CALIFORNIA
ENERGY
COMMISSION

RESOURCE, RELIABILITY AND ENVIRONMENTAL CONCERNS OF AGING POWER PLANT OPERATIONS AND RETIREMENTS

DRAFT STAFF WHITE PAPER

PREPARED IN SUPPORT OF THE 2004 INTEGRATED ENERGY POLICY REPORT UPDATE PROCEEDING (03-IEP-01)

AUGUST 13, 2004
100-04-005D

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DISCLAIMER

This staff white paper was prepared by California Energy Commission staff. Opinions, conclusions, and findings expressed in this report are those of the authors. This report does not represent the official position of the Energy Commission until adopted at a public meeting.

Abstract

This staff white paper examines the reliability effects of the retirement of aging generating units in California, and the resource and environmental effects of continued reliance on these aging units. The white paper identifies factors that may affect an owner's decision on whether to retire a generating unit, and examined a wide range of possible retirements to determine potential effects on local, regional (also called zonal) and system-wide reliability. The staff also examined the natural gas use and environmental effects of continued reliance on the aging generating units. Potential replacements for retired plants are also examined to determine relative effects on fuel efficiency and air emissions. The staff noted that efficiency and emission rates from the electric generating sector as a whole could either increase or decrease following the retirement of aging units, depending upon the mix of technologies used to replace the retired generation.

Acknowledgments

We would like to thank the following people who participated in preparing this report. The Energy Commission staff members include:

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EXECUTIVE SUMMARY

This Draft Staff White Paper assesses the implications for electric service reliability, environmental impact and natural gas use from both the unexpected retirement of aging steam boiler generating units in the state, and the continued reliance on these units. The need for this investigation was raised by the Energy Commission in the 2003 Integrated Energy Policy Report (Energy Report), and is part of the 2004 Energy Report update proceeding.

To investigate the concerns raised in the 2003 Energy Report, the Energy Commission initialized a study of 66 aging generating units, which were selected as representative of the type of plant most likely to retire in the identified study time frame from now through 2008. The 66 units are located at 22 different power plant sites (see Figure ES-1 for the location of these units). These units are 26 to 52 years old and use outdated technology.

Staff held three workshops and numerous individual meetings with key agencies, companies and individuals, and gathered extensive information from many sources in an attempt to:

- Analyze the role that individual aging power plants play in maintaining a reliable power system, including as generating capacity resources and providers of local reliability services;
- Examine in more detail the factors affecting retirement decisions, and analyze a range of retirements that can be anticipated over the next few years; and
- Assess the implications of both potential retirements and continued reliance on older plants on system reliability and efficiency, and the environment.

Much of the confidential information requested from the CA ISO and the participating generators as part of this study was either submitted late in the study process, or has yet to be received. The staff will review this information as it becomes available, and issue a supplement to this study if the new information changes any conclusion of this white paper, or provides additional value.

Definitions

One issue uncovered during this investigation is that some key terms are used differently by different parts of the industry, which has led to some miscommunication, especially concerning local, regional and state-wide reliability. The staff proposes the following definitions for these key terms for the purposes of establishing a common frame of reference. “Local reliability” refers to areas where service could be disrupted by the failure of a relatively few number of large components (generally, a combination of two failures, such as the loss of a major transmission intertie or large generating unit). These areas include the nine “local reliability areas” (LRAs) formally designated by the CA ISO as areas requiring contracted Reliability Must-Run (RMR) units in order to provide reliable service and address local market power concerns (see Appendix D for a discussion of the RMR process). For the purposes of this study, local reliability also includes any area that, following selected aging unit retirements, could experience service interruptions after the failure of one or two major components.

“Regional or zonal reliability” refers to the ability to provide cost-effective service (i.e., avoid price “spikes”) in any one of three very large load center regions, which loosely follow the geographical definitions of Northern, Central and Southern California, but are more accurately described electrically by the large load centers in those regions. The CA ISO refers to these areas of load as “zones” rather than regions, but the two terms are interchangeable (see Appendix D for a map showing three different regions or zones, as well as the LRAs discussed above and the relative location of the aging generating units under study). There are also several “sub-regions” within the three larger regions, such as the Greater San Francisco Bay area or the Greater Los Angeles Basin, that have unique reliability issues. For instance, in the Los Angeles Basin, which includes the load centers in Los Angeles, Ventura, Orange and western Riverside Counties, aging units are used to alleviate congestion on the transmission lines feeding the region, as well as to provide a reserve margin of generation for use during emergencies.

“System-wide reliability” refers to the ability to balance generation with load state-wide (i.e., not taking transmission constraints into consideration). Because of transmission constraints, the retirement or failure of any single generating unit that is part of this study would not have a system-wide effect, but rather either a local reliability effect or a regional reliability effect, or in some cases both.

Preliminary Staff Analysis

The Role of Aging Plants: Preliminary analysis of data gathered to date from the California Independent System Operator (CA ISO) and the participating generators show that the aging units under study play key roles in ensuring reliable electric service within the state:

- They provide local reliability service in select areas through the CA ISO’s RMR process.
- They provide regional reliability by acting as a margin of generating reserve for use during supply emergencies.
- Those owned by municipal utilities or irrigation districts provide cost-effective baseload and other services, usually very near their load centers.

- They provide incremental generation to meet demand at peak times, especially on hot summer days, coming on-line at very low power levels in the morning, steadily increasing power levels during the day until the late afternoon peak, then ramping down into the evening and coming off line as air conditioning load drops.
- They are used to alleviate transmission system congestion by offsetting intertie overloading with generation at or near the load.

Regional Reliability Effects

The Energy Commission's Summer 2004 California Statewide Electricity Supply/Demand Outlook shows that, even without plant retirements and with all known expected new power plant development, generation reserve margins during the study period may become very thin, especially during an unusually hot spell. Retirements could adversely affect the reserve margin, though the forecast indicates that retirements of up to about 1,500 MW by 2008 (beyond those already planned) may not create undue reliability problems, especially under normal conditions, and actually could significantly improve the market for the remaining players. Retirements beyond that level, however, could reduce regional reserve margins to unacceptable levels, causing price spikes, load curtailment, and possibly rolling blackouts during periods of very high demand.

Subregional Reliability Effect

The staff has identified two areas of the state, the Greater Los Angeles Basin (defined as Los Angeles, Ventura, western Riverside and Orange Counties) and the Greater San Francisco Bay Area, as special sub-regions where plant retirements not only could affect regional reserve margins, but also the ability to control system congestion on the transmission system feeding the sub-region. Staff's preliminary transmission system analysis shows that retirements within the Los Angeles Basin subregion could reduce the capability of importing power into the area, as well as potentially reduce generating reserve margins to unacceptable levels.

Local Reliability Effects

Staff's analysis indicates that RMR units are not likely to retire, based on statements by the CA ISO and the generators that no unit will retire as long as it holds an RMR contract. Therefore, these units are not likely to create local reliability problems in any of the identified nine Local Reliability Areas. However, a preliminary analysis of the effects of retirements on the transmission system shows some potential for creation of local reliability problems from retirements of certain non-RMR units, though these problems could likely be avoided through transmission system upgrades.

Efficiency of Aging Units Compared to Newer Units

Nameplate data from manufacturers indicate that the aging generating units under study are 30 to 40 percent less efficient than newer combined-cycle generating plants. However, operational data collected continuously in a database maintained by the U.S. EPA show that, given their variability in operation, the aging boiler units under study are closer to 15 percent less efficient than newer combined-cycle plants on average (and closer to 10 percent less efficient if the six most inefficient units are eliminated from the aging plant sector average). As the same operational data show, newer combined-cycle plants perform relatively poorly at low power levels, compared to full-power operations, while the efficiency of the aging units under study remains nearly constant at any power level, which explains why the actual efficiencies are closer than the manufacturer's data would imply. The aging generating units under study compare favorably with newer simple-cycle combustion turbines in efficiencies, though preliminary specifications of the next generation turbine (Westinghouse's LS 600) show an efficiency edge over these aging boiler units.

SCR Installation

All of the 66 units under study are in full compliance with applicable air quality standards. All but 20 have been retrofitted with Best Available Retrofit Control Technology (selective catalytic reduction), and those that have not are either scheduled for upgrades (primarily LADWP's units), are located in areas in attainment with air quality standards, or comply with Air District requirements through another method, such as operating one or groups of units under an emissions cap that gives the owner the option to limit operations or upgrade controls (see notes in Table ES-1 at the end of Chapter 1). The generators stated that selective catalytic reduction installation costs are not a factor in decisions on whether to retire a unit.

Emission Rates

Emissions data from the U.S. EPA show that retrofitted units have emission rates per therm of gas burned (lbs/Btu) essentially identical to those of newer combined-cycle plants. However, because of relative efficiencies, the data also show that aging boiler units produce about 10-15 percent more emissions per unit of generation (lbs/MWh) than their combined-cycle counterparts, when operated in typical load-following mode. The EPA data also show that the average emission factor of the selected group of aging generating units is considerably better than that of existing simple-cycle combustion turbines, regardless of their mode of operation. Therefore, retiring these aging units offers some opportunity to improve emissions from the electric generator sector. But improper planning, and transmission systems limitations, could also cause emissions from the sector to increase following retirements of the aging units if, for instance, the lost generation is primarily replaced by existing combustion turbine units.

Will Aging Units Retire?

Public information available from the CA ISO and FERC indicates that aging generating units without RMR or other contracts have limited ability to recover their operations and maintenance costs because they cannot compete through much of the year in the markets open to them (energy and ancillary services). Data supplied by the CA ISO and the generators show that, compared to new combined-cycle plants, these aging units have higher fuel costs because of their relative efficiencies, and higher staffing costs because of their lack of automated controls and need for more frequent maintenance. Considering all available public data, and backed by confidential data supplied by the CA ISO and the generators, the staff considers it unlikely that non-contracted aging boiler units are able to earn a profit in today's market, and likely are operating at a loss. Some of the generators participating in this study stated they may retire their units because they cannot recover their costs in today's market. Other aging unit owners implied they may wait out this period of uncertainty in hopes that others will retire and, therefore, improve market conditions, or that market reforms will provide new revenue opportunities. Because of the difficulty in anticipating future decisions by corporate boards and management, it is impossible to accurately predict the likely amount of capacity that may retire in the near future. However, considering all the evidence so far in this proceeding, the staff believes the threat to reliability from retirements should not be underestimated.

The Replacements for Retired Aging Plant Capacity

The capacity lost due to aging plant retirements will likely be replaced by a variety of sources, including demand-side management (efficiency and conservation), new renewable energy project development, increased generation at existing power plants, or new power plants. The exact mix of technology that would replace a given aging unit is unknown, though additional analysis could be done in this area to identify factors that would limit options in the replacement mix. For example, replacing retired boiler unit capacity through increased demand-side management could be very difficult in some areas, while others may have considerable more potential to accelerate these goals. Similarly, the state is planning to accelerate renewable generation development, and a sufficient amount of dispatchable renewable generation may eventually become available to replace retired boiler unit capacity. However, considering the nascent state of this program, doing so within the study period (2004-08) would present a formidable challenge. Transmission system upgrades could well eliminate the need for some aging units that currently provide local reliability services, or compensate for future retirements, and some upgrades could even increase the ability to transfer power from region to region, reducing pressures on regional reliability. However, the known, upgrades planned during the study period are not expected to significantly affect the need for aging plant capacity to maintain adequate reserve margins in any region. But a concerted and effective transmission planning effort could change this assessment. In the short-term, retired aging unit generation would likely be replaced by generation from existing plants, followed later by generation from newly constructed power plants, along with demand-side management (efficiency and conservation) and renewables. Because many existing plants have higher heat rates and emission factors compared to the aging boiler units under study (e.g., existing peaker units), the replacements for retired capacity could actually raise overall fuel use and air emissions from the electric generating sector in the short-run, depending on the exact mix of technology employed.

Environmental Compliance Costs Associated with Once-Through Cooling Systems

The generators indicated that expected costs associated with compliance with new regulations governing the impacts of once-through cooling systems are not likely to drive retirement decisions in the study time period. The staff agrees with this assessment, largely because the new rules are not expected to have their full effect until after the study period. However, the staff has identified a significant information gap in this area, especially concerning the cumulative impact of plants using such systems located near each other. In addition, the limited information available indicates that these systems could have far greater effects on marine biological resources than once thought. An examination of EPA's recent rules also indicates that compliance with the rules for renewals of National Pollution Discharge Elimination System (NPDES) permits could be very expensive, depending on the final form of the rules (which are already the subject of a lawsuit) and the type of mitigation ultimately deemed appropriate for each plant. This expense could drive decisions concerning re-powering or replacing units at existing coastal plant sites. However, because these issues are not expected to be resolved within the next four years, once-through cooling issues and costs are not expected to cause retirements during the study period.

The Next Steps in Staff's Analysis

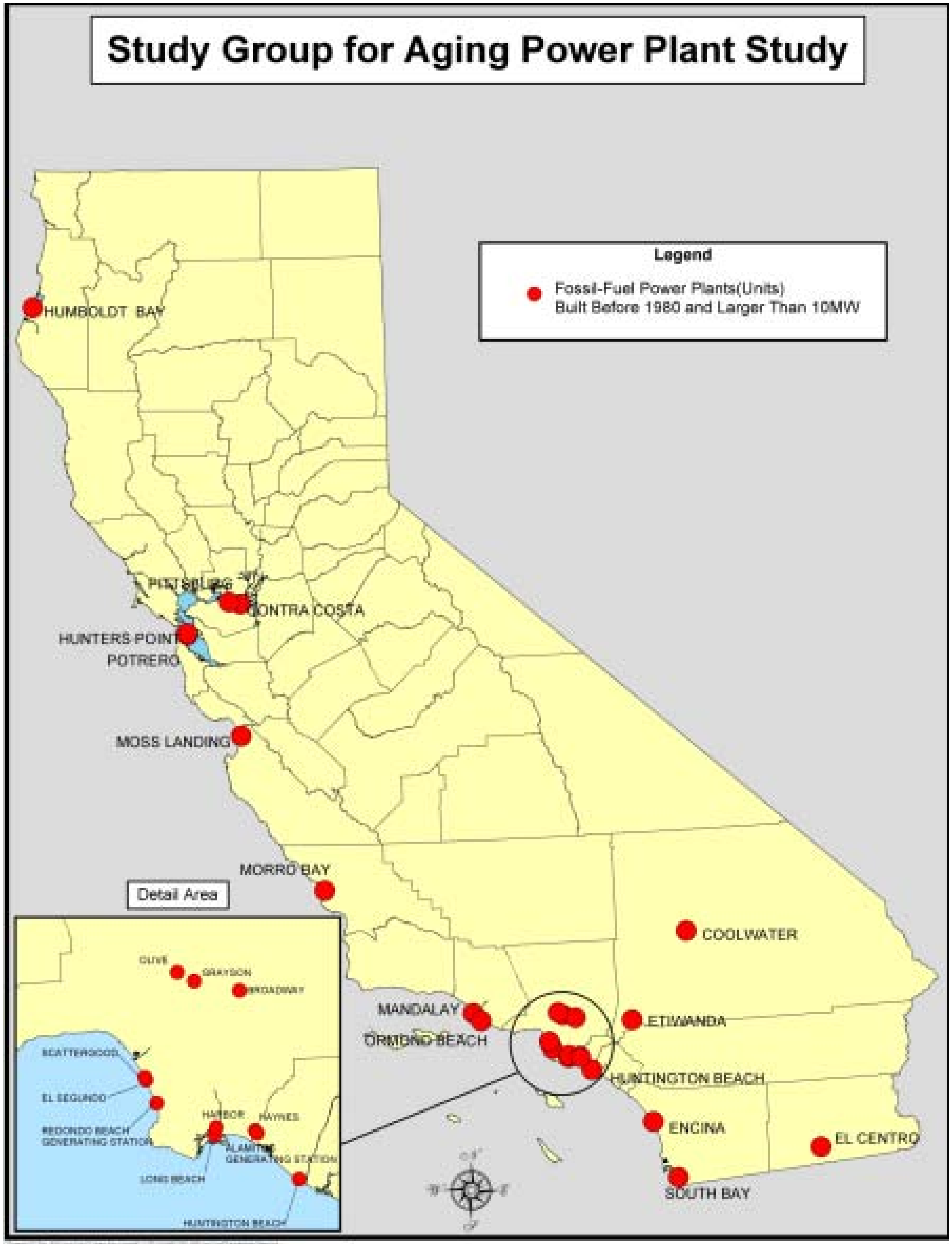
The staff considers the threat to regional and sub-regional reliability from retirements to be of most concern, and therefore recommends ongoing analysis of the effects of potential retirements in the 2005 Energy Report to inform policy makers. This analysis should examine the effects of retirements on generation reserve margins, and resultant pricing effects, as well as on the ability to control congestion on transmission interties, and to create new local reliability problems. The analysis should identify factors that might limit the options for replacing retired boiler capacity.

The staff also recommends continued high-level involvement between the Energy Commission, the CA ISO and the California Public Utilities Commission on the various proceedings underway at the CA ISO and the CPUC addressing these issues, such as the CPUC's resource adequacy and procurement proceedings, and the CA ISO's ongoing transmission system sensitivity analysis of potential retirements, conducted in conjunction with PG&E, Edison and SDG&E. Staff recommends further study of this issue, and close coordination between the Energy Commission, the CA ISO and the electric utilities in the state to ensure needed transmission upgrades are identified, such as through the retirement sensitivity analysis now underway by the utilities and the CA ISO, with results expected this fall.

The staff recommends continued examination of the potential air quality effects of retirements, including the potential air quality implications of the possible replacements for the retired capacity. The staff also recommends close coordination with the air districts and the California Air Resources Board to best plan for the possible replacements for retired capacity, as well as identify cost-effective opportunities to reduce overall emissions from the generating sector.

The staff also recommends ongoing study in the 2005 Energy Report and beyond of both the biological effects of once-through cooling systems employed by most of the 66 units under study, and the effect that the US EPA's new rules governing those impacts may have on plant retirement decisions. The staff believes additional information is needed about the effects of these systems on marine biological resources, especially about cumulative impacts from multiple plants located near each other. This information is likely to be crucial when making decisions concerning the future use of plants using seawater for cooling purposes.

Public Participation: To take comments on this white paper and to present any further findings, the Committee will hold a workshop on August 26, 2004, 9 a.m. – 5 p.m., at the CalEPA Central Valley Room, 1001 I Street, Sacramento, CA (for directions see http://www.calepa.ca.gov/EPAbldg/location.htm). The staff may also provide additional information at the workshop based on continued collection of data for this study. All parties are invited to attend the workshop, and make presentations if desired. The Committee will issue a formal notice for this workshop shortly.



Study Group for Aging Power Plant Study
Legend
Fossil-Fuel Power Plants(Units) Built Before 1980 and Larger Than 10MW
HUMBOLDT BAY
PITTSBURG
CONTRA COSTA
HUNTERS POINT
POTRERO
MOSS LANDING
MORRO BAY
Detail Area
COOLWATER
MANDALAY
ORMOND BEACH
ETIWANDA
HUNTINGTON BEACH
ENCINA
EL CENTRO
SOUTH BAY
OLIVE
GRAYSON
BROADWAY
SCATTERGOOD
EL SEGUNDO
REDONDO BEACH GENERATING STATION
HARBOR
HAYNES
ALAMITOS GENERATING STATION
LONG BEACH
HUNTINGTON BEACH

Table ES-1
Aging Power Plant Study Group

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data						Other Information						
	Plant	Unit	In-Service Year	Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MMBtu)	Heat Rate (Btu/ kWh)	Capacity Factor	RMR[2]	ISO or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redev-elop-ment Plan[6]	SCR[7]	County
1	Contra Costa	6	1964	340	876,534	8,635,012	395,697	0.0458	9,851	0.294			SF	YES	NO	NO[a]	Contra Costa
2	Contra Costa	7	1964	340	1,148,685	11,231,342	103,704	0.0092	9,778	0.386	RMR		SF	YES	NO	YES	Contra Costa
3	Humboldt Bay	1	1956	52	194,615	2,427,851	868,937	0.3579	12,475	0.427	RMR		NC	YES	NO	NO[b]	Humbold
4	Humboldt Bay	2	1958	53	190,383	2,496,030	872,666	0.3496	13,111	0.410	RMR		NC	YES	NO	NO[b]	Humbold
5	Hunters Point	4	1958	163	514,614	5,320,219	198,976[c]	0.0374[c]	10,338	0.360	RMR		SF	YES	YES	NO[c]	San Francisc
6	Morro Bay	1	1956	163	30,826	343,384	20,521	0.0598	11,140	0.022			SCC	YES	NO	NO[d]	San Luis Obispo
7	Morro Bay	2	1955	163	80,218	852,057	51,193	0.0601	10,622	0.056			SCC	YES	NO	NO[d]	San Luis Obispo
8	Morro Bay	3	1962	338	503,361	4,776,954	159,684	0.0334	9,490	0.170		ISO	SCC	YES	NO	NO[d]	San Luis Obispo
9	Morro Bay	4	1963	338	1,000,637	9,545,492	336,051	0.0352	9,539	0.338		ISO	SCC	YES	NO	NO[d]	San Luis Obispo
10	Moss Landing	6	1967	739	2,276,079	20,879,237	182,344	0.0087	9,173	0.352		ISO	NCC	YES	NO	YES	Montere
11	Moss Landing t	7	1968	739	1,730,249	16,032,235	281,251	0.0175	9,266	0.267		ISO	NCC	YES	NO	YES	Montere
12	Pittsburg	5	1960	325	547,082	5,652,989	132,775	0.0235	10,333	0.192	RMR		SF	YES	NO	YES	Contra Costa
13	Pittsburg	6	1961	325	703,877	7,523,108	88,369	0.0117	10,688	0.247	RMR		SF	YES	NO	YES	Contra Costa
14	Pittsburg	7	1972	720	2,760,981	27,536,340	1,113,654	0.0404	9,973	0.438	RMR		SF	YES	NO	NO[a]	Contra Costa

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	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data						Other Information						
	Plant	Unit	In-Service Year	Dependable Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MMBtu)	Heat Rate (Btu/kWh)	Capacity Factor	RMR[2]	ISO list or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redev-elop-ment Plan[6]	SCR[7]	County
15	Potrero	3	1965	207	570,643	5,927,227	325,825	0.0550	10,387	0.315	RMR		SF	YES	NO	NO[a]	San Francisc
16	Encina	1	1954	107	152,068	1,671,418	34,264	0.0205	10,991	0.162	RMR		SD	YES	NO	YES	San Dieg
17	Encina	2	1956	104	191,628	2,142,231	43,916	0.0205	11,179	0.210	RMR		SD	YES	NO	YES	San Dieg
18	Encina	3	1958	110	195,769	2,143,917	43,950	0.0205	10,951	0.203	RMR		SD	YES	NO	YES	San Dieg
19	Encina	4	1973	293	933,529	10,730,897	219,983	0.0205	11,495	0.364	RMR		SD	YES	NO	YES	San Dieg
20	Encina	5	1978	315	1,051,716	10,982,456	225,140	0.0205	10,442	0.381	RMR		SD	YES	NO	YES	San Dieg
21	South Bay	1	1960	147	459,135	4,654,531	60,028	0.0129	10,138	0.357	RMR		SD	YES	YES	YES	San Dieg
22	South Bay	2	1962	150	466,098	4,400,057	52,738	0.0120	9,440	0.355	RMR		SD	YES	YES	YES	San Dieg
23	South Bay	3	1964	171	319,847	3,312,646	42,271	0.0128	10,357	0.214	RMR		SD	YES	YES	YES	San Dieg
24	South Bay	4	1971	222	84,940	1,023,633	42,206	0.0412	12,051	0.044	RMR		SD	YES	YES	YES	San Dieg
25	Alamitos	1	1956	175	142,973	1,809,301	56,448	0.0312	12,655	0.093			SC	YES	NO	YES	Los Angeles
26	Alamitos	2	1957	175	167,808	2,164,441	52,874	0.0244	12,898	0.109			SC	YES	NO	YES	Los Angeles
27	Alamitos	3	1961	320	1,043,989	11,092,851	206,735	0.0186	10,625	0.372	RMR		SC	YES	NO	YES	Los Angeles
28	Alamitos	4	1962	320	710,764	7,777,048	122,890	0.0158	10,942	0.254			SC	YES	NO	YES	Los Angeles

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29	Alamitos	5	1969	480	1,433,863	14,778,258	92,473	0.0063	10,307	0.341			SC	YES	NO	YES	Los Angeles
30	Alamitos	6	1966	480	619,790	6,626,709	104,371	0.0158	10,692	0.147			SC	YES	NO	YES	Los Angeles
31	Coolwater	1	1961	65	86,692	920,494	45,130	0.0490	10,618	0.152		ISO	SDT	NO	NO	NO[e]	San Bernardin
32	Coolwater	2	1964	81	108,811	1,122,952	100,371	0.0894	10,320	0.153		ISO	SDT	NO	NO	NO[e]	San Bernardin
33	Coolwater	3	1978	241	924,133	8,879,376	934,507	0.1052	9,608	0.438			SDT	NO	NO	NO[e]	San Bernardin
34	Coolwater	4	1978	241	781,626	7,657,460	819,318	0.1070	9,797	0.370			SDT	NO	NO	NO[e]	San Bernardin
35	El Segundo	3	1964	335	1,061,387	10,399,010	58,862	0.0057	9,798	0.362			SC	YES	NO	YES	Los Angeles
36	El Segundo	4	1965	335	1,340,186	13,301,719	99,620	0.0075	9,925	0.457			SC	YES	NO	YES	Los Angeles
37	Etiwanda Generating Station	3	1963	320	543,179	5,969,559	69,468	0.0116	10,990	0.194			SC	NO	NO	YES	San Bernardin
38	Etiwanda Generating Station	4	1963	320	258,695	3,019,710	50,263	0.0166	11,673	0.092			SC	NO	NO	YES	San Bernardin
39	Huntington Beach	1	1958	215	647,852	7,405,994	81,300	0.0110	11,432	0.344	RMR		SC	YES	NO	YES	Orange
40	Huntington Beach	2	1958	215	699,436	7,633,953	87,194	0.0114	10,914	0.371	RMR		SC	YES	NO	YES	Orange

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	Plant	Unit	In-Service Year	Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MM Btu)	Heat Rate (Btu/ kWh)	Capacity Factor	RMR[2]	ISO list or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redev-elop-ment Plan[6]	SCR[7]	County
41	Long Beach	8	1976	303	81,883	939,891	94,578[f]	0.1006[f]	11,478	0.031		ISO	SC	YES	NO	NO[f]	Los Angeles
42	Long Beach	9	1977	227	31,254	362,036	36,421[f]	0.1006[f]	11,584	0.016		ISO	SC	YES	NO	NO[f]	Los Angeles
43	Mandalay	1	1959	215	499,331	4,710,452	23,304	0.0049	9,434	0.265			SCC	YES	NO	YES	Ventura
44	Mandalay	2	1959	215	564,964	5,144,509	31,252	0.0061	9,106	0.300			SCC	YES	NO	YES	Ventura
45	Ormond Beach	1	1971	750	1,189,349	12,028,916	93,498	0.0078	10,114	0.181		ISO	SCC	YES	NO	YES	Ventura
46	Ormond Beach	2	1973	750	1,210,342	12,059,181	93,552	0.0078	9,963	0.184			SCC	YES	NO	YES	Ventura
47	Redondo Beach	5	1954	175	83,476	1,127,491	79,601	0.0706	13,507	0.054		ISO	SC	YES	YES	YES	Los Angeles
48	Redondo Beach	6	1957	175	47,302	670,001	24,897	0.0372	14,164	0.031		ISO	SC	YES	YES	YES	Los Angeles
49	Redondo Beach	7	1967	480	965,701	9,843,859	130,365	0.0132	10,193	0.230		ISO	SC	YES	YES	YES	Los Angeles
50	Redondo Beach	8	1967	480	984,254	9,695,744	92,965	0.0096	9,851	0.234		ISO	SC	YES	YES	YES	Los Angeles
51	Grayson	3	1953	19	[h]	[h]	[h]	[h]	[h]	[h]		MUNI	SC	NO	NO	NO[h]	Los Angeles
52	Grayson	4	1959	44	63,853	864,829	14,693	0.0170	13,544	0.166		MUNI	SC	NO	NO	NO[h]	Los Angeles
53	Grayson	5	1969	42	70,442	950,925	21,418	0.0225	13,499	0.191		MUNI	SC	NO	NO	NO[h]	Los Angeles
54	Grayson	8	1977	95	8,385	134,416	16,066[i]	0.1195[l]	16,031	0.010		MUNI	SC	NO	NO	YES	Los Angeles
55	El Centro	3	1952	44	47,419	585,886	96,064	0.1640	12,355	0.124		MUNI	SDT	YES	NO	NO[g]	Imperial

Table ES-1
Aging Power Plant Study Group

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data						Other Information						
	Plant	Unit	In-Service Year	Dependable Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MMBtu)	Heat Rate (Btu/kWh)	Capacity Factor	RMR[2]	ISO list or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Site Redevelopment Plan[6]	SCR[7]	County
56	El Centro	4	1968	74	162,881	2,013,284	439,453	0.2183	12,360	0.252		MUNI	SDT	YES	NO	YES	Imperial
57	Haynes	1	1962	222	464,105	4,731,220	57,391	0.0121	10,194	0.239		MUNI	SC	YES	NO	YES	Los Angeles
58	Haynes	2	1963	222	592,599	6,061,029	69,419	0.0115	10,228	0.305		MUNI	SC	YES	NO	YES	Los Angeles
59	Haynes	5	1967	341	482,782	4,643,557	48,018	0.0103	9,618	0.162		MUNI	SC	YES	NO	YES	Los Angeles
60	Haynes	6	1967	341	581,001	5,727,857	36,530	0.0064	9,859	0.194		MUNI	SC	YES	NO	YES	Los Angeles
61	Scattergood	1	1958	179	449,830	4,508,090	26,317	0.0058	10,022	0.287		MUNI	SC	YES	NO	YES	Los Angeles
62	Scattergood	2	1959	179	523,083	5,234,260	24,232	0.0046	10,007	0.334		MUNI	SC	YES	NO	YES	Los Angeles
63	Scattergood	3	1974	445	259,997	2,568,005	15,980	0.0062	9,877	0.067		MUNI	SC	YES	NO	YES	Los Angeles
64	Broadway	B3	1965	66	70,886	849,285	19,605	0.0231	11,981	0.123		MUNI	SC	NO	NO	YES	Los Angeles
65	Olive	1	1959	46	19,535	244,391	22,738	0.0930	12,511	0.048		MUNI	SC	NO	NO	YES	Los Angeles
66	Olive	2	1964	55	48,249	580,744	45,567	0.0785	12,037	0.100		MUNI	SC	NO	NO	YES	Los Angeles
	Total			17,126	36,993,000	377,117,000	10,186,000										

Table ES-1 Notes

[1] 1994 Electricity Report, Electricity Supply Assumptions Report (ESPAR), Part III, The Availability, Price and Emissions of Power from the Southwest and Pacific Northwest.

