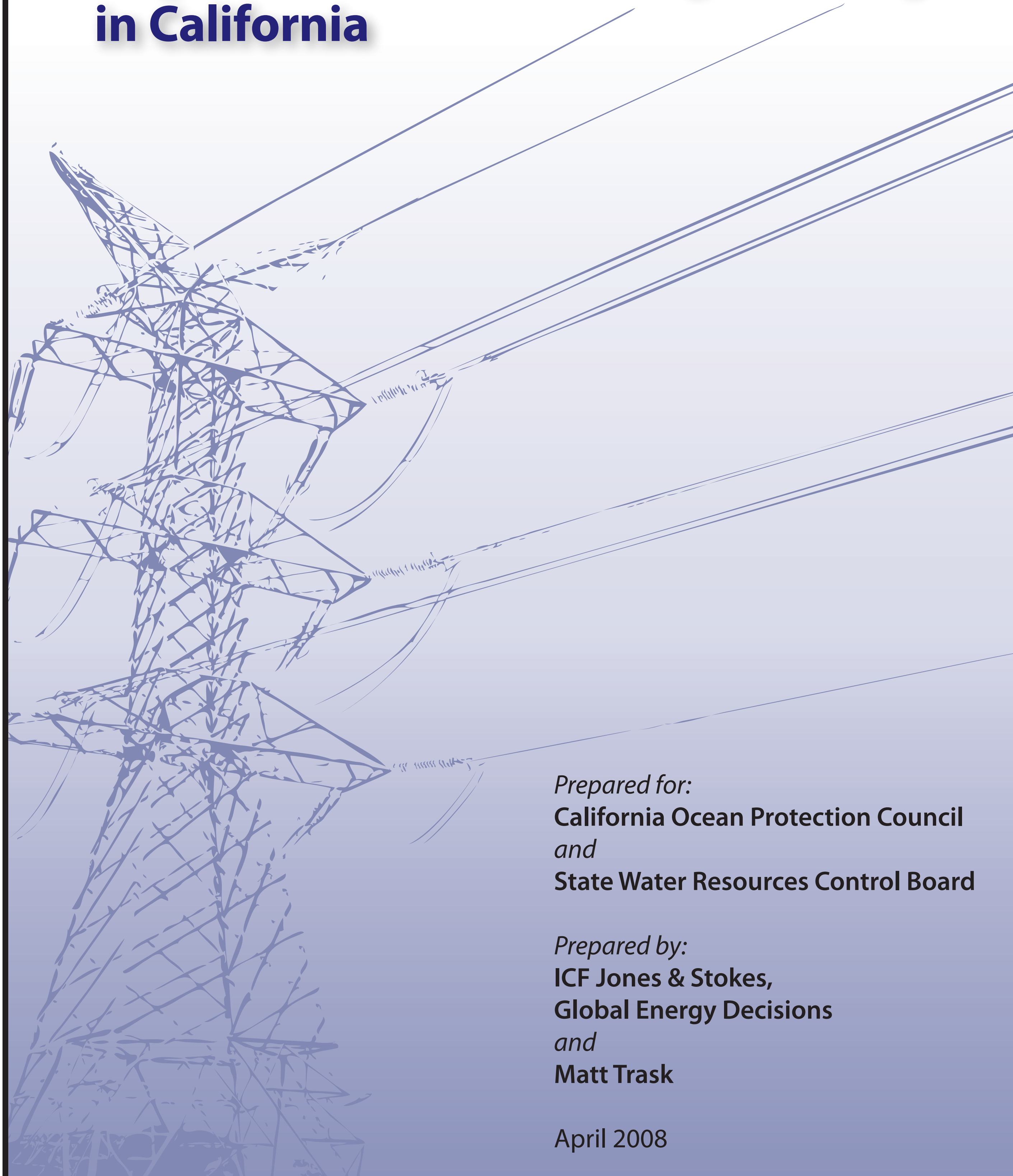
Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California



Prepared for:
California Ocean Protection Council
and
State Water Resources Control Board

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ELECTRIC GRID RELIABILITY IMPACTS FROM ONCE-THROUGH COOLING IN CALIFORNIA

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The following people were instrumental in the preparation of this study, especially the state agency personnel who participated in the Working Group established as a peer review group. Their service was greatly appreciated.

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Executive Summary

This study examines the general energy implications of the State Water Resource Control Board's pending policy decision concerning use of seawater at coastal power plants. As most recently proposed, the pending decision would direct the owners of 19 coastal and estuary power plants in the state to greatly reduce their seawater use from previously permitted levels or take some other action to comply with Section 316(b) of the federal Clean Water Act. These plants all use once-through cooling (OTC) systems, pumping seawater through the plant's condensers and then back into the ocean. A complete list of these 19 plants is shown in **Table 1 -1**. They consist of two large nuclear plants built in the 1970s, and a mixture of mostly older, less-efficient gas-fired steam boiler plants along with a few modern gas-fired combined-cycle plants.

The California Grid and the Role of OTC Plants

As depicted in **Figure 1-1**, the OTC plants deliver power to critical points in California's electricity grid, especially within the state's largest Local Reliability Areas (LRAs), where the ability to import power is limited and the local utility must instead rely on local power plants to maintain electric service reliability. Some OTC plants are needed year around to provide reliability service within an LRA because no other resource is available to supply that service. Others are needed only during period of very high demand, such as during a summer heat wave, and are idled for much of the rest of the year. Three other OTC plants – the two nuclear plants and the newest gas-fired plant – are located along key intra-regional transmission lines, playing a significant role in reducing congestion along those vital transmission paths.

The nuclear plants provide baseload service, operating at or near maximum power levels 24 hours per day, shutting down only for maintenance and refueling. Together, the two nuclear plants provided about 13 percent of the state's total electric energy needs in 2005, and about 63 percent of the total energy produced by all the OTC plants. The gas-fired plants generally operate as load-followers, operating at low power levels in the morning and gradually ramping power levels up to match demand during the day, and reversing the process in the late afternoon into evening. Power levels at the gas-fired OTC plants generally match their age, with the newer, more efficient combined-cycle plants operating at higher levels than the older, less-efficient steam boiler plants. The exceptions are those older plants located in LRAs, where no other resource is available to serve local load.

Threats to Electric Reliability

In general, generation at most of the older OTC plants has trended downward in recent years because their relative age and inefficiency has made them less competitive with newer generation. Already faced with this competitive disadvantage, several of the owners of these plants have stated that the Board's new rules could force the retirement of several generating units, especially those already on the verge of financial non-viability, possibly posing a threat to electric system reliability. Though retirement presents the greatest threat to electric reliability, compliance with the new rules also presents reliability concerns, including the potential reduced net generation from OTC plants after they convert to wet cooling, and the unavailability of the nuclear plants while they shut down to convert.

This study examined those threats using a computer modeling effort to simulate the potential economic impacts of the Board's pending decision, and resultant reliability impacts that could occur when and if OTC generating units are retired. The modeling effort simulated effects on California's electric power grid caused by retirement and/or derating of OTC plants, identifying and quantifying transmission system segment overloads that could occur following OTC plant retirements. The modeling effort also showed how costs to the ratepayer could change depending on how and when the Board's new policy is enacted, and produced estimates of the net changes in power plant emissions caused by the new policy.

Analysis of the modeling results, as well as of other studies and sources of information, shows that though certain trends are evident, predicting the future operation of any one plant is conjecture at best. Faced with tough economic decisions, plant owners could choose to retrofit their OTC plants with an alternative form of cooling, repower their plants by essentially building a new plant using alternative cooling and then decommissioning the old one, or shut the plant down, either permanently and convert to another use, or temporarily while waiting for more favorable economics for repowering or retrofitting.

The greatest threat to electric system reliability would occur in the extremely unlikely event of OTC plant owners choosing en masse to retire their plants without sufficient time for the industry to assess the impact of those retirements and plan accordingly. The modeling examined a wide range of retirements and time frames for policy enactment. The most severe effects were found in the extreme cases of all OTC plants retiring in 2009, which would require no less than a WWII-like mobilization effort to locate and site combustion turbines, the only type of plant that could be placed on-line in such a short time-frame, while also enacting emergency conservation measures. However, the modeling also showed that given sufficient time to react, the electric industry could likely tolerate and compensate for mass OTC plant retirement at relatively modest costs to the ratepayer.

In all but one of the cases examined in the 2015 time frame, when many other currently planned power plants throughout the Western U.S. and Canada will be on-line, the modeling showed that OTC plant retirements could be compensated for solely through transmission upgrades. The one exception was in the extremely unlikely event that all OTC plants are permanently retired, including the two nuclear plants, which would require construction of new generating plants along with substantial transmission upgrades, costing ratepayers as much as $11 billion. In other words, under all but the most extreme scenarios, more than enough power plants are expected to be operating in 2015 to more than compensate for any or all OTC plant retirements, with a projected 28 percent reserve margin of supply over demand in the Western half of North America. The key will be ensuring the transmission system is capable of delivering power from those plants to the loads presently served by OTC plants.

The California Independent System Operator is currently working with all interested parties in developing California's Transmission Plan, and OTC plant retirements is a key issue in its development. With input from the California Energy Commission, the Plan will be the first step in ensuring the state makes sufficient investment in transmission upgrades to provide the greatest benefit to the ratepayers. The CAISO and CEC will also be heavily involved in the California Public Utilities Commission's Resource Adequacy process, which will be the primary proceeding for ensuring electric reliability as the Board's OTC policy is enacted.

Cost to the Ratepayer

In the extreme case of all OTC plants retiring in 2015, including the nuclear units, the modeling showed that substantial new transmission system upgrades would be needed to allow out-of-region plants to compensate for the retirements. Projected costs for these transmission upgrades range from about $314 million up to about $1 billion, with a significant part of that occurring outside of California. Removing all 21,000 MW of current OTC generation would also reduce generation reserve margins to unacceptable level, requiring addition of about 4,000 MW of new generation in the Western U.S. and additional transmission capacity to access that generation, at an estimated cost range of $3 billion to as much as $11 billion, depending on the type and location of new generation, and the type of transmission upgrades constructed to access the new generation. The less severe case of all OTC plants except the nuclear units retiring in 2015 showed that the retirements could be compensated for with as little as $135 million in in-state transmission system upgrades. These costs would likely eventually be passed along to ratepayers, though some could be absorbed by the transmission system owners or their wholesale customers.

Such mass retirements are highly unlikely, however. Far more likely is that while some OTC plants may permanently retire and convert to another use, others will repower their plants, building new generating units at their existing sites that can successfully compete in the future marketplace, and still others will convert their cooling system or take other action to comply with the new rules allowing them to operate their present plants unrestricted. Older plant owners have many incentives for repowering, including provisions in state law and regulation that essentially give preference to repowered coastal plants in the utility power contracting process. They also have ready availability of natural gas and transmission infrastructure at the present site, and the efficiency improvement offered by new plant technologies will greatly improve their ability to compete with other resources.

Owners of the newer combined-cycle plants, as well as some of those providing reliability services within an LRA, have incentive to convert their cooling systems, or take whatever other action is available to them to comply with the new rules. This is because they are positioned to continue to earn significant revenue, or in the case of those owned by a utility are capable of providing service that would otherwise have to be replaced by building a new plant or making purchases elsewhere, likely at a greater cost than converting their present plants to an alternate cooling system.

The utilities, which own and operate the nuclear plants, also have strong incentive to convert their cooling systems rather than retire because they rely heavily on that generation to serve their customers, and replacing that generation would be very expensive. The owners have amortized the costs of the plants over the entire term of their licenses, which extend into the 2020's, and shutting them down prior to then would likely prevent full cost recovery. This incentive is apparent in the owners' willingness to spend as much as $700 million now to replace leaky steam generators in order to extend the lifetimes of their plants to the end of their license periods. Considering that PG&E would have had to spend over $1.5 billion in 2006 alone to replace the generation from the Diablo Canyon plant, investing as much as $1 billion now in retrofitting an alternate cooling system to allow continued operation of that plant would appear to be more than justified.

Conclusions

Impacts to Electric System Reliability

In summary, the analyses conducted for this study shows that while the Board's pending OTC policy does have potential to negatively affect electric reliability, proper planning can compensate for any plant retirements and prevent reliability problems, provided the industry has sufficient time to respond. The general consensus of the energy industry is that 5 years is needed to plan, site, permit, and construct a new major power plant, and 7 years is needed for a new major transmission line. However, the vast majority of the transmission upgrades identified in the analysis to compensate for OTC plant retirements are relative modest, requiring only 1-3 years to construct and place in-service. Because the transmission planning process in the state has improved considerably in recent years, the state seems well poised to compensate for most OTC plant retirements in the 2012 and beyond time period by constructing transmission upgrades to tap into the excess generating capacity that is projected to occur then. More challenging, however, is planning and building the needed out-of-state transmission infrastructure through the inter-regional planning process, in which California has little control over the outcome, to compensate for the extreme case of all OTC plants retiring, including the nuclear units.

Proper planning is also essential to ensure ratepayers get the greatest benefit from the infrastructure constructed to compensate for OTC plant retirements and conversions. According to the modeling effort costs could range from as little as around $100 million to as much as $11 billion, depending on how and when the policy is enacted, and how the energy industry responds to OTC plant retirements. Though transmission system upgrades are identified as the least-cost alternative for replacing OTC retirements, doing so present its own challenges because many upgrades would be needed out of the state. Careful analysis is needed to develop an optimal combination of new plant construction and transmission system improvements to ensure the greatest benefit to the ratepayer following any OTC plant retirements, and to ensure such infrastructure can be developed in a timely manner.

Impacts to the Environment

Though the Board's policy decisions are exempt from the provisions of the California Environmental Quality Act, it conducts its own CEQA-equivalent investigation of the potential effects on public safety and the environment to ensure its policy making process fully considers such effects. Conclusions that can be drawn from the analyses in this study applicable to that investigation include:

The effects of the Board's new policy on net power plant sector emissions across the Western half of North America (from British Columbia and Alberta to Baja California and the 14 U.S. states in between) would be significant only if all OTC plants including the nuclear units are retired, which would result in a modest 1-2 percent increase in CO2 emissions sector-wide. All other scenarios examined showed either no change or a modest reduction in net CO2 emissions because the plants replacing the retired OTC plants in general would be considerably more efficient. Other types of emissions from the power sector, including NOx, SOx and mercury, showed virtually no change regardless of how many OTC plants are retired.

The indirect environmental impacts that could occur due to the Board's new policy would be directly related to the amount of new infrastructure constructed to compensate for any retirements. Depending on how and when the policy was enacted the infrastructure needed could range from quite modest to extremely vast, from as many as 800 new small power plants in the state at a cost of well over $10 billion if all OTC plants are retired in 2009, to as little as $135 million in modest, low-impact transmission upgrades in the still unlikely event that all but the nuclear plants are retired in 2015.

All such infrastructure development would be subject to environmental and technical analyses and approvals. With the exception of a few land use impacts related to zoning issues, power plant construction in California in recent years resulted in no significant, unmitigated impacts to public safety and the environment. And though major transmission line projects often result in unmitigated impacts to visual resources, especially those through national forest and park lands, the vast majority of the upgrades identified in the modeling effort would have no impacts, even during construction. Therefore, with proper planning and oversight, the Board's policy is not likely to result in significant cumulative impacts to public safety and the environment, though one area of concern is cumulative land use impacts because of zoning issues.

The most realistic scenarios examined, in which some OTC plants would be retired while others repower or convert their cooling systems, showed potential for significant benefits to the environment because the overall power sector would be more efficient and produce fewer emissions, and because marine ecosystem impacts caused by use of OTC technology would be greatly reduced.

Recommendations

Though this study makes optimistic conclusions about the industry's ability to compensate for mass OTC plant retirements at relatively modest costs, it is extremely important to understand that the modeling effort conducted for this study was limited in scope, capable of only taking a snapshot of the big picture, due to time constraints. Ideally, the modeling effort would have been expanded to thousands of runs examining each OTC plant in great detail, instead of the limited number of runs that were possible for this study.

Because of this limitation, the key recommendation arising from this study is that the industry must continue comprehensive study of the issue, examining the reliability implications of retirement of each plant individually and in combinations with all other plants, and constantly reassess the reliability implications of the Board's new policy as it is planned and enacted. Fortunately, such a study is now underway at the California Independent System Operator, with full participation by the state's water agencies, the energy industry, non-governmental organizations, and individuals. Cooperation amongst the agencies involved in shaping policy affecting the future reliability of the grid, including the Water Board and the energy agencies, is essential in assuring the Board's policy results in no impact to electric system reliability, nor to the environment.

Chapter 1
Introduction

The California Ocean Protection Council (OPC) and State Water Resources Control Board (Board) have commissioned this study to investigate claims that the Board's pending policy decision concerning use of seawater at coastal power plants could have a significant negative impact on the overall reliability of the state's electricity grid. The study also examines the potential indirect impacts to the environment that could result from the Board's decision.

As most recently proposed, the pending decision would direct the owners of 19 coastal and estuary power plants in the state to greatly reduce their seawater use from previously permitted levels, or take other actions to reduce the environmental impact of using seawater for cooling the plants, in order to comply with Section 316(b) of the federal Clean Water Act.[1] These plants all use once-through cooling (OTC) systems, pumping seawater from an intake structure through the plant's condensers, and then back into the ocean or estuary through a discharge structure. These plants are often referred to as OTC plants, as well as coastal/estuary plants, and collectively are known as the "OTC fleet." They consist of three basic types of power generating units: older, gas-fired steam boiler plants; newer gas-fired combined-cycle plants[2]; and two very large nuclear power plants. A complete list of these 19 plants is shown in **Table 1 -1.**[3]

The California Grid

As depicted in **Figure 1-1**, California's electricity grid is composed of many thousands of miles of high-voltage transmission lines delivering power from hundreds of power plants throughout the Western US and Canada to the distribution systems of dozens of investor-owned and customer-owned electric utilities in the state. The grid is highly interconnected, meaning that power can be transferred over long distances from generators scattered across the West to

[1] Details of the Board's proposed decision can be found at http://www.waterboards.ca.gov/npdes/docs/cwa316b/316b_scoping.pdf .
[2] Combined-cycle plants consist of one or more combustion turbine-generator sets (essentially, jet engines driving electric generators) plus a steam turbine-generator that uses steam produced by the waste heat from the combustion turbine exhaust.
[3] The list shows 20 plants, but the proposed Gateway plant has not yet been built, and its design was recently changed to use air cooling, leaving 19 plants that currently use OTC technology in the state. One of those, the Hunters Point Plant, is slated for shutdown under a formal agreement, leaving a group of 18 OTC plants, often referred to as the "OTC fleet," as the study group.

end-use customers across the state through a network of wires and substations that is largely self-regulating because if its vast size.[4]

However, some areas in the state are more interconnected than others. Because of limits on the ability to move power over key transmission lines, and the difficulties of building new lines within the state, many areas of the state are located within transmission cul-de-sacs, where the ability to import power is limited, and the local utility must instead rely on local power plants to maintain electric service reliability. These areas are referred to as Local Reliability Areas, or LRAs. Almost all the OTC power plants are located in one of four LRAs: the Greater Bay Area, Big Creek/Ventura, Los Angeles Basin, or San Diego (see Figure 1-1); and three OTC plants not in an LRA are located along key intra-regional transmission lines, playing a significant role in reducing congestion along those vital transmission paths.

More than 95 percent of the customers in those four LRAs are served by just four entities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Los Angeles Department of Water & Power (LADWP), and San Diego Gas & Electric (SDG&E).[5] These utilities are charged with securing sufficient generation to maintain reliable service to their customers, including sufficient reserve margins to handle system emergencies, such as the unexpected loss of major power plants or transmission lines. The California Independent System Operator (CAISO) is the "control-area operator"[6] for the state's investor-owned utilities, and is the entity charged with assuring reliability in the service territories of those utilities (PG&E, SCE and SDG&E) on a day-to-day basis. Those three utilities work with the California Public Utilities Commission to assure reliability standards are met on a yearly basis through contracts under the CPUC's Resource Adequacy and Long-Term Procurement Processes. As a government entity, LADWP is its own control area operator, and has its own process for maintaining reliability standards within its service territory.

Prior to the restructuring of the electric utility industry in California under AB 1890, all the OTC plants in the state were owned by PG&E, SCE, SDG&E or LADWP. Those utilities still own some OTC generation, though all but five OTC plants in the state are now owned by large energy companies, which purchased the plants from the state's investor-owned utilities in the late '90s as a means of entering the California power market. This divestiture of power resources was meant to bring diversity and competition to the California market, but it has also complicated the energy planning process in the state because of the difficulty in predicting the future decisions of so many owners.

[4] Large interconnected systems generally are more stable than smaller systems due to the self-canceling effect of many loads being turned on and off at any one time. The larger the system, the more likely that increases in electricity demand in one location will be offset by decreases in other areas. This provides a reliability benefit and an environmental benefit, since power plant operations are more predictable and steady, avoiding the increased air pollution that comes from sudden changes in power plant operations.
[5] Several cities within both the Los Angeles and Greater Bay Area LRAs are served by small municipal utilities, such as the Cities of Palo Alto, Alameda, Riverside, Pasadena, and Burbank.
[6] A control-area operator performs both generation and transmission control functions within a given area.

TABLE 1-1. STATUS OF COASTAL PLANTS USING OTC

Plant Name	Year In Service	2006 Capacity (MW)	Location	Owner	Repowering Plans / Present Role and Potential Replacements
Alamitos	Unit 1: 1956 Unit 2: 1957 Unit 3: 1961 Unit 4: 1962 Unit 5: 1964 Unit 6: 1966	1950	Long Beach	AES	No announced plans to repower or convert cooling system. / Provides load-following service to LA Basin area under SCIT.[1] Units 1&5 under contract to DWR at least through 2010, and Unit 6 at least through 2007. Bear Energy has dispatch rights to all the plant output under a long term "Tolling Agreement."[2] The plants can also be dispatched by the CAISO, through Williams, under the terms of a Must Run Agreement which is in place to provide grid reliability services during times the plant wouldn't normally be running for economic reasons. There is also an agreement between California DWR and Alleghany Energy Supply Company, LLC, concerning the Alamitos generation. Potential replacements include repowering at same or nearby site, possible transmission upgrade to increase import capability.
Gateway (Old Contra Costa Unit 8)	N/A	0	SF Bay-Delta	PG&E	Partially completed 530 MW Unit 8 transferred to PG&E and renamed Gateway in 2007. As originally proposed would use the same water intake as Units 6&7, but recent license amendment to change from OTC to air cooling is under CEC review.
Contra Costa	Units 6&7: 1964	680	SF Bay-Delta	Mirant	No announced plans. Unit 7 equipped with closed-cycle system that perhaps is 316(b) compliant. / Provides service to PG&E in the transmission-constrained Bay-Delta area. Units 4&5 held RMR contracts in 2007. Could be replaced by new generation on-site or nearby, or possible transmission upgrade to increase import capability.
Diablo Canyon	Unit 1: 1984 Unit 2: 1985	2195	SLO County	PG&E	No announced plans to repower or convert cooling system. CPUC has approved the replacement of the steam generators, which will significantly extend the life of the project. Current licenses expire in 2021 for Unit 1 and 2025 for Unit 2. / Provides baseload power to PG&E's main transmission lines in the Central Valley. Could be replaced by new generation on site or nearby, though available natural gas pipeline capacity could limit ability to quickly develop replacement capacity. No know transmission upgrade could replace all generating capacity.
El Segundo	Unit 3: 1964 Unit 4: 1965	670	Santa Monica Bay	NRG	CEC issued License in Feb 2005 to repower now-retired Units 1&2 to 630 MW with OTC. An amendment to change to dry cooling was filed June 2007 / No replacement needed.
Encina	Unit 1: 1954 Unit 2: 1956 Unit 3: 1958	929	San Diego County	NRG	NRG has proposed to repower Units 1-3 with a 550 MW combined cycle plant using air cooling. Units 4&5 with OTC would be retired in future. / Provides baseload and load-following service to SDG&E territory, and local reliability service to SD Local Reliability Area. Units 1-5 held RMR contract in 2007. No replacement needed, nor possible other than repower on-site or nearby because of transmission constraints. Transmission upgrades are proposed, but new line development considered very difficult in heavy urban area.
Harbor	CC Units 3-5: 2001	240	LA Harbor	LADWP	No announced plans for cooling system conversion. Only 75 MW Unit 5 (steam turbine using HRSG from Units 1-4) uses OTC. Units 1-5 (165 MW) are air-cooled peakers. / Provides peaking and load-following service to LADWP's system.
Haynes	Unit 1: 1962 Unit 2: 1963 Unit 3: 2005 Unit 4: 2005 Unit 5: 1966 Unit 6: 1967	1611	Long Beach	LADWP	Units 3&4 replaced with new 575 MW combined-cycle plant in 2005 re-using OTC. Units 1&2 replacement underway re-using OTC. No announced plans concerning cooling system conversion, nor of repowering Units 5&6. / Provides peaking, load-following and baseload service for DWP territory. Could be replaced by new generation within DWP territory. Transmission upgrades to allow increased imports would be challenging within LA area, and overall system is very constrained, limiting imports into DWP territory, especially from outside SoCal.

[1] See glossary.
[2] Williams Energy Marketing and Trading originally held this contract but sold it to Bear Energy, a subsidiary of Bear Sterns, in November 2007.

