DOCKETED

Docket Number:	12-AFC-03
Project Title:	Redondo Beach Energy Project
TN #:	201113
Document Title:	City of Redondo Beach Staff Report on rezoning power plant area
Description:	City staff report on the proposed rezoning fo the power plant area. Report cites blighting in the harbor area and attributes blight to power plant presence.
Filer:	James A Light
Organization:	Building A Better Redondo
Submitter Role:	Intervenor
Submission Date:	11/5/2013 7:29:41 AM
Docketed Date:	11/5/2013

redondo BEACH

STAFF REPORT
REDONDO BEACH PLANNING DEPARTMENT

AGENDA ITEM: 15 (PUBLIC HEARINGS)

HEARING DATE: MAY 20, 2004

APPLICATION TYPE: AMENDMENTS TO THE GENERAL PLAN, HARBOR/CIVIC CENTER SPECIFIC PLAN, COASTAL LAND USE PLAN AND ZONING ORDINANCE FOR THE COASTAL ZONE

CASE NUMBER: (PC) 04-40

APPLICANT'S NAME: CITY OF REDONDO BEACH

APPLICANT'S REQUEST AS ADVERTISED:

The Planning Commission will consider recommending to the City Council adoption of amendments to the Land Use element of the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone applicable to all industrial uses in the Coastal Zone. The amendments propose establishing a "Coastal Reserve" for large industrial areas in the Coastal Zone that are appropriate for reuse for non-industrial uses and where the precise future uses have not yet been determined. The proposed amendments would provide for the amortization and removal of non-conforming uses and structures in areas designated as a Coastal Reserve. The AES Redondo Generating Plant site is proposed to be designated as a Coastal Reserve, and the amendments would provide that the existing generating plant uses and structures would be considered non-conforming uses and structures.

DEPARTMENT'S ANALYSIS OF REQUEST:

A community planning process has been under way to transform and revitalize the portion of the city's Coastal Zone formerly known as "Heart of the City" into a high quality resident and visitor serving area containing parks and recreation areas and/or commercial, residential and civic uses. Such a transformation is not feasible unless large scale industrial uses that have a blighting impact on the area are removed.

The largest existing industrial sites appropriate for nonindustrial uses in the future include the approximately 2.6 acre site just west of the Post Office and east of N. Francisca Avenue, the 1.6 acre City Maintenance Yard, and the approximately 50 acre AES Redondo Generating Plant site. The power generating plant is the major blighting influence in this area due to the size of the site, the visual impact of the use on the surrounding area, and undesirable environmental impacts of the use that effect the public health, safety, and welfare. The transformation of this portion of the city depends on removal of the power generating plant and reuse of the site for other purposes.

EXISTING LAND USE POLICIES

On March 19, 2002 the City Council adopted the Heart of the City Specific Plan and corresponding amendments to the General Plan, Coastal Land Use Plan, and Zoning Ordinance establishing new land use policies and standards. In response to a referenda petition, on June 4, 2002 the City Council repealed the Specific Plan and General Plan amendments and reinstated the Harbor/Civic Center Specific Plan. However, the amendments to the Coastal Land Use Plan and Zoning Ordinance that were not subject to the referenda petition could not be repealed by the City Council without a new public hearing process.

The past actions have created inconsistencies between the various plans that are not yet resolved, but that are intended to be resolved by the planning process underway. Land uses may not be approved unless consistent with each of the plans. Furthermore, the Coastal Commission will not approve any development approved by the City that is inconsistent with the Land Use Plan certified by the Coastal Commission in 2001 prior to the "Heart of the City" process.

Recognizing the inconsistencies and the process underway to resolve them, the City Council enacted a moratorium on approval of discretionary land use approvals within the former "Catalina Avenue Redevelopment Project area" (including the power plant site and other industrial sites). The moratorium has been in place since September 2, 2003 and may be extended once more for an additional year.

The various plans do have one thing in common: they all allow for and envision reuse of sites containing industrial and power plant uses for non-industrial use. However, the future uses permitted on these sites have not yet been determined.

Certified Coastal Land Use Plan

The Coastal Zone includes the portion of the city west of Pacific Coast Highway. An amended Coastal Land Use Plan (LUP) was certified by the Coastal Commission on May 7, 2001 that was determined to be consistent with the policies of the Coastal Act, including the protection and provision of public access; the protection and encouragement of facilities that provide public recreation; the protection of the marine environment; the protection of the scenic and visual quality of coastal areas; and the reservation of land along and near the coast for priority uses, including coastal dependent, visitor serving uses and recreation.

The land use section of the certified LUP (as contained in Resolution No. CC-0104-20, adopted on April 3, 2001) recognizes that a planning process is underway to consider new land use and development standards for the AES Redondo Generating Plant site, the Harbor/Pier area, and the North Catalina Corridor. In the meantime, the certified LUP retains an Industrial designation for several properties, including the power plant site, the mini-storage property abutting the power plant to the east, the topsoil property at 750 N. Francisca Avenue west of the Post Office, and the City Yard on N. Gertruda Avenue east of Catalina Avenue. The industrial category in the LUP is described as "a relatively light industrial district intended to accommodate small to medium-size industrial operations that do not result in obnoxious output that would detrimentally impact surrounding districts."

General Plan and Harbor/Civic Center Specific Plan

Power generating plant site.

The AES Redondo Generating Plant (formerly the Southern California Edison Generating Plant) is designated as "P" (Public) in the General Plan. Policy 1.46.1 of the General Plan permits governmental, facilities, parks and recreation, public safety facilities, cultural uses, schools, and public utility and infrastructure uses in such areas. Policy 1.46.2 allows for the reuse of public and utility properties and facilities for private use and establishes criteria for determining the type and intensity of future uses.

The Harbor/Civic Center Specific Plan was adopted in conjunction with existing General Plan policies and is consistent with the existing General Plan. The specific plan provides that public utility land uses are permitted on the power plant site subject to a Conditional Use Permit. The Harbor/Civic Center Specific Plan also identifies this site to be appropriate for reuse in the future and recommends establishing a new plan for future non-industrial use of the site. The specific plan states:

> "In anticipation of the end of the useful economic and physical life of the Southern California Edison Company Generating Plant, take necessary steps within an appropriate time frame to establish plans for the comprehensive reuse of the site for nonindustrial uses. Said plan shall demonstrate compatibility with the stated objectives of the General Plan and this Specific Plan for the character and function of surrounding areas; be designed to be physically well-integrated with surrounding areas and circulation patterns; and provide for a high quality of design and amenities in recognition of the site's prominent and integral location within the city."

The specific plan identifies the generating plant as a nuisance that results in significant adverse environmental impacts. The specific plan states:

> "In consideration of the various lower and moderate-density commercial and residential land uses surrounding the Zone, implement, as possible and financially feasible any reasonable means, methods, or ways of eliminating entirely or reducing, as much as possible, the range of significant adverse environmental impacts that are created through operation of the Southern California Edison Plant (these measures could include, but are not limited to: external noise walls or fences, landscaping shields and buffering, additional internal noise insulation or air quality filtering systems, etc.)."

Other Industrial Uses

Other industrial uses in the Coastal Zone are on sites smaller than three acres including:

- the topsoil property at 750 N. Francisca Avenue, designated I-2 Industrial in the General Plan. Light industrial use is permitted under both the General Plan and the Harbor/Civic Center Specific Plan;
- the mini-storage site abutting the east boundary of the power generating plant site, designated C-5 in the General Plan. Commercial and light industrial use, including mini-storage, is permitted under both the General Plan and the Harbor/Civic Center Specific Plan;
- the City Maintenance Yard east of Catalina on N. Gertruda Avenue, designated C-5 in the General Plan. Commercial uses and governmental facilities are permitted under both the General Plan and the Harbor/Civic Center Specific Plan.

Amended Coastal Land Use Plan and Zoning Ordinance for the Coastal Zone

In conjunction with the former Heart of the City plan, amendments were adopted to the Coastal Land Use Plan including some provisions that cannot be implemented due to inconsistency with the General Plan and because the amendments have not been certified by the Coastal Commission. Portions of the zoning ordinance adopted for the Coastal Zone also cannot be implemented within the former Heart of the City area for the same reason. The most significant inconsistency is as follows:

- the amended LUP and zoning ordinance permit residential use in the former "Heart of the City" area, and do not permit commercial and industrial uses in much of the Catalina Avenue corridor;
- the General Plan and Harbor/Civic Center Specific Plan permit commercial and industrial uses in the former "Heart of the City" area, but do not permit residential uses.

The western portion of the AES Redondo Generating Plant is designated as Waterfront District and the eastern portion is designated as Catalina Corridor in the amended LUP and zoning ordinance. The other industrial uses east of the power generating plant (the topsoil site, mini-storage site, and City Yard) are all designated Catalina Corridor.

The Waterfront District permits uses such as marina-related commercial services and facilities, parks, recreation and open space, lodging, offices, theaters, commercial recreation, and residential. The Catalina Corridor District permits uses such as residential, offices, and civic uses. Both districts specify various open space requirements and limit future power generating facilities to a portion of the existing site (either the area containing Units 7 and 8 and Tanks 2-4 or alternatively the area containing Units 5-8).

PROPOSED PLANS

The City contracted with the University of Southern California (USC) Center for Economic Development for facilitation services associated with a community consensus building process related to the former "Heart of the City" study area. This process included numerous community meetings from September 2003 through March 2004. The process resulted in two alternative visions: "Heart Park" proposes the power generating plant site and surrounding area be developed as park and open space, while the "Village Plan" proposes a mix of park and open space, residential, commercial, and civic uses. The City Council at its May 4, 2004 meeting directed staff to prepare recommendations for placing an advisory ballot measure on these two alternative visions for the November 2, 2004 election.

COASTAL RESERVE

It is proposed that the General Plan authorize the designation of industrial areas within the Coastal Zone as a "Coastal Reserve". It is intended that this designation be applied to large industrial areas that have been determined to be appropriate for non-industrial urban development and/or parks, recreation and open space in the future, and where the precise future uses have not yet been determined. This designation is consistent with the policies of the Coastal Act to reserve land in the Coastal Zone for priority uses, including coastal dependent, visitor serving uses and recreation.

New development would not be permitted in the Coastal Reserve prior to the approval of necessary amendments to the General Plan, Specific Plan, Coastal Land Use Plan, and Zoning Ordinance ensuring consistent land use policies relating to future uses. Existing industrial uses in the Coastal Reserve would be declared non-conforming uses that would be required to be discontinued and removed according to schedules in the Zoning Ordinance.

It is recommended that a minimum of a 5-acre site be used as the threshold for considering designation of a Coastal Reserve, and that a Coastal Reserve be designated for the power generating plant site. There is substantial evidence that the power generating plant has significant nuisance impacts on a widespread surrounding area and that continuation of the plant would make infeasible the implementation of plans consistent with the proposed community visions. There is no evidence indicating a similar level of impacts for other industrial uses on smaller sites in the area.

