	782 - 1,301 MW plus SONGS					New generation need ranges from most effective to less effective locations
	Ellis**	388	124	512	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	284	91	375	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

^ This has assumptions of new generation coming from repowering of OTC units.
% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering)
* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA
** In addition to generation requirements, two 79 MVAR shunt capacitors (Johanna & Santiago) and 140 MVAR at HB were modeled to mitigate voltage collapse concern to maintain load. If Santiago N-2 SPS is used (drop Santiago load), then no new unit is needed (i.e., no OTC repowering) but two shunt caps are still needed.

3. Table 18 provides a summary of study results with *incremental uncommitted* EE, CHP and the Del Amo – Ellis 230kV line loop-in project modeled. With the loop-in project in service, it eliminates the need for local generation in the Ellis sub-area for the *mid net load* sensitivity analyses. However, because the loop-in project has the effects of reducing impedance in the southern Orange County area, it causes more power to flow through the area, thus increasing the overload on the Serrano – Villa Park #1 230kV line under an N-1-1 contingency of the Serrano – Lewis #1, followed by the Serrano – Villa Park #2 230kV line. Therefore, more local generation would be needed to mitigate this increased overloading concern.

Table 18: Summary of sensitivity assessment with *incremental uncommitted* EE, CHP and Del Amo – Ellis 230kV loop-in project

Portfolios	Area	LCR			New Gen. Required ? ^	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	Western LA	6,155	869	7,024	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	LA Basin Overall	7,288	1,519	8,807	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range		1,042 - 1,677 MW plus SONGS				New generation need ranges from most effective to less effective locations
	Ellis	0	0	0	No	None	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	274	91	365	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA.

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering).

3. Transient Stability Assessments

A key concern with the implementation of the SWRCB's Policy on OTC plants is whether future generation portfolios that include significant penetration of renewable generation, coupled with potential shutdown or retirement of some OTC generating units would contribute to the reduction of generation inertia needed to maintain dynamic stability under critical contingencies. To address this concern, the ISO performed transient stability assessments for the trajectory RPS portfolio study case for under peak load conditions. In addition, both an on-peak and off-peak load evaluations were performed for the environmentally constrained RPS portfolio study case. A minimum amount of OTC generation was modeled for these studies, based on the results of the local capacity requirement assessments. Environmentally constrained study case represents stressed conditions due to the presence of significant amount of distributed generation (i.e., photovoltaic generation) which has no inertia. This RPS portfolio also has less conventional generation dispatch than other RPS portfolios.

The following tables provide summary of transient stability study results. Critical contingencies in the WECC and ISO BAA were performed to determine whether dynamic stability performance met WECC transient stability reliability criteria.

Table 19: Summary of transient stability studies for peak load conditions

Contingencies	Trajectory Portfolio Case		Environmentally Constrained Case	
	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?
Diablo G-2	√	√	√	√
Diablo – Midway 500kV N-2	√	√	√	√
IPPDC Bi-polar	√	√	√	√
Los Banos North 500kV N-2	√	√	√	√
Los Banos South 500kV N-2	√	√	√	√
Lugo South 500kV N-2	√	√	√	√
Lugo – Vincent 500kV N-2	√	√	√	√
Midway-Vincent 500kV N-2	√	√	√	√
PDCI Bipolar	√	√	√	√
Palo Verde G-2	√	√	√	√
SONGS G-2	√	√	√	√
Table Mtn.-Tesla+VacaDixon-Tesla 500kV N-2	√	√	√	√
Sunrise + SWPL N-2	√	√	√	√
Vincent – Antelope 500kV N-2	√	√	√	Does not meet for Correct 66kV substation

Table 20: Summary of transient stability study results for off-peak load conditions

Contingencies	Environmentally Constrained Case	
	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?
Diablo G-1	√	√
Diablo – Midway 500kV N-2	√	√
IPPDC Bi-polar	√	√
Tesla – Metcalf 500kV line	√	√
Vincent – Antelope 500kV N-2	√	√
Lugo South 500kV N-2	√	√
Lugo – Vincent 500kV N-2	√	√
Midway-Vincent 500kV N-2	√	√
PDCI Bipolar	√	√
Palo Verde G-2	√	√
SONGS G-1	√	√
Vincent – Mesa 230kV N-2	√	√
Sunrise + SWPL N-2	√	√

Based on the study results, it appears that the studied RPS portfolios met WECC transient stability reliability criteria with the minimum amount of generation at the existing OTC plants as determined from the local reliability assessment. The environmentally constrained portfolio for the peak load conditions did have slightly worse results for a double-element contingency condition for a radial sub-transmission substation in the SCE service territory. The results were a frequency excursion beyond the WECC minimum frequency limit (i.e., below 59.0 Hz for Category C contingency). However, this frequency excursion was for a radial load system and did not affect network facilities.