TABLE 1-1. STATUS OF COASTAL PLANTS USING OTC

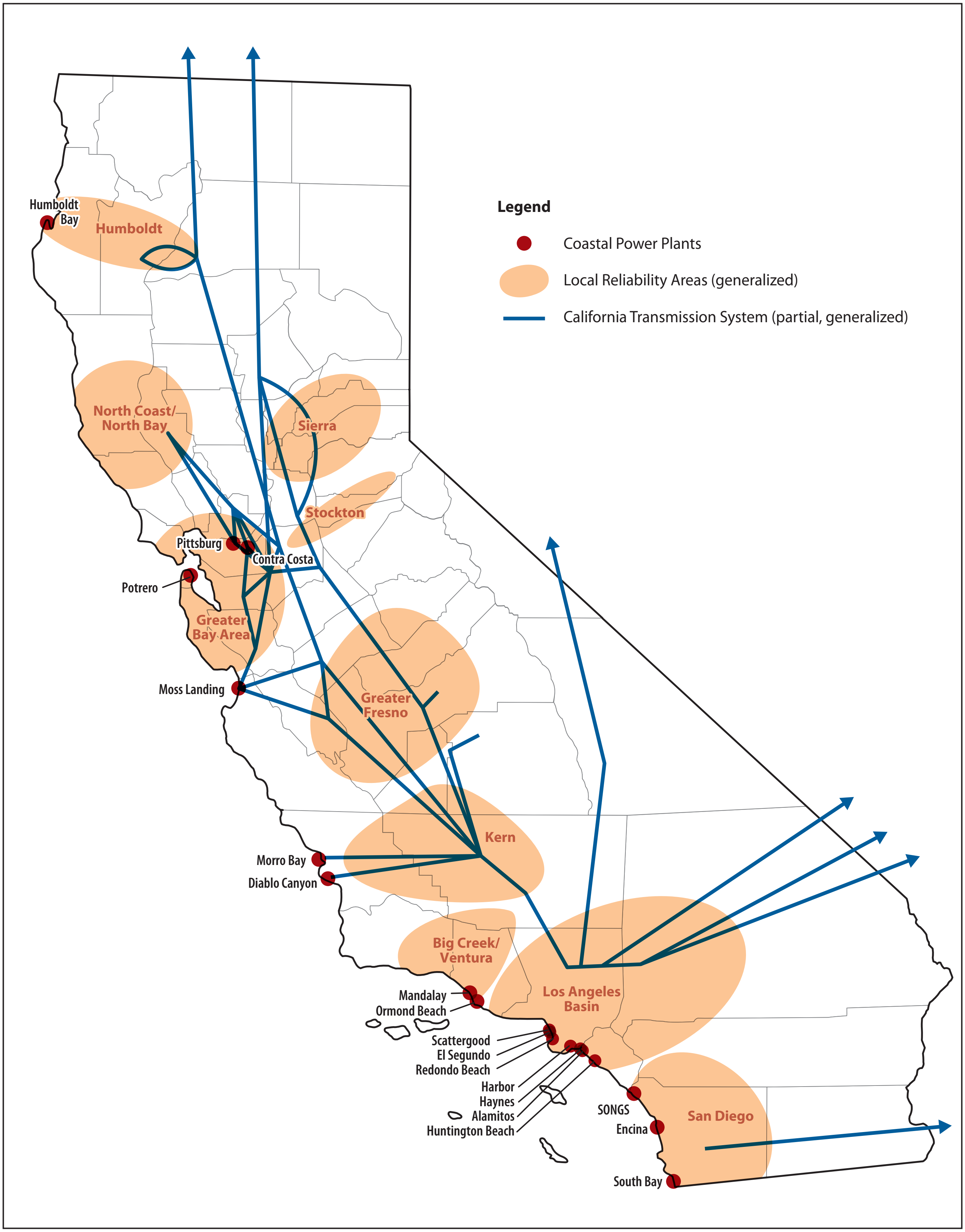
Humboldt Bay	Unit 1: 1956 Unit 2: 1958	105	Humboldt Bay	PG&E	Application to repower with 163 MW reciprocating engine that does not require OTC under licensing review at CEC. / Provides baseload and load-following service to PG&E territory, and local reliability services to Humboldt Local Reliability Area. Units 1&2 held RMR contract in 2007. Weakly interconnected to other LRA's. No replacement needed.
Huntington Beach	Unit 1: 1958 Unit 2: 1958 Unit 3: 2003 Unit 4: 2003	880	Orange County	AES	Units 3 & 4 repowered w OTC in 2003. CEC approved post-project CEQA review and mitigation 9/06. No announced plans for other repowering or converting cooling system. / Provides peaking and load-following service to SoCal Edison territory under SCIT. Older units have run at almost twice the capacity factor of newer units in recent years, apparently due to contract provisions. Units I&2 are under contract to DWR through 2010; Units 3&4 are under contract for on-call energy to SCE. Potential replacements include new plant with alternate cooling at same or nearby site, and possibly transmission upgrades to increase import capability, though such development would be difficult in the densely populated urban area.
Mandalay	Unit 1: 1959 Unit 2: 1959	560	Ventura County	Reliant	No announced plans to repower or convert the cooling system. SoCal Edison, which owns surrounding land, has proposed building an air-cooled 45 MW peaker adjacent to the steam units. / Provides load-following service to the SoCal Edison's system, primarily in the transmission-constrained BigCreek/Ventura local reliability area. Potential replacements include new plant with alternate cooling at same or nearby site, though the city generally has not supported construction of new industrial facilities within its borders; or possibly transmission upgrades to increase import capability into the BigCreek/Ventura area, though such development would be difficult in the densely populated urban area.
Morro Bay	Unit 3: 1962 Unit 4: 1963	676	Morro Bay	LS Power	A repower license with OTC was issued by the CEC in 2004, but it will not be final until the RWQCB permit is issued. Construction has not begun. Plant has operated at very low capacity factors in recent years. / Provides load-following service to PG&E service territory, very near to where Diablo Canyon enters the PG&E grid. Potential replacements include new plant with alternate cooling at same or nearby site, though present site is constrained because of proximity to recreational, residential and commercial uses; or possibly transmission upgrades to increase import capability into PG&E's southern system.
Moss Landing	Unit 6: 1967 Unit 7: 1968	1478	Monterey Bay	LS Power	No announced plans to repower these units or convert cooling system for any unit. Units 6&7 have operated at low capacity levels in recent years, while the newer combined-cycle units have run over 50 percent capacity factor. / Provides load-following service to PG&E's service territory. Potential replacements include new plant with alternate cooling at same or nearby site, though present site is constrained because of proximity to recreational, residential and commercial uses; or possibly transmission upgrades to increase import capability into PG&E's system.
	CC Units 1&2: 2002	1060	Monterey Bay	LS Power	CEC issued license with OTC in 2000. Operations began 2002.
Ormond Beach	Unit 1: 1971 Unit 2: 1973	1500	Ventura County	Reliant	No announced plans to repower or convert the cooling system. / Provides load-following service to the SoCal Edison's system, primarily in the transmission-constrained BigCreek/Ventura local reliability area. Has operated at very low power factors in recent years, as low as 0.6 percent for Unit 1 in 2006. Potential replacements include new plant with alternate cooling at same or nearby site, though local opposition to the existing plant is strong; or possibly transmission upgrades to increase import capability into the BigCreek/Ventura area, though such development would be very difficult in the densely populated urban area.
Pittsburg	Unit 5: 1960 Unit 6: 1961	650	SF Bay-Delta	Mirant	No announced plans to repower or convert to an alternate cooling technology. / Provides service to PG&E in the transmission-constrained Bay-Delta area. Could be replaced by new generation on-site or nearby, or possibly by transmission upgrade to increase import capability to the Greater Bay Area local reliability area.

TABLE 1-1. STATUS OF COASTAL PLANTS USING OTC

Potrero	N/A	363	SF Bay	Mirant	Repower Proceeding terminated 3/06. Project anticipated to be shut down when 145 MW SF Reliability Project is completed, scheduled for December 2008. / Units 3-6 held RMR contract in 2007. Replacement assumed to be SF Reliability Project.
Redondo Beach	Unit 5: 1954 Unit 6: 1957 Unit 7: 1967 Unit 8: 1967	1310	Santa Monica Bay	AES	No announced plans to repower or convert cooling system. One unit under contract to DWR at least through 2010. / Provides peaking and load-following service to SoCal Edison territory under SCIT. Units 5 & 6 are part of the contract between Bear Energy and California DWR (see Alamitos plant info above), and also part of the contract between Alleghany Energy Supply Co. and DWR. Units 5&6 have run at very low levels (less than 2 percent) in recent years. Potential replacements include new plant with alternate cooling at same or nearby site, and possibly transmission upgrades to increase import capability, though such development would be very difficult in the densely populated urban area.
San Onofre	Unit 1: 1983 Unit 2: 1984	2167	San Diego County	SCE (75.1%) SDG&E (20%) Anaheim (3.2%) Riverside (1.8%)	No announced plans for converting cooling system. CPUC is considering the approval of the replacement of steam generators, which would significantly extend the life of the project. Current licenses expire in 2022 for both units. / Provides baseload power to LA and San Diego regions, located at interconnection of those systems.
Scattergood	Unit 1: 1958 Unit 2: 1959 Unit 3: 1974	803	Santa Monica Bay	LADWP	LADWP is under a consent decree to replace the project, but has not announced plans to repower or convert cooling system. / Provides load-following and baseload service for DWP territory. Two units burn mixture of nat. gas and digester gas from nearby wastewater treatment plant. Could be replaced by new generation within DWP territory. Transmission upgrades to allow increased imports would be challenging within LA area, and overall system is very constrained, limiting imports into DWP territory, especially from outside SoCal.
South Bay	Unit 1: 1960 Unit 2: 1962 Unit 3: 1964 Unit 4: 1971	703	San Diego Bay	LS Power	Application to repower to 620 MW combined cycle with air cooling now under licensing review at CEC. / Provides baseload and load-following service to San Diego area, and local reliability service to SD Local Reliability Area. Units 1-4 held RMR contract in 2007. Transmission constraints severely limit ability to import power to region, and upgrades would be difficult in heavily urban area, so likely replacement would be new plant on same or nearby site.

Notes:

Green denotes plants switching to dry cooling
Three plants in CEC licensing review for repowering without OTC (El Segundo, Humboldt, South Bay)
One new unit in CEC licensing review using air cooling – Gateway (old Contra Costa Unit 8)
One plant will add combustion turbines and retire steam units using OTC – Encina
Two plants retired: Hunters Point in 2006, Long Beach combined cycle units in 2005.



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Jones & Stokes

Figure 1
Locations of Power Plants, Local Reliability Areas, and California's Major Transmission System

Reliability Effects of the Board's OTC Decision

Because of their location, almost all the OTC plants currently play vital roles in maintaining the reliability of the grid, especially during times of high demand such as during summer heat waves, and any action that could affect the future viability of those plants must be carefully considered to ensure that action will not threaten future reliability. In this case, the Board's pending decision would likely have a significant effect on the future costs of OTC plant operation, and OTC plant owners will have to factor those costs in their decisions concerning future operations of their plants. The vast majority of OTC plants are older, steam boiler plants, many of which are shut down for most of the year because they are not able to compete with newer plants, further complicating the economics of any decision concerning future operations.

The Board's proposed decision would allow plant owners to comply by either installing an alternate cooling system, such as dry cooling (essentially a very large radiator) or wet cooling (cooling towers), or take some other action to reduce the environmental impact of their seawater use. Costs for installing an alternate cooling system is estimated to range from a few million dollars for newer, combined-cycle plants, to more than $1 billion for the nuclear plants. Several parties have argued that the financial impacts associated with the Board's decision could result in the retirement of many plants, rather than converting their cooling systems or taking some other action to comply with the new rules, possibly causing generation shortages during times of high demand and/or low available generating capacity. This study is intended to address those concerns.

Report Organization and Methodology

This study involves:

1. A discussion of the processes in place that address potential reliability impacts, including the roles of the state's utilities and energy agencies in maintaining reliability (Chapter 2);
2. A description of the present role of OTC plants, and a discussion of the factors affecting their future role, including the effect of cooling system conversions and the incentives to repower[7] OTC plants (Chapter 3);
3. An investigation of potential impacts to electric reliability caused by enacting the Board's policy recommendation (Chapter 4); and,
4. An examination of actions that could reduce potential reliability and indirect environmental impacts to less than significant levels (Chapter 5).

The study includes a modeling effort intended to simulate the potential economic impacts of the Board's pending decision, and resultant reliability impacts that could occur when and if coastal or estuary plants are retired. The modeling effort is intended to simulate effects on California's electric power grid caused by

[7] Repower refers to the process of building a new power plant on an existing site.

retirement and/or derating[8] of coastal/estuary power plants. The modeling scenarios are purposely designed to help analyze some of the worst-case possibilities that could occur, such as assuming all plants using once-through cooling in the state will retire and be replaced by generation either within the same local transmission area as the retired plants or by generation from outside the transmission area. More realistic scenarios were also examined in order to provide a range of potential impacts that the Board could consider in its decision making process.

Global Energy Decisions (GED) conducted the modeling for this effort, as it has for similar studies conducted for the California Energy Commission. The modeling effort first involved conducting simulations of the economic effects of a range of OTC plant retirements and/or deratings. Using the results of the economic modeling, GED then conducted targeted reliability modeling to identify and quantify transmission system segment overloads that could occur following OTC plant retirements. The reliability modeling includes simulations of grid operations during system emergencies as well, such as the outage of a major generating station or transmission line, again identifying and quantifying the transmission line segment overloads that would occur. The analysis also includes an estimate of the cost of alleviating these overloads. Finally, in an effort to assess the potential impact or benefit to air quality in the region, the modeling effort also produced estimated effects on overall power plant emissions in the state, as well as out-of-state plants that wheel power to California.

[8] Derating refers to the reduced net generating capacity of OTC plants that convert to alternate cooling systems. These systems require additional pumps and fans and generally consume more energy than OTC systems, thus reducing the maximum amount of power the plant can deliver to the grid. For a full discussion of this issue, see the recent report, “California Coastal Power Plants: Cost and Engineering Analysis of Cooling System Retrofits,” conducted for the OPC by Tetra Tech, Inc.

Chapter 2
The Process of Maintaining Reliability

Because of the inherent uncertainty in predicting the future business decisions of power plant owners and developers, the state's utilities and energy agencies must be prepared to take necessary action to ensure reliability is maintained when OTC plant owners convert their cooling systems, repower their plants, or retire. Since its inception in 1998 the CAISO has assessed and maintained electric system reliability for most of the state through its Reliability Must Run (RMR) process.[9] But in the past year responsibility for maintaining reliability started shifting away from the CAISO and back to a joint effort of the utilities and the CPUC in the Resource Adequacy (RA) and Long-Term Procurement processes, which in turn are also linked to the CEC's biennial energy policy planning process and the CAISO's transmission planning process.

CAISO RMR/LCR Process

Until recently the CAISO assured local reliability within the state's 10 identified Local Reliability Areas (LRAs) through its RMR process. That process has now been overhauled and renamed the Local Capacity Requirements (LCR) process, though it still results in awarding RMR contracts to generators when needed. The process has largely been supplanted by the CPUC's Resource Adequacy process, discussed below, though the CAISO will continue with its annual LCR assessment and award one-year RMR contracts accordingly.

In the LCR process, the CAISO annually assesses the means for meeting load demand in each of the state's 10 LRAs. It first determines the demand for power within each LRA, lists the in-area generation available to meet that demand, including those contracted through the Resource Adequacy process, and identifies transmission constraints and possible fixes that would allow generation from outside the area to reach that demand. The CAISO then weighs the costs of any identified transmission fix against reliance on an in-area power plant, including the cost of upgrades needed to keep that plant in compliance with any new environmental regulations, and decides which option provides the greatest benefit for the state's ratepayers.

In the past, the CAISO has gone to considerable lengths to ensure plants are available in certain areas through the RMR process, including paying for air emissions controls at several plants. However, the number of plants subject to

[9] The Los Angeles Department of Water & Power conducts its own reliability planning process, as discussed later in this chapter.

RMR contracts has reduced considerably in recent years. At present, only a handful of OTC plants hold RMR contracts requiring that they be available to provide services when called upon by the CAISO. In 2007, the only OTC units subject to RMR contracts were the operating units at the South Bay, Encina, Potrero and Humboldt plants, plus Contra Costa Units 4&5. South Bay and Encina serve the San Diego LRA, and the rest serve the Bay Area LRA. In 2006 all those plants plus Contra Costa Unit 7, Pittsburg Units 5&6, Alamitos Unit 3 and Huntington Beach Units 1&2 held RMR contracts. The reduction in the need for RMR units between those years has been credited both to new transmission system improvements and to the implementation of the CPUC's RA process.

CPUC Resource Adequacy and Long-Term Procurement Processes

The CPUC embarked on its RA rulemaking after passage of AB 57 (Wright. Electrical corporations: procurement plans) in 2002, which provided guidance on utilities' electricity procurement and electricity demand reduction programs, including how costs of those activities would be recovered in rates.

Through the RA process, the CPUC:

- Reviews and approves plans for the utilities to purchase energy
- Establishes policies and utility cost recovery for energy purchases
- Ensures that the utilities maintain a set amount of energy above what they estimate they will need to serve their customers (reserve margin)
- Implements a long-term energy planning process

Though the CAISO will continue to conduct annual assessments of RMR needs within the 10 LRAs in the state, utilities and other load-serving entities (LSE's) in the state now have responsibility to identify and purchase their energy needs, including on-peak energy needs plus a 15-17 percent reserve margin, throughout their service territories. Under the RA and procurement processes, the LSE's assess their energy and local reliability needs over a 10-year planning horizon and, upon approval of the CPUC, release annual (RA) or biennial (Long-Term Procurement) requests for offers to meet those needs. The biennial procurement process was ordered so utilities could integrate the results of the CEC's biennial Integrated Energy Policy Report, along with the findings of the Energy Action Plan, into their resource plans and resultant request for offers. The offers can range from sales of short-term peaking power from existing plants, to long-term baseload or load-following power from future plants, and everything in between. The utilities are also allowed to reduce their energy and capacity needs through aggressive pursuit of efficiency and conservation programs, and earn profits by doing so, and also must include in their plans proposals for meeting the 20 percent Renewable Portfolio Standards requirement in coming years.

The CPUC and participating LSE's are encouraging all types of proposals to meet their future needs, such as purchasing power from existing plants or new or repowered plants that would be owned by independent developers, buying plants built for them by others (turnkey), or implementing new efficiency and conservation programs. OTC plant owners have submitted bids to the utilities in response to recent RA request for proposals, resulting in some of those plants being awarded contracts for as long as 4 years (to 2011), even though the RA process specifies only a minimum one-year term.[10]

Future OTC Plant Participation in RA/LTP

Looking forward, many of the present OTC plants would appear to have somewhat of an advantage in the RA/procurement process because of the passage of Assembly Bill 1576 in 2005, which gives repowered OTC plants preferential treatment over other plants.[11] AB 1576 authorizes the state's utilities to enter into long-term contracts for the output of certain repowered generation facilities, and allows the utilities to recover the costs of those contracts in their rates "from all customers who benefit from the repowered facilities." The bill created a new class of power plants: repowered units necessary for local reliability with costs recovered on a cost-of-service basis even though they are not owned by a regulated electric utility. To qualify, the bill requires that:

- The repowering is of an existing project, located within the existing boundaries of the existing plant, not requiring significant additional rights-of-way or fuel-related transmission facilities, and would result in significant and substantial increases in efficiency;
- The CEC certifies that the project is eligible for certification pursuant to Section 25550.5 of the Public Resources Code, which mandates that the CEC process the repowering application within 180 days; and
- The CAISO (or other applicable system operator) certifies that the project is necessary for local area reliability, and the CEC or local governing body concurs.

AB 1576 resulted in an order in the CPUC's Long-Term Procurement proceeding stating:

"If new generation resources are required, utilities should first consider the advantages of repowering existing plants or developing brown field sites located close to load, rather than developing new green field sites remote from load and requiring substantial transmission and other upgrades to the system."

Though the aging non-nuclear OTC plant owners may have somewhat of a regulatory advantage in winning bids in the RA and procurement proceedings following a repower, many other factors can affect the ability to repower an existing OTC unit, as well as the cost of doing so. Those factors are discussed in Chapter 3. Because of these factors, predicting the viability of any single present or repowered OTC plant in the future would be speculative at best.

[10] The CPUC is now considering multiple-year forward contracts, as is the CAISO in its LCR process.
[11] Nunez, Electrical corporations: rates: repowering projects

LADWP Planning Process

As a government entity, the Los Angeles Department of Water and Power (LADWP) is exempt from the CPUC and CEC processes, and acts as its own control area operator rather than using the CAISO for such service. It also conducts its own energy system planning and procurement through a public process. Its planning, operations and procurement are overseen and approved by its Board of Commissioners, whom are appointed by the City Mayor and approved by the City Council. LADWP supplies nearly 22 gigawatt-hours (GWh) of electricity a year for the city's 1.4 million electric customers.

According to its most recent Integrated Resources Plan (2007), LADWP's plan for meeting future energy needs within its service territory largely reflect that of the state as a whole. LADWP's record peak load of about 6,163 MW occurred in July 2006. It has an installed generation capacity of 7,336 MW. It's three OTC plants, Harbor, Haynes and Scattergood, total 2,636 MW in generating capacity.

DWP's 2007 plan includes a strong preference for efficiency and conservation programs as the first means for meeting new energy requirements. It also includes goals of supplying 20 percent of its energy needs through renewable resources by 2010, and reducing its reliance on fossil-fueled power plants, especially coal-fired plants, as a means of reducing overall greenhouse gas emissions.

The utility also plans to:

- pursue expanding and enhancing its electric transmission system, particularly to gain access to renewable energy resources
- continue to repower additional in-basin generation consistent with power system needs and environmental requirements
- provide reliability enhancement measures for existing generating units and transmission and distribution system[12]

LADWP has several transmission upgrades planned and it, along with several of its municipal utility neighbors in the LA Basin, was the most recent entity to construct a major transmission line in California – the 1200 MW Mead-Adelanto 500-kV line between Southern Nevada and Southern California.[13] Though that line and other LADWP lines (such as the Mead-Phoenix line between Southern Nevada and Central Arizona) are not connected to the transmission lines controlled by the CAISO, LADWP has also made efforts in recent years to improve its interconnection with SCE, now allowing transfer of thousands of megawatts on an hourly basis between the two systems.[14] LADWP is also expanding its transmission lines in the Tehachapi Wind Resource Area to accommodate at least 500 MW of wind and other renewables as part of a larger

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[12] 2007 Final IRP Executive Summary.

[13] January 1996 in-service date with participants: LADWP, Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside, Vernon and Western Area Power Administration.

[14] See http://www.energy.ca.gov/2004_policy_update/documents/2004_roadshow_hearings/ public_comments/LADWP_2004-10-13.PDF

project that will add 1,150 MW of transfer capability for renewables and other transmission needs.[15]

Because it plans, sites, approves and constructs all its own transmission projects, LADWP's transmission planning and approval process is more stream-lined than that for the state's regulated utilities, though it still faces the same difficulties in siting and constructing lines in heavily urban area. In short, DWP's transmission planning process appears to be robust and ongoing, as is its resource planning process concerning development of new or repowered power plants.

Addressing future repowering of its OTC plants, LADWP's 2007 Integrated Resource Plan noted that repowering of existing units offers many benefits, such as already having transmission and natural gas supplies on-site, but cautions that further repowers of OTC plants is uncertain because of the evolving policy on seawater use. The IRP stated that, since a court decision that negated the U.S. EPA's proposed rules enforcing Section 316(b), DWP began studying possible means of compliance:

During this period, LADWP began a Characterization Study to determine an appropriate impingement mortality (IM) and entrainment (E) reduction method. When this study is complete, the IRP states, the results will be used to determine an appropriate course of action to 1) give guidance to the State in determining Best Professional Judgment (BPJ) and 2) comply with the Clean Water Act Section 316 (b) requirements.

The process of determining the appropriate reduction method(s) may require investigating the cost and feasibility of alternate IM/E reduction technologies. The IRP states that in order to fully assess the performance capabilities of IM/E reduction technologies, pilot studies will need to be conducted in late 2007/early 2008. Ultimately, LADWP stated its selected means for 316 (b) compliance will most likely be decided based upon the State's determination of BPJ and/or a State-wide Policy and/or a new Rule is promulgated by EPA.

LADWP is also concerned about the effect of rules enforcing Section 316(a) of the CWA, regulating the thermal effect of using seawater for cooling, on the ability to operate or repower its OTC plants:

"The potential reclassification of Haynes as an estuarine discharge, which is being disputed by LADWP, is particularly problematic. Haynes, with its once-through cooling water system, would be unable to comply with the Thermal Plan. Absent a variance from the Thermal Plan, Haynes, as presently configured, would be unable to operate. In order to obtain a variance, LADWP may need to perform thermal studies to demonstrate that the thermal criteria are more stringent than necessary to protect the environment and receive concurrence from the Regional Water Quality Control Board. An alternative to seeking a thermal variance would be to discontinue the use of once-through cooling via the use of cooling towers which, aside from the significant cost considerations and spatial constraints, could very well be un-permittable due to the significant

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[15] LADWP, April 17, 2007, presentation on Renewable Transmission at April 17, 2007, IEPR workshop, on-line at: http://www.energy.ca.gov/2007_energypolicy/documents/2007□04□17_workshop/public_comments/16%20Randy%20Howard%20LADWP.pdf

environmental impacts they would create, including impacts to the aquatic environment (the Long Beach Marina from which the Haynes Generating Station draws its cooling water could go stagnant and the San Gabriel River Flood Control Channel into which the facility discharges cooling water could be markedly altered)."

Though the factors affecting LADWP's decision to repower their OTC plants are somewhat different than for the companies owning OTC plants, in the end the decisions will likely still be based primarily on economics. The economic decisions of a municipal utility do not include the need for a profit margin, but it must justify the costs of a repower to its Board and its customers. Its planning time for developing new or repowered resources may be somewhat shortened compared to the private sector because the same entity would propose the plant and approve its cost recovery in rates, but its siting, regulatory approval, construction, and testing processes and timelines are essentially identical to that of private developers.[16] Therefore, timelines for developing new power plants or transmission projects for DWP should be quite similar to that for any other developer: about 5 years for a new power plant, and about 7 years for a new major transmission line.[17]

[16] The CEC has jurisdiction over the approval of any power plant of 50 MW or greater in the state, including repowers, regardless of whether the developer is a private company or a municipal utility.

[17] These estimates are based on observed timelines for recent projects, and the collective consensus of the state energy agencies advising this study.

Chapter 3
Present and Future OTC Plant Operations

Present Role

The 19 power plants (54 generating units, 50 gas-fired and 4 nuclear) using once-through cooling (OTC) in the state represent a wide range of power plants in terms of age, technology, and level of power operations. As shown in **Table 3-1**, Coastal Plant Generation and Capacity Factors, 2006, OTC plant operations in 2006 ranged from very low (0.2 percent capacity factor[18] for Ormond Beach 1) to extremely high (102.9 percent for Diablo Canyon 1). All available power plants in California, including all the OTC plants, operated at comparatively very high levels in 2001 during the power crisis that followed enactment of AB1890, which fundamentally changed the state's electric power market. Since then, as new power plants were constructed, transmission systems were upgraded and new policies enacted, power operations at the OTC plants have generally trended downwards. Of the 50 fossil-fueled OTC units in the state, 32 operated at less than 15 percent capacity factor in 2006.