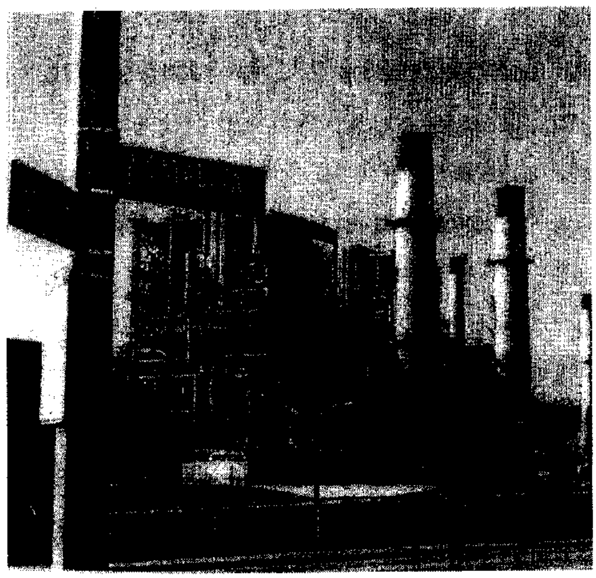
Power generating plant site.

The existing land use policies and proposed new planning visions for the former "Heart of the City" area share one thing in common: they all envision reuse of the power generating plant site for non-industrial use in the future. Due to its dominance and nuisance impacts on the surrounding area the power generating plant site is appropriate for designation as a Coastal Reserve.

The first power generation plant was opened in 1905 in this general location by Henry Huntington to power his Pacific Electric Railway and to open nearby land for residential development. After World War II, the Southern California Edison (SCE) Company constructed a new state-of-the-art power plant vital to the suburbanization of the South Bay and region. Today, most of the power plant site is no longer used to generate power.

The plant is located in an area that was once the industrial corridor of the City. However, now the area south of Beryl Street and area east of Catalina Avenue is developed with multiple-family residential uses. To the west of the plant are the marinas and harbor area serving both residents and visitors. East of the plant, the Catalina Avenue corridor includes a hodge podge of commercial and industrial uses, many of which are neglected and blighted facilities.

In April 1998, SCE sold the Redondo Generating Station to the AES Corporation of Arlington, Virginia. AES purchased three plants from SCE and currently owns more than 100 plants worldwide. The acquisition of the Redondo Generating Station was based on the assumption that the capacity of the plant could be increased, while making surplus land available for redevelopment. Initially, AES removed the stacks associated with the decommissioned portion of the power plant as evidence of their commitment to proceed with reuse of a portion of the site. AES has continued to hold the property for development and has never submitted an application to the California Energy Commission for the expansion, upgrading or modernization of the energy production capacity of the site.



The generating plant is not currently designated as RMR (Run Must Run) which means it is not under contract to the California Independent System Operator (ISO) to provide guaranteed power production. Furthermore, the generating plant units are on the ISO list of units with reliability concerns (as indicated in the attached "Proposed List of Plants for APPS Analysis" prepared by the California Energy Commission).

The AES Redondo generating plant has been included in a study group for the Aging Power Plant Study being undertaken by the California Energy Commission (CEC) to examine the reliability and resource implications of California's reliance on older, inefficient power plants (see attachment). The CEC staff briefing on this study states:

> "The staff is also developing criteria for identifying particular generating units where increasing operations of the units or extending their lifetimes could have unwanted environmental effects. In applying the criteria, the staff will consider four basic factors related to environmental performance: air emissions and emission rates; cooling water sources and treatment of waste water discharge; indigenous flora and fauna and related habitat and wetlands; and community plans for reuse of the power plant site." (Source: "Staff Briefing Paper on Aging Power Plant Study", California Energy Commission, March 2004)

The CEC is concerned that continued operation of obsolete power plants has adverse environmental impacts on air emissions, water quality, and biological resources. New generating plants no longer need to be located near ocean cooling water sources, and therefore obsolete plants located in urbanized areas surrounded by residential development can be replaced by generating plants with reduced impacts located away from coastal communities.

The AES generating plant includes stacks 200 feet high and other structures that visually dominate and have a blighting impact on surrounding properties. Data on residential property values in the area provide evidence of this adverse economic influence (see attachment). There is no doubt that these impacts are primarily attributable to the power generating plant and these impacts would remain even if the smaller industrial uses were removed. Furthermore, due to high coastal land values, reuse of the power plant site would almost certainly lead to reuse of other industrial sites, but reuse of the other industrial sites would have no similar impact on reuse of the power generating plant site.

The continuation of the power generating plant also harms the quality of life for residents by blocking visual and public access connections to the waterfront. This is inconsistent with Coastal Land Use Plan policies intended to enhance public access to the waterfront.

The power plant also harms the public health and quality of life due to air emissions, noise (including low frequency noise impacts identified in the 1992 EIR for the General Plan), impacts on the marine environment with cooling water intake and heated water discharge, and contaminated soils and groundwater. The site is contaminated by fuel-related hydrocarbons including the storage tank areas, fuel pumping area, oil/gas separator area, power generating areas, waste storage area, switchyard areas and solvent wash area. In addition, a variety of metal and solvent contaminants are present due to leakage from the retention basin areas that collect wastewater from power plant boiler cleaning procedures and from general cleaning wastes at the facility. The soil and groundwater contaminants include arsenic, vanadium, and nickel.

Amortization

Under California law, cities may require removal of existing non-conforming structures after a reasonable phase out period, referred to as an amortization period, based upon the city's conclusion that the harm from continued use of the structure outweighs the harm to the property owner. Adoption of an appropriate amortization period is required to take into account the remaining useful economic life of the use and other relevant economic factors such as investment in the use.

The proposed zoning amendments would allow for amortization of nonconforming uses in a Coastal Reserve and provide that the power generating plant is a non-conforming use. An amortization period is recommended to require that the power generating plant be discontinued by January 1, 2018 and removed by January 1, 2019. This schedule is based on the remaining useful life and other economic information contained in reports prepared for AES in 2003 and that were submitted by AES to the State Board of Equalization (see attachments). These public records, as discussed in an attached memo from The Davis Company, confirm that the above period is sufficient to enable operation of the plant for its remaining useful life, and to enable recoupment of investment.

The City is not proposing an amortization period shorter than the remaining useful life of the generating plant. However, it should be noted that the California courts have been willing in some cases to allow local governments to set an amortization period which is less than the remaining useful life of the nonconforming use and allow termination of the use, if the use is detrimental to public health or safety (*Livingston Rock and Gravel Co. v. County of Los Angeles*, 1954; *People v. Gates*,1974).

As a non-conforming use, the power generating plant is permitted to be maintained and repaired until the end of the amortization period. The recommended zoning amendments also permit the power generating plant to make any improvements ordered by the Public Utilities Commission, the South Coast Air Quality Management District, the Regional Water Quality Control Board, or other federal, state, or regional agency having jurisdiction to make and enforce orders to meet water quality, air emission, and other requirements. Expansion of a non-conforming use is not permitted.

Environmental Status:

The initial study prepared for the proposed amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Coastal Zoning Ordinance concluded that the amendments would not have a significant effect on the environment, and therefore a Negative Declaration should be prepared pursuant to the California Environmental Quality Act of 1970, as amended. The Initial Study was noticed and circulated for public review and comment from April 22, 2004 to May 13, 2004, pursuant to Chapter 3, Title 10 of the Municipal Code.

Department's Recommendation:

It is recommended that the Planning Commission adopt the following resolution by title only, waiving further reading:

A RESOLUTION OF THE PLANNING COMMISSION OF THE CITY OF REDONDO BEACH RECOMMENDING THAT THE CITY COUNCIL:

(1) ADOPT NEGATIVE DECLARATION NO. 04-04; AND

(2) AMEND THE GENERAL PLAN, HARBOR/CIVIC CENTER SPECIFIC PLAN, COASTAL LAND USE PLAN, AND ZONING ORDINANCE FOR THE COASTAL ZONE TO:

A) DESIGNATE LARGE INDUSTRIAL AREAS IN THE COASTAL ZONE THAT ARE APPROPRIATE FOR REUSE FOR NON-INDUSTRIAL DEVELOPMENT AND/OR PARKS, RECREATION AND OPEN SPACE AS COASTAL RESERVES;

B) PROVIDE FOR DISCONTINUATION AND REMOVAL OF INDUSTRIAL USES INCLUDING POWER GENERATING FACILITIES IN AREAS DESIGNATED AS COASTAL RESERVES; AND

C) TO DESIGNATE THE AES REDONDO GENERATING PLANT SITE AS A COASTAL RESERVE AND TO PROVIDE THAT ALL EXISTING GENERATING PLANT USES AND STRUCTURES ON THE SITE ARE NON-CONFORMING USES AND STRUCTURES THAT SHALL BE DISCONTINUED BY JANUARY 1, 2018 AND REMOVED BY JANUARY 1, 2019.

Prepared by:

Randy Berler

Randy Berler
Interim Planning Director

Attachments:

Recommended resolution
Negative Declaration No. 04-04
"AES Residual Land Value and Cost Recovery" (memo), The Davis Company, May 10, 2004
"Indication of Negative Impact of AES Plant on Property Values in Nearby Areas" (memo), Regan Associates, May 10, 2004
"Staff Briefing Paper On Aging Power Plant Study", California Energy Commission, March 2004
"Proposed List of Plants for APPS Analysis", California Energy Commission, 2004
"Aging Natural Power Plants in California", California Energy Commission, July 2003
"An Appraisal Report Prepared for AES Redondo Beach, LLC", The Delahooke Appraisal Company
"AES Redondo Beach Generating Station Fair Market Value Report as of January 1, 2003" prepared by AUS Consultants

RESOLUTION NO.

A RESOLUTION OF THE PLANNING COMMISSION OF THE CITY OF REDONDO BEACH RECOMMENDING THAT THE CITY COUNCIL:
(1) ADOPT NEGATIVE DECLARATION NO. 04-04; AND
(2) AMEND THE GENERAL PLAN, HARBOR/CIVIC CENTER SPECIFIC PLAN, COASTAL LAND USE PLAN, AND ZONING ORDINANCE FOR THE COASTAL ZONE TO:

- **A) DESIGNATE LARGE INDUSTRIAL AREAS IN THE COASTAL ZONE THAT ARE APPROPRIATE FOR REUSE FOR NON-INDUSTRIAL DEVELOPMENT AND/OR PARKS, RECREATION AND OPEN SPACE AS COASTAL RESERVES;**
- **B) PROVIDE FOR DISCONTINUATION AND REMOVAL OF INDUSTRIAL USES INCLUDING POWER GENERATING FACILITIES IN AREAS DESIGNATED AS COASTAL RESERVES; AND**
- **C) TO DESIGNATE THE AES REDONDO GENERATING PLANT SITE AS A COASTAL RESERVE AND TO PROVIDE THAT ALL EXISTING GENERATING PLANT USES AND STRUCTURES ON THE SITE ARE NON-CONFORMING USES AND STRUCTURES THAT SHALL BE DISCONTINUED BY JANUARY 1, 2018 AND REMOVED BY JANUARY 1, 2019.**

WHEREAS, the Planning Commission of the City of Redondo Beach held a public hearing on the 20th day of May, 2004, at which time all interested parties were given an opportunity to be heard and to present evidence;

WHEREAS, notice of the time and place of the public hearing was provided by: publication according to law in The Beach Reporter, a newspaper of general circulation in the City first class; mailing of notices to the owners of the subject property proposed for designation as a Coastal Reserve and to all property owners within 300 feet of the proposed Coastal Reserve; and posting notice along the street frontage of the proposed Coastal Reserve;

NOW, THEREFORE, THE PLANNING COMMISSION OF THE CITY OF REDONDO BEACH FINDS AS FOLLOWS:

1. In compliance with the California Environmental Quality Act of 1970, as amended (CEQA), and State and local guidelines adopted pursuant thereto, the City of Redondo Beach prepared an Initial Study of the environmental effects of the proposed amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone, and Negative Declaration No. 04-04 has been prepared in compliance with CEQA and the State and local guidelines.

