California Environmental Protection Agency

Air Resources Board

Report to the Governor and Legislature

Interim (Phase 1) Report: AB 1318 South Coast Air Basin Electricity Needs Assessment and Permitting Recommendations

July 2010

State of California
California Environmental Protection Agency
AIR RESOURCES BOARD
Stationary Source Division

Report to the Governor and Legislature

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EXECUTIVE SUMMARY

A. Introduction

Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009)[1] 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 (CAISO), 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).[2] The report is to include recommendations for meeting those reliability needs while ensuring compliance with state and federal law. 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. This interim report serves as Phase 1 in delivering the electric reliability and air permitting assessment envisioned in AB 1318. A final report (Phase 2) is expected to be completed by fall of 2011.

B. Scope of this Report

This report is considered an interim step in completing the evaluation required by AB 1318. This report contains the following:

- Executive Summary, provides background on events leading to the passage of AB 1318 legislation and the need for an integrated electric reliability and air permitting analysis for the SCAB; summarizes the key findings in this report; describes how ARB and the energy agencies will proceed to implement the work needed to deliver a comprehensive assessment meeting the scope required by AB 1318; and establishes a timeline with major milestones when work is projected to be completed.
- Chapter I, Air Permitting, provides an overview of California's air regulatory program for new or expanding facilities, including information specific to the jurisdiction of SCAQMD; summarizes the legal decisions and legislative actions that affect the issuance of air permits in SCAQMD; and introduces a list of potential strategies that may provide solutions to mitigate the availability and cost of emission reduction credits in SCAQMD.
- Chapter II, Electric Reliability, provides an assessment of what is known concerning electric reliability in the SCAB based on studies already completed or in progress up to May 2010 that covers out through year 2014, and what additional assessments and studies are needed to understand the long-term

[1] See text of Assembly Bill 1318 in Appendix A
[2] This report has been prepared with input from the technical staff of the CEC, CPUC, and CAISO – referred to collectively as the energy agencies in this document.

need for fossil fuel-fired power plant additions to ensure that reliability and operational needs are satisfied.

For this interim report, Chapters I and II are essentially self-contained chapters. The final (Phase 2) report is expected to provide a much more integrated discussion of the results of the electric reliability assessment and how those results translate into emission offset obligations and how existing permitting mechanisms can be modified to ensure electric reliability is maintained in the SCAB.

C. Key Findings

Given its role as an interim update on progress, this Phase 1 report does not include conclusions or recommendations. Instead, it provides information that will be used as a starting point in conducting the more detailed assessment required by AB 1318. For example, this report includes key findings that will inform the analysis performed during the preparation of the final Phase 2 report. Specifically, this report makes the following findings:

- More detailed analysis and studies are needed to complete an electric reliability assessment for the SCAB that addresses all of the parameters outlined in the legislation;
- Renewable, once-through cooling (OTC), and electric reliability studies need to feed into the analysis;
- A full public process is needed to provide opportunities for review and comment;
- A final Phase 2 report is scheduled to be delivered to the Governor and Legislature by fall of 2011; and
- Until a final Phase 2 report is completed, the evaluation of electrical generation projects will be conducted by the energy and air-quality agencies on a case-by-case basis.

D. Background

SCAQMD has the distinction of having some of the worst air quality in the nation. Approximately half of California’s population resides within the boundaries of SCAQMD. The District regulates over 28,000 stationary sources and has issued over 80,000 permits to construct and operate.

The federal Clean Air Act establishes the requirements for new and modified stationary sources of air pollution under the New Source Review (NSR) program. California law imposes additional requirements for new and modified sources, including that each local air district has a stationary source control program designed to achieve a “no net increase” in emissions of nonattainment pollutants or their precursors. The no net increase provision is accomplished through the use of emission offsets. Emission offsets are reductions in emissions from existing emitting sources and are required for the permitting of new facilities, relocations of existing facilities, and modifications or expansions at existing facilities. SCAQMD provides specified exemptions for offset requirements through its Rule 1304 (Exemptions). However, to comply with the no net increase requirement, the District itself provides the offsets to cover these exempt sources through its internal offset credit bank. In addition, the District has established a Priority Reserve through Rule 1309.1 that makes available offsets for innovative technologies, research operations, and essential public services. Rule 1309.1 was amended in 2006 to allow certain electrical generating facilities access to the District's internal offset credit bank. In addition, the District adopted Rule 1315 (Federal New Source Review Tracking System), which sets forth the eligible credits for the internal bank and the tracking mechanism for such credits.

In August 2007, the Natural Resources Defense Council, Communities for a Better Environment, Coalition for a Safe Environment, California Communities Against Toxics, and Desert Citizens Against Pollution, filed two lawsuits against SCAQMD challenging the District's adoption of amendments to Rule 1309.1 and Rule 1315. The environmental groups argued that SCAQMD had no authority to adopt a rule providing credits to power plants because it interfered with CEC's exclusive authority, and raised several California Environmental Quality Act (CEQA) issues.

In July 2008, the State Court issued a ruling invalidating Rules 1309.1 and 1315 based on the District's failure to perform an adequate CEQA analysis. The District was unsuccessful on a subsequent appeal of the Court's decision. The lawsuit in federal court was dismissed by the court and an appeal has yet to be filed by the plaintiffs.

As a result of the State Court decision, sources granted exemptions under Rule 1304 and sources qualifying for access to the Priority Reserve no longer have access to or are covered by the Districts bank of offset credits. Permits could no longer be issued for these types of sources unless offsets could be found and purchased in the open market. Acquiring offsets is a challenging task given the scarcity and exorbitant price of emission reduction credits in the SCAQMD.

Concerned with the potential for significant economic impacts in the Southern California Region, Governor Schwarzenegger approved Senate Bill 827 (Wright, Chapter 206, Statutes of 2009) in October 2009. This Bill allowed the District to re-establish its emissions bank to continue permitting essential public services until May 1, 2012. In anticipation of the Bill's expiration, the District is in the process of amending Rules 1309.1 and 1315 to address the CEQA issues identified in the State Court's ruling for point sources other than power plants.

Neither Senate Bill 827 nor the District's proposed amendments provide relief for electrical generating facilities. In anticipation that a more in-depth analysis is critical to evaluate the need for generation to ensure reliability of the grid in SCAQMD, AB 1318 was enacted to require ARB, the State's energy agencies, and others to work together to identify the future needs for generation and make recommendations to ensure that generation facilities can get sited to provide an increased supply of electricity.

E. Rationale for a Two-Phase Approach to Completing the Report

AB 1318 requires that ARB (a) consult with CPUC, CEC, CAISO, and SWRCB; (b) prepare a report that evaluates the electrical system reliability needs of the SCAB; and (c) recommend the most effective and efficient means of meeting the electrical system reliability needs while ensuring compliance with State and federal law.

Consultation with Energy Agencies and State Water Resources Control Board
Consistent with the legislation, ARB staff met with representatives from CEC, CPUC, CAISO, and SWRCB to discuss schedule, responsibilities, available information, and the need for studies to support the evaluation required under AB 1318. The agencies collectively concluded that a two-phase approach was the best option to provide a comprehensive report that would fulfill the directives of AB 1318. In order to manage the analysis required to meet the directives of the legislation, two technical teams have been formed, guided by ARB staff, which will operate in tandem.

1. Electric Reliability Team: This team, made up of representatives from CEC, CPUC, CAISO, and SWRCB, draws upon the expertise of the energy agencies and closely-related work being undertaken on the effect of power plant shut downs, repowers, or retrofits to comply with the phase-out of OTC systems.
2. Air Quality Regulatory Team: This team is expected to be made up of representatives from ARB, U.S. EPA, SCAQMD, and staff in the CEC's Siting, Transmission, and Environmental Protection Division and is examining how existing permitting mechanisms for power plants might be revised.

ARB has determined that an extensive public process will be needed to solicit input from affected parties and stakeholders.

Evaluation of Electric Reliability Needs of the South Coast Air Basin
It was the consensus of staff from ARB and the energy agencies that, given the short timeframe of AB 1318, studies already completed or underway that were expected to be completed by mid-2010 did not have sufficient detailed information on various load and resource scenarios to provide for a complete reliability assessment, by July 2010, as required by the legislation.

In addition, information from the existing studies would likely not provide adequate information about reliability needs beyond the 2014 timeframe. More detailed studies are required to provide an analysis that extends out to the 2015 through 2020 time frame (or between five to ten years out). The inter-agency team understands this to be the intent of AB 1318 as the appropriate timeframe for a long-term reliability study. Existing reliability studies do not extend beyond 2020, but the practice of a rolling 10-year forward time period will provide information beyond 2020. Finally, few if any studies address the full extent of the geographic scope required by AB 1318.

Traditional reliability studies focus on capacity needed to satisfy stylized stressed conditions, such as summer peak demand. In order to support the focus of AB 1318 on possible revisions to air quality permitting programs, the type of power plant is important since its operating profile over time directly affects its air emissions, and thus the amount of offsets that must be procured. Existing reliability studies do not address the type of new generation that may be required for providing operational support to integrate renewable generation. Although further analysis is already under way, time is required to complete this effort and to integrate it into OTC retirement studies.

Recommendation to Meet Electric Reliability Needs Consistent with State and Federal Law

In conducting the electric reliability needs assessment to determine necessary capacity additions, AB 1318 specifies that the evaluation ensure compliance with State and federal law.

AB 1318 requires that the agencies assess the degree to which preferred energy, environmental, and greenhouse gas (GHG) reduction policies and regulations might moderate reliance upon new fossil generation requiring offsets. For example, new energy efficiency policy initiatives are likely to reduce demand and thus some of the capacity needed to serve load and satisfy applicable national and regional reliability standards. In addition, development of renewable energy, along with required transmission upgrades, may reduce the dispatchable capacity development within the SCAB to satisfy these standards. In addition, the SWRCB policy with respect to the use of ocean water for cooling existing power plants may result in the repowering, retrofit, or retirement of up to 7,500 megawatts (MW) of generation capacity under SCAQMD jurisdiction. The extent to which the policy will force retirements, retrofits, or repowering and to which reliability standards require that retired capacity be replaced with dispatchable capacity within SCAQMD needs to be assessed.

AB 1318 also requires that the agencies develop recommendations for ensuring that the amount and type of fossil generating capacity identified for reliability needs (after taking into account load reductions through new programmatic efforts and renewable generation development) can obtain necessary approvals to construct and operate. The approach or strategy for developing these recommendations is highly dependent on the outcome of the reliability study and supplemental assessment of power plant operating profiles. Furthermore, developing a strategy that will satisfy State and federal requirements is highly dependent on the potential environmental impacts of additional generation capacity needs.

Staff of the energy agencies have developed an initial list of necessary studies to outline the efforts required to complete a technical reliability study of the SCAB. In addition, the energy agencies and ARB representatives agreed to a fall 2011 target date for submission of a comprehensive final electric reliability and permitting report to the Legislature and Governor’s Office.

F. Public Process for Development of the Report

As stated previously, the Legislature directed ARB to develop a report in consultation with CEC, CPUC, CAISO, and SWRCB. In addition to coordination with the specified entities, ARB staff plans to initiate a process to encourage and provide multiple opportunities for public review and comment through public workshops.

ARB staff plans to take steps to see that stakeholders are aware of, and will have an opportunity to participate in, the report development process.

Staff has established a webpage (http://www.arb.ca.gov/energy/esr-sc/esr-sc.htm) for this effort, which will be regularly updated. The webpage contains a description of the report, its status, public participation information, and staff contacts.

A draft of the final report will be made available for public comment prior to finalization.

This interim report can also be viewed at http://www.arb.ca.gov/mandrpts/mandrpts.htm. If you would like to receive a hard copy of the interim report, please contact Ms. Stephanie Kato, Staff Air Pollution Specialist, Air Resources Board, at (916) 324-1840 or skato@arb.ca.gov.

G. Schedule and Process for Completion of Final (Phase 2) Report

The technical teams estimate that a comprehensive report can be completed by fall 2011 for delivery to the Governor and Legislature. The teams have developed the proposed schedule outlined in Table ES-1 establishing the timeframe for the final report.

Table ES-1. Schedule for Completion of Final (Phase 2) Report

Date	Milestone
Summer 2010	Establish schedule for public workshops
September 2010 – June 2011	ARB and energy agencies to work together to fully evaluate available data as well as initiate additional studies for determining system needs out to the 2020 timeframe
	Preliminary results of CAISO 2011 Transmission Planning Process reliability assessment and 33% Renewables Integration Study
	Preliminary draft of permit program recommendations
	Revised draft of permit program recommendations
	Revised analysis of reliability using OTC compliance data
	Preliminary drafts of electricity and permit chapters
	Preliminary draft final report (internal agency review)
	Public Workshops (two prior to and one after release of draft report)
July 2011	Draft report circulated to energy agencies for comprehensive review
Fall 2011	Submit final report to Legislature and Governor's office

Based on the recommendations of the 2011 final report, ARB staff anticipates participating in subsequent efforts with SCAQMD and other interested parties to implement new permitting mechanisms for power plants sited within the jurisdiction of SCAQMD.

H. Near-Term and Long-Term Electric Reliability

- For the near-term, given the time necessary (three to five years) to obtain permits and approvals for major power generation facilities, SCAQMD and CEC should proceed in evaluating applications. The need for offsets and availability will have to continue to be evaluated on a case-by-case basis until a recommendation in the 2011 final report can be developed and implemented.
- For the long term (up until 2020), a more robust analysis must be completed to identify the amount and type of additional capacity required in the SCAB, transmission system upgrades that reduce requirements for in basin generation development, and what changes to air credit regulations of the SCAQMD and state/federal laws might be required to allow incremental fossil power plant capacity to be permitted while not adversely affecting attainment of air quality standards.
- The long-term analysis includes the following additional studies to satisfy the objectives of AB 1318:
    - Extend the load and resource scenario analysis tool to encompass the Los Angeles Department of Water and Power (LADWP) balancing authority area (LA BAA) and populate the expanded spreadsheet tool using best available information about policy options for LA BAA that the inter-agency team can assemble on its own;
    - Conduct joint power flow and stability studies for the entire South Coast region by extending the OTC study called for in the joint energy agency proposal to SWRCB, also described in the 2011 Transmission Planning Process (TPP) draft Study Plan, in two aspects: (1) assessing additional cases beyond those that can be investigated in the 2011 TPP, and (2) evaluating options for the LADWP balancing authority;
    - Examine the reliability impacts to the Southern California Import Transmission (SCIT) nomogram to determine what potential generating resource and/or transmission system upgrades are needed to accommodate in-basin fossil capacity reduction and replacement by higher levels of imports, especially renewable imports. It is noted that the SCIT nomogram encompasses the entire Southern California footprint, not just SCAB area; and
    - Translate the capacity requirements identified in the above studies into emission credits for criteria pollutants by making use of renewable integration and other system simulation studies to determine patterns of operating hours across the year. Given such patterns, select a likely

generating technology, and then use standard emission factors to convert energy generated into emissions.

I. Strategies to Increase Offset Availability

This interim report does not include conclusions or recommendations regarding specific strategies that will increase the availability of offsets in the SCAB. Instead, it provides concepts that will be used as a starting point in conducting more detailed analyses of the legal, environmental, and administrative issues associated with each concept. In general, these concepts fall into the following six primary strategy categories:

- Modification of SCAQMD Current Policies and Procedures;
- Modification of SCAQMD Rules and Regulations;
- Modification of State Law;
- Modification of ARB Current Policies and Procedures;
- Modification of Federal Law; and
- Modification of U.S. EPA Current Policies and Procedures.

The list of specific concepts under each strategy that will be evaluated is contained in Chapter I (see Table I-7) of this report.

I. AIR PERMITTING

This chapter presents a broad overview of California's air regulatory structure and the major provisions that affect the permitting of new or expanding facilities. The chapter also provides air regulatory information specific to the SCAB, as well as a summary of the legal decisions and legislative actions that pertain to the issuance of air permits in the SCAB. The chapter concludes with a list of potential strategies that will be evaluated during Phase 2 of this project that may provide near- and long-term solutions to increase the availability and mitigate the cost of emission reduction credits in the SCAB.

A. Air Regulatory Structure

The regulation of sources of air pollution is conducted at three levels of government in California: federal, State, and local.

ARB has established health-based State ambient air quality standards to identify outdoor pollutant levels considered safe for the public. Once State standards are established, State law requires ARB to designate each area as attainment, nonattainment, nonattainment-transitional, or unclassified for each State standard. The area designations indicate the healthfulness of the air quality throughout the State. In addition, the federal Clean Air Act requires the United States Environmental Protection Agency (U.S. EPA) to set national ambient air quality standards (NAAQS) for wide-spread pollutants from numerous and diverse sources considered harmful to public health and the environment. A pollutant for which an ambient air quality standard is established is called a —criteria" pollutant.

The federal Clean Air Act requires states to directly regulate sources of air pollution through a state implementation plan (SIP) to provide for implementation, maintenance, and enforcement of NAAQS. The SIP outlines all of the national, statewide, and regional strategies that will be used to meet air quality standards by a given date. At the federal level, U.S. EPA is responsible for implementation of the federal Clean Air Act. Some portions of the Act are implemented directly by U.S. EPA; other portions are implemented by state and local agencies.

Responsibility for attaining and maintaining ambient air quality standards in California is divided among ARB and the 35 independent local air pollution control and air quality management districts (districts). ARB and the districts follow the California Health and Safety Code and U.S. EPA regulations to do what is necessary to meet the requirements of the State and federal Clean Air Acts.

California is geographically divided into air basins for the purpose of managing the air resources of the State. An air basin generally has similar meteorological and geographic conditions throughout. The State is currently divided into 15 air basins.

In the air quality regulatory sector, power plants and other industrial facilities are known as —stationary sources,” while —mobile sources” include both on- and off-road sources such as passenger cars, trucks, heavy-duty construction equipment, marine vessels, and lawn and garden equipment. State law gives ARB direct authority to regulate pollution from mobile sources, fuels, and consumer products. Primary responsibility for controlling pollution from stationary sources lies with the districts. This responsibility includes developing region-specific rules, permitting, enforcement, collecting data associated with emissions inventory, and the preparation of local air quality plans. The districts may obtain authority from U.S. EPA to be the primary implementing and enforcing agency for certain federal requirements, such as New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and the Prevention of Signification Deterioration (PSD) program.

The boundaries of each district in relation to the boundaries of each air basin are shown in Figure I-1.

Figure I-1. Map of California Air Districts and Air Basins

Source: Air Resources Board

SCAQMD is the agency responsible for attaining and maintaining State and federal clean air standards in the SCAB. The SCAB includes all of Orange County and portions of Los Angeles, Riverside, and San Bernardino counties. Within Riverside County, the SCAQMD has jurisdiction over the Salton Sea Air Basin and a portion of the Mojave Desert Air Basin (see Figure I-2).

Figure I-2. Map of SCAQMD Jurisdiction and Air Basins in Southern California

Source: South Coast Air Quality Management District

The SCAB is home to about half the population of the state of California. It is the second most populated urban area in the United States and one of the smoggiest.[A] Table I-1 summarizes the ambient air quality area designations for the SCAB and the three districts in the South Central Coast Air Basin (SCCAB), which includes San Luis Obispo, Santa Barbara, and Ventura. The SCCAB has been identified by ARB as an ozone transport region for pollutants into the SCAB.

Table I-1. Air Quality Area Designations for the South Coast Air Basin and South Central Coast Air Basin[B]

Pollutant	SCAB		San Luis Obispo		Santa Barbara		Ventura	
	Federal	State	Federal	State	Federal	State	Federal	State
Ozone[3], 1-hour	N/A[4]	Extreme N		Moderate N		Moderate N		Severe N
Ozone, 8-hour	Extreme N	N	A	N	A	N	Serious N	N
PM2.5 (2006)	N	N	A	A	A	U	A	N
PM10	Serious N	N	A	N	A	N	A	N
CO	A	A	A	A	A	A	A	A
Nitrogen dioxide	A	N	A	A	A	A	A	A
Sulfur dioxide	A	A	A	A	A	A	A	A
Sulfates	-	A	-	A	-	A	-	A
Lead	A	N (Los Angeles Co.)	A	A	A	A	A	A
Hydrogen sulfide	-	U	-	A	-	A	-	U
Visibility reducing particles	-	U	-	U	-	U	-	U

N/A = not applicable, N = nonattainment, A = attainment, U = unclassified. A dash (-) means there is no standard for that pollutant.