The OTC plants can generally be separated into three basic categories of generation: baseload, load-following, and ancillary service provider. Because of physical limitations on how rapidly they can increase or decrease power operations, the state's two nuclear plants (four generating units, totaling 4,486 MW generating capacity) provide year-around baseload service, operating at or near maximum levels for 24 hours a day unless taken out of service for maintenance or refueling. The newer fossil-fueled OTC units (e.g., Moss Landing CC Units 1&2) generally operate at considerably higher capacity factors than the older OTC plants and are assumed to be load-followers, meaning they increase or decrease power operations (called ramp up or ramp down) as the demand for electricity changes over the day. Load followers operating at relatively high capacity factors are considered to be "in the money," meaning they are able to sell a significant portion of their output on a daily basis in an open power market. The older, less-efficient gas-fired OTC plants generally provide needed local reliability or ancillary services, and occasionally make sales into the market when demand is high or more efficient plants are not available. Reliability and ancillary services include spinning and non-spinning reserve

[18] Annual capacity factor measures actual plant generation compared to the theoretical maximum amount of generation the plant could possibly produce if it operated at full capacity for the entire year, expressed in a percentage ratio.

service,[19] under which many OTC plants stand ready to provide service in an emergency situation, such as when a power plant or important transmission line unexpectedly trips off-line.

As discussed in Chapter 2, reliability services were until recently generally provided through a reliability must-run (RMR) contract with the California Independent System Operator. These one-year contracts are awarded to plants considered vital to local reliability in one of 10 local reliability areas (LRA) in the state. The RMR process has been overhauled and renamed the Local Capacity Reserve process, and has largely been superseded by the California Public Utilities Commission's (CPUC) Resource Adequacy process.

Of the 54 OTC units in the state, South Bay Units 1-4, Encina Units 1-5, and Potrero Units 3-6 were awarded RMR contracts for 2007. The South Bay and Encina Units serve the San Diego reliability area; the Contra Costa and Potrero Units serve the Greater Bay Area reliability area; and the Humboldt Units serve the Humboldt reliability area. Contra Costa Units 1&2 and Humboldt Bay Units 1&2 were also awarded RMR contracts for 2007, but only for ancillary services and not for straight generating capacity. Contra Costa Units 1&2 have been converted to synchronous condensers and no longer use OTC. Contra Costa Unit 7, Pittsburg Units 5&6, and Huntington Beach Units 1&2 held RMR contracts for 2006, but those were not renewed after the CAISO determined the generating capacity or ancillary service provided by those plants had been superseded by contracts signed under the Resource Adequacy (RA) process administered by the California Public Utilities Commission.

Within the OTC plant fleet, the RMR plants generally operate at somewhat higher power operations than non-RMR plants of similar age because they essentially have a captive market, but not always. Contra Costa Unit 7, for example, had a capacity factor of just 3.8 percent in 2006 and its non-RMR sister Unit 6 had a 0.9 percent capacity factor, indicating they are not needed for energy the majority of the time, but in times of stress they can be essential for reliability services. The Humboldt Bay plants, on the other hand, operated above 45 percent capacity factors because at least one of those units must be on line at all times to meet the local load requirements in a transmission-constrained local reliability area.

Other than the nuclear units, only the relatively new Moss Landing combined-cycle Units 1&2 operated above a 50 percent capacity factor in 2006, participating almost daily when available in the day-ahead energy market administered by the CAISO. Next highest of the non-RMR fossil plants was LADWP's Haynes plant, at 24.7 percent. All other non-RMR fossil units operated at less than 21 percent. These low power levels generally reflect the age and relative inefficiency of the OTC gas-fired fleet, compared to the overall generating fleet that serves the California market.[20]

[19] Spinning reserve refers to plants that are fully started up with turbines spinning but at minimum load, serving only the internal loads of the plant. Non-spinning reserve refers to plants that are not running but can be started up and placed on-line quickly in the event of an emergency.
[20] There are exceptions, where older non-RMR plants run at higher levels than newer ones at the same site. These anomalies appear to be largely due to current contract requirements.

Table 3-1. Coastal Plant Generation and Capacity Factors, 2006

		Unit-Level Capacity Factors						Net MWh						MW					
PlantName	Unit	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006
Alamitos	1	10.0%	9.5%	8.1%	6.5%	2.7%	3.3%	152,582	145,384	124,706	99,975	41,526	50,032	175	175	175	175	175	175
	2	20.7%	11.1%	8.5%	6.9%	2.1%	2.7%	316,701	169,842	130,173	105,647	32,665	41,327	175	175	175	175	175	175
	3	44.5%	35.0%	36.7%	23.7%	9.1%	17.1%	1,246,193	1,000,506	1,046,905	675,929	260,716	487,623	320	326	326	326	326	326
	4	47.6%	23.6%	20.8%	19.1%	5.5%	7.9%	1,334,192	669,664	591,286	543,098	155,027	225,536	320	324	324	324	324	324
	5	66.9%	33.7%	20.2%	25.2%	9.3%	9.3%	2,812,989	1,431,646	858,710	1,070,064	393,998	393,097	480	485	485	485	485	485
	6	63.8%	18.8%	18.4%	10.8%	10.1%	11.3%	2,681,308	798,059	782,660	459,661	427,180	479,110	480	485	485	485	485	485
Contra Costa Power Plant	6	62.0%	28.5%	1.9%	4.1%	1.1%	0.8%	1,846,500	847,953	56,233	121,481	34,088	24,928	340	340	340	340	340	340
	7	49.7%	37.1%	16.3%	21.6%	10.0%	3.8%	1,479,248	1,103,846	484,714	643,188	296,949	113,880	340	340	340	340	340	340
Diablo Canyon	1	98.4%	72.7%	99.2%	74.6%	86.0%	102.9%	9,503,622	7,020,202	9,585,431	7,208,257	8,313,575	9,944,983	1103	1103	1103	1103	1103	1103
	2	89.8%	96.4%	80.0%	83.1%	98.1%	88.5%	8,648,375	9,285,006	7,699,608	8,001,944	9,441,727	8,520,000	1099	1099	1099	1099	1099	1099
El Segundo Power	1	19.4%	3.3%					297,022	47,571					175	163				
	2	17.0%	1.6%					259,904	22,837					175	163				
	3	24.4%	35.3%	23.7%	8.8%	12.5%	11.6%	716,640	1,035,943	696,180	258,510	366,353	339,515	335	335	335	335	335	335
	4	56.0%	45.6%	19.7%	7.8%	10.2%	9.5%	1,644,671	1,338,198	578,943	228,547	297,908	277,742	335	335	335	335	335	335
Encina	1	41.1%	16.8%	13.8%	20.4%	15.6%	4.6%	342,217	139,554	114,506	169,757	146,205	42,911	95	95	95	95	107	107
	2	40.2%	19.4%	15.5%	23.7%	17.3%	9.6%	366,631	176,549	141,348	216,139	157,440	87,071	104	104	104	104	104	104
	3	46.5%	18.8%	21.1%	34.2%	18.7%	11.6%	447,600	181,019	203,478	329,607	179,890	111,523	110	110	110	110	110	110
	4	56.5%	33.1%	33.7%	43.9%	30.7%	17.9%	1,484,827	869,626	886,183	1,153,198	806,465	470,393	300	300	300	300	300	300
	5	42.6%	34.6%	38.5%	43.5%	19.9%	18.7%	1,214,083	985,062	1,095,215	1,237,406	575,978	541,681	325	325	325	325	330	330
Harbor	CC	28.4%	31.7%	24.9%	15.1%	13.5%	9.1%	594,510	664,712	496,052	300,721	267,526	180,326	239	239	227	227	227	227
Haynes	all	23.6%	16.5%	17.7%	14.5%	25.9%	24.7%	3,315,253	2,328,262	2,484,718	2,046,335	3,648,483	3,481,810	1606	1606	1606	1606	1606	1606
Humboldt Bay	1	62.1%	39.7%	26.8%	38.7%	46.6%	46.2%	288,284	184,332	124,366	179,741	216,451	214,673	53	53	53	53	53	53
	2	77.3%	38.8%	18.7%	38.4%	45.0%	45.6%	365,819	183,478	88,236	181,674	212,662	215,772	54	54	54	54	54	54
Huntington Beach	1	36.2%	31.5%	36.5%	38.6%	26.0%	20.4%	681,118	593,836	687,507	726,128	489,439	384,361	215	215	215	215	215	215
	2	32.4%	37.4%	36.8%	40.8%	22.1%	16.7%	610,778	704,718	692,315	767,623	415,798	314,227	215	215	215	215	215	215
	3			8.2%	18.7%	19.3%	11.6%			160,724	368,439	379,713	229,597	225	225	225	225	225	225
	4			8.9%	17.5%	13.7%	10.8%			175,356	344,740	269,646	212,553	225	225	225	225	225	225
Mandalay Generating Station	1	53.7%	25.2%	14.2%	15.5%	7.3%	7.8%	1,011,606	474,274	268,375	291,888	137,567	148,318	215	215	215	215	215	218
	2	54.2%	28.2%	18.1%	20.1%	11.2%	8.6%	1,019,962	531,217	341,282	378,187	211,460	163,999	215	215	215	215	215	218
Morro Bay Power Plant	1	30.5%	2.1%	0.3%				416,270	28,773	3,824				156	156	156			
	2	34.1%	5.1%	1.2%				465,793	70,032	16,661				156	156	156			
	3	67.6%	18.2%	5.3%	8.5%	6.3%	6.8%	1,776,305	477,710	140,106	223,373	166,175	178,531	300	300	300	300	300	300
	4	55.9%	36.2%	5.3%	4.1%	5.8%	5.6%	1,468,682	952,001	139,114	108,775	153,085	145,994	300	300	300	300	300	300
Moss Landing Power Plant	CC1		29.7%	60.0%	50.2%	50.0%	56.7%		1,403,695	2,839,092	2,376,068	2,365,094	2,682,447		540	540	540	540	540
	CC2		26.0%	53.6%	58.9%	53.2%	56.6%		1,230,641	2,536,060	2,787,905	2,518,509	2,679,697		540	540	540	540	540
	6	57.2%	36.2%	9.0%	5.6%	3.8%	6.2%	3,532,315	2,223,839	554,528	344,032	235,205	380,210	705	702	702	702	702	702
	7	79.9%	27.1%	11.8%	12.0%	3.8%	10.8%	4,914,734	1,664,460	724,555	736,306	231,933	663,004	702	702	702	702	702	702
Ormond Beach Generating Station	1	46.5%	17.7%	11.2%	20.0%	2.0%	0.2%	3,054,687	1,161,114	737,821	1,313,299	133,615	15,939	750	750	750	750	750	806
	2	45.0%	17.9%	16.5%	14.2%	6.0%	6.5%	2,953,302	1,175,626	1,081,400	935,344	391,101	456,997	750	750	750	750	750	806
Pittsburg Power Plant	5	54.4%	19.1%	26.0%	23.1%	12.0%	7.4%	1,548,201	543,207	740,839	657,632	341,666	211,384	325	325	325	325	325	325
	6	62.3%	23.9%	7.0%	20.3%	7.1%	5.2%	1,774,791	681,269	197,881	578,967	202,408	147,870	325	325	325	325	325	325
	7	71.4%	40.9%	16.3%	9.0%	1.7%	1.4%	4,504,836	2,581,405	1,026,447	566,225	108,788	87,997	720	720	720	720	720	720
Potrero Power	3	56.4%	30.0%	45.5%	46.6%	21.3%	28.8%	1,022,727	544,528	824,960	844,596	385,621	521,444	207	207	207	207	207	207
Redondo Beach LLC	5	10.8%	5.4%	8.3%	2.3%	1.0%	1.7%	165,674	83,270	126,838	35,915	14,631	26,960	175	175	175	175	175	179
	6	24.3%	3.1%	1.7%	1.5%	1.1%	1.7%	372,640	47,314	25,810	22,599	17,250	26,225	175	175	175	175	175	175
	7	67.2%	22.8%	12.6%	17.5%	6.6%	6.7%	2,824,702	960,270	529,386	736,394	278,134	287,648	480	480	480	480	480	493
	8	66.7%	23.2%	8.6%	11.1%	2.7%	5.6%	2,802,693	975,607	360,689	467,634	114,197	242,145	480	480	480	480	480	496
San Onofre	2	96.1%	86.1%	98.4%	81.6%	90.5%	68.4%	9,492,023	8,499,969	9,712,482	8,054,877	8,931,731	6,753,997	1127	1127	1127	1127	1127	1127
	3	57.2%	96.7%	87.1%	70.7%	95.9%	69.0%	5,649,799	9,548,152	8,596,269	6,976,282	9,468,279	6,816,843	1127	1127	1127	1127	1127	1127
Scattergood	all	24.8%	16.5%	31.7%	24.8%	13.6%	21.3%	1,743,859	1,160,981	2,227,165	1,741,384	956,572	1,498,069	803	803	803	803	803	803
South Bay Power Plant	1	51.5%	35.5%	34.1%	43.6%	45.9%	32.5%	613,499	423,016	406,292	519,153	546,285	387,083	136	136	136	136	136	136
	2	51.2%	37.3%	39.2%	51.3%	35.8%	29.7%	610,371	444,848	466,938	611,512	427,043	353,689	136	136	136	136	136	136
	3	31.0%	16.2%	22.2%	29.8%	23.6%	7.0%	569,850	298,819	409,023	548,004	434,765	128,967	210	210	210	210	210	210
	4	9.6%	4.1%	2.5%	12.5%	6.7%	4.8%	179,238	77,007	46,489	234,612	125,877	89,415	214	214	214	214	214	214

Notes: Coastal Power Plant Units with Once-Through Colling - Unit-Level Capacity Factors calculated based on CEC QFER generation database.
(Include steam turbine and combined-cycle units, exclude simple-cycle combustion turbine units)

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On an average day, the non-nuclear OTC plants provide a small portion of the state's energy and capacity needs, but the RMR plants (and the units chosen through the RA process) play a vital roll in providing voltage and frequency support in local reliability areas, or acting as spinning or non-spinning reserve units standing at the ready in case a major power plant or transmission line trips off-line. In winter months, when power demand is lowest, many OTC units are shutdown for months at a time. However, essentially every generating plant that can deliver power to the California grid, including the entire OTC fleet, operates at near maximum levels on peak demand days, which occur in the hot summer months. Specific plants can also be in high demand during unusual hot spells in the "shoulder months" in spring and fall when other plants are off-line for maintenance.[21]

Future Operations

Though the power output of the non-nuclear OTC plants have generally trended downward in recent years, their future power levels could increase, remain the same, or decrease, whether or not they continue to use OTC. Future power levels of any power plant in California depend on many factors beyond the owner's control, including:

- the extent of peak and average load growth;
- success of new demand-side management programs;[22]
- progress in developing new, more-efficient power plants, including the repowering of other OTC units, and in improving the transmission system;
- the degree to which state goals for renewable energy production are met; and
- the amount of new natural gas infrastructure constructed and resultant effect on prices

These factors are briefly discussed below.

Load Growth

The highest peak load total in the state in 2006 was 60,129 MW. By comparison, the total generating capacity of the OTC fleet is just under 21,000 MW, about 4500 MW of which come from the two nuclear plants. Load growth in the state is projected to continue at about 1.1 to 1.2 percent per year for the foreseeable future, but load factor (the ratio of average load to peak load) is expected to worsen because of the concentration of residential development in high-

[21] Backed by official state policy, the state's regulated utilities buy the most fuel-efficient (i.e., least-cost) power available to fulfill demand. Only during period of high demand are they forced to buy power from the less-efficient older plants that make up the bulk of the OTC fleet.
[22] Demand-side management refers to efforts that reduce or avoid peak loads, such as conservation and efficiency programs, and load-shifting to off-peak hours.

temperature areas, especially the Inland Empire region,[23] and resultant high use of residential air conditioning use on peak demand days. The trend of having a greater proportion of homes in warmer areas, and having more homes and businesses with central air conditioning, is expected to continue throughout the forecast period.[24] Therefore, though the growth in energy use overall may slow due to accelerated efficiency and conservation goals, the growth in demand for peak generating capacity may not match that reduction. This means the state may need considerably more generating capacity in the future than it does now in order to meet the peak, but have lower overall energy demand throughout the year.

Efficiency and Renewables

The CEC's load growth forecasts assume a certain level of success in meeting demand-side management goals, and its supply forecasts assume a certain level of success in meeting the state's renewable resource development goals. To the degree that the state can implement new efficiency and conservation programs in the coming years beyond those goals, as well as resolve engineering and other challenges of meeting 20 percent of the state's needs with renewable power resources by 2010,[25] the need for the non-nuclear OTC plants in the future could decrease considerably. This reduced need could perhaps force some of them into retirement based on market economics alone, regardless of any requirement concerning OTC. This would especially be so if solar power development makes significant penetration into the market because solar is readily available when it is needed most on hot summer days, and in that sense would compete directly with the non-nuclear OTC fleet during the times that they are now most competitive. Indeed, the CEC Staff's recent Scenarios report predicted that the effects of retiring all aging power plants by 2012 (not just the OTC plants) would be considerably less than without such aggressive implementation of demand-side management.[26]

On the other hand, if renewable and demand-side goals are not met and peak demand continues to grow faster than overall demand, the state will likely continue to rely on power plants that are idle for much of the year—running only during the hottest times of the summer or during unpredicted heat waves during the shoulder months when many other plants are off-line for maintenance. In that case, the relevant issue for OTC plant owners would be whether they can compete against new plants constructed in the coming years, and whether transmission system improvements would reduce reliance on current OTC generators, both for reliability service and for peak generation.

[23] The Inland Empire is the largest area of Southern California, consisting of inland areas between the Orange County and Los Angeles County coast and Palm Springs and other desert cities. It contains more than 50 cities, including Riverside, San Bernardino and Ontario, and is one of the fastest growing parts of the country.
[24] CEC Load Forecast, 2008-2018, http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF
[25] Under the Renewable Portfolio Standards requirement of state law SB107, by 2010 at least 20 percent of the energy purchased by the state's utilities must come from renewable resources.
[26] This report is discussed in detail in Chapter 4.

New Plant Development

The CEC cites new power plant development as the primary reason that non-nuclear OTC plant generation has trended downwards in recent years. Just under 13,000 MW of new generation has come on line in the state since the power crisis of 2001, while 73 generating units totaling about 6,130 MW in generating capacity were retired during that period. Another 2,278 MW is under construction, and nearly 7,000 MW of projects have been approved but are currently on hold for a variety of reasons.[27] The CEC is currently processing Applications for Certification (AFCs) for another 7,500 MW of generating capacity, and another 6,500 MW of projects have been announced but have not yet filed AFCs with the CEC. The CEC also expects another 6,700 MW of projects will be announced in the near future.[28]

The nearly 30,000 MW of plants that are either planned, in the permitting process, or under construction would seem to more than compensate for the extremely remote possibility that all the present OTC plants retire in the near future. But the key issue would be whether the new plants would be able to provide the same services currently provided by OTC plants. To do that, the new plant would have to connect to the transmission grid at an equivalent location or at another point that would allow transferring power to where it is needed. Because all but two of the 16 non-nuclear OTC plants are located in transmission-constrained regions, their replacement would require construction of a new or repowered plant in the same region or upgrading the transmission system such that replacement power could come from outside the region.

Replacement of retired OTC units in the LA Basin offers additional challenges because of the complexity and variability of the transmission system in the area. For instance, Southern California Edison's part of CAISO control area already imports the majority of its power requirements through one or more of the eight major transmission lines feeding the regions. Because of this, a complex set of operating procedures know as the SCIT nomogram was developed and has to be followed to ensure that sufficient generating capacity is on line and operating to ensure stability of the grid. However, generally a minimum of 40 percent of SCE's load has to be covered by in-basin generation, and the exact amount and location of that needed generation changes almost constantly depending on the loading of each of the eight transmission lines feeding the region. This means that some power plants not only have to be available to start up to cover emergencies but some need to be synchronized and ready to ramp up immediately to follow loads to assure frequency control and voltage support.

Transmission System Upgrades

Transmission upgrades could have as much or more of an effect on future non-nuclear OTC plant production as new power plant development, especially those

[27] Economic issues are generally cited as the main issue plants are postponed, usually related to unpredicted expenses found during the development process such as needing substantial transmission system upgrades, changes in the market affecting economic viability of a plant, or uncertainty related to contracting for the plant's output.
[28] See http://www.energy.ca.gov/sitingcases/FACTSHEET_SUMMARY.PDF

providing local reliability services within one of the state's 10 LRAs where transmission constraints limit the ability to transfer power in or out of that area (see Figure 1-1 in Chapter 1). Only the two nuclear plants and the Morro Bay and Moss Landing plants are not within an LRA, but although they do not supply reliability service within an LRA, those plants are critically located within the transmission system to help alleviate congestion on key transmission lines between Northern and Southern California (Morro Bay, Moss Landing and Diablo Canyon) and between the Los Angeles and San Diego areas (San Onofre).

Until recently, the transmission process in the state was widely criticized as Byzantine and ineffective, mostly because of a disconnect between the planning and permitting process for transmission projects. For instance, before 2004 the CAISO would approve a proposed transmission project and utilities would then apply for approval from the CPUC to build the project and recover the costs of the project from ratepayers through the Certificate of Public Convenience and Necessity (CPCN) process. But the CPUC and CAISO used different criteria for deciding whether a transmission project was needed, resulting in conflicting decisions.

Prompted by passage of AB 57 (see below) in 2002, the CEC, CPUC and the now-defunct California Power Authority pledged to improve the transmission planning process in the state through the Energy Action Plan (EAP), which was updated by the CEC and CPUC in 2005. The EAP noted that:

> "An expanded, robust electric transmission system is required to access cleaner and more competitively priced energy, mitigate grid congestion, increase grid reliability, **permit the retirement of aging plants, and bring new renewable and conventional power plants on line** (emphasis added). Streamlined, open and fair transmission planning and permitting processes must move projects through planning and into construction in a timely manner. The state agencies must work closely with the CAISO to achieve these objectives and to benefit from its expertise in grid operation and planning."[29]

The EAP has been effective in improving the planning process, resulting in an agreement in 2004 between the CAISO and CPUC to use the same criteria for approving a transmission project as for obtaining a CPCN for construction. Further, it resulted in the CAISO proposing in January 2007 to completely overhaul its transmission planning process, which would now include an open, stakeholder-approach that enlisted the support and assistance of the state's investor-owned utilities, the CEC, the CPUC, and virtually anyone else concerned with planning, siting, constructing and operating new projects.[30]

The Legislature has also been highly interested in streamlining the transmission planning process in the state and last year passed Senate Bill 1059,[31] which also helps build a bridge between the transmission planning process and the permitting process. The bill directed the CEC to designate transmission corridor zones on state and private lands available for future high-voltage transmission

[29] See http://www.energy.ca.gov/energy_action_plan/index.html
[30] See http://www.caiso.com/thegrid/planning/
[31] SB 1059, Escutia and Morrow, Chapter 638, Statutes of 2006

projects, consistent with the state's electricity needs identified in the CEC's biennial Integrated Energy Policy Report and Strategic Transmission Investment Plan. Similar federal legislation[32] directed the Department of Energy to study barriers to transmission planning and construction and led DOE in 2006 to designate much of Southern California and Western Arizona as a National Interest Electric Corridor, within which DOE was granted federal eminent domain authority to secure land for new rights-of-way.[33] In effect, the energy agencies are now working more directly with the utilities and all other interested parties in developing effective transmission planning than probably any time in history.

However, despite these hoped for improvements, licensing major transmission lines is extremely contentious. Numerous citizens of a region are exposed to the visual pollution of a transmission line, and the need to condemn land from many property owners can create delays even if the project is ultimately constructed. Transmission line development in a urbanized setting is inherently even more contentious than development of a power plant, because many more impacts are distributed along its path than those concentrated around a power plant. Also complicating the process is that inter-state coordination is often needed for those out-of-state projects that benefit California.

Transmission Projects in Planning

The CAISO to date has approved at least 360 transmission projects at a total cost of more than $4.5 billion since the power emergency of 2001. In its most recent transmission plan, released in January 2007, the CAISO documented another 159 projects that the state's three largest utilities, Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison, are considering as part of their long-range transmission planning. Among these projects, 94 are in PG&E's service territory, 32 are in SCE's service territory, and 33 are in SDG&E's service territory.

For PG&E, the CAISO stated the 92 transmission projects would be used to interconnect new customers, improve service reliability, meet customer demand, and/or reduce the need for local generating capacity within certain LRAs (categorized as "reduce LCR"[34]). The projects range from minor, (such as replacing a transformer or upgrading the automatic controls that protect a portion of the system,) to large projects that involve major construction of new lines. A brief analysis of these projects shows that out of the 92 projects, 10 have already been approved by the CAISO that would reduce LCR in the Bay Area LRA and therefore would likely reduce the need for local OTC plants providing reliability services. Nine others are recommended for approval by CAISO staff, and another six are under consideration.

[32] Section 1221 of the Energy Policy Act of 2005
[33] DOE Docket No. 2007–OE–02
[34] LCR stands for local capacity requirements, referring to the CAISO's LCR process for assuring local reliability within the state's 10 LRAs. See http://www.caiso.com/1c44/1c44b8e0380a0.html

SCE's transmission projects have slightly difference categorizations: "provide operational flexibility, mitigate (transmission system) congestion, mitigate reliability criteria violations, meet customer demand, or (provide) access to low-cost resources." Except those built to meet customer demand, almost all these projects have potential to reduce the need for local generating capacity in the Los Angeles or BigCreek/Ventura LRA's, and could affect the need for generation now produced by OTC plants within those areas. Of the 32 SCE projects listed in the plan, six that would reduce reliability criteria violations in the two LRA's have already been approved by the CAISO, another eight are recommended for approval, and four are under consideration.

The biggest project approved by the CAISO so far this year was SCE's $1.8-billion expansion plan for the Tehachapi area of Southern California, which would allow greater access to the area's abundant wind energy. SCE still must obtain approval from the CPUC, but the CPUC last June assured the state's investor-owned utilities that it would allow cost recovery from ratepayers for transmission construction to serve renewable-energy plants.[35]

SDG&E was still in the process of finalizing its transmission expansion plan when the 2007 CAISO Transmission Plan was published, so no information was available concerning the ability of any new transmission project in that area to reduce the need for generation from the South Bay or Encina power plants, which currently supply reliability services within the San Diego LRA. The plan noted, "However, moving toward 2007, this issue is anticipated to be resolved as CAISO and PTOs [Participating Transmission Owners] are developing unified planning assumptions, a single study plan, and organized schedules/major milestones for all studies performed by CAISO and PTOs. This effort will enhance the efficiency of the entire planning process and ensure seamless flow of information."