2. The proposed amendments are necessary to discontinue and remove large-scale industrial uses, including power generating uses, that have a blighting impact within the Coastal Zone and that are appropriate for reuse for non-industrial uses in the future.

3. The amortization schedule set forth for the AES Redondo Generating Plant site in the proposed zoning amendments constitutes a reasonable balance between the competing interests of the community and individual monetary burden and is supported by documents filed with the State Board of Equalization relating to the valuation of the site.

4. The designation of Coastal Reserves and discontinuation and removal of non-conforming industrial uses and structures in Coastal Reserves is necessary to protect the public health and welfare.

5. The proposed amendments will have a "de minimis" impact on Fish and Game resources pursuant to Section 21089(b) of the Public Resources Code.

NOW, THEREFORE, THE PLANNING COMMISSION OF THE CITY OF REDONDO BEACH, DOES HEREBY RESOLVE AS FOLLOWS:

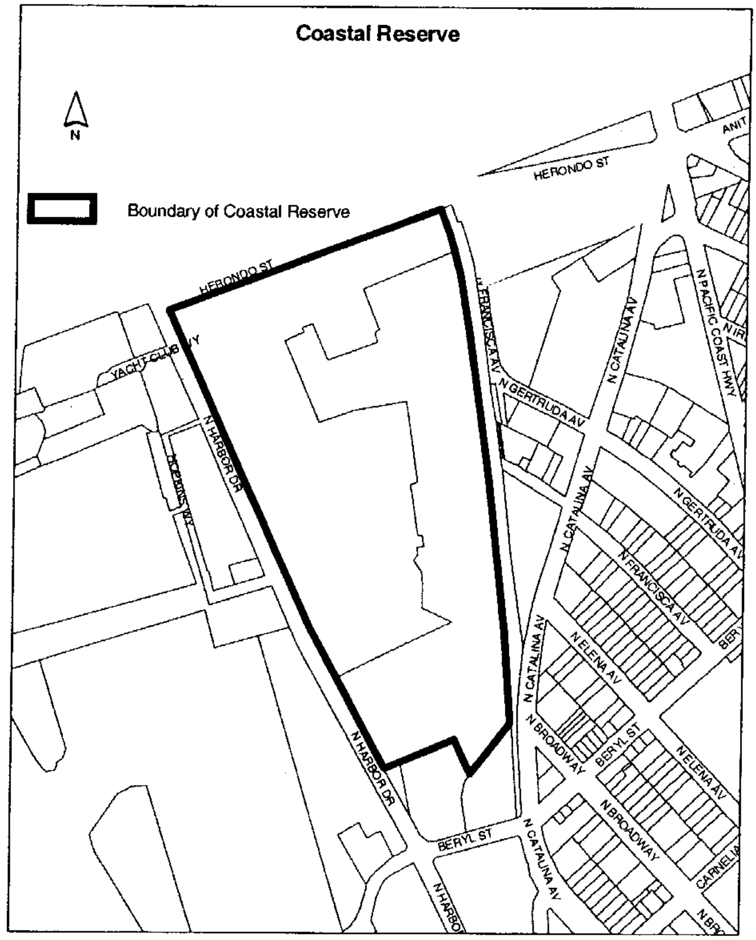
SECTION 1. The Planning Commission recommends that the City Council concur in the above findings and adopt Negative Declaration No. 04-04.

SECTION 2. The Planning Commission recommends that the City Council add Policies 1.52.4 through 1.52.6 to the Land Use element of the General Plan to read as follows (additions indicated by underline):

1.52.4 The Coastal Reserve designation identifies large industrial areas of at least five (5) or more acres that are appropriate for reuse for non-industrial urban development and/or parks, recreation and open space in the future, and where the precise future uses have not yet been determined. The preparation of any necessary General Plan, Specific Plan, Coastal Land Use Plan, and Zoning amendments shall precede any new development in the Coastal Reserve.

1.52.5 Until such time as the power generating plant on the AES Redondo Generating Plant site is discontinued and removed, the site shall be designated as a Coastal Reserve. All existing generating plant uses and structures on the AES Redondo Generating Plant site shall be considered non-conforming uses and structures.

1.52.6 In the Coastal Reserve, any nonconforming industrial use and structures used for such industrial use, and any existing and former power generating plant facilities (including all facilities, structures, equipment, and storage, whether currently utilized or not) shall be discontinued and removed subject to standards and schedules developed in the Zoning Ordinance, except that the city may approve reuse of structures incorporated into a new use approved by the city.



SECTION 3. The Planning Commission recommends that the City Council amend the text for Catalina Avenue Sub-area, Zone 2, of the Harbor/Civic Center Specific Plan to read as follows (additions indicated by underline, excluding bold underline of existing section headings), deletions indicated by ~~strikethrough~~):

Land Use/Development Policies

Until such time as the power generating plant on the AES Redondo Generating Plant site is discontinued and removed, the site is designated as a Coastal Reserve pursuant to Policy 1.52.5 of the Land Use element of the General Plan. The Coastal Reserve designation identifies large industrial areas of at least five (5) or more acres in the Coastal Zone that are appropriate for reuse for non-industrial urban development and/or parks, recreation and open space in the future, and where the precise future uses have not yet been determined. The preparation of any necessary General Plan, Specific Plan, Coastal Land Use Plan, and Zoning amendments shall precede any new development in the Coastal Reserve.

Primary Land Uses

- None. All existing uses and structures on the site shall be considered non-conforming uses and structures. Existing and former power generating plant facilities (including all facilities, structures, equipment, and storage, whether currently utilized or not) shall be discontinued by January 1, 2018 and removed from the site by January 1, 2019, except that the city may approve reuse of structures incorporated into a new use approved by the city. ~~Public Utility Land Uses, subject to the granting of a Conditional Use Permit (including, but not limited to, facilities, structures, equipment, and storage related to the operation of a public utility) to the extent determined to be legally permissible. Minor additions or changes may be exempted from the requirement of a Conditional Use Permit.~~

Alternative Land Uses

- None

Urban/Architectural Design Policies

~~*Maximum Permitted Building Density*~~

- ~~To be determined by the City Planning Commission during the appropriate Site Plan and Design Review procedures associated with and necessary for the issuance of a conditional use permit.~~

~~*Maximum Permitted Building Height*~~

- ~~To be determined by the City Planning Commission during the appropriate Site Plan and Design Review procedures associated with and necessary for the issuance of a conditional use permit.~~

~~*Required (Horizontal) Building Setbacks*~~

- ~~To be determined by the City Planning Commission during the appropriate Site Plan and Design Review procedures associated with and necessary for the issuance of a conditional use permit.~~

~~*Recommended Massing/Articulation*~~

- ~~To be determined by the City Planning Commission during the appropriate Site Plan and Design Review procedures associated with and necessary for the issuance of a conditional use permit.~~

Supplemental Land Use Policies

- In anticipation of the end of the useful economic and physical life of the ~~Southern California Edison Company~~ AES Generating Plant, take necessary steps ~~within an appropriate time frame~~ prior to the end of the amortization period to establish plans for the comprehensive reuse of the site for nonindustrial uses. Said plan shall demonstrate compatibility with the stated objectives of the General Plan and this Specific Plan for the character and function of surrounding areas; be designed to be physically well-integrated with surrounding areas and circulation patterns; and provide for a high quality of design and amenities in recognition of the site's prominent and integral location within the city.

Supplemental Recommended Urban/Architectural Design Policies

In consideration of the various lower and moderate-density commercial and residential land uses surrounding the Zone, implement, as possible and financially feasible any reasonable means, methods, or ways of eliminating entirely or reducing, as much as possible, the range of significant adverse environmental impacts that are created through operation of the ~~Southern California Edison~~ AES Redondo Power Generating Plant during the period that the generating plant continues to operate prior to its removal no later than January 1, 2019 (these measures could include, but are not limited to: external noise walls or fences, landscaping shields and buffering, additional internal noise insulation or air quality filtering systems, etc.).

Supplemental Transportation/Circulation Policies

No additional transportation/circulation policies, above and beyond those previously included within the Specific Plan Area-Wide policies, have been specified for Zone 2 of the Catalina Avenue Corridor Sub-Area.

Supplemental Infrastructure/Utilities Policies

No additional infrastructure/utilities policies, above and beyond those previously included within the Specific Plan Area-Wide policies, have been specified for Zone 2 of the Catalina Avenue Corridor Sub-Area.

SECTION 4. The Planning Commission recommends that the City Council amend subsection G of subsection C of Section VI of the Coastal Land Use Plan relating to conditionally permitted uses in the Waterfront District, to read as follows (additions indicated by underline, deletions indicated by ~~strikethrough~~):

G. CONDITIONAL USES

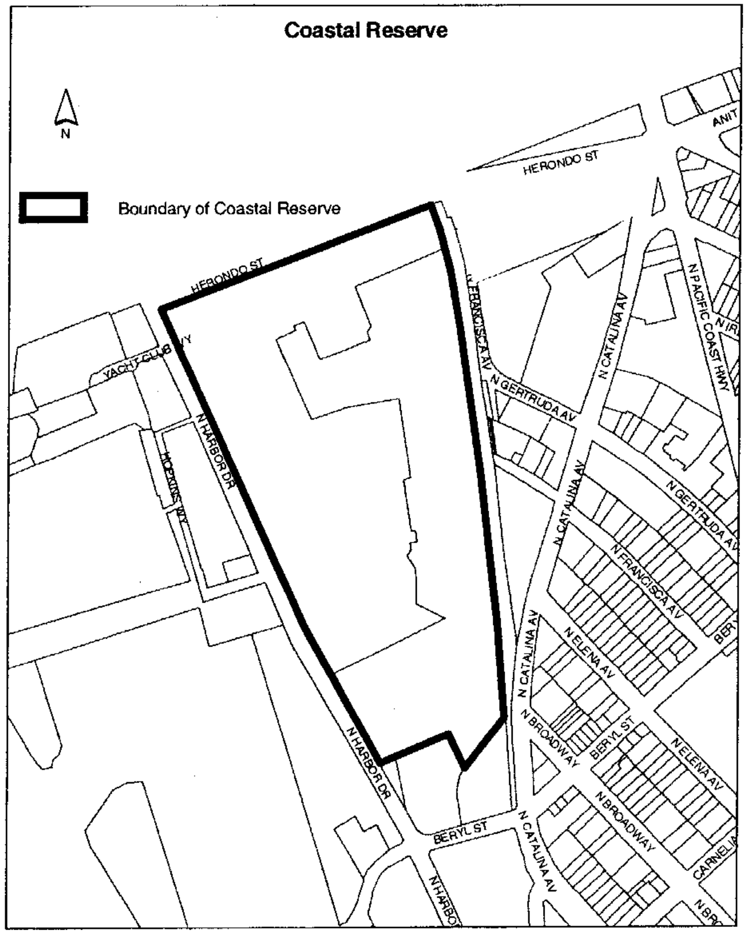
1. Limited Project-Serving Convenience Retail - if part of a larger multi-unit development of one hundred fifty (150) or more units; not to exceed 1,500 square feet per development.
2. Indoor Wholesale and Commercial Sales and Services shall be allowed if they are determined by the City to be of the same general character as those uses allowed in the Harbor Drive District, and/or supportive of the permitted uses listed above.
3. Bars and Nightclubs, including establishments providing entertainment or permitting dancing, and establishments serving alcoholic beverages not clearly ancillary to food service, will only be allowed in the Village Core, International Boardwalk, and Pier.
4. Clubs and Lodges.
5. Public utility facilities, except for power generating facilities.
   ~~a. Future power generating facilities shall be limited to the portion of the AES Generating Plant site identified as the "Plant 3" site, containing Units 7 and 8 and Tanks 2-4 or alternatively the "Plant 2" and "Plant 3" sites containing Units 5-8.~~
2. Schools.
3. Day care centers.
4. Antennae for public communications.
5. Public transit facilities.