[2] RMR - 2004 Reliability Must-Run unit.

[3] ISO List or MUNI - on the CAISO list of units with reliability concerns or owned by a municipal utility.

[4] Air Basin
NC = North Coast
NCC = North Central Coast
SC = South Coast
SCC = South Central Coast
SD = San Diego
SDT = Southwest Desert
SF = SF Bay Area

[5] Plants that use Once-Through Cooling (OTC) and may be potential sites for desalination facilities.

[6] The facility has a city- or county-formulated site reuse plan (SRP) which indicates local priorities for future use of the site.

[7] SCR Installed as of 2004. Emission factors in columns to the left are for 2002 and may not represent emissions levels with the use of SCR.

- [a] Bay Area APCD Rule 9-11 has a staggered implementation schedule. Mirant, the owner of Potrero, Contra Costa, and Pittsburg boiler units has opted to comply via a "system cap, where all their boilers are held to an instantaneous cap. Currently, some units are cleaner than others and can be used to "balance" out the units that have not yet installed SCR. The final cap, in force 1/1/05, limits the boiler units to a combined 0.018 lbs NOx/mm Btu.

- [b] SCR installation is not required by an air district BARCT rule or SIP.

- [c] Bay Area APCD Rule 9-11 has a staggered implementation schedule. PG&E, the owner of the Hunters Point boiler opted, to comply via a "system cap, where all the boilers units are held to an instantaneous cap. Currently, the only operating boiler unit at Hunters Points is Unit 4. The final cap, in force 1/1/05, limits the unit to 0.018 lbs NOx/mm Btu. PG&E has purchased and surrendered to the district Interchangeable Emission Reduction Credits (IERCs) to comply with the system cap. The NOx emission factor shown is for 2000. The NOx emissions are calculated using the 2000 emission factor and the 2002 fuel use.

[d] San Luis Obispo County APCD Rule 429 limits NOx emissions from all four boiler units to 2.5 tons per day, resulting in an effective emission factor of 0.0209 lbs/mmBtu. Emission controls (e.g., SCR) or operations limits or some combination of the two could be used to comply with the daily mass cap.

[e] Mojave Desert AQMD Rule 1158 requires that after December 31, 2002, NOx emissions from all units at the Coolwater facility (boilers and CTCC) be capped at 1,319 tons per year. SCR is not currently required to comply.

[f] South Coast BARCT Rule 2009 only requires steam injection on the seven combustion turbines at the Long Beach combined-cycle facility. The 2002 NOx emissions are calculated using the 2002 fuel use and the average 2003 emissions factor.

[g] NOx emissions limited by Imperial District prohibitory Rule 400.

[h] Units 3, 4, and 5 burn landfill gas, which is incompatible with SCR. No data was available for Unit 3, but the Grayson facility is subject to District Rule 1135 and is limited to a system cap of 0.2 lbs NOx/MWHR or 390 lbs NOx/day.

[i] No NOx emission data available. NOx emissions calculated with 2002 fuel use and permit limit of 30 ppm

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CHAPTER 1: INTRODUCTION AND BACKGROUND

Introduction

In the 2003 Energy Report, the Energy Commission noted that retirement of older generating units can affect reserve margins in the state. The Energy Commission estimated that 4,630 MW of aging plant capacity could retire by the end of 2008, while the California Independent System Operator (CA ISO) estimated that up to 7,232 MW could retire. Merchant generators indicated that as much as 10,000 MW could retire in the same period. The 2003 Energy Report also stated that the state could help to reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas-fired power plants and replace or repower them with new, more efficient plants. In addition, the 2003 Energy Report noted that the aging power plants are more polluting than modern power plants.

Background

This staff white paper was prepared in support of the Energy Commission's 2004 Update to the 2003 Integrated Energy Policy Report (Energy Report). The 2003 Energy Report noted several concerns that were raised by various parties about the efficiency and environmental impact of California's aging power plant fleet, but also noted that many aging generating units are needed to ensure electric service reliability. Because of these concerns, the Energy Commission decided to undertake a detailed study of aging power plants and the costs, benefits, and strategies for their replacement as part of the 2004 Energy Report Update proceeding.

This white paper was the subject of three workshops held at the Energy Commission on March 24, May 18, and June 9, 2004, and comments received during those workshops were part of the record of evidence tapped for this study, as were written comments from participants in the study, as well as the general public and other interested parties. The staff also conducted about two dozen meetings with the generators participating in the study, the CA ISO, and several other agencies to gather information for this study. The staff issued data requests to the generators and, through a subpoena process, to the CA ISO. Many of the responses arrived very late in the study process, or have yet to arrive; the staff will analyze this data as it is submitted, and perhaps issue a supplement to this study if the new information either changes staff's conclusions, or provides significant additional value to the study. Only the non-confidential portions of the generator responses were considered for this report. A workshop is scheduled for August 26, 2004, to take comment on this draft staff white paper, in preparation for the 2004 Energy Report Update.

Report Overview

This report begins by describing the role that the aging power plants under study play in the overall electrical system from a physical perspective, as well as from the standpoint of regulation and operation. It then describes the analysis conducted by staff concerning both the effects on electric reliability from plant retirements, and the potential effect on reliability from forced outages at aging plants that continue to operate. The white paper then examines the economics of aging plant operations, and the resultant pressures on decisions to retire, as well as the likely alternatives to aging unit generation assuming retirements occur.

The report concludes with an examination of the implications to air emissions and other environmental impacts from both the continued operation of the aging boiler units, and from their retirement. The environmental analysis also examines factors that could increase the cost of continuing to operate the aging units, and therefore possibly contribute to decisions to retire. The scope of this study is limited to the present through the end of 2008, as this is the period during which the bulk of possible retirements are expected to occur. After 2008, decisions made during the resource adequacy and procurement proceedings at the CPUC are expected to be fully implemented, including development of needed new resources.

Much of the finer technical detail of the staff's analysis can be found in the appendices following the main portion of this white paper. At the end of the white paper the staff has produced a glossary of terms and a list of acronyms to assist the reader.

The Study Group

Staff initially selected a group of 66 aging generating units in the state, totaling 17,126 MW in generating capacity, to use as a basis for this study, and all 66 of those units are included in the analysis of environmental, natural gas resource and other issues. Staff narrowed the study group to 50 units for the retirement-related portion of the electric reliability analysis conducted for this study, based on published resource plans and other evidence that 16 of these units, all owned by either PG&E or four municipal utilities, will not be retired during the study period or, in the case of the Hunters Point plant, are scheduled for retirement as soon as possible. All but one owner of the 50 units subject to the electric reliability analysis agreed to participate in this study, and provided extensive data on aging plant operations at the request of staff. One generator, AES, opted out of participation in the study after agreeing with staff that its aging units in California are not at risk of retirement during the study period because they are under contracts with third parties to provide services throughout and beyond the study period.

The 66 units range from 26 years to more than 50 years old, and from 19 MW to 750 MW in generating capacity. The analysis was limited to boiler units because these types of units are those most expected to retire during the time period in numbers that could affect reliability of the electric grid in the state. The 66 units represent a range of technological development of the boiler/steam generator unit, starting with the relatively archaic boiler units built just after WWII, to the highly advanced fluidized bed boilers built in the late 1970s. Yet all are essentially identical in function: natural gas is combusted inside a massive metal structure to absorb the heat of combustion. The heat is transferred to water that is pumped into the boiler by the main feed pump. The water is converted to steam and routed to the blades of a multi-stage turbine (steam exits one stage and enters the next, lower pressure stage; this repeats many times, depending on the design of the turbine). The turbine spins a generator, which in turns transmits electricity into the grid. The steam coming out of the final stage of the turbine is routed into a heat exchanger called a condenser, where it is cooled and converted back into water and pumped back into the boiler by the feed pump. The condenser is cooled by any of a number of sources, though most of the 66 units under study use seawater drawn from the ocean or nearby channels as the ultimate source of cooling.

Study of older combustion turbine generators was not included, though these units have very high fuel use and emission rates, because their owners are less likely to retire these units due to their very low fixed and non-fuel variable costs (they are unmanned, for instance, requiring no operations staff). Therefore, the staff considers it unlikely that these types of units will retire in sufficient numbers to have significant adverse effects on reliability.

The Role of Aging Power Plants

Chapter 2 of this white paper includes an examination of the fairly wide range of services that the aging boiler units under study supply to the California grid. The 12 municipal units under study supply generation directly to the municipality, avoiding the need to purchase power elsewhere and ensuring a reliable local supply. Of the 54 non-municipal units, several provide vital local reliability services through the CA ISO’s Reliability Must-Run (RMR) process (see Appendix D for a detailed description of the RMR process), while essentially all of them provide a valuable reserve margin of generating capacity for use during supply emergencies. Aging units in the greater Los Angeles Basin area also play a role in alleviating transmission congestion on the transmission lines feeding into that extremely large load center. Geographically, the Los Angeles Basin is defined as Los Angeles, Ventura, Orange, western Riverside and western San Bernardino Counties; electrically, this special subregion is more defined by the ring of very large substations near the perimeter of the Basin, through which all imported power must pass to reach the load centers inside. For example, though some of the substation and intertie infrastructure is physically located in San Bernardino County, the electric load in that area is essentially inconsequential when considering the large load centers further west and south, and therefore has no effect on transmission system congestion in the Basin.

Aging Plant Economics

Chapter 2 continues with an examination of the costs and revenues associated with aging boiler unit operation in the present market. Staff gathered information from multiple sources, including the CA ISO, the Federal Energy Regulatory Commission (FERC) and directly from the generators, to try to determine the relative profitability of the aging units, and therefore the likelihood of retiring these units. The revenue streams available to these units include the day- and hour-ahead spot (or short-term) energy markets, ancillary services markets, Reliability Must-Run (RMR) contracts with the CA ISO, and other contracts with third parties for the sale of energy, capacity or other services.

In addition to the standard operations and maintenance (O&M) costs, staff examined other factors that might push a unit towards retirement. These include the costs of installing selective catalytic reduction (SCR) to comply with air emissions standards, or the expected cost of complying with the recently released rules governing the marine biological impacts from once-through seawater cooling systems used at coastal power plants (please see Chapter 6, Environmental Issues, for a detailed discussion of these topics).

What are the Likely Effects on Local, Regional and System-Wide Reliability from Retirements?

In Chapter 3, Reliability Analysis, the staff examined the effects of a range of retirements of aging plants on local, system-wide or regional reliability. The Chapter also includes an analysis of the effects on local, regional and system-wide reliability from the continued reliance on aging units.

These three types of reliability require careful description, as the terms are used differently by different players in the industry, causing much miscommunication. The CA ISO has identified nine local reliability areas (LRAs) in the state, based on “contingency criteria” applied to that area. Contingency analysis can be described as examining effects that occur when things go wrong. The criteria for identifying LRAs is generally defined as areas that could experience outages or reduced power quality following the failure of two large components, such as the sudden outage of a transmission line due to a circuit breaker failure or the loss of a generating unit due to a turbine trip. While “local reliability” generally refers to effects or requirements in these nine areas, the staff’s preliminary transmission system analysis indicates that the retirement of plants in the Los Angeles Basin, for example, could create localized effects, such as circuit breaker overloads, that would affect only small portions of the Basin, rather than the entire region. Many planners refer to this type of problem as a “local reliability” concern, since it only affects a relatively small area, even though there are no identified LRAs in the Los Angeles Basin area.

Regional or zonal reliability generally refers to three regions that are separated by a major transmission bottleneck, PG&E's Path 15 line. Geographically, these regions are defined similar to the geographical definitions of Northern, Central and Southern California. Electrically, based on demand and transmission constraints, the three regions consist of two extremely large areas, North of Path 15 (NP15) and South of Path 15 (SP15), separated by a smaller area along the length of Path 15 in Kings, Kern and Merced Counties in Central California (see map in Appendix D showing the three regions).

Looking deeper into the regions, the staff identified the greater Los Angeles Basin as a special sub-region that is susceptible to reliability effects from the retirement of aging generating units. Because some or all of the six major interties into Los Angeles experience congestion during much of the summer, the generation within the Los Angeles area, which includes many of the aging generating units subject to this study, becomes increasingly important not only in meeting incremental demand, but also in alleviating the congestion on the interties. The analysis of reliability effects of aging unit retirements within the Los Angeles basin therefore includes the effect that such retirements would have on transmission congestion, as well as on the simple ability to balance load and generation, and on the possibility of creating local reliability problems, such as circuit breaker or transformer overloads (please see Chapter 3, Reliability Analysis, for details of the analysis of local, sub-regional, regional and system-wide reliability).

The staff's analysis of retirement effects on the transmission system was designed to be compatible with a similar but far more detailed study that is now underway and scheduled for completion this fall. The CA ISO and the investor-owned electric utilities are currently involved in this detailed study of the potential effects of retirements of the same 50 units subject to the reliability analysis of this white paper, including those in the Los Angeles Basin. Energy Commission staff are involved in this study as well, including participation in an industry group formed by the ISO to monitor the progress of the study. The utilities are now conducting sensitivity studies of the potential retirements, which will then be used as the basis for the ISO's analysis. The outcome of this study will provide information that the CA ISO and industry stakeholders could use to help determine the need for transmission system improvements or additional RMR contracts to ensure local reliability in the event of aging plant retirements.

Forced Outage Rates for Aging Boiler Units

In addition to potential reliability effects of plant retirements, continued reliance on these aging units also has potential implications for service reliability. The staff had concern that these aging boiler units may have relatively high forced outage rates (FOR) because of the age of their components. FOR information was gathered from the generators, but the staff found very little other information available about the outage rates of older units, largely because the reporting of such information is not mandatory at any level. The staff would strongly support an effort to make the reporting of forced outage rate information mandatory for all generators, municipal and private alike. However, some information on outage rates for the 66 units under study was gleaned from continuous emission monitoring system (CEMS) data and other sources, such as the national averages of forced outage rates reported by the North American Electric Reliability Council. The analysis of this information makes up the second part of Chapter 3.

The Future of Aging Plant Economics

In Chapter 4, the staff analyzes the factors that are likely to have effects on the economics of aging plant operations. The analysis includes an assessment of the likely future need for energy and capacity needs by the state's large investor-owned utilities, and discusses current limitations on utility contracts. The staff also analyzed present trends in electric and natural gas industry regulation to assess their future effects on aging plant economics. Several proceedings pending at the California Public Utilities Commission have or are expected to produce major decisions concerning: how utilities procure electric power for their customers, such as by signing contracts directly with generators; and how much generation should be held in reserve to ensure an adequate supply of generating capacity. The chapter concludes with an examination of future natural gas use by the aging plant sector.

Likely Replacements for Retired Aging Units

In Chapter 5, the staff considered the possible and likely replacements for any retired aging unit. This included examination of the ability to replace retired aging boiler unit capacity with new plants, existing plants, transmission system upgrades, demand-side management (efficiency and conservation) and renewable energy sources, all of which will play a role in the system in the future. For the purposes of this study, staff tried to identify factors that might limit the ability and effectiveness of all these possible replacements to replace retired boiler capacity in the study period.

Air Quality or Other Environmental Effects from Continued Reliance on Aging Generating Units

A large part of this study focused on the environmental effects created by the continued operation of these aging units. The staff also examined costs related to environmental compliance to assess the effects of these costs on aging plant economics. The air quality assessment focuses on the potential effects on air emissions from continued reliance on these units, many of which are the subject of controversy in nearby communities.

The staff also examined the potential impact to marine biological resources from the continued operation of the aging boiler units under study, most of which rely on once-through seawater systems to cool the plants. This is a highly controversial subject in many communities, and is the subject of recently released rules by the US EPA governing the renewal of permits associated with the use of once-through cooling systems. The analysis includes both an assessment of the potential impacts of the continued use of these systems, as well as the potential effect of the new EPA rules on retirement or re-powering decisions.

Information Sources

This report draws upon material in several other staff reports, including the following:

- ***Preliminary Electricity and Natural Gas Infrastructure Assumptions***, February 2003, Publication No. 100-03-004SD.
- ***Electricity Infrastructure Assessment***, May 2003, Publication No. 100-03-007F.
- ***2003 Environmental Performance Report,*** August 2003, Publication No. 100-03-010.

All three of the staff reports mentioned above can be found on the Energy Commission website at the following address:
http://www.energy.ca.gov/energypolicy/documents/index.html

CHAPTER 2: THE ROLE OF AGING GENERATING UNITS

As a result of the construction of nearly 10,000 MW of new power plants in California during the past three years, reliance on aging, less efficient facilities for energy has declined markedly since the 2000 – 2001 energy crisis. As shown in Figure 2-1, production from the aging plants under study has fallen to 10 percent of total state electricity consumption, and 29 percent of gas-fired generation in California, both below levels in the 1990s. This has occurred despite gas-fired generation in total, becoming an increasingly large share of the state's total consumption (33 percent).

Figure 2-1
Aging Plant Output and Generation Share, 1996 – 2003 (% and GWh)

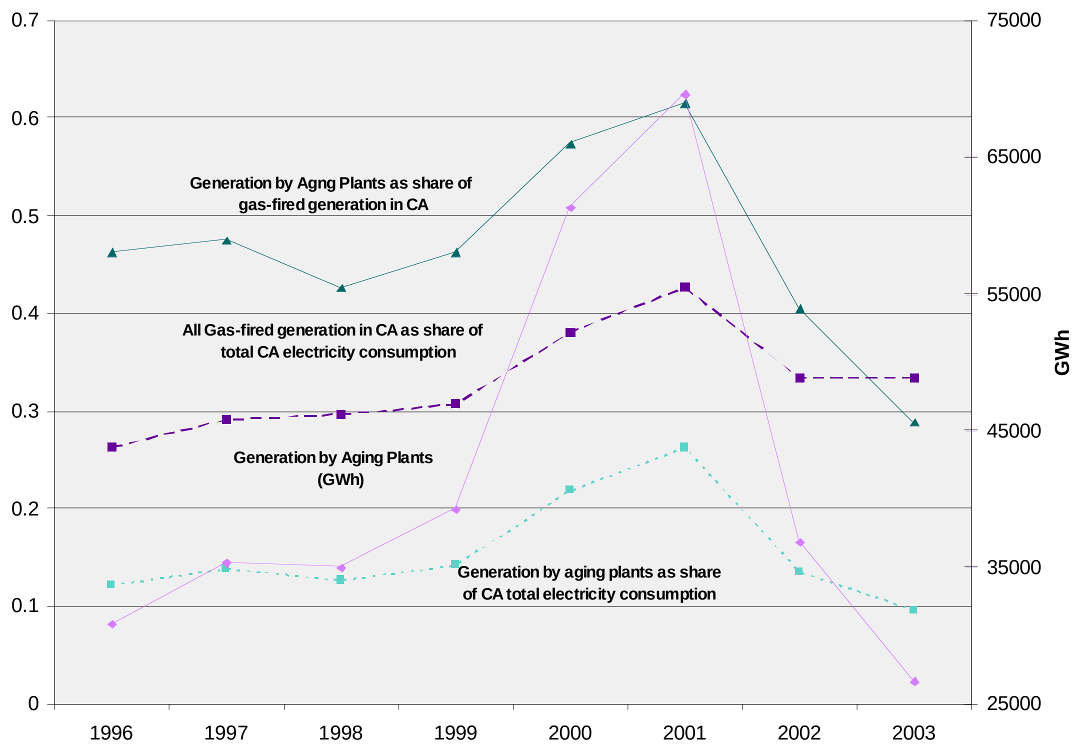
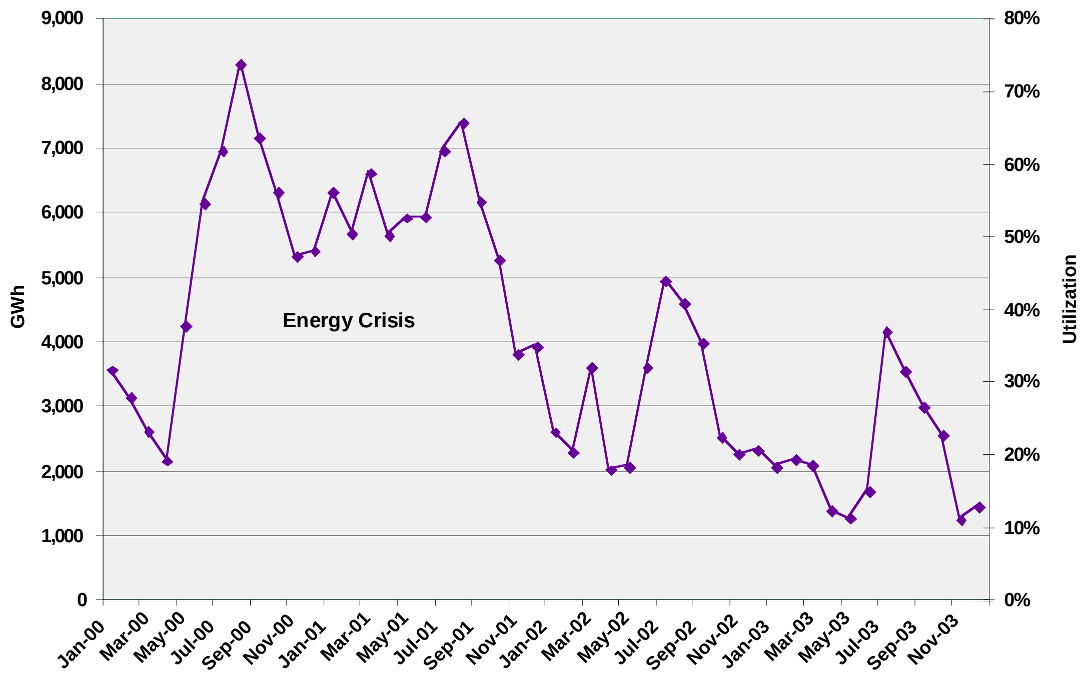


Figure 2-2 shows that the utilization rate[1] for the fleet of the aging plants under study[2] declined from 48 percent in 2001 to 26 percent in 2002, and 18 percent in 2003.

Figure 2-2
Output and Capacity Factor of Aging Plants, 2000 – 2003 (GWh)



Despite lower utilization, aging power plants continue to play a vital role in the reliable delivery of electricity to California consumers:

- All aging plants are used to meet energy needs and peak demand during the summer, and provide capacity during "shoulder" months (May, early June, October), when many plants are off-line for maintenance and unexpectedly high temperatures can cause spikes in energy demand. This service is often referred to as providing system reliability; (for a discussion of this and other reliability concepts, see Appendix D).
- Many aging plants ensure local reliability by providing such services as frequency control, voltage support and voltage-ampere reactive (VAR) support to an area where few other sources can provide that service, which are necessary for the stability of the electricity system, as well as deliver reasonably-priced energy in transmission-constrained areas, even when transmission lines and other power plants are out of commission and during periods of very high demand.
- Energy from many aging units has also been used to alleviate transmission congestion between the CA ISO's three transmission zones. This interzonal congestion, currently a problem in southern California during high demand hours, requires energy from aging plants to ensure zonal reliability. Zonal reliability also requires that intra-zonal congestion can be resolved without interrupting delivery to consumers.

Meeting Energy Needs and Peak Demand During the Summer

Figure 2-2 shows that aging plants had a utilization rate during the third quarter of 2003 of 29.4 percent, much higher than during the other quarters of the year. While hydro, nuclear, coal, cogeneration, renewable generation and new gas-fired combined-cycled plants meet the state’s baseload needs year-round, air conditioning use during the summer results in greater demand for electricity, and requires the increased operation of less efficient, aging units (for a description of how different generation resources are used to meet California’s energy needs over the course of the year, see Appendix C). The lines in Figure 2-3 represents the average aggregate generation from the units under study over the course of a week (Sunday through Saturday) in each of the four quarters in 2003. The shape of each curve reflects increased reliance on aging plants during daylight hours; the position of the curve for the third quarter illustrates increasing dependence on these units during summer months.

Figure 2-3 does not fully capture the extent to which the state relies upon aging plants, as it illustrates output from these plants during a typical week in each quarter on the year. Figure 2-4 illustrates the output from the plants under study during an average week during the third quarter of 2003, as well as the output during the week in which demand was greatest, as a result of very high temperatures.

Figure 2-3
Average Week during 2003, by Quarter

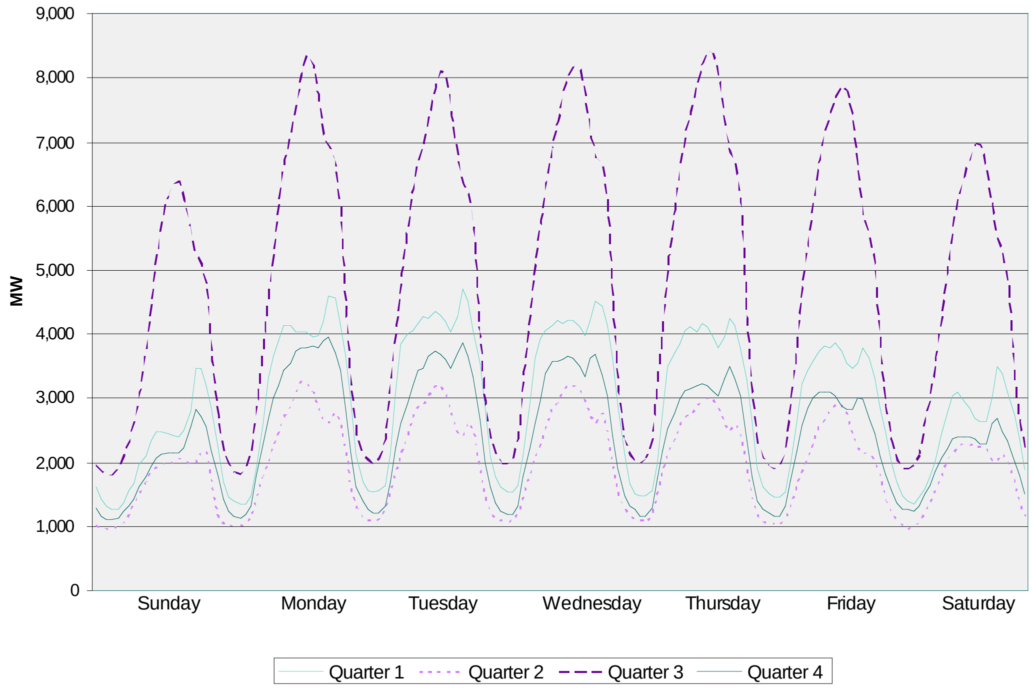
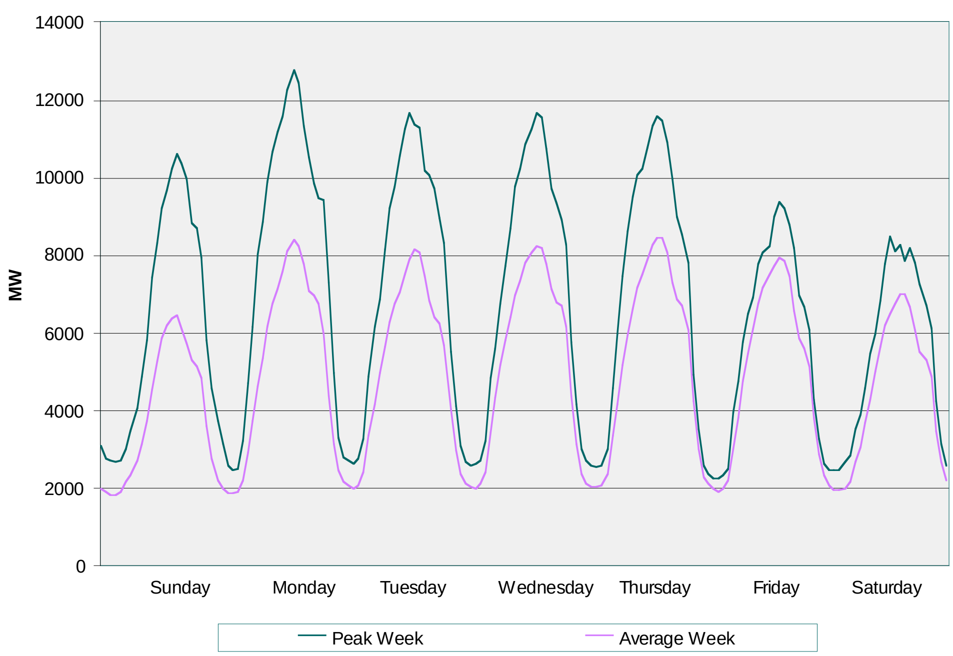


Figure 2-4 Average and Peak Weeks during Third Quarter, 2003



The importance of aging plants in the provision of system reliability at any point in time depends on California's peak reserve margin: the amount of generation capacity in excess of expected peak summer demand. Fifteen percent is a commonly accepted value for the planning reserve margin necessary to ensure an acceptable probability of involuntarily curtailing delivery (*e.g.,* no more than one day in ten years). Energy Commission staff estimates that the state's planning reserve margin for 2004 is 15 percent[3] (each 500 MW of capacity retired would yield a 1 percent reduction in the reserve margin). This reserve margin, as well as the utilization of aging plants during the peak week of the third quarter, indicates that they play a crucial role in the provision of system reliability.