1. Stationary Source Permitting

This section summarizes the primary State and federal requirements for permitting stationary sources of air pollution in California. Each district has adopted rules as part of the SIP to meet State and federal ambient air quality standards. District rules define the procedure and criteria that districts must use in permitting stationary sources. Although district specific rules vary in scope and level of stringency depending on its air quality status, the general procedure for permitting new and expanding sources is the same throughout the State. Pollutant-emitting sources must first obtain an authority to construct (or permit to construct) before beginning construction, and a permit to operate after the completed facility demonstrates compliance with district rules and the facility's permit conditions. Where applicable, district permit programs incorporate federal stationary source program requirements.

District requirements for stationary sources generally fit into two categories. The first category of rules applies to the construction and operation of new and modified (or expanding) stationary sources. These rules are referred to as the NSR program. A second category of requirements is rules which every source, or every source in a

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[3] Ozone is not a directly-emitted pollutant. Agencies regulate NOx and VOC, which are ozone precursors.

[4] On June 15, 2005, the 1-hour ozone standard was revoked for all areas except the 8-hour ozone nonattainment Early Action Compact Areas (EAC) areas (those do not yet have an effective date for their 8-hour designations).

certain category of sources, must meet. These are often referred to as prohibitory rules. They apply whether or not a source is new or existing.

a. State New Source Review

The California NSR program is the foundation of stationary source emission control and allows industrial growth to continue in polluted areas while not undermining progress toward meeting clean air standards. The NSR permit program is derived from the California Clean Air Act and is codified in Division 26 of the California Health and Safety Code. Specific to NSR, each district has a stationary source control program designed to achieve a “no net increase” in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds. NSR programs provide mechanisms to (1) reduce emission increases up-front through clean technology and (2) result in a net reduction in emissions. This is accomplished through two major requirements in each district NSR rule: 1) best available control technology (BACT)[5] and 2) offsets.

i. Best Available Control Technology

Depending on the quantity of air pollutants that will be emitted from the source and the area designation for that pollutant, the new or modified source may be required to install BACT. BACT is triggered on a pollutant-by-pollutant basis and on an emission unit basis (generally an individual piece of equipment or an integrated process consisting of several pieces of equipment). In the SCAQMD, any increase in oxides of nitrogen (NOx), volatile organic compounds (VOC), particulate matter of 10 micrometers or less in aerodynamic diameter (PM10), carbon monoxide (CO), or oxides of sulfur (SOx) triggers BACT.

BACT requires use of the cleanest, state-of-the-art technology to achieve the greatest feasible emission reductions. In order to identify BACT for a specific piece of equipment or process, district staff conduct a comprehensive case-by-case evaluation of the cost and effectiveness of technologies or strategies. This includes obtaining testing results or similar proof that the emission levels have been achieved in practice. District staff also conduct a broad search (internationally, in some instances) for technologies or strategies that have demonstrated (through testing on similar categories of stationary sources) a reduction in emissions to the lowest levels. The cost of the identified technologies is compared to the district BACT cost-effectiveness threshold. If the cost is lower than the threshold, then the technology or strategy can be designated as BACT for that category of stationary source. District staff does not consider cost for technologies or strategies that are already deemed achieved in practice.

[5] In California, BACT is synonymous with the federal term Lowest Achievable Emission Rate (LAER) for nonattainment area permit requirements.

ii. Emission Offsets

In addition to BACT requirements, owners of new or modified sources may be required to mitigate, or offset, the increased emissions that result after installation of BACT. Offsetting is the use of emission reductions from existing sources to offset emission increases from new or expanding sources. This may be done by purchasing emission reduction credits (ERC) from another company and/or cleaning up the existing facility (or a source owned by another company) beyond what is required by law. The amount of offsets required depends on the distance between the source of offsets and the new or modified source.

Offsets are generally required at a greater than 1-to-1 ratio so that when the new or modified facility begins operation, more emissions are reduced than are increased. If a source obtains emission offsets outside the local area (i.e., interbasin), or if one type of pollutant is offset against another type (i.e., interpollutant), the source must use air quality modeling to show that these offsets will result in a net benefit. Some districts have pre-established ratios for interpollutant offsets in their rules. The offset thresholds and offset ratios for SCAQMD are given in Table I-2. While BACT is triggered on an emission unit basis, offsets are triggered on a project basis.

Table I-2. SCAQMD Offset Thresholds and Offset Ratios[C]

NOx	VOC	PM10	CO	SOx
≥4 tons emitted per year	≥4 tons emitted per year	≥4 tons emitted per year	≥29 tons emitted per year must model emissions to show no interference with attainment status	≥4 tons emitted per year
If offsets come from ERCs: 1.2:1.0 If offsets come from Priority Reserve: 1.0:1.0 If offsets come from ERCs from facilities not located in SCAB: 1.2:1.0	If offsets come from ERCs: 1.2:1.0 If offsets come from Priority Reserve: 1.0:1.0 If offsets come from ERCs from facilities not located in SCAB: 1.2:1.0	If offsets come from ERCs: 1.2:1.0 If offsets come from Priority Reserve: 1.0:1.0 If offsets come from ERCs from facilities not located in SCAB: 1.2:1.0	If offsets come from ERCs: 1.2:1.0 If offsets come from Priority Reserve: 1.0:1.0 If offsets come from ERCs from facilities not located in SCAB: 1.0:1.0	If offsets come from ERCs: 1.2:1.0 If offsets come from Priority Reserve: 1.0:1.0 If offsets come from ERCs from facilities not located in SCAB: 1.2:1.0

Interpollutant Offsets
Where emission reductions of the same type of pollutant are not available, some district rules allow the use of interpollutant offsets. SCAQMD Rule 1309 (Emission Reduction Credits and Short Term Credits) authorizes interpollutant offsets on a case-by-case basis if the trade results in an equivalent or greater offset of the source's nonattainment pollutants. The permit applicant must also demonstrate that the emissions will not cause or significantly contribute to the violation of an ambient air quality standard.

Specifically, interpollutant trades between PM10 and precursors that form PM10 (VOC, NOx, SOx)[6] may be allowed. PM10 emissions are not allowed to offset NOx or VOC in ozone nonattainment areas.

Interbasin and Inter-District Offsets
The California Health and Safety Code section 40709.6 outlines specific minimum requirements regarding the use of interbasin offsets, which are also reflected in SCAQMD Rule 1309:

- The stationary source to which the emission reductions are credited is located in an upwind district that is classified as being a worse nonattainment status than the downwind district;
- ARB has established that there is an emission transport relationship between the two districts and an overwhelming impact on the downwind district accepting the offsets;
- The downwind district accepting the offsets has adopted a rule to discount the emission reduction credits from the upwind stationary source; and
- The interbasin emission offset transaction has been approved by both districts.

Transport
State law gives ARB the responsibility to assess how the movement of air pollutants from one air basin to another (referred to as —transport”) impacts State ozone concentrations. The movement of air pollutants between areas can increase the ozone levels in downwind areas. In addition to identifying upwind and downwind relationships between air basins, ARB assesses the degree of impact. State law directs ARB to determine if the contribution of transported pollution is overwhelming, significant, inconsequential, or some combination of contributions.

The only area that ARB has established a transport relationship of emissions into the SCAB is for districts in the SCCAB (San Luis Obispo, Santa Barbara, and Ventura districts).[D] Because the transport relationship is classified as inconsequential (San Luis Obispo and Santa Barbara) to significant (Ventura) and the SCAB has a worse ambient air quality area designation than the districts in the SCCAB, this effectively means that there are no opportunities for SCAQMD to allow use of offsets from a neighboring air district to mitigate projects in their jurisdiction.

b. Prohibitory Rules

Each district has rules aimed at limiting emissions from existing stationary sources. However, these rules apply to new sources as well. Prohibitory rules may be generic, such as limiting the maximum level of a particular pollutant (such as NOx) at any facility, or they may address specific equipment, such as a turbine, a boiler, or a reciprocating internal combustion engine. Sources are also subject to a general nuisance rule which provides authority to the district to control the discharge of any air contaminants,

[6] As defined in SCAQMD Rule 1302 (Definitions).

including odor, that will cause injury, detriment, nuisance, endangerment, discomfort, annoyance, or which have a natural tendency to cause damage to business or property. In most cases where BACT is required for a particular pollutant, the required control technology and corresponding emission level will be more stringent than what is required by the prohibitory rule. Except where a source is exempt from permit, the proponent of a new or expanding source will have to demonstrate compliance with both NSR and prohibitory rule requirements in any permit application submitted to the district.

c. Federal Program

In addition to the district rules, there are also federal rules which govern the permitting of new or modified stationary sources: federal NSR and PSD. The purpose of federal NSR is to ensure that air quality does not deteriorate any further in areas with bad air quality (“nonattainment areas”), while PSD ensures that areas with good air quality will continue to maintain good air quality (“attainment areas”). Many district rules incorporate these federal regulations by reference. As in the State NSR program, federal nonattainment NSR regulations require LAER[7] (similar to California BACT) and offsets.

New major stationary sources and major modifications at existing major stationary sources that meet emissions applicability thresholds outlined in the federal Clean Air Act and in existing PSD regulations must obtain a PSD permit outlining how they will control emissions. The permit requires facilities to apply BACT, which is determined on a case-by-case basis taking into account, among other factors, the cost and effectiveness of the control.

The Clean Air Act Amendments of 1990 required that all states develop operating permit programs. Under these programs, known as Title V operating permits programs, every major industrial source of air pollution (and some other sources) must obtain an operating permit. The permits, which are reviewed every five years, contain all air emission control requirements that apply to the facility, including the requirements established as part of the preconstruction permitting process.

In addition to permitting rules, the U.S. EPA establishes rules that apply to specific industries and/or types of equipment. Rules that limit criteria pollutants are known as New Source Performance Standards (NSPS), and rules that limit hazardous (toxic) air pollutants are known as Maximum Achievable Control Technologies (MACT).

The overall impact of the federal permitting regulations for criteria pollutants on stationary sources in California is minimal due to California’s more stringent requirements, stemming from the California Clean Air Act and the more stringent California ambient air quality standards.

On May 13, 2010, U.S. EPA issued a final rule to address GHG emissions from stationary sources under the federal Clean Air Act permitting programs. The rule sets

[7] Lowest Achievable Emission Rate.

thresholds for GHG emissions that define when permits under the NSR PSD and Title V operating permits programs would be required for new or existing facilities. The CAA permitting program emission thresholds for criteria pollutants are 100 and 250 tons per year. While these thresholds are appropriate for criteria pollutants, they are not feasible for GHGs, because GHGs are emitted at much higher volumes. The rule —tailors” the permit programs to limit which facilities will be required to obtain PSD and Title V permits. Without this tailoring rule, these lower CAA thresholds would take effect automatically for GHGs on January 2, 2011. Many entities advocated for higher thresholds since the volume of permits at the standard thresholds would overwhelm U.S. EPA's ability to process permit applications and issue permits.

To date, most PSD permitting in California has been done by U.S. EPA Region IX. The SCAQMD submitted a PSD rule (Regulation XVII) to U.S. EPA on August 13, 1999, but it has not yet been approved into the SIP. The District also has a partial delegation agreement with U.S. EPA to implement the federal PSD permitting program.

The GHG tailoring rule requires PSD permitting of GHGs beginning January 2, 2011, if a source is already subject to PSD and GHGs are increased by 75,000 tons per year CO_2e. After July 1, 2011, PSD permits are required for new sources with GHG emissions at 100,000 tons per year CO_2e, or modifications at existing facilities that increase GHG emissions by at least 75,000 tons per year CO_2e. New or modified facilities with GHG emissions that trigger PSD permitting requirements would need to apply for a revision to their operating permits to incorporate the best available control technologies and energy efficiency measures to minimize GHG emissions. These controls will be determined on a case-by-case basis during the PSD process. U.S. EPA is currently developing BACT policy guidance.

Similar to the requirements for PSD permits, only sources currently subject to the operating permit program would be subject to Title V requirements for GHG emissions. However, after July 1, 2011, Title V operating permit requirements will apply to sources based on their GHG emissions even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tons per year CO_2e will be subject to Title V permitting requirements.[E]

ARB staff is currently working closely with U.S. EPA on the implications for California with respect to implementation of the GHG tailoring rule. ARB staff, in consultation with both U.S. EPA and SCAQMD, will evaluate the potential impacts of the tailoring rule on AB 1318 efforts.

d. Senate Bill 288

California air districts with SIP-approved rules or districts with rules adopted and submitted to the SIP, but which were never approved, may have issues with Senate Bill 288 (SB 288) compliance. SB 288 was created to prevent districts from backsliding on existing NSR/PSD requirements. Relaxation is based on comparing district rules that existed on December 30, 2002, (and were approved into the SIP or submitted but not approved) against the new proposed rule or proposed amendments to the SIP submitted/approved rule (see also discussion in section F of this chapter).

2. California Environmental Quality Act Requirements

Before the district can issue or deny a permit for a project which may have a significant effect on the environment, the project must comply with CEQA codified in the State Public Resources Code. State regulations for implementing CEQA are codified in title 14 of the California Code of Regulations beginning with Section 15000 (known as the State CEQA Guidelines). The purpose of CEQA is to ensure that a project's environmental impacts and alternatives are disclosed to governmental decision-makers and the public, and that any impacts are mitigated to the maximum extent feasible. In general, the CEQA process addresses mitigation of project emissions that do not require a district permit or that are not already addressed by the district's regulatory program.

CEQA applies to governmental decisions that require the exercise of judgment or deliberation (i.e., "discretionary activities"), as opposed to decisions involving only objective measurements regarding the wisdom or manner of carrying out a project. In addition, CEQA does not apply to statutorily or categorically exempt projects, which are defined in CEQA. By law, no regulatory agency can issue any permits until the project has been approved by the lead agency. The lead agency is generally the agency with the broadest discretionary authority in approving the project; this is typically the local land use agency such as a county planning department. However, air districts can also have this responsibility. In the case of power plants sized at 50 MW and greater, using thermal technologies, the California Energy Commission is the lead agency.

a. The CEQA Process

If a project is not exempt from CEQA review, it is evaluated to determine if there is the possibility of a significant effect on the environment.[8] If a significant effect is possible, the lead agency prepares an initial study to evaluate the potential for an effect. If there are no potential impacts, a negative declaration is issued by the lead agency. If a potential impact exists which the project proponent can and will commit to mitigate, a mitigated negative declaration can be issued. Otherwise, the lead agency will issue a notice of preparation (NOP) of an environmental impact report (EIR). At this point, responsible agencies may comment on the required content of the EIR. These comments are then used by the lead agency to produce a draft environmental impact report (DEIR). The purpose of a DEIR is to assess any significant effect on the environment by the project and to evaluate potential mitigation measures. This report is available for review by responsible agencies and the public during the public review period. Comments on the DEIR by any of these parties may be submitted prior to the end of the public review period on such topics as completeness and accuracy of the draft EIR. The lead agency then reviews these comments and prepares a final EIR with

[8] A significant effect on the environment is defined as a substantial adverse change in the physical conditions which exist in the area affected by the proposed project.

responses to comments on the draft EIR. The final EIR is used by the lead agency in approving the project and by responsible agencies in issuing permits.

b. CEQA Requirements

With respect to air quality impacts, CEQA review generally focuses on identifying the additional emissions related to projects that affect land uses. CEQA Guidelines provide a set of significance criteria to determine whether a project will: (1) conflict with or obstruct implementation of the applicable air quality plan; (2) violate any air quality standard or contribute substantially to an existing or projected air quality violation; (3) result in a cumulatively considerable net increase of any criteria pollutant for which the region is nonattainment for State of federal standards; (4) expose sensitive receptors to substantial pollutant concentrations; or (5) create objectionable odors affecting a substantial number of people.

Where applicable, the emission thresholds established by the district may be relied upon to make CEQA determinations of significance. However, unlike district rules, CEQA analyses must also consider: impacts of facility construction; indirect emissions from increased mobile source activity; and the cumulative impacts of projects within the area. For example, construction impacts might include fugitive dust emissions raised by mobile construction equipment. Indirect emissions may include emissions from trips to and from work by employees as well as increases in emissions from commercial vehicles using the facility. The lead agency can, at times, require air quality mitigation measures that go beyond the permitting requirements of the local air district.

Standard mitigation measures for construction equipment have typically included equipment maintenance requirements; use of CARB-certified diesel for all off-road and portable diesel-powered equipment; and use of newer, cleaner engines or retrofit of existing engines with diesel oxidation catalysts, catalyzed diesel particulate filters, or other district-approved retrofit devices on diesel-powered equipment. Standard mitigation measures for fugitive PM10 control for construction activities have typically included paving, watering, or applying non-toxic soil stabilizers on all unpaved access roads, parking areas, and staging areas; watering dirt stock-piles; and sweeping streets at the end of each day if visible soil material is carried onto streets, or wash off trucks and equipment leaving the site.

Cumulative effects means the individual effects from the project are considered along with the effects of past projects, other current projects, and reasonably foreseeable future projects. Air quality impacts can be estimated using air quality modeling. The significance of new emissions can be evaluated against growth projections of emission forecasts in the SIP. If there is a significant impact, the lead agency will evaluate the need for mitigation measures identified in the EIR, such as providing offsets, before approving the project.

B. Power Plant Siting in California

CEC has been given authority under State law for a consolidated approval process for the siting of major power plants that use thermal energy. This process allows a project applicant to submit a single application for all necessary State and local approvals. This siting process is intended to avoid duplication, provide a timely review, and provide analysis of all aspects of a proposed project, including need, environmental impact, safety, efficiency, and reliability. The siting process fully satisfies CEQA requirements by integrating CEQA's purposes and objectives to assure that all potential impacts of a major project are reviewed.

CEC has the exclusive authority to approve the construction and operation of power plants that will use thermal energy and have electric generating capacities of 50 MW or larger. CEC's authority supersedes that of all other State and local agencies, particularly in regards to requirements for permits, and federal agencies to the extent provided by federal law. However, CEC solicits other public agencies' participation in the power plant siting process to ensure that the construction and operation of power plants will comply with applicable local, State, and federal requirements. For example, the CEC siting process incorporates the air district's NSR program, which includes an evaluation of compliance with BACT and offset requirements. As with non-power plant projects, the district independently evaluates the power plant project, prepares permit conditions to address applicable air quality requirements, and provides public notice and comment opportunity. After the power plant is constructed, the district issues an operating permit and conducts normal enforcement activities to ensure compliance of the power plant with applicable air quality rules and regulations.

Currently, there are six power plant projects (representing a total of nearly 3,000 MW) proposed to be located in SCAQMD that are either undergoing review, or are on hold even though they have already been approved by the CEC licensing process. Table I-3 summarizes licensing and emissions information about the six power plant projects.

Table I-3. Recent California Energy Commission Power Plant Projects in SCAQMD[F]

Project Name	Capacity (MW)	Licensing Status	Permitted or Estimated PM10	Offsets Status
Walnut Creek Energy Park – Edison Mission Energy	500	On Hold/ Approved 2/27/2008	463 lbs/day	Not Secured
Sun Valley Energy Project – Edison Mission Energy	500	In Review (filed 12/1/2005)	463 lbs/day	Not Secured
El Segundo Power Redevelopment Project – NRG	560	Approved 6/30/2010	615 lbs/day	Secured
Sentinel Peaker – Competitive Power Ventures (CPV)	850	In Review (filed 6/26/2007)	972.5 lbs/day	Secured
Solar Millennium Palen – Solar Millennium	484	In Review (filed 8/24/2009)	2.37 lbs/day[9]	Not Required
Watson Cogeneration Steam and Electric Reliability Project	85	In Review (filed 3/19/2009)	289.1 lbs/day	Secured

Two of the power plants in the table above (Walnut Creek Energy Park and Sun Valley Energy Project) have not secured the offsets required to move forward in the permitting process. The remaining four power plants (El Segundo Power Redevelopment Project, Sentinel Peaker, Solar Millennium Palen, and Watson Cogeneration Steam and Electric Reliability Project) appear to have no constraints with respect to obtaining offsets.

Walnut Creek was approved by the CEC in 2008, but since it had secured ERCs through the District's Priority Reserve, it cannot move forward until an alternative source of ERCs is found. For Sun Valley Energy, the applicant had planned to offset PM10 emissions with purchase of ERCs and/or credits from the Priority Reserve. However, as a result of the 2008 legal decision, the applicant was put on notice in May 2009 by CEC that the project could not proceed without a clear path forward to obtain the necessary ERCs.