SECTION 5. The Planning Commission recommends that the City Council add subsection 14 to subsection D (Land Use Policies) of Section VI of the certified Coastal Land Use Plan to read as follows (additions indicated by underline):

14. The Coastal Reserve designation identifies large industrial areas of at least five (5) or more acres that are appropriate for reuse for non-industrial urban development and/or parks, recreation and open space in the future, and where the precise future uses have not yet been determined. The preparation of any necessary Coastal Land Use Plan amendments shall precede any new development in the Coastal Reserve.

a) Until such time as the power generating plant on the AES Redondo Generating Plant site is discontinued and removed, the site shall be designated as a Coastal Reserve. All existing generating plant uses and structures on the AES Redondo Generating Plant site shall be considered non-conforming uses and structures.

b) In the Coastal Reserve, any nonconforming industrial use and structures used for such industrial use, and any existing and former power generating plant facilities (including all facilities, structures, equipment, and storage, whether currently utilized or not) shall be discontinued and removed subject to standards and schedules developed in the Zoning Ordinance, except that the city may approve reuse of structures incorporated into a new use approved by the city.



SECTION 6. The Planning Commission recommends that the City Council add subsection (g) to Section 10-5.2000 to Article 8, Chapter 5, Title 10 of the Municipal Code, to read as follows (additions indicated by underline):

10-5.2000 Purpose.

The specific purposes of this article are:

(a) To limit the number and extent of nonconforming uses and structures which conflict with the provisions of this title by restricting their enlargement, their reestablishment after abandonment, and their alteration or restoration after destruction of the structures they occupy;

(b) To eventually eliminate nonconforming uses and structures or provide for their alteration to conform with the provisions of this title;

(c) To allow structural improvements and minor additions to structures containing nonconforming uses to be considered in order to prevent these structures from becoming blighted and having detrimental impacts on the surrounding neighborhood, provided that such improvements or additions shall not adversely impact surrounding property, that there is no increase in the degree of nonconformity with respect to the development standards for the zone in which the property is located, and that the life of the nonconforming structure is not substantially increased;

(d) To allow for the reconstruction of existing nonconforming residential structures that are destroyed by disaster in residential zones;

(e) To allow for minor improvements and additions to nonconforming structures containing conforming uses, provided that there is no increase in the degree of nonconformity with respect to the development standards for the zone in which the property is located;

(1) To allow for minor improvements and additions to nonconforming structures containing conforming uses located on beachfront lots or structures located immediately adjacent to vertical public access ways as designated in Table IX of the certified Land Use Plan, provided that the life of the nonconforming structure is not substantially increased.

(f) To eventually eliminate billboards which have a blighting impact on the City's commercial corridors.

(g) To eliminate large industrial uses, including power generating uses, that have a blighting impact on development within the Coastal Zone.

SECTION 7. The Planning Commission recommends that the City Council add Section 10-5.2008 to Article 8, Chapter 5, Title 10 of the Municipal Code, to read as follows (additions indicated by underline):

10-5.2008 Termination of existing nonconforming industrial uses and structures.

(a) In any area identified as a Coastal Reserve in the Land Use element of the General Plan and/or in the Coastal Land Use Plan, any nonconforming industrial use and structures used for such industrial use, and any existing and former power generating plant facilities (including all facilities, structures, equipment, and storage, whether currently utilized or not), shall be discontinued and removed from the site according to the following amortization schedule:

(1) In the Coastal Reserve applicable to the AES Redondo Generating Plant site, existing and former power generating plant facilities (including all facilities, structures, equipment, and storage, whether currently utilized or not), shall be discontinued by January 1, 2018 and removed by January 1, 2019, except that the city may approve reuse of structures incorporated into a new use approved by the city.

SECTION 8. The Planning Commission recommends that the City Council amend Section 10-5.1614 of Article 4, Chapter 5, Title 10 of the Municipal Code, to read as follows (additions indicated by underline, deletions indicated by ~~strikethrough~~):

10-5.1614 Public utility facilities.

(a) **Purpose.** The purpose of this section is to ensure that new public utility facilities and additions to existing facilities are compatible with surrounding properties and consistent with the public health, safety, and welfare of the City. While these regulations recognize the authority of applicable state agencies, it is the intent of the City to exercise any and all authority that it may have now or in the future under the California Constitution or general law with regard to the construction of any improvements or the making of any other changes to any public utility facility in the City. Inasmuch as it cannot be predicted with reasonable certainty at this time which such improvements, facilities or changes may be proposed to be made in the future, the source of the authority of the applicable state agency thereover and, consequently, the authority of the City thereover, it is necessary to write this section in general terms and allow its application to vary with the facts and the law governing each case.

(b) **Criteria.** Application for a Conditional Use Permit for a public utility facility, as required by the provisions of subsection (c), shall be subject to the following development criteria in addition to all other applicable land use and development standards in this chapter:

(1) The site for the proposed construction, reconstruction, erection, alteration, or placement shall be of adequate size and shape to accommodate the proposed use, yards, courts, walls, fences, and landscaping buffers, parking, and other required features.

(2) Adequate street access shall be provided to carry the quantity and kind of traffic generated by the proposed use and designed to provide adequate ingress and egress for fire-fighting equipment or other safety equipment.

(3) The proposed use shall have no adverse effect upon any abutting property, the neighborhood, or the City, and the proposed use shall protect the public health, safety, convenience, interest, and general welfare. In order to insure this provision and to comply with the purposes and intent of this chapter and the General Plan, any development standards or conditions may be imposed to create orderly and proper uses, as determined by the Planning Commission/Harbor Commission or City Council. Whenever a referenced municipal code section uses the term Planning Commission or Harbor Commission, it shall mean for the purposes of this Section 10-5.1614 the Planning Commission unless the subject property is within the Harbor-Pier area as defined in subsection (a) of Section 10-5.2512, in which case it shall mean the Harbor Commission.

(4) The applicant may be required, as a condition of approval, to dedicate land for street or park purposes where indicated on the General Plan and to restrict areas perpetually as open space for common use by appropriate covenants.

(5) A time limit for development may be imposed as provided in subsection (j) of Section 10-5.2506 (Conditional Use Permits).

(c) **Conditional Use Permit required.** Subject to the following provisions, a public utility facility shall be a conditionally permitted use in any zone. The City Engineer may require that an application for such Conditional Use Permit be referred to the Public Works Commission for review, report and recommendation prior to action thereon by the Planning Commission or Harbor Commission, as the case may be. Notwithstanding the above, a public facility use that has been required to be discontinued in an area identified as a Coastal Reserve pursuant to Section 10-5.2008 of this chapter shall be considered a non-conforming use subject to the provisions of Section 10-5.2002 of this chapter, except that an improvement ordered by a federal, state, or regional agency to meet federal and state air quality and water quality requirements shall be subject to a Conditional Use Permit as provided in subsection (c)(3) of this section.

(1) A Conditional Use Permit shall be required for the construction, reconstruction, erection, alteration or placement of any improvement or the making of any other physical change in or to any public utility facility; provided, however, that where such improvement, facility or change is to be made pursuant to any order of the Public Utilities Commission, the South Coast Air Quality Management District, the Regional Water Quality Control Board or other state or regional agency having jurisdiction to make and enforce such order, the Planning Commission/Harbor Commission, or the City Council on appeal shall not make any decision or impose any condition in conflict with any such order or any condition thereof unless, in the opinion of the City Attorney, the City is not preempted therefrom under Article 11, Section 7 of the California Constitution by the enactment of general laws or the subject of such order is a municipal affair under Article 11, Section 5 of said Constitution.

(2) Notwithstanding the provisions of subsection (c)(1) of this section, a Conditional Use Permit shall not be required for the following activities:

a. Repair or maintenance of any public utility facility;

b. Construction, erection or alteration of any building, or adjacent parking facilities therefor, used solely for the purpose of a business office to serve a public utility. (Note: Planning Commission Design Review of such exempt public utility facilities, however, may be required by other provisions of this Code);

c. Any construction, reconstruction, erection, alteration, or placement of any telephone or electric power line or gas or water pipeline located in any public or private right-of-way or across any private property installed pursuant to a utility service agreement;

d. Any work of improvement on such a facility which has a value, as determined by the City's Building Official, for building permit purposes of Fifty Thousand and no/100ths ($50,000.00) Dollars or less and which, as found and determined by the Planning Director, will not have an appreciable adverse effect on the occupants of surrounding properties or on the general public and which is not inconsistent with the City's General Plan;

e. Any construction, reconstruction, erection, alteration or placement of any meters or measuring devices adjacent to customer residences or other facilities;

f. Any construction, reconstruction, erection, alteration or placement of any safety devices, such as pipeline pressure regulators or voltage regulators;

g. Emergency activities, such as, but not limited to, repair of downed power lines, broken gas or water lines or repair of existing equipment within an established distribution system which must be undertaken in order to avoid an immediate threat to human health or property.

<u>(3) In the case of a non-conforming public facility use in an area identified as a Coastal Reserve pursuant to Section 10-5.2008 of this chapter, a Conditional Use Permit shall be required for the construction, reconstruction, erection, alteration or placement of any improvement required pursuant to any order of the Public Utilities Commission, the South Coast Air Quality Management District, the Regional Water Quality Control Board, or other federal, state, or regional agency having jurisdiction to make and enforce such order. The Planning Commission/Harbor Commission, or the City Council on appeal shall not make any decision or impose any condition in conflict with any such order or any condition thereof unless, in the opinion of the City Attorney, the City is not preempted therefrom under Article 11, Section 7 of the California Constitution by the enactment of general laws or the subject of such order is a municipal affair under Article 11, Section 5 of said Constitution.</u>

SECTION 9. The Planning Commission recommends that the City Council amend subsection G of Section I of Attachment A of the Coastal Zoning Ordinance, relating to the Waterfront District land use standards, to read as follows (additions indicated by <u>underline</u>, deletions indicated by ~~strikethrough~~):

A. CONDITIONAL USES

1. Limited Project-Serving Convenience Retail – if part of a larger multi-unit development of one hundred fifty (150) or more units; not to exceed 1,500 square feet per development.

2. Indoor Wholesale and Commercial Sales and Services may be allowed if they are determined by the City to be of the same general character as those uses allowed in the Waterfront District, and/or supportive of the permitted uses listed above.

3. Bars and Nightclubs, including establishments providing entertainment or permitting dancing, and establishments serving alcoholic beverages not clearly

ancillary to food service, will be allowed in the Village Core, International Boardwalk, and Pier.

4. Clubs and Lodges.

5. Schools, Adult Day Care Centers, and Child Day Care Centers (except on the ground floor of the Village Core, International Boardwalk, and Pier).

6. Public Utility Facilities, except for power generating facilities ~~(future power generating facilities shall be limited to the portion of the AES Generating Plant site identified as the "Plant 3" site, containing Units 7 and 8 and Tanks 2-4 or alternatively the "Plant 2" and "Plant 3" sites containing Units 5-8)~~.