System reliability also requires sufficient capacity in each of the CA ISO's three transmission zones to meet energy needs in that zone once imports are accounted for. The SP15 (southern California) zone has had the least amount of new capacity during 2001 - 2004, but a higher than expected growth in demand during 2003 – 2004, and is the location of most of the state's aging capacity. As such, the retirement of aging capacity threatens system reliability by reducing the already low reserve margins in southern California.

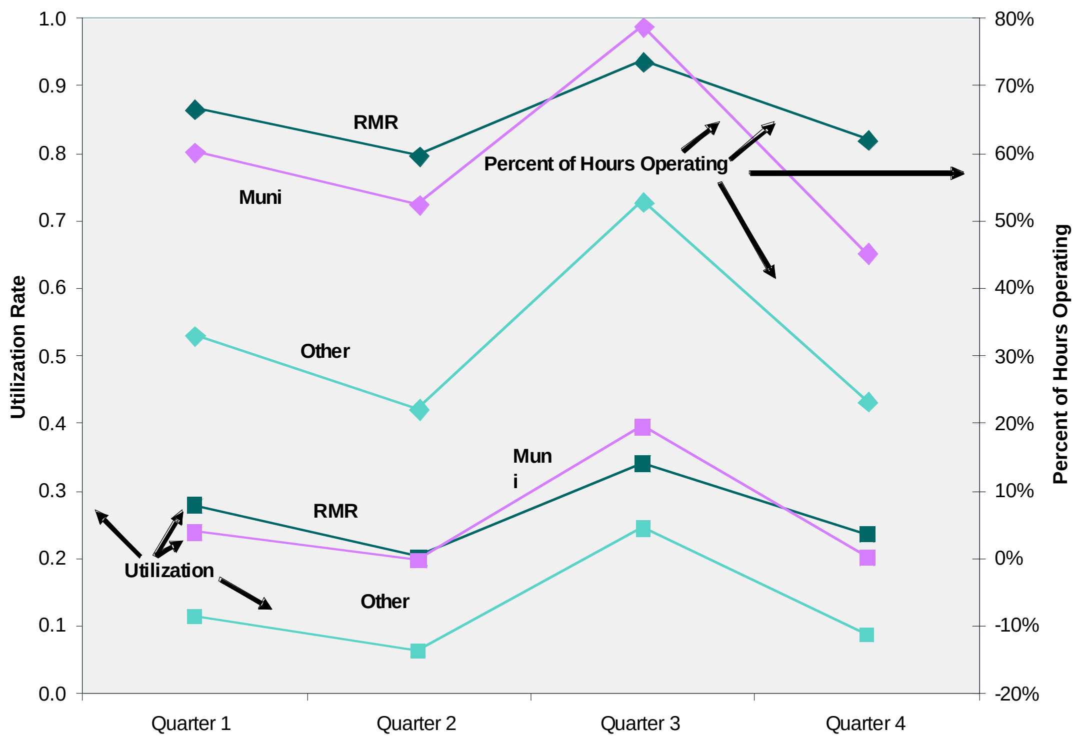
Providing Local Reliability Services

Of the 66 units under study, 20 currently hold Reliability Must-run (RMR) contracts with the CA ISO, totaling 4,554 MW of capacity. These units are located in one of nine local reliability areas (LRA) designated by the CA ISO (see Appendix D, Figure D-1) in which there is insufficient local generation to ensure that energy can be reliably delivered at reasonable prices under adverse conditions. For example, limits on the ability to import energy into San Francisco currently require the operation of Mirant's Potrero Unit 3 to ensure the uninterrupted delivery of energy to consumers in the city in the event of the failure of a major transmission line. Absent an RMR contract, the need for this unit would allow its owner to extract a high price for making the unit available and providing energy from it during a failure event.[4]

Several of the plants under study provide local reliability services without RMR contracts.[5] LADWP, in its role as a grid operator, also needs aging plants for local reliability services but, as both owner of plants and the grid operator, it does not need to offer a contract to ensure availability of a generating unit. Staff does not have access to information regarding operating procedures in the LADWP control area, but notes that consumption in load centers requires local generation to maintain frequency control and provide voltage and VAR support, all necessary for system stability. This is likely to explain the similarity in utilization rates and hours of operation for RMR and LADWP-owned units. Aging units with RMR contracts and those needed by municipal utilities for local reliability experience a less dramatic reduction in output during non-summer months than merchant units that do not serve this function, as they are needed for local reliability throughout the year. In general, merchant units not needed for local reliability operate during fewer hours of the year and at a lower utilization rate. Figure 2-5 illustrates this difference.

Figure 2-5

Hours of Operation and Utilization Rates, 2003, by Quarter



Zonal Reliability and Alleviating Inter- and Intra-zonal Congestion

Even if there is enough generation capacity on a state-wide basis to meet future demand in aggregate, and RMR contracts (and muni-owned units) ensure local reliability, the bulk transmission system may be incapable of delivering sufficient power from where it is generated to where it is consumed. This has recently become a major problem in southern California. For example, energy provided by sellers under contracts with the California Department of Water Resources (DWR) has been generated outside the SP15 zone in such quantities that utilities have scheduled correspondingly little generation inside the zone, but transmission capacity into the zone is insufficient to import all of the energy scheduled day-ahead (*i.e.*, there is interzonal congestion). Under these circumstances, the CA ISO not only calls upon the handful of RMR units in SP15 to provide the necessary energy, but also calls upon the aging units in the zone under the FERC-imposed must-offer requirement. Aging units are often needed to supply incremental generation on days when major transmission lines are congested, such as PG&E's Path 15, limiting the ability to transmit power from one part of the state to another.

Looking deeper into the regions, the staff has also identified the greater Los Angeles Basin as a special sub-region within the South of Path 15 Region where any one or even all of the half-dozen interties feeding the basin can become congested, leaving only in-load pocket generation to provide incremental energy demand once the lines become congested. This sub-region is defined by the major transmission interties that feed the greater Los Angeles area, and is unique within the state. Because all the interties into Los Angeles are often fully subscribed, and experience congestion on high-demand days, the generation within the Los Angeles area, which includes many of the aging generating units subject to this study, becomes increasingly important not only in meeting incremental demand, but also in alleviating the congestion on the interties.

The schedulers and control room operators who direct generation and transmission operation in the region are constantly balancing the system by adjusting generation within the region to prevent congestion on the interties, using the Southern California Intertie Transmission (SCIT) nomogram. Under the SCIT operating procedures, operators will use the output of any one of a dozen or so generating units within the basin to alleviate the congestion on one or more of the interties feeding the region. The unit selected to best alleviate the congestion depends on the degree to which all five interties into the basin are congested; different units are used to address different combinations of congestion on the interties.

Municipal Units, RMR Contracts and Retirements

Energy Commission staff believes that aging plants owned by municipal utilities and those with DWR and RMR contracts are significantly less likely to retire than others. The remaining 8,543 MW must either enter into long-term contracts with load-serving entities or compete in the short-term and forward energy markets

Energy Commission staff believe that the aging plants owned by municipal utilities are unlikely to be retired without replacement capacity during the next four years for several reasons.

- All of the municipally-owned plants under study, with one exception, are subject to the jurisdiction of the SCAQMD. As such, they have recently made decisions regarding investment in emission control upgrades pursuant the district’s Rule 2009, and have retired some facilities, while upgrading many others.
- The municipal utilities can recover the costs of maintaining and operating aging facilities from their retail rates. Merchant generators, in the absence of a long-term contract, cannot be certain of cost recovery.
- LADWP is currently replacing Haynes Units 3 & 4 with a new combined-cycle plant, which is scheduled to be on-line on December 2004. It has stated its intent to replace Haynes Units 1 & 2 with a new plant prior to December of 2008. It has also announced its intention to repower Scattergood Units 1 and 2 by June of 2006, and recently completed the re-powering of its Valley Units 1, 2, 3 and 4.
- The Imperial Irrigation District has stated its intent to repower El Centro Unit 3 prior to Summer 2008. In addition, in April 2004, it solicited offers for 250 – 280 MW of capacity beginning in 2007.

All parties to a DWR contract held by the Williams Company, administered by SDG&E, told the staff that the capacity dedicated to the contract is expected to remain available throughout its duration. This means that Alamitos Units 1 & 5, Huntington Beach Unit 1 and Redondo Beach Unit 1 (a total of 1,045 MW) are expected to be in service at least through the end of 2010 and Alamitos Unit 6 (480 MW) is anticipated to be on line at least though the end of 2007.

Those plants with RMR contracts must remain in service to meet local reliability needs unless demand-side programs or transmission upgrades reduce the need for these services, or new plants are built to provide them. Potential changes in the need for aging plants to provide local reliability services were discussed in the previous section**).**

Considering all these factors, the staff has concluded that a total of 8,583 MW of the aging units subject to this study are not likely to retire during the study period of now through 2008. The remaining generating capacity from the study group, totaling 8,543 MW, is at a higher risk of retirement at present because of limited opportunities to participate in markets or obtain contracts. Therefore, though the staff cannot predict with any accuracy the likely amount of retirements during the study period, it has determined that retirements of sufficient numbers to affect reliability are of a high enough probability to warrant examination of the potential reliability effects of retirements.

The Economics of Aging Plant Operation

Aging plants can provide capacity and energy products of various types (*e.g.*, peaking *vs.* baseload, year-round *vs.* seasonal) at varying levels of competitiveness. The only product they cannot provide competitively is baseload energy, as newer combined-cycle plants have considerably lower steady state, full-load heat rates. As noted in the previous chapter, those aging merchant units not providing local reliability services to the CA ISO tend to provide energy on a load-following basis, primarily during the summer. During load-following operations, aging boiler units are considerably more competitive with newer plants because their differences in aggregate heat rate when steadily increasing or decreasing power levels through the day is far closer than when operated steady state at full-load.[6]

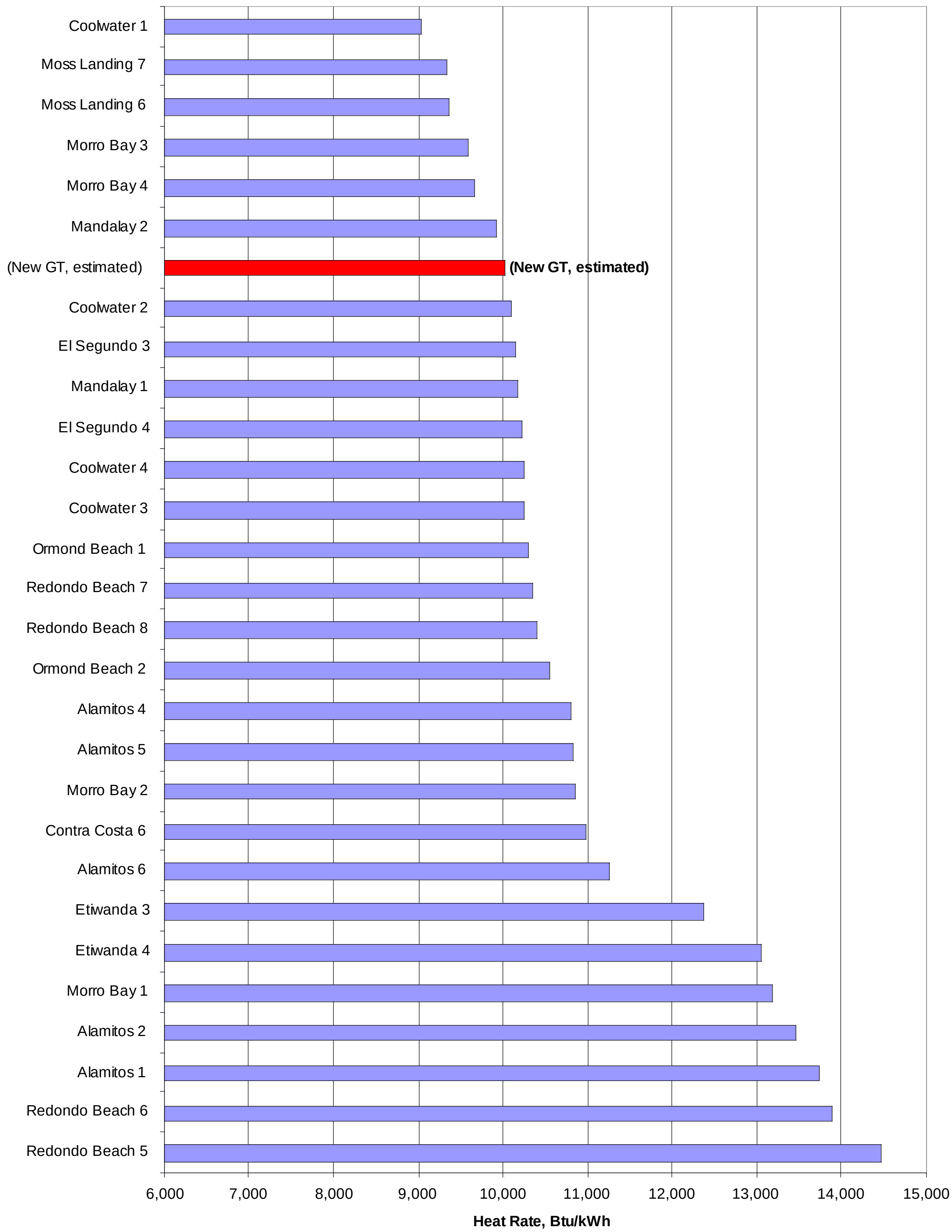
In this section, staff estimates the revenues from providing this energy in an effort to ascertain whether these units can rely on the energy market in the long-run and whether they can competitively provide a capacity product until – and perhaps after – new facilities come on line. It concludes that most aging units are unlikely to recover enough revenue from energy markets to ensure continued operation if dependent upon them, but are likely to be competitive providers of capacity products, perhaps even after a new cohort of load-following gas turbines come on line.

Variable Costs

Most of the aging plants under study are steam boilers, with heat rates at full output ranging from 8,720 to 12,150 Btu/kWh.[7] A unit's heat rate indicates the efficiency with which it converts natural gas to electricity, and allows calculation of the electricity price at which the unit recovers its fuel cost (*e.g.*, at a gas price of $6/MMBtu, a unit with a heat rate of 11,000 Btu/kWh spends $66 on fuel to produce one MWh of electricity). The lower the heat rate, the more "competitive" the unit is, all else being equal. With a capacity-weighted average heat rate at full output of 9,600 Btu/kWh, these aging units require 35 to 40 percent more fuel at full output than the combined-cycle plants that have been brought on line during the past three years.

Full load heat rates overstate the efficiency with which the aging plants under study have actually produced electricity, however. The average heat rate of the plants under study during 2003 was 10,550 Btu/kWh (Figure 2-6 presents the average heat rates of the merchant units without RMR contracts). This higher heat rate reflects both the load-following role played by aging plants (cycling up and down consumes more fuel) and the adverse conditions under which they frequently operate (during periods of high summer temperatures, heat rates are higher because air and cooling water temperatures are higher). See Appendix A for the full-, average- and minimum-load heat rates of all of the units under study.

Figure 2-6
Average Heat Rates of Non-RMR, Merchant Units (Btu/kWh)



Source: Estimated from 2003 EPA Continuous Emission Monitoring Survey data

In addition to fuel costs, units incur variable operation and maintenance costs (*i.e..*, non-fuel costs that vary with the amount of electricity generated). These are unit-specific and, as they are market-sensitive, not available to Energy Commission staff. While estimates vary, they tend to do so around $2 - $3/MWh.

The variable operating costs (fuel costs plus variable O&M costs) of many aging steam turbines compare favorably with recent prices in forward markets for on-peak energy [8] during summer months, and for a handful of units during the remainder of the year. The average market heat rates (MHR) for 2004 are presented in Table 2-3, which illustrates that almost all aging plants can recover the fuel costs of generating during peak hours during the summer**.** But because even mid-day prices have been too low to yield a profit during non-summer months, many aging units have run little, if at all, during the rest of the year, with the exception of occasional heat spells on spring days when other units are down for scheduled maintenance.

Table 2-3
Average Market Heat Rates, SP15

2004			
Month	**Gas**	**Elect**	**MHR/1,000**
Jan	5.23	56.99	10.72
Feb	5.36	54.06	9.80
Mar	5.10	52.16	9.94
Apr	4.68	50.18	10.35
May	4.62	50.93	10.43
Jun	4.69	56.64	11.45
Jul	4.80	64.90	12.78
Aug	4.85	69.83	13.56
Sep	4.84	61.83	12.05
Oct	4.84	54.75	10.43
Nov	5.01	56.26	10.34
Dec	5.18	58.82	10.47

Source: Forward market data from November 2002 – June 2004

- Market heat rate (Btu/kWh) is the ratio of the electricity price to the gas price
- Based on average of daily forward prices.
- Gas prices are for SoCal Topock Hub ($/mmBtu)
- Electricity prices are for on-peak hours, SP15 delivery ($/MWh)

A comparison of the heat rates in Figure 2-6 to the market heat rates above indicates the months in which units could recover fuel costs if generating during peak hours. It is necessary to keep in mind, however, that the units must also recover the above-mentioned variable operation and maintenance costs, as well as earn enough profit during peak hours to offset both losses during off-peak hours and the costs of starting up. These units were originally designed to operate around the clock because they require 8 to 24 hours to bring up to full output,[9] and can only be started at high cost.[10] Accordingly, the most profitable way to operate these plants, considering their load-following mode of operation, is to turn them on for extended periods, running them at full output during the day when market prices are high enough to yield a profit, and reduce them to their minimum sustainable level of operation during off-peak hours when prices are low (see Appendix A for the units' minimum operating levels). At these minimum levels, however, they consume an average of 12,900 Btu/kWh, rendering their off-peak operation unprofitable.

Finally, operating revenues over the course of the year must cover often substantial "going forward" capital costs, the subject of the next section.

Fixed Costs

Continued operation of aging units requires that they not only recover variable costs, but their annual fixed-revenue requirement (AFRR) as well. These are equal to the expenses incurred to keep the unit available, even if it is not called upon to provide energy, such as replacement of worn components. If a plant owner believes that he will not recover these costs over some time horizon, he will have an incentive to retire or mothball the unit. When dependent upon energy markets for revenue, recovery of a unit's AFRR requires that the average price received for electricity it produces be above its variable costs (fuel plus variable O & M costs). The required difference will be greater the less energy the unit produces; a unit with a utilization rate of 40 percent that requires an average price of $25/MWh above its variable costs to recover its AFRR will require $100/MWh when operated at a 10 percent utilization rate.

Staff does not have access to the AFRR of many of the units under study as such information is market-sensitive. The fixed cost requirements of units under RMR contract are displayed in Table 2-4.

Table 2-4
Annual Fixed Revenue Requirements
Selected Units, 2004

Unit	AFRR ($ million)	$/kW-yr
Alamitos 3	7.437	$23.24
Alamitos 1	4.834	$27.62
Alamitos 2	4.834	$27.62
Alamitos 4	8.84	$27.63
Alamitos 5	13.26	$27.63
Alamitos 6	13.26	$27.63
Encina 1	3.03	$28.32
Encina 2	3.429	$32.97
Huntington Beach 1	7.2	$33.49
Huntington Beach 2	7.2	$33.49
Encina 3	4.35	$39.55
Pittsburg 5	14.585	$44.88
South Bay 4	11.734	$52.86
Pittsburg 6	18.098	$55.69
Encina 5	17.711	$56.23
Encina 4	16.772	$57.24
Pittsburg 7	43.007	$59.73
Contra Costa 6	21.204	$62.73
South Bay 1	9.737	$66.24
South Bay 2	10.07	$67.13
South Bay 3	11.693	$68.38
Contra Costa 7	23.505	$69.54
Potrero 3	17.054	$82.39
Humboldt 1	5.293	$101.79
Hunters Point 4	16.598	$101.83
Humboldt 2	5.574	$105.17

Source: 2002-2004 RMR contracts between CA ISO and unit owners, filed with the FERC. All values are from 2004 contracts except Alamitos Unit 3 (2002) and Contra Costa Unit 6 (2003).

A comparison of the average forward prices during November 2002 – June 2004 for the summer of 2004 (whether defined as July - September or May - October) to the prices needed during the summer to recover their annual fixed costs over that period reveals that, while six units in Table 2-4 would have come very close to recovering their AFRR (within 5 percent), the remaining units would fall short. Those units that nearly recovered were Alamitos Units 3-6 and Huntington Beach Units 1-2. An analysis of 2003 data yielded a similar conclusion.

It should be noted that 2004 market heat rates may not be entirely representative of those that would prevail in every year. With lower reserve margins, the market heat rate would be expected to rise. This implies that a handful of aging units could competitively provide summer peaking energy if other aging plants retired. Revenue sufficiency may not be reached, however, until reserve margins are at levels that contribute to price spikes in near-term markets, and that fail to provide a desired amount of system reliability.

As mentioned above, staff lacks the verifiable information on the AFRRs of other, non-RMR units necessary to evaluate whether they could competitively provide energy during peak hours during the summer, or for a longer period. Because the heat rates of several non-RMR units are lower than those of the most efficient RMR units, it is entirely possible that they could subsist on the energy market if required to do so. If these low heat rates were offset by high AFRRs, however, they too may require a contract or capacity payment in order to remain in operation beyond the near-term.

Aging Plants as Competitive Providers of Capacity

While most of the aging RMR units could not competitively provide peaking energy during the summer, much less during other hours of the year, they may be competitive providers of peaking capacity. Table 2-4 indicates that these units could recover AFRR for capacity payments ranging from $23 - $105/kW-year.[11] With the exception of the highest fixed-cost units, this compares favorably to the estimated requirements of a new gas turbine, which has implications for the role that aging steam turbines may play in California's electricity system in the coming years.

Modern gas turbines designed to provide load-following services have a heat rate at full output (approximately 9,500 Btu/kWh) similar to or less than that of most aging units, but offer the advantage of being able to start up and shut down instantly and at lower cost, allowing them to completely shut down during off-peak hours. But, though the next generation of gas turbines will be able to generate at a lower variable cost than aging boiler units, they must recover fixed costs that are not incurred by older units. The construction of a new gas turbine anticipates a revenue stream sufficient to recover construction costs (*i.e.*, provide a return to a substantial amount of investor equity) and repay debt. While the necessary revenue is project-specific and not directly observable, estimated values are $80/kw-year[12] and up. Table 2-4 indicates that several RMR units should be able to provide capacity at a lower price than new combustion turbines. Even many aging units with heat rates well above that of a typical gas turbine (9,500 Btu/kWh) may be able to provide capacity competitively because their lower fixed costs compared to a new gas turbine or combined-cycle are likely to more than offset higher operating costs.

At least one gas turbine manufacturer, General Electric, anticipates initial production in late 2005 of a new model (LMS100) with a heat rate of 7,600 to 7,950 Btu/kWh.

This substantial reduction in operating costs, if realized without a marked increase in fixed costs, will increase the competitiveness of new gas turbines as sources of capacity, and likely marginalize some aging units that would otherwise provide the product at a competitive price.

In summary, it is likely that, if left to rely upon the energy market as a source of revenue, some share of the aging merchant capacity without RMR contracts will retire during 2005 -2008. Absent more information regarding the fixed costs of the non-RMR units under study, staff cannot provide a sufficiently informed estimate of the amount of capacity that may retire. If contracts for capacity are sought by load-serving entities in California, however, existing aging capacity can be expected to successfully compete for provision of this service. The need of the state's IOUs for this service is discussed in Chapter 4.

ENDNOTES

[1] The utilization rate, or “capacity factor” is defined as the energy from a plant as a share of total possible energy, the latter being the amount of energy produced had the plant generated at full output in every hour of the year.
[2] The numbers include values for 64 of the 66 units under study. The accuracy of available output data for Long Beach 8 & 9 is suspect and thus omitted from the analysis
[3] Staff estimate. See http://www.energy.ca.gov/reports/2004-07-08_700-04-005REV.PDF
[4] The RMR contract, which provides the owner with 50 percent of the unit’s going-forward capital costs, requires Potrero to sell its output at its cost of generation or at the competitive market clearing price for all of Northern California, whichever is highest.
[5] Only the CA ISO solicits RMR contracts, the other major control area operators in the state (LADWP, SMUD, Imperial Irrigation District) rely upon their (utility-owned) generation.
[6] US EPA CEMS Data.
[7] Based on 2003 US EPA CEMS data
[8] Delivery from 6:00 am to 10:00 pm, Monday through Sunday excluding holidays; also known as 6 x 16 (“6 by 16”) energy.
[9] Startup times vary by unit, and by the temperature of the components at the time startup is initiated. Boiler units operating daily during peak months use various methods to keep the major components warm through the night, to reduce startup time the next day.
[10] With one exception, required start-up times are taken from 2004 RMR contracts, which are filed with the Federal Energy Regulatory Commission. The 2004 RMR contracts reveal reimbursement for start-ups of roughly $8,000 per start for Encina Units 1-3, $21,000 - $29,000 for Encina Units 4 and 5, Contra Costa Unit 7, Potrero Unit 3 and Huntington Beach Units 1 and 2, $47,000 - $52,000 for Contra Costa Unit 6 and Pittsburg Units 5 and 6, and $138,000 for Pittsburg Unit 7. The value for Contra Costa Unit 6 is from its 2003 RMR contract.
[11] In practice, aging plants likely would require slightly higher capacity payments than indicated by these values, as they would need to recover expenses incurred in remaining at minimum operating levels during off-peak hours so as to be available the next day. A plant whose minimum operating level is 15 percent of its full capacity and has full- and minimum-load heat rates of 9,500 and 12,500 Btu/kWh, respectively, witnesses roughly a 10 percent increase in total operating costs due to off-peak operation.

[12] Estimate from the California Energy Commission’s Staff Report, Comparative Cost of California Central Station Electricity Generation Technologies, Publication Number 100-03-001, August 2003, Table D-10, Appendix D Cost of Generation Report.

CHAPTER 3: RELIABILITY ANALYSIS

Background

This chapter explores the potential impact to maintaining electric system reliability in light of the possible retirement of certain power plants, and the continued reliance on other aging power plants to meet system needs. Understanding the reliability implications of either the continued reliance on aging power plants or the impending retirements of certain power plants is critical information that the state must have in assessing the value of these facilities. As such, staff conducted cursory examinations to develop information that would be useful in addressing these reliability concerns using analytic methods described below. The results from these analyses are described in this chapter in addition to recommendations for future work.

Reliability Analysis of Plant Retirements

This section examines the impact that aging power plant retirements could have on local and regional reliability and provides recommendations for future study. Little information is currently available that addresses the potential impact that aging power plant retirements could have on maintaining local and regional reliability within California. In order to better understand the effects of aging power plant retirements, staff performed preliminary transmission system analyses to determine the reliability impact on the California power grid (Appendix E, Figure 1) of retiring units that staff identified as being at risk for retirements before the end of 2008. The transmission system analyses consisted of: 1) a study of the effects of retirements on local reliability; and, 2) a study of the effects of retirements on regional reliability in the greater Los Angeles Basin, where supply and demand are balanced using the Southern California Intertie Transmission (SCIT) nomogram.

Local Reliability Analysis

This analysis assessed the local reliability impacts of unit retirements on the transmission system. The local reliability analysis was performed using the GE PSLF power flow model. A base case developed by the CA ISO to characterize the present interconnected electric grid in the west served as the input to the model. New units currently under construction and expected to be in service in the timeframe of this analysis were added to the base case in the appropriate years. Potential system impacts were analyzed by simulating outages of major transmission lines and generators over 100 MW, according to the North American Electric Reliability Council/Western Electricity Coordinating Council (NERC/WECC) and CA ISO Planning Standards. These studies cover 2005, 2006, 2007 and 2008 system conditions in Southern California and 2005, 2007[13] and 2008 system conditions in Northern California.

Regional Reliability Analysis

The regional reliability or SCIT nomogram analysis was conducted to evaluate the impact of unit retirements on the operating transfer capability and import limitations of SCIT paths (please see Chapter 2 for a discussion of SCIT). Appendix E, Figure 2 is the latest SCIT nomogram for 2004 summer operating season. The regional reliability study was performed using the GE PSLF dynamic stability model. In this study, technical assessments covered 2005, 2007 and 2008 for the summer operating season only. The starting point power flow base case used for the SCIT nomogram maximum import limit analyses was the most recent seasonal SCIT Operational Transfer Capability base case from the CA ISO for 2004 summer operating season.