Without extensive analysis of each of these transmission projects, determining their exact effect on future OTC fleet generation is not possible. However, the three utilities have strong financial incentives to continue to improve their transmission systems in order to gain access to cheaper generation sources, including newer, more efficient generation within the state, as well as out-of-state generation in the Pacific Northwest and Desert Southwest. The 2007 Transmission Plan appears to confirm that the utilities are indeed pursuing that strategy, and by all reports the process for moving the projects from planning to construction has improved, and continues to do so.[36]

While all parties agree that transmission improvements can effectively mitigate many problems in the electric utility industry, including continued reliance on older, less-efficient power plants (many of which are OTC plants), and that the transmission planning process is rapidly improving, the main issue concerning the ability of transmission improvements to replace lost OTC generating capacity is time. Many of the projects listed in the CAISO's transmission plan that are meant to reduce local reliability needs are not slated for completion until after

[35] See http://enr.construction.com/news/powerIndus/archives/070205a.asp

[36] Since this project began, the 2008 Transmission Plan process is well underway. A draft 2008 Transmission Plan was released by the CAISO in early December 2007, and a stakeholder meeting was held in mid-December. It is set to be finalized and adopted by the CAISO Board later in January 2008 or early February. See http://www.caiso.com/1f49/1f49c0029850.pdf

2012, and the ones projected before that date are the low-hanging fruit, made up of relatively modest reconductorings[37] and transformer replacements.

According to the CAISO's report, no major transmission projects (those requiring new corridors over extended distances) are slated for completion prior to 2015. The CEC's transmission corridor program and DOE's similar effort on the national level are still in their nascent stages, and it is now impossible to predict whether they would result in construction of new major transmission lines prior to 2015. Therefore, though the likely effect of future transmission system improvement alone would be to enhance the current downward trend of generation from the non-nuclear OTC fleet, quantifying that effect would require an exhaustive analysis of each proposed transmission project, which is beyond the scope of this study.

Future OTC Plant Operations

Using information from recent studies and electric power-related data collected by the CEC and CAISO, this study attempts to predict the effects of the Water Board's OTC decision on future operations of the OTC fleet, and the resultant impact on the reliability of the entire grid. The OTC plant owners are also looking at these same data and sources of information, and will likely make their decisions affecting future operations based on long-term goals, weighing costs and benefits.

Their options under the Board's proposed OTC policy include:

- continuing operation of the present facility with a retrofitted cooling, or take some other action to comply with the Board's new policy
- repowering the present facility in conjunction with installing either dry cooling or wet cooling
- retiring and converting the site to some other land use

As to predicting which option a given plant owner would choose, very little evidence exists that would allow such a prediction to be anything more than speculation. Some of the OTC plant owners hold contracts that require they remain available to provide various services to the grid, such as the RMR contracts discussed above. But those contracts extend for only one year, giving their owners little long-term security. Others are still under contract with the state Department of Water Resources, which took over acquisition of energy resources for the state's investor-owned utilities from the now-defunct Power Exchange in the wake of the 2001 power crisis. Alamitos Units 1&5, Huntington Beach Units 1&2 and a unit at the Redondo Beach site are under contract to DWR at least through 2010.[38]

[37] A reconductoring involves replacing the cables and perhaps some towers on an existing transmission line, resulting generally in increasing the power carrying capacity of that line. Reconductoring projects are exempt from CEQA review.

[38] During the 2001 energy crisis, the Governor and the Legislature gave DWR the statutory authority to purchase and schedule all electricity used by the then nearly bankrupt major power utilities in the state. DWR used its authority to enter into long-term contracts with power producers to

Several OTC plants are also now under obligation to provide reliability services in coming years as a result of the CPUC's Resource Adequacy (RA) process. **Table 3-2** shows the amount of OTC generating capacity currently obligated to provide reliability service in each of the four local reliability areas where OTC plants are located.[39] As shown in the table, 15,343 MW of OTC generating capacity are under contract in 2008. The contracted capacity in those areas declines to 12,602 MW in 2010, 8839 MW in 2011, and 6391 MW in 2012. However, as in the RMR process, the utilities are only required to sign yearly contracts for reliability services, meaning that the decrease in capacity under contract after 2008 does not imply reduced need for these plants, but instead reflects the immediate one year-ahead nature of the RA program and RMR contracting timelines. The structure of the longer-term RA program, which may extend the procurement obligations farther into the future, is under consideration at the CPUC in rulemaking R.05-120-013.

Table 3-2. Local Capacity Requirements Satisfied From OTC Power Plant Capacity (MW)

Load Pocket	2008	2009	2010	2011	2012
West LA Basin Subtotal	6544	6401	5950	4122	2202
Greater Bay Area Subtotal	2252	2252	1532	882	207
San Diego Subtotal	1619	1619	0	0	0
Big Creek-Ventura Subtotal	1109	197	721	945	1742
Not in Local Area	3819	4399	4399	2890	2240
Grand Total	**15,343**	**14,868**	**12,602**	**8839**	**6391**

OTC plant owners are also looking at whether cooling system conversion, with or without also repowering, would pay off in the long term. For an individual power plant owner, the greater their present ability to compete in an open market, the more likely they are to convert their OTC systems while not repowering. However, given the relative inefficiency and age of much of the OTC gas-fired fleet, and given that many of them already operate at very low power levels, repowering their facility while installing an alternate cooling method, or retiring and converting to another use, may be more likely options for the bulk of the OTC fleet.

Most of the owners of the less-efficient OTC plants are relatively recent entries into the California market. They are major energy companies that bought into the California market by purchasing the plants from the state's three major investor-owned utilities, which were encouraged to divest much of their generating fleets in the state law that mandated the restructuring of the state's energy industry, AB1890. These companies must now decide how best to maximize the value of their investments, such as through repowering.

stabilize the volatile wholesale energy market and to provide the revenue certainty needed by suppliers to secure financing for construction of necessary new power plants. DWR has been renegotiating the terms and conditions of those contracts when possible.

[39] This data is presented in aggregated form because the terms of individual contracts are confidential. It includes units awarded contracts under the RA process, units owned by the local utility, and units contracted to DWR. The Humboldt reliability area is not included because the only OTC plant there will be shut down as soon as PG&E completes construction of its replacement.

Repowering of existing facilities offers considerable economic benefits compared to developing a new power plant elsewhere. An existing facility already is connected to the grid, and a replacement facility of at least equal generating capacity generally can be accommodated in the grid without any major transmission system upgrades.[40] They also already have natural gas supply to the site, consisting generally of 36 to 48-inch pipelines routed to the site from backbone gas pipeline systems. Transmission and gas pipeline system upgrades for new facilities on undeveloped sites can easily range into the hundreds of millions of dollars and in some cases are higher than the cost of the facility itself (Calpine's San Joaquin Valley facility, for example). With the utility switchyard and gas supply pipeline already on-site, present OTC plants have a considerable economic advantage over undeveloped sites for this reason alone.

The state's Legislature and Governor, through passage of AB 1576 (discussed in detail in Chapter 2), have also provided incentives for repowering OTC plants by allowing utilities to contract directly with repowered units at existing OTC sites and automatically recover the costs of such contracts in their rates. Because all but two of the non-nuclear OTC plants are located within a local reliability area, they also have an advantage of being able to provide power where it is needed most—near the state's large load pockets—giving them an edge in providing service compared to plants outside the area.

The state's evolving greenhouse gas policy also may have a significant effect on decisions about whether to retire or repower aging OTC units. A recent bill, the Global Warming Solutions Act of 2006 (AB 32) declared the state's policy to reduce in-state greenhouse gas emissions to 2000 levels by 2010, to 1990 levels by 2020, and 80 percent below 1990 levels by 2050. The CEC's recent 2007 Integrated Energy Policy Report (IEPR) listed several challenges that must be overcome in order meet the goals of AB 32, including continued reliance on aging generating units, most of which use OTC. "California's aging power plants are extremely inefficient compared to current technologies that are 20 to 30 percent more efficient; these plants need to be either repowered or retired and replaced with cleaner technologies that operate at higher efficiency to contribute to AB 32 goals."[41]

In the 2005 IEPR, the CEC urged the state's utilities to undertake long-term planning and procurement to allow for the orderly retirement or repowering by 2012 of the aging plants in that study group, which included units at all the non-nuclear OTC plants. The 2007 IEPR repeats that recommendation, and notes, "Currently, only PG&E has submitted a long-term procurement plan that contains enough new generation and transmission investments to avoid relying on aging plants after 2012. In contrast, SCE relies on these plants through 2016, and SDG&E's plan relies on the aging Encina facility throughout its planning period (although the Encina owner has announced plans to replace the old plant with a modernized design better suited to evolving loads and dispensing with ocean water cooling)."

[40] Repowered plants are considerably more efficient than the older units they replace, meaning they can generate more power with the same amount of fuel. However, their maximum generating capacity into the grid may be limited by transmission constraints.
[41] CEC-100-2007-008-CTF. On-line at: http://www.energy.ca.gov/2007_energypolicy/index.html

Finally, the CEC stated in its 2007 IEPR, “California’s policy makers want to encourage retirement of the remaining steam boiler plants in California and encourage development at those sites of cleaner, combustion-based technologies that operate at higher efficiency and thereby reduce the demand for natural gas. However, planning for investment in capital-intensive projects like new power plants must incorporate the risk that applications could be substantially delayed or denied if once-through cooling is used.”

OTC plant owners, then, would seem to have considerable incentives to repower their facilities, using some other form of cooling than OTC. However, various constraints, such as incompatible land uses around a given site, could greatly affect the ability to repower certain sites. With the exception of the new units recently constructed at the Haynes, Moss Landing, and Huntington Beach plants, all of the existing OTC generating units in the state were constructed prior to the enactment of the California Environmental Quality Act (CEQA) or the Warren-Alquist Act, which created the California Energy Commission and its CEQA-equivalent process for approving new thermal power plants of 50 MW or greater. Until and unless they seek permits for the repowering, the owners of older OTC plants have no assurance that repowerings would be allowed at present sites nor that environmental mitigation-related expense would make such repowerings uneconomical if allowed at all.

The aging OTC boiler plants in Southern California also may have difficulty in obtaining inexpensive air emission offset credits to compensate for the impact of air emissions from a repowered facility, as the South Coast Air Quality Management District has decided to award offsets related to a repowering based on that plant’s recent emissions, rather than historical highs.[42] Because the aging boiler OTC units have operated at relatively low power levels in recent years, their owners would likely have to purchase substantial amounts of emission offset credits for a repowered facility, at considerable cost. The exact effect on repowering decisions from this policy alone is uncertain, but certainly reduces the economic advantages of repowering compared to other areas of the state. SCAQMD is conducting its own electric reliability study related to its Rule 1309.1, discussed in detail in Chapter 5, which it expects to complete in late 2008.

Therefore, though certain trends are evident and well-supported, predicting the fate of any one plant is speculative at best. For that reason, this study includes an analysis of a broad range of possible scenarios encompassing all OTC plant owners following enactment of the Board’s OTC decision, and the resultant effects on the grid. The scenarios analyzed range from the extreme case of all OTC plants retiring in 2009, to a more realistic case of phasing in the new rules over time while allowing owners to either convert their cooling systems (with or without also repowering) or limit annual power operations to a specific capacity factor, as well as several other scenarios in between.

[42] Rule 1309.1, which sets stringent emission rate limits for nitrogen oxides (NOx) and coarse particulate matter (PM10) and required developers to obtain a power sales contract and a license from the CEC before they can obtain priority reserve credits for that facility. Municipal-owned plants will only be given credits to build projects that serve their native load. SCAQMD also limited the total amount of credits available for in-district generation to 2,700 MW of generation, though any power plant applicant can petition the SCAQMD board for a waiver of the requirement for a contract or to go over the 2,700 MW limit provided the applicant can demonstrate that the power plant is needed in the Basin.

The scenarios analysis also considers the likely replacements for the lost generation from any OTC plant that is retired or is limited in power operations. Location and timeline are the key factors to consider, as transmission system constraints could prevent a plant at another location from providing the same service as a retired plant, The time needed to develop a needed replacement could leave a gap in reliability service in the interval between OTC plant retirement and its replacement coming on line. These factors are discussed in detail in Chapter 4.

Effects of Likely Compliance Measures

This section discusses the potential impacts to grid system reliability that could occur as a result of actions taken by plant owners to comply with the Water Resources Control Board's new Clean Water Act Section 316(b) policy. Chapter 4 of this study focuses on the potential effects of the plant owners deciding to retire their units rather than try to comply with the new policy. This section instead discusses the physical changes that could occur at present OTC plants as their owners employ other methods and technologies that would bring their plants in compliance with the new rules, and the resulting effect on grid reliability. Much of the information in this chapter comes from the study, *California Coastal Power Plants: Cost and Engineering Analysis of Cooling System Retrofits*, conducted for the Ocean Protection Council by Tetra Tech, Inc.[43]

Changes to Plant Infrastructure

As originally proposed, OTC power plant owners would have several options to choose from in deciding how to comply with the Board's new rules. These include switching to some other form of cooling technology, with the target of achieving a 90 to 95 percent reduction in impingement and entrainment mortality rates compared to OTC use.[44] The Board proposed the new rules as a response to similar rules proposed by the U.S. EPA implementing Clean Water Act Section 316(b), which addresses impingement and entrainment impacts of OTC systems. Following the release of the Board's Scoping document in June 2006, however, a court decision negated many of the EPA's proposed rules, and as a result EPA suspended the rules on July 9, 2007. The Water Board is therefore considering other options for its new policy, including elimination of its originally proposed generating cap option, and instead mandating that units convert their cooling systems or shut down by a given date.

The expected methods for compliance are to convert their OTC cooling systems to either wet cooling or dry cooling.[45] Wet cooling involves constructing cooling

[43] See http://www.resources.ca.gov/copc/OTC.htm

[44] The impacts of cooling water withdrawals are characterized as entrainment, where small aquatic organisms are carried by the cooling water into the power plant and are killed, and as impingement, where the cooling water intake traps larger organisms against the intake screens. Cooling water effluent can also create impacts on aquatic organisms due to the thermal impact of the heated seawater discharge. Thermal impacts are covered under CWA Section 316(a).

[45] See ref. 1, and "Emerging Issues and Needs in Power Plant Cooling Systems" by Wayne C. Micheletti and John M. Burns, P.E., among others.

towers and piping to circulate water in a loop from the power plant's condensers (where steam exiting the turbine is converted back into water to be pumped back into the boiler or steam generator) to the cooling tower. Dry cooling is generally not considered a feasible replacement for present OTC plants because of cost and the relatively higher effect on efficiency than wet cooling (as discussed below). For these reason, most studies of the issue have concluded that wet cooling with forced-draft towers will be the most likely method employed for system conversion.

The net effect on power plant operations of converting to wet cooling is a decrease in the amount of power they can deliver to the grid, mostly due to the added internal or "parasitic" load of the mechanical draft cooling tower fans. Wet cooling systems often produce visible water vapor plumes that can create visual impacts, or safety concerns near highways and airports.[46] Plants near such locations are often required to install "plume-abatement" systems. These additional plume-abatement systems consume extra energy, further reducing the maximum net generation from the plant to the grid. Conversion to wet or dry cooling is also expected to have some negative effect on the overall thermal efficiency of the plant due to increased coolant temperatures and resultant effect on steam turbine backpressure, further reducing the maximum amount of power a converted plant could deliver to the grid.

Other possible methods of compliance with the new rules are discussed in the various studies and proposals cited in this chapter, such as use of variable speed seawater pumps, re-designed intake structures, advanced screening methods, and placing velocity caps on seawater flows. However, those same studies also stressed that such compliance methods have not been tested, and thorough site-specific study would likely be needed prior to their approval in any given location. Studies of this nature first require an extensive baseline study, usually followed by years of gathering data in order to prove that unproven technology will work.

It is important to note that methods of cooling system compliance have been topics of considerable controversy in the industry. For example, the Electric Power Research Institute recently released its own study of OTC issues in California concluding that many other alternatives could effectively achieve entrainment and entrapment goals, including flow reduction, velocity caps, fish collection and return systems, and restoration.[47] Though use of other methods to achieve desired impingement and entrainment goals may or may not be possible in any given case, installation of wet cooling or dry cooling (with or without repowering the plant), on the other hand, would not require such extensive baseline and follow-up studies because their effectiveness has already been proven. Also, this study is focused on examining actions that have potential to threaten grid reliability, which when applied to possible compliance measures would mean examining those technologies that use the most power, and therefore

[46] This is why most wet cooling towers are situated in a straight line in the direction of the predominant wind. This minimizes the width of any visible water vapor plume.

[47] The EPRI study also asserts that banning use of OTC in California would have no effect on the overall marine environment. See "Assessment of Once-Through Cooling System Impacts to California Coastal Fish and Fisheries," December 2007, and "Issues Analysis of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling in California Coastal Plants," TR-052907 Final Report, October 2007, both on-line at: http://www.waterboards.ca.gov/npdes/cwa316.html

would have the greatest effect on net generation to the grid. For these reasons, this section considers only the potential economic and reliability effects of use of wet or dry cooling.

Economic Effects

The Tetra Tech and EPRI studies cited above contain estimates of the costs of converting the cooling systems of each of the 18 OTC plants in California to wet cooling with seawater makeup. Both studies concluded that dry cooling would not be a viable option for converting the cooling system of an existing plant (though it remains an option for use at new or repowered plants) and therefore did not estimate the costs of dry cooling retrofits. Fixed costs of converting cooling systems at existing plants include purchase and installation of the cooling towers and related equipment, design and construction costs related to making changes to the existing plant condensers to accommodate the new cooling technology, related permitting and testing costs, and annual operations and maintenance (O&M) costs amortized over the life of the facility.

Pulled from the Tetra Tech study, **Table 3-3** shows the annual fixed costs (including procurement, design and engineering, permitting, construction, testing, O&M, and lost generation due to net generation reductions) for 15 of the 18 OTC plants. The Encina, Potrero and South Bay plants were not included as those plants were set to be repowered or retired. Total capital cost alone, the one-time expense of design, permitting and construction of the new cooling system, ranged from a low of $2.5 million for Harbor, to a high of $107.6 million for Diablo Canyon. By comparison, the nearly 18 GWh of electricity produced by the Diablo Canyon units in 2006 would have cost more than $1.5 billion had PG&E purchased the energy from other producers.[48]

[48] At PG&E's reported average cost of replacement power of $0.084/kWh, according to its 2006 annual report.

Table 3-3. Annualized Capital Cost for OTC Plants Retrofitting to Wet Cooling from Tetra Tech Study

Unit ($000)	Case 5	Case 6-8
Northern CA	**138,700**	
Contra Costa	9,300	
Diablo Canyon	83,800	
Morro Bay	8,400	
Moss Landing 1-2 CC	7,100	7,100
Moss Landing 6-7	18,300	
Pittsburg	11,800	
Southern CA	**152,500**	**29,800**
Alamitos	19,800	
Harbor	2,500	2,500
Haynes	14,800	14,800
Huntington Beach	12,500	12,500
Mandalay	5,200	
Ormond Beach	12,500	
Redondo Beach		didn't study
SONGs	54,600	
Scattergood	15,600	
Southbay	15,000	esitmated based on the number of units, capacity and Scattergood cost

Annualized capital costs are calculated by amortizing total capital costs over 20 years with assumed discount rate of 7%

Net Generation Reduction

Cooling system conversion to either wet or dry cooling generally results in a small but significant reduction in the net generating capacity the plant can deliver to the power grid. This reduction comes from two sources: (1) the increased parasitic energy use of the added equipment and (2) the increase in heat rate, or the amount of fuel needed to produce a megawatt-hour of energy, caused by the loss of heat exchange efficiency when not using cold ocean water for cooling.

The parasitic load consists of large blowers that draw air through the cooling towers, plus the pumps used to circulate the water between the plant condensers and the cooling towers or air-cooled condenser. Because wet and dry cooling water intake temperatures are generally higher than the seawater intake temperatures in OTC systems, the cooling water cannot absorb as much heat at the same mass flow-rate. This generally leads to increased back pressure on the

Table 3-4. Net Energy Penalty

Unit Name	Unit No	Max Rating	Installation Date	Retirement Date	Cooling Tower Fan Use	Cooling Tower Pump Use	Derated Pmax	Heatrate Increase	Difference
North California		**6752**					**6671**		**81.2725**
Contra Costa	6	335	1/1/1964	1/1/2019	0.55%	0.80%	330.5	0.8%	
Contra Costa	7	337	1/1/1964	1/1/2019	0.55%	0.80%	332.5	0.8%	
Diablo Canyon	1	1113	5/1/1985	1/1/2045	0.74%	0.78%	1096.1	3.7%	
Diablo Canyon	2	1135	3/1/1986	1/1/2046	0.74%	0.78%	1117.7	3.7%	
Morro Bay	3	337	12/1/1962	1/1/2017	0.50%	0.60%	333.3	1.3%	didn't study the capacity derating and heat rate change, but updated an earlier study on cost and feasibilty of alternative cooling system
Morro Bay	4	336	8/1/1963	1/1/2018	0.50%	0.60%	332.3	1.3%	see above
Moss Landing	6	754.3	12/1/1967	1/1/2022	0.58%	0.19%	748.5	1.4%	
Moss Landing	7	755.7	8/1/1968	1/1/2023	0.58%	0.19%	749.9	1.4%	
Moss Landing CC	1	510	7/11/2002	1/1/2057	0.29%	0.21%	507.5	0.5%	
Moss Landing CC	2	510	7/11/2002	1/1/2057	0.29%	0.21%	507.5	0.5%	
Pittsburg	5	312	9/1/1960	1/1/2016	0.58%	1.63%	305.1	0.9%	
Pittsburg	6	317	6/1/1961	1/1/2016	0.58%	1.63%	310.0	0.9%	
South California		**11133**					**10982**		**150.15105**
Alamitos	1	175	9/1/1956	1/1/2016	0.56%	0.43%	173.3	1.2%	
Alamitos	2	175	2/1/1957	1/1/2016	0.56%	0.43%	173.3	1.2%	
Alamitos	3	332	12/1/1961	1/1/2016	0.48%	0.56%	328.5	1.3%	
Alamitos	4	335	6/1/1962	1/1/2016	0.48%	0.56%	331.5	1.3%	
Alamitos	5	485	3/1/1964	1/1/2019	0.50%	0.57%	479.8	1.6%	
Alamitos	6	495	9/1/1966	1/1/2021	0.50%	0.57%	489.7	1.6%	
Encina	4	300	11/1/1973	1/1/2028	0.50%	0.60%	296.7	1.3%	
Encina	5	330	11/1/1978	1/1/2033	0.50%	0.60%	326.4	1.3%	
Harbor CC	10a	113.5	1/1/1994	1/1/2049	0.33%	0.33%	112.8	0.4%	
Harbor CC	10b	113.5	1/1/1994	1/1/2049	0.33%	0.33%	112.8	0.4%	
Haynes	1	222	9/1/1962	1/1/2017	0.48%	0.79%	219.2	1.1%	
Haynes	2	222	4/1/1963	1/1/2018	0.48%	0.79%	219.2	1.1%	
Haynes Repower	1a	287.5	1/26/2005	1/1/2060	0.26%	0.07%	286.6	0.5%	
Haynes Repower	1b	287.5	1/26/2005	1/1/2060	0.26%	0.07%	286.6	0.5%	
Haynes	5	341	8/1/1966	1/1/2021	0.59%	0.69%	336.6	1.2%	
Haynes	6	341	3/1/1967	1/1/2022	0.59%	0.69%	336.6	1.2%	
Huntington Beach	1	225.8	6/1/1958	1/1/2016	0.51%	0.66%	223.2	1.2%	
Huntington Beach	2	225.8	12/1/1958	1/1/2016	0.51%	0.66%	223.2	1.2%	
Huntington Beach	3M	225	5/1/1961	1/1/2016	0.49%	0.63%	222.5	1.2%	
Huntington Beach	4M	227	7/1/1961	1/1/2016	0.49%	0.63%	224.5	1.2%	
Mandalay	1	215	5/1/1959	1/1/2016	0.51%	0.52%	212.8	0.9%	
Mandalay	2	215.3	8/1/1959	1/1/2016	0.51%	0.52%	213.1	1.0%	

Table 3-4. Net Energy Penalty

Unit Name	Unit No	Max Rating	Installation Date	Retirement Date	Cooling Tower Fan Use	Cooling Tower Pump Use	Derated Pmax	Heatrate Increase	Difference
Ormond Beach	1	741	8/1/1971	1/1/2026	0.47%	0.65%	732.7	1.4%	
Ormond Beach	2	775	3/1/1973	1/1/2028	0.47%	0.65%	766.3	0.5%	
San Onofre-SONGS	2	1122.9	8/1/1983	1/1/2043	0.82%	1.27%	1099.4	2.7%	
San Onofre-SONGS	3	1108.7	4/1/1984	1/1/2044	0.82%	1.27%	1085.5	2.7%	
Scattergood	1	179	12/1/1958	1/1/2016	0.53%	0.80%	176.6	1.6%	
Scattergood	2	179	7/1/1959	1/1/2016	0.53%	0.80%	176.6	1.6%	
Scattergood	3	445	10/1/1974	1/1/2029	0.49%	2.25%	432.8	1.1%	
South Bay	1	146	7/1/1960	1/1/2016	0.53%	0.80%	144.1	1.6%	
South Bay	2	150	6/1/1962	1/1/2017	0.53%	0.80%	148.0	1.6%	
South Bay	3	175	9/1/1964	1/1/2019	0.53%	0.80%	172.7	1.6%	
South Bay	4	222	12/1/1971	1/1/2026	0.53%	0.80%	219.0	1.6%	
Total		**17885**					**17653**		**231.42355**
Encina	1	100	11/1/1954	6/30/2010	repowered		315		
Encina	2	104	7/1/1956	6/30/2010	repowered		236.3		
Encina	3	110	8/1/1958	6/30/2010	repowered		157.5		
Mandalay	3	130	4/1/1970	1/1/2025	CT, does not require cooling water				
Redondo Beach	5	178.9	10/1/1954	1/1/2016	Zonal and land use prevent conversion to wet cooling				
Redondo Beach	6	175	7/1/1957	1/1/2016	see above				
Redondo Beach	7	493.2	2/1/1967	1/1/2022	see above				
Redondo Beach	8	486.9	7/1/1967	1/1/2022	see above				
Sources:									
http://www.resources.ca.gov/copc/OTC.htm									

steam turbines connected to the condensers, reducing their efficiency somewhat. Therefore, wet and dry cooling systems use larger pipes and pumps compared to OTC systems to compensate for higher inlet temperatures.