7. Antennae for Public Communications.

8. Public transit facilities.

SECTION 10. The Planning Commission recommends that the City Council amend subsection B of Section I of Attachment B of the Coastal Zoning Ordinance, relating to the Catalina Corridor District land use standards, to read as follows (additions indicated by underline, deletions indicated by ~~strikethrough~~):

B. CONDITIONAL USES

1. Lodging may be permitted if it can be determined that the proposed development will be of a quality and character consistent with the goals of the Specific Plan.

2. Indoor Wholesale and Commercial Sales and Services may occur if determined by the City to be of the same general character and/or supportive of the permitted uses listed above - including the following:

   a. Commercial recreation, e.g. bowling alley, roller-skating rink, indoor golfing, etc.

   b. Photographic processing and wholesale supply, printing, engraving, lithography and publishing.

   c. Tool and equipment sales and showrooms, particularly those that do not feature equipment rental, equipment servicing, nor any outdoor equipment storage areas.

   d. Recreational equipment sales and service.

e. Furniture showrooms and sales outlets.

3. Public Halls, Lodges, and Clubs

4. Public and Quasi Public Buildings and Uses - of a recreational, educational, religious, cultural, or public service type.

5. Schools, Adult Day Care Centers, and Child Day Care Centers.

6. Public Utility Facilities, except for power generating facilities ~~(future power generating facilities shall be limited to the portion of the AES Generating Plant site identified as the "Plant 3" site, containing Units 7 and 8 and Tanks 2-4)~~.

7. Antennae for Public Communications.

8. Churches.

9. Convalescent Facilities.

10. Public transit facilities.

FINALLY RESOLVED, that the Planning Commission forward a copy of this resolution to the City Council so the Council will be informed of the action of the Planning Commission.

PASSED, APPROVED AND ADOPTED this 20th day of May, 2004.

Matthew Kilroy, Chair
Planning Commission
City of Redondo Beach

ATTEST:

STATE OF CALIFORNIA)
COUNTY OF LOS ANGELES) SS
CITY OF REDONDO BEACH)

I, Randy Berler, Interim Planning Director of the City of Redondo Beach, California, do hereby certify that the foregoing Resolution No. **** was duly passed, approved and adopted by the Planning Commission of the City of Redondo Beach, California, at a regular meeting of said Planning Commission held on the 20th day of May, 2004, by the following roll call vote:

AYES:

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CITY OF REDONDO BEACH

NEGATIVE DECLARATION NO. 04-04

In accordance with Chapter 3, Title 10, of the Redondo Beach Municipal Code (Environmental Review Pursuant to the California Environmental Quality Act), a Negative Declaration is hereby issued for the following project:

1. **PROJECT LOCATION:**

Industrial areas within the Coastal Zone (including the AES Redondo Generating Plant site) in the City of Redondo Beach

2. **PROJECT DESCRIPTION:**

Amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone, providing for amortization, discontinuation and removal of industrial uses including power generating facilities in the Coastal Zone.

3. **PROJECT SPONSOR:**

City of Redondo Beach
415 Diamond Street
Redondo Beach, CA 90277
(310) 372-1171

4. **FINDING(S) OF THE DECISION-MAKING BODY:**

The City Council of the City of Redondo Beach, as decision-making body, has reviewed Initial Environmental Study (IES 04-04) and has considered all comments and responses to comments received during the 21-day public review period. On the basis of these documents and public testimony presented at the public hearing held on **[DATE]**, the City Council finds that the proposed amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone will not result in any significant impacts upon the environment, according to the criteria for determining significant effect, as set forth in Article 2 of Chapter 3, Title 10 of the Redondo Beach Municipal Code. This determination is supported since no new development is permitted to replace amortized uses prior to the consideration of additional amendments to the General Plan, Coastal Land Use Plan, and Zoning Ordinance establishing permitted uses.

By virtue of the fact that full amortization will not occur until 2018, the impacts that will occur at that time cannot be foreseen. There are innumerable variables in the way that the surrounding area could develop by that time. Environmental analysis does not take place in a hypothetical vacuum, but relies on physical development to serve as its guideposts.

From a planning perspective, 2018 is simply too far in the future to make any discussion of impacts meaningful. Indeed, a discussion of such impacts would be so speculative and of such little value that it would actually impair the decision-making process rather than inform it. To the extent that impacts can be said to be foreseen and meaningfully discussed in the broadest possible sense, the Heart of the City EIR, on which this Negative Declaration and IES in part rely, has already analyzed them. The Heart of the City EIR was able to analyze future impacts to a greater extent than can be analyzed here because that project proposed actual uses, whereas here, the future use of the property after amortization is complete cannot be presently ascertained. If a project is proposed at any point prior to the end of the amortization period that would permit new uses to replace existing uses subject to amortization (including amendments to the General Plan, Coastal Land Use Plan, and Zoning Ordinance and/or proposed development), an Initial Environmental Study would be prepared to determine whether the impacts of such project have already been evaluated in the Heart of the City EIR or whether there are any additional impacts to be studied that have not been studied in the previous EIR.

The City Council further finds that the proposed amendments will have a de minimis impact on Fish and Game resources pursuant to Section 21089(b) of the Public Resources Code.

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CITY OF REDONDO BEACH
INITIAL ENVIRONMENTAL STUDY NO. 04-04

1.	**Project Title:**	Amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone, providing for amortization, discontinuation and removal of industrial uses including power generating facilities in the Coastal Zone.
2.	**Lead Agency Name and Address:**	City of Redondo Beach 415 Diamond Street Redondo Beach, CA 90277
3.	**Contact person and phone number:**	Randy Berler, Interim Planning Director (310) 318-0637
4.	**Project Location:**	Industrial areas within the Coastal Zone (including the AES Redondo Generating Plant site).
5.	**Project Sponsor's Name and Address:**	City of Redondo Beach 415 Diamond Street Redondo Beach, CA 90277
6.	**Coastal Land Use Plan Designation:**	Areas designated industrial in the certified Coastal Land Use Plan.
7.	**Zoning:**	Areas in the Coastal Zone designated Waterfront and Catalina Corridor permitting industrial or power generating plant uses.

8. **Description of Project:** *(Describe the whole action involved, including but not limited to later phases of the project, and any secondary, support, or off-site features necessary for its implementation.)*

The project consists of amendments to the General Plan Land Use Element, Harbor/Civic Center Specific Plan (Catalina Avenue Sub-Area, Zone 2), Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone, applicable to all industrial uses in the Coastal Zone. The amendments propose establishing a "Coastal Reserve" for large industrial areas in the Coastal Zone that are appropriate for reuse for non-industrial uses and where the precise future uses have not yet been determined. The proposed amendments would provide for the amortization and removal of non-conforming uses and structures in areas designated as a Coastal Reserve. The AES Redondo Generating Plant site is proposed to be designated as a Coastal Reserve in order to facilitate the transition to non-industrial use, and the amendments would provide that the existing generating plant uses and structures would be considered non-conforming uses and structures. The preparation of any necessary General Plan, Specific Plan, Coastal Land Use Plan, and Zoning amendments would precede any new development in the Coastal Reserve.

9. **Surrounding Land Uses and Setting:** *(Briefly describe the project's surroundings.)*

The City of Redondo Beach is located south and west of the City of Los Angeles, along the coastline of the Santa Monica Bay. The City is bounded by the Pacific Ocean and the cities of Manhattan Beach, Hermosa Beach, Hawthorne, Lawndale, and Torrance.

Originally incorporated in 1892, Redondo Beach contains a mixture of both older and new types of development. Virtually all land within the City has been developed. Therefore, current trends in development are primarily of an "infill" or "recycling" nature. The majority of the City is devoted to residential land uses, although commercial, light industrial, and recreational uses are also important to the overall composition of the area.

Development around existing industrial zones including the power generating plant site in the Coastal Zone include harbor and harbor-related uses (King Harbor and Redondo Beach Pier), offices, public storage facilities, small-scale industrial uses, including auto repair shops and maintenance yards, retail centers and individual commercial buildings, hotels, a main branch post office, and residential uses.

10. **Other agencies whose approval is required:** *(e.g., permits, financing approval, or participation agreement.)*

Amendments to the certified Coastal Land Use Plan are subject to approval of the Coastal Commission.

Factors Potentially Affected:
The environmental factors checked below would be potentially affected by this project, involving at least one impact that is a "Potentially Significant Impact" as indicated by the checklist on the following pages.

☐ Land Use and Planning	☐ Transportation/Circulation	☐ Public Services
☐ Population and Housing	☐ Biological Resources	☐ Utilities and Service Systems
☐ Geological Problems	☐ Energy and Mineral Resources	☐ Aesthetics
☐ Water	☐ Hazards	☐ Cultural Resources
☐ Air Quality	☐ Noise	☐ Recreation
☐ Mandatory Findings of Significance		

Determination.

On the basis of this initial evaluation:

☒ I find that the proposed project **COULD NOT** have a significant effect on the environment, and a **NEGATIVE DECLARATION** will be prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will not be a significant effect in this case because the mitigation measures described on an attached sheet have been added to the project. A **NEGATIVE DECLARATION** will be prepared.

☐ I find that the proposed project **MAY** have a significant effect on the environment, and an **ENVIRONMENTAL IMPACT REPORT** is required.

☐ I find that the proposed project **MAY** have a significant effect(s) on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets, if the effect is a "potentially significant impact" or "potentially significant unless mitigated." An **ENVIRONMENTAL IMPACT REPORT** is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, there **WILL NOT** be a significant effect in this case because all potentially significant effects (a) have been analyzed adequately in an earlier **EIR** pursuant to applicable standards and (b) have been avoided or mitigated pursuant to that earlier **EIR**, including revisions or mitigation measures that are imposed upon the proposed project.

Randy Berler

Signature

April 22, 2004

Date

Randy Berler, Interim Planning Director

City of Redondo Beach

Evaluation of Environmental Impacts:

1) A brief explanation is required for all answers except "No Impact" answers that are adequately supported by the information sources a lead agency cites in the parentheses following each question. A "No Impact" answer is adequately supported if the referenced information sources show that the impact simply does not apply to projects like the one involved (e.g. the project falls outside a fault rupture zone). A "No Impact" answer should be explained where it is based on project-specific factors as well as general standards (e.g. the project will not expose sensitive receptors to pollutants, based on a project-specific screening analysis).

2) All answers must take account of the whole action involved, including off-site as well as on-site, cumulative as well as project-level, indirect as well as direct, and construction as well as operational impacts.

3) "Potentially Significant Impact" is appropriate if there is substantial evidence that an effect is significant If there are one or more "Potentially Significant Impact" entries when the determination is made, an EIR is required.

4) "Potentially Significant Unless Mitigated Incorporated" applies where the incorporation of mitigation measures has reduced an effect from "Potentially Significant Impact" to a "Less than Significant Impact." The lead agency must describe the mitigation measures, and briefly explain how they reduce the effect to a less than significant level (mitigation measures from Section 17, "Earlier Analyses, "may be cross-referenced).

5) Earlier analyses may be used where, pursuant to the tiering, program EIR, or other CEQA process, an effect has been adequately analyzed in an earlier EIR or negative declaration. Section 15063(c)(3)(D). Earlier analyses are discussed in Section 17 at the end of the checklist.