Candidate Power Plants

The proposed list of power plants that were considered as candidates for inclusion in the analyses is summarized in Appendix E, Exhibit 1. While staff initially identified 66 aging boiler units as study group for this paper, staff reduced the group to 50 units by eliminating 16 units that are not considered at any risk of retirement during the study period. For the purposes of this paper, staff assumed that power plants owned by the investor-owned and municipal utilities are significantly less likely to retire than the merchant plants.

Candidate plants are prioritized according to risk of retirement as high (H), medium (M) or low (L), based on staff's best professional judgment. Criteria for assigning the relative risk of retirement are based largely on whether a given unit is under contract throughout the study period. Those units that are currently not under any type of contract and participate in the energy market as their sole revenue source are considered at highest risk of retirement. Those that participate in other markets, such as the ancillary services market, or that are under contract for at least part of the study period, are considered at medium risk of retirement. Those that will remain under contract for the entire study period are considered at low risk of retirement. The transmission system analyses studied only those units that are categorized as high and medium risk of retirement as identified in Tables 3-1 and 3-2.

Table 3-1
High and Medium Risk Retirements
in the SCE and SDG&E Areas

	2005	2006	2007	2008
High Probability Units				
Coolwater 1 & 2	X	X	X	X
Long Beach 8 & 9	X	X	X	X
Etiwanda 3 & 4			X	X
South Bay 1-4				X
Medium Probability Units				
Mandalay 1 & 2		X	X	X
Ormond Beach 1 & 2		X	X	X
El Segundo 3 & 4			X	X
Coolwater 3 & 4				X
South Bay 4		X	X	
Encina 1-5				X

Table 3-2
High and Medium Risk Retirements
in the PG&E Area

	2005	2006	2007	2008
High Probability Units				
Contra Costa 6				X
Morro Bay 1 & 2	X	X	X	X
Pittsburg 7				X
Medium Probability Units				
Contra Costa 6		X	X	
Contra Costa 7				X
Morro Bay 3 & 4		X	X	X
Pittsburg 5 & 6				X
Pittsburg 7		X	X	

Results of Local Reliability Analysis

The study analyzed the impacts of plant retirements under normal (NERC Category A contingencies, N-0) and with a single element, circuit, generator or transformer out of service (NERC Category B contingencies, N-1 or G-1). The staff's analysis of the base cases predicts that, even without any retirements, some overloading is likely to occur during the study period, assuming no changes to current infrastructure. These overloads could lead to partial outages, as circuit breakers are opened either manually or automatically to prevent damage to the system. Overloads under normal conditions or with a single element out of service would require mitigation. Overloads under normal conditions are usually mitigated through the upgrade or if possible the rerate of transmission facilities, while overloads under contingency conditions can sometime be mitigated through operating procedures.

SCE Area

In the contingency analysis, the SCE area had the most overloads caused by the removal of the high and medium risk power plants. There were no overloads identified under Category A, normal, conditions although several overloads were identified under Category B, single contingency, conditions. The Category B overloads included:

- The Devers 500/230-kV transformer overloads by as much as 9 percent over its rated capacity.
- The Mira Loma 500/230-kV transformer overloads by as much as 5 percent over its rated capacity.
- The Vincent #1 500/230-kV transformer overloads by 19 percent over its rated capacity in 2006 which increases to 29-percent by 2008.
- The Vincent #3 and #4 transformers begin overloading in 2005 and reach a maximum overload of 7 percent over its rated capacity in 2008.
- The La Fresa-Redondo Beach 230-kV lines overload by 27-28 percent over it’s rated capacity in 2007 and 2008

The full list of overloads is presented in Appendix E, Table 8. Typically, utilities would mitigate transformer overloads by replacing the existing transformer with a new transformer or adding an additional transformer to the substation. Line overloads are usually mitigated by re-rating the line if that is possible or by reconductoring.

SDG&E Area

The staff’s analysis showed that retirement of the high and medium risk plants in San Diego would cause one new overload and exacerbate several other overloads that occur with the high and medium risk plants operating.

- In 2006 the study identified no overloads
- In 2007 the Miguel 500/230-kV transformer overloads are not significantly higher when units are retired than compared to the case with no retirements.

- A number of overloads were identified in the 2008 cases, and increase in number and severity as units are retired. For example:
  - Without any retirements the highest overload (21 percent over its rated capacity) occurs on the Miguel 230/138-kV transformer; this overload increases to 35 percent when both the high and medium probability units are retired.
  - The 16 percent overload noted on the Mission-Friars 138-kV line when no retirements are assumed increases to 68 percent over its rated capacity when both the high and medium probability units are retired.
  - An overload of 48 percent over its rated capacity is noted on the Friars-Doublet Tap 138-kV line when both the high and medium probability units are retired.

Appendix E, Table 8 provides the full list of overloads in the San Diego area. Because most of the overloads occur even if the high and medium risk plants operate SDG&E would probably be required to mitigate them even if the at risk plants continue to operate. However, because the retirement of the medium and high risk plants does increase the existing overloads it would be prudent to mitigate these overloads in a way that would allow the network to meet Category B (n-1) reliability requirements if these plants were to retire.

PG&E Area

In the PG&E area, the analysis found no overloads in 2005, but determined that a few existing facilities would experience overloads in 2007 and 2008, most likely due to load growth in the PG&E area. These overloads were insensitive to the shutdown of the candidate aging power plants, and therefore, were ignored. The staff's analysis revealed that:

- In 2005 overloads could occur as shown in Appendix E, Table 9. This case was run so that future years could be compared. (The 2005 base case already has all high and medium probability units off-line.)
- Appendix E, Table 10 shows the 2007 PG&E overloads. These overloads are similar to the 2005 overloads. The 2007 base case (no retirements) identified 103 overloads under contingency conditions. When high and medium risk units were retired, the observed overloads under n-1 contingency conditions decreased to 75.
- In 2008 overloads identified under normal (n-0) conditions increase slightly from the base case as units are retired, as shown in Appendix E, Table 11. The overloads identified under contingency (n-1) conditions decrease when the high and medium risk units are retired. Some of the decreases are large enough to eliminate the overloads. There are some exceptions:

- The 12 percent loading over the equipments rated capacity noted on the Moss Landing to Metcalf 230-kV lines, when no retirements are assumed, increases to 20 percent when the high risk units are retired, and increases to 19 percent when both the high and medium risk units are retired.
- The 10 percent loading over the equipments rated capacity in the contingency case (n-1) without any retirements on the Warnerville 230/115-kV transformers in 2008 increases to 18 percent when the high probability units are retired, and increases to only 11 percent when both the high and medium probability units are retired.
- In 2008, two contingencies caused voltage deviation violations to increase by more than 1 percent when both the high and medium probability units are retired (Appendix E, Table 14). These two contingencies were loss of the Olinda – Tracy 500 kV line and loss of the Geysers #12 – Fulton 230 kV line. The change in the voltage deviations seen for these two contingencies is likely due to the reduced voltage support in the Bay Area from the retirement of the generating units.

The PG&E network will undergo many improvements over the next five years and these improvements will be designed to eliminate many of the overloads identified in this study. When overloads are exacerbated by the retirement of high and medium risk plants, the mitigation of these overloads could be done in such a way that overloads will not occur even if the plants retire.

Results of Regional Reliability Analysis

The SCIT nomogram sets the limit on imports into southern California. There is some concern that the retirement of older generating units in southern California could lower the amount of power that could be imported into southern California. Overall the retirement of the high risk plants in southern California appears to have a negligible effect on SCIT in 2005 and 2007 and the 400 MW reduction observed in 2008 could probably be partially mitigated with simple equipment additions.

The results of the SCIT nomogram import limit analysis are provided in Appendix E, Table 13. The impact to the SCIT nomogram import limit in 2005 and 2007 due to the shutdown of units with a high risk of retirement is negligible. This is largely due to the fact that the only retired units are the two Coolwater units. In addition to the high risk retirements, a sensitivity analysis was performed on the 2007 case shutting down all of the units deemed to have a medium risk of retirement. The SCIT maximum import level for this scenario decreased by approximately 200 MW below the level in the scenario with only the high risk units shutdown[14]. For 2008, the SCIT nomogram import limit was reduced by 400 MW due to the retirement of the high risk units. The 2008 SCIT reduction is likely due to the lack of reactive voltage support at the South Bay 69 kV bus, and could possibly be partially mitigated by the addition of shunt capacitors or dynamic voltage support in the local area.

Transmission Analysis Conclusions

The results of these studies indicate only a couple of local reliability problems in northern California due to the shutdown of units identified as having either high or medium probability of retirement. In addition, there were some significant transformer and 230 kV line overloads in southern California caused by the shutdown of units identified as having either high or medium probability of retirement (Appendix E, Table 8). One impact of shutting down both the high and medium probability units in Southern California is the significant level of SCIT imports required (15,542 MW in 2007 and 15,939 MW in 2008) to allow the estimated loads in the area to be served. These amounts could be decreased by approximately 800 MW if generation in the LADWP area is maximized and additional generation is scheduled to SCE.

The SCIT nomogram maximum import limit could be decreased by as much as 400 MW due to the retirement of the South Bay generation in 2008. It may be possible to mitigate this impact by adding either passive or active voltage support.

Studies were not performed on the cases with all high, medium, and low probability units shutdown because it is not possible to construct a solved based case due to the lack of sufficient generation and import capability to serve the projected load. Additional resources, either transmission or new local generation, would need to be identified and modeled before this analysis could be undertaken.

Reliability Analysis of Aging Plant Operation

One of the factors to be considered in assessing older electrical generating units is their mechanical reliability. The question being, “Can we still depend on these units to provide power when it’s needed?” This section discusses how the reliability of a power plant is typically measured, the difficulties of obtaining reliability data, and the difficulties of using the data once it is obtained. In addition, this section provides a summary of the current Energy Commission’s Equivalent Forced Outage Rate (EFOR) database, and proposes an alternative method for looking at the reliability of these older units.

How Reliability is Measured

The reliability of a power plant is measured by its Forced Outage Rate (FOR) – and for the case where partial outages occur, by its Equivalent Forced Outage Rate (EFOR). In simplest terms, this measures the percent of time that a unit generates power when called upon. As of about one year ago, this definition has been changed for plants with small capacity factors to EFOR-demand (EFORd). These forced outage definitions are defined by the North American Electric Reliability Council

(NERC) via a method and sub-agency called Generating Availability Data System (GADS). For additional information see the NERC/GADS website.

Problems with Acquiring Data

Up until about 1994, the Energy Commission obtained the necessary EFOR data directly from the utilities, using a collection method called Common Forecasting Methodology (CFM). The Energy Commission recently restarted its efforts to design a new data collection method, but EFOR data is not yet available. Another source of potential data is the above mentioned NERC/GADS, which collects data from the utilities on a voluntary basis but does not release unit specific data directly, only national averages. Past comparisons of the CFM data to the national average NERC/GADS data found the correlation to be poor, and Energy Commission staff decided to make no further use of this data.

The CPUC may in the future allow the Energy Commission to gain access to the NERC/GADS unit specific data (Rulemaking 02-11-039) starting in Fall 2004. However, only a third to one-half of the major units in California provide data to NERC/GADS, which is why NERC is trying to pass legislation to make this data collection mandatory, rather than voluntary. The CPUC can make the submittal of future performance data to NERC/GADS mandatory – but it does not appear the requirement would extend to municipal utilities. At this point, it remains unclear if Qualifying Facilities (QFs) would submit outage rate data.

The Problems with Using Data

Even when data is available, it is usually outdated. Wear and tear causes the failure rate to increase, but good maintenance practices will bring the rate down. The dilemma is that historical EFORs will increase and decrease over time, and without detailed knowledge and understanding of maintenance schedules, predicting EFORs with confidence is not possible. It is commonly accepted that EFORs tend to be lower during the peak season than the rest of the year.[15] But little else can be said about NERC's EFOR data that can apply directly to the aging fleet under study.

Energy Commission EFOR Database

Energy Commission staff uses EFOR values primarily for its computer modeling programs, such as MAPs and Marketsym, but also for assessing resource adequacy. In the absence of CFM data, staff has pursued several options, as described above, but presently relies on the data provided by Henwood Associates as a part of the Marketsym lease. Since Henwood considers this database to be proprietary, this report is precluded from making specific references to individual power plants by name.

Despite the fact that Henwood has attempted to keep their database as current as possible, the EFORs for the aging power plants are in general quite old; 72 percent come from sources at least 8 years old (50 percent from 1996 CPUC ECACs and 21 percent from the Energy Commission's *ER 94*). And 28 percent are designated as generic, which is vague terminology but apparently is not unit specific.

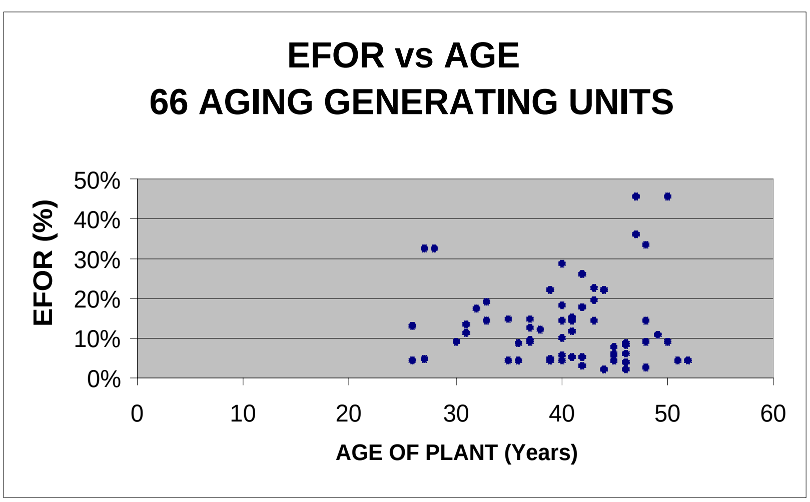
Whatever the apparent shortcomings, this data represents Henwood's best effort and therefore represent data that they deem as usable. Staff compared the EFORs to the age of the plant for the 66 plants, and summarized the data in Figure 3-1.

It is evident from examining this figure that there is no simple relationship between reliability and the age of the plant. The figure casts doubt on the intuitive notion that EFORs simply increase with age, while backing the commonly accepted axiom within the industry that good maintenance can keep EFORs at an acceptable level.

Operations Analysis

One of the benefits cited by deregulation proponents was that it would motivate power plant operators to maintain the reliability of their aging units in order to maximize their profitability – at least during the peak periods. Staff attempted to find evidence that this is happening. The staff decided to analyze actual summer capacity factors to gain some insight as to whether these plants are running more than would be expected given the existing EFOR values. Staff elected to use the only verifiable data available, a Continuous Emissions Monitoring System (CEMS) database administered by the Environmental Protection Agency, which includes all but 4 of the 66 units (Grayson Units 3 & 8 and Long Beach Units 8 & 9 are missing). Since the missing capacity of 862 MW is only 5 percent of the total 17,126 MW, the compromise seemed reasonable.

Figure 3-1



Because capacity factors also reflect times that an owner may choose to idle the plant (reserve shutdown), as well as mechanical reliability, they can only be considered indicative of EFORs, rather than definitive. In order to improve this representation, staff looked for months when reserve margins were sufficiently small to cause these units to run at high levels if they were available. Table 3-3 is a summary of the monthly capacity-weighted capacity factors for the 62 power plants.

The high capacity factors in Table 3-3 show that the aging power plants were heavily relied upon during peak months of the years when they were most needed (2000 and 2001). It also indicates – but does not prove – that they were available when needed. Based on the existing EFOR database, which has a capacity-weighted EFOR of 14.2 percent, a maximum capacity of 85.5 percent would be expected. Adding in the effect of reserve shutdown, the capacity factor should be much smaller than this due to low generation during off-peak periods, if nothing else.

To give a better indication of their performance Table 3-4 was created, showing the number of units that were available at 100 percent, greater than 90 percent, and greater than 80 percent capacity factors.

Table 3-3
Weighted Capacity Factors for
62 of the 66 Aging Power Plants

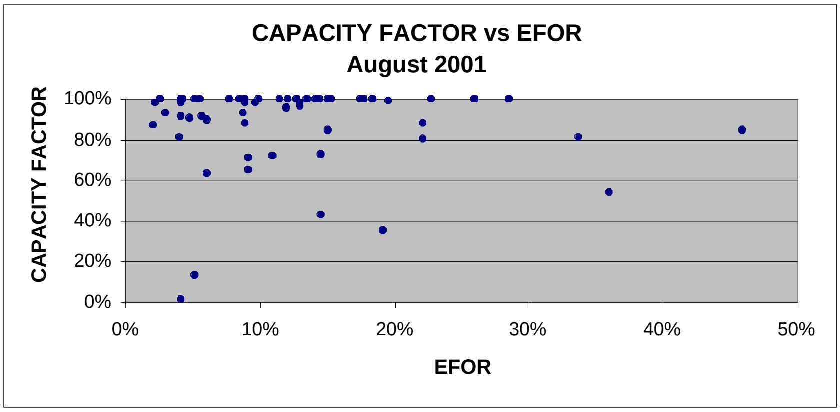
	2000	2001	2002	2003
June	82.9%	76.1%	69.2%	42.7%
July	87.5%	83.8%	84.4%	72.7%
August	91.6%	92.2%	76.7%	66.1%
September	83.5%	80.6%	71.5%	57.4%

Table 3-4
Number of Units Having High Capacity Factors
for 62 of the 66 Aging Power Plants

# of Units	CAPACITY FACTOR = 100%			CAPACITY FACTOR > 90%			CAPACITY FACTOR > 80%		
	2000	2001	2002	2000	2001	2002	2000	2001	2002
June	0	0	0	35	24	24	40	34	29
July	20	21	17	38	34	33	45	44	46
August	30	24	17	48	42	32	52	52	36
September	0	0	0	38	31	21	47	37	33

Figure 3-2 shows the individual unit capacity factors as a function of their EFORs for the 62 aging power plants, for August of 2001 – other months are quite similar. It is obvious that there is no simple relationship between capacity factor and EFORs.

Figure 3-2
Capacity Factor vs. EFOR



EFOR Analysis Conclusions

The Energy Commission staff has reviewed its reliability (EFOR) database, the facts surrounding it and other relevant data - and has found the following:

- Due to 10-year lapse in data acquisition, the Energy Commission reliability data is in general quite old, making it difficult to accurately assess the current reliability of the 66 aging power plants. This is affecting our modeling and resource adequacy calculations.
- Performance during peak periods is generally better than the overall annual EFOR would indicate.
- EFORs change over time – increasing with use and decreasing with maintenance. Without maintenance schedules and the ability to use them, it is virtually impossible to predict future EFORs using historical EFORs.
- There is no simple relationship between EFORs and age of the power plant, since good maintenance plays a dominant role.
- It appears from examining the capacity factors of the aging power plant group during periods of low reserve margin that they are capable of reliably providing power during those peak summer month periods when they are most needed.

Reliability Analysis Recommendations

Staff recommends that the CA ISO study the impact of potential plant retirements with the investor-owned utilities in their annual grid assessment process. In its preliminary transmission analyses, staff identified the potential impact that the retirement of aging power plants could have on the grid. These types of analyses should be undertaken annually by the utilities in order to identify the system upgrades that may be necessary in the event of the unplanned retirement of aging power plants.

Staff also recommends that Energy Commission collect current data on power plant availability as part of the CFM process beginning with the 2005 IEPR. Staff has concluded that the current data on the reliability of aging power plants is old and outdated and, therefore, not useful to address ongoing reliability issues for aging power plants.

ENDNOTES

[13] The PG&E retirements for 2006 and 2007 were the same, so 2006 was not studied but it should be similar to 2007

[14] In order to develop a case with this level of SCIT import with both medium and high probability units turned off, it was necessary to turn on all available resources in the SCE area as well as most of the generation in the LADWP area. In order to accommodate the increased LA generation, 1,100 MW of additional import was scheduled from LADWP to SCE.

[15] NERC/GADS Performance of Generating Plant Committee, Case Study of the Month - May 2002, “Design or Management - Which Influences Your Plant's Reliability Most?” - Robert R. Richwine.

CHAPTER 4: THE FUTURE OF AGING PLANT OPERATIONS

The 8,543 MW of merchant generation without RMR or DWR contracts must either procure energy or capacity contracts with LSEs, be awarded a reliability contract by the CA ISO (or some other form of reliability contract), or successfully compete in the energy market in order to generate enough revenue to warrant continued operation. All evidence indicates that, for many plants, the latter is unlikely unless reserve margins decline to lower levels and spot market prices increase accordingly.

In this section, staff analyzes the energy and capacity needs of the state's investor-owned utilities (which meet 73 percent of the state's demand for electricity), as well as the regulatory environment in which they and other load-serving entities procure resources. In combination, these provide insight as to the demand for those products which can be provided by aging plants and the possibility that it will be provided by other resources, both existing and yet-to-be built.

Projected Investor-Owned Utility Needs for Energy and Capacity

Load growth and the expiration of some of the DWR contracts during the past year have resulted in a need for additional capacity in the state during the third quarter of 2004. As load growth continues and DWR contracts continue to expire, this need will increase during 2005 – 2010. As of this writing, staff estimates that the three IOUs will need to contract with approximately 5,000 MW of additional capacity for summer 2005, and another 5,000 MW by the end of the decade. Over this period, capacity will also be increasingly needed during the remaining quarters of the year, and peaking energy will be increasingly needed as well (for a discussion of capacity and energy, see Appendix C). Baseload energy will most likely not be needed for most, if not all of this period, as existing DWR contracts, recent procurement decisions (those relating to power-purchase agreements from baseload units under construction – Mountainview, Palomar, and Otay Mesa), and renewables required under the state's renewable portfolio standard (RPS).

The implications of the lack of need for baseload products for utilities is a reduced incentive for permitted but yet-to-be completed combined-cycle plants to come on line before 2010. The most frequently cited reason for delays in their completion is uncertainty regarding the recovery of investment and thus the need for long-term contracts (10+ years) to provide baseload energy. If current demand-side and renewable targets are met, it is less likely that the state's IOUs will be offering to enter into long-term contracts for baseload energy for delivery prior to 2009 - 2010. While combined-cycle plants may be able to provide load-following services competitively in the period prior to being needed for baseload energy (2006-2009), a perhaps likely candidate to compete with aging plants for provision of needed capacity during this period are those merchant combined-cycle plants that have come on line during the past three years (or are expected to do so in the next two years) without long-term contracts.[16] To the extent that these new merchant plants are currently unencumbered, they can provide these products at prices competitive with those of aging plants, in large part because their fixed costs are already sunk. A yet-to-be built combined-cycle plant, on the other hand, requires expected revenues for fixed-cost recovery in the neighborhood of $80/kw-year or more,[17] but a developer may be unlikely to commit to completion in exchange for a contract of medium length (one to three years) to provide load-following services.

Regulation, Uncertainty, and Long-Term Contracts

As of this writing, the IOUs are limited to five-year contracts for non-renewable energy and capacity, with notable exceptions: SCE's 30-year contract for the purchase of the output from the 1,056-MW Mountainview facility, and SDG&E's proposed 10-year purchase agreement with Calpine's Otay Mesa plant.[18] As of this writing, multi-year contracts require that delivery begin during the current calendar year; contracts for deliveries beginning in 2005 or later are limited to a maximum term of one year.

Staff notes the following possible obstacles to the procurement of energy and capacity under five-year (and, if allowed by the CPUC, longer) contracts.

- The possibility that direct access legislation will reduce the load obligations of the IOUs creates a risk that longer-term contracts will ultimately become stranded. All the IOUs have suggested that mitigation of this risk requires either
  - a decision on direct access that reduces load obligation uncertainty,
  - clauses in contracts allowing utilities to assign them to other load-serving entities if load obligations change, or
  - guarantees of the recovery of stranded costs (*e.g.*, non-bypassable charges).
- Direct access providers (entities that provide wholesale power to retail customers who have opted out of bundled service from a utility) face even more unstable load obligations and are thus even less likely to enter into long-term contracts, even if their (predominantly industrial) customers consume electricity around the clock.
- The IOUs have noted that the capacity components of contracts more than three years in length are effectively considered debt by credit-rating agencies, and thus have a negative impact on the rating of utility debt issues unless there is a compensating increase in equity on the utility's balance sheet. A decision on this (debt equivalence) is expected in the IOUs' Cost-of-Capital proceedings at the CPUC by the end of 2004.
- The near-term energy needs of the utilities are largely limited to the peak hours of the summer. It is only during 2007 – 2008 that more than a minimal amount of energy will be needed during the remaining months of the year. Because utilities

do not need delivery of baseload energy year-round under longer-term contract for another five years or more, and given uncertainty regarding direct access, they may be reticent to solicit such products now, even if given the authority to do so.

Resource Adequacy Requirements for Load-Serving Entities

During 2005 – 2007, utilities may choose between contracting for energy and capacity needs in advance or purchasing them in near-term or real-time markets as the need arises. Effective in 2007, the CPUC has imposed a resource adequacy requirement (RAR) on the state's investor-owned utilities and direct access providers.

A RAR, whether accompanied by a formal capacity market or not, encourages the continued operation by providing fixed-cost-recovery guarantees for an increased amount of capacity for a determined length of time. While the details of this specific requirement are still being worked out, it will require each utility and direct access provider to procure 90 percent of its peak summer capacity needs, beginning with the summer of 2008, at least one year in advance. One of the details that may be revised is the onset of the requirement. Governor Schwarzenegger has asked that this be moved forward to 2006.

The CPUC has recently required that load-serving entities under its jurisdiction consider both local-reliability and deliverability requirements in both their short- and long- run resource procurement. Considerations of deliverability may encourage or increasingly require utilities to procure resources located in or proximate to their services areas, depending on the (yet-to-be-determined) specifics of the deliverability requirement

Extending a resource adequacy requirement to the municipally-owned utilities might further discourage the retirement of aging plants by providing a certain revenue stream for some fixed period of time. The extent to which this is an effective mechanism depends upon the extent to which said utilities must turn to aging plants to provide capacity. While it is generally known that certain municipal utilities have enough capacity to meet their peak needs and that others do not, staff does not currently have the data necessary to assess the extent to which these entities, in aggregate, require additional capacity to meet an RAR.

Changing Needs and Contract-Based Instruments for Local and Zonal Reliability

Finally, RMR (or similar) contracts could be used as instruments to secure zonal and system reliability, extending a guarantee of going-forward-cost recovery to a greater number of aging units. RMR contracts have historically been intended to ensure local reliability, but have increasingly been used, by the CA ISO, along with denial of must-offer waivers for zonal reliability, *i.e.*, to mitigate congestion on the bulk transmission system. Acknowledging that this was not their original intent, the CA ISO has submitted tariff changes to FERC which would formalize this role, creating the possibility that the amount of capacity under RMR contract (or a similar instrument) might increase in service of this function. It is possible that denial of must-offer waivers in order to secure zonal reliability has reduced the revenue to some aging plants by keeping prices in the CA ISO's energy market low; units called under must-offer do not bid into the energy market.

Some stakeholders, including merchant generators and the Independent Energy Producers Association, have called for "short-term reliability contracts," which would guarantee the availability of generation capacity when needed to meet zonal and local reliability needs in exchange for some degree of cost recovery.

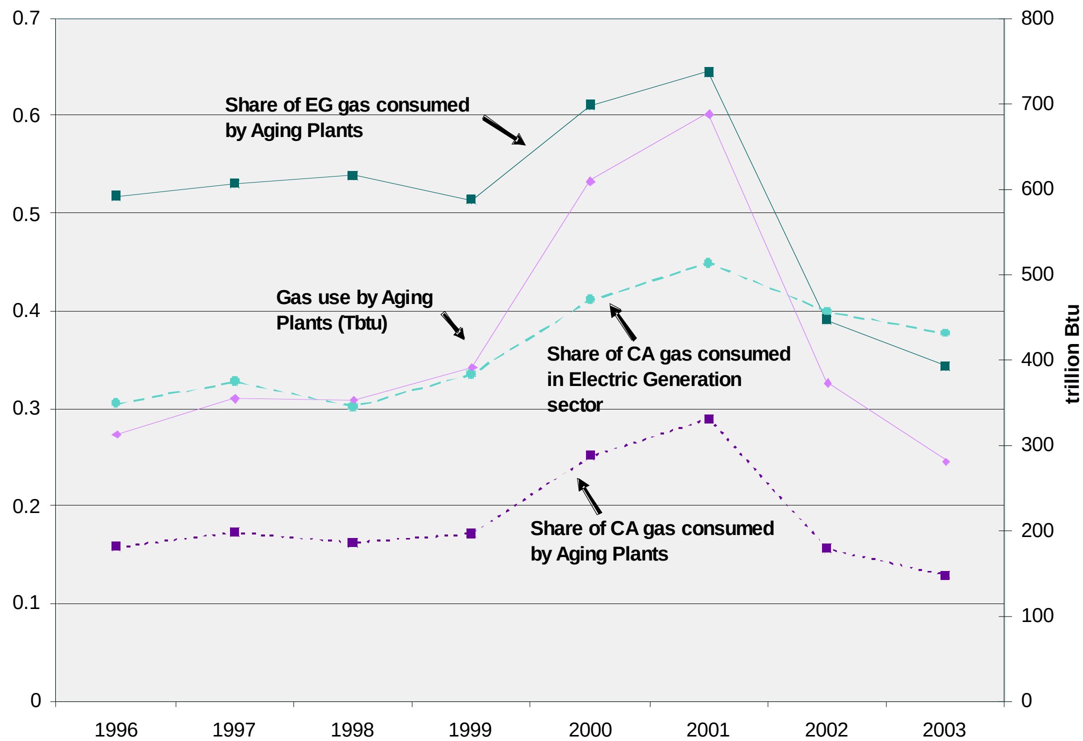
On July 2, 2004, CPUC staff forwarded a proposed resolution to the CPUC's Committee on Generation Facility Standards, which would forbid the mothballing or retirement of any generation facility without the approval of both the CA ISO and the CPUC. While this would require design and implementation of a cost recovery mechanism for those plants that would otherwise go out of service, adoption of this resolution would allow the CA ISO and CPUC to extend cost recovery guarantees to aging plants in order to meet as-of-yet undefined reliability needs.