El Segundo is a repowering project and has available RECLAIM[10] trading credits (RTC) to offset NOx from the existing facility in addition to RTCs that can be transferred from the Long Beach Generation Station. The applicant has purchased some PM10 ERCs and had planned to purchase the remaining balance from the District's Priority Reserve until the 2008 legal decision blocked that action. However, since SB 827 restores the SCAQMD Rule 1304 offset exemption for boiler repowering projects, El Segundo should no longer be constrained by offset limitations.

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[9] Reported yearly value of 865.72 lbs/yr was divided by 365 to estimate daily PM10 emissions for comparison to other projects.

[10] RECLAIM is an acronym for the SCAQMD's **RE**gional **CL**ean **A**ir **I**ncentives **M**arket program.

The Sentinel project qualifies for Priority Reserve credits based on meeting specific requirements outlined in AB 1318. Additional details regarding AB 1318 offset provisions as they apply to the Sentinel project are contained in Section D of this chapter.

Offsets are not required for the Solar Millennium Palen project since emissions for all pollutants will be less than the applicable offset threshold exemption levels in SCAQMD Rule 1304.

The Watson Cogeneration Project is a modification to an existing source through installation of a new turbine. The applicant plans to accept a cap on PM10 emissions such that offsets will not be required for the new turbine. The existing PM10 emission limit for the existing four turbines will be applied as a cap for all five units.

C. SCAQMD Offset Program and its Use by Power Plant Projects

In SCAQMD, project emissions requiring offsets are mitigated using ERCs or short-term credits (STCs). ERCs can be either privately-owned or come from Priority Reserve credits from the District's Account. ERCs are generated when a source shuts down or controls its emissions to a greater degree than what is required by law and applies to the District to bank these emissions. Alternatively, if a source fails to apply for an ERC, the SCAQMD claims the offsets as —orphan shutdowns" and deposits them in its internal bank. The District uses these offsets to supply the needed offsets for essential public services and for projects that are exempt from offsets under SCAQMD rules. Sources that are exempt from offsets include primarily small businesses, equipment replacements, relocations, and pollution control projects, as well as emergency equipment.

There are three types of STCs in SCAQMD rules: short-term emission reduction credits (STERC), mobile source emission reduction credits (MSERC), and area source emission reduction credits (ASERC). STERCs are created from existing ERCs that are divided, in part or in whole, over a period of no more than seven years. MSERCs provisions are contained in SCAQMD Regulation XVI (Mobile Source Offset Programs) and come from emission reductions due to voluntary repair of on-road heavy polluting vehicles, vehicle scrapping, clean vehicle programs, and clean diesel marine vessel programs. ASERCs are contained in SCAQMD Rule 2506 and consist of the turnover of non-mobile sources within the District that are not subject to local or State permitting or registration. STCs must be used within the same year they are created.

SCAQMD Exemptions from Offsets
Some exemptions to SCAQMD offset requirements for all or part of the offset liability of a new or modified emission source are possible under Rule 1304 (Exemptions). For example, if a new or modified project emits less than four tons per year of NOx, SOx, VOC, or PM10, then the project is exempted from the offset requirements of Rule 1303. However, SCAQMD must offset all pollutants exempted under Rule 1304 due to no net

increase requirements in State law.[11] The District complies with this requirement by drawing ERCs from the Priority Reserve in an annual NSR Balance Report. Other exemptions in Rule 1304 include in-kind replacements, portable equipment, emergency equipment, facility relocation, regulatory compliance requirements, and electric utility boiler replacements.

Limited PM10 Offset Availability and Priority Reserve Rule Development
In 1998, SCAQMD learned that the price and volume of offset market trading for PM10 ERCs were becoming unstable. The cost of PM10 ERCs increased to be prohibitively expensive, which led to a shrinking number of market transactions.

In April 2001, SCAQMD approved amendments to Rule 1309.1 (Priority Reserve) to allow temporary access to Priority Reserve credits by qualifying electric generating facilities (EGFs), including new power plant projects. The access was granted to EGFs that performed a good faith effort to purchase PM10 ERCs, were deemed data complete in 2000, 2001, 2002, or 2003, and had a contract to sell at least 50 percent of their power to the California grid, in addition to other provisions. Each EGF was required to show proof of their good faith efforts being made to SCAQMD by contacting ERC holders.

In 2001, qualifying EGFs could purchase PM10 Priority Reserve credits for $25,000 per pound per day, which translated into approximately $11.5 million for a 500 MW power project (approximately 460 pounds per day of PM10). The projects under CEC jurisdiction that qualified were Inland Empire (670 MW), El Segundo (630 MW), and Malburg Generation Station (134 MW). Inland Empire is now operational (Unit 1 online in January 2009 and Unit 2 online in May 2010), Malburg went online in October 2005, and El Segundo was disqualified as an EGF because the applicant filed a major amendment to the project to change the turbine manufacturer, the ultimate capacity, and eliminate the OTC system.

The El Segundo case is unusual in that it used both the Priority Reserve and the Rule 1304 utility boiler exemption to satisfy SCAQMD offset requirements. The Rule 1304 offset exemption was granted via the replacement of a utility boiler with combustion turbines of the same or lower capacity. However, since the El Segundo boilers were 340 MW total and the new combustion turbines were 630 MW, the project proponent had to offset the additional 46 percent of their project emissions. For PM10, the proponent chose to use the Priority Reserve. Since the boilers did not produce as much PM10 as the turbines, SCAQMD used the reductions from the boiler shut down and emission credits from the District Account in addition to Priority Reserve credits purchased by the project proponent to comply with the offset requirements.

After the 2003 window shut on the Priority Reserve, SCAQMD found significant interest from power plant developers in reopening it. Given the need for power development

[11] For new or modified stationary sources in extreme nonattainment areas, California Health & Safety Code section 40920.5 requires BACT for any source with potential to emit ≥10 lbs/day and a program designed to achieve a no net increase for all sources for all nonattainment pollutants and precursors.

identified in the CEC's 2005 Integrated Energy Policy Report, the SCAQMD began the process of amending Rule 1309.1 again. However, the U.S. EPA took a more active role in the process and challenged the inventory of credits comprising SCAQMD's internal bank. As a result, SCAQMD agreed to eliminate a large portion of the credits remaining in the District Account given a lack of documentation. The remaining credits were documented as real, quantifiable, permanent, and verifiable by the SCAQMD which was accepted by U.S. EPA.

Additionally, U.S. EPA proposed a reporting requirement to clarify the source and disposition of all credits and debits to the District Account. SCAQMD agreed and drafted a rule for adoption Rule 1315 (Federal New Source Review Tracking System). Rule 1315 (adopted September 8, 2006) enabled the SCAQMD to replenish the District Account to some degree by allowing them to harvest, as needed, the 0.2 of the 1.2:1 offset ratio imposed by Rule 1303 on all offsets surrendered. With Rule 1315 in place and the District Account ratified by U.S. EPA, SCAQMD proposed the second amendment to Rule 1309.1 to allow limited use of Priority Reserve credits by qualifying EGFs.

However, at this point, several community and environmental groups had become aware of the proposed amendment and intervened in the process. The involvement of these groups engaged SCAQMD into a long public debate to develop and redevelop compromises in an attempt to address the issues of the parties involved. This finally culminated in an amendment that was adopted by the District Governing Board in August 2007.

The 2007 amendment placed additional requirements on EGFs to qualify for access to the Priority Reserve compared to the 2001 amendment. The new amendment defined three new zones based on the average annual ambient PM2.5 concentration and defined an Environmental Justice Area based on the percentage of population below the poverty level. The requirements on an EGF to qualify became more restrictive as the number of zone facilities increased, or if they were located in an environmental justice area. These requirements are more restrictive than any other air district has ever imposed on any class of pollutant emitting device. However, qualifying EGFs could purchase PM10 Priority Reserve credits at a cost of $92,000 per pound per day, which translates into a cost of about $42.32 million for a 500 MW power plant; a 370 percent increase in cost compared to the 2001 amendment. Finally, the Governing Board ordered the SCAQMD staff to spend the fees as close as possible to the project site.

Immediately following the Governing Board's approval of the 2007 amendment for Rule 1309.1, the intervening community and environmental groups filed a lawsuit in California Superior Court to enjoin the Board's action and set aside the amended rule. In July 2008, the court ruled in favor of the plaintiff and suspended the amended rule and Rule 1315. The court stated that SCAQMD had failed to perform an adequate CEQA analysis to evaluate the potential impacts of all twelve power plants that proposed to make use of the Priority Reserve under the amended rules.

Following the ruling in the State Court, the litigants brought a separate action in federal court asking the court to find that there are no remaining ERCs in the District Account.

Following the 2008 court decision, two options remained for power plants: (1) qualify for an exemption under Rule 1304 and hope offsets can be obtained from the District Account, or (2) procure ERCs on the open market. Access to Rule 1304 is limited to existing power plants qualifying for the repowering exemption, and therefore was not available to new power plant projects on undeveloped land. Until Rule 1315 is restored, allowing access to Rule 1304 in conjunction with credits in the District Account, the only option for power plants was securing ERCs on the open market for whatever price they can negotiate, thus avoiding the District Account altogether. The current high prices of ERCs in SCAQMD are directly correlated to an extreme shortage of available ERCs. Furthermore, the owners of these ERCs may have no interest in selling such ERCs if they have their own internal industrial facility expansion plans.[G]

D. Summary of Legal Decisions and Legislation

As described above, under federal and state law, the District can issue permits for new, replaced, relocated, or modified equipment only if emission increases are offset by emission reductions from other equipment. Emission offsets are generally provided by the permit applicant in the form of ERCs. District rules do, however, allow some types of facilities, such as essential public services, to obtain offsets from the District Rule 1309.1 (Priority Reserve). District Rule 1304 (Exemptions) also allows exemptions from the offset requirement for facilities with low emissions, or certain types of actions, such as equipment replacements or some relocations.

1. Court Decision

A lawsuit (Case No. BS 110792) was brought on August 31, 2007, against SCAQMD by the Natural Resources Defense Council, Communities for a Better Environment, Coalition for a Safe Environment, and California Communities Against Toxics. The lawsuit challenged the adoption of SCAQMD Rule 1315 (Federal New Source Review Tracking System) used for tracking the District’s internal credit bank and amendments to Rule 1309.1 (Priority Reserve), which allowed power plants to access credits in the District’s internal credit bank.

The November 2008 final court ruling on this lawsuit by Los Angeles Superior Court Judge Ann I. Jones revoked SCAQMD Rule 1315 that specifies how the District accounts for and calculates the amount of emission reductions available to fund the Priority Reserve and offset exemptions. Because of this decision, the District could not issue permits to construct that rely on credits from Rule 1309.1, or that rely on a Rule 1304 offset exemption. This situation will exist until the District adopts a new rule that addresses the court concerns. In the meantime, without emergency measures such as special legislation, permits to construct can only be issued to applicants providing offsets in the form of ERC certificates that are owned by applicants or that are purchased from ERC holders in the open market.[H]

2. Senate Bill 827

Senate Bill 827 (SB 827) authorizes the SCAQMD to begin issuing permit applications that were frozen by the State court decision. The bill allows the District to resume issuing at no charge emission offsets to small to medium-size businesses, and public service facilities. Specifically, the District can resume issuing permits to construct for sources that rely on offsets from the Priority Reserve or a Rule 1304 offset exemption, such as businesses that emit less than four tons per year of NOx, VOC, PM10, and SOx emissions, as well as public service facilities such as police and fire stations, schools, hospitals, landfills, and sewage treatment plants. With respect to power plants, SB 827 restores the Rule 1304(a)(2) electric utility steam boiler replacement offset exemption for sources that repower with clean and more efficient power generating equipment such as combined-cycle gas turbines. SB 827 serves as a stopgap measure, temporarily lifting the permit moratorium while allowing the District time to complete rulemaking on its emission offset program pursuant to the State court decision. The legislation expires on May 1, 2012.[I]

3. Assembly Bill 1318 Power Plant Provisions

Effective January 1, 2010, AB 1318 requires the Executive Officer of SCAQMD to credit to the District's internal emission credit accounts and transfer to eligible power plants, emission credits in the full amounts needed to issue permits for eligible power plants to meet requirements for SOx and PM10. AB 1318 requires power plants receiving credits to pay mitigation fees in accordance with the provisions of SCAQMD Rule 1309.1 as amended August 3, 2007.

In order to be eligible for ERCs pursuant to AB 1318, a power plant must meet all of the following requirements:

- Be subject to the permitting jurisdiction of the CEC;
- Have a purchase agreement executed on or before December 31, 2008, to provide electricity to a public utility for use within the Los Angeles Basin (LA Basin) Local Reliability Area; and
- Be under the jurisdiction of the SCAQMD but not be within the SCAB.

The proposed CPV Sentinel Energy Project to be located in Desert Hot Springs is the only known plant to be eligible under this provision.

In implementing this offset transfer, AB 1318 requires the District to rely on the internal offset tracking system used prior to adoption of SCAQMD Rule 1315 or a new tracking system approved by U.S. EPA. The District is implementing AB 1318 through a SIP revision which provides a federally-approved mechanism to transfer credits from the District's internal accounts to offset the CPV Sentinel Energy Project, because Sentinel is not eligible for either Rule 1304 or the May 3, 2002, version of Rule 1309.1. Therefore, the CPV Sentinel Energy Project AB 1318 offset tracking system will be submitted to U.S. EPA for approval and inclusion into the SIP.[J]

E. Availability and Cost of Emission Reduction Credits

Since 1993, California Health and Safety Code sections 40709 and 40709.5 have required local air districts to collect information about the cost of offset transactions from stationary source owners who purchase offsets as required by district NSR programs. Districts are required to collect specific information about offset transactions including the price paid in dollars per ton, the pollutant traded, the amount traded and the year of the transaction. Districts are also required to annually publish this information without revealing the identity of the parties involved with the transaction. Districts that are not required to submit a plan for attainment of state ambient air quality standards and that also meet federal air quality standards are exempt from these requirements.

Table I-4 presents the average, median, high, and low costs for NOx, VOC, PM10, CO, and SOx offset transactions reported in 2007. Mean values in Table I-4 represent the statewide average cost of a transaction, where each transaction is weighted equally in the calculation regardless of the number of tons traded per transaction.

Table I-4. 2007 Prices Paid Statewide in Dollars per Transaction per Ton of Offsets

	NOx	VOC	PM10	CO	SOx
Average	$45,176	$25,370	$97,442	$7,188	$35,091
Median	$20,000	$24,829	$43,000	$500	$21,500
High	$602,740	$95,616	$1,293,151	$35,616	$356,164
Low	$49	$5	$49	$1	$100

In 2007, South Coast had a total of 172 ERC transactions. The high, low, and average offset costs for each pollutant in the district are shown in Table I-5.[K]

Table I-5. 2007 Prices Paid in SCAQMD in Dollars per Ton of Offsets

	NOx	VOC	PM10	CO	SOx
Average	$546,575	$38,102	$598,613	$25,232	$249,817
High	$602,740	$95,616	$1,293,151	$35,616	$356,164
Low	$186,301	$5	$322,521	$3,131	$167,397

A comparison of the average offset costs in Table I-4 and Table I-5 show that prices in the SCAQMD are significantly higher (from six to 12 percent) for NOx, PM10, and SOx.

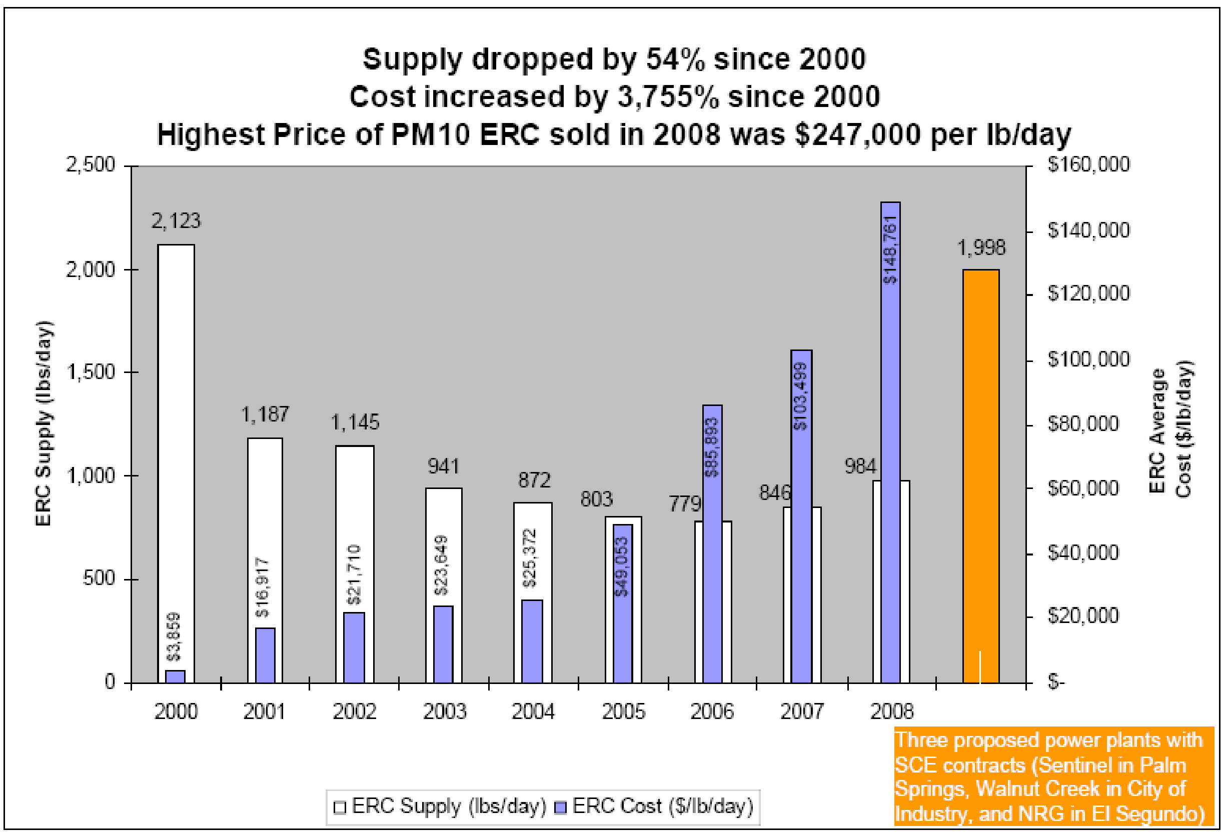
Table I-6 provides a snapshot of ERCs available for sale in SCAQMD. There are enough PM10 ERCs to permit approximately two 500 MW peaking power plants if credits from all ERC holders could be purchased. This table does not include the totals for short-term ERCs.[L]

Table I-6. Summary of Total Active Emission Reduction Credits in the SCAQMD Bank, July 2010

Available NOx ERCs (lbs/day)	Available PM10 ERCs (lbs/day)	Available VOC ERCs (lbs/day)	Available SOx ERCs (lbs/day)	Available CO ERCs (lbs/day)
1,165	800	11,769	773	2,435

In SCAQMD, the availability of ERCs on the open market is scarce and in some cases very expensive, especially for PM10. Figure I-3 shows how the cost of PM10 ERCs has increased significantly relative to the drop in supply. In addition, the last bar in the chart shows how the PM10 emissions from three proposed power plants in the SCAQMD are about twice that of the ERC supply in 2008. Based on typical project emissions and the average market price of ERCs in 2008 and 2009, the SCAQMD estimates that the cost of ERCs if the District does not provide offsets credits is $100-200 million for a state-of-the-art power plant project. At an estimated $1,000 per kilowatt[M] turnkey capital cost for a 500 MW combined cycle gas turbine power plant, the cost of offsets is 20 percent to 40 percent of the capital cost of the facility.

Figure I-3. PM10 ERC Supply and Average Cost Trends (2000 to 2008)[N]



Source: South Coast Air Quality Management District.

F. Identification of Options to Increase Offset Availability in the SCAQMD

As a result of the permit moratorium brought about by the 2008 court decision, SCAQMD hosted a series of NSR Working Group[12] meetings, which were open to the public, to discuss the availability and price of offsets that are needed for permitting new and modified stationary sources. The purpose of the meetings was for the District staff to work with businesses, environmental groups, community representatives, and agencies to develop near- and long-term solutions to address the availability of offsets, as well as other implementation issues. The Working Group met four times starting in January 2009, with the last meeting held in May 2009. The Group discussed a number of strategies to increase permitting flexibility and increase offset availability. The work products from those meetings, recommended strategies submitted by the California Council for Environmental and Economic Balance (CCEEB), and subsequent discussions with the AB 1318 Air Quality Regulatory Team were used to outline the list of potential strategies and concepts in Table I-7 for increasing offset availability in the SCAQMD.[O]

ARB staff has organized this list by strategy categories with individual concepts under each main strategy. It is possible that concepts listed under ―Modify SCAQMD Current Policies and Practices” would actually require a rule amendment. ARB staff expects to use the concepts in Table I-7 as a starting point and will conduct an evaluation of each concept, to include the legal, environmental, administrative, and timing issues associated with their implementation. It should be noted that this is not considered a final or complete list of strategies that ARB staff plans to assess under AB 1318. ARB staff will use a public process to solicit additional strategies and input before the final report is released.