6) Lead agencies are encouraged to incorporate into the checklist references to information sources for potential impacts (e.g., general plans, zoning ordinances). A source list should be attached, and other sources used or individuals contacted should be cited in the discussion.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
1. LAND USE AND PLANNING. Would the proposal:				
a) Conflict with general plan designation or zoning? (Source #'s: 1, 2, 3, 5)	☐	☐	☒	☐
b) Conflict with applicable environmental plans or policies adopted by agencies with jurisdiction over the project? (1)	☐	☐	☐	☒
c) Be incompatible with existing land use in the vicinity? (1, 2, 3, 5)	☐	☐	☒	☐

Issues (and Supporting Information Sources):	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
d) Affect agricultural resources or operations (e.g. impacts to soils or farmlands, or impacts from incompatible land uses)? (3)	☐	☐	☐	☒
e) Disrupt or divide the physical arrangement of an established community (including a low-income or minority community)? (1, 3)	☐	☐	☐	☒
2. POPULATION AND HOUSING. Would the proposal:				
a) Cumulatively exceed official regional or local population projections? (1, 3, 4)	☐	☐	☒	☐
b) Induce substantial growth in an area either directly or indirectly (e.g. through projects in an undeveloped area or extension of major infrastructure)? (1, 3, 4)	☐	☐	☐	☒
c) Displace existing housing, especially affordable housing? (1)	☐	☐	☐	☒
3. GEOLOGIC PROBLEMS. Would the proposal result in or expose people to potential impacts involving:				
a) Fault rupture? (1, 3, 4)	☐	☐	☐	☒
b) Seismic ground shaking? (1, 3, 4)	☐	☐	☒	☐
c) Seismic ground failure, including liquefaction? (1, 3, 4)	☐	☐	☒	☐
d) Seiche, tsunami, or volcanic hazard? (1, 3, 4)	☐	☐	☐	☒
e) Landslides or mudflows? (1, 3, 4)	☐	☐	☐	☒
f) Erosion, changes in topography or unstable soil conditions from excavation, grading, or fill? (1, 3, 4)	☐	☐	☐	☒
g) Subsidence of the land? (1, 3, 4)	☐	☐	☐	☒
h) Expansive soils? (1, 3, 4)	☐	☐	☐	☒
i) Unique geologic or physical features? (1, 3, 4)	☐	☐	☐	☒
4. WATER. Would the proposal result in:				
a) Changes in absorption rates, drainage patterns, or the rate and amount of surface runoff? (1)	☐	☐	☒	☐
b) Exposure of people or property to water related hazards such as flooding? (1, 3, 9)	☐	☐	☒	☐
c) Substantially alter the drainage pattern or course of a stream or river? (1, 3, 9)	☐	☐	☐	☒

Issues (and Supporting Information Sources):	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
d) Changes in the amount of surface water in a water body? (1)	☐	☐	☐	☒
e) Changes in currents, or the course or direction of water movements? (1)	☐	☐	☐	☒
f) Change in the quantity of ground waters, either through direct additions or withdrawals, or through interception of an aquifer by cuts or excavations, or through substantial loss of groundwater recharge capability? (1, 3, 4)	☐	☐	☐	☒
g) Altered direction or rate of flow of groundwater? (1, 3, 4)	☐	☐	☐	☒
h) Impacts to groundwater quality? (1)	☐	☐	☐	☒
i) Substantial reduction in the amount of groundwater otherwise available for public water supplies? (1)	☐	☐	☐	☒
j) Stormwater system discharges from areas for materials storage, vehicle or equipment fueling, vehicle or equipment maintenance (including washing), waste handling, hazardous materials handling or storage, delivery or loading docks or other work areas? (1, 10)	☐	☐	☐	☒
k) A significantly environmentally harmful increase in the flow rate or volume of stormwater runoff? (1, 10)	☐	☐	☐	☒
l) A significantly environmentally harmful increase in erosion of the project site or surrounding areas? (1)	☐	☐	☐	☒
m) Stormwater discharges that would significantly impair the beneficial uses of receiving waters or areas that provide water quality benefits (e.g. riparian corridors, wetlands, etc.)? (1)	☐	☐	☐	☒
n) Harm to the biological integrity of drainage systems and water bodies? (1)	☐	☐	☐	☒
5. AIR QUALITY. Would the proposal:				
a) Violate any air quality standard or contribute to an existing or projected air quality violation? (1, 3, 4, 14)	☐	☐	☒	☐
b) Expose sensitive receptors to pollutants? (1)	☐	☐	☐	☒
c) Alter air movement, moisture, or temperature, or cause any change in climate? (1)	☐	☐	☐	☒
d) Create objectionable odors? (1)	☐	☐	☐	☒

Issues (and Supporting Information Sources):	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
6. TRANSPORTATION/CIRCULATION. Would the proposal result in:				
a) Increased vehicle trips or traffic congestion? (1, 3, 4, 6)	☐	☐	☒	☐
b) Hazards to safety from design features (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment)? (1)	☐	☐	☐	☒
c) Inadequate emergency access or access to nearby uses? (1)	☐	☐	☐	☒
d) Insufficient parking capacity on-site or off-site? (1, 5)	☐	☐	☐	☒
e) Hazards or barriers for pedestrians or bicyclists? (1)	☐	☐	☐	☒
f) Conflicts with adopted policies supporting alternative transportation (e.g., bus turnouts, bicycle racks)? (1, 3)	☐	☐	☐	☒
g) Rail, waterborne or air traffic impacts? (1)	☐	☐	☐	☒
7. BIOLOGICAL RESOURCES. Would the proposal result in impacts to:				
a) Endangered, threatened, or rare species or their habitats (including but not limited to plants, fish, insects, animals, and birds)? (1, 3, 4)	☐	☐	☐	☒
b) Locally designated species (e.g., heritage trees)? (1, 3, 4)	☐	☐	☐	☒
c) Locally designated natural communities (e.g., oak forest, coastal habitat, etc.)? (1, 3, 4)	☐	☐	☐	☒
d) Wetland habitat (e.g.. marsh, riparian, and vernal pool)? (1, 3, 4)	☐	☐	☐	☒
e) Wildlife dispersal or migration corridors? (1, 3, 4)	☐	☐	☐	☒
8. ENERGY AND MINERAL RESOURCES. Would the proposal:				
a) Conflict with adopted energy conservation plans? (1, 3)	☐	☐	☐	☒
b) Use non-renewable resources in a wasteful and inefficient manner? (1)	☐	☐	☐	☒
c) Result in the loss of availability of a known mineral resource that would be of future value to the region and the residents of the State? (1, 3)	☐	☐	☐	☒

9. HAZARDS. Would the proposal involve:

Issues (and Supporting Information Sources):	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
a) A risk of accidental explosion or release of hazardous substances (including, but not limited to: oil, pesticides, chemicals, or radiation)? (1)	☐	☐	☐	☒
b) Possible interference with an emergency response plan or emergency evacuation plan? (1)	☐	☐	☐	☒
c) The creation of any health hazard or potential health hazard? (1)	☐	☐	☐	☒
d) Exposure of people to existing sources of potential health hazards? (1)	☐	☐	☐	☒
e) Increased fire hazard in areas with flammable brush, grass, or trees? (1, 2)	☐	☐	☐	☒
10. NOISE. Would the proposal result in:				
a) Increases in existing noise levels? (1, 3, 4)	☐	☐	☐	☒
b) Exposure of people to severe noise levels? (1, 12)	☐	☐	☐	☒
11. PUBLIC SERVICES. Would the proposal have an effect upon, or result in a need for new or altered government services in any of the following areas:				
a) Fire protection? (1, 3, 4)	☐	☐	☒	☐
b) Police protection? (1, 3, 4)	☐	☐	☒	☐
c) Schools? (1, 3, 4)	☐	☐	☐	☒
d) Maintenance of public facilities, including roads? (1, 3, 4)	☐	☐	☐	☒
e) Other governmental services? (1, 3, 4)	☐	☐	☒	☐
12. UTILITIES AND SERVICE SYSTEMS. Would the proposal result in a need for new systems or supplies, or substantial alterations to the following utilities:				
a) Power or natural gas? (1, 3, 4)	☐	☐	☐	☒
b) Communications systems? (1, 3, 4)	☐	☐	☐	☒
c) Local or regional water treatment or distribution facilities? (1, 3, 4)	☐	☐	☐	☒
d) Sewer or septic tanks? (1, 3, 4, 13)	☐	☐	☐	☒
e) Storm water drainage? (1, 3, 4)	☐	☐	☐	☒
f) Solid waste disposal? (1, 3, 4)	☐	☐	☐	☒

Issues (and Supporting Information Sources):	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
g) Local or regional water supplies? (1, 3, 4)	☐	☐	☐	☒
13. AESTHETICS. Would the proposal:				
a) Affect a scenic vista or scenic highway? (1, 3)	☐	☐	☐	☒
b) Have a demonstrable negative aesthetic effect? (1)	☐	☐	☒	☐
c) Create light or glare? (1, 5)	☐	☐	☐	☒
14. CULTURAL RESOURCES. Would the proposal:				
a) Disturb paleontological resources? (1, 3, 4, 8)	☐	☐	☐	☒
b) Disturb archaeological resources? (1, 3, 4, 8)	☐	☐	☐	☒
c) Affect historical resources? (1, 3, 4, 7)	☐	☐	☐	☒
d) Have the potential to cause a physical change which would affect unique ethnic cultural values? (1)	☐	☐	☐	☒
e) Restrict existing religious or sacred uses within the potential impact area? (1)	☐	☐	☐	☒
15. RECREATION. Would the proposal:				
a) Increase the demand for neighborhood or regional parks or other recreational facilities? (1, 3, 4)	☐	☐	☐	☒
b) Affect existing recreational opportunities? (1, 3, 4)	☐	☐	☐	☒
16. MANDATORY FINDINGS OF SIGNIFICANCE.				
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal, or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☒
b) Does the project have the potential to achieve short-term, to the disadvantage of long-term, environmental goals?	☐	☐	☐	☒
c) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.)	☐	☐	☐	☒

Issues (and Supporting Information Sources):	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
d) Does the project have environmental effects which will cause substantial adverse effects on human beings, either directly or indirectly?	☐	☐	☐	☒

17. EARLIER ANALYSES.

Earlier analyses may be used where, pursuant to the tiering, program EIR, or other CEQA process, one or more effects have been adequately analyzed in an earlier EIR or negative declaration. Section 15063(c)(3)(D). In this case a discussion should identify the following on attached sheets:

a) ***Earlier analyses used.*** *Identify earlier analyses and state where they are available for review.*

b) ***Impacts adequately addressed.*** *Identify which effects from the above checklist were within the scope of and adequately analyzed in an earlier document pursuant to applicable legal standards, and state whether such effects were addressed by mitigation measures based on the earlier analysis.*

c) ***Mitigation measures.*** *For effects that are "Less than Significant with Mitigation incorporated," describe the mitigation measures which were incorporated or refined from the earlier document and the extent to which they address site-specific conditions for the project.*

LIST OF SOURCES/ATTACHMENTS *(These reports are available at the City of Redondo Beach Planning Department, Door E, 415 Diamond Street, Redondo Beach, California 90277):*

1) Discussion of Environmental Evaluation
2) General Plan Map of Redondo Beach
3) Redondo Beach General Plan, 1992
4) General Plan EIR, 1992
5) Redondo Beach Zoning Ordinance
6) Institute of Traffic Engineer's Trip Generation Manual
7) Historic Resources Surveys, 1986, 1996, and 2001
8) Archeological Research and Site Identification for Resources Reported to be Located within the City of Redondo Beach, 1996
9) Federal Emergency Management Agency Flood Map
10) C of A refers to a condition of approval of the resolution. This does not necessarily signify that a significant environmental impact has been identified but rather may be a way to reduce even insignificant impacts or may be a standard condition of approval.
11) Harbor/Civic Center Specific Plan, 1992
12) Municipal Code Title 2, Chapter 24 (Noise Ordinance)
13) Wastewater System Master Plan and Wastewater Revenue Rate Analysis (WSMP), prepared in January, 1994 by Kennedy/Jenks Consultants
14) South Coast Air Quality Management District CEQA Air Quality Handbook, April 1993
15) Heart of the City EIR

ATTACHMENT 1
DISCUSSION OF ENVIRONMENTAL EVALUATION

1. Land Use and Planning

The project involves amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone to amortize and eliminate industrial uses on larger sites in the coastal zone, and permit replacement of these uses with non-industrial uses to be determined and permitted prior to completion of the amortization period. The amortization of the industrial use will not cause any land use impacts. The subsequent reuse of the site is likely to cause impacts beyond those experienced from the existing industrial uses in the coastal zone in terms of traffic and utility consumption as described below, but the extent of those impacts cannot be determined until the future use is determined.