4. Loads and Resources Evaluations for Zonal Areas and ISO Balancing Authority Area (BAA)

To address concerns as to whether generation supplies would be adequate for zonal areas (i.e., NP26 or SP26) or ISO balancing authority in the long-term (i.e., 2021 time frame), a supply and demand assessment was performed for two load conditions: 1-in-2 and 1-in-10 heat wave load projections. This approach is similar to the ISO annual summer assessment in which a supply and demand outlook was assessed for the next upcoming summer. In addition, the assessment reported here was based on import assumptions using projected 2021 Maximum Import Capability (MIC). The 2021 long-term assessment is considered informational only because the official long-term supply and demand outlook is typically carried out under the CPUC Long-Term Procurement Plan (LTPP) process with significant participation from various stakeholders. The ISO assessment is intended to be used for informational purposes to provide an indication of potential trends or areas of concerns for further considerations in future regulatory or planning assessment.

The following tables are summaries for the summer 2021 supply and demand outlook for the *trajectory portfolio* for the 1-in-2 and 1-in-10 heat wave load projections with projected 2021 MIC import assumption. From these assessments, it appears that there is no resource deficiency identified for 1-in-2 heat wave load projections. For a 1-in-10 heat wave load projections, it indicates that the operating reserve margins for ISO BAA and SP26 zonal areas are thin at about 3%.

Table 21: Estimated summer 2021 supply and demand outlook (1-in-10 load conditions) — trajectory portfolio with 2021 MIC estimates

Summer 2021 Loads and Resources Outlook - Trajectory Portfolio

1-in-10 Demand and 1-in-10 Generation & Transmission Outage Scenarios

Summer 2021 Outlook - RA Imports (Using Projected MIC for ISO BAA)

Resource Adequacy Conventions	ISO (MW)	SP26 (MW)	NP26 (MW)
Existing Generation (2012 NQC)	50,427	24,677	25,750
Retirements			
(Known & OTC Gen determined not needed for LCR Area)	(8,939)	(5,106)	(3,833)
High Probability Capacity Additions			
(thermal generation under construction or have PPA)	5,305	2,009	3,296
Total Projected Renewable Generation Additions			
(NQC Values)	8,920	6,936	1,984
- Wind Generation	809	638	171
- Non-Wind Renewable Generation	8,111	6,298	1,813
Hydro Derates - only used for drough year	0	0	0
Outages (1-in-10 Generation & Transmission)	(6,844)	(3,872)	(3,616)
Net Interchange	11,225	10,132	4,843
Total Net Supply (MW)	60,093	34,776	28,424
DR & Interruptible Programs (use 2012 figures)	2,296	1,721	576
Demand (1-in-10 summer temperature)	60,773	35,507	26,760
Surplus/(Deficiency) (MW)	**1,616**	**990**	**2,239**
Operating Reserve Margin	**2.7%**	**2.8%**	**8.4%**

Table 22: Estimated summer 2021 supply and demand outlook (1-in-2 load conditions) — trajectory portfolio with 2021 MIC estimates

Summer 2021 Loads and Resources Outlook - Trajectory Portfolio			
1-in-2 Demand and 1-in-2 Generation & Transmission Outage Scenarios			
Summer 2021 Outlook - RA Imports (Using Projected MIC for ISO BAA)			
Resource Adequacy Conventions	ISO (MW)	SP26 (MW)	NP26 (MW)
Existing Generation (2012 NQC)	50,427	24,677	25,750
Retirements			
(Known & OTC Gen determined not needed for LCR Area)	(8,939)	(5,106)	(3,833)
High Probability Capacity Additions			
(thermal generation under construction or have PPA)	5,305	2,009	3,296
Total Projected Renewable Generation Additions			
(NQC Values)	8,920	6,936	1,984
- Wind Generation	809	638	171
- Non-Wind Renewable Generation	8,111	6,298	1,813
Hydro Derates - only used for drough year	0	0	0
Outages (1-in-2 Generation & Transmission)	(4,698)	(2,033)	(2,677)
Net Interchange	11,225	10,132	4,843
Total Net Supply (MW)	62,239	36,615	29,363
DR & Interruptible Programs (use 2012 figures)	2,296	1,721	576
Demand (1-in-2 summer temperature)	56,029	32,467	24,940
Surplus/(Deficiency) (MW)	8,507	5,869	4,999
Operating Reserve Margin	15.2%	18.1%	20.0%