1. Implementation Issues Requiring Legislation

A number of the strategies and concepts in Table I-7 may require changes to State or federal law before they can be implemented, which could add significant timing constraints to their overall feasibility. For example, many of the concepts require an amendment to SCAQMD's NSR rules and would trigger a Senate Bill 288 (SB 288) evaluation. SB 288, the ―Protect California Air Act of 2003," was signed into State law on September 22, 2003, with an effective date of January 1, 2004. That law, developed in response to concerns regarding federal changes to NSR, places restrictions on changes that California districts can make to their local NSR rules. SB 288 prohibits a district from amending its NSR rule to be less stringent than its rule that existed on December 30, 2002. SB 288 specifically prohibits air districts from making rule changes that would exempt a source or reduce its obligations relative to what they were on December 30, 2002, for any of the following program elements:

- Requirements to obtain permits to construct prior to beginning construction;

[12] The NSR Working Group members consist of representatives from U.S. EPA, ARB, industry, trade associations, local government agencies, environmental and community groups, manufacturers, and consultants.

- Requirements to apply state-of-the-art air pollution control technology (i.e., California BACT);
- Requirements to conduct an air quality impact analysis;
- Requirements for monitoring, recordkeeping and reporting that make them representative, enforceable, and publicly accessible;
- Requirements for regulating any air pollutant covered by the NSR rules; and
- Requirements for public participation, including requirements for a public comment period, public notification, or a public hearing prior to issuing a permit to construct.

SB 288 further details the types of rule requirement changes that are barred if they result in exempting a source or reducing its obligations for any of the program elements listed above. Those types of barred rule requirement changes are the following:

- Changes in how it is determined whether New Source Review requirements apply to a given change at a facility
- Changes in the definition of "modification" or "routine maintenance, repair or replacement"
- Changes in calculation methods, threshold, or other New Source Review procedures
- Changes to any definitions or requirements of district New Source Review rules[P]

2. Actions Following the Fall 2011 Final Report

When the fall 2011 final report is completed, it will provide a new electricity assessment through 2020 and a series of recommendations for air permitting changes. It is possible that some combination of SCAQMD changes in practices and rule modifications will be sufficient to accommodate any needs for offsets for new power plants required in the 2013-2015 period, but that legislation will be needed to create an appropriate offset bank and a means to allocate these to necessary power plants that will have to be added through the remainder of the decade. Thus, while the AB 1318 project will come to an end, the process started by it – to devise long-term solutions to the problem of finding offsets for power plants needed in the SCAB – will continue.

Table I-7. Potential Options to Increase Offset Availability in the SCAQMD

	Strategy	Concept	Additional Description	Potential Outcome
A	Recommendations to Modify SCAQMD Current Policies and Practices	1) Surrender offsets prior to start of equipment operation rather than at the time of permit application	• Consistent with federal NSR • Permit conditioned to require surrender of offsets prior to start of operation	Applicants have more time to secure offsets
		2) Calculate future ERCs and convert existing ERCs to annual instead of daily credits (e.g., calculate offsets for peakers like baseload plants)	• ERC issuance in total lb/yr based on Rule 1306(c)(1) and modified (c)(4) • Offset requirements also in lb/yr [modified Rule 1306(b)]	Creates more near-term and long-term ERCs
		3) Establish a joint ARB/SCAQMD team to review all ERC applications to ensure consistency in the ERC process	• Efficiency improvement • Can potentially lead to more credit generating opportunities • Provides additional information for market participants	Offsets can be calculated, identified, and procured more quickly
		4) Evaluate additional mechanisms for increasing credit generation opportunities	• Rule 1625: Generation of ERCs for PM • Rule 2511: Credit Generation Program for Locomotive head end power (HEP) • Bonnet system to capture emissions from hotelling ships and idling locomotives • Port sources • Restaurant PM controls	Creates more long-term ERCs from non-traditional sources of equipment
		5) Provide the opportunity for consultation meetings prior to submittal of an application to generate ERCs and make the facility's NSR balance available to the applicant upon request without requiring the facility to submit a public record request		Offsets can be calculated, identified, and procured more quickly
		6) Limit use of ERCs and RTCs as mitigation under Hearing Board. Mitigation should be more closely tied to the time of the violation.		Creates more near term and long-term ERCs
		7) Consider allowing facilities the opportunity to lease ERCs for short-term use.		Creates more near term and long-term ERCs
		8) Issue a policy document outlining SCAQMD requirements for interpollutant trades allowed under Rule 1309(h)		Offsets can be calculated, identified, and

	Strategy	Concept	Additional Description	Potential Outcome
		including establishing the offset ratio based on pollutant types and geographical location.		procured more quickly
		9) Explore whether the economic downturn has freed up some offsets from industrial sources that have reduced production.		Creates more near-term ERCs
		10) Revise procedures for evaluating potential to emit to better match expected power plant operations	Current practices in determining monthly patterns and hours of operation may not match expected operation of new power plants scheduled more often to integrate renewables than to cover peak load	Reduce ERCs required in return for tighter limits on operation
B	Recommendations to Modify SCAQMD Rules and Regulations	11) Propose defensible changes to Rules 1302, 1304, and 1306 in order to provide maximum flexibility for electrical generation sources to obtain offsets.		Creates more near term and long-term ERCs
		12) Revise Rule 1304 exemptions for repowering power plants from an automatic exemption for any plant to a selective exemption based on regional need for capacity		Reduce drain on internal offset bank for power plants not needed
		13) Modify Rule 1304 exemption for repowering to allow shutdown of capacity at one location to provide an exemption for equivalent capacity at another location	Repowering is not necessarily the best option for using scarce internal bank offsets since transmission system changes may reduce needs in some locations and increase needs in others	Greater flexibility in the use of the existing exemption with no change in ambient air quality impacts
		14) Discount newly generated ERCs to best available retrofit control technology (BARCT) instead of BACT (a so-called “BACT Time Out”)		Creates more near term and long-term ERCs
		15) Eliminate Rule 1304 exemption for repowering of power plants and create a new rule applicable to all powerplants, both repowering of existing facilities and new greenfield facilities		
C	Recommendations to Modify State Law	16) Make recommendations to focus SB 288 to provide more flexible options to increase offset availability while maintaining air quality protections		Creates more near term and long-term ERCs

	Strategy	Concept	Additional Description	Potential Outcome
D	Recommendations to Modify ARB Current Policies and Practices	17) Transfer to ARB the responsibility for calculating, issuing, and tracking ERCs		Offsets can be calculated, identified, and procured more quickly
E	Recommendations to Modify Federal Law	18) Consult with U.S. EPA regarding opportunities for changes in the federal Clean Air Act that would provide maximum flexibility for electrical generation sources to obtain offsets		Creates more near term and long-term ERCs
F	Recommendations to Modify U.S. EPA Current Policies and Procedures	19) Request expedited U.S. EPA approval of STCs in Rule 1309 and Rule 1303(b)(2)(B) to allow the SCAQMD to issue permits using STCs		Offsets can be calculated, identified, and procured more quickly

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II. ELECTRIC RELIABILITY

A. Introduction

This chapter provides an assessment of what is known concerning electricity reliability in the SCAB and what additional assessments and studies are needed to understand the long-term need for fossil power plant additions to ensure that reliability and operational needs are satisfied. A fundamental premise of Assembly AB 1318 – that the SCAB is a unit of analyses that lends itself to reliability assessment - is at odds with the practices of the electricity industry. There are two separate balancing authority areas (BAA) – one operated by LADWP and one operated by CAISO – and each pursues their own reliability studies and activities with minimal interaction. Although bulk transmission is increasingly studied and planned on a coordinated basis, this is not the case for local area reliability assessments and decisions about how to assure satisfaction of applicable reliability standards through time. Thus, conducting the assessment required by AB 1318 necessitates complicated efforts to understand and correlate existing practices, and possible changes in such practices, between two areas that are under different operational control from an electricity reliability perspective, but common from the perspective of air quality regulations.

This chapter is composed of six sections in addition to this introduction.

(1) Section B, Background sets the stage for understanding the issue of electric system reliability in the SCAB;

(2) Section C, Need for New and Repowered Gas-Fired Capacity in the SCAB addresses the question of why additional new fossil capacity is needed to support: (1) regional and local reliability needs, (2) the expanding role of highly flexible capacity to support both existing operational requirements as well as integration of substantial renewable generating capacity serving the energy needs of the region, and (3) the challenge of complying with other environmental policies, such as the mitigation of harm to marine life from OTC power plants in the LA Basin;

(3) Section D, Near-Term Need for Capacity Additions Based Upon Existing Studies assesses the existing studies that evaluate need for capacity through year 2014 and summarizes the consensus of the energy agencies about these studies;

(4) Section E, Long-Term Need for Capacity Additions by Type of Generation describes how longer-term reliability assessments would be conducted and how the factors that AB 1318 requires be evaluated might affect the long-term need for resource additions;

(5) Section F, Studies that Need to be Completed to Provide a Final AB 1318 Report in Fall 2011 summarizes the additional studies that should be completed in order to satisfy the requirements of the legislation and which of these are already under way as a result of energy agency plans and which ones are new just for this effort; and

(6) Section G, Observations and Conclusions provides some perspective about what is known at this point about reliability needs.

B. Background

Electric system reliability is governed by a wide range of state and federal law, Federal Energy Regulatory Commission (FERC) orders affecting the North American Electric Reliability Corporation (NERC), and NERC standards [modified in some cases to suit the circumstances within the Western Electricity Coordinating Council (WECC)], as well as from each BAA.

1. NERC/WECC Reliability Standards

Currently, CAISO Grid Planning Standards applicable to Southern California include the following:

1. **NERC/WECC Planning Standards** – CAISO must comply with the standards specified in the NERC/WECC Planning Standards unless WECC or NERC formally grants exemption or deference to the CAISO.
2. **Specific Nuclear Unit Standards** – The criteria pertaining to the Diablo Canyon and San Onofre Nuclear Power Plants, as specified in Appendix E of the Transmission Control Agreement.
3. **Combined Line and Generator Outage Standard** – A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.
4. **New Transmission versus Involuntary Load Interruption Standard**
    a. Involuntary load interruptions are not an acceptable consequence in planning for CAISO Planning Standard Category B disturbances (either single contingencies or the combined contingency of a single generator and a single transmission line), unless the CAISO Board decides that the capital project alternative is clearly not cost effective (after considering all the costs and benefits). In any case, planned load interruptions for Category B disturbances are to be limited to radial and local network customers as specified in the NERC Planning Standards.
    b. Involuntary load interruptions are an acceptable consequence in planning for CAISO Planning Standard Category C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the CAISO Board decides that the capital project alternative is clearly cost effective (after considering all the costs and benefits).
    c. In cases where the Standards 4a and 4b would result in the elimination of a project or relaxation of standards that would have been built under past planning practices, these cases will be presented to the ISO Board for a determination as to whether or not the projects should be constructed.

The above standards are intended to apply to system planning studies and not system operating studies. In addition, the standards above are not fully applicable to the Local

Capacity Requirement (LCR) studies, which have their own Local Capacity Technical (LCT) requirements.

In some cases, it may require several years to complete approved transmission projects to meet these standards. In the interim, CAISO relies on the interim solutions such as operating procedures, or System Protection System, to meet applicable NERC/WECC/CAISO reliability standards.

2. Roles of the CAISO and State Agencies

a. CAISO and LADWP

CAISO is the planning authority for the bulk of the state's transmission system and is charged with developing, integrating and coordinating needed transmission infrastructure. The State of California has vested the CAISO with responsibility to maintain a **reliable electricity system** for those regions under its operational control.[13] Specifically, CAISO has the responsibility to —ensure the efficient use and reliable operation of the transmission grid consistent with the achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council[14] and the North American Electric Reliability Council.[15]"

LADWP and several other publicly-owned utilities have responsibilities comparable to those of the CAISO as balancing area authorities.

b. California Public Utilities Commission

CPUC oversees the rates and service of investor owned utilities in California (Southern California Edison, Inc. is the largest investor owned utility in SCAB), as well as permitting transmission lines and ensuring electric reliability. Public Utilities Code Section 454.5 requires investor owned utilities to file procurement plans with CPUC describing how the utility will meet the electrical needs of its customers while maintaining reasonable rates. Public Utilities Code Section 380 requires CPUC, in consultation with CAISO, to establish resource adequacy requirements for all load-serving entities (LSE), including ensuring investment are made in new generating capacity and ensuring existing generating capacity that is economic is retained. CPUC's Resource Adequacy program ensures adequate generation is procured in the short term, while the Long Term Procurement Plan program uses a ten-year timeframe to assess needs and authorize the financing of new resources.

[13] California Public Utility Code No. 345
[14] Now known as Western Electricity Coordinating Council (or WECC)
[15] Now known as North American Electric Reliability Corporation (NERC)

c. California Energy Commission

CEC is generally directed to work toward assuring that a reliable supply of electrical energy is maintained.[16] Following the electricity crisis of 2000-2001, the portions of the Public Resources Code giving direction to CEC energy planning and forecasting activities were revised to institute a biennial integrated energy policy report (IEPR) to advise the governor and legislature. Section 25302(c) identifies —assessment and forecast of system reliability and the need for resource additions, efficiency, and conservation…" as the first substantive topic which the biennial IEPR is required to address. CEC also has a broad mandate to oversee resource adequacy activities of the publicly-owned utilities and to report to the legislature through the IEPR about this topic.[17]

C. Need for New and Repowered Gas-Fired Capacity in the South Coast Air Basin

1. Introduction

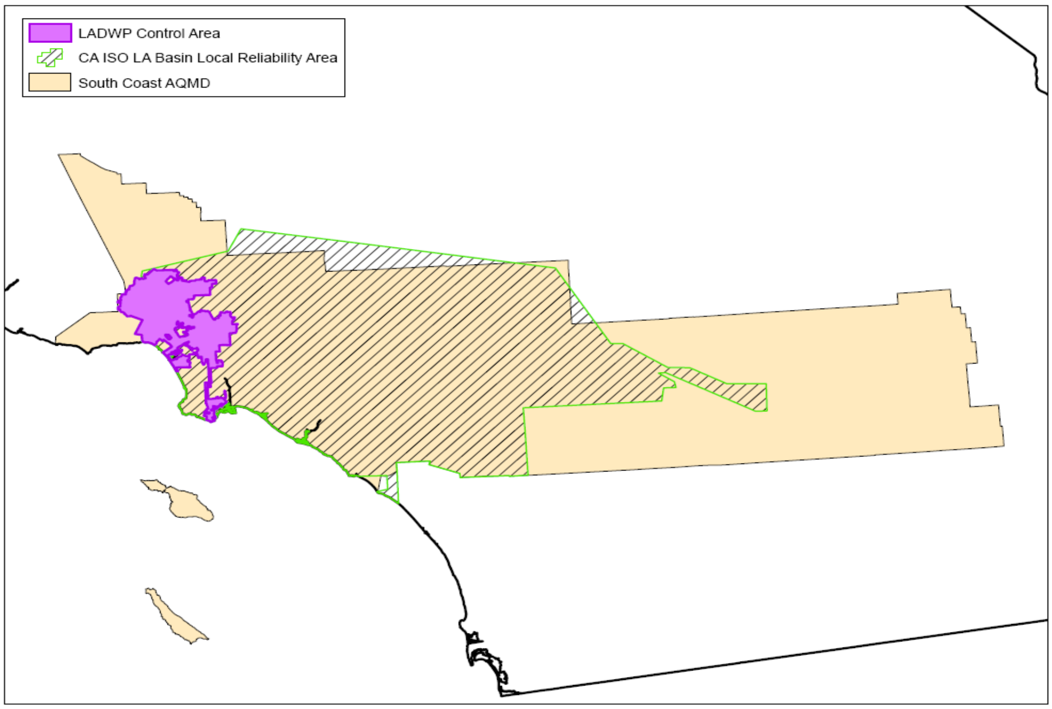
As balancing authorities, CAISO and LADWP are responsible for ensuring reliability in the areas under their jurisdiction, based on standards set by NERC.[18] This means that sufficient generation capacity must exist and be available for dispatch to meet demand, even under adverse conditions. These conditions include the failure of a major generator and transmission line during periods of extremely high demand.

For CAISO, reliability requires sufficient capacity at several different geographic levels. For example, sufficient capacity must be available across the entire control area to insure system-wide reliability under peak demand conditions. This is secured by imposing (system) resource adequacy (RA) requirements on LSEs in the control area.[19] Zonal reliability requires sufficient capacity in the northern and southern halves of the control area (NP26 and SP26, respectively) to meet demand under peak load conditions and with the failure of a major system component.[20] Local reliability requires sufficient capacity in each of several local capacity areas (LCA) in the CAISO control area to meet peak demand given the sequential failure of two major system components.

[16] Public Resources Code, Section 25001.
[17] Public Utilities Code, Section 9620.
[18] These standards can be found at www.nerc.com/page.php?cid=2|20
[19] LSEs must secure control of capacity equal to 115% of their forecasted monthly peak load one month prior to the start of the month; the California ISO is allowed to dispatch this capacity to meet demand when needed. The California ISO's *2010 Summer Loads and Resources Operations Preparedness Assessment* (May, 2010) indicates that, based on a peak load forecast of 47,139 MW, 54,210 MW of capacity is needed to serve load.
[20] For Southern California, for example, peak demand must be met with the failure of the DC Intertie that connects the regions with the Pacific Northwest, or the loss of a major 500kV intertie line and a nuclear generating unit.
A related Southern California-wide constraint, known as SCIT, requires that specific amounts of generation be available in SP26 to maintain import capability into the region. This differs from the zonal reliability requirement in that the latter is based on MW of capacity, whereas SCIT is based upon the amount of *inertia* provided by each power plant.

These areas are transmission-constrained; limits on the ability to import energy into the LCA create requirements for generation capacity within the area to reliably serve it, if only under peak load conditions. The LA Basin LCA is an area under SCAQMD jurisdiction, as depicted in Figure II-1.

Figure II-1. Local Capacity Areas within SCAQMD



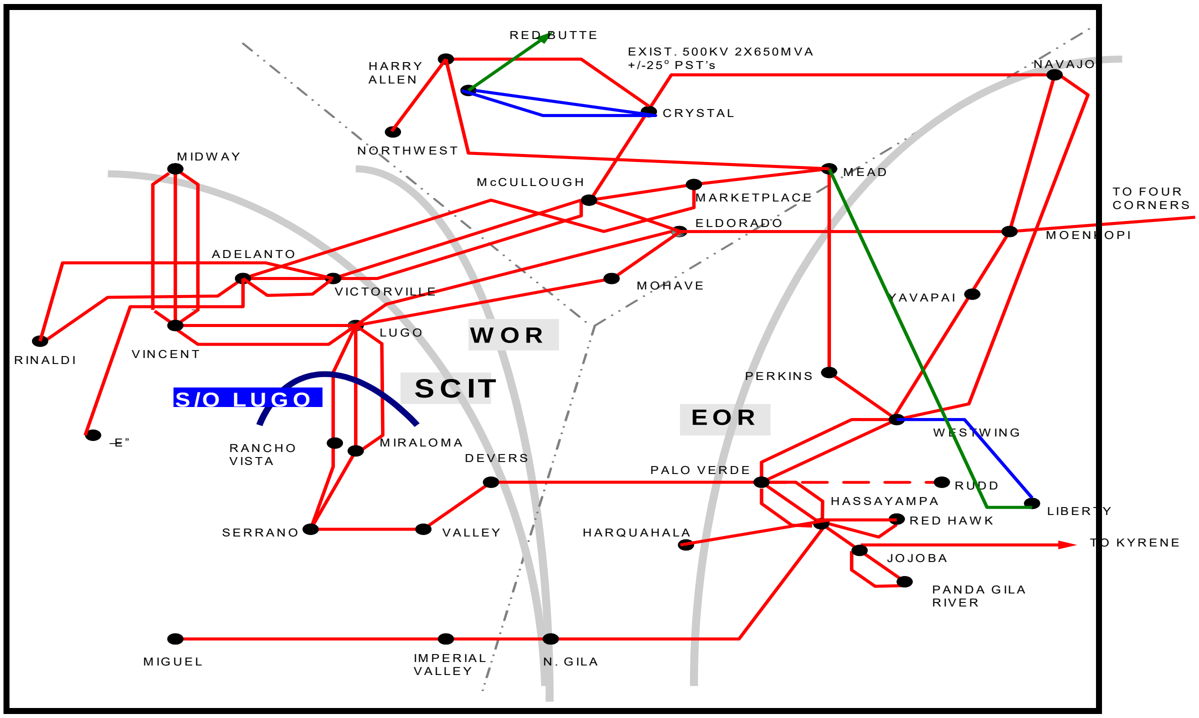
Source: California Energy Commission

This LCA is defined by 13 major transmission lines, whose (limited) ability to transport energy into the LA Basin creates the need for generation with the CAISO portion of the LA Basin.[21] The amount of capacity needed in each LCA to reliably serve load is determined annually by CAISO for the following year. This capacity is secured by requiring LSEs to meet local RA requirements, with the CAISO contracting for additional capacity if necessary.