Even with the comparatively oversized cooling systems, existing plants converting from OTC to either wet or dry cooling plants still suffer a small reduction in efficiency, meaning they have somewhat higher heat rates. **Table 3-4,** Net Energy Penalty**,**[49] shows the projected increases in heat rate and in overall "energy penalty" (the total for heat rate plus parasitic load) from conversion of existing OTC systems in the state to wet-cooling using seawater makeup. As can be seen, the increase ranges from very modest, about 1 percent for the new combined-cycle plants, to a high of about 5.5 percent for the two nuclear plants, and 2-3 percent for the older boiler plants.[50] Dry-cooled plants are more vulnerable to this effect because they rely on air temperature alone, and do not benefit from the latent heat loss associated with evaporation in a wet system.

The efficiency hit is lower for the new combined-cycle plants because they consist of one or more combustion turbines (CT's) and generally just one steam turbine. The CT's are essentially jet engines and do not require condensers because they do not use steam. The steam turbine is powered by steam created in the heat-recovery steam generator using the high-temperature exhaust of the jet engines.[51] Because the CT's are air cooled, only the relatively small steam turbine is affected by the increase in cooling water temperatures generally seen in wet or dry cooling conversions, resulting in a substantially lower overall reduction in heat rate than would be found in older boiler units.[52]

According to the data presented in the Tetra Tech study, the nuclear units take a greater energy penalty hit than the gas-fired units because their larger steam turbines would be more sensitive to increases in back pressure caused by higher cooling water temperatures, compared to the smaller boiler and combined-cycle steam turbines. Intake temperature is predicted to rise between 6 and 13 degrees at the San Onofre plant, for instance, resulting in an increase in turbine back pressure of between 0.5 and 0.85 inches HgA. This translates to an increase in heat rate of between about 1.5 percent and 3 percent depending on the exact inlet temperature.[53]

The Tetra Tech study and others stress that their predictions of effects on heat rate and parasitic load are necessary based on vendor information and many assumptions, rather than real data, because very few plants have converted their OTC systems. Actual effects on heat rate could be considerably different than predicted if, for example, the plant owners come up with a design for altering the plant condensers such that they are not so sensitive to changes in back pressure.

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[49] Source: Tetra Tech, Inc.

[50] The boiler units and most combined-cycle units can compensate for some of the reduced heat rate by over-firing their boilers, if their design allows. The energy penalty for these plants would then be the increased amount of gas they must burn to compensate for the reduced heat rate, rather than the lost sales of lowered generating output.

[51] Most heat-recovery steam generators (HRSG) also can be "over-fired" by burning additional natural gas in the turbine exhaust feed into the HRSG.

[52] Source: Tetra Tech, Inc., MIcheletti/Burns

[53] The two units at SONGS have slightly different heat rate curves in relation to turbine back pressure.

Overall, the Tetra Tech study predicts a net loss of 231 MW of generating capacity in the state caused by the energy penalty associated with converting OTC systems to wet cooling. Of that, 81 MW would be in Northern California and 150 MW would be in Southern California. These estimates are for peak energy demand times, during the hot summer months when inlet temperatures are likely to be the highest of the year. Both the heat rate effect and the parasitic load effect could be somewhat lower in other months because inlet temperatures would be lower, and perhaps one or more cooling cells could be taken off-line and still maintain lower inlet temperatures than during summer months. The overall effect of the maximum potential reduction in net generating capacity is examined in Scenario 5 of the modeling effort conducted for this study, as discussed in Chapter 4.

Downtime

Another factor potentially affecting grid reliability is the downtime needed at the OTC plants to convert their systems to wet or dry cooling. The plants could continue operating through much of the construction of the new system, but would need to shut down to make the necessary alternations to the plant condensers, and connect the cooling towers. The older OTC units that generally operate only during summer months could easily accommodate this outage during the non-summer months when they are not in use.

The Tetra Tech study predicts reduced power operations caused by outages related to cooling system conversion only at the nuclear units and, to a considerably lesser effect, the combined-cycle OTC units. Shutdowns for cooling system conversions were estimated to extend from a low of 6 weeks for the combined-cycle units to a high of 6 months or more for the nuclear units. However, with proper scheduling,[54] conversion shutdowns should have no effect on overall grid reliability in the state.

The impacts to power system economics and grid reliability from cooling system conversion are therefore limited to the slight reduction in overall net generation to the grid caused by increased parasitic load and heat rate.[55] These impacts are analyzed and discussed thoroughly in Chapter 4.

[54] Proper scheduling here would mean coordinating the needed shutdowns through the CPUC and CEC reliability processes, and not scheduling conversion of both units at a nuclear plant at the same time, for example.
[55] Or the increase in demand for natural gas for those plants that over-fire their steam generators to compensate for reduced cooling system intake temperatures.

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Chapter 4
Reliability Analysis

This study used a computer modeling effort to simulate the economic and reliability effects of various levels of retirements and/or reduced net generation that could occur after enactment of the Board's policy. By examining a wide range of potential future scenarios, the modeling provides a range of potential costs that could occur depending on how and when the policy is enacted. The modeling first examined the WECC-wide[56] economic effects of OTC plant retirements or deratings. The results of the first model runs informed the resultant reliability models, which focused on areas most affected by the lost generation.

The modeling was not used to predict future behavior of any one plant owner, but rather is an analytical tool used to bracket the likely economic and reliability effects over a wide range of potential retirements or cutbacks. It examined worst-case scenarios, which in this case would be immediate retirement of virtually all OTC power plants, as well as less severe cases in which a certain number of plants would repower with alternative cooling systems and others operate at low power levels in order to comply with the new rules, while leaving their options open to repower in the future.[57]

Technical Details[58]

The modeling exercise involved running both (a) economic chronological hourly unit commitment and dispatch models for determining power supply economics among the case studies, and (b) standard AC load flow models for determining reliability. The economic analysis was used to craft appropriate reliability analysis, with the intent of finding the worst-case effects in all local reliability areas (LRA's) in the state. The economic studies covered all hours of the week, running typical weeks for each month and scaling the results for total annual

[56] WECC is an acronym for the Western Electricity Coordinating Council, one of eight reliability councils in the country under the North American Electric Reliability Council. But it also refers to its geographical coverage, which ranges from the Canadian provinces of Alberta and British Columbia to the Northern portion of Baja California in Mexico, and all 14 U.S. states in between.

[57] The Board's originally proposed OTC policy would have allowed plants to comply with CWA Section 316(b) by maintaining power operations at or below 15 percent annual capacity factor. However, the 15 percent number was based on a similar proposal by U.S. EPA that has since been negated by a court decision. Therefore, Board staff directed that this study also examine the possible effects of raising or lowering the annual capacity factor limit somewhat. This scenario was actually ran three times, with the annual capacity factor limit assumed to be 10, 15 or 20 percent, respectively. This information is being used by the Board to determine whether to offer a generation cap at all in its ultimate decision.

[58] Much of the details of this chapter are meant more for electric power industry professionals than for water industry professionals or the general public. Those readers not interested in the computer modeling details may choose to scan the first part of this chapter, and focus more on the "results" discussion later.

impact. The economic analysis is a deterministic analysis, meaning that normal conditions are assumed to occur on every hour. The reliability studies examined the LRA's that the economic modeling predicted will suffer the greatest impact due to OTC retirements or cutbacks. They were done on a worst-case single hour or moment-in-time basis, consistent with standard transmission planning analysis as developed by WECC, the North American Electric Reliability Council and other reliability organizations.

Both the economic model and the reliability model reflect data bases that cover the entire WECC. The economic model involved analysis of the entire WECC. The reliability modeling focused on localized reliability issues within the affected LRAs, including those containing multiple load-serving entities such as the Greater Los Angeles LRA, which is served by SCE, LADWP and a multitude of other municipal utilities. For those areas outside the identified LRA's, the reliability modeling incorporated a form of "equivalencing" portions of the WECC that are not affected by the matters being modeled.

Compatibility with Other Modeling Efforts

Though this study is intended to be as compatible as possible with similar modeling efforts conducted by the CEC, CPUC and CAISO, in the end it has a considerably different purpose than those analyses, and therefore must depart from those efforts somewhat. Among other things, this modeling effort will assist in determining whether the Board's decision would create a significant impact to Utilities and Public Services, as defined by the California Environmental Quality Act. The Board's pending OTC decision is exempt from the requirements of CEQA. However, the Board's internal policy is to conduct a CEQA-equivalent examination of potential impacts in order to ensure environmental and other factors are considered in its decision-making process. The implications of this study in relation to the Board's CEQA-equivalent process are discussed in Chapter 5.

The modeling effort for this study identified transmission system overloads that, absent the Board's decision, would otherwise not occur, and produced estimated costs of constructing the new infrastructure that would be needed to alleviate those overloads. In this way, the study estimates the costs that the ratepayers of the state would incur as a result of the Board's decision, and potential environmental impacts associated with construction of the needed infrastructure. The study also shows how the costs and impacts could vary depending on the way the rules are phased in. As a by-product, the modeling also produced estimated effects on total air emissions from all power plants caused by the new policy, available for use in an air quality analysis of the Board's pending decision.

In contrast, a recent study by CEC Staff[59] of essentially the same issues (though confined geographically to SoCal Edison's service territory) was meant to assess

[59] "Scenario Analysis of California's Electricity System," plus appendices, Publication # CEC-200-2007-010-SD, on-line at http://www.energy.ca.gov/2007_energypolicy/documents/index.html

the need for new resources that could be needed following retirement of aging plants. It also examined a different subset of power plants, focusing only on aging plants (those greater than 55 years in service), which include an inland plant that does not use OTC, while this study examines all OTC plants, including the nuclear units and a few new combined-cycle units. However, because both studies use identical computer models and have nearly identical assumptions, and because there is considerable overlap in the subset of generating units examined, they are quite compatible, and provide information useful to these studies and others.

Modeling Assumptions and Inputs

Both the CEC Staff's and this modeling efforts relied heavily on forecasts of load, demand response, generation availability, and future transmission system upgrades produced by the WECC and the CEC, as well as on historical data, such as observed WECC-wide generator forced-outage rates,[60] observed seasonal effects on maximum generating capacity,[61] and recent reports on costs associated with converting power plant cooling systems, such as the recent Alternative Cooling System Analysis, conducted for OPC by Tetra Tech, Inc.[62] Specifically, both the CEC Staff's and this modeling efforts used input assumptions based in large part on the Fall 2006 Power Market Reference Case produced by Global Energy Decisions for the WECC. However, the load forecasts for California for this study were updated from the Fall 2006 Reference Case to be the CEC load forecast for 2006 through 2016, then extrapolated out to 2020.

The base case for this study was based on the CEC Staff's Case 1b, with limited changes made to reflect the purpose of this study, such as assuming all OTC plants are not retired during the study period. The effects of retirements were then compared to this base case. The specifics of this study's base case were derived from (a) an extensive data base of existing generation and transmission facilities in WECC, developed and maintained by Global,[63] (b) economic data produced by the MARKETSYM model (see below), and (c) modeling "set-up" and future assumptions developed by Global Energy professionals based on their extensive knowledge of WECC Power Markets. Data concerning deliverability, dispatchability, and operating characteristics of each plant came from the CEC Scenarios Case 1b. Existing plant capacities (Max ratings) in Global's database are based on plant owners' filings to the Energy Information Administration (Form 860). Capacities for new generating plants are based on Global's research on public announcements. The capacity numbers are consistent with those used in the CEC Case 1b study. For reliability studies, the model assumed that the state's utilities and energy agencies will proactively act to assure that needed

[60] The observed forced-outage rates are based on data showing the number and length of non-voluntary outages by each generating unit or plant, such as those caused by a mechanical failure at the plant.
[61] The maximum generating capacity of power plants is generally reduced during times of high temperatures and/or humidity, compared to cooler and drier times.
[62] http://www.resources.ca.gov/copc/OTC.htm
[63] Global Energy maintains a data business unit whose staff monitors publicly available sources of data to build and maintain this database, which is used for studies such as this and can be licensed by others. As was done for the CEC study, much of the data used in Global Energy's economic data base can be made available to interested parties on a non-confidential basis. However, access to the entire database would require signing a non-disclosure agreement.

power supplies are available when the 1-in-10 peak occurs, including required reserve margins, if physically possible.[64]

The economic studies and the reliability studies kept common assumptions where they were needed. However, since the reliability studies were "instantaneous" analyses of extreme events, and the economic studies were all hours (typical week) of normal conditions, the models have different needs and purposes. Both the CEC Staff's Scenarios Analysis and the CAISO's analysis of the Sunrise transmission project also involved economic studies and reliability studies. The interactions between the models and input assumption commonality for this study were similar to what the CEC and CAISO did in those proceedings.

This study makes generic assumptions about the type of power plant or transmission project that could replace any lost capacity based on the time available to plan and construct the replacement unit or transmission system upgrade. Whether the replacement was generation or transmission, the modeling assumed that all present standards for system operation would continue to be met, meaning the replacement would provide essentially all the same capabilities (or more) and standards as existed before the lost capacity, including, for example, dispatchability (ramp-up and ramp-down rates), and voltage and frequency stability requirements during transient events.

The study assumed that the type of generation that would arise to replace a retired or derated OTC unit would be directly related to the time interval between the date the Board's new policy is announced and date it is enacted. For instance, in the unlikely event that the policy is enacted in 2009 and all OTC plant owners decide to immediately retire, the only type of power plant that could be constructed in time to replace them would be small peaker plants. The process of siting and constructing a sufficient number of peaker plants in that time frame would require a mobilization effort on the order of what the entire nation went through during World War II, likely including drastic conservation measures. On the other hand, if the policy is announced in 2008 and enacted in 2015, the likely replacements would be large combined-cycle plants, given that industry would have 7 years to plan and construct the plants.

Models Used

This modeling exercise involved running both (a) MARKETSYM™, an economic chronological hourly unit commitment and dispatch model for determining power supply economics among the cases studies, and (b) PowerWorld, a standard AC load flow models for determining reliability. MARKETSYM™ is a multi-area, chronological production simulation model that operates on the PROSYM simulation engine and a detailed, sophisticated, relational database. MARKETSYM™ was used in the CEC Scenarios project, and by the CPUC in approving the Miguel-Mission and DPVII transmission

[64] "Physically possible" in this case refers to constraints on timely development of replacement generation, including timelines to develop certain types of generating resources or transmission projects.

lines. The model was also discussed in detail in the CPUC Modeling Proceeding I05-06-041.[65]

MARKETSYM™ incorporates:

- individual power plant characteristics including heat rates, start-up costs, ramp rates, and other technical characteristics of plants;
- zonal transmission link ratings, losses, and wheeling rates;
- forecasts of resource additions and fuel costs over time;
- forecasts of loads for each utility or load serving entity in the region; and,
- the cost and availability of fuels that supply the plants.

MARKETSYM™ simulates the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The model is based on a zonal approach where market areas (zones) are delineated by critical transmission constraints. The simulation is based on a mathematical objective function that minimizes the cost of serving load within the modeled electric system, subject to a number of operational constraints, as well as on the assumed strategic behavior (bidding) of market participants. In common with the general optimization solution, the PROSYM solution computes a shadow price of loads, often known as the System Lambda, which describes the additional cost to the system of serving an additional MW of load, or replacing a MW of lost generation. Monte Carlo analysis[66] is employed to incorporate individual unit forced outages. The result is a price forecast, depending on bidding strategies that allows existing and new generators to recover all short- and long-term costs (including financing costs) from the market.

PowerWorld Simulator is an interactive power systems simulation package designed to simulate high voltage power systems operation over a range of time frames, from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses. PowerWorld supports detailed modeling of load-tap changer and phase-shifting transformers, switched shunts, generator reactive capability curves, generator cost curves, load schedules, transaction schedules, DC lines, multi-section lines, and remote bus voltage control. The PowerWorld OPF (Optimal Power Flow) simulation is capable of capturing the effect of flows on every transmission line and tests for congestion. If congestion is present across a given path, PowerWorld optimally re-dispatches generator units to relieve this congestion. Economic data can be inserted into the power flow solution to assess not only the technical aspects of a system change such as a re-dispatch, but its economic importance as well.[67]

[65] See http://www.cpuc.ca.gov/proceedings/I0506041.htm
[66] See, for example, http://www.vertex42.com/ExcelArticles/mc/MonteCarloSimulation.html
[67] See http://www.powerworld.com/products/simulator.asp

Modeling Methodology

The economic analysis was used to assess the effects on power system economics from various combinations of OTC unit retirements or deratings, and to craft appropriate reliability analysis, with the intent of finding the worst-case effects in the 10 LRAs identified in the CAISO's recent Local Capacity Requirement study.[68] The economic analysis is a deterministic analysis, meaning that normal conditions are assumed to occur on every hour.

The reliability studies examined the four LRA's that the economic modeling predicted would suffer the greatest impact due to OTC retirements or cutbacks, such as those showing large price spikes during extreme demand days. The reliability modeling accounted for the entire WECC transmission system, down to 69 kV in all areas and even lower in many. By modeling at this level of detail the reliability modeling fully accounted for zonal (inter-area), local (intra-area) and system (interconnection) constraints and congestion.

The reliability analyses were done on a worst-case single hour or moment-in-time basis, consistent with standard transmission planning analysis as developed by the WECC, the North American Reliability Council, and other reliability organizations. The reliability analysis cases assumed a 1-in-10 peak load, which generally simulates a heat wave-driven extremely high load. The analysis attempted to find a way to meet this load without violating CAISO-established Transmission Planning Reliability Criteria. To do this, the model first attempted to meet the 1-in-10 peak load under "N-0"[69] conditions, when all transmission lines and major generating units are operating.

The modeling also included a contingency analysis to test the combined effects of plant retirements or deratings with possible transmission line outages under "N-1" conditions. Using the results of the CAISO's 2008 LCR Study and other sources,[70] Global identified the transmission lines segment outages that would have the greatest effect on reliability within each applicable LRA, and ran the contingency analysis in order of importance, identifying the line overloads that would occur during such a contingency. The modeling also considered the effects of the combined loss or derating of OTC plants with the unplanned loss of the single largest generator in a load pocket and the most important transmission line segment by re-running all the "N-1" contingencies under an "L-1/G-1" outage. Unlike some other modeling programs, PowerWorld automatically readjusts the system following a line or unit outage, simulating the automatic generator controls (AGC) that adjust generator frequency and voltage output to compensate for a sudden outage elsewhere. Other models select a single nearby generating units to act as a proxy for the line or unit outage, rather than adding AGC software to simulate the constant automatic adjustments and readjustments that occur following a grid disturbance. After the PowerWorld AGC software

[68] "2008 Local Capacity Technical Analysis Overview and Study Results," CAISO, April 3, 2007 See http://www.caiso.com/1c44/1c44b8e0380a0.html

[69] An N-0 or "n minus zero" event means that all major power generating units and major transmission line segments are operating. An N-1 event is when an important generating unit or transmission line segment trips off-line, disrupting the grid. N-1 events can be classified as G-1 (generation) or T-1 (transmission) events.

[70] For example, the CAISO study does not cover LADWP's service territory, requiring Global Energy to obtain technical information concerning intra-area transmission congestion within LADWP's service territory from other sources, which it then incorporated into its confidential database.

adjusted the applicable generators and system reaches equilibrium, the model then identified the line overloads, low voltage violations, etc., under each of those N-0, N-1 and L-1/G-1 outages.

The model then attempted to determine how best these line overloads, low voltage violations, etc., might be fixed, whether through transmission upgrades or new lines or through use of in-area generation, and produces cost estimates for each "fix" option. All such overloads and resultant costs were summed together to estimate the total impact to system reliability under each scenario, the total MW of needed power generating facilities, and the total miles of needed transmission lines, number of new transformers, etc. The cost estimate was used to help assess feasibility of the proposed mitigation, and the infrastructure estimate helped assess the total physical impact to the environment caused by construction and operation of new power plants and transmission projects. In addition to estimating the cost of mitigating impacts to electric reliability, the model also produced estimates of the net change in air emissions, both within California and across the Western U.S. that would occur under each scenario.

The Scenarios

By examining a wide range of future scenarios, the modeling effort for this study provided useful information about the potential grid reliability and environmental effects of plant retirements or cutbacks, the options available to the state to compensate for those retirements, and the approximate cost of those options. This study did not evaluate individual plant retirements but instead looked for significant impacts by analyzing reasonable bounds of the impacts that could occur as a result of the State Water Board's policies. The analysis looked at the OTC fleet as a whole, examining "what-if?" scenarios involving assumptions that multiple retirements and/or net generation reductions will occur, thus avoiding the speculative nature of attempting to predict the future operation of any given generating unit.

This modeling effort included six basic scenarios for economic modeling, and two for reliability modeling. To examine the effects of possibly phasing in the OTC rules over time, all scenarios ran in three different years, showing the differences in impacts if the proposed policy take effect in 2009, 2012 or 2015, respectively. The assumptions for each scenario are discussed below and shown in **Table 4-1**.

Base Case

At the suggestion of CEC Staff,[71] this effort used a slightly modified version of the base case used for the CEC Staff's recent similar effort for the SoCal Edison territory (Case 1b in its 2007 IEPR Scenario Analysis of California's Electric

[71] The CEC Staff recommended changes because their own work in the 2007 IEPR was only able to assess aging power plants in the SCE service area, rather than statewide, and they felt that some changes were appropriate for this effort, such as placing more emphasis on the need for in-area generation in many of the state's Local Reliability Areas.

Table 4-1. Summary of Scenarios

OTC Reliability Study Economic Modeling Scenarios	Capacity (Global Energy)	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Principle Characteristics		Remove any OTC retirement	All OTC plants retire when their NPDES permits expire except nuclear units; Replaced with GenAeros in 2009, a mix of GenGT and GenCC in 2012, and GenCC in 2015	All OTC plants retire when their NPDES permits expire except nuclear units; Energy needed will be replaced out-of-area imports.	Same as Case 1 except nuclear units also retire	Same as Case 2, except nuclear units also retire	Same as Base Case but with derating of the OTC plants based on Tetra Tech study.	10% capacity factors on OTC plants, with the exception that all repowering proposals are completed, nuclears remain at present MW ratings, CC units convert to wet cooling	15% capacity factors on OTC plants, with the exception that all repowering proposals are completed, nuclears remain at present MW ratings, CC units convert to wet cooling	20% capacity factors on OTC plants, with the exception that all repowering proposals are completed, nuclears remain at present MW ratings, CC units convert to wet cooling
Alamitos 1-6	1997	Not retired	Retire in 2009, replace with 20*100MW GenAero in 2009, 9*225MW CC 2012 & 2015	Retire in 2009, no replacing capacity	Retire in 2009, replace with 20*100MW GenAero in 2009, 9*225MW CC 2012 & 2015	Retire in 2009, no replacing capacity	**To be decided by Tetra Tech study**	Repowering to 2*250 CC	Repowering to 2*250 CC	Repowering to 2*250 CC
Gateway (old Contra Costa 8)	530	Online date 6/1/2009	Operate at 530 MW w/ dry cooling	Operate at 530 MW w/ dry cooling	Operate at 530 MW w/ dry cooling	Operate at 530 MW w/ dry cooling		Operate at 530 MW w/ dry cooling	Operate at 530 MW w/ dry cooling	Operate at 530 MW w/ dry cooling
Contra costa 6-7	672	Not retired	Retire in 2009, replace with 7*100MW GenAero in 2009, 4*160MW GenGT in 2012, 3*225MW GenCC in 2015	Retire in 2009, no replacing capacity	Retire in 2009, replace with 7*100MW GenAero in 2009, 4*160MW GenGT in 2012, 3*225MW GenCC in 2015	Retire in 2009, no replacing capacity		operate at 10% capacity factor	operate at 15% capacity factor	operate at 20% capacity factor
Diablo Canyon 1-2	2248	Not retired	Not retired	Not retired	Retire in 2009, replace w/ 22*100MW GenAero in 2009, 10*225 MW GenCC in 2012 & 2015	Retire in 2009 and no replacing capacity		not retired	not retired	not retired
El Segundo 3-4	660	Not retired	Not retired in 2009, repowering to 3*225 MW starting 1/1/2010.	Not retired in 2009, repowering to 3*225 MW starting 1/1/2010.	Not retired in 2009, repowering to 3*225 MW starting 1/1/2010.	Not retired in 2009, repowering to 3*225 MW starting 1/1/2010.		Not retired in 2009, repowering to 3*225 MW starting 1/1/2010.	Not retired in 2009, repowering to 3*225 MW starting 1/1/2015.	Not retired in 2009, repowering to 3*225 MW starting 1/1/2010.
Encina 1-5	944	Units 1-3 repowering to 3*180 MW GT in 2010	Units 1-3 repowered to 3*180MW GT in 2010; Units 4-5 replaced with 2*245MW CC in 2012	Units 1-3 repower to 3*180MW GT in 2010; Units 4-5 will retire in 2012 without replacement.	Units 1-3 repowered to 3*180MW GT in 2010; Units 4-5 replaced with 2*245MW CC in 2012	Units 1-3 repower to 3*180MW GT in 2010; Units 4-5 will retire in 2012 without replacement.		Units 1-3 repowered to 3*180MW GT in 2010; Units 4-5 operate at 10% capacity factor	Units 1-3 repowered to 3*180MW GT in 2010; Units 4-5 operate at 15% capacity factor	Units 1-3 repowered to 3*180MW GT in 2010; Units 4-5 operate at 20% capacity factor
Harbor CC 10	227	Not retired	Retire in 2009, replaced w/ 2*110MW GenAero in 2009, and converted to 1*225MW in 2012 & 2015	Retire in 2009, no replacing capacity	Retire in 2009, replaced w/ 2*110MW GenAero in 2009, and converted to 1*225MW in 2012 & 2015	Retire in 2009, no replacing capacity		Convert to wet cooling	Convert to wet cooling	Convert to wet cooling
Haynes 1-6	1701	Not retired	Retire in 2009, replaced w/ 17*100MW GenAero in 2009, 11*160MW GenGT in 2012 & 2015	Retire in 2009, no replacing capacity	Retire in 2009, replaced w/ 17*100MW GenAero in 2009, 11*160MW GenGT in 2012 & 2015	Retire in 2009, no replacing capacity		Convert to wet cooling	Convert to wet cooling	Convert to wet cooling
Humboldt Bay 1-2	105	Repowering to 10*16.3 MW dual fuel engines, starting 10/1/2009	Repowering to 10*16.3 MW dual fuel engines, starting 10/1/2009	Repowering to 10*16.3 MW dual fuel engines, starting 10/1/2009	Repowering to 10*16.3 MW dual fuel engines, starting 10/1/2009	Repowering to 10*16.3 MW dual fuel engines, starting 10/1/2009		Repowering to 10*16.3 MW dual fuel engines, starting 10/1/2009	Repowering to 15*16.3 MW dual fuel engines, starting 15/1/2009	Repowering to 10*16.3 MW dual fuel engines, starting 10/1/2009
Huntington Beach 1-4	903	Not retired	Retired in 2011, replaced w/ 6*160MW GenGT in 2012, 4*225MW GenCC in 2015	Retire in 2011, no replacing capacity	Retired in 2011, replaced w/ 6*160MW GenGT in 2012, 4*225MW GenCC in 2015	Retire in 2011, no replacing capacity		Convert to wet cooling	Convert to wet cooling	Convert to wet cooling
Mandalay 1-3	560	Not retired	Retired in 2009, replaced w/ 6*100MW GenAero in 2009, 4*160MW GenGT in 2012m and 3*225 GenCC in 2015	Retire in 2009, no replacing capacity	Retired in 2009, replaced w/ 6*100MW GenAero in 2009, 4*160MW GenGT in 2012m and 3*225 GenCC in 2015	Retire in 2009, no replacing capacity		Repowering to 2*250 CC	Repowering to 2*250 CC	Repowering to 2*250 CC