2. Population and Housing

Reuse of amortized industrial uses may result in an increase in population and housing in the future, depending on future amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone. Such amendments would be subject to environmental review. Any application for development of housing on former industrial sites in the coastal zone would be subject to separate environmental review to determine whether there are any significant impacts caused by the specific project.

3. Geologic Problems

In Redondo Beach, as in most of Southern California, there is the potential for seismic ground shaking from seismic activity in the region. Areas of the City may also contain liquefiable materials, resulting from locally perched groundwater. Although exposed to regional and local seismic risks, projects within the affected zone will be designed according to the seismic building code requirements. This project involves amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone. Each specific development project would be subject to separate environmental review.

4. Water

No significant impacts are anticipated as a result of the amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone. Future use would likely consume less potable water than the existing industrial uses in the coastal zone. Future development projects would be subject to separate environmental review. Before construction of any specific development project begins, the site will be reviewed for drainage requirements.

5. Air Quality.

The City is located within the South Coast Air Basin. Air quality in the Basin exceeds State and Federal ambient air quality standards. The amendments result in no changes that would generate additional emissions over existing development standards. In fact, a reduction in emissions is likely in the conversion from industrial uses, but cannot be determined until specific replacement uses are identified. Furthermore, any application for development on the former industrial sites in the coastal zone would be subject to separate environmental review to determine whether there are any significant impacts caused by the specific project.

6. Transportation/Circulation

The proposed amendments will not result in immediate additional generation of traffic or additional parking demand. Increases in traffic from future uses are likely, but the increment of additional traffic will be determined by future uses, subject to future amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone. Such amendments would be subject to environmental review. Increases in congestion and trip generation from future uses are likely over current industrial uses. Future reuse development projects would be subject to separate environmental review to consider potential impacts associated with the project.

7. Biological Resources

The affected sites have been developed for decades. No sensitive species or habitat areas are known to exist in these areas.

8. Energy and Mineral Resources

The proposed project is not of the nature, location, or extent to significantly affect natural resources. Future development projects are subject to future amendments to the General Plan, Harbor/Civic Center Specific Plan, Coastal Land Use Plan, and Zoning Ordinance for the Coastal Zone. Such amendments would be subject to environmental review. Additionally, any development project is required to comply with the State Energy Conservation Standards for New Residential and Non-Residential Buildings (Title 24, Par. 6, Article 2, California Administrative Code). The loss of electrical power generation within the coastal zone is not expected to be significant in terms of the regional capacity for power generation.

9. Hazards

The existing power generating plant site has some potential to generate hazards and has documented soils contamination that will have to be remediated to acceptable standards prior to reuse. The standards to which the site will have to be cleaned will depend on the types of allowable future use. Future development projects in areas affected by the proposed amendments would be subject to separate environmental review to consider potential impacts associated with the project.

10. Noise

The existing industrial uses, including electrical generation and auto body repair, among others, create some localized noise impacts that will cease upon discontinuation and removal of the use. Each future development project would be subject to separate environmental review to consider potential noise impacts and to ensure appropriate design to mitigate noise impacts from the future uses and for sensitive receptors on the reuse site, as appropriate.

11. Public Services

The project area is served by police, fire, and other services, including services particularly needed by industrial facilities emergency evacuation. Reuse of industrial sites will demand a different type of emergency response services, dependent on the future use. Community services and emergency medical care demand would likely increase from that required for an industrial use in the coastal zone. A specific development project would be subject to separate environmental review to consider potential impacts to public services.

12. Utilities and Service Systems

The project area is adequately served by existing utility and service systems. Future use would require more local distribution facilities, and new service networks for sewer, water and other local connections to serve new development.

13. Aesthetics

The proposed removal of the industrial uses in the coastal zone will be a substantial aesthetic improvement as new urban uses or recreational open space areas are developed. Future development projects would be subject to separate environmental review to consider potential aesthetic impacts, including view corridors.

14. Cultural Resources

The proposed amendments do not impact cultural resources. Cultural resource sites are known to existing onsite. Future development projects would be subject to separate environmental review to consider impacts on these historic and archaeological resources.

15. Recreation

Removal of the industrial uses in the coastal zone will provide the opportunity for additional recreational space in the City. The type and extent of this opportunity will be determined in the future.

16. Mandatory Findings of Significance

The project does not have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal, or eliminate important examples of the major periods of California history or prehistory. No natural animal habitat exists within the affected zone, and little if any, natural animal life is present. Vegetation is limited to non-native and ornamental species used for landscaping and street trees at the perimeter. No rare, unique or endangered plant species exist in the affected zone. Therefore, no impacts to unique, rare or endangered plant or animal species, or their respective habitat, would occur with the proposed project.

As identified in all impact discussions herein, no significant impacts requiring mitigation are expected to occur with implementation of the proposed project. The project would not be expected to sacrifice short-term environmental goals at the expense of long-term environmental goals. No significant cumulative impacts have been identified in connection with the proposed project and, the proposed project poses no threat to human health or safety.

MITIGATION MEASURES

None required.

DAVIS
The Davis Company

Michael Davis
James D. Williams

May 10, 2004

To: Planning Commission, City of Redondo Beach

From: James D. Williams, The Davis Company

AES RESIDUAL LAND VALUE AND COST RECOVERY

In the process of approving an amortization ordinance for the AES site in Redondo Beach among the issues to be considered by the Planning Commission and the City Council are:

1. If the AES power generation plant were not at its present site, what would the value of the land be?

2. Will the amortization ordinance allow AES the opportunity to recover the cost of the existing facility?

3. What is the remaining useful life of the AES power generating facility?

Land Value

AES filed a land appraisal report with the State Board of Equalization in December, 2003, challenging the assessed value of the Redondo Beach site. The report was prepared by the Delahooke Appraisal Company. The title of the report was:

An Appraisal Report Prepared for AES Redondo Beach, LLC of the Property Located
11190 N. Harbor Drive
Redondo Beach, CA 90277
Prepared By the Delahooke Appraisal Company
Scott D. Delahooke, MAI
Effective Date of Appraisal, January 1, 2003

The appraisal report addresses the Fair Market Value of the AES property, 28.82 acres, on an "as is" basis excluding building value. The effective date of the appraisal is January 1, 2003 and the date of inspection is July 9, 2003. The report states on page "iii" that " The appraisal assignment involves only the valuation of the underlying land based on its highest and best use. The improvements and FFE are not included in the appraisal. This is the request of the client."

1601 Response Road, Suite 380, Sacramento, CA 95815 916.567.9510 TEL. 916.567.9540 FAX
11150 Santa Monica Blvd., Suite 200, Los Angeles, CA 90025 310.473.1457 TEL. 310.473.3962 FAX

In determining the highest and best use of the property the report states on page 16, "The facility is an out-of-date electrical power generating plant with eight generating units. Units 1 through 4 are not operational. The remaining turbines employ steam turbine technology which is significantly less efficient than new combined cycle gas turbine technology. Typically, the plant operates only two of the four operational turbines.

In view of this, AES announced (when) that electrical production would not be expanded and did not need all of the owned land. City officials began working on a plan to develop the unused portion of the site. "

On page 22 the report includes the "Highest and Best Use Analysis" and concludes that, " The Highest and Best Use of the subject site "as if vacant" would be to develop with a mixed use project (industrial and residential)."

Residential Land Use

In determining the land value the report uses the "Sales Comparison Method" to reach a determined value for both industrial and residential land uses.

The report states on page 38 that the amount of land for residential land use is based on the Edison property (21.61 acres) and the AES property (28.82 acres). " According to the city's redevelopment plan approximately two thirds (or 33.80 acres) of the 50.43 acre site is planned for redevelopment with residential uses." Of the 33.80 acres, 21.61 acres is a tank farm leaving 12.2 acres for residential development.

On page 42 the report estimates the value of the residential site to be $2,180,000/acre or a total value of $26,595,000.

Industrial Land Use

For industrial land use, the report concludes that 16.62 acres should be designated for industrial use with a land value of $575,000/acre and a total value of $9,556,500. The conclusion that 16.62 acres is designated for industrial use is based on the assumption that the AES power generating facility will remain on that "southwestern portion of the site..." This industrial site is the remaining land available after deducting the tank farm area and the residential area, [50.43ac (-) 21.61ac (-) 12.2ac = 16.62ac.]

Total Land Value and Final Value Estimate

The combined value determined by the Sales Comparison Method for the "Industrial Land' and the " Residential Land" is set at $36,150,000 on page 43 of the report. This amount is then adjusted downward by $10, 480,000, the pro rated amount for site demolition and environmental clean up costs, for a final "as is Fee Simple Estate Market

Value for the subject property as of January 1, 2003," of **$25,670,000**. This final value estimate is stated on page 45 of the report.

Based on the analysis by the appraiser of the 28.82 acres owned by AES it would be reasonable to assume that the value of the property absent existing structures would be $25,670,000 as of January 1, 2003.

Cost Recovery

Also among the documents filed by AES with the Board of Equalization was a valuation of the existing AES buildings and facilities excluding land. The title of that report was:

AES Redondo Beach, LLC
AES Redondo Beach Generating Station
Fair Market Value Report
As of January 1, 2003
AUS Consultants, Valuation Services Group

While not used in the final valuation, the report includes an income approach, pre tax cash flow statement. On page 29 the report states: "The total DCF [discounted cash flow] for Redondo Beach is $174,300,000 as of January 1, 2003." The DCF is based on a cash flow projection from 2003 to 2017 a fifteen-year period. The DCF does not include any cash flow statement from May 18, 1998 the date of purchase to 2003. The discounted cash flow is stated to include the underlying land value for the purposes of valuation. An after tax DCF of $152,400,000 is also stated but is based on the maximum tax rate of 40.75% in order to establish the present property value.

Since the land appraisal is based on a pre tax value and the effective or true tax rate of AES is not known the pre tax DCF is applied to evaluate cost recovery. The AES cash flow prior to the 2003 statement is not known, but a simple proration of the $174,300,000 for twenty years, the full term of the Williams Energy Services Company Tolling Agreement, would result in a DCF of **$232,400,000**. This is not the usual method of evaluating cash flow but is based on information available to the City of Redondo Beach as a matter of public record. A request was made by the City to AES for more complete cash flow information but this information was not provided.