Finally, individual transmission constraints can create the need for threshold amounts of capacity in geographic areas within an LCA. For example, capacity from a subset of the generation units in the LA Basin LCA is needed to meet capacity requirements resulting from transmission constraints for two of the thirteen major transmission lines defining the LA Basin LCA. These are located south of the Lugo substation in western San Bernardino County. Figure II-2 depicts the boundaries of these important areas from an electrical schematic perspective.

[21] In this document, —LosAngeles Basin LCA" refers to the transmission-constrained portion of the California ISO control area. ―Los Angeles basin" refers jointly to the LCA and the LADWP control area.

Figure II-2. Substation Assignment to Key Subareas



Source: CAISO

LADWP, in its capacity as a balancing authority, is responsible for reliability in its control area. This area is depicted in Figure II-1, and lies entirely within the boundaries of SCAQMD.[22] Limits on the amount of energy that can be imported into the control area establish (LAWDP) system-wide capacity requirements; the configuration of the transmission grid within the control area creates LCRs for the western and southern parts of the transmission system. This is discussed in more detail below.

The geographic dimensions that are relevant to meeting reliability needs are a function of transmission constraints and, as can be seen from Figure II-1, do not align with SCAB or SCAQMD boundaries. However, the need for generation capacity within the area under SCAQMD jurisdiction is largely a need for capacity within the LA Basin LCA and LADWP.[23]

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[22] LADWP also provides service to the Owens Valley, located in western Inyo County. This is a very small share of LADWP's load obligations and is ignored in this document. References to “the entire LADWP control area,” are intended to exclude the Owens Valley.

[23] It is possible that, under scenarios in which minimally acceptable amounts of capacity are retained in the Los Angeles Basin LCA, there would be a need for new dispatchable gas-fired capacity in the eastern portion of the area under SCAQMD jurisdiction. Additional studies would need to be undertaken to determine if this is the case.

2. Import Limits for Southern California

Although planning assessments of reliability rarely address both the CAISO and LADWP BAAs, there are operational limits in which the two systems have to be considered collectively. The maximum amount of imports that can be safely brought into Southern California is calculated using the SCIT nomogram. A nomogram is essentially a tool to show the operational limits for two or more variables, which if operated within, would maintain reliable service. Figure II-2 provided a schematic defining East of River (EOR) and West of River (WOR). The SCIT nomogram includes the following attributes:

- Maximum SCIT level based on the amount of flow from the EOR path (also commonly known as WECC Path 49);
- Maximum SCIT flows that are dependent on the amount of inertia (in MWs) being available from generating units that are on-line in the LA Basin area;
- A maximum limit of 16,451 MW based on current assessment, depending on the EOR flow as well as the availability of on-line generating units' inertia;
- Seasonal variation due to load changes and available on-line generation.

The current operational SCIT nomogram can be accessed through the CAISO website.[24]

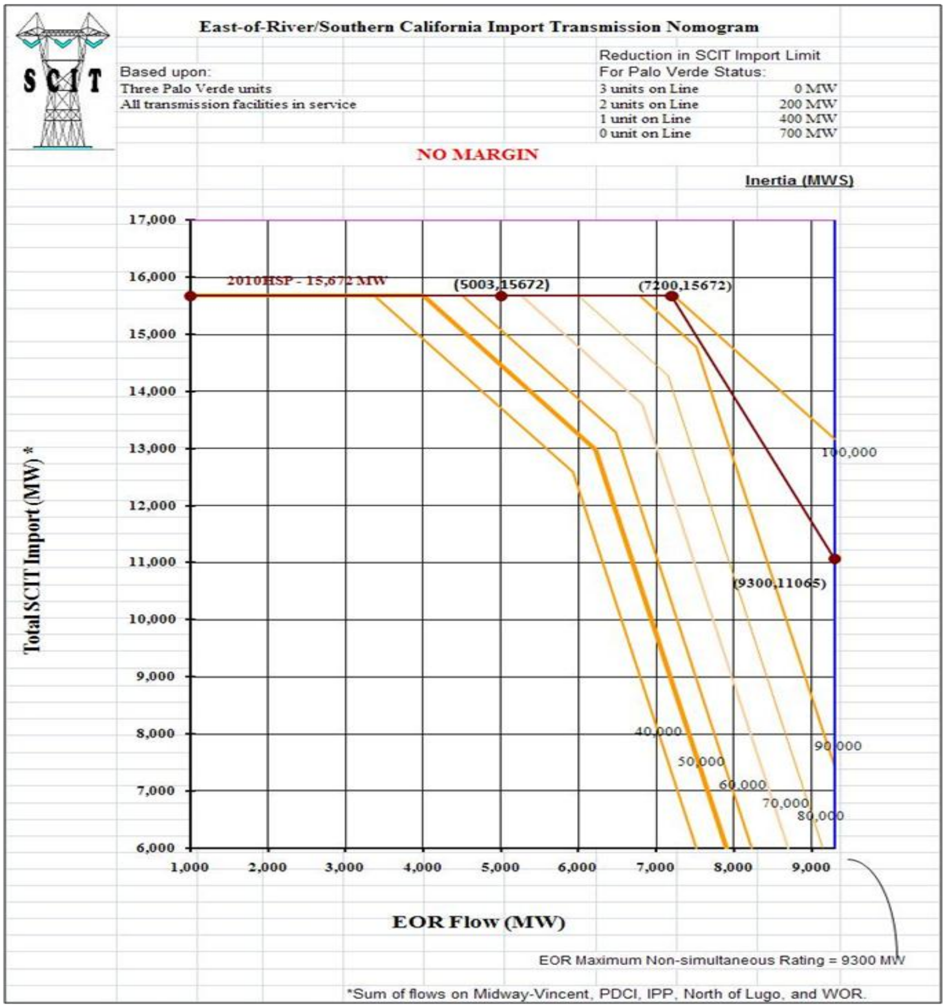
Figure II-3 shows an example of the SCIT nomogram for the operations in the spring of 2010. From the nomogram, the total amount of imports into Southern California is dependent on the amount of total flow on the WECC Path 49 (East of River)[25] and the amount of generating units' inertia[26] within the SCIT nomogram cut plane (i.e., primarily within LA Basin). The more on-line generation within the SCIT nomogram cut plane, the higher its inertia and ability to provide more imports to the LA Basin. The amount of imports into LA Basin is proportional to the amount of internal generation's inertia. Thermal generation typically has high inertia, and therefore is critical in enabling the system to support more imports. Many renewable technologies have low inertia. Solar photovoltaic, whether central station units in the desert or roof top units on the customer side of the meter, have essentially no inertia value. Central solar thermal technologies on the other hand can have as much inertia as a fossil power plant, because the source of the electricity – a large rotating generator shaft – is essentially the same even though the source of the heat to turn the turbine portion of the shaft is different.

[24] http://www.caiso.com/27a4/27a4aa0c5e260.pdf

[25] WECC Path 49 (East of River) consists of flows on five 500kV lines from Arizona to California, Arizona to Nevada and one 345 kV line from Arizona to Nevada.

[26] Inertia is a physical constant of each turbine-generator that defines its ability to store rotational kinetic energy and is analogous to mass.

Figure II-3. An Example of SCIT Nomogram



3. Offset Needs Influenced by Type of Power Plant and Expected Usage

The amount of air credits (market-based ERCs, offsets from a District's internal bank, etc.) that a new power plant requires are only weakly related to its capacity. Its combustion technology and the maximum annual hours of operation have traditionally been more important factors in determining the amount of air credits needed to obtain an air permit. Emission factors for the criteria pollutants differ substantially from one combustion technology to another. Emission factors may be very sensitive to partial load operations versus full-load operations for one technology, but not so sensitive for another.

The choice of power plant technology is related to expected patterns of operation. For example, a simple cycle combustion turbine may be selected if the power plant is likely to run only a small number of hours per year, because its purpose is really to alleviate a contingency that does not occur frequently. On the other hand, a combined cycle power plant may be selected if the facility is expected to operate more than perhaps 20 percent annual capacity factor. Within combined cycles, if the power plant is expected to operate steadily at only a few power levels, this implies a particular configuration of combustion turbines and heat recovery steam boilers compared to a plant that is designed to be highly flexible by starting up and shutting down many times, or ramping up and down rapidly across the hours of the day. Such power plant technology choices and expectations about patterns of operation interact with emission factors to determine expected ranges of emissions from a given amount of capacity.

Electricity reliability studies do not typically address type of power plant or expected pattern of operation throughout a normal year. Thus, the routine assessments conducted for reliability are necessary, but not sufficient to provide an estimate of the range of offsets needed over time in SCAB. Additional studies will be required to translate needed capacity additions into technology type and expected patterns of operation.

Further, limited aggregate amounts of emission offsets available to power plants may itself interact with electricity system needs to determine the type of capacity that is added to the system. For example, satisfying the LCRs to assure reliability might be achieved by installing more capacity with severe operational limitations than has traditionally been permitted. This would spread available air credits to more capacity by accepting low number of hours of operation per year or per month. Conversely, the need to locate dispatchable capacity that helps with renewable integration by ramping up and down in a wide range every day might increase emissions per unit of capacity, thus limiting the total amount of capacity that can be permitted from a given amount of air credits.

Finally, changing transmission and generation topologies may affect which plants are needed to maintain reliability, thus allocation of emissions credits must consider the evolving reliability needs of the grid.

Thus, while this chapter currently stands alone from the air permitting chapter for this interim report, the final AB 1318 report is expected to present the results of iterations back and forth between assessments of electricity reliability and other assessments of new and existing permitting mechanisms.

D. Near-Term Need for Capacity Additions Based Upon Existing Studies

1. Introduction

The utilities, balancing authorities and energy agencies routinely conduct studies of reliability requirements and other rationales for resource additions. Because CAISO operates a large balancing area with numerous transmission owners and open and transparent markets, it has an extensive and largely public process for conducting reliability studies. As an integrated utility, LADWP has less need to publish its reliability studies and practices publicly since it does not have to facilitate communication among numerous market participants. The disparity between these two balancing authorities means that there are numerous studies of local and regional reliability requirements for the portions of the CAISO within SCAB, and much less public information about LADWP. This asymmetry of information is part of the rationale for this project needing much more time to be completed than contemplated in the AB 1318 legislation, and why only near-term assessments can be evaluated at all for this interim report. Longer-term assessments of any kind, let alone the highly complex ones required to satisfy the requirements of AB 1318, necessitate new studies that have never previously been undertaken. Thus, this section addresses existing short-term studies and their relevance in light of near-term expected conditions, while later sections of this section describe the additional studies that will need to be conducted in the second half of 2010 and first half of 2011.

2. Existing Studies

There are four existing studies, and other sources of information, that address resource needs for areas within or similar to SCAB. These are:

- 2011 LCR study for LA Basin
- 2012-2014 LCR Study for LA Basin
- 2009 IEPR assessment of OTC/air quality permitting conflicts for Southern California
- 2008 Study of OTC power plant replacement by transmission for Southern California
- Summary of LADWP transmission and repowering plans
- Scenario analysis tool to evaluate various load and resource futures

The following subsections will provide a brief summary of each.

a. 2011 LCR Study for Los Angeles Basin (CAISO, April 2010)

The CAISO routinely performs a number of LCR studies. These studies typically focus one year ahead for use in the resource adequacy process and establish the minimum amount of generation that is needed to meet national and regional reliability standards[27] in a local transmission-constrained area. Figure II-4 illustrates the LA Basin LCR study area. The LA Basin LCR study area covers the largest load serving area with 20,223 MW of peak demand[28] in four counties: Los Angeles, Orange, Riverside and San Bernardino. This area has a total of 12,309 MW of internal generation.

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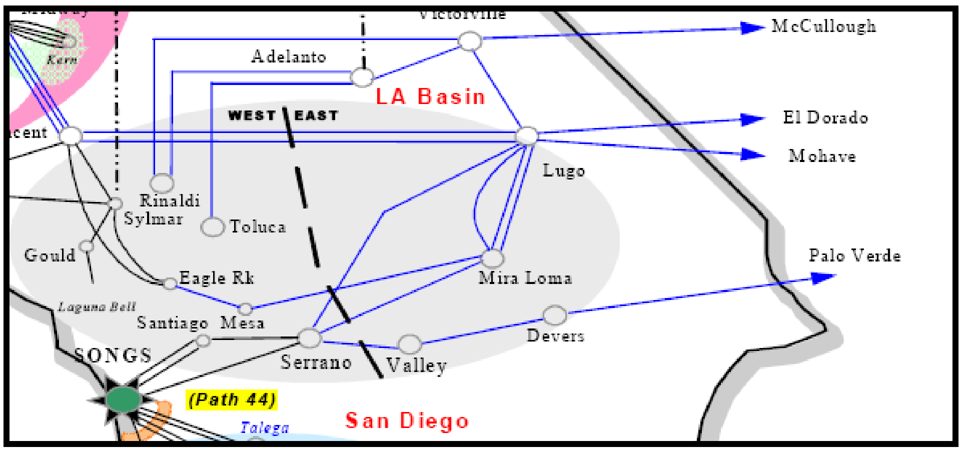
[27] The ISO is required to comply with North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) planning standards.
[28] Including losses per peak demand projection from the California Energy Commission (CEC)

For 2011, the CAISO LCR study indicated a need of 10,589 MW of generation located within LA Basin LCR area.[29] This amount of generation is required to maintain reliability to the South of Lugo path within Southern California Edison (SCE) service territory. The South of Lugo path consists of three 500kV transmission lines south of SCE's Lugo Substation and is a major electrical corridor in serving the load in LA Basin (Figure II-4). The LCR of 10,589 MW represents 86 percent of the CAISO's LA Basin total available existing generation.

The 2011 LCR requirement is higher than the comparable value for 2010 because import capability has been reduced due to retirement of the Antelope to Mesa transmission line, which is going to be replaced by a new line with more capacity. This illustrates the interaction between the transmission system configuration and the need for generating capacity within the local area. Once the new line is completed, the need for local generating capacity to serve LCR needs may decline. However, operational needs may increase to facilitate integration of renewable generation.

Figure II-4. Los Angeles Basin LCR Study Area



b. 2012-2014 LCR Study for Los Angeles Basin (CAISO, December 2009)

In addition to the annual one-year ahead studies, whose results impose procurement obligations of LSEs, the CAISO also performs an evaluation for potential longer-term LCRs for informational purposes only. The most recent study covers the period 2012 to 2014.[30]

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[29] CAISO, April 2010, 2011 Local Capacity Technical Analysis: Final Report and Study Results, http://www.caiso.com/2488/2488bcca65490.pdf

[30] CAISO, December 2009, 2012-2014 Local Capacity Technical Analysis: Report and Study Results, http://www.caiso.com/2495/2495c63b23450.pdf

After the CAISO published the results for the 2012-2014 LCR study in late 2009, there were further updates to the status of several major transmission projects, such as LADWP's Green Path North project and SCE's Tehachapi Transmission project. Since the 2014 LCR study assumed that these projects would be available to support 2014 peak loads, and later the status of these projects changed, the study results for 2014 are no longer valid. Therefore, for this summary report, the CAISO only provides a brief discussion of the LCR study results for year 2012 and not for year 2014.

For 2012, the LA Basin LCA is expected to have a total of 12,255[31] MW of internal generation and a peak demand of 20,178 MW[32]. For 2012, the LCR study indicated a need of 10,512 MW of generation located within LA Basin LCR area. This still represents 86 percent of its total available generation, which is a significant amount of existing generation. Similar to the 2011 LCR study results, of the 12,255 MW of total area generation, 4,927 MW is generated from OTC power plants, which are subject of the State Water Board's water policy on the use of coastal and estuarine waters for power plant cooling.

c. 2009 IEPR Assessment of Once-Through Cooling/Air Quality Permitting Conflicts for Southern California (CEC, December 2009)

In the 2009 Integrated Energy Policy Report (*2009 IEPR*), CEC assessed the interactions between retirement of existing OTC capacity and the barriers induced by absence of functional air credit mechanisms for power plants. This analysis focused exclusively on the SCE portion of the CAISO system. SCE is the major utility in the Southern California region. However, many municipal utilities are also located there including: LADWP, Burbank Water and Power, Glendale Water and Power (all in the LADWP BAA); and Anaheim, Riverside, Pasadena, and other smaller municipals in the CAISO BAA. SCE likely will be the most affected by the SCAQMD ruling.

CEC staff evaluated the supply-demand balance in the South of Path 26 region (SP26)[33] using two alternative OTC retirement scenarios: (1) retirements assumed by the CPUC in the most recent decision authorizing procurement by SCE[34], and (2) a retirement schedule matching the OTC compliance dates in the June 2009 OTC policy

[31] This reflects a reduction of some QF generation in the area.
[32] Including losses per peak demand projection from the California Energy Commission (CEC). This peak demand for the 2012 study was not updated in time for the 2012-2014 LCR evaluation due to the new CEC demand forecast not being endorsed by the CEC Commissioners until December 2009. By that time, the 2012 longer term LCR study was essentially completed, and could not incorporate the latest CEC demand forecast in time for the study results.
[33] California Energy Commission, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System,* February 2009, CEC-200-2009-002-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-002/CEC-200-2009-002-SD.PDF].
[34] D.07-12-052

proposal of the SWRCB staff. Results of this effort and an earlier staff paper from February 2009 were discussed at a September 24, 2009, workshop.[35]

The results of rapid retirement are shown in the bottom row of Table II-1. Under the retirement assumptions used in authorizing procurement by SCE, SP-26 has more capacity than necessary to sustain a 15 percent reserve margin through 2011, but falls below that level in 2012 and gets progressively worse, resulting in a seven percent reserve margin in 2014. This increases the risk of maintaining grid reliability in situations like unexpected outages, which the full 15 percent planning reserve margin is designed to address.

The top highlighted row in Table II-1 shows the results of revising the OTC retirement assumptions to match the schedule proposed by the energy agencies and accepted by SWRCB staff in its June 2009 draft OTC policy.[36] The deficits relative to the designed planning margin, shown in the bottom highlighted row, are eliminated, and there are comfortable surpluses throughout the five-year period.

Additionally, the SWRCB, in consultation with the energy agencies, has delayed the compliance dates for OTC power plants in the LA Basin to allow time for replacement infrastructure to be developed and brought on-line. Rather than uniform compliance dates for classes of power plants as it originally proposed, SWRCB has adopted a regional focus with those regions able to develop replacement capacity more quickly getting compliance dates closer in time. Due to the air credit issues being addressed through AB 1318, Southern California OTC power plants have compliance dates further into the future. In the absence of OTC-induced retirements during 2010-2014, the reserve margin remains at or above 25 percent.[37] However, once the full OTC retirements occur in later years, the 15 percent planning reserve margin cannot be satisfied unless additional resources are brought on-line.

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[35] Energy Commission staff presentation, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#092409].

[36] SWRCB adopted a final OTC policy on May 4, 2010. While there have been some slight adjustments in the compliance schedule compared to the June 2009 draft, they do not materially affect this analysis.

[37] Subsequent to publication of the 2009 IEPR, the SWRCB set a compliance date of December 2011 for the South Bay facility (708 MW). Table 1 shows the staggered retirement of South units as a Firm Retirement; meeting the compliance date established by the SWRCB would result in the retirement of an additional 354 MW in 2012 and 2013. On May 4, 2010 SWRCB adopted a final policy with slight adjustments in the compliance schedule compared to the June 2009 draft; these do not materially affect this analysis.