Table 4-1. Summary of Scenarios

OTC Reliability Study Economic Modeling Scenarios	Capacity (Global Energy)	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Morro Bay 3-4	673	Not retired	Retire in 2009, replace w/7*100MW GenAero in 2009, replace with 4*170MW GenGT in 2012, and 3*225 GenCC in 2015	Retire in 2009, no replacing capacity	Retire in 2009, replace w/7*100MW GenAero in 2009, replace with 4*170MW GenGT in 2012, and 3*225 GenCC in 2015	Retire in 2009, no replacing capacity		operate at 10% capacity factor	operate at 15% capacity factor	operate at 20% capacity factor
Moss Landing ST 6-7	1510	Not retired	Retire in 2009, replace w/ 15*100MW GenAero in 2009, 10*160MW GenGT in 2012, and 6*225MW GenCC in 2015	Retire in 2009, no replacing capacity	Retire in 2009, replace w/ 15*100MW GenAero in 2009, 10*160MW GenGT in 2012, and 6*225MW GenCC in 2015	Retire in 2009, no replacing capacity		operate at 10% capacity factor	operate at 15% capacity factor	operate at 20% capacity factor
Moss Landing CC 1-2	1020	Not retired	Retire in 2009, replace w/ 10*100MW GenAero in 2009, 4*255 GenCC in 2012&2015	Retire in 2009, no replacing capacity	Retire in 2009, replace w/ 10*100MW GenAero in 2009, 4*255 GenCC in 2012&2015	Retire in 2009, no replacing capacity		Convert to wet cooling	Convert to wet cooling	Convert to wet cooling
Ormond Beach 1-2	1516	Not retired	Retire in 2009, replace w/ 15*100MW GenAero in 2009, 9*160MW GenGT in 2012 & 2015	Retire in 2009, no replacing capacity	Retire in 2009, replace w/ 15*100MW GenAero in 2009, 9*160MW GenGT in 2012 & 2015	Retire in 2009, no replacing capacity		operate at 10% capacity factors	operate at 15% capacity factor	operate at 20% capacity factor
Pittsburg 5-7	1311	Not retired	Retire in 2009, replace w/ 13*100MW GenAero in 2009, 6*225 GenCC in 2012&2015	Retire in 2009, no replacing capacity	Retire in 2009, replace w/ 13*100MW GenAero in 2009, 6*225 GenCC in 2012&2015	Retire in 2009, no replacing capacity		operate at 10% capacity factors	operate at 15% capacity factor	operate at 10%, 15% or 20% capacity factors
Potrero ST & GT	362	Replaced by SFERP of 147MW on 12/1/2008	Replaced by SFERP of 147MW on 12/1/2008	Replaced by SFERP of 147MW on 12/1/2008	Replaced by SFERP of 147MW on 12/1/2008	Replaced by SFERP of 147MW on 12/1/2008		Replaced by SFERP of 147MW on 12/1/2008	Replaced by SFERP of 147MW on 12/1/2008	Replaced by SFERP of 147MW on 12/1/2008
Redondo Beach 5-8	1334	Not retired	Retire in 2009, replace w/ 13.5*100MW GenAero in 2009, 6*225MW GenCC in 2012&2015.	Retire in 2009, no replacing capacity	Retire in 2009, replace w/ 13.5*100MW GenAero in 2009, 6*225MW GenCC in 2012&2015.	Retire in 2009, no replacing capacity		operate at 10% capacity factors	operate at 15% capacity factor	operate at 20% capacity factor
San Onofre 2-3	2231	Not retired	Not retired	Not retired	Retire in 2011, replace w/ 15*160MW GenGT in 2012, 10*225MW GenCC in 2015	Retire in 2011 and no replacing capacity		Not retired	Not retired	Not retired
Scattergood 1-3	803	Not retired	Retire in 2009, replace w/ 8*100MW GenAero in 2009, 5*160MW GenGT in 2012 & 2015	Retire in 2009, no replacing capacity	Retire in 2009, replace w/ 8*100MW GenAero in 2009, 5*160MW GenGT in 2012 & 2015	Retire in 2009, no replacing capacity		Repowering to 2*250 CC	Repowering to 2*250 CC	operate at 20% capacity factor
South Bay ST & GT	708	Not retired	Repowering to 2*310 CC in 2010	Repowering to 2*310 CC in 2010	Repowering to 2*310 CC in 2010	Repowering to 2*310 CC in 2010		Repowering to 2*310 CC in 2010	Repowering to 2*310 CC in 2010	Repowering to 2*310 CC in 2010

Note: (1) It may be difficult to meet the local reliability requirement in Case 2 and Case 4, and the assumptions regarding OTC plant retirements may need to be modified for these cases.

(2) Same assumptions with CEC Case1b (Revised) with regard to load, renewable resources, demand side management programs, and energy efficiency programs.

(3) Global Energy's capacity numbers are derived from EIA Form 860, with the exception of Gateway and Moss Landing CC which are based on Global Energy's research on public announcements.

System), in which greater emphasis is placed on ensuring resource adequacy requirements are met in all areas of the state. Using the CAISO's most recent LCR study and other sources, Global adjusted model assumptions to account more for intra-area congestion within the SDG&E and LADWP service territories, and within the Greater Bay Area LRA in PG&E's territory. These assumptions are similar to those recommended by the CEC following its study of aging plant retirements in the SCE territory. In essence, these revised assumptions place more emphasis on the constraints created by intra-area transmission congestion, and result in a somewhat greater need for in-area generation in order to maintain reliability standards. Otherwise the base case for this modeling effort used all the same assumptions and inputs as the CEC's Case 1b, with the one exception that this study's base case assumes all OTC plants are not retired throughout the study period (2009-2015), while the CEC's case 1b assumed some OTC plants will have retired at different times during their study period (2009-2020).

Case 1

All OTC plants are assumed to retire when their NPDES permits expire,[72] except the four nuclear units. This results in retirement of 4582 MW in Northern California in 2009 and beyond, and retirement of 6363 MW, 7622 MW, and 7622 MW in Southern California in 2009, 2012, and 2015 respectively. The replacement for this retired capacity was assumed to come from new local gas-fired resources located at or near the vicinity of the retired plant. The assumed gas-fired resources are aero-derivative combustion turbines (CT's) in 2009, a mix of conventional CT's and combined-cycle units in 2012, and predominantly combined-cycle in 2015.

Case 2

Same as Case 1, except the retired capacity was replaced by out-of-region[73] gas resources. New plants out of region were added when necessary, otherwise replacement power came from existing surplus plants.

Case 3

Same as Case 1, except the nuclear units are also retired when their current NPDES permits expire, meaning Diablo Canyon nuclear units (2200 MW) are retired in 2009; and the San Onofre units (2254 MW) remain on in 2009, but are retired by 2012.

[72] Many plant NPDES permits are already expired. Others will expire between 2009 and 2012, but all will have expired by 2015. See http://www.waterboards.ca.gov/npdes/ for further information.
[73] "Out of region" refers to plants located outside of the transmission-constrained regions where OTC plants generally are located. This would refer to the constraints associated with the 10 Local Reliability Areas in the state, but also larger areas separated by constraints, such as Northern and Southern California.

Case 4

Same as Case 2, except the nuclear units retire as in Case 3.

Case 5

Same as Base Case but with derating of all coastal units reflecting the predicted reduction in net generation to the grid caused by conversion to wet cooling, including nuclear units, with derated amounts based on Tetra Tech study findings.

Case 6

All OTC plants are limited to operate at no more than a 10 percent capacity factor starting in 2009. For 2012 and 2015, Harbor, Haynes, Huntington Beach and Moss Landing CC are assumed to convert to wet cooling and Alamitos 1-2, Mandalay 1-2, and Scattergood 1-2[74] are each assumed to repower to a 500 MW CC. All other OTC plants operate at no more than a 10 percent capacity factor. This case involved assuming OTC plants sign a PPA that provides them a capacity payment and, in turn, transfers their operating decisions to a third party. The third party would have an agreement with permitting agencies providing that (a) the plant will not be operated at higher than the maximum allowed capacity factor for the year (10 percent in this case) and (b) provides that the available operating hours will be limited to periods when the CAISO determines conditions warrant the plant being operated for reliability (e.g., summer months when the CAISO forecasts high temperature situations or CAISO is aware that other units are on unplanned maintenance).

Case 7

Same as in Case 6 except that the capacity factor limit is 15 percent.

Case 8

Same as in Case 6 except that the capacity factor limit is 20 percent.

[74] These plants were chosen arbitrarily, on the assumption that some of the present OTC plant owners will have sufficient incentive to chose repowering of their plants rather than retire them.

Table 4-2. Comparison of Production Costs in California Across Scenarios

Old Thermal Generation Retirement and Replacement of Once-Through Cooling Economics Study

Comparison of Production Cost in California across Scenarios (2009)

	CEC Case 1b	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5[7]	Case 6[4]	Case 7[4]	Case 8[4]
Scenario Characteristics (OTC plant retirement and replacement)		None of OTC plants were retired	All OTC plants retire in 2009 except nukes and Encina 4-5 & Huntington Beach which will be retired in 2011, replace w/ GenAero	All OTC plants retire in 2009 except nukes and Encina 4-5 & Huntington Beach which will be retired in 2011, replace w/ imports	Same as Case 1 except nukes also retire	Same as Case 2 except nukes also retire	Same as base case, with deratings and heat rate adjustment based on Tetra Tech study	10% CF except nukes & units that will be converted to wet cooling	15% CF except nukes & units that will be converted to wet cooling	20% CF except nukes & units that will be converted to wet cooling
Load										
CA Co-incident Peak Load (MW)	58381	58381	58381	58381	58381	58381	58381	58381	58381	58381
CA Energy Load (GWh), including pumping load	301,143	301,117	301,089	302,033	301,099	302021	301,119	301,139	301,109	301,105
CA Dump Power (GWh)	0	0	0	0	0	0	0	0	0	0
CA "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0
Generation										
CA in-State Generation (GWh)	210277	210354	206738	207885	199400	200913	210223	206170	207220	207911
Remote Genereration (GWh)	38014	37765	37824	37854	38001	38004	37775	37821	37823	37808
CA Net Import (GWh)	52853	52997	56526	56295	63699	63104	53120	57148	56067	55386
Remaining OTC Generation (GWh),	N/A	52034	36046	36379	19144	19748	51767	42069	43970	45576
OTC Replacing Generation (GWh)[5]	N/A	0	10369	0	13124	0	0	0	0	0
CA Reserve Deficiency (GWh)	0.2	0.5	0	775	0	776	0.3	184	140	51
Costs										
CA Total System Cost ($000)[1]	12,466,535	11,929,565	14,029,425	11,971,821	15,170,049	12,757,194	11,913,823	12,054,273	12,083,831	12,067,499
CA Per Unit System Cost ($/MWh)	41.40	39.62	46.60	39.64	50.38	42.24	39.57	40.03	40.13	40.08
CA In-state Generation Cost ($000)	8,877,634	9,042,846	8,742,371	8,828,302	9,057,739	9,199,023	9,019,992	8,854,237	8,964,979	9,006,843
CA Fuel Costs ($000)	7,040,803	7,147,242	6,873,381	6,937,323	7,219,230	7,334,293	7,123,520	6,940,637	7,040,577	7,084,202
CA VOM Costs ($000)	394,259	393,784	400,018	393,292	370,795	361,922	393,251	386,781	388,486	389,530
CA Start Costs ($000)	78,858	78,638	43,870	75,439	40,670	78,756	79,996	100,349	109,369	107,326
CA FOM Costs ($000)	1,267,549	1,327,010	1,321,769	1,321,769	1,321,769	1,321,769	1,327,010	1,327,010	1,327,010	1,327,010
CA Emission Costs (SO2, Nox, Hg) ($000)	96,165	96,173	103,333	100,480	105,275	102,282	96,216	99,460	99,537	98,775
CA Remote Generation Cost ($000)	855,742	848,046	850,527	852,272	858,420	858,908	848,619	850,741	850,870	850,218
CA Net Import Charge ($000)[2]	2,733,028	2,038,542	2,264,701	2,254,045	2,723,354	2,660,995	2,045,168	2,335,248	2,256,095	2,204,269
CA Reserve Deficiency Cost ($000)[6]	131	131	-	37,201	-	38,269	43	14,047	11,887	6,169
Annualized Capital Cost ($000[8]			2,171,826		2,530,536					
Emissions										
CA-Instate Emissions										
CO2 (000 ton)	57940	58056	55621	56361	59869	61083	57882	56586	57454	57786
Nox (000 ton)	232	232	233	234	234	237	232	233	233	233
SO2 (000 ton)	67	67	67	67	68	68	67	67	67	67
Hg (ton)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Emissions from Remote Generation										
CO2 (000 ton)	27103	26846	26868	26886	26952	26956	26848	26866	26866	26859
Nox (000 ton)	49	48	48	48	48	48	48	48	48	48
SO2 (000 ton)	16	15	15	15	15	15	15	15	15	15
Hg (ton)	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29

Table 4-2. Comparison of Production Costs in California Across Scenarios

	CEC Case 1b	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5[7]	Case 6[4]	Case 7[4]	Case 8[4]
Scenario Characteristics (OTC plant retirement and replacement)		None of OTC plants were retired	All OTC plants retire in 2009 except nukes and Encina 4-5 & Huntington Beach which will be retired in 2011, replace w/ GenAero	All OTC plants retire in 2009 except nukes and Encina 4-5 & Huntington Beach which will be retired in 2011, replace w/ imports	Same as Case 1 except nukes also retire	Same as Case 2 except nukes also retire	Same as base case, with deratings and heat rate adjustment based on Tetra Tech study	10% CF except nukes & units that will be converted to wet cooling	15% CF except nukes & units that will be converted to wet cooling	20% CF except nukes & units that will be converted to wet cooling
Emissions from Rest of WECC (remote Gen excluded)										
CO2 (000 ton)	332727	332989	334432	334487	337585	337420	332991	334701	334182	333894
Nox (000 ton)	503	504	504	504	506	506	504	504	504	504
SO2 (000 ton)	445	447	447	447	448	448	447	447	447	447
Hg (ton)	3.46	3.46	3.46	3.46	3.47	3.47	3.46	3.46	3.46	3.46

Notes:

(1) Total system cost includes CA in-state generation cost, remote generation cost, and net import charge, and capital cost associated with repowering, conversion to wet or dry cooling, and replacement with other technologies.

(2) In CEC case 1b, the net import charge was calculated by multiplying the net import in CA and SP15 market clearing prices. In this study, the net import charge is calculated by multiplying the net import at each zone by the corresponding zonal market clearing prices and then summing up the zonal import charges at all zones.

(3) Only the energy generated from OTC plants that were NOT repowered, replaced, or and converted to wet cooling is reported

(4) The following units are assumed to convert to wet cooling in Case 6-8 in 2012 and 2015 (but not 2009): Harbor, Haynes, Huntington Beach, and Moss Landing CC

(5) Incluing generation from units assumed to convert to wet cooling

(6) The reserve deficiency cost is calculated assuming each incidence of reserve deficiency costs the higher of $10,000 or $10/MW (WECC RMS Criteria)

(7) In 2009 OTC plants are limited to operate at 15% CF, with the exception of Harbor CC, Haynes Repowered CC units and Moss Landing CC which are assumed to exempt from the CF requirement.

(8) The annualized capital cost is based on (a) CEC Staff Report CEC-200-2007-011-SF " Comparative Costs of California Central Station Electricity Generation Technlogies" and (b) Tetra Tech study on conversion to wet coolings.

	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	
Northern California System Cost										
CA Total System Cost ($000)[1]	4,853,177	5548109	4850567	6639912	5573460	4852211	4893546	4916058	4931148	
CA In-state Generation Cost ($000)	4,459,347	4114458	4264414	4204975	4369624	4451753	4251397	4276138	4304474	
CA Fuel Costs ($000)	3,557,651	3240670	3370273	3367607	3510819	3550895	3360724	3384932	3411867	
CA VOM Costs ($000)	181,958	173640	176442	135611	137251	181743	173384	173614	173970	
CA Start Costs ($000)	30,107	15554	33081	16784	36510	29471	27470	27784	28889	
CA FOM Costs ($000)	645,606	640365	640365	640365	640365	645606	645606	645606	645606	
CA Emission Costs (SO2, Nox, Hg) ($000)	44,025	44229	44254	44608	44680	44038	44213	44202	44142	
CA Remote Generation Cost ($000)	199600	202065	203775	209766	210228	200183	202292	202428	201792	
CA Net Import Charge ($000)[2]	194229	497861	382378	1132735	993608	200275	439856	437493	424881	
CA Reserve Deficiency Cost ($000)[6]	0	0	0	0	0	0	0	0	0	
Annualized Capital Cost ($000)		733725		1092435						
Southern California System Cost										
CA Total System Cost ($000)[1]	7,076,388	8481316	7121254	8530137	7183734	7061612	7160728	7167773	7136352	
CA In-state Generation Cost ($000)	4,583,499	4627913	4563888	4852763	4829399	4568239	4602840	4688841	4702369	
CA Fuel Costs ($000)	3,589,591	3632711	3567049	3851623	3823475	3572624	3579913	3655645	3672335	
CA VOM Costs ($000)	211,826	226379	216851	235184	224671	211508	213397	214872	215560	
CA Start Costs ($000)	48,530	28315	42358	23886	42246	50525	72879	81585	78437	
CA FOM Costs ($000)	681,404	681404	681404	681404	681404	681404	681404	681404	681404	
CA Emission Costs (SO2, Nox, Hg) ($000)	52,148	59104	56226	60666	57603	52178	55247	55335	54634	

Table 4-2. Comparison of Production Costs in California Across Scenarios

	CEC Case 1b	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5[7]	Case 6[4]	Case 7[4]	Case 8[4]
Scenario Characteristics (OTC plant retirement and replacement)		None of OTC plants were retired	All OTC plants retire in 2009 except nukes and Encina 4-5 & Huntington Beach which will be retired in 2011, replace w/ GenAero	All OTC plants retire in 2009 except nukes and Encina 4-5 & Huntington Beach which will be retired in 2011, replace w/ imports	Same as Case 1 except nukes also retire	Same as Case 2 except nukes also retire	Same as base case, with deratings and heat rate adjustment based on Tetra Tech study	10% CF except nukes & units that will be converted to wet cooling	15% CF except nukes & units that will be converted to wet cooling	20% CF except nukes & units that will be converted to wet cooling
CA Remote Generation Cost ($000)	648445	648462	648497	648654	648680	648436	648448	648443	648426	
CA Net Import Charge ($000)[2]	1844313	1766840	1871667	1590619	1667387	1844894	1895392	1818602	1779388	
CA Reserve Deficiency Cost ($000)[6]	131	0	37201	0	38269	43	14047	11887	6169	
Annualized Capital Cost ($000)		1438101		1438101						

Table 4-2. Comparison of Production Costs in California Across Scenarios

Old Thermal Generation Retirement and Replacement of Once-Through Cooling Economics Study

Comparison of Production Cost in California across Scenarios (2012)

	CEC Case 1b	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6[4] [5]	Case 7[4] [5]	Case 8[4] [5]
Scenario Characteristics (OTC plant retirement and replacement)		None of OTC plants were retired	All OTC plants retire except nukes , replace w/ a mix of GenGT & GenCC	All OTC plants retire except nukes , replace w/ import	Same as Case 1 except nukes also retire	Same as Case 2 except nukes also retire	Same as base case, with deratings and heat rate adjustment based on Tetra Tech study	10% CF except nukes & units that will be converted to wet cooling & repowered	15% CF except nukes & units that will be converted to wet cooling & repowered	20% CF except nukes & units that will be converted to wet cooling & repowered
Load										
CA Co-incident Peak Load (MW)	60780	60780	60780	60780	60780	60780	60780	60780	60780	60780
CA Energy Load (GWh), including pumping load	312371	312385	312,353	313,178	312302	313125	312406	312386	312371	312371
CA Dump Power (GWh)	0	0	0	0	0	0	0	0	0	0
CA "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0
Generation										
CA in-State Generation (GWh)	229156	231538	238526	229255	230274	217469	231393	234272	234314	234314
Remote Genereration (GWh)	37617	37327	37084	37525	37462	37850	37350	37238	37259	37259
CA Net Import (GWh)	45598	43520	36743	46398	44565	57806	43664	40876	40798	40798
Remaining OTC Generation, including nuclear (GWh)[3]	N/A	46867	31261	31261	0	0	0	33171	33341	33341
OTC Replacing Generation (GWh)[6]	N/A	0	38505	0	45261	0	46256	20918	20758	20758
CA Reserve Deficiency (GWh)	0	0	0	641	0	641	0	0.4	0	0
Costs										
CA Total System Cost ($000)	10,359,889	9924274	11,898,632	9,947,268	13,388,642	10,935,503	10254765	10088550	10088089	10088089
CA Per Unit System Cost ($/MWh)	33.17	31.77	38.09	31.76	42.87	34.92	32.83	32.30	32.30	32.30
CA In-state Generation Cost ($000)	7665113	7911078	8,126,191	7,743,511	8,636,740	8,178,002	7941010	7982170	7983143	7983143
CA Fuel Costs ($000)	5,811,697	6,000,181	6,174,850	5,825,723	6,741,237	6,329,739	6030015	6,057,058	6,060,656	6,060,656
CA VOM Costs ($000)	413,677	418,760	438,750	418,300	373,046	345,032	417458	423,824	423,768	423,768
CA Start Costs ($000)	63,655	60,810	62,079	64,739	65,089	64,761	62102	65,510	63,202	63,202
CA FOM Costs ($000)	1,284,766	1,335,763	1,335,763	1,335,763	1,335,763	1,335,763	1335763	1,335,763	1,335,763	1,335,763
CA Emission Costs (SO2, Nox, Hg) ($000)	91,318	95,563	114,750	98,986	121,604	102,706	95672	100,014	99,755	99,755
CA Remote Generation Cost ($000)	827,590	817,427	806,348	826,575	822,941	839,850	818502	813,513	814,540	814,540
CA Net Import Charge ($000)	1,867,186	1,195,769	860,931	1,343,606	1,201,407	1,881,061	1204053	1,059,647	1,057,186	1,057,186
CA Reserve Deficiency Cost ($000)[7]	-	-	-	33,577	-	36,590	0	-	-	-
Annualized Capital Cost ($000)[8]			2,105,161		2,727,555		291200	233,220	233,220	233,220
Emissions										
CA-Instate Emissions										
CO2 (000 ton)	60714	61376	63197	59580	72893	68539	61660	62037	62046	62046
Nox (000 ton)	235	235	238	237	240	246	236	236	236	236
SO2 (000 ton)	63	63	62	63	63	64	63	63	63	63
Hg (ton)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Emissions from Remote Generation										
CO2 (000 ton)	26942	26663	26553	26758	26731	26902	26675	26624	26634	26634

Table 4-2. Comparison of Production Costs in California Across Scenarios

Nox (000 ton)	46	46	46	46	46	46	46	46	46	46
SO2 (000 ton)	14	13	13	13	13	13	13	13	13	13
Hg (ton)	0.23	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Emissions from Rest of WECC (remote Gen excluded)										
CO2 (000 ton)	353877	353197	350369	354549	353820	359446	353216	352054	351968	351968
Nox (000 ton)	501	501	500	502	502	503	501	501	501	501
SO2 (000 ton)	437	438	438	439	439	440	438	438	438	438
Hg (ton)	3.54	3.55	3.55	3.55	3.56	3.56	3.55	3.55	3.55	3.55
Notes:										
(1) Total system cost includes CA in-state generation cost, remote generation cost, and net import charge, and capital cost associated with repowering, conversion to wet or dry cooling, and replacement with other technologies.										
(2) In CEC case 1b, the net import charge was calculated by multiplying the net import in CA and SP15 market clearing prices. In this study, the net import charge is calculated by multiplying the net import at each zone by the corresponding zonal market clearing prices and then summing up the zonal import charges at all zones.										
(3) Only the energy generated from OTC plants that were NOT repowered, replaced, or and converted to wet cooling is reported										
(4) The following units are assumed to convert to wet cooling in Case 6-8 in 2012 and 2015 (but not 2009): Harbor, Haynes, Huntington Beach, and Moss Landing CC										
(5) The following additional units are assumed to be repowered with non-OTC technologies: Alamitos 1-2, Mandalay 1-2; Scattergood 1-2.										
(6) Incluing generation from units assumed to convert to wet cooling										
(7) The reserve deficiency cost is calculated assuming each incidence of reserve deficiency costs the higher of $10,000 or $10/MW.										
(8) The annualized capital cost is based on (a) CEC Staff Report CEC-200-2007-011-SF " Comparative Costs of California Central Station Electricity Generation Technlogies" and (b) Tetra Tech study on conversion to wet coolings.										
	Base Case	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**	**Case 7**	**Case 8**	
Northern California System Cost										
CA Total System Cost ($000)[(1)]	4,187,789	4807492	4215240	5544272	4692813	4342230	4192535	4191436	4191436	
CA In-state Generation Cost ($000)	3,876,761	3632384	3829968	3845477	4117234	3888750	3790372	3793472	3793472	
CA Fuel Costs ($000)	2,962,342	2736752	2913886	2969093	3218491	2974112	2882024	2884827	2884827	
CA VOM Costs ($000)	186,496	176212	184194	150531	160548	186153	182638	182782	182782	
CA Start Costs ($000)	23,731	15390	27552	21251	33317	24267	21599	21754	21754	
CA FOM Costs ($000)	664,600	664600	664600	664600	664600	664600	664600	664600	664600	
CA Emission Costs (SO2, Nox, Hg) ($000)	39,593	39431	39736	40001	40278	39619	39512	39511	39511	
CA Remote Generation Cost ($000)	149246	138172	158357	154654	171552	150306	145338	146356	146356	
CA Net Import Charge ($000)[(2)]	161783	393525	226915	606250	404028	164475	249726	244509	244509	
CA Reserve Deficiency Cost ($000)[(6)]	0	0	0	0	0	0	0	0	0	
Annualized Capital Cost ($000[(8)]		643,411		937,891		138,700	7100	7100	7100	
Southern California System Cost										
CA Total System Cost ($000)[(1)]	5,736,485	7091140	5732028	7844371	6242690	5912536	5896014	5896653	5896653	
CA In-state Generation Cost ($000)	4,034,317	4493807	3913542	4791263	4060768	4052261	4191798	4189671	4189671	
CA Fuel Costs ($000)	3,037,840	3438098	2911836	3772144	3111247	3055904	3175035	3175829	3175829	
CA VOM Costs ($000)	232,264	262538	234106	222515	184484	231306	241186	240986	240986	
CA Start Costs ($000)	37,080	46689	37187	43837	31444	37835	43911	41448	41448	
CA FOM Costs ($000)	671,164	671164	671164	671164	671164	671164	671164	671164	671164	
CA Emission Costs (SO2, Nox, Hg) ($000)	55,970	75319	59250	81603	62428	56053	60502	60244	60244	
CA Remote Generation Cost ($000)	668181	668176	668217	668287	668298	668196	668175	668185	668185	
CA Net Import Charge ($000)[(2)]	1033986	467406	1116691	595157	1477034	1039579	809921	812677	812677	
CA Reserve Deficiency Cost ($000)[(6)]	-	0	33577	0	36590	0	0	0	0	
Annualized Capital Cost ($000[(8)]		1,461,750		1,789,664		152,500	226120	226120	226120	