Natural Gas Use by Aging Plants

The plants under study consumed some 281 trillion Btu of natural gas in 2003, 34 percent of the natural gas consumed in the state's electricity sector, and 13 percent of California's total consumption.

Figure 4-1 shows the decline in gas consumption by aging plants during 2001 – 2003. This reduction mirrors their decline in electricity production (the consumption of the individual units under study is presented in Appendix A).

Figure 4-1
Natural Gas Consumption by Aging Plants, 1996 - 2003



The aging power plants under study consume as much or more fuel per unit of electricity than all other gas-fired components of the system except older peaking plants devoted solely to providing super-peak energy during the summer (these have heat rates in the 12,000 – 20,000 BTu/kWh range). The aging plants had an average heat rate of 10,500 Btu/kWh during 2003, which is approximately what newer gas turbines would consume if cycled in the manner that aging plants have been. Limited evidence indicates that a combined-cycle plant consumes gas at a rate of 8,000 Btu/kWh when utilized in this manner.[19]

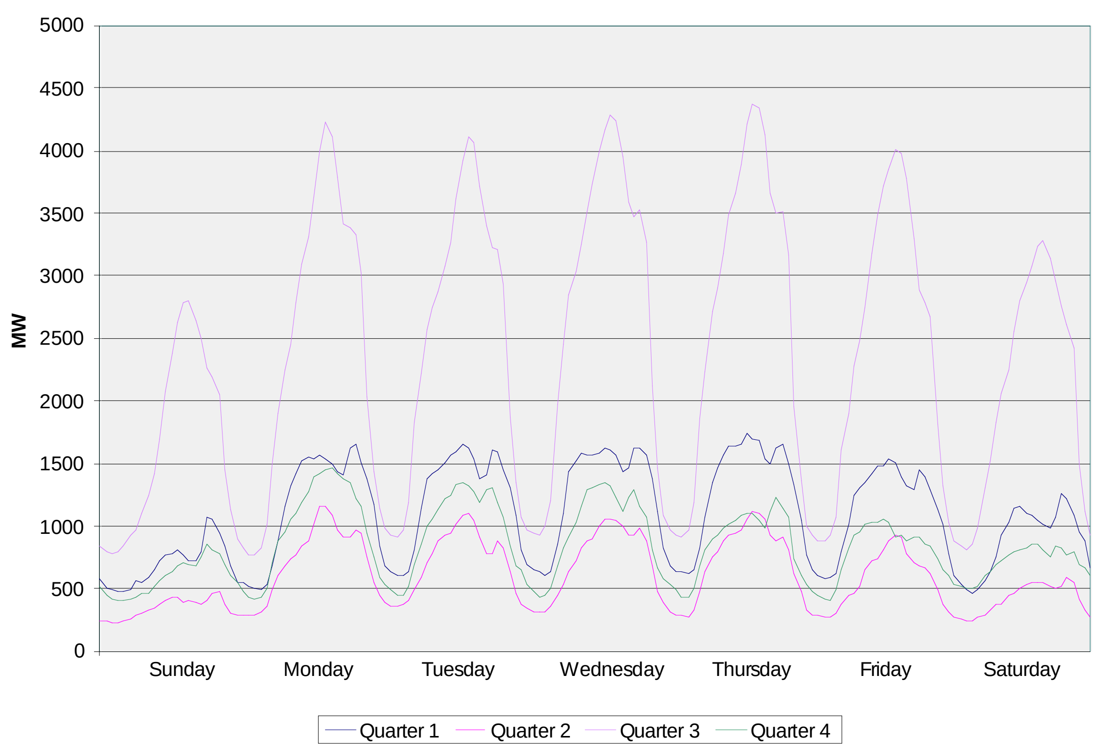
The potential change in natural gas consumption from reduced reliance on aging facilities depends upon the aging plants that retire and the resources that would supplant them. The set of units that staff believes are at greatest risk of retirement consumed 91 trillion Btu of natural gas in 2003, roughly one-third of gas consumed by the entire set of aging plants, 11 percent of the natural gas consumed by California's electrical generation sector, and 4 percent of the state's total consumption.

Should a share of these aging plants retire during 2005 – 2008, realization of the demand-reduction targets established by the state's Energy Action Plan will not only mitigate – to some extent – the adverse impacts of these retirements on system reliability, but do so without simultaneously offsetting the desired reduction in natural gas demand. In other words, the demand-side resources that are expected to meet load growth during the next four years should displace energy from aging plants and therefore reduce natural gas consumption, compared to the case with no demand-side resources implemented.

To the extent that the retirement of aging plants in 2005 – 2008 requires the energy from these plants be produced by other resources, the logical candidates to do so during this period are newer combined-cycle plants that are not encumbered by DWR or other contracts (these include the facilities anticipated being completed during this period, *e.g.*, Metcalf) and any new renewable facilities that come on line (for the baseload portion), and the remaining aging plants and peaking plants (for the load-following portion). As mentioned above, the needs of the state's IOU's indicate that long-term contracts for baseload energy are not likely to be offered in any quantity during 2004 – 2008, discouraging the completion of permitted-but-delayed baseload facilities whose owners (or financiers) require a revenue guarantee.

The total reduction in gas consumption from retirements during 2005 – 2008 is apt to be small. Figure 4-2 illustrates the typical generation of the non-RMR merchant plants in aggregate by quarter in 2003.

Figure 4-2
Typical Weekly Generation, by Quarter
Aging Non-RMR Merchant Units (Aggregate, MW)



The baseload component of generation from these resources is 500 – 1000 MW, depending on the quarter selected. The gas consumption for this share of the output[20] of these plants in 2003 was 15.5 trillion Btu, or 16 percent of total gas use by these plants, and slightly less than 2 percent of total gas consumption by the state's electricity generation sector. It is for this component of the generation of these plants that gas-efficient resources (existing combined-cycle plants, both in-state and more remote, at full output, renewables) can be expected to be used.

For the remaining (load-following) portion, combined-cycle plants, existing gas turbines, and the remaining aging plants are the most likely providers of replacement energy, leading to reductions in natural gas use that are capped at 20 percent or so (this would require that all of the output of the retiring aging plants in their load-following capacity be supplanted by combined-cycle plants). Total gas consumption by these plants when load-following was 76 trillion Btu; a 20 percent savings would be another 15 trillion Btu, or, again, slightly less than 2 percent of gas use by the electricity generation sector in California.

ENDNOTES

[16] A list of permitted but incomplete plants can be found at the Commission's website: http://www.energy.ca.gov/sitingcases/all_projects.html#approved
[17] Cost of Generation report
[18] SDG&E has also entered into a "turnkey" agreement for the Palomar facility, under which it will be constructed by Sempra Energy, then turned over to the utility for operation
[19] CEMS data for 2003 from the La Paloma facility
[20] Estimate based on gas consumption when the aggregate hourly output of the units likely to retire in 2003 was less than or equal to 500 MW (1000 MW for the third quarter).

CHAPTER 5: ALTERNATIVES TO AGING BOILER UNITS

California's reliance on the plants under study may change during the next four years. Successful implementation of the state's preferred policy of meeting growth with energy efficiency programs, tariff-based peak demand reduction, and other demand-side measures will reduce the need for new power plants, while utilities and merchant developers with long-term contracts are expected to add more than 5,000 MW of capacity.

A reduction in the dependence on aging plants can be accomplished in three general ways:

- Reducing the demand for energy and capacity,
- Upgrading the transmission system to improve access to newer, out-of-state generation facilities and/or to reduce the need for local and zonal reliability services provided by aging plants, and
- Building new generation capacity in California

Demand Management

State policy has established a preference for meeting future energy needs with demand-side management. Accordingly, the CPUC has mandated that the state's investor-owned utilities meet a share of peak load needs with energy efficiency and demand response programs.

Table 5-1 indicates that these programs are targeted to meet 70 percent of California's peak load growth through 2008. To the extent these targets are not reached, the state will continue to rely upon aging plants unless additional new generation capacity or imports from neighboring states are available to meet California's growing energy needs, especially during the summer peak.

Table 5-1
Statewide Peak Load Projections and Demand-Side Targets 2004 - 2008

	2004	2005	2006	2007	2008
Statewide coincident peak demand	**53,896**	**54,500**	**55,487**	**56,195**	**57,090**
Incremental energy efficiency programs	108	262	483	792	1,208
Adjusted peak demand	**53,788**	**54,238**	**55,004**	**55,403**	**55,882**
Demand Response Programs					
IOU/CPA demand bidding programs	333	403	430	460	496
Direct load cycling programs	300	330	363	399	439
Critical peak pricing programs	133	389	734	1,080	1,425
Voluntary load reduction Programs	130	117	105	95	85
Total: Demand response programs	**896**	**1,239**	**1,632**	**2,034**	**2,445**
Net peak demand	**52,892**	**52,999**	**53,372**	**53,369**	**53,437**
Net peak demand +15% reserves	**60,826**	**60,949**	**61,378**	**61,374**	**61,452**

Includes IOU programs and targets; does not consider possible reductions due to programs implemented by municipal utilities, irrigation districts and other load serving entities, which collectively serve one-fourth of the state's electricity consumers.

Does not include reductions due to interruptible rate and emergency response programs, which are projected to fall by 200 MW over 2004 – 2008

Source: Staff estimates of peak demand, program targets

Staff notes that, while demand-side programs may promote system reliability, it may be more difficult for these programs to have a substantial effect on local and zonal reliability needs in the near-term. Most of the aging plants under study with RMR contracts are located in the Greater San Francisco and San Diego LRAs (the Alamitos, Huntington Beach and Humboldt facilities are the exceptions). Effectiveness in this regard would require programs that target peak loads for specific, rapidly-growing geographic areas, and that could deliver reductions in load in these areas with the speed and certainty required by the CA ISO.

Upgrades to the Transmission System

Investment in transmission upgrades can reduce reliance on California's aging power plants in two ways. First, upgrades that increase the ability to import energy from neighboring states and Mexico increase system reliability by reducing the need for less efficient, aging capacity in California. Second, upgrades can increase the amount of energy that can be delivered to the major load centers in California, reducing the use of aging plants to provide zonal reliability as well the need to sign RMR contracts with aging facilities in areas with local reliability concerns.

A discussion of the status and impact of upgrades to the bulk transmission system that are expected to increase the ability to import power from outside California can be found in the *Draft Staff Transmission White Paper, prepared for the 2004 IEPR Update*.

The CA ISO's 2005 Local Area Reliability (LAR) studies indicate that the need for RMR capacity in 2005 will be roughly the same as for 2004 (9,063 MW). A discussion of the status and impact of transmission upgrades which will have an impact upon RMR capacity needs can be found in *Draft Staff Transmission White Paper, prepared for the 2004 IEPR Update*. The potential impact of new generation facilities on the need for local reliability services from aging plants is discussed in the next section.

Planned New Generation

To the extent that demand-side programs and increased imports from neighboring states do not offset peak load growth, new power plants will be needed to meet demand growth during 2004 - 2008. Even if transmission upgrades reduce the need for local reliability services provided by aging plants, declining reserve margins indicate that the present generating fleet may have to be augmented or replaced in order to maintain desired levels of system reliability.

Table 5-2 reflects Energy Commission staff's estimate that roughly 5,800 MW of new capacity is likely to come on line between now and 2008. Retirements totaling 1,135 MW have already been announced (see Appendix B for the complete list of new plants and known retirements). Nearly half of the additions will be owned by municipal utilities and irrigation districts, who, as load-serving entities, can recover the costs of construction and operation through retail rates. The remainder will be built by merchant generators, all but two of whom (Metcalf and Pastoria) have long-term contracts with California utilities.

Table 5-2
Planned Capacity Additions and Retirements (MW), California, 2005 – 2008

	2005	2006	2007	2008
Total Additions	1754	3190	345	563
SP-15 Additions	915	2142	185	563
Retirements		1135		
Net Additions	1754	2055	345	563
Cumulative Net Additions	1754	3809	4154	4717

- 916 MW of the retirements are inside SP-15
- Does not include new merchant renewable generation that may come on line during the period other than those facilities that have already entered into long-term contracts. Staff estimates that this may be from 500 – 1,000 MW by 2008.

Source: Staff estimate

New power plants located in LRAs can provide local reliability services in lieu of aging facilities currently under RMR contract, as well as reduce the need for actions needed to ensure zonal reliability. For example, new facilities already on line in the Greater San Francisco Bay Area LRA may eliminate the need for an RMR contract with Pittsburg Unit 7 as early as 2005. Staff expects that the following major facilities will come on line in LRAs during 2005 – 2008 or are likely to do so; it is not certain, however, that they will be able to supplant existing facilities in providing local reliability services on a MW-for-MW basis:

- Metcalf (600 MW; Calpine; Greater San Francisco LRA) is expected on line by July 2005. This may eliminate the need to contract with a unit at the Contra Costa or Pittsburg facilities in 2006)
- Palomar (546 MW; Sempra, San Diego LRA) is expected on line by July 2006. This may eliminate the need to contract with one or more units at the South Bay plants in 2007.
- Otay Mesa (590 MW; Calpine, San Diego LRA) faces numerous obstacles[21,] but may come on-line as early as summer 2007. If accompanied by a set of transmission upgrades requested by the utility, Otay Mesa may eliminate the need for RMR contracts with one or more units at Encina or South Bay in 2008.

In summary, demand-side programs, transmission upgrades and new power plants may reduce the need for aging units during 2005 – 2008. If proposed energy efficiency and demand response targets are met and 5,800 MW of new plants are completed during this period, this reduction will be substantial. If realized, however, these factors will encourage the retirement of aging units. Under a market system it may be difficult to sustain a surplus of units needed solely for system reliability without regulatory requirements. A reduction in the need for aging capacity to maintain system reliability will encourage the retirement of units whose costs are not covered by contracts to provide local and zonal reliability. As their revenue from the market falls, the most costly aging facilities will retire, until market prices are high enough to encourage the remaining units to stay on line. This may not occur, however, until system reliability (*i.e.*, the reserve margin) is at a low level, and the system is experiencing price spikes in wholesale spot markets and is threatened with involuntary delivery interruptions

Upgrades to the Transmission System

Investment in transmission upgrades can reduce reliance on California's aging power plants in two ways. First, upgrades which increase the ability to import energy from neighboring states and Mexico reduce the need for less efficient, aging capacity in California. Second, upgrades can increase the amount of energy that can be delivered to the major load centers in California, reducing the need to sign RMR contracts with aging facilities in these areas for local reliability services.

Two major upgrades are scheduled to operating by 2008 and will increase the transmission networks import capability into southern California by as much as 1,160 MW. The Miguel-Mission 230 kV line #2 will increase the import capability into San Diego by 560 MW and is expected to be operating by June of 2006. The short-term Southwest Transmission Expansion Plan upgrades will increase the import capability into the Los Angeles Basin by approximately 500 MW. There are no other major projects planned to increase the transmission capacity into California before 2009.

The 2003 Grid Expansion Plans for PG&E, SCE and SDG&E indicated that many projects would lower RMR needs in California between 2006 and 2008. PG&E identified four projects, SCE identified no projects that reduced RMR requirements and SDG&E identified one line in its expansion plan and another set of lines in a filing at the CPUC.

PG&E in its 2003 Electric Grid Expansion Plan identified four transmission projects that would reduce or eliminate the need for specific areas or RMR pockets including:

- Two projects, the Lakeville-Sonoma 115 kV line and the Fulton 230 kV line that could reduce the 326 MW RMR requirement in the Fulton area starting in 2007.
- The Metcalf-Moss Landing 230 kV reconductoring project could reduce 4,087 MW RMR requirement for the Greater San Francisco Bay Area by a yet to be determined amount.
- The addition of a 230/70 kV transformer in 2006 at the Henrietta substation will eliminate the need for the 49 MW RMR requirement in the Henrietta RMR pocket in central California

A new 230/60 kV transformer installed at the Colgate substation near Nevada City will eliminate the 58 MW RMR requirement for the Colgate RMR pocket in 2006.

SDG&E identified the Miguel-Mission 230 kV line #2 as a project that could reduce RMR costs and in the filing for a Certificate of Public Convenience and Necessity at the CPUC justified the costs of the Otay Mesa Power Purchase Agreement Transmission Project based the reduction of RMR costs. The impact of these transmission projects on SDG&E RMR needs is still being studied.

ENDNOTES

[21] San Diego Gas & Electric has indicated a willingness to enter into a long-term power purchase agreement with Calpine for output from an Otay Mesa facility, starting from January 2008. The contract is contingent upon the CPUC approving specific transmission upgrades and assigning the DWR contract with the Sunrise facility currently administered by SDG&E to another utility. The CPUC's approval of this agreement has met with legal challenges that have yet to be resolved.

CHAPTER 6: ENVIRONMENTAL ISSUES ASSOCIATED WITH AGING PLANTS

Air Pollutant Emissions and Ambient Air Quality

In order to understand the effect of the California aging power plants on air pollutant emission inventories and ambient air quality, it is important to describe the California fuel-fired generation sector, its air pollutant emissions, and the California air quality setting. The key findings of the air section regarding aging units are:

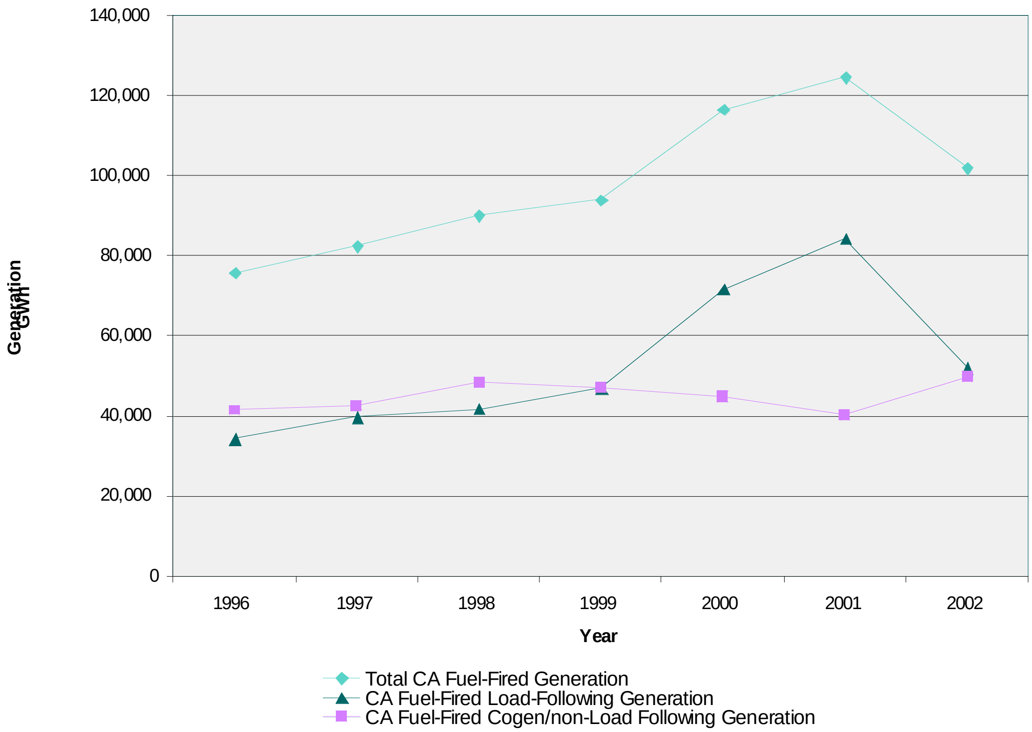
- The aging units are all in compliance with air quality rules and regulations;
- The aging units' aggregate NO_x emission rate (i.e., emission factor) is less than the in-state fuel-fired[22] generation aggregate NO_x emission rate;
- The PM10 and PM2.5 emission factors vary across the aging units, but are similar to the aggregate PM10 emission factor for in-state fuel-fired generation;
- The aging units' aggregate CO_2 emission factor is slightly lower than the in-state fuel-fired generation average; and
- The air quality implications of retirement and/or replacements are uncertain since the technology type, dispatch profile and location of replacement energy providers is uncertain.

California Fuel-Fired Generation

California has about 34,600 MW of fuel-fired generating capacity[23] that produced anywhere from 75,000 to 125,000 GWh annually from 1996 to 2002. The variation in total energy output from the fuel-fired units is shown as the top curve in Figure 6-1.[24]

Included in Figure 6-1 is a further differentiation, although imprecise, of the fuel-fired generation units into two groups: 11,500 MW, consisting mostly of base-loaded and cogeneration units, and 24,100 MW, consisting mostly of load-following units.[25] As shown in Figure 6-1, during the period from 1996 to 2002 the base-loaded portion held energy production fairly constant, even during the energy crisis of 2000 – 2001.

Figure 6-1
California Fuel-Fired Generation Energy Production

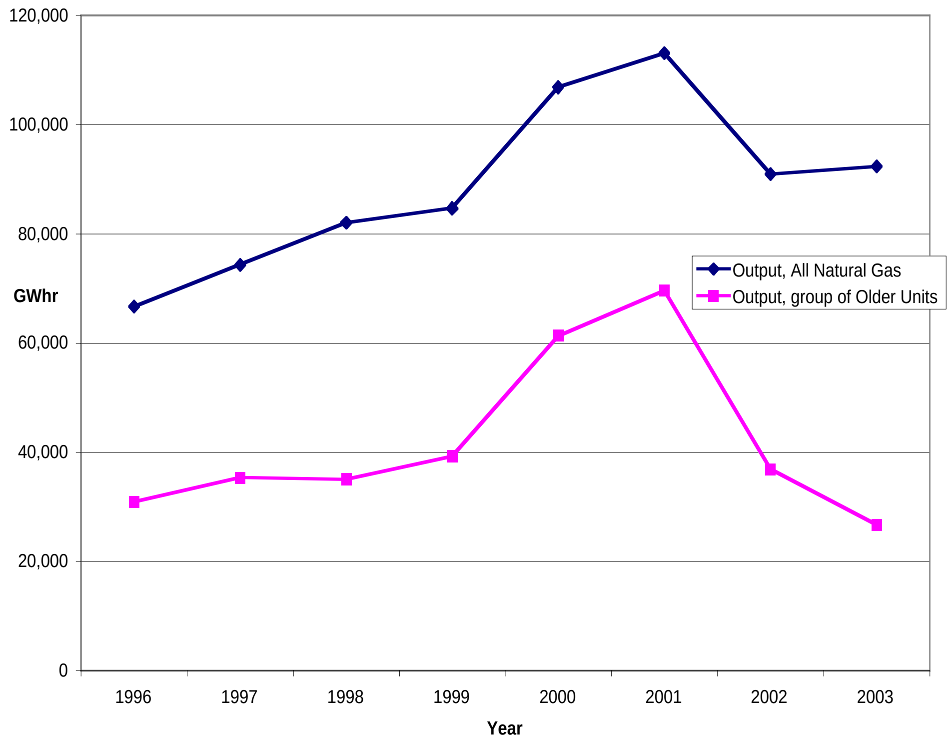


Source: 2003 EPR

The aging power plants under study constituted 16,500 MW of the 24,100 MW of load-following portion, and are the units that provided most of the increased output during the energy crisis, as shown by the 40,000 GWh swing between 1996 and 2001 in Figure 6-2. With hydropower near normal levels, and new projects coming on-line, the energy output from the aging power plant study group has dropped in recent years to below pre-1996 levels. In addition, the increased production from new units (see the slight increase in energy production from “All Natural Gas” units between 2002 and 2003 in Figure 6-2) contributed to the continuing decline of output from the aging units in recent years.

The 66 units in the aging power plant study are exclusively natural gas-fired, and are all steam boilers units except for four combined-cycle plants. Other units in the load-following portion of the fuel-fired fleet are the natural gas and liquid fuel fired peaking combustion turbines, and new natural gas-fired merchant combined-cycle plants (e.g., Los Medanos, Delta, and Sutter).

Figure 6-2
Aging Power Plant Study Group Energy Production



Power Plant Emissions

Power plants in California that burn fuel produce regulated air pollutant emissions, called criteria pollutants, and global climate change (GCC) gases, which are currently not regulated. The criteria pollutants considered in this report are particulate matter (PM10 and PM2.5, less that 10 and 2.5 microns, respectively) and oxides of nitrogen (NO_x). The most frequent violations of ambient air quality standards in the state are those for particulate matter and ozone.[26] Emissions of carbon monoxide (CO), reactive organic gases (ROG), and sulfur dioxide (SO_2) from power plants in this study do not significantly contribute to violations of ambient air quality standards, and therefore, are not discussed here.

Ozone violations occur in much of California in the sunny summer months. PM10 and PM2.5 violations are more frequent in the winter months when inversions (i.e., stagnant conditions) hold the PM and precursor emissions (NO_x, SO_2, and ROG) close to the ground. Ozone is a regional problem, whereas particulate matter violations can have both local and regional effects.

The primary generation related GCC gas is carbon dioxide (CO_2), resulting from the combustion of carbon-based fuels. The potential implications of CO_2 emissions are global and are not affected by local meteorology or topography.

Ambient Air Quality Setting

More than 90 percent of Californians breathe unhealthy levels of one or more air pollutants during some part of the year (CARB 2003). California ambient air quality is the result of a complex interaction of air pollutant emissions, topography, and meteorology. For example, the emissions spike from cars and trucks during the morning commute are often trapped in an air basin by mountain ranges, allowing the emissions to "cook" for extended periods of time in California's signature calm, sunny weather, resulting in the brown smog (ozone) we are so familiar with. Statewide ozone levels, shown in Figure 6-3 as an example of our ambient air quality setting, have been trending downward, but are starting to flatten due to increasing population and vehicle miles traveled, as shown in Figure 6-4. The decreases in ozone shown in Figures 6-3 and 6-4 are the direct result of decreases of ozone precursors - NO_x and ROG.

Figure 6-3
Statewide Ozone Trend

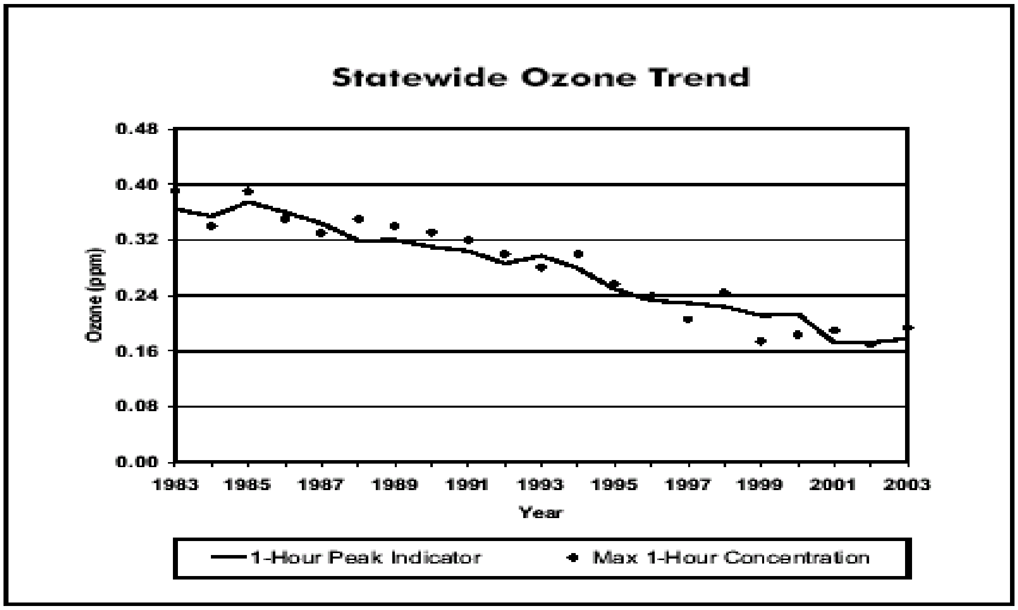


Figure 3-4

Source: CARB 2004 California Almanac of Emissions and Air Quality

Figure 6-4
Air Quality versus Growth

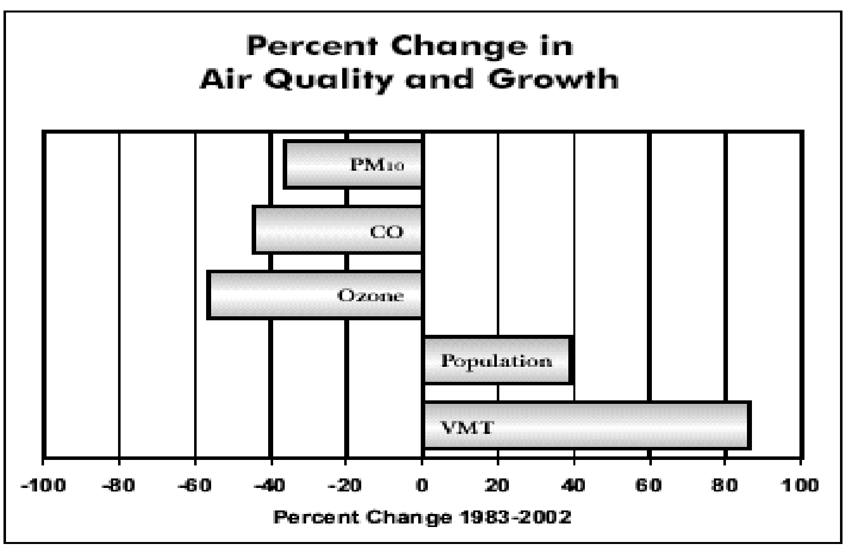


Figure 3-1

Source: CARB 2004 California Almanac of Emissions and Air Quality

Figure 6-5
Statewide Ozone Precursor (NO_x) Emissions Inventories

NOx Emission Trends (tons/day, annual average)								
Emission Source	1975	1980	1985	1990	1995	2000	2005	2010
All Sources	4815	4986	4949	4850	4142	3663	3040	2519
Stationary Sources	1226	1247	1004	881	703	627	511	531
Area-wide Sources	83	88	91	87	87	90	93	89
On-Road Mobile	2435	2459	2721	2675	2301	1915	1518	1127
Gasoline Vehicles	2149	1975	1936	1789	1535	1113	757	536
Diesel Vehicles	286	484	784	885	766	802	761	590
Other Mobile	1072	1192	1133	1207	1052	1031	918	772

Table 3-2

Source: CARB 2004 California Almanac of Emissions and Air Quality

CARB predicts that continued emission reductions should result in continued air quality improvements, albeit slow and inconsistent from air basin to air basin. For example, the reductions of the historical and forecast inventory table of ozone precursor NO_x is shown in Figure 6-5. Note that most reductions in 2005 and 2010 will come from the mobile sector; stationary source emissions inventories, which include power plants, are expected to slightly increase in this same time period due to increases in the population and economy.