Table II-1. Staff Planning Assumptions and Reserve Margin Results for Southern California Using High, Rapid Retirements

Supply/Demand Forecast	2010	2011	2012	2013	2014
Peak Demand	27,995	28,363	28,800	29,256	29,620
Existing Generation	22,927	22,927	22,927	22,927	22,927
Net Imports	10,100	10,100	10,100	10,100	10,100
DR & Interruptible	1,491	1,512	1,534	1,547	1,551
New Thermal	995	1,707	1,992	1,992	1,992
New Renewable	162	251	533	965	1,157
Firm Retirements	(354)	(354)	(354)	(354)	(708)
Total Generation	35,321	36,142	36,731	37,177	37,020
Reserve Margin w/o High and Rapid OTC Retirements	**26%**	**27%**	**28%**	**27%**	**25%**
Surplus over 15%	**3,127**	**3,525**	**3,611**	**3,532**	**2,957**
Add'l OTC Retirements (per CPUC D.07-12-052)	(1,850)	(3,050)	(4,500)	(5,350)	(5,350)
Reserve Margin w OTC Retirements	20%	17%	12%	9%	7%
Surplus over 15%	**1,277**	**475**	**(889)**	**(1,818)**	**(2,393)**

Source: California Energy Commission

The court ruling affecting SCAQMD rules has had similar impacts on publicly owned utilities outside of the Southern California portion of the CAISO control area. LADWP has units at three power plants totaling over 2,500 MW of capacity that use OTC and apparently intends to repower most of the units in these plants in order to comply with SWRCB OTC policy. In securing air quality permits for re-powering, LADWP has faced the same challenges as other entities within the SCAQMD's jurisdiction, since its ability to use SCAQMD's Rule 1304 exemption from providing air credits for its repowers has been blocked by the court ruling.

The court decision on priority reserves also threatens 1,910 MW (gross nameplate) of the capacity that had been expected to come on-line in SCE service area from 2010 to 2013 (Table II-2).

Specifically, three power plants licensed or before the CEC that are located in the LA Basin LCA area, if developed, these plants would allow retirement of some of the existing aging OTC power plants. Importantly, each of these plants has a long-term contract with SCE that is approved by the CPUC. The specific projects, which are summarized in Table II-2, are:

- Sentinel Units 1 and 2 totaling 850 MW nameplate[38] capacity. An Application for Certification (AFC) for the facility is before the CEC; a Final Staff Assessment (FSA) was issued in two parts – October 2008 and April 2010. Pursuant to SB 827,

[38] ―Nameplate" refers to the manufacturer's rating for output of power plant equipment.

SCAQMD identified to the CEC the ERCs for the facility from its District account. CEC staff analyzed the ERCs in the April 2010 FSA. Evidentiary hearings on the April 2010 FSA are scheduled for July 19, 2010. If the Tehachapi Renewable Transmission Project becomes operational, the LA Basin LCR may be reduced in geographic area. If this occurs this plant may no longer serve LCR needs.

- The El Segundo Repowering Project was granted a license for Units 1 and 2 from the CEC in 2005 (existing two units have a nameplate capacity of 335 MW each; a license was granted for a repowered facility with a nameplate capacity of 630 MW). In June 2007, NRG petitioned to amend its license to shift from an OTC technology and build a 560-MW (nameplate, 550 MW contract) air-cooled facility. Its construction will result in the closure of Unit 3 (335 MW) at the existing facility, resulting is a net change in (contract) generating capacity of 215 MW. This project has secured ERCs pursuant to a Rule 1304 exemption.
- Edison Mission Energy's Walnut Creek project (500 MW) was approved by the CEC in February 2008, and has a contract with SCE. Because this project secured ERCs through SCAQMD's Priority Reserve, it cannot move forward until an alternative source of ERCs is found.

Table II-2. SCE Capacity Impacted by SCAQMD Rule

Facility	Nameplate Capacity (MW)*[39]	Net Contract Capacity (MW)
Sentinel	850	728
El Segundo Repower	560	215
Walnut Creek	500	479

Source: California Energy Commission

The 2009 legislative session debated several attempts to resolve the impacts of the superior court decision. AB 1318 and SB 827 passed the legislature and were signed by the Governor. AB 1318 defines several criteria that, if satisfied, allocate air credits from SCAQMD's internal bank to power plants. The two Sentinel units are eligible for such credits, and the CEC is now completing its licensing activities for the Sentinel facilities. SB 827 would apparently restore repowering exemptions via Rule 1304, so LADWP's strategy of OTC compliance through repowering may no longer be blocked by air credit limitations. Walnut Creek is not helped by either AB 1318 or SB 827, and a comparable bill, SB 388 (Calderon), created to authorize air credits for it, did not pass the legislature in 2009.

This analysis shows the strong interdependencies of the likely consequences of the SWRCB's OTC mitigation policies with air credit availability to support new power plant development. In the L. A. Basin, there is a clear conflict. This conflict has been shifted

[39] The CEC has permitting jurisdiction for all thermal power plants with capacity of 50 MW or greater. The CEC's permitting process does not substitute for the requirements of other entities, so the difficulties in acquiring air credits in the SCAB means that projects that would normally get a permit from the CEC have been delayed.

out beyond 2014 – the near-term period requiring immediate action – toward the end of the 2010 decade.

The combination of legislation passed in the 2009 legislative session, SWRCB adoption of an OTC policy with delayed compliance dates for Southern California generators, and SCAQMD efforts to find air credits from its internal bank to implement AB 1318 and SB 827 mean that the reliability threats presaged by the rapid retirement scenario are less likely than the near-term future of excess capacity through 2014 exemplified by the delayed retirement scenario.

d. Study of OTC Power Plant Replacement by Transmission for Southern California (CAISO, November 2008)

In response to the State Water Resources Control Board (―Water Board") scoping study (February 2008) on the use of coastal and estuarine waters for power plant cooling, the CAISO performed a preliminary transmission analysis to determine the reliability impacts to both the local areas as well as to the zonal systems due to absence of **non-nuclear** OTC thermal generating units.[40]

The system impacts were identified primarily by the transmission studies assuming the retirement of Southern California non-nuclear, OTC plants in 2015 as then proposed by SWRCB staff. A caveat for this preliminary study is that the study results are for bookend assessment on the potential maximum reliability impact on CAISO Controlled Southern California electric system had the OTC non-nuclear thermal power plants shut down due to the State Water Board's required implementation of its policy. Other potential scenarios include potential retrofit, or re-powering of existing OTC generating units. Since plant by plant implementation is not yet known until generation owners submit their implementation plans in response to the State Water Board's OTC policy, the CAISO attempted to study the bookend scenario, recognizing that the study results would show the worst reliability impacts. Another reason for performing system studies of the potential impact of OTC plants retirement in Southern California is because of the relationship between generation in service and the SCIT Nomogram.[41]

i. Reliability Impacts

The following provides a summary of the bulk system impacts due to potential retirement of OTC generating units in CAISO-controlled Southern California grid.

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[40] CAISO, November 2008, Impacts on Electric System Reliability from Restrictions on Once-Through Cooling in California (http://www.caiso.com/1c58/1c58e7a3257a0.html). For the two nuclear plants, the CAISO did not remove them from the November 2008 analyses. This is based on understanding with the SCRCB Staff at the time that design changes and/or additions for the nuclear generating units are subject to the Nuclear Regulatory Commission (NRC) approval.

[41] The SCIT Nomogram is used to ensure reliability operations in Southern California for different import levels. Discussion of the SCIT Nomogram was provided earlier in this Chapter..

a. WECC Path 26 (Midway – Vincent 500kV) exceeded the approved path rating of 4,000 MW by 1,321 MW;
b. WECC Path 66 (California – Oregon Interface or COI) exceeded the approved rating of 4,800 MW by 966 MW;
c. SCIT total flow is exceeded by 4,763 MW beyond its current operational limit of 16,200 MW;
d. Low voltage was identified at many high-voltage (500kV and 230kV) buses in Southern California;
e. Transformers at three 500/230kV substations in Southern California are thermally overloaded: Vincent, Serrano and Valley;
f. Major 500kV lines are thermally overloaded:
   - Midway – Vincent # 2 500kV line
   - Hassayampa – N. Gila 500kV line
   - Imperial Valley – N. Gila 500kV line
   - Southern California is subject to post-transient voltage instability under critical N-1, N-2 of 500kV lines and G-2 of nuclear generating units under summer peak load conditions
g. Southern California is subject to transient voltage dip beyond WECC transient voltage criteria under critical overlapping G-1 (SONGS) and N-1 of 500kV line contingency conditions;
h. Southern California is subject to transient voltage instability with Pacific DC Intertie outage at peak load;
i. Southern California is subject to transient undamping conditions (i.e., transient stability concerns) under various critical double 500kV line outage (N-2) and two nuclear generating outage (G-2) conditions.

ii. Preliminary Estimated Cost Impacts Due to the Need for Transmission Mitigation

CAISO estimated that about $5 billion (+/- 50% accuracy) in transmission upgrades would be required to mitigate reliability concerns identified in the November 2008 CAISO transmission studies on reliability impact on operational restrictions on OTC plants. The following is the summary of potential transmission upgrades, if they are determined to be feasible for construction based on applicable state and local environmental review:

a. Construct two new 500kV substations to serve load in LA Basin – estimated cost $1 billion
b. Re-arrange 500kV lines to new 500kV substations; add two 500kV lines to increase import capability via additions to Paths 66 (California-Oregon Interface) and 26 (Midway-Vincent) – estimated cost $2 billion
c. Other transmission upgrades in Pacific Northwest to facilitate more imports into California – estimated cost $1 billion
d. Add more dynamic reactive support to Southern California area – estimated cost $300 million
e. Mitigate local transmission overloads – estimated cost $150 million

f. Construct new 500/230kV substation in the Greater Bay Area - $500 million

The above are significant transmission upgrades that may turn out to be infeasible for construction from applicable state and local environmental review. In addition, more costs would incur subject to WECC review and requirement of mitigation of major intertie paths that could provide additional import capability to CAISO-controlled grid.

iii. Other Non-Quantified Impacts

The following impacts were not quantified due to limited time in completing the transmission studies. These were to be evaluated at a later date:

a. System Resource Adequacy impacts;
b. Operational requirement impacts for 20 percent and 33 percent Renewables Portfolio Standard (RPS) such as regulation, ramping, etc. The operational impacts (i.e., regulation requirement) due to implementing 20 percent RPS mandate were evaluated and included in the 2007 CAISO's ―Report on Integration of Renewable Resources" (http://www.caiso.com/1ca5/1ca5a7a026270.pdf).

e. Summary of LADWP Transmission and Repowering Plans (LADWP)

This subsection concerning LADWP is drawn from published LADWP studies and discussions with CEC staff. There are no published LADWP studies that compare with those published by the CAISO.[42]

According to the utility, almost all the existing in-basin gas-fired capacity, including the OTC units, is needed for local reliability. These needs derive from the configuration of LADWP's transmission system, specifically the radial nature of the western and southern parts of the system. Table II-3 reports the LADWP portion of each plant's capacity which is required to meet local reliability needs.

[42] According to section 3.B(3) of the SWRCB adopted OTC policy, LADWP will annually provide a reliability report to the SWRCB beginning December 31, 2010.

Table II-3. Power Plant Capacity and Amounts Required to Satisfy System Reliability Needs, LADWP

Facility	Capacity (MW)*	Required Capacity (MW)**
Harbor	466	463
Haynes	1,584	1,565
Scattergood	795	793
Valley	576	326
Total	3,421	3,147

*Net maximum plant capability, 2007 Final Integrated Resource Plan
** *Power System Reliability Overview*, presentation at the Committee Workshop on the Potential Need for Emission Reduction Credits in the South Coast Air Quality Management District, California Energy Commission, September 24, 2009

f. Scenario Analysis Tool to Evaluate OTC Scenarios (Energy Agencies, June 2010)

CAISO and the State energy agencies (CEC and CPUC) have been working to create a Load and Resource Scenario Analysis Tool to guide assessment of the impacts of the State Water Board's policy on OTC plants. This study tool provides an initial screening process for assessing local and system capacity needs out to 2020 within the ISO balancing authority area under a range of possible planning scenarios for the purpose of identifying timeframes when removing gas-fired generation units using OTC may cause shortage of resources in LCAs or in larger regions (i.e., North of Path 26 or South of Path 26) within the CAISO BAA. The CAISO intends to use this tool in connection with annual studies commencing in its 2011 transmission planning process.[43] This screening tool incorporates the latest LCR results available from the CAISO and projects LCR results forward for each LCA using the load forecast adopted by the CEC.

This tool is designed to be able to evaluate, to a certain degree[44], the consequences on local reliability of various demand-reducing or supply-side policies of interest to the state energy agencies, similar to those that AB 1318 requires to be assessed. The user can select from these alternative assumptions to evaluate a hypothetical future demand and resource scenarios. Using this approach, the tool identifies years in which there would likely be a shortage of resources resulting from gas-fired generating units using OTC coming offline to repower, retrofit or retire. The CAISO intends to undertake additional technical studies (i.e., power flow, post-transient and transient stability assessment) for the years in which the tool identifies potential resource shortages.

[43] The CAISO has posted this tool on its website at http://www.caiso.com/1c58/1c58e7a3257a0.html.
[44] This Tool provides an assessment for different load and resource scenarios. However, to complete reliability assessment of transmission system, power flow, voltage stability, and transient stability analyses in accordance with national and regional reliability standards need to be evaluated.

Table II-4 provides the preliminary results from exercising the tool using current understanding of OTC-induced retirements along with some limited retirement induced by other factors. Other settings defining the scenario are set to conservative levels that limit reliance upon new policies and thus maximize the need for new fossil capacity. Although surplus capacity is diminishing as the years move forward, there is a still a margin of excess through year 2014. This analysis assumes no other further unavailability of generation in the analyses.

Table II-4. Sampled Assessment of Local Capacity Requirements in the Los Angeles Basin Load Pocket of the CAISO BAA

Analytic Element	2011 (MW)	2012 (MW)	2013 (MW)	2014 (MW)
1 in 10 Peak Load (latest IEPR, split to Area)	20,164	20,475	20,800	21,064
Transmission improvements that affect LCR	0	0	0	0
LCR	10589	10900	11225	11489
Total Net Qualifying Capacity in area as of 2010 plus new additions from scenarios	11540	11540	11540	11540
Renewable Construction Scenarios with Potential New Renewable Resource Additions	0	0	0	0
Incremental Preferred Demand Side Management	0	0	0	0
Demand Response Resources	986	986	986	986
Retirements	452	452	452	452
Surplus or deficiency (MW)	**1485**	**1174**	**849**	**585**

Source: Scenario Analysis Tool, Huntington Beach units 3-4 retire in 2011 scenario, CEC Staff, 6/11/2010.

3. Overview of Conclusion to be Drawn from Existing Studies

a. Consensus Across the Existing Studies

As shown in Table II-4, current surplus in the Los Angeles Basin is 1,485 MW above the local capacity requirement for 2011. This surplus[45] is projected to be reduced to 585 MW by 2014.

Possible capacity additions during 2010-2014 include, but are not limited to the following:

- The Southern California Public Power Authority's Canyon Power Plant (200 MW) was licensed by CEC in March 2010 and is under construction.
- The Riverside Energy Resource Center (RERC) expansion (96 MW) was granted a Small Power Plant Exemption license in February 2009 and is under construction.
- The three projects with contracts with SCE whose development was affected by the court ruling (Sentinel, El Segundo and Walnut Creek) may come on line by 2014. These total 1,910 MW of new capacity.[46]

While El Segundo, Sentinel, and Walnut Creek have contracts with SCE totaling 1,422 MW (Table II-2), significant delays in permitting have made the projects' original timelines unobtainable. It is unclear how this will impact development of the projects. The above list does not consider renewable capacity that might be developed, including rooftop photovoltaic above and beyond that already included within the load forecast adopted by the CEC in the *2009 IEPR*. Nor does it include combined heat and power (CHP) projects that might be developed, although CHP projects of substantial size may require ERCs.[47]

It is also possible that the LA Basin LCA for the 2012-2014 period may reduce its LCR, once critical transmission additions such as Tehachapi Transmission Project's Segments 4 – 11 are completed. The analysis completed by the CAISO of year 2014 made certain assumptions about transmission project development that are no longer valid (i.e., the delay of in-service dates of the Tehachapi Transmission Project for Segments 4 – 11, and LADWP no longer pursuing its Green Path North Project), but if these projects occur in the future they may reduce LCR needs.

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[45] This assumes no additions, retirements, or transmission upgrades other than the retirement of Huntington Beach Units 3 and 4 (452 MW total) due to license expiration.
[46] Total contract capacity minus El Segundo 3 capacity is 1,422 MW (Table II-2).
[47] The list does not include the Sun Valley and San Gabriel projects (500 and 696 MW, respectively), currently before the Energy Commission. Neither project has a long-term power purchase agreement for its output or a source of ERCs, and thus cannot realistically be assumed to be a likely candidate for construction by 2014.

b. Factors Affecting Needs beyond Minimally Satisfying LCR Requirements

The sufficiency of current resources to satisfy requirements in Southern California in general and the LA Basin LCA in particular through 2014 does not obviate the need to create an enduring mechanism to make ERCs available to the electricity generation sector commensurate with system needs. There are still uncertainties even in the near-tem period out to 2014 and about power plant access to necessary air credits that could make these conclusions invalid.

i. Uncertainties in the 2014 Time Horizon

There are numerous uncertainties that could change the planning assumptions that agency staff have been considering in its assessments. These include:

- While the compliance schedule set forth by SWRCB considers the possibility that the infrastructure needed to replace the existing gas-fired OTC facilities in the LA Basin LCA may not be in place until 2020, the time lags associated with bringing new capacity on line (or repowering existing capacity) require that ERCs be available well in advance of this date. Should reliability needs require that a substantial share of the capacity associated with OTC facilities be largely repowered or replaced with new in-basin capacity, these facilities may have to be shut down and upgraded in a staggered fashion over a several-year period, say 2015 – 2020, in order to comply with the SWRCB policy without threatening reliability in the LA Basin.
- Reserve margins in the LA Basin LCA may be reduced by merchant plant shutdowns on or in advance of the date by which generators must implement interim measures to mitigate the impacts of OTC (2015[48]). Should such measures require substantial capital investment, generators may shut down if they have no guarantee of cost recovery.[49]
  It is less likely that merchant capacity will be built/replaced without a long-term power purchase agreement (or guarantee of construction cost recovery), which, in turn, requires CPUC authorization for utility procurement. Should the 2010 Long-term Procurement proceeding[50] underway at the CPUC yield authorization for the financing of new capacity in the LA Basin LCA in late 2011, project developers will need ERCs in early 2012. Even if such authorization is delayed until the following procurement cycle (2014), the timely replacement of OTC capacity in the LCA would be facilitated by ERCs being available earlier, so that applications before the CEC for the development of in-basin projects will not be delayed.

[48] More precisely, 5 years from the approval of the SWRCB policy
[49] It is unclear whether the CAISO possesses any mechanisms to compel a generator to continue operating if they wish to shut down.
[50] R.10-05-006

- LADWP has an agreement with SCAQMD to repower Units 5 and 6 (565 MW) at its Haynes facility and Units 1 and 2 at Scattergood (358 MW) by December 31, 2013, but is currently negotiating to extend these dates. It hopes to replace the Haynes units with six natural gas-fired combustion turbines by 2014; the environmental impact statements have been approved and on May 4, 2010 , the utility's commissioners approved issuing an Request for Proposal (RFP) for up to $579 million for the design and construction of the units. The utility has also expressed intent to replace the units at Scattergood by 2015, but this may be postponed. [51]

- Units 3 and 4 at AES's Huntington Beach facility may shut down as soon as September 2011. In May 2001, CEC approved an emergency license allowing these units to be refurbished and to resume operations. The license was granted for a ten year period, and currently expires September 30, 2011. AES has petitioned that it be extended until 2020 to enable AES to license and construct replacement capacity at the site. Given the unusual circumstances associated with the existing permit for Units 3 and 4, it is unclear how and whether CEC will grant this request.

ii. Reliance on Rule 1304 Exemptions

At the present time, SCAQMD Rule 1304 exemptions for repowering of existing steam-boiler power plants is the only “source” of air credits for power plants. Clearly this does not allow for new “greenfield” power plants, which presents problems for the competitive development of the infrastructure that may be needed to achieve full compliance with the SWRCB policy. It is unclear whether these sites are appropriate from the perspective of the integration of intermittent renewable generation, while reliably serving loads in the LA Basin. While SCAQMD's Rule 1304 exemption allows existing facilities to be repowered, it effectively limits development of merchant facilities in the basin to the owners of existing facilities: AES, NRG and Reliant. As owners of existing electric utility steam boilers in the area under SCAQMD jurisdiction, they may develop replacement capacity in the form of combined cycle or advanced gas turbines at a far lower cost than parties who must buy ERCs on the open market.