5. Conclusions

The main drivers behind new local generation need at the existing OTC generating sites in the L.A. Basin are the needs in the Western L.A. Basin area and the Ellis sub-area[20]. If the most effective generating units at the OTC generating sites were selected, the generation need at those sites for all four RPS portfolios would range from 1,900 MW to 2,500 MW. If generating units at less effective OTC generating sites were selected, the generation need at those OTC sites for all four RPS portfolios would be in the range of 2,900 MW to 3,900 MW, depending on the RPS portfolio. Time-constrained RPS portfolio would have the highest amount of generation need at the existing OTC plants, whereas the environmentally constrained RPS portfolio would result in the lowest need, due to significant penetration of distributed generation. However, transient stability study results indicated that the trajectory RPS portfolio would have better dynamic stability performance than the environmentally constrained RPS portfolio. This is because the distributed generation, which is in much higher penetration in the environmentally constrained case than other RPS cases, has no inertia.

[20] Completion of the Del Amo – Ellis loop-in project and Orange County Region Automatic Undervoltage Load Shedding Scheme (OC-UVLS) eliminate this need in the Ellis sub-area. However, eliminating the new generation need in the Ellis sub-area would affect the Western LA Basin as its location is more effective in meeting the new generation need for the larger Western LA Basin LCR area.

For AB 1318 study purpose of determining emission offset needs associated with new additions of conventional generation, determination for emission offset needs for conventional generation in the South Coast Air Basin (SCAB) footprint should be based on the need for repowering or replacement of the OTC generation that was determined to be needed to maintain local reliability in the L.A. Basin. The total aggregated emission offset needs for the area under SCAB jurisdiction should include the reliability needs identified for both ISO and LADWP Balancing Authority Areas (BAAs). LADWP performed its own local capacity need to serve its load in the L.A. Basin.

APPENDIX A

Text of AB 1318

BILL NUMBER: AB 1318   CHAPTERED
BILL TEXT

CHAPTER 285
FILED WITH SECRETARY OF STATE OCTOBER 11, 2009
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AMENDED IN SENATE SEPTEMBER 1, 2009
AMENDED IN ASSEMBLY JULY 6, 2009
AMENDED IN ASSEMBLY MAY 14, 2009
AMENDED IN ASSEMBLY MAY 4, 2009

INTRODUCED BY   Assembly Member V. Manuel Perez
(Principal coauthors: Senators Ducheny and Benoit)
(Coauthor: Assembly Member Nestande)

FEBRUARY 27, 2009

An act to add Section 39619.8 to, and to add and repeal Section 40440.14 of, the Health and Safety Code, and to amend Section 21080 of the Public Resources Code, relating to the South Coast Air Quality Management District.

LEGISLATIVE COUNSEL'S DIGEST

AB 1318, V. Manuel Perez. South Coast Air Quality Management District: emission reduction credits: California Environmental Quality Act.

(1) Under existing law, every air pollution control district or air quality management district governing board, except as specified, is required to establish by regulation a system by which all reductions in the emission of air contaminants that are to be used to offset certain future increases in the emission of air contaminants are required to be banked prior to use to offset future increases in emissions, as provided.

The California Environmental Quality Act (CEQA) requires a lead agency, as defined, to prepare, or cause to be prepared, and certify the completion of, an environmental impact report (EIR) on a project that it proposes to carry out or approve that may have a significant effect on the environment or to adopt a negative declaration if it finds that the project will not have that effect. CEQA also requires a lead agency to prepare a mitigated negative declaration for a project that may have a significant effect on the environment if revisions in the project would avoid or mitigate that effect and there is no substantial evidence that the project, as revised, would have a significant effect on the environment. CEQA exempts certain specified projects from its requirements.