Air Regulations: Emission Reductions and Controls

Because we cannot affect changes in meteorology and topography, the United States Environmental Protection Agency, the California Air Resources Board, and local air quality districts regulate emissions and emission sources to achieve and maintain ambient air quality standards. Those regions experiencing violations of the national and state ambient air quality standards are designated as “non-attainment.” The relative stringency of air regulations reflect whether the region is non-attainment and needing emission reductions, or in attainment and only requiring “maintenance” air regulations.

Air districts’ ambient air quality attainment and maintenance plans rely on reductions of emissions from existing emission sources, and control and/or offset of emissions from new sources. The fuel-fired generation sector and its air pollutant emissions have been, and will continue to be, a vital component of regulated emission reductions and controls. These include emission control retrofits, retirements, and operational limits (e.g., curtailments) that result in emissions reductions from existing generating units, and the use of best available control technologies and the offset of some emission increases for new fuel-fired generation units.

New Source Review Rules

In order to achieve emission reductions while allowing for ongoing economic activities, including new businesses and emission sources, air districts implement New Source Review (NSR) rules. The rules require new sources to employ the emission control technologies that are as clean as possible, and to provide offsets for some of the emissions increases resulting in no net increase or a reduction of emissions in an air basin. NSR rules were not in effect at the time the aging units under study were built. However, nearly all of the units have had to retrofit with best available retrofit control technologies or fuel switch to reduce their emissions, primarily of NO_x and SO_2.

Retrofit and Curtailment Rules

In the early 1990s, air districts promulgated NO_x, and in some cases CO, retrofit rules for most of the then utility-owned power plants (now the aging power plant study group). Some aging units, such as Humboldt, are located in a federal attainment area and have not been subject to any retrofit requirements. Most of the other aging units were required to reduce NO_x emission rates by 80 to 90 percent through the use of selective catalytic reduction (SCR) technology. In some cases, owners opted to retire the units rather than extend the life of the unit.

Some retrofit rules prescribed operational curtailments or emissions caps. For example, the four boiler units at the Morro Bay Power Plant are limited to 2.5 tons per day of NO_x (SLOAPCD Rule 429). The Hunters Point boiler units 2 and 3 were limited to a 2 percent capacity factor from May 1 to October 31, and no more than 4 percent for the entire year (BAAQMD Rule 9-11). They are now retired. Similarly, rules adopted at the same time for most of the peaking combustion turbines curtailed operations to 870 hours, or 10 percent annual capacity factor, to achieve emission reductions (BAAQMD Rule 9-9).

Generation Sector Emissions Footprint 1975 - 2003

From an air pollutant emissions perspective, our fuel-fired generation system is relatively clean and getting cleaner in recent years. The existing fuel-fired generation sector has significantly reduced total emissions and emission rates, and new generation units employ best available control technologies and offset most emission increases. Between 1975 and 2000, NO_x and PM10 emissions and emission rates decreased significantly, as shown in Table 6-1. Air districts have only recently begun to monitor PM2.5 levels.

Table 6-1
NO_x, PM10, and PM2.5 emissions

Pollutant	Source of Emissions	1975	2000
NO_x [a]	From All Sources (tons per day)	4,761	3,743.5
	From Power Generation (tpd)	385	124
	% Power Generation	8.1%	3.3%
	Average Emission Factor, Fuel-Fired lb/MWh	3.3	0.66
PM10 [a]	From All Sources (tpd)	1,864	2,148.8
	From Power Generation (tpd)	49.6	11
	% Power Generation	2.7%	0.51%
	Average Emission Factor, Fuel-Fired lb/MWh	0.42	0.07
PM2.5	From All Sources (tpd)	NA	848.1
	From Power Generation (tpd)	NA	10.4
	% Power Generation	NA	1.22%
	Average Emission Factor, Fuel-Fired lb/MWh	NA	0.06
a. The 2000 values are not from the 2001 EPR. CARB has adjusted the inventories and the corrected values are reported here.			

Source: CEC 2001 and CARB 2004

NO_x emissions from the California generation sector are comparatively small and getting smaller, on both a total emissions and emissions rate basis. PM10 and PM2.5 emissions from the generation sector are negligible when compared to the overall inventory, and will stay fairly constant given that most generation already uses natural gas (the lowest PM emitting fossil fuel) and post-combustion controls for natural gas units are non-existent and unlikely. The relative contribution of PM2.5 from the generation sector compared to the total PM2.5 emissions inventory is about 1.22 percent. PM emissions from combustion sources tend to be primarily (about 95 percent) PM2.5, whereas PM10 inventories can be dominated by non-combustion sources such as fugitive dust emissions from industrial and agricultural processes.

Table 6-2
Statewide and Generation CO_2 Emissions
(million tons/year)

Pollutant	Source of Emissions	1999
CO2	From All Sources	381.1
	From CA Power Generation	61.0
	% Power Generation	16%
	Emission Factor (tons/MWh)	0.71
	From Aging Power Plants	22.9
	% Aging Power plants	6.0%
	Aging Plant Emission Factor (tons/MWh)	0.61
Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999 November 2002, Publication #600-02-001F, California Energy Commission.		

Source: CEC 2002 and 2003

The aging units contribute 6 percent (in the form of CO_2) to the state's GCC inventory. In aggregate, in-state electricity generation contributes 16 percent to the state's GCC gas inventory, compared to about 45 percent nationally.

NO_x Emissions: California Generation and the Aging Power Plant Study Group

Figure 6-6 shows the total fuel-fired fleet and the three sub-categories of base-load and cogeneration, load following/non-aging units, and the aging power plants. While the statewide average fuel-fired NO_x emission factor is 0.66 lb/MWh, the "base-loaded" portion of the generation units average 0.95 lb/MWh.[27] The aging unit portion of the fleet averaged 0.28 lb/MWh in 2002, and averaged even less in 2003, as shown in Figure 6-7. The downward trend is due to the continuing installation of SCR on the aging power plant boilers.

If you exclude the NO_x emissions from the Humboldt units (at 3.5 lb/MWh) and the Coolwater units (at 0.9 lb/MWh), which have not had to install SCR to comply with retrofit rules, [28] the average aging power plant NO_x emission factor drops to 0.13 lb/MWh. This was expected since the retrofit rules[29] targeted NO_x emission rates of 0.18 to 0.10 lb/MWh. Some of the aging power plants in the South Coast air district are averaging 0.05 to 0.08 lb NO_x/MWh. Aggregate NO_x emission factors for generation technologies supplying electricity to California are shown in Figure 6-8.

Figure 6-6
2002 California Fuel-Fired Generation
Total = Baseload + Load-Following + Aging Units

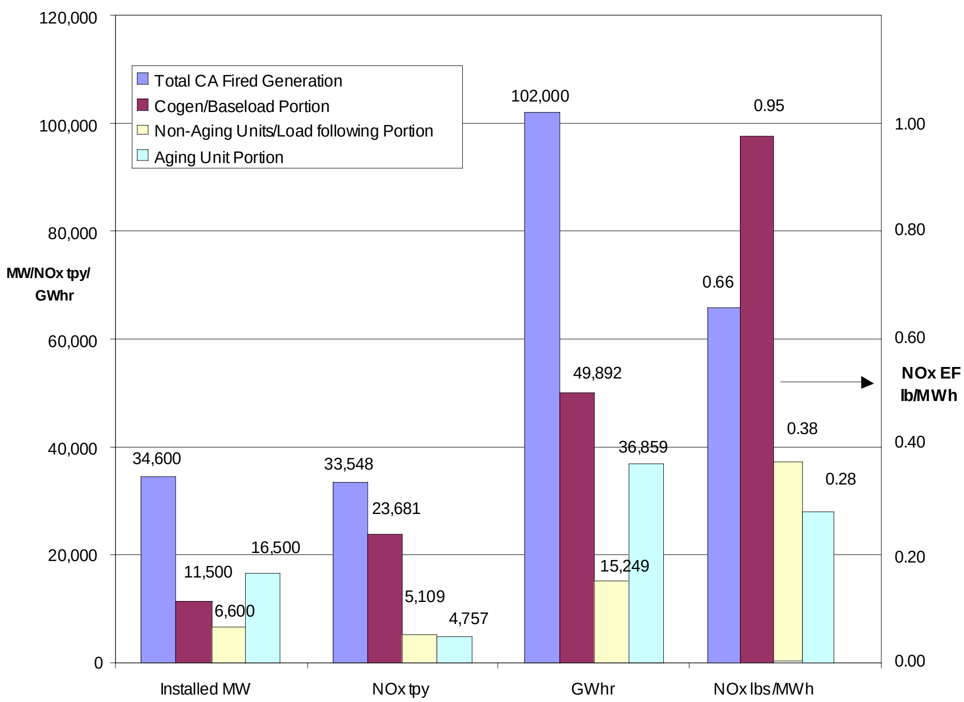


Figure 6-7
Aging Power Plant NOx Emissions (tpy) and Emission Factors (lb/MWh)

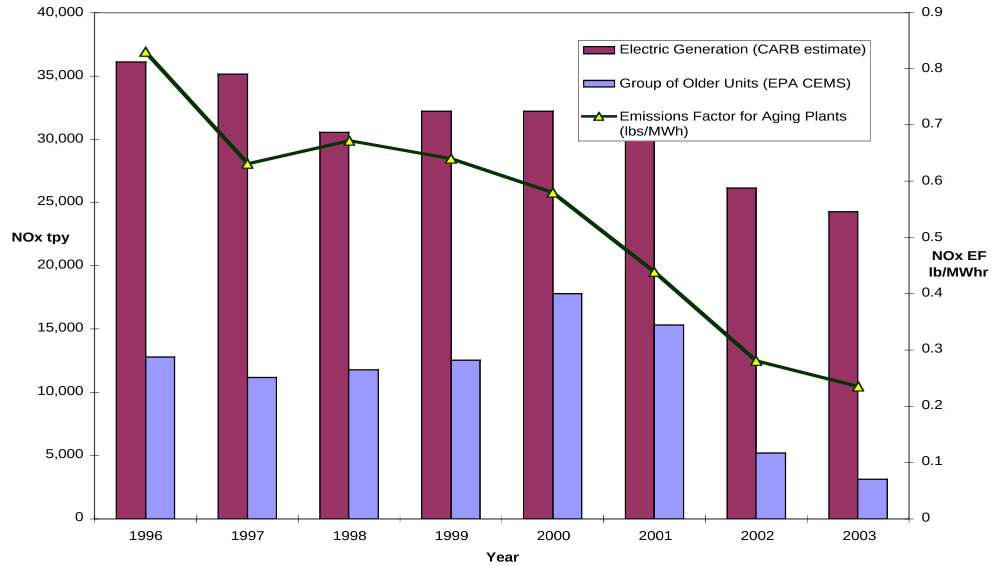
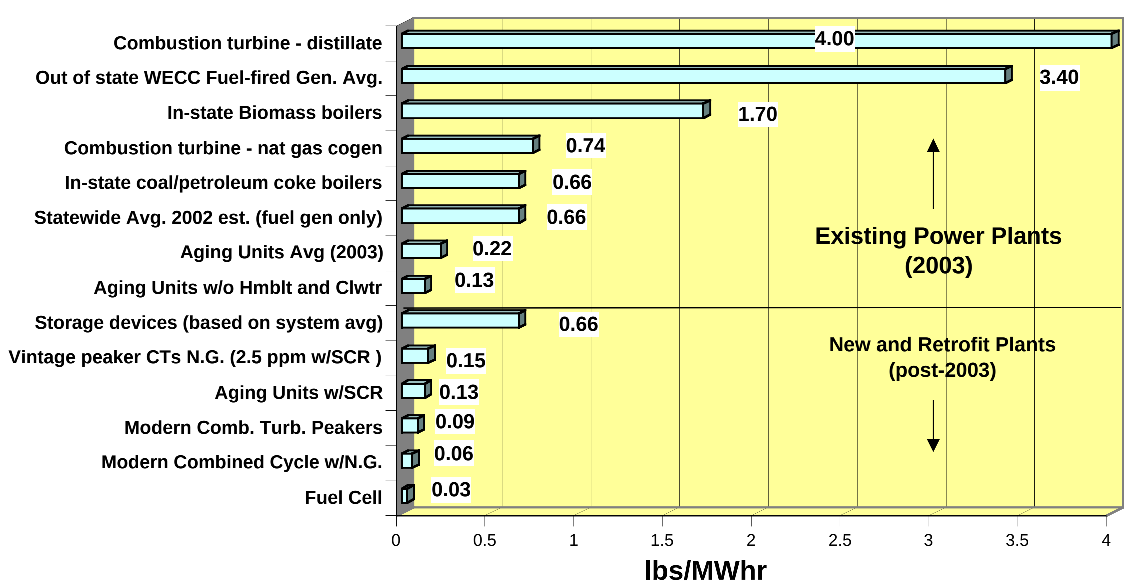


Figure 6-8
Electricity Generation NOx Emission Factors (lb NOx/MWh)



Aging Power Plant NO_x Emissions and Regional Attainment Strategies

While the generation sector, and in particular, the aging units have reduced emissions (for example, NO_x emission rates have been reduced by as much as 99 percent in some air districts), we cannot say that more reductions will not be required from the aging units.[30] Every district has an Air Quality Plan tailored to their local mix of emissions, topography, and meteorology. As local economies, populations, and emission inventories grow, the emissions mix will change. A district will decide which sectors to control and what emissions reductions are most cost effective. Aging plants may be treated differently in one district than in another.

In this context, the aging power plants have become a very small portion of the total inventory. As shown in Table 6-3, NO_x emissions from the aging units for 2003 for the air districts that have fully implemented aging unit retrofit rules were almost zero percent (South Coast, Monterey, San Diego, and Ventura) of the total NO_x emissions.

In the Bay Area, while the aging units are currently in compliance with the retrofit rules, more NO_x retrofits are likely to be required to maintain compliance with the retrofit rule. The Potrero boiler is scheduled to install SCR in the fall of 2004, and Contra Costa Unit 6 and Pittsburgh Unit 7 will either curtail operations or retrofit with SCR in order operate under the "system cap" in 2005. As discussed above, the Humboldt facility is in compliance with all district rules, and the air basin is in attainment. In the Mojave air district, the Coolwater units are in compliance with district rules, and the district is not currently considering retrofit rules or additional emission reductions for these units. In the San Luis Obispo air district, the Morro Bay units comply with the district's daily NO_x mass cap, but the rule does effectively limit operations (energy output) of the four boiler units. If the power plant owner wanted to operate the units to generate for more hours on a daily basis, SCR would have to be installed under the requirements of the retrofit rule, resulting in reductions of the NO_x emission rate and emissions.

Table 6-1 illustrated the downward trends of emissions, emission rate, and relative contribution to statewide air for the generation sector from 1975 to 2000. Table 6-3 shows that the aging power plants are an even smaller portion of the NO_x emissions for the air district where they are located. This is due to the installation of SCR on the aging boiler units and dispatch levels similar to pre-energy crisis conditions. Whether the aging units will remain at these levels depends on electricity demand, power plant retirements and construction, and annual hydro production levels. Given that the NO_x emissions are such a small portion of the most air districts' inventories, additional reductions may not be cost effective.

Table 6-3
Aging Unit 2003 NO_x versus 2003 District NO_x

Air District	2003 Aging Unit NO_x Annual Average Tons/day	2003 District Total NO_x Annual Average tons/day	Aging unit % of Total NO_x
Bay Area	1.7	588.2	0.3%
North Coast (Humboldt)	1.1	28.97	3.7%
South Coast	1.8	1073.29	0.2%
Mojave	1.9	167.07	1.1%
San Luis Obispo (Morro Bay)	0.1	26.47	0.6%
Monterey (Moss Landing)	0.1	85.61	0.1%
San Diego	0.7	219.41	0.3%
Ventura	0.2	63.02	0.4%
Statewide Total	8.6	3333.407	0.3%

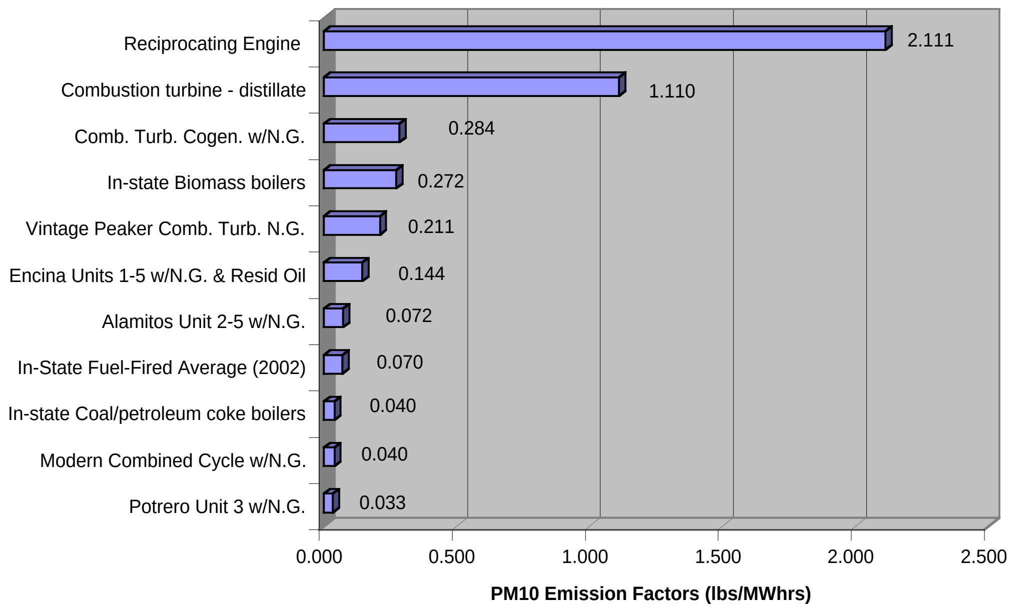
PM Emissions from the Generation Fleet

PM10 emission rates, shown in Figure 6-9, are low and cannot get much lower, as the fuel-fired generation already uses natural gas almost to the exclusion of dirtier (relative to PM10 and PM2.5 emission rates) fuels such as coal, biomass, and oil. The coal-based generation is very clean due to the consistent use of baghouses for PM control. The other solid-fueled units (i.e., biomass) are not as clean with respect to PM emissions. PM emissions from the aging units vary significantly, and with the use of fuel oil. Only five of the aging units can use fuel oil (Humboldt, Potrero, Coolwater, Encina, and South Bay), but only for emergencies. PM emissions from the aging units are about the same as the statewide generation PM averages.

Aging Power Plant PM10 and Regional Attainment Strategies

With regard to PM10 and the districts' efforts to reach and maintain attainment of ambient air quality standards, the aging power plant PM10 emissions are very small, especially when compared to the districts' total PM10 inventory as shown in Table 6-4. The PM10 values in Table 6-4 are calculated by multiplying unit operating hours times a default PM10 emission factor. Since the aging units do not have continuous emissions monitoring for PM emissions to provide specific emission factors, the statewide generation PM10 emission factor from Table 6-1 was assumed to be representative for any MWh generated by the natural gas-fired aging units. The PM2.5 emissions are shown in Table 6-5 are calculated at 95 percent of the PM10 emissions in Table 6.4.The percentage of PM2.5 from aging units compared to the total district PM2.5 higher, as district and statewide PM2.5 inventories are less than the PM10 inventories shown in Table 6-4.

Figure 6-9
PM10 Emission Factors (lb/MWh) of Existing and Potential Replacement Generation



While we do not know whether district Air Quality Plans will require PM10 reductions from the aging plants, it is unlikely because natural gas is the cleanest fuel available and there are not any natural gas PM10 post-combustion controls in place today or likely in the future. However, every district has an Air Quality Plan tailored to their local mix of emissions, topography, and meteorology. As local economies, populations, and emission inventories grow, the emissions mix will change. A district will decide which sectors to control and what emissions reductions are most cost effective.

Table 6-4
Aging Unit 2003 PM10 Emissions versus
2003 District PM10 Emission Inventories

Air District	2003 Aging Unit PM10 annual average tons/day	2003 District Total PM10 annual average tons/day	Aging unit % of District Total PM10
Bay Area	0.370	202.11	0.18%
North Coast (Humboldt)	0.022	79.97	0.03%
South Coast	1.228	339.71	0.36%
Mojave (Coolwater)	0.125	96.57	0.13%
San Luis Obispo (Morro)	0.030	32.42	0.09%
Monterey (Moss Landing)	0.128	75.58	0.17%
San Diego	0.383	125.74	0.31%
Ventura	0.243	49.64	0.49%
Statewide Total	2.554	2186.00	0.12%

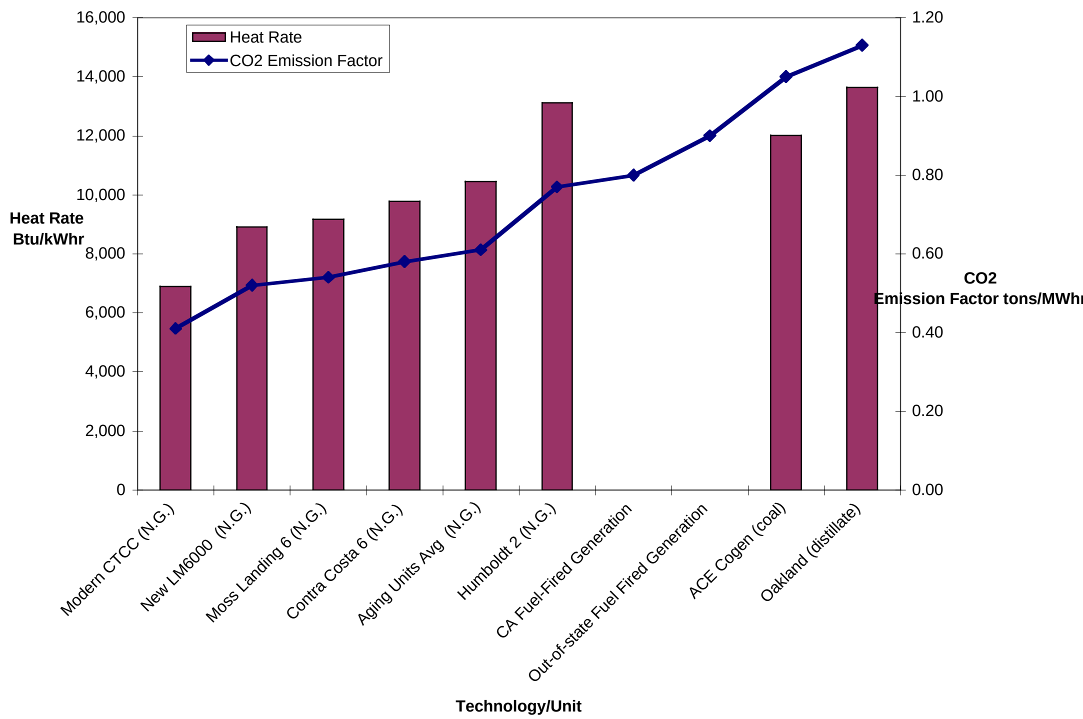
Table 6-5
Aging Unit 2003 PM2.5 Emissions versus
2003 District PM2.5 Emission Inventories

Air District	2003 Aging Unit PM2.5 annual average tons/day	2003 District Total PM2.5 annual average tons/day	Aging unit % of District Total PM2.5
Bay Area	0.352	86.81	0.41%
North Coast (Humboldt)	0.021	35.19	0.06%
South Coast	1.167	129.55	0.90%
Mojave (Coolwater)	0.119	29.86	0.40%
San Luis Obispo (Morro)	0.029	14.31	0.20%
Monterey (Moss Landing)	0.122	33.09	0.37%
San Diego	0.364	50.79	0.72%
Ventura	0.231	31.80	0.73%
Statewide Total	2.426	859.70	0.28%

CO_2 Emissions: California Generation and the Aging Power Plants

The California fuel-fired generation CO_2 emission factor for 2002 was 0.8 tons/MWh, while the 2002 CO_2 emission factor for out-of-state (Western Electricity Coordinating Council – WECC, which supplies electricity to California) fuel-fired generation was about 0.9 tons/MWh. This is because California uses so little coal and oil in-state and relies on a diverse generation resource mix that emits relatively low amounts of GCC gases (CO_2). The aging plants' aggregate CO_2 emission factors are slightly lower that the fuel-fired average. A modern simple cycle combustion turbine or a combined-cycle plant would have better CO_2 emission factors, as shown in Figure 6-10, due to higher thermal efficiencies than most of the aging units.

Figure 6-10
CO_2 Emission Factors (tons/MWh) of Existing and Potential Replacement Generation



Potential Air Emission Implications of Replacement Units

Given the low emissions and emission factors associated with the California generation system and the subset of the aging units, it is not clear how emissions or emission rates would change as aging units are retired or replaced. If some aging units are retired without replacement (i.e., immediate retirements without time to design, permit, or build the replacement plants), reliance on the in-state and out-of-state resource mix of the remaining system would be neutral to negative with respect to emissions. The aging plant NO_x emissions factors are better than the statewide average, such that increased operation from the exiting generating plants that are currently underutilized would result in increased NO_x emissions. Changes in PM10 and PM2.5 emissions are most likely neutral. Increased operation of underutilized units would increase emissions with respect to recent historical generation emissions at those units, but would be within the limits of their air permits. Further, emission reduction credits generated from aging unit retirements would be available for sale and use within an air district, such that the emissions would not "go away" but would get reused and continue to be part of the regional air quality. Lastly the emissions changes could occur almost anywhere in California and the WECC, therefore, the air quality implications are highly uncertain. CO_2 emissions, on a per MWh basis, could either decrease or increase with the retirement of some of the aging units, depending on the location and type of technology for the replacement.

If some aging units are replaced by new units, the effect on emissions and emission rates would depend on the technology used to generate the replacement capacity and energy and its location. While combined-cycle units emit less criteria and GCC gas emissions on a per MWh basis at steady state base-load operation, the difference in emission rates will decrease when combined-cycle units increase the number of start-up and transients events required to match the peaking to load-following modes currently required of the aging units. For example, the effects of dispatch on a combined-cycle's heat rate and NO_x emission factor are shown in Figure 6.11. Because the dispatch profile, emission rate, and location of the replacement unit is uncertain, the affect of the aging plant replacements on NO_x and CO_2 emissions and air quality is also uncertain. The replacement power plant would probably be neutral with respect to PM emissions. Again, emission reduction credits generated from aging unit retirements would be available for sale and use within an air district, such that the emissions would not "go away" but would get reused and continue to be part of the regional air quality.

Further, we have seen most aging units being replaced with a CTCC that is much larger, and proposed to, but may not, operate at a much higher capacity factor. This results in on-site potential emissions being higher than historical emissions. Table 6-6 shows how on-site emissions will change with the construction of the 1000 MW Mountainview CTCC at the 126 MW San Bernardino steam turbine power plant (circa 1957).