Table 4-2. Comparison of Production Costs in California Across Scenarios

Old Thermal Generation Retirement and Replacement of Once-Through Cooling Economics Study

Comparison of Production Cost in California across Scenarios (2015)

	CEC Case 1b	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6[4][5]	Case 7[4][5]	Case 8[4][5]
Scenario Characteristics (OTC plant retirement and replacement)		None of OTC plants were retired	All OTC plants retire except nukes , replace w/ a mix GenCC	All OTC plants retire except nukes , replace w/ import	Same as Case 1 except nukes also retire	Same as Case 2 except nukes also retire	Same as base case, with deratings and heat rate adjustment based on Tetra Tech study	10% CF except nukes & units that will be converted to wet cooling & repowered	15% CF except nukes & units that will be converted to wet cooling & repowered	20% CF except nukes & units that will be converted to wet cooling & repowered
Load										
CA Co-incident Peak Load (MW)	63042	63042	63042	63042	63042	63042	63042	63042	63042	63042
CA Energy Load (GWh), including pumping loac	322479	322446	322,453	322,638	322407	322614	322444	322470	322470	322470
CA Dump Power (GWh)	0	0	0	0	0	0	0	0	0	0
CA "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0
Generation										
CA in-State Generation (GWh)	249293	251160	260393	248149	257332	235554	250843	253469	253578	253578
Remote Genereration (GWh)	37780	37483	37202	37615	37240	37981	37486	37435	37439	37439
CA Net Import (GWh)	35406	33803	24858	36874	27835	49079	34115	31566	31453	31453
Remaining OTC Generation, including nuclear (GWh[3]	N/A	49200	34376	34376	0	0	48442	36063	36119	36119
OTC Replacing Generation (GWh)[6]	N/A	0	48685	0	69463	0	48442	20375	20052	20052
CA Reserve Deficiency (GWh)	0	0	0	163	0	163	0	0	0	0
Costs										
CA Total System Cost ($000)	10,708,709	10,299,464	12,158,797	10,275,824	13808585	11525616	10630895	10468833	10472198	10472198
CA Per Unit System Cost ($/MWh)	33.21	31.94	37.71	31.85	42.83	35.73	32.97	32.46	32.47	32.47
CA In-state Generation Cost ($000)	8,201,276	8,526,992	8,857,478	8,322,592	9,808,932	8926137	8551921	8593120	8602759	8602759
CA Fuel Costs ($000)	6,358,839	6,597,468	6,880,305	6,385,184	7,870,461	7063214	6624436	6652841	6662718	6662718
CA VOM Costs ($000)	438,495	441,695	462,945	438,739	402,625	359406	440128	445775	446182	446182
CA Start Costs ($000)	62,765	58,578	69,507	66,200	81,083	67763	57962	60744	60358	60358
CA FOM Costs ($000)	1,245,628	1,330,363	1,330,363	1,330,363	1,330,363	1330363	1330363	1330363	1330363	1330363
CA Emission Costs (SO2, Nox, Hg) ($000)	95,549	98,889	114,357	102,107	124,400	105390	99032	103397	103138	103138
CA Remote Generation Cost ($000)	873,303	862,539	847,636	868,838	848,636	884768	862573	860120	860348	860348
CA Net Import Charge ($000)	1,634,130	909,933	427,135	1,068,672	535,508	1697352	925201	782373	775871	775871
CA Reserve Deficiency Cost ($000)[7]	-	-	-	15,721	-	17,359	0	-	-	-
Annualized Capital Cost ($000)[8]			2,026,549		2,615,509		291200	233,220	233,220	233,220
Emissions										
CA-Instate Emissions										
CO2 (000 ton)	60344	61292	63864	59363	76771	69227	61488	61825	61907	61907
Nox (000 ton)	236	236	239	238	243	248	238	237	237	237
SO2 (000 ton)	67	67	66	67	66	67	67	67	66	66
Hg (ton)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Emissions from Remote Generation										
CO2 (000 ton)	27009	26730	26605	26789	26629	26951	26730	26708	26710	26710
Nox (000 ton)	46	46	46	46	46	46	46	46	46	46
SO2 (000 ton)	14	13	13	13	13	13	13	13	13	13
Hg (ton)	0.23	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Emissions from Rest of WECC (remote Gen excluded)										

Table 4-2. Comparison of Production Costs in California Across Scenarios

CO2 (000 ton)	368443	367984	364264	369346	365563	374514	368092	366982	367022	367022
Nox (000 ton)	509	509	508	509	509	511	509	509	509	509
SO2 (000 ton)	441	442	442	442	443	443	442	442	442	442
Hg (ton)	3.55	3.56	3.56	3.56	3.56	3.57	3.56	3.56	3.56	3.56
Notes:										
(1) Total system cost includes CA in-state generation cost, remote generation cost, and net import charge, and capital cost associated with repowering, conversion to wet or dry cooling, and replacement with other technologies.										
(2) In CEC case 1b, the net import charge was calculated by multiplying the net import in CA and SP15 market clearing prices. In this study, the net import charge is calculated by multiplying the net import at each zone by the										
(3) Only the energy generated from OTC plants that were NOT repowered, replaced, or and converted to wet cooling is reported										
(4) The following units are assumed to convert to wet cooling in Case 6-8 in 2012 and 2015 (but not 2009): Harbor, Haynes, Huntington Beach, and Moss Landing CC										
(5) The following additional units are assumed to be repowered with non-OTC technologies: Alamitos 1-2, Mandalay 1-2; Scattergood 1-2.										
(6) Incluing generation from units assumed to convert to wet cooling										
(7) The reserve deficiency cost is calculated assuming each incidence of reserve deficiency costs the higher of $10,000 or $10/MW.										
(8) The annualized capital cost is based on (a) CEC Staff Report CEC-200-2007-011-SF " Comparative Costs of California Central Station Electricity Generation Technlogies" and (b) Tetra Tech study on conversion to wet coolings.										
		Base Case	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**	**Case 7**	**Case 8**
Northern California System Cost										
CA Total System Cost ($000)[1]		4,457,805	5012110	4482472	5841533	5100668	4611683	4471421	4467184	4467184
CA In-state Generation Cost ($000)		4,211,256	4363771	4105357	4875896	4490447	4217237	4126036	4117841	4117841
CA Fuel Costs ($000)		3,290,402	3441659	3186011	3972349	3589911	3297759	3209933	3202188	3202188
CA VOM Costs ($000)		194,474	201760	189937	183870	164544	193695	190769	190549	190549
CA Start Costs ($000)		20,954	15084	23907	14236	30214	20393	19932	19781	19781
CA FOM Costs ($000)		664,600	664600	664600	664600	664600	664600	664600	664600	664600
CA Emission Costs (SO2, Nox, Hg) ($000)		40,826	40668	40902	40841	41179	40790	40802	40723	40723
CA Remote Generation Cost ($000)		170005	155070	176264	155867	192008	170042	167591	167822	167822
CA Net Import Charge ($000)[2]		76544	-99617	200851	-77597	418213	85704	170694	174421	174421
CA Reserve Deficiency Cost ($000)[6]		0	0	0	0	0	0	0	0	0
Annualized Capital Cost ($000)[8]			592886		887366		138700	7100	7100	7100
Southern California System Cost										
CA Total System Cost ($000)[1]		5,841,659	7146687	5793352	7967052	6424948	6019212	5997412	6005013	6005013
CA In-state Generation Cost ($000)		4,315,737	4493707	4217235	4933036	4435689	4334684	4467084	4484918	4484918
CA Fuel Costs ($000)		3,307,066	3438646	3199173	3898112	3473302	3326676	3442907	3460530	3460530
CA VOM Costs ($000)		247,221	261185	248802	218754	194863	246433	255006	255633	255633
CA Start Costs ($000)		37,624	54423	42293	66848	37549	37569	40812	40577	40577
CA FOM Costs ($000)		665,764	665764	665764	665764	665764	665764	665764	665764	665764
CA Emission Costs (SO2, Nox, Hg) ($000)		58,063	73689	61204	83559	64212	58242	62595	62415	62415
CA Remote Generation Cost ($000)		692533	692566	692574	692769	692760	692531	692529	692525	692525
CA Net Import Charge ($000)[2]		833388	526752	867821	613105	1279139	839497	611679	601450	601450
CA Reserve Deficiency Cost ($000)[6]		-	0	15721	0	17359	0	0	0	0
Annualized Capital Cost ($000)[8]			1433662		1728142		152500	226120	226120	226120

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Results

The primary purpose of the modeling was to provide an estimate of the amount of new infrastructure that would be needed under the various scenarios, and therefore provides a basis for a general assessment of the physical impacts that would be caused by the construction and operation of that infrastructure. Importantly, the economic modeling also examined effects on costs to ratepayers, and produced data allowing calculation of the net change in power plant air emissions throughout the Western U.S.

Effects on Costs to the Ratepayer

As seen in **Table 4-2**, Comparison of Production Cost in California across Scenarios (2015), the least cost scenario is the Base Case, in which no OTC plants retire. This scenario is considerably lower cost than the CEC Staff's Case 1b, which assumed OTC plants would retire once they reach 55 years of age. However, only the extreme cases of retiring all OTC units, or all but the nuclear units, and replacing them with in-area generation showed significantly higher costs to the ratepayer.[75] All other scenarios showed relatively modest cost increases compared to the base case, and in most instances actually showed a modest cost reduction compared to the CEC Staff's Case 1b baseline.

Effect on Net Emissions

The economic modeling also showed that only the extreme scenarios of all OTC plants retiring, including the nuclear units, would have an appreciable effect on overall power sector emissions in the Western half of North America. Most of the presently regulated "criteria" air emissions (NOx, SOx and Hg) from the power plant sector showed essentially no change regardless of which scenario was analyzed. Only CO2 emissions showed appreciable change, ranging from a modest reduction in overall emissions if all OTC units except the nuclear units are retired, to an increase of between 1 and 2 percent overall if the nuclear units are also retired.

This is to be expected since CO2 emissions are directly related to the efficiency of the plants on line, and the assumed replacements for any retired OTC plant are more efficient than the average OTC unit. However, if the nuclear units, which have no air emissions associated with plant operation, are also retired, their replacement would of course have significant emissions, which when balanced against the relative increased efficiency of the replacement of the bulk of the OTC fleet would result on a 1-2 percent net increase in CO2 emissions in the WECC area.

[75] More accurately, these figures are actually total costs that must be absorbed in the system, either by the ratepayer, the utility, or the generator. The vast majority of those costs would eventually be passed on to the ratepayer; however, depending on whether the applicable regulating entity (the CPUC for investor-owned utilities) allows passing the costs along to ratepayers, some costs may be absorbed by the utility or the applicable power plant owners.

Effects on Reliability

The outcome of the economic analysis showed that reliability effects would be greatest in 2015 because of projected load growth, and would be most concentrated in the San Diego, Los Angeles Basin, Big Creek/Ventura and Greater Bay Area LRAs. Therefore the reliability modeling focused on the effects in 2015 in these four areas. The reliability analysis identified transmission line segment overloads that would occur under the various scenarios and contingencies analyzed, as shown in the scenarios matrix provided for this modeling effort. Mitigation for those overloads was assumed to be the most cost-effective option for each overload, usually constructing transmission projects and/or in-area generation. The results of the reliability modeling runs are reported in a scorecard format and all overloads and proposed mitigation documented in **Table 4-3**.

Table 4-3. Reliability Modeling Results

Estimated Line Costs (in millions)	In California Improvements	Outside CA	TOTAL
$277.9			
Transmission Devices			
Cap Bank	$26.3	$9.6	$35.9
SVC or Sync Cond @ $10K/MVAR	$53	$19	$71.7
Sync Cond ($10-$40) @$40/kvar	$210	$76	$286.9
STATCOM @ $55/KVAR	$289	$105	$394.5
DVAR ($80-$100/kvar)	$526	$191	$717.2
Range of estimate costs for transmission improvements	**$313.8**		
	$349.6		
	$564.8		
	$672.4		
	$995.1		

The results of the economic analysis showed that Cases 2 and 4 resulted in the greatest threats to electric reliability, which is why Global's reliability modeling focused on these two extreme scenarios, in which all OTC plants are assumed to retire (except the nuclear units in Case 2).[76] The reliability modeling essentially pushed all the variables to the limit: maximum peak load in all service areas occurring at once, maximum generating capacity at its lowest due to highest assumed ambient temperatures, and one important generating unit and/or important transmission line operating that day tripped off-line unexpectedly.

[76] Cases 1 and 3, in which retired OTC capacity is replaced by in-area generation, showed no reliability impact because these two cases because the replacements are assumed to be capable of providing the same service as the retired unit and would be connected to the same point in the grid, making these two cases functionally equivalent to the Base Case.

The modeling effort in general considered the costs of replacing the retired OTC generation with both transmission upgrades and new power plant construction. Because so many of the OTC units currently run at very low power levels, yet are needed at maximum capacity for about 100 hours per year, new plant construction was clearly the more expensive option in almost all cases. **Table 4-4** shows the new generating capacity that would be required in the cases of all OTC plants retiring. In the extremely unlikely event that all OTC plants would immediately retire following enactment of the new OTC rules, and that new plants of equal size would be constructed to replace the retired units even though most of the new units would run only a few weeks per year, costs would be very high.

Table 4-4. Replacement Capacity (MW) Needed in Case 1 and Case 3

	2009	2012	2015
North CA			
Case 1	4500	4570	4530
Case 3	6700	6820	6780
South CA			
Case 1	8820	10505	10480
Case 3	8820	12745	12730
CA Total			
Case 1	**13320**	**15075**	**15010**
Case 3	**15520**	**19565**	**19510**
Note: SONGS NPDES permits expires in 2011			

For example, in the most extreme case, where all OTC plants retire in 2009 including the nuclear plants, the state would need 15,520 MW of new generation or an equal amount of peak load-reduction programs to replace the lost OTC capacity. Because of the short time frame, the only replacement generation even remotely feasible would be combustion turbines, especially portable, aero-derivative, trailer-mounted turbines,[77] which can be sited, connected and started up relatively quickly. Those types of turbines range generally from about 20 MW up to 100 MW, meaning that 150 to 800 new turbines would need to be sited and connected in an extremely short period, though emergency conservation efforts could likely reduce that number considerably. This would require nothing short of a major "war-time" mobilization effort, including strict and severe conservation programs and efforts beyond extreme to even find and procure that many turbines worldwide.

[77] These refer to a relatively new type of turbine based on those used in the commercial aircraft sector, which can be mounted on a frame capable of being towed by truck, These units often consist of one turbine unit and a separate trailer-mounted control unit. During the power crisis of 2001, the CEC enacted an emergency siting program to permit such units in as little as 3 weeks.

If OTC plants were all retired in 2012, and only replacement generation considered as an option, as much as 19,569 MW[78] of new capacity or conservation would be needed. This is the equivalent of 20 very large (1,000 MW) gas-fired combined-cycle plants, costing upwards of $11 billion. But building such plants would make absolutely no sense, since many of them would run for only a few weeks per year. Thus, transmission upgrades are clearly the lower cost option for resolving the transmission line overloads that would occur following mass OTC plant retirement. For this reason, and because the reliability modeling focuses solely on finding the least-cost mitigation to reliability impacts, in every case the least-cost mitigation options turned out to be transmission system upgrades.

The modeling showed that even if all OTC plants retire in the state, including the nuclear units, the resultant need for new transmission infrastructure to compensate for the lost capacity is relatively modest. Assuming the nuclear units do retrofit their cooling systems, but all other OTC units retire, the need for new infrastructure would be even less. As shown below in **Table 4-5**, Case 2 (all OTC units retired except the nuclear units) would result in the need to upgrade 142 miles of existing transmission line, plus make other related component upgrades such as new transformers where needed, for a total cost of $135.1 million. The more severe scenario of Case 4 (all OTC units retiring including the nuclear units), showed that costs could range from about $314 million to as much as $995 million, depending upon the type of transmission projects employed to compensate for any retirements. These projects include the $135.1 million from the non-nukes scenario, plus considerable extra costs both inside and outside California to make needed upgrades for importing power to replace the lost nuclear generation. The costs of upgrades associated with all other scenarios analyzed are considerably less than $135 million.

These numbers give credence to the conclusion of this study (discussed in detail in Chapter 5): the enactment of the Board's pending policy concerning use of OTC is not likely to create impacts to electric system reliability, or significant cumulative air quality impacts to the environment, providing the industry is given sufficient time to account for any retirements that may occur. However, this modeling effort was very limited in scope, allowing essentially only a snapshot of a range of possibilities (from worst case to more realistic scenarios) that could occur following enactment of the Board's planned policy. Ideally, a comprehensive modeling effort of the retirement of every OTC unit, individually and in combination with all other OTC units, would likely reveal further details concerning potential costs and impacts. Such a comprehensive effort would require thousands of reliability modeling runs, compared to the handful that were feasible for this study. Fortunately, the CAISO is currently conducting such a study, as discussed further below.

[78] The needed capacity jumps considerably between 2009 and 2012 because of load growth.

Table 4-5. Transmission Upgrade Costs

From Bus Number	Name	To Bus Number	Name	Ckt	Length	Voltage (KV)	Cost($ million/mile)	Total Cost ($million)	Length	Bus Number	Bus Name
San Diego											
22664	POMERADO	22668	POWAY	1	2.5	69	0.29	0.725			
22844	TALEGA	24131	S.ONOFRE	1	6.9	230	0.65	4.485			
22844	TALEGA	24131	S.ONOFRE	2	6.8	230	0.65	4.42			
LA Basin											
24016	BARRE	24154	VILLA PK	1	9.2	230	0.65	5.98			
24016	BARRE	25201	LEWIS	1	5.5	230	0.65	3.575			
24137	SERRANO	24154	VILLA PK	2	3.3	230	0.65	2.145			
24137	SERRANO	24192	SERRASTR	1	1	230	0.65	0.65			
24137	SERRANO	24194	SERRASTR	2	1	230	0.65	0.65			
24138	SERRANO	24192	SERRASTR	1	-	500/230	13	13			
24138	SERRANO	24194	SERRASTR	2	-	500/230	13	13			
24156	VINCENT	24221	VINCESTR	1	-	500/230	13	13			
24114	PARDEE	24217	WARNETAP	1	22	230	0.65	14.3			
24115	PASTORIA	24217	WARNETAP	1	20	230	0.65	13			
24411	DEL SUR	24477	TAP 50	1	0	69	0.29	2.755	9.5	24418	LANCSTR*
24421	OASIS SC	24442	TAP 68	1	0	69	0.29	2.03	7	24418	LANCSTR**
Bay Area											
30810	GREGG	30820	HELMS PP	1	62	230	0.65	40.3			
30526	PITSBG D	30528	DEC PTSG	1	0.85	230	0.65	0.5525			
30526	PITSBG D	30528	DEC PTSG	2	0.85	230	0.65	0.5525			
TOTAL					**141.9**			**135.12**			

*In Column 18, DEL SUR (24411) is connected to LANCSTR (24418) through TAP 50 (24477). Global Energy estimated the distance from DEL SUR to LANCSTR as TAP 50 substation could not be found.

**In Column 19, OASIS SC (24421) is connected to LANCSTR (24418) through TAP 68 (24442). Global Energy estimated the distance from OASIS SC to LANCSTR as TAP 68 substation could not be found.

Legend:

(yellow)	Reference from WECC transmission case
(orange)	Global Energy Estimate
(gray)	SSG-WI 2005 Transmission Planning Program 2015 Reference Case Key Assumptions Matrix

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Other Studies

California Energy Commission Scenarios Project

The results of the modeling effort for this study would seem to be considerably different than that of a very similar study called the "Scenarios Project" conducted by the Staff of the California Energy Commission, a part of which examined the retirement of aging power plants in Southern California Edison (SCE) territory. That portion of the CEC study was commissioned to examine the potential effects of a recommendation adopted first in the CEC's 2005 Integrated Energy Policy Report (IEPR), and repeated in the 2007 IEPR, that "the CPUC should require that IOUs procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012."[79]

The CEC modeling effort started with the assumption in its base case that aging power plants would retire at 55 years old. A few plants reached this benchmark before 2012, while most were between 2012 and 2020, and a few came after 2020. Because the aging portion of the OTC fleet already runs at very low power levels, the CEC noted that "the continuation of aging power plants in the resource mix beyond 2012 contributes little to the projections of overall fuel use and GHG emissions from California power plants." But, "[b]ecause it is uncertain whether, or how these aging power plants will be retired and their capacity replaced, the scenario project undertook an additional analyses of this topic."

As discussed above, the CEC Staff's modeling effort used identical models and nearly identical assumptions as used in this study, including assumptions on how any retired generation would be replaced.[80] The CEC Staff's scenario assumed that 4,140 MW of aging capacity in SCE's territory would retire in 2012 and be replaced from resources either located in or deliverable to the east side of SCE's service territory. Total aging plant capacity in SCE territory is about 6,650 MW. The CEC study stated that 4,140 MW was chosen as the maximum amount of OTC capacity that could be retired and not replaced locally, providing certain transmission system upgrades are completed.

This marks a key difference in the modeling efforts for the CEC Staff Scenarios report and this study. In effect, CEC Staff concluded that replacing the additional 2,250 MW of lost generation with out-of area generation would be infeasible because the needed infrastructure would be prohibitive, both because of expense and because of time, the latter referring to the time needed to construct the identified major infrastructure in the time frame allowed.

The CEC approach assumed that none of the aging plants would be repowered, but instead would be replaced either by new power plants built on the eastern edge of SCE's territory, or by power imports delivered to the eastern edge. This

[79] This policy would not affect municipal utility sales or purchases from aging plants.
[80] One difference is that in the Scenarios report Global Energy Decisions conducted the economic modeling, and Navigant Consulting conducted the reliability modeling, while Global conducted both the economic and reliability modeling for this Electric Reliability report.

assumption was widely criticized by one commissioner who felt strongly that many of the current coastal OTC plants could and should be repowered.[81]

To assess the potential combined affects of aging plant retirements with enactment of other state policies, the CEC effort included many "what-if" scenarios that examined the potential reliability effects of aging plant retirements under three different sets of assumptions: (1) one in which current energy efficiency and renewables policies are fully enacted, (2) another assuming these policies are enacted plus considerably more savings from additional energy efficiency measures, and (3) a third in which current policy goals are met plus a considerably larger amount of renewables are built. All three cases assumed that planned transmission upgrades would be completed as scheduled.

The CEC analysis identified transmission system overloads and methods to resolve the overloads through transmission upgrades. Under Case 1, the CEC study concluded that even if all 6,650 MW of aging plant capacity in the SCE territory was retired, the impact to reliability could be mitigated with sufficient new capacity (about 8,000 MW[82]) built or delivered to the eastern edge of SCE's system, combined with substantial upgrades to SCE's internal transmission system. Timing, however, was cited as a key factor in maintaining reliability. "Due to the costs and lead time required to plan, permit, and develop both the required replacement capacity and … transmission upgrades, retirement of large amounts of the Aged Plant generation in the SCE area by 2012 would be difficult. However a phased retirement plan could likely be developed that would allow sufficient lead time for the development of both the required generation and transmission projects."

The predicted impacts to reliability were substantially less in CEC Staff's Cases 2 and 3, in which the industry either enacts conservation and efficiency measures well beyond current goals or installs renewable energy generating facilities that far exceed current goals. Under both cases, the CEC study found that the impacts to reliability of retired aging OTC plants within the SCE territory would be somewhat less in 2012, and substantially less in 2016 as new programs achieve their greatest potential.

Overall, the results of the CEC Staff study "indicate that significant transmission upgrades would be required to replace Aged Plants located on the western side of the SCE service area with replacement capacity on the eastern side of the service area, and that there are differences in associated transmission upgrades depending upon the resource build-out strategy…. Power plant development and transmission line upgrades can involve extensive planning and licensing processes with long and uncertain lead-times and results. Therefore, this study suggests that close coordination is needed among the pertinent parties with respect to power plant retirement, the planning and development of replacement

[81] Statement of Cmmr. John Geesman, August 16 CEC Workshop Transcript, Pg. 235. Because of this criticism, plus the other incentives favoring repowerings mentioned above, this study included a scenario in which several plants were assumed to repower.

[82] The CEC study predicted that as little as 7,200 MW would need to be built to replace retired aging plant capacity, depending on where in SCE's system the new facilities interconnected. Without aging plant retirements, the CEC study predicted that 3,800 MW of new generating capacity would be needed in SCE territory just to meet load growth.

resources, and the planning and development of the required transmission line upgrades."[83]

The Differing Results of This Study and the CEC Staff Scenarios Report

Compared to this study, the CEC Staff Scenarios report in general found a greater need for new infrastructure, and thus greater costs and environmental impacts associated with plant construction, compared to the OPC/WRCB Electric Reliability Report. There are two main reasons for this: the subset of generating units examined and the year examined.

The Scenarios report examined aging power plants in the state, those at or near 50 years of age, located within the service territory of Southern California Edison in the greater Los Angeles Area. These included an inland plant that does not use OTC, which has a greater effect than might seem intuitive because it plays a key role in alleviating the congestion found in the eastern edge of SCE's territory, where imports come in. Another key difference was that "to stress the system for contingency studies" the Scenarios report also assumed one unit at the San Onofre plant was out of service. The Scenarios report chose 2012 for the reliability study time frame because that was the date by which the Energy Commission was recommending the "orderly retirement" of aging plants.

