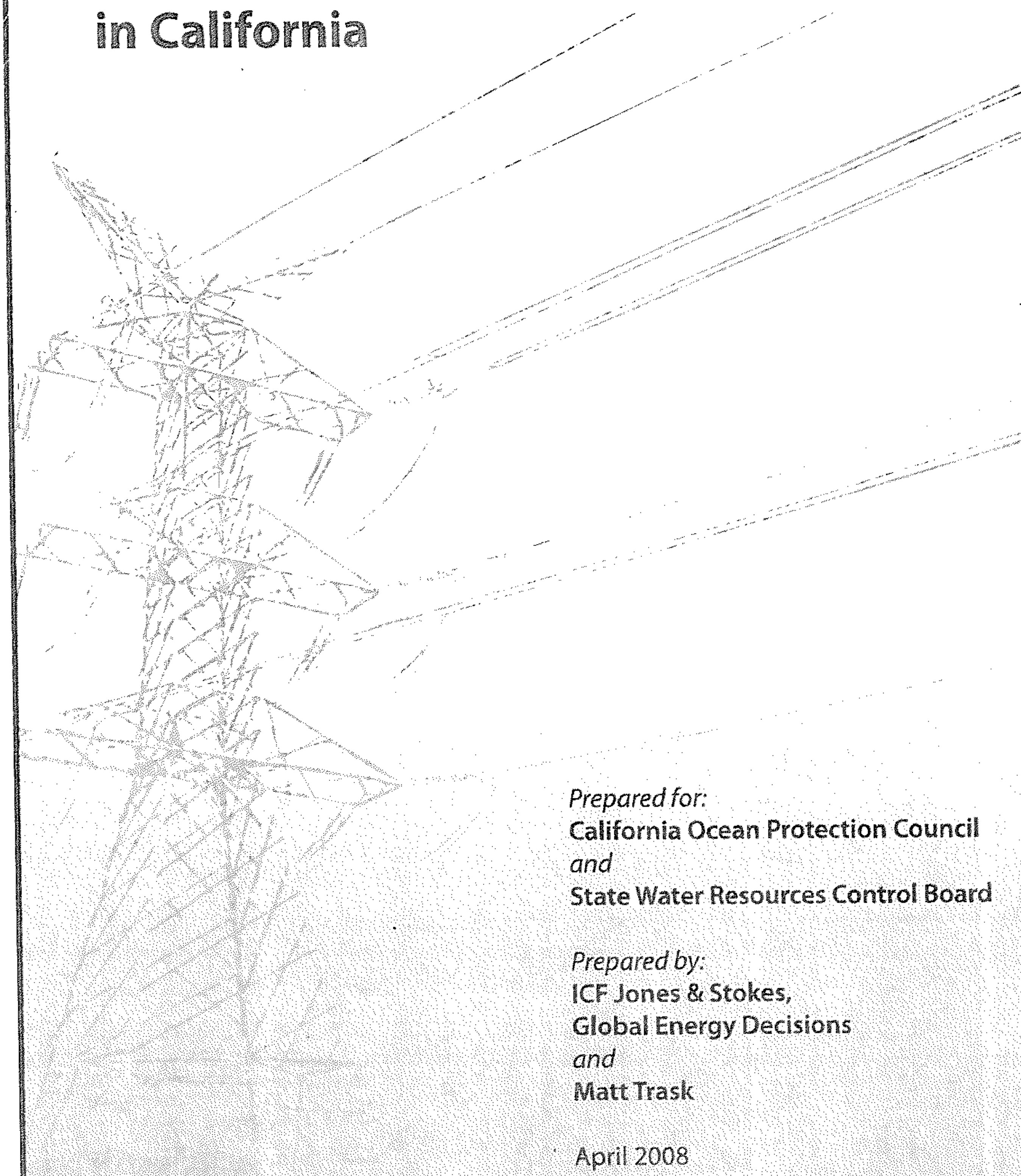
Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California



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California Ocean Protection Council
and
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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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[i]The role of the working group is discussed in Chapter 4. Participation in the Working Group does not necessarily imply endorsement by working group members of this study or its conclusions.