This bill would require the executive officer of the South Coast Air Quality Management District, upon making a specified finding, to transfer emission reduction credits for certain pollutants from the south coast district's internal emission credit accounts to eligible *electrical generating facilities, as described. By imposing these duties on the South Coast Air Quality Management District, the bill would impose a state-mandated local program. The bill would exempt from CEQA certain actions of the district undertaken pursuant to the bill. These provisions would be repealed on January 1, 2012.*

The bill would require the State Air Resources Board, in consultation with specified agencies, to prepare and submit to the Governor and the Legislature a report that evaluates the electrical system reliability needs of the South Coast Air Basin and recommends the most effective and efficient means of meeting those needs while ensuring compliance with state and federal law.

(2) This bill would state the findings and declarations of the Legislature concerning the need for special legislation.

(3) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. (a) The Legislature finds and declares all of the following:

(1) Sufficient rotating electrical generation capacity is required within the Los Angeles Basin Local Reliability Area to ensure stable operation of the power grid.

(2) Energy efficiency and renewable resources, which are primarily located outside of the Los Angeles Basin Local Reliability Area, may not be sufficient to satisfy the in-basin rotating electrical generation capacity need.

(3) In October 2005, the Public Utilities Commission and the State Energy Resources Conservation and Development Commission (commission) adopted the Energy Action Plan II, which establishes a policy that the state will rely on clean and efficient fossil fuel-fired generation to the extent energy efficiency and renewable resources are unsuitable.

(4) The Energy Action Plan II establishes a policy that the state will encourage the development of cost-effective, highly efficient, and environmentally sound supply resources to provide reliability and consistency with the state's energy priorities.

(5) Executive Order S-14-08, signed by the Governor on November 17, 2008, calls for a new, more aggressive renewable energy target, increasing the current goal of obtaining 20 percent of the energy used by electrical corporations from clean, renewable sources by the year 2010 to 33 percent by the year 2020.

(6) New electrical generating capacity in the Los Angeles Basin Local Reliability Area is required to meet best available control technology (BACT) standards and is required to fully offset any remaining emissions of nonattainment pollutants, including sulfur oxides and particulate matter with emission credits.

(b) The South Coast Air Quality Management District shall have the full authority to carry out the provisions of this act.

SEC. 2. Section 39619.8 is added to the Health and Safety Code, to read:

39619.8. On or before July 1, 2010, the state board, in *consultation with the Public Utilities Commission, the State Energy Resources Conservation and Development Commission, the State Water Resources Control Board, and the Independent System Operator, shall prepare and submit to the Governor and the Legislature a report that evaluates the electrical system reliability needs of the South Coast Air Basin and recommends the most effective and efficient means of meeting those needs while ensuring compliance with state and federal law, including, but not limited to, all of the following policies and requirements:*

(a) The California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500)).

(b) Section 316(b) of the federal Clean Water Act, and any policies and regulations adopted by the State Water Resources Control Board as these regulations applied to thermal powerplants within the basin.

(c) State and federal air pollution laws and regulations, including, but not limited to, any requirements for emission reductions credits for new and modified sources of air pollution.

(d) Renewable energy and energy efficiency requirements adopted pursuant to Division 1 (commencing with Section 201) of the Public Utilities Code and Division 15 (commencing with Section 25000) of the Public Resources Code.

(e) Division 13 (commencing with Section 21000) of the Public Resources Code.

(f) The resource adequacy requirements for load-serving entities established by the Public Utilities Commission pursuant to Section 380 of the Public Utilities Code.

SEC. 3. Section 40440.14 is added to the Health and Safety Code, to read:

40440.14. (a) The executive officer of the south coast district, upon finding that the eligible electrical generating facility proposed for certification by the State Energy Resources Conservation and Development Commission meets the requirements of the applicable new source review rule and all other applicable district regulations that must be met under Section 1744.5 of Title 20 of the California Code of Regulations, shall credit to the south coast district's internal emission credit accounts and transfer from the south coast district's internal emission credit accounts to eligible electrical generating facilities emission credits in the full amounts needed to issue permits for eligible electrical generating facilities to meet requirements for sulfur oxides (SOx) and particulate matter (PM2.5 and PM10) emissions.

(b) (1) In implementing subdivision (a), the south coast district shall rely on the offset tracking system used prior to the adoption of Rule 1315 of the South Coast District until a new tracking system is approved by the United States Environmental Protection Agency and is in effect, at which point that new system shall be used by the south coast district.

(2) In addition to using the prior offset tracking system, the district shall also make use of any emission credits that have resulted from emission reductions and shutdowns from minor sources since 1990. The district shall make any necessary submissions to the United States Environmental Protection Agency with regard to the crediting and use of emission reductions and shutdowns from minor sources.