Figure 6-11
Effects of Dispatch on Combined Cycle Heat Rate and NO_x Emission Factor

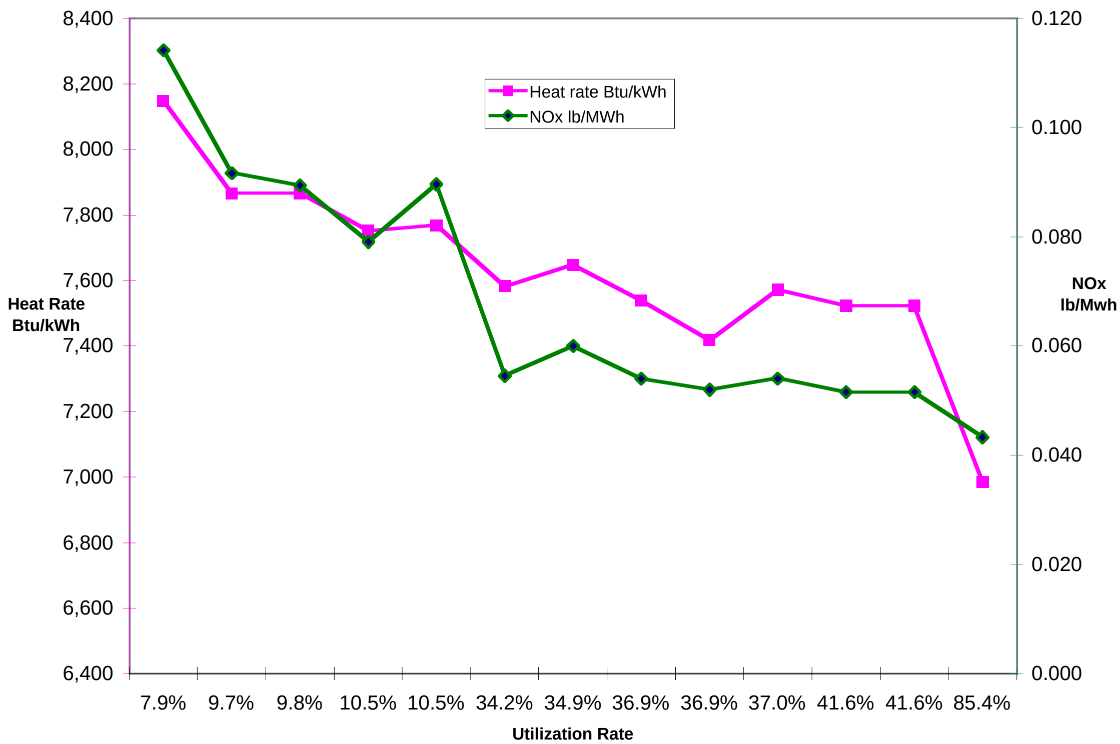


Table 6-6
Emissions - CTCC Replacing an Aging Boiler Unit

	San Bernardino Power Plant – Historical Emissions (lb/day)	Mountainview Power Plant - Permitted Emissions (lb/day)
NO_x	2,646	3,213
CO	58	2,720
ROG	19	347
SO_x	19	154
PM10	6	1,161

In this case, local permitted emissions will increase dramatically over historical[31] emissions. Whether this will result in changes in local impacts depend on changes in stack heights, daily and seasonal operational dispatch, emissions concentrations, location of mitigation and offsets, and ambient air quality trends. Therefore, it is difficult to predict the effect of aging power plant replacements on local public health or even regional air quality.

Biology

This section examines the effects on biological resources from continued reliance on aging generating units. The analysis focuses mostly on the potential impacts to marine biological resources of once-through seawater cooling systems, which are used for cooling 53 of the 66 aging generating units under study. Also included are brief discussions of terrestrial biological resource impacts, and the benefits to all biological resources provided by various programs in effect at the aging generating plants.

Once-Through Cooling Basics

Of the 22 power plants that are the subject of this staff white paper, 17 are located adjacent to tidal waters and use a once-through seawater cooling system to cool the power generating units. In once-through cooling, water is withdrawn from a source, pumped through a heat exchanger, and discharged at a higher temperature, usually to the same body of water from which it was withdrawn. Because of its low capital and operating costs, and potential for higher power plant operating performance, once-through cooling is still favored for older coastal power plants (CEC 2002). Because once-through cooling systems withdraw and discharge large volumes of seawater, they have adverse effects on aquatic organisms. Once-through cooling may create impacts on aquatic resources through impingement, entrainment, and thermal discharge.

Impingement occurs when organisms are trapped against the intake screens by the force of the water being drawn through the cooling water intake structures. Aquatic organisms impinged on intake screens are usually killed. Entrainment refers to the passage of small organisms such as fish eggs and larvae and other plankton, through the intake screens and into the power plant. Most scientists assume that entrained organisms are either killed or severely injured and later die after discharge. The discharge of heated waters also may have adverse thermal effects on aquatic organisms sensitive to temperature changes.

The withdrawal of large quantities of cooling water in power plant once-through cooling systems has the potential to affect large quantities of aquatic organisms. The United States Environmental Protection Agency (EPA) estimates that the current number of fish and shellfish that are killed from impingement and entrainment from cooling water intake structures at large power plants in the United States is over 3.4 billion annually (EPA 2004).

Recent entrainment studies done at several California coastal power plants (Moss Landing, Morro Bay, Diablo Canyon, and San Onofre) have all found substantial adverse impacts to local marine resources. For example, at Diablo Canyon on the central California coast, a recent entrainment study indicated that the best estimate of the loss of productivity due to the power plant intake was equivalent to the loss in production of 7.75 miles of open coast habitat from the shoreline out to nearly 2 miles offshore, an area of 9,920 acres (Tenera 2000). At the San Onofre Nuclear Generating Station, located along the southern California coast, a study determined that intake losses were equivalent to the removal of 13 percent of the queenfish, 6 percent of the white croaker and 5 percent of the California grunion populations from the entire Southern California Bight (Murdoch et al 1989), an area of coastline that starts at Point Conception (Santa Barbara county) and goes south into Mexico. Locally, within about 2 miles of the San Onofre Nuclear Generating Station, the density of queenfish and white croaker in shallow-water samples decreased by 34 percent and 36 percent respectively after Units 2 and 3 began commercial operations (EPA 2001). The California Coastal Commission determined these impacts to be significant and the power plant operator was required to mitigate for the losses. The flows through these plants are many times that through the aging boiler units under study, and the nuclear plants tend to operate for a much larger portion of the year. Still, these studies provide evidence that once-through cooling systems likely have much larger effects on marine biological resources than previously thought.

Losses of large numbers of small forage fish at power plant intakes can have ripple effects farther up the food chain. For example, EPA (2004) predicted that entrainment of forage fish resulted in subsequent reductions of predator populations (including commercially and recreationally important larger fish species) as high as 25 percent.

In contrast to the potentially significant effects of impingement and entrainment, measurable thermal impacts generally are localized and species specific. For example, in the immediate vicinity of the discharge at the Potrero Power Plant in San Francisco Bay, elevated temperatures of the thermal discharge are associated with noticeable changes in the species composition and abundance of intertidal and subtidal algae, but have been observed to have little effect on invertebrates or fishes (Southern Company 2000). A study of thermal effects at El Segundo Generating Station noted only minor differences between the biological communities near the outfalls and areas without outfalls (Benson et al 1973). Fewer species of fish were found near the outfalls compared to areas without outfalls, although the total number of individual fish was actually greater near the outfalls. Two species, the white seaperch and the walleye surfperch, were significantly more abundant at areas without outfalls than at the outfalls. The results suggest that some species of fish may avoid the areas of elevated temperature around an outfall and some species are attracted to the higher temperatures. The National Pollution Discharge Elimination System (NPDES) permits, which among other things govern the thermal discharges at coastal power plants, set a limit on the temperature elevation allowed.

Some of the aging power plants under study, including Contra Costa, Moss Landing, Potrero, and Encina, have reported thermal discharges that exceeded the limits in their NPDES permits.

Section 316(b) of the Clean Water Act

Section 316(b) of the Clean Water Act requires EPA to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. Technologies that reduce impingement include:

- A velocity cap on an offshore intake structures to direct the flow horizontally;
- A fish handling and return system;
- An intake velocity of 0.5 feet per second (fps) or less;
- Barrier nets; and,
- Traveling screens to remove debris and fish from the intake.

Technologies that reduce entrainment include:

- Fine mesh screen (which. unless accompanied by a very gentle velocity, turns entrainment into impingement); and,
- Aquatic filter barrier system (sometimes called a Gunderboom), – which, by greatly increasing the area of the water passing through the net, reduces velocity to the point that organisms can escape.

Technologies that may reduce both impingement and entrainment include:

- Reduction in flow;
- Possible relocation of the intake to a less sensitive area; and
- Possible seasonal restrictions in flow to avoid sensitive seasons.

Appendix F in this white paper provides information on the cooling water intakes of the aging power plants that are the subject of this study. None of the facilities have fine mesh screens or intake velocities consistently below 0.5 fps. Most of the plants with offshore intakes (El Segundo, Huntington Beach, Ormond Beach, and Scattergood) have velocity caps. Both the Contra Costa and the Pittsburg power plants have variable speed intake pumps, which can help to reduce the intake of water, especially in sensitive seasons. These plants also have fish escape systems. These power plants are located at the eastern end of the San Francisco Bay Estuary where several sensitive fish species, as well as the recreationally important striped bass, are vulnerable to impacts of the intake. In addition, Unit 7 of the Contra Costa Power Plant and Unit 7 of the Pittsburg Power Plant are equipped with closed-cycle systems that greatly reduce the intake of water. Several power plants (Morro Bay, Moss Landing, Encina, South Bay, Alamitos, and Long Beach) have traveling screens, which may slightly reduce impingement losses.

In summary, only the Contra Costa and Pittsburg power plants have technology to reduce entrainment. Most of the power plants have some technology to reduce impingement. In many cases, however, the only technology to reduce impingement is traveling screens, which may not significantly reduce impingement losses. Appendix F shows the permitted volume of the intakes of each of the aging power plants, as well as recent average flows. Most of the plants have been operating at considerably less than their permitted flows. Operators indicated that they did not foresee a change in flows in the next few years. Therefore, the impingement and entrainment impacts are likely to remain similar in the near future. However, should an increase in energy demand occur, there is the potential that some of the coastal power plants could increase water intake up to their permitted level and, thus, increase impingement and entrainment impacts.

Recent Changes to Section 316(b) Regulations

In 1993, Riverkeeper led a coalition of environmental groups in suing EPA on the basis that EPA failed to adopt uniform technology-based standards for cooling water intake structures as required under the Clean Water Act. In 2000, a U.S. District Court signed a consent degree requiring EPA to promulgate new regulations in three phases:

- Phase I for new facilities;
- Phase II for existing large power plants; and
- Phase III for existing small power plants and other facilities.

The aging power plants in this study fall under Phase II. The new Phase II regulations came out in February of 2004, and were published in the *Federal Register* on July 9, 2004. The new Phase II regulations call for existing facilities to meet specified performance standards. Power plant owners could avoid having to comply with these new standards by switching to some other type of cooling system, such as a wet-cooled system that uses recycled water instead of seawater, or a dry-cooled system. If the owners plan to continue use of seawater once-through cooling systems, the new regulations require them to:

- Reduce impingement mortality of all life stages of fish and shellfish by 80 to 95 percent compared to a baseline mortality of a plant with no controls to reduce impingement; and
- For many facilities (including those that are the subject of this white paper), reduce entrainment of all life stages of fish and shellfish by 60 to 90 percent of the baseline mortality of a plant with no controls to reduce entrainment.

Because EPA recognizes that it may be difficult for an existing power plant to retrofit its structures to comply with these standards, the new rule offers a range of alternatives to meet the standards. These alternatives allow owners to comply with the rules if they can:

- Demonstrate that the facility has reduced flow commensurate with closed-cycle recirculating system;
- Demonstrate that the facility has reduced design intake velocity to 0.5 fps;
- Demonstrate that existing design and construction technologies, operational measures, and/or habitat restoration measures meet the performance standards;
- Demonstrate that the facility has selected design and construction technologies, operational measures, and/or restoration measures that will, in combination with any existing design and construction technologies, operational measures, and/or habitat restoration measures, meet the performance standards;
- Demonstrate that the facility has installed and properly operates and maintains an approved technology; or
- Demonstrate that a site-specific determination of Best Technology Available is appropriate.

For the first alternative, if a power plant has already reduced or plans to reduce its flow to that of a closed-cycle circulating system, it will have met the performance standards for both impingement and entrainment, and no further demonstration will be necessary. If a facility has an intake velocity of 0.5 fps or less, it will have met the standard for impingement because studies have shown that most organisms can escape impingement when flows are gentle. Such a facility may still have to demonstrate that it meets or will meet the standard for entrainment, however. The third alternative requires the power plant operator to demonstrate that it currently meets the performance standards, while the fourth alternative requires demonstration that the facility will meet performance standards through a combination of existing new technologies, operational measures and/or habitat restoration measures.

The fifth alternative specifies that certain technologies may be identified that would automatically meet the performance standards if the power plant installs them, and no further demonstration is necessary. So far, the EPA has specified only one such approved technology - the use of a fine mesh cylindrical wedgewire screen on certain types of rivers, which would not apply to any of the power plants in this study. However, this alternative gives the various Regional Water Quality Control Boards (RWQCB) authority to identify approved technologies for their regions. Finally, the last alternative allows the power plant owner to demonstrate that it cannot meet the performance standards for its facility either because the cost of meeting the standards is significantly greater than EPA estimated in formulating the new 316(b) rule, or because the benefits that would be derived from complying with the standards do not justify the cost of compliance. If this last alternative is deemed appropriate for a particular power plant, the facility would still have to reduce impingement and entrainment to the extent practicable.

How Will the New 316(b) Regulations be Implemented?

The variety of alternatives for compliance with the new 316(b) regulations makes them very complex. Based on information received from staff of two RWQCBs (Michael Thomas, Central Coast RWQCB and Tony Rizk, Los Angeles RWQCB, personal communication with Dr. Noel Davis, June 16, 2004) and the operators of the aging power plants, it is not yet clear how the new regulations will be implemented. According to Michael Thomas, the application of the new 316(b) rule probably will evolve as it is put into practice. Because each of the six coastal RWQCBs in the state is autonomous, the new 316(b) regulations may be implemented differently in each region.

The aging power plants will have to comply with the new regulations when their existing NPDES permits are up for renewal. NPDES permit expiration dates for the plants under study range from 1999 to 2007 (see Appendix F for further details).

The process specified in the new 316(b) regulations is likely to extend for many years, and likely well past the study period for this white paper of now through 2008. For example, a time table for submitting information for NPDES permit renewal to the local RWQCB starts with a Comprehensive Demonstration Study showing compliance with the standards in the new rule, which must be submitted 6 months prior to the expiration of the existing NPDES permit. Before beginning the Comprehensive Demonstration Study, the facility operator must submit a proposal for the information that will be collected in the Comprehensive Demonstration Study. The local RWQCB must review and approve the proposal before the study begins. The new regulations state that a facility up for permit renewal before 2008 may request an extended schedule for submitting its Comprehensive Demonstration Study. The extended schedule should not extend beyond three and half years of publication of the final rule. Therefore, the aging power plants in this study likely will just be submitting their Comprehensive Demonstration Studies by 2008.

At this point, the information required for the Comprehensive Demonstration Study is uncertain. Typically, 316(b) studies of the impacts of entrainment require at least a year (and sometimes more) of sampling plankton near the intake at a minimum of twice per month and, in some cases, weekly. Processing and analysis of the samples is time consuming. Therefore, these studies usually require at least 18 months to complete and currently cost in the range of $1 million. However, the new 316(b) regulations allow old studies to be used if the plant operator can demonstrate that they are still applicable and that conditions have not changed substantially since the original study. At this point, it is not known how lenient the various RWQCBs will be in accepting old studies.

For the aging power plants in this study, it is uncertain what technologies could be implemented to meet the performance standards in the new rule. In formulating the new rule and estimating the cost of compliance, EPA primarily considered the installation of fine mesh screens as the technology to reduce entrainment. However, unless the fine mesh screens are associated with a very gentle intake velocity, organisms excluded from entrainment by the fine mesh would become impinged on the screen rather than entrained. The daily cooling water intake of almost all the power plants in this study is high, and reducing the velocity at these intakes to a protective 0.5 fps would require greatly enlarging the cross-sectional area of the intake or the use of an aquatic filter barrier system, such as a Gunderboom. An aquatic filter barrier was investigated as a method of reducing entrainment at Morro Bay and Diablo Canyon (M. Thomas, Central Coast RWQCB, personal communication). To reduce intake velocity at Diablo Canyon to the extent that organisms would not be impingement on the intake screen, would require an aquatic filter barrier 8 miles long, using available technology. At Morro Bay, the size of an aquatic barrier necessary to reduce velocities would occupy most of Morro Bay. In addition to the great size of an effective aquatic filter barrier for the power plants in this study, in most cases they are likely difficult to maintain, and must withstand the force of storm waves or strong tidal currents. Fouling by algae or sediment would also be a problem.

A more practical way to reduce entrainment would be to change operations to reduce cooling water flows. At this point, it is not known if such a change in operations would be practical for any of the power plants in this study or what the implications on their operations would be. One possibility for some power plants might be a seasonal reduction in flow to entrain fewer organisms in the late winter and spring when plankton tends to be more abundant. However, the Comprehensive Demonstration Study would have to show that such a seasonal restriction would enable the power plant to meet the performance standard for entrainment. In cases where year long entrainment studies have been done, such as at Morro Bay, Moss Landing, and Diablo Canyon, the studies determined that larvae were present all year and that seasonal flow restrictions would not sufficiently reduce entrainment impacts (M. Thomas, Central Coast RWQCB, personal communication). Year-round entrainment impacts are likely to occur at the aging power plants in this study.

Some power plants could meet the entrainment performance standards by relocating their intake to a less sensitive location. However, relocation of an intake would be very expensive.

The new 316(b) regulations allow restoration as an option for meeting the performance standards. However, Riverkeeper sued EPA over the use of restoration to meet performance standards in the Phase I regulations, on the grounds that the Clean Water Act does not specifically authorize habitat restoration as mitigation. Currently, they have filed an administrative appeal protesting the restoration option for the Phase II regulations. The problem with restoration, if it remains as a compliance option in the Phase II 316(b) rules, is that practical restoration opportunities may not directly restore the species most vulnerable to the impacts of the intake. For example, there are opportunities to restore tidal wetlands in California but the fishes most affected by aging power plant intakes may be open ocean species such as queenfish and white croaker that would not benefit directly from tidal wetlands restoration. Also, it is extremely difficult to determine an appropriate dollar value for restoration. Again, the species most affected by the intake may not have any commercial value, but only ecological value.

For most of the California power plants, EPA has specified retrofitting of the intake with a fine mesh screen as the technology used to estimate the cost implications of the new 316(b) rule. Because fine mesh screens alone are unlikely to meet performance standards for the aging power plants in this study, the costs estimated by EPA are likely to be much less than the cost for each of these facilities to actually meet performance standards. Therefore, it is likely that many of the power plants in this study will choose to demonstrate that a site-specific determination of Best Technology Available is appropriate, and that the cost of meeting the performance standards is significantly greater than the costs estimated by EPA in formulating the new regulations. However, these plants will still need to implement whatever methods are practicable to approach the performance standards. At this point, it is unknown what technologies or operational changes could be implemented at a cost similar to those estimated by EPA.

What are the Implications of the New 316(b) Regulations for the Aging Power Plants in this Study?

During the 4.5 year period for this study, the new Phase II 316(b) regulations are unlikely to have any effect on aging power plants. All of the power plant operators queried in this study indicated that they intend to comply with the rule and none thought that the rule was likely to cause a power plant to retire. The aging power plants will have almost until 2008 to submit the Comprehensive Demonstration Study required by the new regulations. Therefore, an aging power plant probably would not be required to install new technology, change operations, or implement a restoration project within the next 5 years. Until 2008, power plants will continue to operate using existing intakes and operational procedures. The impacts to aquatic resources of impingement and entrainment over the next 5 years likely will remain similar to what currently exists.

In the longer term, the requirements of the new 316(b) regulations might push an aging power plant into retirement if the costs of meeting the performance standards, or of switching to another type of cooling system such as dry-cooling or wet-cooling using recycled water, were higher than the revenue potential of the plant. When fully implemented, the new 316(b) regulations likely will reduce the impacts of impingement and entrainment on aquatic resources, but because it is unclear at this time how the rule will be implemented, the reduction in impacts is difficult to predict. For example, if most existing facilities obtain a site-specific determination that the costs to meet performance standards are much higher than the costs estimated by EPA, then only a few facilities may meet the standards of the new rule.

Cumulative Impacts

In some areas, such as Santa Monica Bay, where more than one power plant withdraws water from the same water body, the cumulative effects of multiple power plants are of particular concern. The impacts of a single power plant's cooling water intake on aquatic resources may be small, but when combined with the effects of the cooling water intakes of additional nearby plants, the cumulative impact may result in a substantial loss of individuals of vulnerable species. The original 316(b) studies of California power plants were done in the late 1970's and only addressed the impingement and entrainment impacts of individual power plants, and did not evaluate the cumulative impact of all the power plants and other facilities on the California coast that use once-through cooling. None of the previous California 316(b) studies even evaluated the impacts of multiple power plants that are in close proximity to each other and withdraw cooling water from the same source.

In its discussion of the environmental impacts of once-through cooling systems, EPA expresses concern that, although the potential for aquatic species to be affected by cooling water withdrawals from multiple facility intakes is high, this type of cumulative impact is largely unknown and has not adequately been accounted for in evaluating impacts (EPA 2004). However, there are no provisions in the new 316(b) Phase II rules to address cumulative impacts. If the Comprehensive Demonstration Studies required by facilities located in close proximity to each other are done in a similar manner, the RWQCB may acquire data that would enable an analysis of cumulative impacts to be done. However, because facilities have a variety of options for complying with the performance standards, different facilities may select different options and may not perform comparable Comprehensive Demonstration Studies.

Other Environmental Issues Related to Aquatic Resources

In addition to the impacts of once-through cooling, aging power plants located next to tidal waterbodies may affect aquatic resources by maintenance dredging to keep the intake clear of sediment. Maintenance dredging occurs at the Encina and Morro Bay power plants. Dredging has a number of effects on aquatic organisms. Benthic invertebrates that live within the dredged sediments usually die. Re-suspended sediment may be carried beyond the limits of the dredging and bury adjacent habitats. Re-suspended sediments can also clog the feeding structures of filter feeding invertebrates, reduce light levels for marine plants, and disturb fishes. In most cases, however, the impacts of maintenance dredging are temporary and localized.

Maintenance dredging also may have environmental benefits. West Coast Power, owner of the Encina Power Plant, spends $2 million every two years to dredge the mouth of Aqua Hedionda Lagoon. Opening the lagoon mouth maintains water quality in the lagoon and helps to support a healthy, tidally influenced estuarine ecosystem as well as beneficial human activities such as aquaculture and marine research. The State and Federally endangered California least tern forages in the lagoon. Keeping the mouth open, thus, helps to maintain an ecosystem that benefits a protected species. Sand dredged from the mouth of the lagoon is placed on down-coast beaches where it provides spawning habitat for California grunion and foraging habitat for shorebirds including the federally threatened western snowy plover.

Some of the aging power plants in this study also provide other environmental benefits. In addition to keeping the mouth of Aqua Hedionda Lagoon open, West Coast Power has been active in efforts to restore eelgrass to the lagoon and to eliminate an invasive alga. Reliant, owner of the Ormond Beach Generating Station, has been working with the California Coastal Conservancy to restore the Ormond Beach wetlands near the facility. Reliant has also put up signs to protect Ormond Beach nesting areas of the California least tern and western snowy plover. In addition, Reliant supports a marine laboratory at its facility that raises abalone.

Some coastal power plant owners (West Coast Power, Duke, and AES) are exploring the possibility of using the water withdrawn for once-through cooling for desalination. It is not known if the use of cooling water for desalination would result in additional intake over the needs of the power plant and subsequent increases of entrainment and impingement impacts.

Inland Power Plants

The Grayson, El Centro, Etiwanda, Olive, Broadway and Coolwater power plants use close-circuit cooling, and water is often circulated several cycles before being discharged. Wastewater discharges are sent to municipal sewer systems, rivers, or to evaporation ponds located on-site. The wastewater discharges can contain high chemical concentrations that were either present in the source water or chemicals introduced to prevent scaling on the interior of pipes.

Wastewater discharges to inland waters are regulated by local RWQCB through the NPDES process, and power plant owners must renew their NPDES permit every five years. The inland power plants for the most part expressed no concerns about their NPDES permits, but as regulations on chemicals become more stringent, the cost of operating the power plant may exceed revenues. One power plant identified upcoming changes in permit limits that would require the purchase of significantly more chemical filters. This additional cost of filtration could perhaps be a factor in decisions to retire units in the future. Innovations in chemical filtration technologies could improve the chances of inland power plants (and other industries) remaining viable in these highly regulated water basins.

Continued operation of these inland facilities does not appear to pose a threat to surrounding ecosystems or to any state or federally listed species. However, enlarging some of these facilities beyond the current footprint could threaten state and/or federally listed and other sensitive species that occur in the region or immediately adjacent to the facility. For example, desert tortoises have been seen immediately adjacent to the Coolwater power plant. Such impacts can be reduced with mitigation and do not typically stop an otherwise lawful activity.

It is highly unlikely that sensitive species concerns or NPDES permit issues would be a reason for any project owner to retire any of the identified inland power plants in the 2004-2008 timeframe covered by the APPS.

Land Use, Socioeconomics and Environmental Justice

The purpose of this section is to examine land use, socioeconomic and environmental justice factors that affect the aging power plants in relation to their community locations. The land use study focused on the facilities that are subject to local plans for reuse or change at their existing sites; community priorities; and other projects related to, or near the aging power plants. Appendix A provides a detailed profile of each generating facility, including a description of the surrounding area, the address, the county, and the local general plan and zoning designations.

The socioeconomic study focused on the aging plants' contributions to the local economy, with respect to the number of operational jobs provided, and property taxes paid.

Land Use

Local Reuse Plans and Community Priorities

Seven aging power plant facilities are subject to local reuse[32] plans or specific local ordinances addressing their future use, with the listing below in geographic order beginning in Northern California. All have waterfront area locations under the jurisdiction of either the San Francisco Bay Conservation and Development Commission (BCDC) or the California Coastal Commission (CCC), with varying community priorities and concerns.

Potrero Power Plant, City/County of San Francisco

The San Francisco Board of Supervisors enacted San Francisco Ordinance 124-01, "Human Health and Environmental Protections for New Electric Generation," on May 21, 2001. The ordinance directed the San Francisco Public Utilities Commission and the Department of Environmental Protections to prepare an energy resource plan that considers all practical transmission, conservation, efficiency and renewable alternatives to fossil fuel electricity generation in the City and County of San Francisco. The ordinance adopted minimum requirements for the protection of human health and the environment for any proposal for new electric generation at the Potrero Power Plant in the southeast sector of the City of San Francisco, and required approval of the Board of Supervisors for any agreement by City officials or departments for new electric generation in southeast San Francisco. The San Francisco ordinance was enacted in response to community concerns related to a May, 2000 proposal for construction of a new 540-megawatt group of generation units at Mirant's Potrero power plant facility. Public concerns included potential impacts such as air quality and public health deterioration, land use conflicts with new housing development in the area, toxics contamination, and environmental justice issues.

In April 2004 the City/County of San Francisco filed an Application for Certification (AFC) with the Energy Commission for a permit to build three new units that would generate 145 MW on a site to be leased from Mirant at the Potrero plant property. That permitting process is in the beginning stage. The proposed project site is further from the waterfront than the existing plant, and is not in the BCDC zone. Community interest is strong, with a number of local public interest and neighborhood groups filing for intervenor status in the permitting proceeding. The Potrero facility and the Hunters Point power plant, noted below, are also discussed in the Environmental Justice section of this report.

Hunters Point Power Plant, City/County of San Francisco

The Hunters Point power plant has been the subject of long standing community environmental concern and controversy, particularly in Southeast San Francisco, which has numerous heavy industrial facilities and the now closed Hunters Point Naval Shipyard. Similar to the Potrero facility, local concerns include air quality, public health, land use conflicts with nearby residential areas, toxics contamination, and environmental justice. The City/County of San Francisco has signed an agreement with the facility's owner, Pacific Gas & Electric (PG&E), calling for the permanent shutdown of the plant as soon as it is no longer needed to sustain electrical reliability. PG&E staff stated they hoped to begin this closure process in 2005, with the actual date dependent on the CA ISO's conclusions on whether the plant would still be needed to maintain local reliability on the San Francisco peninsula.

Morro Bay Power Plant, City of Morro Bay, San Luis Obispo County

Residents of the City of Morro Bay have expressed support for a new, modern Morro Bay Power Plant. In November 2000, city voters approved Ballot Measure Q, a nonbinding advisory measure that asked whether City voters supported in concept the development of a modernized power plant to replace the existing plant, provided it complied with applicable environmental and regulatory standards. At the same time, City voters defeated a companion measure, Ballot Measure P, sponsored by a local citizen's group, which would have required voter approval of any City General Plan amendments regarding construction or modernization of energy facilities in Morro Bay. Duke Energy has proposed demolition of the original Morro Bay power plant sometime after the start of commercial operation of a repowered power plant adjacent to the existing facility, which is still in the Coastal Zone but further away from the waterfront.

Redondo Beach Generating Station, City of Redondo Beach, Los Angeles County

During the last several years, the City of Redondo Beach has had an active, occasionally controversial planning process. The Heart of the City contains the harbor/civic center area, and the Redondo Beach power plant, which is within the coastal zone. These planning efforts have been influenced by public referendums, which have placed the General Plan designations and zoning for the area in a state of flux, with some inconsistencies. Currently the site has a public facility designation with generation use specified, and it has a Public-Generation (P-G) zoning classification. The City adopted a new Specific Plan in 2002 that included the power plant site, but following a referendum that Specific Plan was rescinded.

Public workshops held in May 2004 on the community's vision for the area show continued agreement regarding the need for gradual reuse of industrial sites, including the power plant, for uses such as parks and related open space, and/or commercial and residential development. Any policy or zoning actions such as implementation of a shift to non-industrial uses would require an amendment to the Local Coastal Plan and the City's General Plan. The City staff is currently discussing zoning options and community concerns with the Redondo Beach power plant owner, the AES Corporation. No changes are expected within the timeframe of this study.