Jones & Stokes. 2008. Electric Grid Reliability Impacts from Once-Through Cooling in California. April. (J&S 041808) Sacramento, CA

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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 CO_2 emissions sector-wide. All other scenarios examined showed either no change or a modest reduction in net CO_2 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 NO_x, SO_x 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:

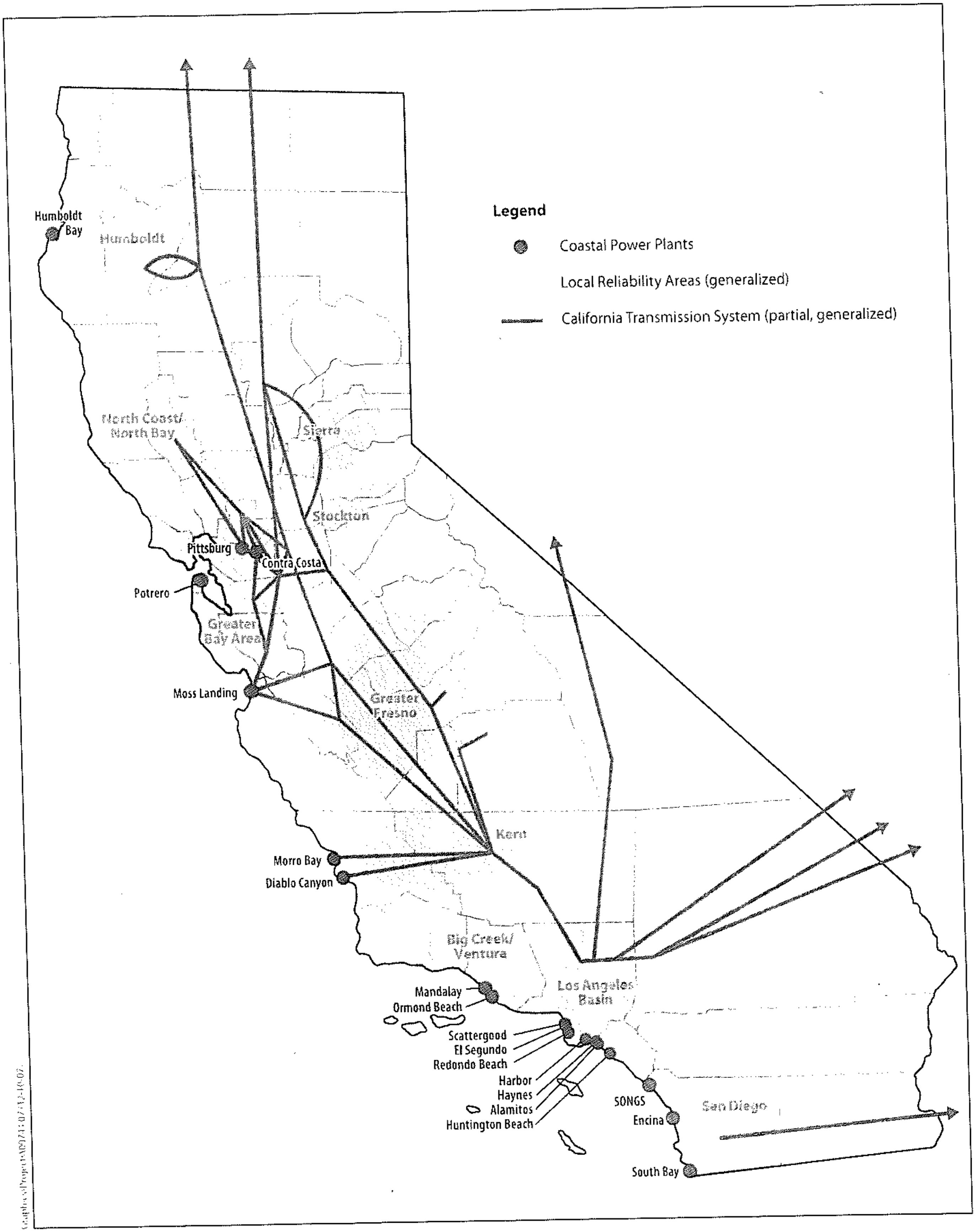
Green denotes plants switching to dry cooling

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.



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 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

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

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.