E. Long-Term Need for Capacity Additions by Type of Generation

1. Introduction

This section describes some important considerations for assessing needed future capacity additions that the near-tem studies previously described do not address. Among these are:

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[51] The 2015 date is from LADWP's 2009 Integrated Energy Policy Report filing with the California Energy Commission. In its September 30, 2009 comments on the SWRCB policy, a date of 2017 is put forth.

- Evaluating needs out to 2020 or beyond to link up to overall state energy policy and GHG emission reduction goals
- Addressing the uncertainties that exist concerning both uncontrolled influences on electric system need as well as whether policy objectives will be satisfied
- Evaluating the multiple perspectives that could lead to capacity requirements for SCAB
- Translating power plant additions by type into air credits needed to permit power plants

<u>Time Horizon</u>: Although AB 1318 does not define a time horizon for the reliability assessment, ARB and the supporting agencies believe that one has to look ahead to at least 2020 in order to understand the need for new fossil power plants in the SCAB and the consideration of new air permitting mechanisms to enable licensing and construction of specific units compatible with the broad considerations required by AB 1318.

<u>Uncertainty</u>: There are numerous uncertainties that affect a long-term need assessment. Some are the usual uncertainties that any planning assessment must confront – economic conditions influencing base electricity demand, fuel prices influencing choice of power plant selection, etc. Others involve policy decisions or interpretations of policy that are as yet unclear. Many are common to any region of California, but others seem to either be unique to, or highly concentrated in, Southern California.

<u>Rationale for Capacity Additions in SCAB</u>: There are at least three considerations that will affect the amount and type of power plant development that must be included in long-term assessments. First, LCRs provide a fundamental constraint on how much capacity must be maintained given load forecasts and the availability of existing fleet. Second, renewable development increase the amount of flexible capacity that must be available to the overall system, yet OTC mitigation policies are leading to the loss of much of the flexible units that exist today. Substantial flexible resources must be added in parallel with the loss of OTC units and the expansion of renewable capacity. Finally, the extent to which major changes in the configuration of the transmission system in Southern California are feasible and cost-effective in allowing for a potential net reduction in in-basin capacity.

<u>Air Credits Associated with Capacity Additions</u>: Although describing the need for capacity additions to satisfy reliability might be sufficient for electricity reliability purposes, such analysis is not enough for this project. From the AB 1318 perspective, the need for capacity is only an input into the subsequent step of addressing the air permitting issues; therefore, the electricity assessment has to characterize the level of usage and thus the type of power plant that is likely to be needed.

The balance of this section will address each of these four considerations in greater depth.

2. Long-Term Planning Horizon

The energy agencies commonly plan major infrastructure out five to ten years into the future. This reflects the reality of developing conceptual plans for specific projects, integration of such plans into overall planning processes, permitting and licensing activities to the extent required, construction of the project itself once approved, and integration into the existing infrastructure. Of course, transmission lines and power plants typically last 30—50 years. Therefore, ten years into the future is the minimum “look ahead” for reliability and other requirements justifying power plant development in the SCAB.

Although LCR studies have not traditionally been conducted for the period 5-10 years into the future, many of the elements needed for such studies exist or can be adapted to provide the inputs for such studies. The severe stresses created by OTC mitigation policies have already resulted in the CAISO committing to conduct certain transmission planning studies for this period.[52] The requirements of AB 1318 add to the need for extending the more in-depth studies commonly reserved for the near-term out to the ten-year time horizon.

Another rationale for examining requirements out at least to 2020 is that most of the major changes to the system are not expected to be fully implemented until 2020 or a few years later. The energy agency commitment to 33 percent renewable energy requirements gradually escalates from the present 20 percent until 33 percent is achieved in year 2020. SWRCB’s OTC mitigation policy does not call for most Southern California OTC power plants to comply until 2020. While 2020 is a compliance date, actual implementation needs to be phased in to protect reliability. Thus, major changes in the electricity system now anticipated to be achieved about 2020 require new power plants and transmission lines to be permitted, financed, and construction begun in the next few years. Air credit requirements will also be changing dramatically at the end of this decade continuing into the next.

3. Uncertainty

There are numerous uncertainties that affect a long-term need assessment. Most of these are obvious – the expected demand for electricity, the degree to which baseline demand might be reduced if additional load-reducing policy measures are pursued and effectively implemented, the degree to which renewable development aided by transmission system upgrades reduce the need for in-basin capacity, and the operational needs to effectively integrate the renewable mandates, etc. Other sources of uncertainty are unique to Southern California, or much more important in Southern California, such as the pace of OTC power plant replacement, the choice by power plant owners between retirement and repowering, the fate of other power plants in the basin that are also old and eventually needing to be replaced, the degree to which coal dependent municipal utilities choose to develop natural gas-fired capacity in the basin

[52] CAISO, 2011 ISO Transmission Plan: Final Study Plan, pp. 23-25, march 2010. See http://www.caiso.com/276a/276af0692d6e0.pdf

as a GHG emission reduction strategy. In addition, due to the concentration of industry in Southern California, the extent to which a CHP strategy, such as the one embodied in ARB's Assembly Bill 32 (AB 32) Scoping Plan[53], is realized will have much larger impacts in Southern California than in other areas of the state.

a. Uncertainties Common to All Regions

Some of the uncertainties discussed above are common to all regions and not necessarily especially unique to assessments of SCAB. These include: (1) base line load growth, (2) reductions in load growth due to effective implementation of additional demand-reducing policy initiatives, and (3) the need for flexible, dispatchable resources to accommodate the variable and intermittent production from most renewable resources. Each of these is discussed in greater detail below.

i. Peak Load Growth

Peak load growth in the LA Basin LCA affects the need for local capacity on approximately a MW-for-MW basis. The expected growth in peak loads in the LA Basin over the next ten years and beyond will be largely a function of economic and demographic variables. Holding the impact of load-modifying policies (energy efficiency and demand-response programs) constant, differences in the rates of economic and population growth over 10 years can be expected to affect peak loads by ± two percentage points, or ± 450 MW for the 1-in-10 year peak load for the Los Angeles Basin LCA. The corresponding value for the LADWP control area is ± 150 MW.

ii. Energy Efficiency and Demand Response Programs

California has committed to minimizing the cost of meeting electricity demand and environmental goals through substantial increases in funding for energy efficiency programs. The efficacy of these programs and the extent to which their impacts are already accounted for in the Energy Commission's most recent demand forecast are subject to substantial uncertainty; this topic is the subject of a recent staff paper.[54] At one extreme, the entire impact of uncommitted energy efficiency programs is already embedded in the CEC's peak load forecasts for the LA Basin LCA and the LADWP control area. At the other, uncommitted energy efficiency programs reduce the peak load in 2020 by 2,687 MW in the former and 616 MW in the latter.

Demand response and interruptible load programs are not considered in calculating the capacity needs in the LA Basin LCA, but can be used to meet the resulting resource

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[53] Air Resources Board, *Climate Change Scoping* Plan, December 2008.

[54] See *Incremental Impact of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*, California Energy Commission (CEC-200-2010-001-CTF; May, 2010). The impacts on peak loads in the Los Angeles Basin LCA were based on the LCA's share of the statewide peak load. The impacts on LADWP peak loads were based on materials submitted to the Energy Commission by the utility for the 2009 Integrated Energy Policy Report proceeding.

adequacy requirements imposed upon LSEs.[55] Accordingly, uncertainty regarding the capacity embedded in these programs translates into uncertainty regarding the (residual) gas-fired generation needed to maintain local reliability. A conservative estimate of the capacity associated with such programs in the LA Basin LCA in 2020 assumes that current levels (986 MW) are maintained.

iii. Additional Resources for Renewable Integration

As the utilities, other LSEs, and generation project developers move toward implementation of the RPS by 2020, it is clear that the variable and intermittent production patterns of wind and central solar (the leading renewable for large scale development) will require flexible, dispatchable resources to operate the system reliably. At the moment, gas-fired combustion turbines and newly emerging very flexible combined cycle power plants are the leading technologies to play this role. The amount and location of these resources is partly dependent upon the location and generating technology characteristics of the renewable fleet, both of which are still considerably uncertain. The current practice of the energy agencies is to examine alternative scenarios of renewable build out over time, and search for common conclusions that can be implemented in the near-term.

b. Uncertainties Unique or Especially Focused in Southern California

Although some aspects of energy use and air quality problems in Southern California are already known, there are additional uncertainties confounding long-term assessments that will be encountered in reliability assessments. These include: (1) highest concentration of OTC power plants in the state, (2) other aging power plants that will eventually need to be replaced or repowered, (3) a concentration of heavy industry that could support an emphasis on CHP projects to increase efficiency in combustion of natural gas or production byproducts, and (4) the legacy of municipal electricity system development that has two independent balancing authority areas within a single air shed. Each of these is discussed in greater detail below.

i. State Water Resources Control Board OTC Mitigation Policy

A major source of uncertainty regarding future ERC needs in the LA Basin is the potential need to retire existing capacity pursuant to the recently-adopted policy SWRCB on OTC and replace it with dispatchable gas-fired capacity located in the basin. Table II-5 lists the power plants subject to this policy. The gas-fired capacity using OTC in the LA Basin LCA totals 4,927 MW. If the OTC generating units are to come off-line for implementation of the SWRCB policy, either for retrofit, re-powering, or

[55] The LCA peak load that is used in studies to estimate the local capacity requirement is not reduced by the MW obtainable through these programs. LSEs may ascribe a peak capacity value to these programs and use them to satisfy the local resource adequacy requirements imposed upon them by the California ISO, thus reducing their need to procure (supply) resources.

to permanently retire, the aggregated amount of these plants would represent a reliability risk in meeting the minimum internal generation requirement for serving load in the LA Basin area.

Table II-5. OTC Power Plants in Southern California

Name	MW	Owner	Control Area	LCA/Sub-area	SWRCB Compliance
El Segundo	670	NRG	CA ISO	LAB/Western	2015
Harbor	227*	LADWP	LADWP		2015
Haynes	1,606	LADWP	LADWP		2019
Alamitos	2,010	AES	CA ISO	LAB/Western	2020
Huntington Beach	904	AES	CA ISO	LAB/Western	2020
Redondo Beach	1.343	AES	CA ISO	LAB/Western	2020
Scattergood	803	LADWP	LADWP		2020
San Onofre	2,246	SCE	CA ISO	LAB/Western	2022
Total	9,809				

*only a share of the 466MW Harbor facility utilizes OTC

Three factors affect the need for capacity in the CAISO portions of SCAB. The most straightforward is the amount of capacity that has to be located in the LA Basin LCA. Short term studies rely upon a particular definition of the LCA, and amounts of capacity, that preliminary, long-term studies indicate could change radically. Second, renewable integration may impose either additional needs for generation or clarify the type of generation needed and its likely operating pattern. Third, system stability as reflected by extending the operational perspectives of the SCIT Nomogram into the planning horizon may also provide a constraint on the minimum amount of capacity that may be needed.

The SWRCB policy on OTC may require the replacement of LADWP units at Haynes, Scattergood and Harbor totaling 2,636 MW. As noted earlier, LADWP intends to replace Units 5 and 6 at Haynes and Units 1 and 2 or 3 at Scattergood. This leaves the Units 1 and 2 at Haynes, Unit 5 at Harbor and the remaining unit at Scattergood to bring into compliance.

LADWP has stated that almost all existing capacity is needed to meet local reliability. While transmission upgrades could reduce the amount of capacity that is needed, the utility claims that such upgrades are "not viable."[56] It is perhaps possible that the Haynes combined cycle could be brought into compliance without modifications that require ERCs, until such time that LADWP submits a compliance plan for Haynes (due six months after approval of the SWRCB policy) and this plan is approved, the amount of capacity requiring replacement will be uncertain. It is possible that, absent transmission upgrades, ERCs will be needed to replace all of the OTC capacity in the LADWP control area.

[56] LADWP Comment Letter on OTC Policy, September 20, 2009, p. 3.

ii. Retirement of Aging, Non-OTC Power Plants

In addition to the OTC facilities that may retire or require replacement in the course of compliance with the SWRCB policy, there are six aging facilities in the Los Angeles basin that are nearing the end of their service lives between 2015-2020. These are shown in Table II-6. Four of these, totaling 430 MW, are peaking facilities operated by public utilities that will have strong incentives to replace them to address local capacity needs. Long Beach, mothballed in 2005 and restarted in 2007 in response to perceived shortages of capacity in the LA Basin, has a contract with SCE that expires in 2017. One of Etiwanda's two units is under contract with SCE through the end of 2010, the other through the end of 2012.

Table II-6. Aging, Non-OTC Power Plants in Southern California

Name	MW	Owner	Control Area	LCA/Sub-area
Broadway	75	Pasadena	CA ISO	LAB/Western
Etiwanda	640	Reliant	CA ISO	LAB/Eastern
Glenarm	45	Pasadena	CA ISO	LAB/Western
Grayson	210[1]	Glendale	LADWP	NA
Long Beach	260	NRG	CA-ISO	LAB/Western
Olive	110	Burbank	LADWP	NA
Total	**1,340**			

*does not include Unit 9, installed in 2003

iii. Combined Heat and Power

ARB's AB 32 Scoping Plan calls for the development of 4,000 MW of CHP in California during the coming decade in order to realize state GHG emission reduction goals. A recent study commissioned by the CEC estimated a market potential of nearly 6,000 MW statewide given sufficient incentives, almost 2,000 MW of which is located in the LA Basin.[57] If this generation is made available to the BAAs[58], CHP developed in the LA Basin could contribute to meeting local capacity needs and thus offset the need to develop pure generation projects. CHP units less than 25 MW in size could be put in place without requiring PM10 ERCs.[59, 60] While this would appear to possibly leave total

[57] Darrow, Ken, Bruce Hedman, Anne Hampson. 2009. *Combined Heat and Power Market Assessment.* California Energy Commission, PIER Program. CEC- 500- 2009- 094- D. 1,580 MW in the Los Angeles Basin LCA, 403 MW in the LADWP control area.
[58] To be considered as contributing to local capacity requirements, CHP projects would have to be generating or available for dispatch during periods of high demand.
[59] SCAQMD, Rule 1304 exempts new or modified sources from offset requirements if they will emit less than 4 tons per year of VOC, NOx, SOx, and PM10.
[60] Estimated using example 9500 HR combustion turbine generator or reciprocating engine and applicable PM10 emission rate to determine size corresponding to 4 tons per year of PM10.

LCRs, and thus ERC needs, unchanged or reduced, increases in fuel combustion due to in-basin CHP development may frequently require ERCs of entities that do not currently own them and that, unlike operators of existing power plants, are not eligible for Rule 2004 exemptions, substantially increasing the need for ERCs from sources other than the SCAQMD account. Furthermore, realizing large amounts of capacity from CHP in the LA Basin will likely require very large projects that will operate at capacity factors at or in excess of 85-90 percent, exporting substantial amounts of energy to the transmission grid. These capacity factors are far higher than the 5-10 percent at which pure generation (peakers) might operate, increasing the number of ERCs that are needed by the electricity sector. The development of the large amount of in-basin CHP implied by the AB 32 Scoping Plan, is highly uncertain, depending not only upon market conditions (e.g., the level of economic activity, the retail cost of electricity relative to the cost of installing and operating CHP) but also on the incentives offered CHP by purchasers of wholesale energy (e.g., utility commitments to purchase energy generated in excess of on-site needs). Negotiations involving CPUC, CHP developers, and the investor owned utilities (IOU) are currently underway and may yield new CHP for inclusion in IOU portfolios by the end of the year. It is possible, if not likely, that these negotiations will yield CHP capacity totals well below the levels targeted by ARB. Furthermore, LADWP does not have an obligation to purchase energy from CHP developers; there are no public filings or statements by the utility that indicate an intent or commitment to do so.

iv. Legacy of Municipal Electric System Development

The SCAB happens to have the LADWP BAA[61] and the Southern California portion of the CAISO BAA within its geographic scope. Each of these systems is assessed, and develops plans, independently. Conceptual tradeoffs between the amount of local generation and increasing the transmission connections between these two systems are constrained by these jurisdictional realities. Even if there are technical options to reduce local generating capacity by cross-system transmission enhancements, it is highly uncertain whether these could be pursued. There are jurisdictional, regulatory, and tax reasons for the status quo.

c. Uncertainty About San Onofre Licensing

An overarching uncertainty that affects power plant development in Southern California is whether San Onofre Nuclear Generating Station (SONGS) will be licensed and operated beyond 2022. Not only is this a very large facility generating lots of energy by virtue of its high capacity factor, it is a key element of the stability of the entire Southern California transmission system. SONGS utilizes OTC and must thus comply with the SWRCB policy; it has a compliance deadline of 2022, coinciding with the expiration of its operating license. Should compliance only be attainable by shutting down the facility, which plays a key role in ensuring reliability in Southern California, a share (possibly substantial) of its 2,254 MW of capacity would likely need to be replaced with

[61] LADWP is the largest municipal utility in the United States. Burbank and Glendale are small systems typical of numerous municipal electric utility departments of city government within California.

dispatchable gas-fired generation in the LA Basin LCA, increasing ERC needs for the electricity sector. The size of this share would depend upon the configuration of the entire Southern California system (and beyond): loads, the quantity, type, location and operation of generation, and upgrades to the transmission grid.

For purpose of this report, SONGS will be presumed to be relicensed and to continue to operate beyond its current date of 2022. An alternative assumption would require a completely new assessment of virtually everything else that is planned or already in process in southern California. At least for this report, the effort to conduct two versions of this analysis – with and without SONGS – is beyond the scope of the AB 1318 project team.

4. Analytic Challenges in Identifying Capacity Needed for Locational, Intertial, and Load-Following Purposes from Gas-Fired Generators in Southern California

There are at least three rationales for locating dispatchable, gas-fired resources within the SCAB: (1) capacity need to satisfy LCA requirements within the geographic scope of SCAB, (2) capacity needed to provide inertia so that the overall Southern California electricity system remains stable under major outage conditions to comply with national and regional reliability standards, and (3) flexible capacity that can be operated as needed to integrate variable and intermittent production from renewables into the system while satisfying customer load and reserve requirements. Each of these concepts was introduced in Section C of this chapter. In addition, to some extent the capacity required for of the first two of these three purposes can be diminished somewhat by feasible and properly designed upgrades to the transmission system. In this section, discussion of these same factors emphasizes the analytic challenges in developing estimated requirements out as far as year 2020.

a. Local Capacity Area Requirements

Earlier in this section, CAISO studies for 2011 and for 2012-2014 were reviewed. At this time there are no regular studies for the ten year time horizon believed to be important to satisfy the requirements of AB 1318. Discussion of the results for year 2014 of CAISO's 2012 – 2014 study indicated that changes in circumstances makes the published results misleading. Reality has intervened so that the assumptions made about 2014 are no longer valid. This is an important lesson – conceptual projects which, if developed, could have important impacts on LCA requirements may not actually be developed, or developed on the schedule assumed in planning studies. One of the challenges for this effort is that the power flow studies to understand the ramifications of proposed transmission upgrades are labor intensive. Conducting enough studies to cover a range of uncertainties accumulates into major resource commitments – whether performed by internal agency staff or contractors. Choosing a limited number of future conditions to explore using these techniques is the proposed way of addressing this problem. Energy agency staff has attempted to reduce the scale of this problem by developing a —scenario analysis tool" that can explore combinations of input assumptions out to 2020 to identify critical years for capacity shortfalls. Armed with these results, more intelligent choices can be made about which years to evaluate more intensively with power flow modeling techniques.

b. Inertia from Generators to Stabilize Grid Voltage and Frequency

Earlier in this section, the SCIT Nomogram was introduced as a tool for facilitating the power plant scheduling process to ensure that imports into Southern California were appropriately matched with on-line generators in Southern California to assure that contingencies that might cause grid stability problems were minimized. This operational perspective is very difficult to extend into the planning time horizon, since many imports are scheduled opportunistically to take advantage of the lower cost of energy from resources outside of Southern California in contrast to those located within Southern California.

A challenge for extending an analysis of SCIT-related stability issues into the 2020 planning horizon is that as OTC mitigation policies cause OTC power plants to retire, or to be scheduled down for extended periods if they are being repowered, lower capacity available within Southern California means lower amounts of imports can be accepted from outside flowing into Southern California.