Huntington Beach Generating Station, City of Huntington Beach, Orange County

The Huntington Beach Generating Station site is located within the City's Southeast Coastal Redevelopment Plan area. No specific redevelopment projects affecting the power plant are planned at this time, and no changes are expected within the timeframe of this study.
The Southeast Huntington Beach Neighborhood Association has raised some environmental justice concerns about the facility's older units, which are discussed in the Environmental Justice section of this report.

Encina Power Plant, City of Carlsbad, San Diego County

The Encina Power plant site is located within a City of Carlsbad redevelopment zone, although there are no current projects affecting the power plant. The site currently has a Public Utilities (U) designation, indicating that the City may evaluate the location of a utility facility in this area in the future. No changes are expected within the timeframe of this study. Carlsbad's scenic coastal location in San Diego County makes it an attractive area for residential and commercial development, which is sometimes viewed by community decision makers and residents as a more valuable, aesthetic replacement for existing industrial activities. The Encina facility owners noted in a June 9, 2004 public workshop that although they have no plans to close the power plant, they have received several inquiries from developers who are interested in possible purchase of the power plant property.

South Bay Power Plant, City of Chula Vista, San Diego County

The South Bay Power Plant and surrounding property, including storage tanks and an electric transmission switchyard, are included in the Chula Vista Bayfront Master Plan (CVBMP). The CVBMP is a joint planning process involving the City of Chula Vista and the site's owner, the Port of San Diego. Duke Energy operates the South Bay plant under lease from the Port. Under a lease agreement, Duke is tentatively scheduled to dismantle the existing plant by 2009.

The purpose of the CVBMP process is to develop a master plan to create a new, attractive bayfront that complements existing and proposed developments.
A new generating facility has been discussed as part of this process, either at the existing location, or at an adjacent site south of the current location. The switchyard and storage tanks may be moved to the same site, depending on the CVBMP land use planning option chosen. A liquefied natural gas (LNG) facility was once proposed in this southern area, with the site sometimes referred to as the "LNG site."

The Chula Vista City Council, a CVBMP Community Advisory Committee (CAC), and the South Bay Power Plant Working Group (i.e., a public committee including representatives from local business, environmental, and environmental justice advocacy groups within the CVBMP process) supported the concept of an "Energy Utility Zone" in this area called the southern Otay District. CVBMP land use planning Option C, which is the CAC's preferred alternative is shown in Figure 6-12**.** These groups and the overall community appear to be accepting of the idea of a modern power plant as part of the CVBMP, as long as a new facility would have greatly reduced emissions, and elimination of once-through cooling water intake from, and discharge to the San Diego Bay. The planning option of including residential units in the vicinity of a new generation was an item in which the Working Group did not reach consensus, and it is still under discussion.

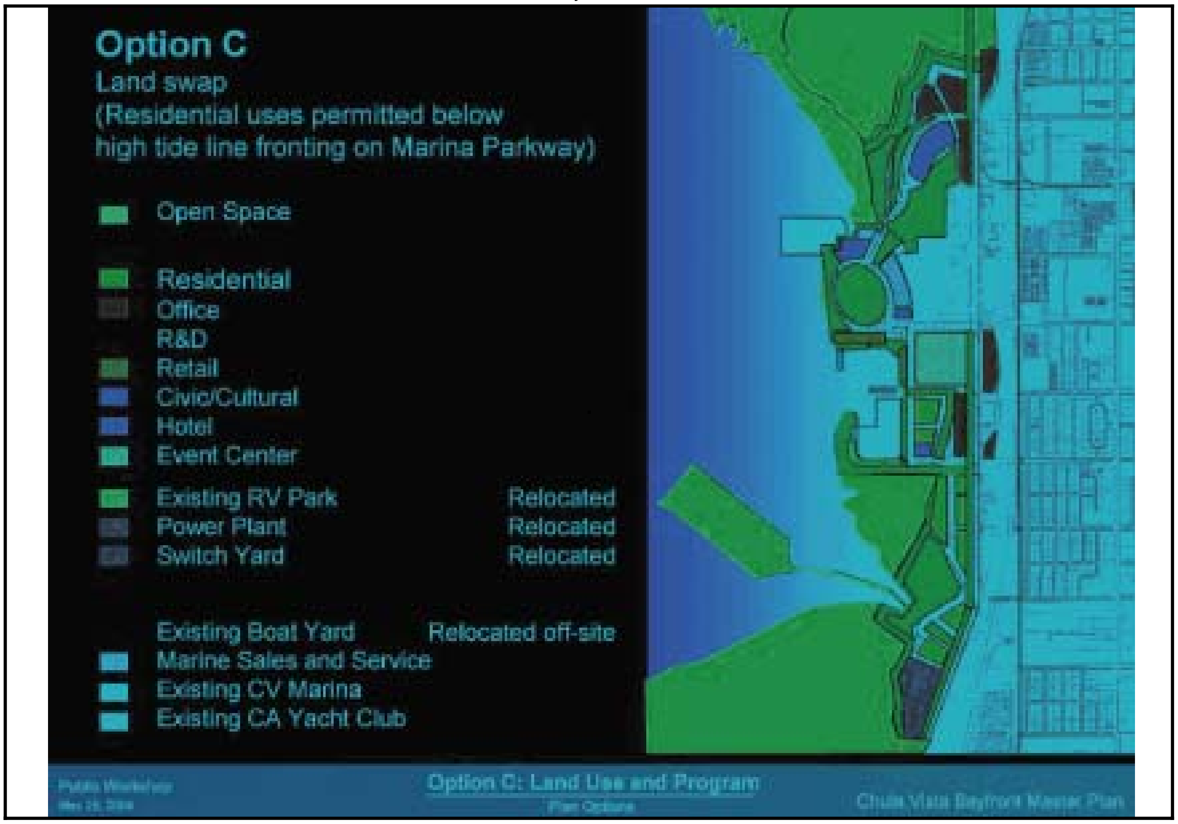
Other Plants with Community Concern

In addition to the seven plants discussed above which are subject to local reuse plans, the Alamitos and Haynes plants in the City of Long Beach, Los Angeles County, are a concern for the surrounding community. Many residents of adjacent neighborhoods would like to see these facilities removed, with the sites used in conjunction with existing wetlands restoration activities in the San Gabriel River watershed. At a minimum, modern facilities with reduced air emissions are preferred. Public health and residential/industrial land use compatibility are also issues, along with an overall residents' priority that the industrial presence in Long Beach should not be intensified. Environmental justice has not been a concern related to these two plants, since they are located in one of Long Beach's most affluent sectors.

On June 24, 2004, the Los Angeles Department of Water and Power (LADWP) released a Notice of Preparation (NOP) initiating an EIR process, for a proposed modernization of its Haynes facility.

Figure 6-12
Land Use

LAND USE - FIGURE 1
Chula Vista Bayfront Master Plan



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION,JULY 2004
SOURCE: Port of San Diego 5/25/2004

Possible Projects Near Aging Power Plants

The major project possibilities are desalination plant proposals that are being considered adjacent to the Moss Landing Power Plant in the community of Moss Landing in Monterey County; the Huntington Beach Generating Station in Orange County, and the Encina and South Bay facilities in San Diego County. Poseidon's proposed desalination facility in Huntington Beach has been controversial, with expressed public concerns regarding biological/marine resource and water quality issues. The City of Huntington Beach has asked for more information in the Environmental Impact Report (EIR) process, and it expects to issue a Draft EIR during Fall 2004.

The Surfrider Foundation has been an active participant in community hearings regarding desalination projects' potential connections to once-through cooling systems at coastal power plants. It stated in the context of Poseidon's proposed Huntington Beach project and the adjacent Huntington Beach power plant, that the desalination facility could provide “an added incentive to keep a potentially dated and dirty plant open.”

Conclusion

Energy Commission staff is not aware of any land use issue that would likely contribute to decisions to retire aging generating units within the time frame of this study.

Socioeconomics

The aging plants under study have typically required 40 to 50 maintenance and operation workers per plant (each plant can have several generating units). In contrast, the Energy Commission’s *2003 Environmental Performance Report* reported that for projects licensed by the Energy Commission after 1996 and online as of December 31, 2002, gas-fired peaker and combined-cycle power plants only needed approximately 2 to 24 operation and maintenance workers. Table 6-6 shows partial data for employment and taxes.

With three companies (five plants) responding to a socioeconomic section of an Energy Commission’s questionnaire, there were a total of 254 operating workers (for four plants) and $755,000 in 2003 property taxes (for two plants). If these plants were retired, then the payroll for 254 operational workers would be lost. Unemployment compensation likely at a lower dollar amount, would replace some operational payroll wages on a short term basis. Additionally, future property taxes would be lost.

El Centro is a repower (has a new prime mover or turbine) and Moss Landing, Morro Bay and El Segundo are replacements (an all-new plant including new technology). For power plants given a repower or replacement, it would result in generally fewer operating workers per MW and a smaller payroll since newer power plants use less operational labor. However, this number may be offset if there were a larger number of higher skilled workers earning more money.

Many variables are involved in estimating whether newer power plants would have a higher assessed value with a repower or replacement. These include the number of MWs and assessment method (cost or market value approach). Staff prefers to use empirical data in order provide this information. So, annual property taxes cannot be estimated. The staff may issue a supplement to this section if additional appropriate and useful data and information become available.

Table 6-6
List of Aging Power Plants

Plant/Owner	Operating Workers	Property Taxes
1*. Contra Costa-Merchant, Mirant		
2*. Humboldt Bay-PG&E	53	$210,000 (for 2003 tax year)
3*. Morro Bay-Merchant, Duke Energy	33	
4*. Moss Landing (For all operating units) - Merchant, Duke Energy	96	
5*. Pittsburg Power-Merchant		
6*. Potrero Power-Merchant, Mirant		$545,000 (for 2003 tax year)
7*. Encina-Merchant		
8*. South Bay Power Plant-Merchant, Duke Energy	72	
9. AES Alamitos-Merchant		
10. Coolwater-Merchant		
11*. El Segundo Power-Merchant, West Coast Power LLC		
12. Etiwanda Generating Station-Merchant		
13*. AES Huntington Beach LLC-Merchant		
14*. Long Beach Generation LLC-Merchant		
15*. Mandalay-Merchant		
16*. Ormand Beach-Merchant		
17*. AES Redondo Beach LLC-Merchant		
18. Grayson-MUNI		N/A MUNIS are exempt from property taxes)
19. El Centro-MUNI		“
20. Haynes-MUNI		“
21*. Scattergood-MUNI		“
22. Broadway-MUNI		“
23. Olive-MUNI		“
Total	**254**	**$754,000**

- Denotes a coastal power plant.

Environmental Justice Issues and Activity

The following facilities are located in communities with a high percentage of people of color and relatively high percentages of poverty. Staff highlighted these facilities, rather than discussing the entire aging power plant list of 66 units, because it was aware of environmental justice activity related to the selected group. These communities also represent areas in the state where the environmental justice issue has been raised by local activists during recent siting procedures for proposed new power plant facilities. Appendix A includes GIS-based maps showing the demographics within a 6-mile radius for all 66 units located at 22 plant facilities.

City/County of San Francisco: Hunter's Point and Potrero Power Plants

The Hunters Point (also known as the Bayview Hunters Point facility) and Potrero power plants have long-been the focus of environmental justice advocates.

In 1994 the San Francisco Energy Company (SFEC) proposed a 240 MW power plant at a site near the existing Hunters Point power plant in the Bayview Hunters Point neighborhood in Southeast San Francisco. Area residents stated that there were frequent air emissions, toxic releases and high noise levels originating from the Hunters Point facility, and discussed the variety of public health problems present in the community. They objected strongly to another power plant in the neighborhood, particularly since the proposed SFEC site was near a residential area and a planned park.

The Innes Avenue Coalition, represented by the Environmental Law Community Clinic at Boalt Law School, UC Berkeley; Morgan Heights Homeowners Association, represented by Golden Gate University Law School Environmental Law and Justice Clinic; the Southeast Alliance for Environmental Justice (SAEJ); the City and County of San Francisco; the San Francisco Department of Public Health; and the San Francisco Housing and Redevelopment Agency; all became intervenors in the Energy Commission's permitting proceedings for the proposed SFEC project. Concerns included air quality and public health impacts, the cumulative impact of multiple heavy industrial facilities with various types of emissions concentrated in Southeast San Francisco, and the plant's location near densely populated communities of low-income people of color.

In 2001, Communities for a Better Environment (CBE) and the City/County of San Francisco became intervenors in Mirant's proposal to repower the Potrero power plant, located in the Potrero neighborhood in Southeast San Francisco. CBE is a statewide environmental health and justice non-profit organization, promoting clean air, clean water and the development of toxin-free communities. CBE provides grassroots activism, environmental research and legal assistance within underserved urban communities. Similar to the issues associated with the existing Hunters Point facility and the proposed SFEC project, both CBE's and the City/County of San Francisco's concerns regarding the Mirant proposal were the public health impacts from air emissions, and the plant's location near densely populated communities of low-income people of color. CBE was also concerned about the cumulative impact of multiple industrial facilities located in Southeast San Francisco.

City of Long Beach: Haynes and Alamitos Power Plants

Staff contacted Communities for a Better Environment (CBE) regarding any issues or activity their organization has had with the Haynes and Alamitos power plants. At this time, staff has had no response from CBE regarding community activity in these areas. Based on the environmental justice demographic screening analysis of a 6-mile radius around each of these projects, there is a substantial population of low-income and people of color surrounding each of these facilities. Staff does not rule out the presence of environmental justice issues in these areas.

City of Chula Vista: South Bay Power Plant (SBPP)

The Environmental Health Coalition (EHC) is a grassroots community-based organization in the San Diego/Tijuana region focused on social and environmental justice issues. EHC has been actively involved for many years in ensuring that the SBPP is closed and replaced. EHC’s concerns regarding the SBPP are the public health impacts from air emissions, the once-through cooling technology on the water quality and marine life in the South San Diego Bay, and the plant’s location near densely populated communities of low-income people of color.

City of Huntington Beach: AES Huntington Beach Power Plant

According to the City of Huntington Beach Planning Department staff contact, community groups, including the Southeast Huntington Beach Neighborhood Association have expressed concerns regarding environmental justice and the long-term presence of the power plant. Their concerns are public health impacts from air emissions, and the plant’s location near densely populated communities of low-income people of color.

City of Pittsburg: Pittsburg Power Plant

According to the City of Pittsburg staff contact, there has been no environmental justice activity from community groups regarding operation of the Mirant Company’s Pittsburg Power Plant.

ENDNOTES

[22] "Fuel-fired" includes all units that draw heat from combustion of a fuel stock, including natural gas, liquid petroleum fuels, coal, biomass and petroleum coke.
[23] The installed in-state fuel-fired capacity is approximate, as some units retired and others were added during the 1996 to 2002 time frame. Note that the 2003 EPR only had data through 2002, but is still illustrative of energy production trends in-state.
[24] Figure 6-1 is from the 2003 Environmental Performance Report.
[25] The split of the California fuel-fired generation for the 2003 EPR into the two groups was also the result of the differences in the availability of air emissions data. The 24,100 MW of load-following units had air emissions data with concurrent generation data readily available, while there was limited emission data matching with generation data for the 11,500 MW of base-load and cogeneration units.
[26] Ozone is not directly emitted, but is a secondary pollutant formed from NOx and ROG in the presence of sunlight.
[27] The emission factor is calculated based on the NOx emissions inventory from CARB, less those emissions accounted for from the load following and aging portions of the fleet, divided by the aggregate MWhr from the base loaded units.
[28] The reason for the exclusion is that both Humboldt and Coolwater are in compliance with local air regulations and district staff indicated that retrofits are not expected to be required for air quality planning purposes. However, retrofits to produce emission reduction credits for sale are always a possibility.
[29] Aging unit retrofit rules: Bay Area Rule 9-11, Monterey Unified Rule 431, San Luis Obispo Rule 429, Venture Rule 59, Mojave Desert Rule 1158, South Coast Rules 1135 and 2009, San Diego Rule 69.
[30] The South Coast Air Quality Management District is currently considering revisions to their NOx "retrofit" rule. If adopted, the proposed changes to the RECLAIM rule could reduce NO_x RECLAIM Trading Credits currently allocated to power plant owners by 5 to 15 percent. The owners of aging power plants located in district indicated that the proposed changes will not be a significant constraint to plant operations in today's electricity market.
[31] Historical emissions are typically based on the most recent 1 to 5 years of operation.
[32] Staff has intentionally not used the term "redevelopment plan" due to the specialized tax mechanisms often associated with local redevelopment plans and zones. The term "reuse plan" is intended to cover the aging plants that are in redevelopment zones and/or are subject to any other local plans or referendums for future use that go beyond the city/county general plan and zoning processes.

GLOSSARY

Ampere – The unit of measure of electric current; specifically, a measure of the rate of flow of electrons past a given point in an electric conductor such as a power line.

Ancillary Services –The services other than scheduled energy that are required to maintain system reliability and meet WSCC and NERC operating criteria. Such services include spinning, non-spinning, and replacement reserves, voltage control, and black start capability.

Annual Fixed-Revenue Requirement (AFRR) – The total annual capital and fixed O&M costs.

Baseload Energy – Electricity that is provided 24 hours a day every month of the year. Refer to Appendix C for more information.

Breaker – A circuit breaker. An automatic switch that stops the flow of electric current in a suddenly overloaded or otherwise abnormally stressed electric circuit.

Bus – Conductors that serve as a common connection for multiple transmission lines.

California Independent System Operator (CA ISO) – The CA ISO is a state chartered, independent, nonprofit corporation that controls the transmission facilities of all participating transmission owning utilities and dispatches certain generation and loads. Its responsibilities include providing non-discriminatory access to the transmission system under its control, managing congestion, maintaining the reliability and security of the transmission grid, and providing billing and settlement charges.

Capacitor – An electric device used to store charge temporarily, generally consisting of two metallic plates separated by a dielectric.

Capacity Factor – A measure of the degree to which the capacity of a generating unit or utility is being used during a certain period of time.

Category Events – The failure of generating and transmission equipment is depicted by the degree or severity of the failure.

> **Category "A" Event** – Normal service; no contingencies.
>
> **Category "B" Event** – An event resulting in the loss of a single element.
>
> **Category "C" Event** – Event(s) resulting in the loss of two or more elements.

Category "D" Event – An extreme event resulting in two or more elements removed or cascading out of service.

CEMS – Continuous Emission Monitoring System.

CFM – Common Forecasting Methodology

Cogeneration – The consecutive generation of thermal and electrical or mechanical energy.

Combined-cycle – An electric generating plant that uses one source of energy to drive two types of turbines; a combustion turbine and a steam turbine.

Congestion – A condition that occurs when there is insufficient capacity (rated in megawatts) on a given transmission path to handle or accommodate the scheduled mix of generation to meet demand.

Interzonal – congestion between zones
Intrazonal – congestion within a zone

Constraints – Physical and operational limitations on the transfer of electrical power through transmission facilities.

Contingency – Disconnection or separation, planned or forced, of one or more components from the electric system.

Control Area – A large geographic area within which a utility, or group of utilities, regulates electric power generation in order to maintain scheduled interchanges of power with other control areas and to maintain the required system frequency.

CPUC – California Public Utility Commission

Demand – The load, expressed in kilowatts or megawatts, that must be served by the generating equipment – and therefore the rate at which electrical energy is delivered to or by a system, or part of a system, at a given instant in time or averaged over any designated interval of time.

Direct Access – The right for a generator to engage in a bilateral contract with a buyer.

Dispatch – The operating control of an integrated electric system to: (i) assign specific generators and other sources of supply to affect the supply to meet the relevant area demand taken as load rises or fall; (ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; (iii) operate interconnections; (iv) manage energy transactions with other interconnected Control Areas; and (v) curtail demand.

Demand Side Management (DSM) – Measures taken by a utility to influence the level or timing of customers' energy demand in order to optimize the use of available utility resources.

DWR – Department of Water Resources

Energy – The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, measured in units of watt-hours or standard multiples thereof, e.g., 1000Wh = 1kWh.

FERC – Federal Energy Regulatory Commission

Forced Outage Rate (FOR) – The percentage of time a power generating unit, transmission line, or other electric facility is forced out of service by equipment failure or some other unexpected event. The forced outage rate excludes planned service shutdowns such as scheduled maintenance.

Frequency Control – Frequency control or frequency regulation is the ability of a Control Area to assist the interconnected system in maintaining 60 Hertz. This assistance can include both turbine governor response and automatic generation control.

GADS – Generating Availability Data System

Generation – Energy delivered from a generator.

Generator – An entity capable of producing energy or ancillary services.

Greater Los Angeles Basin – Defined here to be Los Angeles, Ventura, Orange and western Riverside Counties.

Grid Operator – The entity responsible for ensuring access to the transmission system and the deliverability of scheduled energy. Also known as control area operator. California's grid operators are the CA ISO, LADWP, SMUD and Imperial Irrigation District.

Heat Rate – The amount of energy input to an electric generator required to obtain a given value of energy output. Usually expressed in terms of British Thermal Units per kilowatt hour (Btu/kWh).

Hour-Ahead Market – The electric power futures market that is established one hour before delivery to end-use customers.

In-load pocket generation – If all the transmission feeding an area (pocket) is congested then any remaining load must be fed by generation located within that area.

Investor Owned Utility (IOU) – An electric or gas utility company that is owned by stockholders (who may or may not be customers of the utility), such as Pacific Gas & Electric and San Diego Gas & Electric.

CA ISO Controlled Grid – The system of transmission lines and associated facilities of the participating transmission owning utilities that have been placed under the CA ISO's operational control.

LADWP – Los Angeles Department of Water and Power

LAR – Local Area Reliability

Load – An end-use device of an end-use customer that consumes power. Load should not be confused with demand, which is a measure of power that a load receives or requires.

Load Centers – Areas where large amounts of electricity are consumed, generally used to indicate a city or large metropolitan area.

Load-Following Energy – Electricity provided to meet increasing demand over the course of the day. Refer to Appendix C for more information.

LARS (Process) – Local Area Reliability Services. The LARS process determines the amount of RMR capacity needed by the CA ISO to ensure local reliability.

LRA – Local Reliability Area. Nine areas designated by the CA ISO as areas requiring RMR units in order to provide reliable service and prevent price gouging. In this study, LRAs also expand to include any area that, following selected aging unit requirements, could experience service interruptions after the failure of one or two major components.

LSE Load-Serving Entity – Any provider of wholesale energy to retail consumers, including utilities, marketers and direct access providers.

Must-Offer (Order, Requirement) – A requirement imposed by FERC in 2001 upon generators to offer energy or capacity into a day-ahead or real-time market. While this requirement exempts selected classes of generators (e.g., hydro generators), it remains in force as of this writing.

Must-Offer Waiver – Agreement between the CA ISO and a generator that the latter does not have to offer energy or capacity into an CA ISO market for some specified period.

MW – Megawatt

NERC – North American Electric Reliability Council

Nomogram – A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and WECC operating criteria.

Peaking Capacity – Capacity used to serve peak demand. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20 percent. See Peaking energy.

Peaking Energy – Electrical energy supplied during a period of relatively high system demands: 6:00 am to 10:00 pm Monday through Sunday excluding holidays.

PG & E – Pacific Gas & Electric

Post Transient Reactive Margin – Reactive power (MVARS) must be available at all load buses to prevent voltage collapse. The amount of reactive power over and above the minimum amount required to avoid voltage collapse is the reactive margin. The amount available after a disturbance has stabilized (post transient period) is the post transient reactive margin.

Power Flow – A generic term used to describe the type, direction, and magnitude of actual or simulated electrical power flows on electrical systems.

Publicly Owned Utility (POU) – An electric or gas utility that is owned by its customers, such as Sacramento Municipal Utilities District (SMUD) or Los Angeles Department of Water & Power (LADWP).

Qualifying Facility (QF) – A generating facility that meets the requirements of federal law for mandatory purchases by investor-owned utilities. To be classified as a QF, the plants generally must cogeneration facilities, generating at least two types of energy (usually electricity and steam), or be renewable energy generators.

Resource Adequacy Requirement (RAR) – Requirement imposed on a load-serving entity to procure capacity equal to some share of peak needs at some point prior to peak demand (e.g., CPUC requirement of IOUs that they procure 90% of peak summer capacity needs 12 months in advance).

Real Time Market – The competitive generation market controlled and coordinated by the CA ISO for arranging real-time imbalance power.

Reliability – The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse affects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – Adequacy and Security.

Local – This is defined as actions or requirements addressing the provision of electric service in areas where the failure of a relatively few number of large components (generally, a combination of two component failures, such as the loss of a major transmission intertie or large generating unit) could have a significant effect on power quality. This would include the nine “local reliability areas” (LRAs) formally designated by the CA ISO as areas requiring RMR units in order to provide reliable service and prevent price gouging.

System – the overall control area

Zonal (or Regional) – refers to actions or requirements that affect service to very large load centers that are somewhat isolated from each other by the limited amount of power that can be transferred from one to the other because of transmission system constraints. These three areas loosely follow the geographical definitions of Northern, Central and Southern California.

Reliability Must-Run (RMR) contracts – Contracts to ensure that the minimum generation (number of units or MW output) required by the CA ISO are on line to maintain system reliability in a local area and mitigates the possibility of market power behavior.

Reserve Margin – The difference between an electric utility’s system capability and anticipated peak load during a specified period, measured either in megawatts or as a percentage of peak load.

Operating – That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Planning – The difference between a Control Area’s expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Renewable Portfolio Standard (RPS) – Requirement that some percentage of energy delivered by a load-serving entity come from a renewable energy source.

SCE – Southern California Edison

SCIT– Southern California Intertie Transmission

SCR – Selected Catalytic Reduction

SDG & E – San Diego Gas & Electric

Seller – An entity that produces or arranges for the production of electrical energy.

Spot Market – The competitive generation market controlled and coordinated by the Power Exchange (PX).

Stranded Costs – The portion of the costs and obligation that utilities incurred to serve customers under the existing regulatory system that cannot be economically recovered in a deregulated system. Contributing to stranded costs are stranded assets (e.g., generating facilities that produce electricity at above-market costs), the non-depreciated portion of a utility's nuclear power plant capital costs, contract payments to qualifying facilities (QFs), and other items.

Transmission Congestion – The condition that exists when market participants seek to dispatch generation in a pattern which would result in power flows that cannot be physically accommodated by the transmission system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based upon requested schedules that cannot be accommodated.

US EPA – United States Environmental Protection Agency

VAR Support – See Voltage support.

Voltage Support – Services provided by generating units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.

WSCC – Western Electricity Coordinating Council

ACRONYMS

AB – Assembly Bill

ALJ – Administrative Law Judge

CA ISO – California Independent System Operator

CCSF – City and County of San Francisco

CEQA – California Environmental Quality Act

CERTS – Consortium for Electric Reliability Technology Solutions

CFE – Comisión Federal de Electricidad

COI – California-Oregon Interface

COTP – California Oregon Transmission Project

CPCN – Certificate of Public Convenience and Necessity

CPUC – California Public Utilities Commission

DOE – U.S. Department of Energy

DOI – U.S. Department of the Interior

DPV2 – Devers-Palo Verde 2

DSM – Demand-Side Management

DWR – California Department of Water Resources

EAP – Energy Action Plan

EIS – Environmental Impact Statement

EIR – Environmental Impact Report

ESI – Energy System Integration

FERC – Federal Energy Regulatory Commission

Hi – High demand scenario

HPPP – Hunters Point Power Plant

IEPR – Integrated Energy Policy Report

IID – Imperial Irrigation District

IOU - Investor-owned Utility

JMTP – Jefferson-Martin Transmission Project

kV – Kilovolt

kWh – Kilowatt-hour

LADWP – Los Angeles Department of Water and Power

LBNL – Lawrence Berkeley National Laboratory

LMP – Locational Marginal Price

LRA – Local Reliability Area

ML – Most likely demand scenario

MW - Megawatt

MWh – Megawatt hour

NP 15 – North of Path 15

NEPA – National Environmental Protection Act

NERC – North American Electric Reliability Council

OIR – Order Instituting Rulemaking

ORA – Office of Ratepayer Advocates

PACI – Pacific AC Intertie

PDCI – Pacific DC Intertie

PG&E – Pacific Gas and Electric

PIER – Public Interest Energy Research

POU – Publicly-owned Utility

PPP – Potrero Power Plant

PRC – Public Resources Code

PRR – Project Rating Review

PWG – Planning Work Group

QF – Qualifying Facility

R&D – Research and Development

RAS – Remedial Action Scheme

RMR – Reliability Must Run

ROW – Right-of-Way

RPS – Renewable Portfolio Standard

RTO – Regional Transmission Organization

SB – Senate Bill

SCE – Southern California Edison

SDG&E – San Diego Gas and Electric

SMUD – Sacramento Municipal Utility District

SONGS – San Onofre Nuclear Generating Station

SP 15 – South of Path 15

SPS – Special Protection Scheme

SSG-WI – Seams Steering Group – Western Interconnection

STEP – Southwest Transmission Expansion Plan

SWPL – Southwest Power Link

SWRTA – Southwest Regional Transmission Association

WECC – Western Electricity Coordinating Council, formerly the WSCC – Western System Coordinating Council

WSCC - Western System Coordinating Council

Western – Western Area Power Administration

WOR – West of (Colorado) River

WRTA – Western Regional Transmission Association

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