(c) Within 60 days of the effective date of this section, for each eligible electrical generating facility, the south coast district

shall report to the State Energy Resources Conservation and Development Commission the emission credits to be credited and transferred pursuant to subdivision (a). The State Energy Resources Conservation and Development Commission shall determine whether the emission credits to be credited and transferred satisfy all applicable legal requirements. In the exercise of its regulatory responsibilities under its power facility and site certification authority, the State Energy Resources Conservation and Development Commission shall not certify an eligible electrical generation facility if it determines that the credit and transfer by the south coast district do not satisfy all applicable legal requirements.

(d) In order to be eligible for emission reduction credits pursuant to this section, an electrical generating facility shall meet all of the following requirements:

(1) Be subject to the permitting jurisdiction of the State Energy Resources Conservation and Development Commission.

(2) Have a purchase agreement, executed on or before December 31, 2008, to provide electricity to a public utility, as defined in Section 216 of the Public Utilities Code, subject to regulation by the Public Utilities Commission, for use within the Los Angeles Basin Local Reliability Area.

(3) Be under the jurisdiction of the south coast district, but not within the South Coast Air Basin.

(e) The executive officer shall not transfer emission reduction credits to an electrical generating facility pursuant to this section until the receipt of payment of the mitigation fees set forth in the south coast district's Rule 1309.1, as adopted on August 3, 2007. The mitigation fees shall only be used for emission reduction purposes. The south coast district shall ensure that at least 30 percent of the fees are used for emission reductions in areas within close proximity to the electrical generating facility and at least 30 percent are used for emission reductions in areas designated as "Environmental Justice Areas" in Rule 1309.1.

(f) This section shall be implemented in a manner consistent with federal law, including the Clean Air Act (42 U.S.C. Sec. 7401 et seq.).

(g) This section shall remain in effect only until January 1, 2012, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2012, deletes or extends that date.

SEC. 4. Section 21080 of the Public Resources Code is amended to read:

21080. (a) Except as otherwise provided in this division, this division shall apply to discretionary projects proposed to be carried out or approved by public agencies, including, but not limited to, the enactment and amendment of zoning ordinances, the issuance of zoning variances, the issuance of conditional use permits, and the approval of tentative subdivision maps unless the project is exempt from this division.

(b) This division does not apply to any of the following activities:

(1) Ministerial projects proposed to be carried out or approved by public agencies.

(2) Emergency repairs to public service facilities necessary to maintain service.

(3) Projects undertaken, carried out, or approved by a public agency to maintain, repair, restore, demolish, or replace property or

facilities damaged or destroyed as a result of a disaster in a disaster-stricken area in which a state of emergency has been proclaimed by the Governor pursuant to Chapter 7 (commencing with Section 8550) of Division 1 of Title 2 of the Government Code.

(4) Specific actions necessary to prevent or mitigate an emergency.

(5) Projects which a public agency rejects or disapproves.

(6) Actions undertaken by a public agency relating to any thermal powerplant site or facility, including the expenditure, obligation, or encumbrance of funds by a public agency for planning, engineering, or design purposes, or for the conditional sale or purchase of equipment, fuel, water (except groundwater), steam, or power for a thermal powerplant, if the powerplant site and related facility will be the subject of an environmental impact report, negative declaration, or other document, prepared pursuant to a regulatory program certified pursuant to Section 21080.5, which will be prepared by the State Energy Resources Conservation and Development Commission, by the Public Utilities Commission, or by the city or county in which the powerplant and related facility would be located if the environmental impact report, negative declaration, or document includes the environmental impact, if any, of the action described in this paragraph.

(7) Activities or approvals necessary to the bidding for, hosting or staging of, and funding or carrying out of, an Olympic games under the authority of the International Olympic Committee, except for the construction of facilities necessary for the Olympic games.

(8) The establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or other charges by public agencies which the public agency finds are for the purpose of (A) meeting operating expenses, including employee wage rates and fringe benefits, (B) purchasing or leasing supplies, equipment, or materials, (C) meeting financial reserve needs and requirements, (D) obtaining funds for capital projects necessary to maintain service within existing service areas, or (E) obtaining funds necessary to maintain those intracity transfers as are authorized by city charter. The public agency shall incorporate written findings in the record of any proceeding in which an exemption under this paragraph is claimed setting forth with specificity the basis for the claim of exemption.