Unfortunately, many of the resources preferred by existing policies – rooftop photovoltaic, central station photovoltaic, and wind – have much lower inertia values per unit of capacity than do the steam boiler/generators that have been configured using OTC technologies and that are likely to be replaced. Modern combined cycle power plants do not have such penalties, but they emit GHG gases and criteria pollutants, which require air credits to be sited.

c. Capacity to Integrate Renewables and Satisfy Demand

The most prominent renewable technologies – wind and central solar – have variable production levels across the months and seasons of the year, and even across the hours of the day, that do not readily match the pattern of demand imposed by customer loads. Solar resources located in the desert with minimal cloud cover have predictable patterns of electricity production based on the known solar illumination varying each day of the year from peak on June 21 to minimum on December 21. Different central solar technologies may be more or less susceptible to production declines due to short term transient cloud cover. Wind generator output is much more intermittent, and historic records of wind patterns at the site of wind projects may not fully reveal the variability that may be experienced in each hour of the year. Analyses of historic production patterns can help to understand the expected size and pattern of the gap that dispatchable resources must satisfy. Thus, predicting wind output is much more difficult than for central solar. Matching projected wind and central solar development with load patterns requires supplemental resources that can be readily dispatched to ―fill gaps.” Several major studies have been conducted trying to develop an estimate of the size of this concern and to better understand the nature of the “gaps” associated with various patterns of renewable buildout that could equally satisfy the 33 percent of renewable energy goal, but have quite different supplemental requirements to assure customer demand is served reliably.

CAISO has a major study underway that is attempting to identify the nature of the dispatchable resources required to accommodate the 33 percent renewable energy by 2020 goal that has been established by the energy agencies and that may be converted into a requirement by statute of ARB regulations. This study is now somewhat behind schedule, but is anticipated to be available in the second half of 2010 to provide a definitive answer to both the amount and type of resource required, but also indicate something about the location within the grid for these dispatchable resources.

d. Interaction between Generation Requirements and Transmission Developments

LCR needs between 2010 and 2020 are strongly correlated to feasible transmission developments in the highly urbanized areas of Southern California. In some instances, new transmission lines or upgrades to existing ones may reduce the capacity required in specific locations and substitute capacity generated elsewhere. While these substitution possibilities do not alleviate the need for generation development, shifting the location of new generation, if feasible, may better accommodate the constraints on air credits in SCAB.

There are currently several transmission projects in the middle of permitting or construction that will affect the LCR needs in the LA Basin LCA. Large projects, such as Tehachapi Renewable Transmission Project (particularly segments 4-11) would, if developed, reduce the LCR needs in the LA Basin LCA significantly. In addition, the CAISO presentation at CEC’s *2009 IEPR* workshop on potential needs for ERCs in the SCAQMD area identified some preliminary implications of several additional transmission lines that, if constructed, would modify the size and shape of the Los Angeles LCA.[62] Although preliminary, these results demonstrate the interaction between transmission system development and the consequences for generating capacity required in specific locales. Projects under development (such as Sentinel) or currently operational that currently serve LCR needs for the LA Basin may no longer serve LCR needs if projected transmission developments become operational. The challenge is to construct studies that can facilitate a comparison between generation and transmission requirements at a level of granularity useful in making repowering versus new greenfield plant, and generation versus transmission project, so as to define the minimum amount of capacity that must be permitted in SCAB. However, the minimum amount of generation additions identified by one study for a particular future year will be subject to change due to updates in load growth expectations and electrical system changes that future studies will consider.

[62] CAISO, presentation by Catalin Micas at *2009 IEPR* workshop, September 24, 2009. See http://www.energy.ca.gov/2009_energypolicy/documents/2009-09-24_workshop/presentations/03_CAISO-Micsa_LA-Basin_LCR_long-term2.pdf

5. Translating Capacity Additions by Plant Type into ERC Requirements

The preceding sections illustrate the substantial uncertainty regarding the long run need for new and replacement gas-fired capacity in the LA Basin. The quantity of ERCs needed per MW for that capacity is uncertain as well. The quantity of ERCs required for a given amount of new or replacement gas-fired capacity in the LA Basin can vary as a result of two factors. The first is the expected emissions from that capacity, which, for PM10, is a function of the output/amount of fuel burned by the capacity. The second is the relationship between the expected operation of new and replacement facilities and the quantity of ERCs required.

Reliability studies, such as those which are conducted to estimate LCRs, do not generally consider the necessary operating characteristics of required capacity, nor yield estimates of their expected annual output. It has been generally assumed that much of the dispatchable capacity needed in the LA Basin to replace OTC units, integrate intermittent renewables, and meet local reliability requirements will operate at relatively low capacity factors. The share of new capacity that provides purely peaking services, however, will be influenced by such factors as the composition of renew able energy in the state's portfolio and the need for electrical inertia from in-basin units. Large amounts of intermittent wind energy, for example, will increase the need for gas-fired generation to provide ramping services (increasing output in the morning, when loads are increasing, while wind generation is falling). Maintaining the state's import capability may require that in-basin units operate under certain load conditions in order to provide inertia. Large amounts of inertia are provided by the OTC steam turbines that may be retired as a result of the SWRCB policy; a large share of this will have to be replaced.

The need for ERCs will also be affected by the relationship between plant emissions and ERC requirements. ERC requirements for PM10 in SCAQMD are currently based on worst-month scenarios, extrapolated over the entire year. These scenarios must assume such transient, adverse events as the prolonged outage of major power plants and/or transmission line and heat storms. As a result, ERC requirements tend to be very high for baseload, load following and peaking power plants. The discrepancy between ERC requirements and actual emissions has grown as increases in renewable generation reduce the amount of energy needed from gas-fired power plants. Baseload power plants can reasonably expect to operate – or be needed in the event of the failure of a major in-basin plant or transmission line - at full output for most of the hours in July and August. They operate at 50-60 percent capacity factors much of the rest of the year, and at even lower levels during the spring hydro runoff.[63] Similarly, load-following units, which might operate at very high capacity factors during the summer in low hydro years and in the event of the prolonged outage of one or two major baseload units, may operate at very low capacity factors during the remainder of the year. Peaking units,

[63] CEC, *Impacts of AB 32 Scoping Plan Electricity Resource Goals on Natural Gas‑Fired Generation*. California Energy Commission. CEC‑200‑2009‑011, pp. 19-21.

which must be able to operate for 8-12 hours every weekday during a summer month in the event of a heat storm, may not operate at all the rest of the year. A revision of air credit requirements to more accurately reflect expected emissions of proposed plants over the entire year would greatly reduce the electricity sector's total need for these credits.

F. Studies Needed to Provide a Final AB 1318 Report in Fall 2011

1. Background

The reliability study required by AB 1318 presents several key issues. First, the required assessments of a large number of preferred energy policies goes well beyond what is normally addressed in electric reliability studies, as the term is used in the electricity industry. Several other types of analyses will be required, such as operational requirements needed to integrate renewable generation. Second, addressing reliability for the SCAB presents technical challenges since this region is defined by the geographic boundaries of an air shed used for criteria pollutant studies and regulations, not for electrical system assessments. It encompasses all of the LADWP balancing authority area, but only a portion of the CAISO balancing authority area.

The overall objectives for the studies described here are:

- Determine the amount of fossil capacity that must be located in the SCAB to satisfy national, regional and ISO reliability standards, such as LCRs and regional needs, for each year out to 2020;
- Determine the amount of fossil capacity that must be located in the SCAB to satisfy national, regional and LADWP reliability standards, for each year out to 2020;
- Determine the amount and type of capacity needed to support renewable integration that must be located in the SCAB;
- Examine future generation requirements in sufficient detail to establish the amount of air credits required for new fossil generation.

Completing the studies identified below should result in an identification of the amount and type of capacity that must be added in the Southern California area that require air credits appropriate to the SCAB. Satisfying existing NERC/WECC reliability standards and other applicable reliability requirements of CAISO and LADWP is a foundation for the minimum amount of capacity, while energy policies and other environmental policies will guide how best to modify load through incremental energy efficiency and other demand-side policies, and to satisfy some portion of capacity requirements with non-fossil generation. A key dimension of this study is the need to distinguish between capacity requiring offsets or other air credits (i.e., fossil generation) and capacity that does not (i.e., central solar and wind). Further, unlike the typical reliability study, this effort may need to distinguish the type of generation needed to integrate State-mandate renewable targets. For example, simple combustion turbines and combined cycles have quite different annual emission profiles, and thus air credit requirements.[64] Thus, as described more fully in the air permitting chapter, a parallel effort to this reliability study is an effort to examine what changes to air credit regulations of SCAQMD and state/federal laws might be required to allow incremental fossil power plant capacity to be permitted while not adversely affecting attainment of air quality standards.

2. Specific Studies

There are two broad categories of studies that appear relevant to the AB 1318 Reliability Study – planned studies already underway due to prior commitments for other projects, and new studies required to address the specific requirements of AB 1318.

a. Planned Studies Already Underway

There are two studies already underway in support of other purposes that appear to be relevant to the information needs of the AB 1318 report:

- CAISO analysis of OTC retirement, repowering, refurbishments in support of determination of a final compliance schedule for the SWRCB OTC policy, and
- CAISO evaluation of the operating characteristics of resources needed to handle the intermittency requirements of the 33 percent renewable generation target for 2020 established as a goal by the energy agencies.

i. OTC Studies within the 2011 TPP

The 2011 TPP includes use of the scenario analysis tool described above. Essentially the scenario analysis tool allows a variety of scenarios to be quickly assessed. Alternative assumptions for the demand-side policy initiatives (incremental energy efficiency, CHP, distributed generation, demand reduction measures, etc.) can be evaluated out to 2020. The inter-agency OTC Team that developed the scenario analysis tool intends that it be used to identify a few key combinations of load and resources that will create adverse conditions. These will then be investigated using more complex methods, such as power flow and stability assessments, that will inform understanding of the timing of needed resource additions located in load pockets where the existing transmission system necessitates local generation. It may be possible that transmission upgrades, if feasible, along with potential replacement power that may be located outside of the load pocket, can reduce some level of fossil generation requirements inside the load pocket, as long as transient and voltage stability are maintained. Such transmission upgrades may allow imports to play a greater role, and, thus, shape how much new fossil capacity is required, of what type, and in what year.

[64] A traditional reliability study does not encompass substantial portions of the analyses described here. They would be provided by several additional analyses, such as operational requirements for integration of renewable generation, using other techniques and sources of data. However, since AB 1318 refers to the collective package of assessments as a reliability study, all of these efforts are described in this draft study plan.

Clearly these are the ingredients needed to understand the extent to which changes in the methods to authorize air credits for new power plants may be warranted.

The OTC study needs to assess each year from 2011 through 2020 in order to properly advise SWRCB as to the specific year in which an individual OTC power plant can be shut down for retrofit or retired. Unlike many other regulations, the proposed OTC policy of the SWRCB staff does not have fixed compliance dates. Rather, the nominal dates in the proposed policy are subject to change based on the advice of the CEC, CPUC and CAISO.[65] Thus the study needs to examine a range of scenarios for each year so as to properly advise SWRCB about the timing constraints on temporary or permanent shutdown schedules. As noted in the stakeholder discussion, this differs from the majority of the 2011 TPP draft Study Plan in which years 1-5 and 10 will be examined. For the OTC scheduling purposes, years 6-9 are more likely to be of interest than years 2-4, since it is virtually impossible to plan for and construct a new power plant or new transmission in this time period.

In the final 2011 TPP Study Plan, the CAISO announced that the full set of combinations of multiple scenarios and annual assessments cannot be completed in this timeframe and with the resources available as part of the 2011 TPP. The CAISO identified a three phase staging of the effort that leaves examination of the load reducing policy measures (i.e., incremental demand response, etc.) outside of the effort that can be completed in the 2011 TPP timeline. Since the OTC purpose covers the entire state, and the AB 1318 effort is focused on Southern California, the cases investigated for OTC purposes cannot focus exclusively on those of most interest from an AB 1318 perspective. Given the narrowing of the scope of what can be accomplished in the 2011 TPP, supplemental resources will be required to “fill in” some of the combinations that represent “sensitivities” around a base case, such as low and mid net load scenarios on the schedule proposed by ARB management. This supplemental effort is described more fully in proposed Study C.3.

ii. 33 Percent Renewables Integration Study

An analysis of the integration requirements for a high renewable future is in process by the CAISO in conjunction with a team of other entities. It is being completed in stages. It is relevant to the issues of dispatchable fossil power plant capacity that must be built in the SCAB, because the intermittency characteristics of renewables require greater dispatchability from the balance of the system than would be required if more conventional resources had been developed. So as the proportion of intermittent renewables grows through time, the overall requirements for ramping and INCing and DECing capacity will increase.[66] Limited scenario investigation is seeking to determine

[65] SWRCB issued a proposed OTC mitigation policy on March 23, 2010. On May 4, 2010, the Water Board adopted the proposed mitigation policy. The policy must still be reviewed and approved by the California Office of Administrative Law.
[66] Ramping, INCing and DECing refer to specific characteristics that the system must have in order to be able to continually balance loads and resources. Power systems have also had these requirements since load fluctuates from hour to hour across the day. These requirements are perceived to increase as some

how sensitive these requirements are to the type and location of renewable build out. Since the old OTC power plants represent a sizeable portion of the existing system capacity that possess these operating characteristics, and these power plants are likely to be retired or repowered into other configurations as a result of the SWRCB's proposed OTC mitigation policy, it is expected that a considerable amount of new dispatchable fossil capacity will have to be developed. A portion of this must be located in the SCAB. It is unclear whether the dispatchable capacity conclusions this study plans to deliver are narrowly enough focused to determine what needs to be located within SCAB versus a more general statement of requirements. If Study B.2 does not reach this level of specificity, then a supplemental effort to determine the specific portions needed within SCAB may be required.

b. New Studies Required

There are four additional studies that energy agency technical staff of CEC, CPUC, and CAISO believe are required to satisfy the objectives of the AB 1318 Reliability Report. These are needed because the charter of AB 1318 is broader than that required to assess OTC capacity retirement/replacement, and must address the issue of the amounts of air credits associated with needed capacity additions.

i. Expanding the Scope of the Scenario Analysis Tool

This study extends the energy agencies' scenario analysis tool to also encompass the LADWP balancing authority area (LADWP, Burbank, and Glendale). The plain language of AB 1318, which stipulates the study scope as reliability for the SCAB, requires extending beyond the CAISO load pockets to reflect LADWP BAA load pockets. The alternative cases being examined in the CTPG process do not address the consequences of load reducing policy initiatives, so CTPG is not a source for this information. This study can be accomplished in two variants. First, assuming that the timeline is too short or for other reasons, the active cooperation of the three utilities in the LADWP BAA is not accomplished. Therefore, the input data for the spreadsheet tool must be developed by the energy agencies. Such an effort is now underway by the Inter-Agency OTC/AB 1318 Team. Second, the cooperation of LADWP and the two other utilities in the LADWP BAA is accomplished to populate the scenario generator. Although LADWP has made a variety of energy efficiency and renewable development plans in the past two years, recently it revised those plans as a result of budget pressures.[67] As a general matter, publicly-owned utilities (POU) are granted much greater flexibility in existing state law to establish their own specific renewables goals and energy efficiency goals than are the IOUs. Therefore, there are greater uncertainties about the specific strategy that LADWP and its smaller municipal partners

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supply resources themselves have variable patterns of production. Power plants with such characteristics are dispatchable.

[67] For example, LADWP announced the cancellation of the Green Path North transmission line as a means to import renewables into the LADWP service area and instead seemed to indicate it will develop renewables in the Owens Valley and import the power through its existing transmission corridor between Barren Ridge and Canyon.

will follow in the future. Acquiring a set of impacts for energy efficiency and other demand-side policy initiatives from LADWP, Burbank, and Glendale would provide greater confidence when the scenario tool is exercised.

ii. OTC Power Flow and Stability Assessments Beyond the 2011 TPP

Power flow studies examine the implications of the conditions defined in the Scenario Analysis Tool in a level of detail that determine whether there are, and if so, how to alleviate overloads of transmission line segments. The analyses committed to in the 2011 TPP for OTC support purposes are insufficient to support AB 1318 needs in two respects: (1) evaluating additional outlying —sensitivity" cases beyond the —most likely" future typically examined in transmission studies (i.e., high net load scenarios) that can be completed in the timeframe of the 2011 TPP (i.e., low and mid net load scenarios, if required), and (2) expanding the analyses beyond the CAISO balancing authority to the LA BAA. For example, the set of demand-side policy initiatives that might reduce load and thus the need for either generation or transmission system additions is a crucial element of AB 1318 studies and go beyond what can be accomplished in the 2011 TPP process for OTC purposes. Extending the standard power flow analysis to alternative scenarios does not require new conceptual breakthroughs, if is simply a labor intensive effort that needs resources to be accomplished.

iii. Examination of Reliability Impacts Using the SCIT Nomogram

This study examines the consequences on imports into Southern California of capacity retirement in the entire Southern California area. The SCIT nomogram reflects the limitations on imports into the entire Southern California region of WECC, not just those portions in a single balancing authority area. Examination of reliability impacts to operating procedures like the SCIT Nomogram are essential to determine whether OTC retirement strategies in the coastal region and imports of power from renewable sources in the Mojave and western Arizona and Western Nevada are technically viable. Such operating procedures are a vital consideration in the day to day operations of the system, and can reveal additional constraints that local capacity reliability assessment studies fail to recognize. These considerations will influence conclusions about the necessary location of dispatchable capacity, and thus the amount of air pollutants that new power plants will be required to offset, or consideration of even larger changes to the transmission system of Southern California.

iv. Determining Operating Profile for Capacity Additions

This study takes the outputs of the previous ones – generation capacity requirements – and makes use of other system simulation studies to determine how the capacity will operate across the year. Determining operating profile is a crucial input into determining how many emissions will be associated with capacity additions that must be located within SCAB. The likely source such operating profiles are system simulation studies, in particular those associated with renewable integration that are already underway. The hypothesis going into this study is that the minimum generation that must be located within load pockets and even in SCAB as a whole is associated with local reliability. These requirements can be most readily satisfied with simple cycle combustion turbines that are highly available, but are not expected to run many hours. Renewable integration and other system simulation studies have superior insights about how often various types of capacity can be expected to operate. On the basis of such insights, capacity needed for local and regional reliability can be identified by type of capacity (peaking, load following or baseload). A generic addition of each such type can be used to identify emissions factors for criteria pollutants. Therefore, this study translates the simple capacity requirement conclusions of those studies whose results are capacity requirements through time and develops a corresponding range of criteria pollutant emissions. This is the basis for understanding the amount of air credits that the air credit permitting mechanism(s) must make available to new or repowered power plants.

c. Status

At this time it is unclear how several of these studies related to AB 1318 will be coordinated among agency staff and accomplished. One or more of the following technical options that are being discussed with the energy agencies are:

a. Discuss with management of applicable BAAs (both CAISO and LADWP) whether to commit resources for additional needed analyses for completion by spring/early summer 2011;
b. Make power flow base cases and other necessary inputs available to other entities (participating transmission owners, consultants to CEC, etc.), subject to applicable confidentiality agreements and market sensitivity protocols, to allow them to undertake some of the quantitative work to supplement what the BAA staff themselves can complete.
c. Have CAISO act as the lead coordinator of additional sensitivity analyses beyond typical scenario analyses with outside resources. The funding for these resources may be contributed by ARB or CEC.

Delivering a final AB 1318 report by “fall 2011” assumes that these resource allocation, funding, and information access issues are resolved by August 2010, so that these complex technical analyses can be set in motion in support of a final report that identifies the range of air credits needed to support reliability in SCAB.

G. Observations

This chapter has provided the collective view of the energy agencies about near term need for capacity to satisfy reliability in the SCAB. Due to the urgency of producing a preliminary Phase 1 Report for the Legislature and the Governor’s Office in July 2010, a range of separate reliability studies prepared for more limited purposes have been consulted for this Report. A more deliberate process to truly understand reliability requirements out to year 2020 and how air permitting mechanisms for power plants in SCAB may be revised to meet the needs for capacity additions planned to operate and serve specific purposes for the LA Basin, will be pursued over the next year. A series of complex studies have been proposed by the energy agencies and at least some of them are already underway as a result of pre-existing commitments prior to AB 1318 as part of OTC evaluation. Some additional studies must be undertaken by the energy agencies to fully implement the broad charter established by AB 1318.

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APPENDIX A

Assembly Bill 1318

BILL NUMBER: AB 1318   CHAPTERED
BILL TEXT

CHAPTER 285
FILED WITH SECRETARY OF STATE OCTOBER 11, 2009
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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.