This study, on the other hand, examines only the retirement of OTC plants, including scenarios where all OTC plants except the nuclear units retire, all OTC plants retire, all OTC plants convert to wet cooling, etc. Though there is considerable overlap of the two studies, and both could be described as "snapshots" of the future, the Scenarios report is more of a close-up of a portion of the state in 2012, while this study examines the "big picture" of the whole state in 2015.

The main difference between the two, however, likely comes from the fact athat this study has been updated with the latest filings at the WECC from utilities and generators all across the western half of North America. These filings show that by 2015, sufficient excess generation would be available in the WECC region to compensate for the retirement of all OTC units in 2015, and that the transmission system will have been considerably upgraded by then. The only unknown, then, would be whether sufficient transmission system infrastructure would exist to deliver power from that excess capacity to the key LRAs of the state.

The Scenarios report concluded that building the needed transmission infrastructure by 2012 to ensure reliability in SCE territory would effectively be infeasible because of cost and time constraints. This study concludes that, because so much new infrastructure would be developed by 2015, the additional new infrastructure needed to compensate for retired OTC generation is feasible, though challenging. This is because significant new facilities outside the state

[83] Scenarios Report Appendix A, "Analysis of Transmission Implications of Aged Power Plant Retirement and Replacement," , by Navigant Consulting, Inc., CEC-200-2007-010-AD2-AP

would be needed, requiring the cooperation of utilities and regulatory agencies across the West, such as through the WECC planning efforts.

The key recommendation arising from both the Scenarios report and this one is that because of the potential threat to reliability, constant re-assessment of reliability effects will be required as the policy is developed and enacted. This can be achieved through continued cooperation between the Water Board and the state's energy regulators and industry as the Board's OTC policy is further developed.

Future Studies

California Independent System Operator Study, Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Through Cooling Systems

The CAISO has also embarked on a comprehensive examination of the effect of retiring aging and OTC plants in all regions of the state. The effort includes an extensive outreach plan to enlist the aid and support of all facets of the energy industry in the state, including the utilities, the CEC, the CPUC, the generators, the Water Resources Control Board, and interested individuals and non-governmental organizations. The goal of the study is to develop plans that take into consideration a variety of scenarios to facilitate retirement and replacement of these facilities as well as alternative solutions such as transmission, distributed generation, and load management programs.[84] Though initially intended to only consider the retirement of aging plants, the study was expanded at the urging of several participants to include the potential retirement or de-rating of all plants using OTC. The CEC noted in the 2007 IEPR that the CAISO study "must address aging facilities owned by the investor-owned and publicly owned utilities and carefully consider issues surrounding once-through cooling and restrictions on emission credits in Southern California."

The CAISO study process has started in earnest by enlisting the support of a very broad range of participants in forming study plans tailored to specific areas of the state. The CAISO's initial study plan states the effort "is primarily a technical study to support California policy objectives related to mitigation of reliance on aging thermal generator units and those that utilize once-through cooling systems. The objective is to identify transmission system and operating reliability problems and alternative potential mitigation options which will maintain reliable electric grid operations in the future."

The CAISO study intends to use similar computer models and assumptions to those used in this study, but it will be much more comprehensive, expanding the

[84] Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Through Cooling Systems, presentation by Larry Tobias, California ISO, September 21, 2007, http://www.caiso.com/1c5e/1c5edff632c50.pdf.

number of scenarios into the dozens and examining potential impacts from retirement or de-rating of each individual OTC plant. “A mix of scenarios will be developed that will include generator operational restrictions for OTC compliance, heat rate penalties and de-rating effects associated with retrofit of OTC, retirement/replacement of old thermal generation, development of new generation (particularly renewable generation), and related reinforcement of the electric transmission system. It is intended that this will be followed by other activities for an economic assessment of mitigation alternatives as well as involvement of other WECC members outside of California whose electric systems may be impacted depending on the results of the technical study and proposed mitigation plans.”[85]

The goal of the CAISO study is to supply decision makers with in-depth information concerning the effects on electric system reliability from aging and OTC plant retirements so that they make appropriate decisions concerning utility resource plans. However, “It is recognized that this technical study activity will pro-actively establish only one of many critical decision criteria that are considered when recommending a preferred plan and that a final decision, based in part on generation procurement costs, will occur following completion of this activity and [will] be accomplished through the California Public Utilities Commission Resource Adequacy Process and therefore via procurement decisions of Load Serving Entities.”

South Coast Air Quality Management District Rule 1309.1 Electric Reliability Study

The South Coast Air Quality Management District (SCAQMD) also recently announced its intention to conduct a comprehensive study of future electric resource needs in its territory, which includes the bulk of both LADWP’s and SCE’s service territories.[86] The District is concerned about the ability of future power plant developers to obtain sufficient air emissions offset credits to build new plants in the region. The emissions offset credit program was developed by the District as a means for power plants to comply with federal and state air quality rules that enforce the Clean Air Act, and essentially is a means of mitigating air quality impacts of power plant operations. The offset credits available for purchase by power plant developers had recently become so expensive that the District became concerned that needed power plants would not be built, threatening electric reliability in the area.

As a stopgap measure, the District in November approved amendments to its Rule 1309.1, which governs the process by which power plant operators purchase or earn emission offset credits as mitigation of their air quality impacts. Specifically, the recent amendments gives temporary access to SCAQMD’s Priority Reserve PM10, SOx and CO accounts to new in-district electric generating facilities with applications deemed complete between 2005 and 2008,

[85] Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Through Cooling Systems Study Plan, Final Draft Version 4.0, November 14, 2007

[86] SCAQMD territory includes all of Los Angeles, Orange and Riverside Counties plus portions of Imperial and San Bernardino Counties. See map at http://www.aqmd.gov/map/MapAQMD1.pdf

provided the operators meet all the other rule requirements.[87] This special bank of credits, developed from facilities that were retired or abandoned, was previously only available to public projects, such as sewer treatment facilities.

Because access to these reserve offset credits is cutoff after 2008, the expected effect is that purchasing sufficient emission offset credits to allow replacement or repowering of current OTC plants after 2008 could become considerably more expensive, perhaps prohibitively so, which could negatively impact electric system reliability.[88] To assess this potential threat to future reliability, the District recently announced a three-year research plan to conduct a multi-phase energy resource planning study focusing on the needs in SCAQMD. The District first intends to conduct a comprehensive resource study to assess future electricity needs in the area and consider alternatives to the need for future power plants, including increased conservation and efficiency measures.[89] The District expects to award a contract for the study soon and start the study process in early 2008, finishing about a year later.

[87] See http://aqmd.gov/ceqa/documents/2007/aqmd/finalea/1309.1/fpea.pdf
[88] SCAQMD Notice of Decision, August 3, 2007, re. CEQA Compliance for Proposed Amended Rule 1309.1
[89] SCAQMD RFP #P2008-05, Electricity Resource Planning for the South Coast Air Quality Management District

Chapter 5
Conclusions

This chapter discusses the conclusions that can be drawn from the analyses conducted for this study. These include conclusions related to the likelihood of plant closures, retrofits and repowerings, and the resultant effect on electric reliability. Also included is an extended discussion of conclusions related to the Board's internal CEQA-equivalent examination of impacts to public safety and the environment that could results from the need to construct and operate additional infrastructure as the result of the Board's decision concerning OTC.

Likelihood of Plant Closures, Retrofits and Repowering

Though predicting the future operations of any one power plant is speculative at best, certain trends are evident that support overall conclusions concerning the OTC fleet. For example, because of recent and expected new power plant construction, operation at the older, less-efficient boiler OTC units is likely to continue to trend downward in coming years. The exceptions are a few plants located in key reliability areas where transmission constraints limit the ability to import power into the area. The nuclear and new combined-cycle, gas-fired OTC plants have run at considerably higher levels than the boiler units, and that trend is likely to continue as well.

Considering all the information presented in this study, it is apparent that some present OTC plant owners clearly will have strong incentives to convert their cooling systems and remain operational if they are required to eliminate OTC. These would include the nuclear units, the newer combined-cycle units, and the boiler units that are heavily relied upon for local reliability service, all of which have a high likelihood of recovering the cost of the retrofit. Owners of some other older boiler plants will also have strong incentives to repower their plants with an alternate cooling method in order to remain competitive in the marketplace while complying with the Board's new policy.

Regardless of the Board's pending policy, repowering of present OTC sites is favored both in state law and in state policy, giving owners of those sites considerable competitive advantage in securing contracts for the output of their repowered plants. OTC plant sites have considerable economic advantages over a green-field site, especially the ready availability of natural gas supply and transmission interconnection.

However, the key factor in a repowering decision will likely be whether the owner can secure contracts for the plants output or, in the case of the LADWP plants, whether repowering makes economic sense for the municipal utility. Also, some existing OTC plant sites have land-use issues that may prevent converting the cooling systems, and others in the South Coast Air District may find difficulties in the future in obtaining sufficient air emission offset credits to allow operation of large, repowered plants.

Also affecting decisions to repower, convert or retire is whether investment in additional transmission improvements to bring more competition to the generating sector proves to be cost effective. The data gathered for this study show that by 2015 the Western U.S. could be awash in excess generating capacity, perhaps allowing considerably greater capability to import power over long distances into the load pockets of California.

With sufficient investment in the transmission system, this excess capacity could potentially compensate for any OTC plant retirements. The last time the system had significant excess generating capacity was in the 1980s. But the excess gradually diminished as load growth absorbed the excess generating capacity, and transmission congestion prevented many of the long-distance deals of the past.

The modeling effort conducted for this study concluded that this era could return, given sufficient planning and investment in transmission system improvements, bringing back the advantages to consumers of having excess generating capacity in a highly interconnected grid. However, this effort would be more than challenging, given that much of the improvements would need to occur out of the state, beyond the control or jurisdiction of the state's energy industry. Therefore, barring an extraordinary interstate transmission planning effort, it appears likely that the state will continue to rely to some degree on in-area generation, as well as power imports from other areas, for the indefinite future. This need will likely provide sufficient incentive to many OTC plant owners to either retrofit their present cooling system or repower their units while also installing an alternate cooling system. Others may retire because their owners believe they will not be able recover the costs of a retrofit or repower, or because of constraints preventing such actions.

Given the choice to retire or convert, the combined-cycle plants are most likely to convert their cooling systems because doing so is relatively inexpensive compared to similar sized boiler or nuclear plants. The privately held newer units also likely would continue making substantial sales through contracts and the day-ahead energy market following system conversion. LADWP will also have a strong incentive to convert the cooling system of its newer plants, if feasible, because of their policy of relying on their own generating assets to supply their customers, and because they will want to maximize their investments in those plants.

The owners of the nuclear units also have strong financial incentives to convert their cooling systems rather than retire, mostly because the nuclear units presently supply power that would costs billions per year to purchase elsewhere. Their owners have also amortized the costs of the units over their entire projected lifetimes, which extend into the 2020's, and they may not be able to fully recover those costs if the units are retired. These incentives are apparent in PG&E's willingness to spend up to $700 million now to replace leaky steam generators at both Diablo Canyon units in order to extend the life of the units to the end of their present NRC license periods (2021 for Unit 1 and 2025 for Unit 2).

The future need for OTC plants is also highly regional in character. PG&E, for instance, is already planning to eliminate purchases from older, boiler OTC units starting in 2012. But Southern California Edison does not plan to eliminate boiler OTC plants from its resource mix until at least 2016, and San Diego Gas & Electric plans to rely on at least one OTC plant throughout its planning period (to 2020). In fact, because of severe transmission constraints that are likely to persist for the indefinite future, SDG&E will continue to rely on essentially all the in-area generation it can get, including the South Bay and Encina OTC plants. If they are required to stop using OTC, the owners of those plants would seem to have strong incentives to repower and/or convert their cooling systems[90] or, in the case of the South Bay plant, build a new, non-OTC plant nearby that can deliver power locally.

Potential Effect of Closures, Repowering or Retrofits on Plant Availability and Resultant Grid Reliability

The modeling effort for this study shows that immediate retirement of all present OTC plants would have severe effects on reliability and would require an effort no less than the mobilization of the country during World War II to cope with the consequences. But it also showed that a phased-in approach for enacting the Board's new rules could have relatively modest impacts on reliability, and that these impacts could be effectively eliminated through proper planning. The modeling also showed that power system costs associated with the Board's new policy could vary widely, depending upon whether any retired OTC units are replaced solely by new power plants constructed in the same area, or by out-of-area generation through an improved transmission system. Depending on how and when the Board's decision is implemented, and how the energy industry responds, costs could vary from around $100 million to $11 billion. The key issues then, as with so many things, are planning and timing.

The California Energy Commission Staff's Scenarios study of retiring aging plants in Southern California Edison's territory also predicted moderate to severe impacts to reliability from plant retirements. But it noted that even if all the aging OTC plants in SCE territory retired, and none of them repowered, reliability could still be maintained through a combination of new or repowered plants built in the area plus transmission upgrades, to ensure all areas are reliably served.

[90] Indeed, the owners of the Encina plant have announced a 540 MW repower project at the present site using dry cooling.

However, the main conclusion of both that study and this one is that to ensure that reliability is maintained the industry must have sufficient time to plan for any future unit retirement or derating. The current, generally accepted planning time for a new major power plant is five years, and for a new major transmission line is seven years. Repowered plants may take somewhat less time to plan and construct, and almost all the transmission upgrades identified in the modeling efforts of this study can be accomplished in considerably less time, including those in Southern California needed to compensate for the retirement of all aging OTC units there.

Therefore, because the future of the OTC fleet will likely consist of a mixture of retired, repowered and retrofitted plants, and because predicting the future of any one plant is speculative at best, the key point in maintaining electric reliability in the future will be to allow sufficient time to plan and implement actions that will compensate for any retirement or derating associated with the Board's policy. Given this flexibility in the process, the Board's policy would not likely create significant impacts to electric system reliability in California.

Potential Actions or Methods to Reduce Environmental Impacts Related to the Board's Pending OTC Decision

Though the Board's pending OTC policy is exempt from the California Environmental Quality Act (CEQA), the Board conducts its own CEQA-equivalent investigation of potential impacts to public safety and the environment caused by its policy decisions. To support that investigation this study also considers whether the policy would create an impact to public services as defined by CEQA, as well as potential mitigation that could reduce that impact, perhaps to less than significant levels.

The CEQA Process

If it were subject to CEQA, the first step in determining whether the Board's decision would result in a significant impact to public services would be to determine the scope of the review conducted to make that decision. The scoping effort would be used to determine the appropriate document for the review, such as an Environmental Impact Report or a Negative Declaration under CEQA. The type of document prepared also sets the level of detail of the review.

Because the likely range of future decisions and facilities under the Board's proposed policy are generically predictable, but the specifics not yet known, the most appropriate approach to evaluating future impacts under CEQA would be to rely on a programmatic impact approach. This approach is also appropriate because the Board would have no control or jurisdiction over any infrastructure that may be constructed as the result of its decision.

A Program EIR is appropriate when an agency is considering adopting a policy, plan, regulatory program or other series of related action. Program EIRs generally analyze broad environmental effects of the program with the acknowledgment that site-specific environmental review would be required for particular components of the program when those specific activities are proposed for implementation. Program EIRs can enable the lead agency to consider broad policy alternatives and programmatic mitigation measures at an early stage when the agency has greater flexibility to deal with them.[91]

In developing a Program EIR, the Lead Agency should try to anticipate likely future scenarios that could ultimately develop under the program, evaluating more than one possible set of future outcomes in equal levels of detail. In essence, this study and its related modeling effort accomplishes the purposes of a programmatic evaluation of potential impacts to electric system reliability. The modeling effort examined a wide range of potential plant retirements or deratings, producing estimates of the new infrastructure that would be needed to maintain system reliability.

Significance and Feasibility

As part of its investigation, the Board considers the effect that project may have on the provision of public services, including delivery of electricity to affected ratepayers. However, CEQA and the Board's CEQA-equivalent process are not specific as to how the Board would determine whether the effect would rise to the level of "significant impact," nor to whether specific actions taken to mitigate that impact would be considered "feasible." Feasible is defined in CEQA as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors." CEQA is generally not specific about what would constitute a "significant impact" to Utilities and Public Services in this case, but the Water Board's internal standard for significance asks: "Will the proposal result in a need for new systems, or substantial alterations to the following utilities: a. Power or natural gas…."

To assist in determining significance, this study compares the effects of its proposed policy against a "no-project" baseline, in which the OTC policy is not changed. The modeling effort for this study shows the differences in costs for the various scenarios examined in comparison to a baseline that assumes no OTC plants are retired. It is important to note, however, that other policies also affect the viability of future operations at present OTC plants, including the CEC's policy seeking an "orderly retirement" of aging OTC units by 2012, as well as the policies governing dispatch of power plants in general.[92] Sufficient evidence exists to conclude that many of the present aging boiler OTC units could retire in coming years, regardless of any change in OTC policy, because of state policy encouraging such retirement, and because of their inability to compete with

[91] CEQA Guidelines Sec. 15168

[92] California's control area operators have long had a policy of "economic dispatch," under which more-efficient (lower cost) power plants are used before less-efficient (higher cost) plants, which also generally results in the lowest-possible overall air emissions from the power sector.

lower-cost options. Adding the costs associated with cooling system conversion could tilt these plants even closer to retirement, possibly creating threats to electric system reliability if a sufficient amount of new infrastructure is not developed in time to compensate for any retirements.

Whether that need for new infrastructure would result in a significant impact to public services, according to CEQA, is a completely different issue, but in this case, it would be unnecessary for the Board to make such a determination. Because the appropriate CEQA review for this project, were it not exempt, would be a Program EIR, and because the development of the infrastructure discussed above is beyond the control or jurisdiction of the lead agency, the lead agency need not determine whether its policy would create a significant indirect impact, nor determine whether any mitigation of such an impact would be feasible. Rather, the lead agency would be required to discuss the potential environmental impacts of the future infrastructure development, and the likely mitigation measures that would apply, in a general way. This general discussion, found below, would be required even if the policy would create the need just one new power plant or transmission project.

Environmental Impacts from Infrastructure Development

The modeling results detailed in Chapter 4 show that both the amount and the timing of needed new infrastructure could vary widely, depending on how the Board's OTC policy is enacted. The potential impacts to public safety and the environment caused by the Board's policy, as defined by CEQA, would be directly related to the physical effects of the construction and operation of the otherwise unneeded infrastructure.

These physical effects would be examined in the environmental reviews of each related project conducted by the applicable jurisdictions in the state. Jurisdiction over the review and approval of these projects varies depending upon the nature of the project. The California Energy Commission (CEC) has sole jurisdiction over all applications to construct thermal power plants[93] of 50 MW or larger in the state. The Federal Energy Regulatory Commission (FERC) has authority over all hydroelectric power plants, the Nuclear Regulatory Commission (NRC) has authority over all nuclear plants, and the applicable local jurisdiction (typically a city or county government) has jurisdiction over all other power plants not subject to CEC, NRC or FERC jurisdiction. Cooling system conversions would likely be the jurisdiction of the authority that either approved or would have approved the original plant.[94] Transmission lines built by regulated utilities in California are generally under the jurisdiction of the California Public Utilities Commission (CPUC), though lines constructed in relation to the development of a new power plant are often approved by the same agency approving the power plant.

[93] Thermal plants are those that use heat as the primary source of energy, which include the burning of any fuel, geothermal energy, and solar thermal energy.
[94] Many OTC plants were constructed prior to such construction and operation being regulated.

The physical impacts of power plant construction and operation typically include effects on air quality, water quality, noise, visual resources, land use and biological resources, among others. Cooling system conversion can create air quality impacts due to drift from the cooling towers, and water quality impacts from the need to recycle or dispose of the concentrated minerals, etc., that remain in the cooling system as water is evaporated.[95] Transmission line projects also create effects in all these areas, though they do not have ongoing noise or air quality effects and seldom result in permanent effects to water quality.[96] A key difference between the two types of projects is that all power plants have similar characteristics for their sites, designs, and impacts, whereas transmission projects vary widely, from minor projects such as replacing a substation, to major projects involving new corridors through hundreds of miles of sensitive habitats and scenic resources.

The air quality impacts of power plants are mitigated generally by obtaining air emission offset credits under programs overseen by the various Air Quality Management Districts and Air Pollution Control Districts in the state. Other impacts, for power plants, cooling system conversions or transmission lines, are mitigated by actions that either avoid, eliminate or reduce the impact to less than significant levels, or compensate for the impact in some way.[97]

Importantly, other than some land use impacts involving zoning designations, the CEC has not approved a power project in the last 7 years, at least,[98] that would result in a significant, unavoidable (unmitigated) impact to public safety or the environment. The Commission conducts a CEQA-equivalent examination of impacts from a project, and then mandates mitigation measures, called "Conditions of Certification," that avoid, eliminate or reduce any predicted significant impact to less than significant levels. Recent orders approving Applications for Certification for construction and operation of large gas-fired power plants typically used this language: "The Conditions of Certification also assure that the project will neither result in, nor contribute substantially to, any significant direct, indirect, or cumulative adverse environmental impacts."[99] This included many projects that use wet cooling, indicating that the conversion of cooling systems, with appropriate mitigation and best management practices, is not likely to result in permanent, unavoidable impacts to public safety or the environment.

Large transmission projects, on the other hand, often are approved even though they will have significant, unavoidable impacts, especially those traversing National Park or National Forest Lands, which are highly valued for their scenic resources. These projects can involve construction of hundreds or even

[95] Approximately 1-3 percent of the water in wet cooling systems is lost to evaporation on a given day, requiring occasional re-filling of the system from a makeup source. As water is evaporated, minerals become more concentrated, requiring occasional "blow-downs" where water is added to the system, then the system is drained, and the process repeated until concentrations are acceptable. These blow-downs create hazardous waste that must be recycled or disposed of in landfills.
[96] Most transmission projects, such as reconductorings and substation improvements, are exempt from CEQA and are instead guided by a set of Best Management Practices.
[97] Recent environmental reviews of power plants and associated transmission line projects can be found through the links on the CEC's Siting Division website at http://www.energy.ca.gov/sitingcases/all_projects.html.
The CPUC's CEQA review of current transmission line project can be found at:
http://www.cpuc.ca.gov/PUC/energy/electric/Environment/Current+Projects/
[98] Investigation into this topic was limited to the period 2000-2007.
[99] See CEC-800-2005-003, Order Approving Roseville Energy Project, April 2005, for example.

thousands of new towers in rough and sensitive terrain, creating air quality and biological resource impacts during construction and permanent visual resource impacts once completed. The lead agencies for these project approvals balance these unavoidable impacts with the public benefit that transmission line projects provide, including for example the ability to import power into areas that are in violation of state or federal air quality standards and thus avoid local emissions into an already polluted air basin.

However, the vast majority of transmission projects discussed in this study in relation to OTC plant retirements are relatively minor, consisting of replacing existing lines or equipment, or adding equipment to existing substations. These types of projects are generally exempt from CEQA, and the approvals of minor projects that are not exempt from CEQA seldom, if ever, include the override of significant, unavoidable impacts. All but a handful of the transmission upgrades identified in this report as mitigation for the retirement of all OTC plants would fall under the category of minor projects, and the vast majority of those would be categorically exempt from CEQA review.

All the infrastructure that would be constructed as a result of the Board's OTC decision would be subject to the jurisdictions described above for review and approval. All would be subject to regulatory approval and those not categorically exempt would be subject to CEQA review at least.[100] All interested parties would be able to participate in the environmental and public safety review of each power plant and major transmission project. Because of these approval processes, and considering that few transmission and power plant projects result in permanent, unmitigated impacts to public safety and the environment, the infrastructure projects that may be built as a result Board's pending OTC decision are not likely to lead to significant, on-going cumulative impacts.[101] The impacts that are likely to occur would be similar to those that are likely to occur in absence of a change in OTC policy, and effective planning could reduce or even eliminate those impacts.

Potential Actions that Could Reduce Impacts from OTC Plant Retirements or Deratings

As discussed above, the key factor for ensuring that electric system reliability standards are maintained following enactment of the Board's pending OTC policy is timing. Maintaining the current level of reliability requires that the state's energy industry have sufficient time to plan and enact actions to compensate for any plant retirement or derating. The modeling effort for this study and others show clearly that a phased-in approach for enactment of the new policy will greatly reduce the potential threats to electric system reliability that could otherwise result.

[100] Some projects that involve federal lands are subject to review and approval by the applicable federal agency under the National Environmental Policy Act (NEPA). Joint NEPA/CEQA investigations are often conducted for projects involving both state and federal lands.
[101] One area of concern is cumulative land use impacts if, for instance, replacing retired OTC plants in the LA Basin resulted in numerous replacement projects that are incompatible with zoning designations or with surrounding land uses.

However, the energy industry also has the opportunity now to take actions that would significantly reduce or even eliminate reliance on OTC plant generation to maintain reliability standards, and therefore greatly reduce the potential reliability effects and indirect environmental impacts of the Board's pending decision. These include effective planning and implementation of transmission projects allowing increased imports of power from outside the populated areas of the state, accelerated conservation and efficiency programs, and removal of roadblocks allowing rapid development and implementation of renewable power resources.

As shown in the CEC Staff's Scenarios study, the effects on system reliability of OTC plant retirements would be significantly reduced if the state's utilities are able to significantly accelerate enactment of effective conservation, efficiency and load-management programs, which collectively are referred to as "demand-side management" or DSM. These programs have proven repeatedly that effective DSM can permanently reduce on-peak energy demand in every area of the state, and continuing and accelerating such programs is a mainstay of energy policy at every level. Similarly, the CEC's Scenarios study also shows that accelerated development of renewable generating resources, and the transmission infrastructure needed to bring renewable generation to load centers, would have a significant beneficial effect on the need to replace retired or derated OTC plant capacity in coming years.

Enacting policy that accelerates transmission system upgrades, DSM programs and renewable energy goals is beyond the control of the Board, however, meaning that such efforts as a response to the Board's pending policy would require action by other agencies, and perhaps the Legislature and Governor's office and inter-regional planning efforts, such as through the WECC. Perhaps the most relevant conclusion of this study, therefore, is that continued cooperation between the state's water agencies, energy agencies, utilities, power plant owners and non-governmental organizations is vital to maintaining electric system reliability standards while achieving water quality goals. Opportunities to continue this cooperation include the CAISO's current study of the effect of aging and OTC plant retirement, as well as its comprehensive transmission planning process, and the CEC's ongoing investigation of OTC issues.

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