(9) All classes of projects designated pursuant to Section 21084.

(10) A project for the institution or increase of passenger or commuter services on rail or highway rights-of-way already in use, including modernization of existing stations and parking facilities.

(11) A project for the institution or increase of passenger or commuter service on high-occupancy vehicle lanes already in use, including the modernization of existing stations and parking facilities.

(12) Facility extensions not to exceed four miles in length which are required for the transfer of passengers from or to exclusive public mass transit guideway or busway public transit services.

(13) A project for the development of a regional transportation improvement program, the state transportation improvement program, or a congestion management program prepared pursuant to Section 65089 of the Government Code.

(14) Any project or portion thereof located in another state which will be subject to environmental impact review pursuant to the National Environmental Policy Act of 1969 (42 U.S.C. Sec. 4321 et

seq.) or similar state laws of that state. Any emissions or discharges that would have a significant effect on the environment in this state are subject to this division.

(15) Projects undertaken by a local agency to implement a rule or regulation imposed by a state agency, board, or commission under a certified regulatory program pursuant to Section 21080.5. Any site-specific effect of the project which was not analyzed as a significant effect on the environment in the plan or other written documentation required by Section 21080.5 is subject to this division.

(16) The selection, credit, and transfer of emission credits by the South Coast Air Quality Management District pursuant to Section 40440.14 of the Health and Safety Code, until the repeal of that section on January 1, 2012, or a later date.

(c) If a lead agency determines that a proposed project, not otherwise exempt from this division, would not have a significant effect on the environment, the lead agency shall adopt a negative declaration to that effect. The negative declaration shall be prepared for the proposed project in either of the following circumstances:

(1) There is no substantial evidence, in light of the whole record before the lead agency, that the project may have a significant effect on the environment.

(2) An initial study identifies potentially significant effects on the environment, but (A) revisions in the project plans or proposals made by, or agreed to by, the applicant before the proposed negative declaration and initial study are released for public review would avoid the effects or mitigate the effects to a point where clearly no significant effect on the environment would occur, and (B) there is no substantial evidence, in light of the whole record before the lead agency, that the project, as revised, may have a significant effect on the environment.

(d) If there is substantial evidence, in light of the whole record before the lead agency, that the project may have a significant effect on the environment, an environmental impact report shall be prepared.

(e) (1) For the purposes of this section and this division, substantial evidence includes fact, a reasonable assumption predicated upon fact, or expert opinion supported by fact.

(2) Substantial evidence is not argument, speculation, unsubstantiated opinion or narrative, evidence that is clearly inaccurate or erroneous, or evidence of social or economic impacts that do not contribute to, or are not caused by, physical impacts on the environment.

(f) As a result of the public review process for a mitigated negative declaration, including administrative decisions and public hearings, the lead agency may conclude that certain mitigation measures identified pursuant to paragraph (2) of subdivision (c) are infeasible or otherwise undesirable. In those circumstances, the lead agency, prior to approving the project, may delete those mitigation measures and substitute for them other mitigation measures that the lead agency finds, after holding a public hearing on the matter, are equivalent or more effective in mitigating significant effects on the environment to a less than significant level and that do not cause any potentially significant effect on the environment. If those new mitigation measures are made conditions of project approval or are otherwise made part of the project approval, the deletion of the

former measures and the substitution of the new mitigation measures shall not constitute an action or circumstance requiring recirculation of the mitigated negative declaration.

(g) Nothing in this section shall preclude a project applicant or any other person from challenging, in an administrative or judicial proceeding, the legality of a condition of project approval imposed by the lead agency. If, however, any condition of project approval set aside by either an administrative body or court was necessary to avoid or lessen the likelihood of the occurrence of a significant effect on the environment, the lead agency's approval of the negative declaration and project shall be invalid and a new environmental review process shall be conducted before the project can be reapproved, unless the lead agency substitutes a new condition that the lead agency finds, after holding a public hearing on the matter, is equivalent to, or more effective in, lessening or avoiding significant effects on the environment and that does not cause any potentially significant effect on the environment.

SEC. 5. Due to unique circumstances concerning the South Coast Air Quality Management District, the Legislature finds and declares that a general statute cannot be made applicable within the meaning of Section 16 of Article IV of the California Constitution.

SEC. 6. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act, within the meaning of Section 17556 of the Government Code.