AES Acquisition Cost

The best information available to the City establishes an acquisition cost for the 28.82 acres of land and the power generating facilities of $249,000,000 as of May 18, 1998. No information is available as to debt, equity, or loan terms for the acquisition.

Cost Recovery Estimate

Based on the public documents prepared for AES the estimated cost recovered on a pre tax, present value basis, as of January 1, 2003 would be $258,070,000, $232,400,000 in estimated pre tax discounted cash flow plus a residual underlying land value of $25,670,000 remaining after the power generating facilities and associated structures have no value. The range of assumptions to establish this estimate have been stated, but the estimate demonstrates within those assumptions that AES, based on the information provided to the State Board of Equalization by AES, will recover its investment of $249,000,000 by 2017.

Remaining Power Facility Life

The remaining useful life of the AES power generating facility is assumed by AUS Consultants to be primarily controlled by the Tolling Agreement between AES and the Williams Energy Services Company. The AUS report states on page 26," The remaining useful life as of January 1, 2003 is estimated at 15 years." The AES power generating facility would have no useful life after January 1, 2018, based on the AUS report.

Edison Property

The Edison property of 21.61 acres has reportedly been sold to AES for $4,000,000 to $4,500,000. The appraised value is reported to be $10,500,000. The appraised value has been reduced by $6,000,000 to $6,500,000 to provide for environmental clean up. The Los Angeles County Assessor has set an assessed value of the property at $13,200,000. No information as to the proposed use of the property by AES is available.

REGAN ASSOCIATES
Real Estate and Economic Consulting

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MEMORANDUM

TO: Randy Berler, Interim Planning Director
City of Redondo Beach

FROM: James P. Regan

SUBJECT: **Indication of Negative Impact of AES Plant on Property Values in Nearby Areas**

DATE: May 10, 2004

At the request of the City of Redondo Beach Planning Department, Regan Associates reviewed various data on property values in areas proximate to the AES plant and similar values in adjacent areas and Citywide. This memorandum summarizes this review. The data reviewed cover the period 1990/1991 through 1999/2000 for purposes of comparability. [1]

Total Commercial and Industrial Property Values

Assessed property values for privately-owned commercial and industrial land and improvements in the immediate area surrounding the AES Plant, generally corresponding to a Study Area for the Redevelopment Agency, have been stagnant or declining over the past 10 years:

(Secured Taxable Roll)	1991/92	1999/00	% Change
Land	$6,178,832	$4,735,413	(23.4%)
Improvements	$1,215,365	$774,076	(36.3%)
Total	$7,394,197	$5,509,489	(25.5%)

[1] The 2000/01 tax roll is not comparable to prior years since it includes the AES and Southern California Edison properties which went on to the local tax roll that year.

The decline in property values was steady throughout the period with an increase noted in only one year.

During the same period, City-wide assessed value of commercial and industrial property (excluding residential and other categories) increased by approximately 5%, with commercial property values showing an increase of about 17%. This indicates a negative change of over 40% compared to the City as a whole.

Residential Property Values

Data on residential values over the 10-year period from 1990/91 to 2000/01 was evaluated for three coastal residential areas: Area 1 is nearest the AES generating plant, bounded by Pacific Coast Highway, Catalina Avenue and Beryl Street. Area 2 is south of Area 1, bounded by Pacific Coast Highway and Catalina Avenue between Beryl Street and Knob Hill Avenue. Further south is Area 3, bounded by Pacific Coast Highway and Catalina Avenue south of Knob Hill Avenue.

Average assessed value data was evaluated over the 1990/01 to 2000/01 periods for ownership housing units, including both single-family units and duplex/two-on-a-lot units. The data show the following value trends:

	Area 1	Area 2	Area 3
Indexed Value Per Unit - Single Family			
1991/92	100.0	100.0	100.0
2000/01	114.1	124.1	154.2
Percent value increase	14.1%	24.1%	54.2%
Indexed Value Per Unit - Condominiums			
1991/92	100.0	100.0	100.0
2000/01	103.3	124.2	141.9
Percent value increase	3.3%	24.2%	41.9%

Average ownership residential properties in Area 1 show a value at the beginning of the period that was not significantly different than adjoining coastal areas to the south. That situation changed during the 1990's. The value increase over the period also shows the depressed nature of residential values in the AES area. The average value increase in Areas 2 and 3 combined is almost 40% for single-family and 33% for two-unit residences compared to increases of 14% and slightly over 3% respectively in Area 1.

These data bear out anecdotal information in the local real estate market about the adverse impact of the AES plant on adjacent residential communities.

CALIFORNIA
ENERGY
COMMISSION

STAFF BRIEFING PAPER ON AGING POWER PLANT STUDY

STAFF BRIEFING ON
AGING POWER PLANT STUDY

MARCH 2004
Pub. No. 100-04-001D

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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STAFF BRIEFING PAPER ON AGING POWER PLANT STUDY

Introduction

As part of the *2004 Integrated Energy Policy Report (IEPR) Update*, the California Energy Commission is undertaking the Aging Power Plant Study (APPS) to examine the reliability and resource implications of California's reliance on older power plants that may be less reliable and available than facilities built more recently.

More than 40 percent of the total gas-fired power generation capacity in California was built in the 1950s and 1960s. These plants are less efficient and may have increased environmental effects compared to new combined-cycle plants because of improvements in technology and plant design. However, some of these power plants may play a key role in supplying power during times of high demand, especially during a generating shortage, as well as in supplying critical reliability services in various regions.

The staff is refining the study plan for this evaluation. The Energy Commission is seeking participation from interested parties throughout the study process, and is now seeking comment concerning the proposed scope and methodology of the study.

The staff will refine the scope and methodology of the study following a scheduled March 24, 2004, workshop on the subject and review of all comments received from concerned parties (see: www.energy.ca.gov/2004_policy_update/notices/index.html). Further public workshops will be held to ensure continued participation by interested parties. The staff intends to complete an initial draft of the APPS in July 2004.

Background

Today, more than 40 percent of the operating generating capacity in California is more than 40 years old. The relative age of this large portion of the state's natural gas-fired power plant fleet was a major issue identified in the Energy Commission's *2003 IEPR*. The *IEPR* is a biennial report in which the Commission assesses the major energy trends and issues facing the state, and uses these results to recommend energy policies that balance broad public interests to conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety. The IEPR process is guided by a Committee made up of two Commissioners, John L. Geesman, Presiding Member, and James D. Boyd, Associate Member.

During the preparation of the *2003 IEPR*, parties testifying before the Energy Commission identified a variety of issues relating to inefficiency and relatively greater environmental effects produced by older natural gas-fired power plants. The issues raised regarding these plants were three-fold.

Because the lower efficiency of these plants makes them less economically competitive, some parties asserted that a significant portion of these plants may be retired or mothballed in the near future, before replacement generation can be brought online, potentially leading to generating capacity shortfalls in California, as well as local system reliability problems. Others stated that if the state needs to rely heavily on some of these plants in coming years, they could have adverse effects on natural gas supplies in the state. Finally, some parties were concerned about potential impacts on the environment caused by continued reliance on these plants. Expressed environmental concerns ranged from the potential air quality effects of reliance on plants using outmoded emissions controls equipment to the effects on the marine environment caused by continued use of once-through cooling systems designed more than 40 years ago.

The interaction between these issues is complex. For example, the least efficient plants are likely to be little used in normal years, and therefore have little effect on natural gas use or the environment. The reduced operation, however, may increase the possibility that plant owners would decide to close these facilities for economic reasons. Conversely, during periods of high demand, combined with a resource shortage, generation from these aging plants may significantly increase, absent continued development of new power plants or other alternatives, such as new transmission lines or demand-side management. Continued use of these aging power plants, therefore, could have implications for the demand and price of natural gas in the state, as well as contribute to ongoing cumulative environmental impacts at a greater rate compared to the use of newer power plants.

In the *2003 IEPR*, the Energy Commission noted that reserve margins in the state are affected by the retirement of older generating units. Estimates of the amount of capacity that could be retired over the next several years range from 4630 MW by the Energy Commission, to 7232 MW by the California Independent System Operator (CA ISO), to as much as 10,000 MW by merchant generators. In addition to their capacity contributions toward reserve margins, some of these aging power plants provide important local reliability services, such as voltage or frequency support in areas where transmission systems are constrained.

To address these wide-ranging concerns, the 2004 IEPR Committee directed staff to prepare an APPS as part of the *2004 Update* to the *2003 IEPR.* The APPS has three main objectives:

- analyze the role that individual aging power plants play in maintaining a reliable power system, including capacity resources and local reliability services;
- examine in more detail the range of retirements that can be anticipated over the next few years; and
- assess the implications of these potential retirements on system reliability and efficiency, and the environment.

The Study Process

This APPS will provide information to the Energy Commission and others concerning the role these aging plants presently play in meeting the needs of the state's electricity system, as well as the resource implications of continued reliance on these plants, both in terms of natural gas use and environmental effects. The study will also provide information concerning the anticipated future role these plants will play in the state's power market. The study will assess the effect on electric reliability from the retirement of less-efficient generating units for economic reasons, as well as to identify regions within the state that may be especially vulnerable to the loss of generating resources. The study will also help identify trends related to factors that affect the rate of retirement and forced outages at older plants.

The staff has tentatively identified a group of older power plants for use in studying the current and anticipated role of aging plants in the state's electricity system and their impacts on the state's resources. The staff used criteria based on a combination of several attributes, including age, size, capacity factor, efficiency, and environmental considerations, to produce the attached list of plants as a preliminary study group for the APPS. The proposed list of power plants is not meant to be exhaustive, nor to suggest that the plants included in the study should be shutdown, retrofited, repowered, or targeted for any other specific action, or that these plants are not in compliance with all the laws, ordinances, and regulations applicable to their operation. Rather, the list is a starting point to use in examining the various issues associated with aging plants, and the potential role they might play in meeting electricity demand in the state in coming years. The staff expects to revise the list based on comments received from interested parties.

Study Group Selection

The staff formed the study group list by culling down a database of more than 1,500 generating units in the state. The list was reduced to 519 units by identifying those built before 1980, and 193 of those are fueled by natural gas. Eliminating units smaller than 10 MW reduced the list to 165. Eliminating the stand-alone combustion-turbine units, which are designed to operate only during peak periods, and units not connected to the grid, and consolidating the combustion turbines and steam turbines of the combined-cycle units, further narrowed the list to 95 units. Of those, 29 units are known to be scheduled for retirement in the near-term, bringing the list down to 66 units. The Energy Commission has access to some data for all but five of the 66 units.

This preliminary selection is meant to provide a representational sampling of those larger plants with relatively higher heat rates (low efficiencies) and relatively higher operation (capacity factors), as well as a sampling representing plants that have particular environmental characteristics. Peaking plants were generally eliminated from the study group, because they are designed to run only during periods of high demand, while remaining idle for the balance of the year. Also eliminated were aging biomass, hydroelectric, nuclear, wind, and solar plants.

The staff is also developing criteria for identifying particular generating units where increasing operations of the units or extending their lifetimes could have unwanted environmental effects. In applying the criteria, the staff will consider four basic factors related to environmental performance: air emissions and emission rates; cooling water sources and treatment of waste water discharge; indigenous flora and fauna and related habitat and wetlands; and community plans for reuse of the power plant site.

Many environmental attributes of power plant units can be measured by their performance with respect to specific criteria: NO_x emissions, water source, the cooling method used, and compatibility with surrounding land uses. Others require closer examination of localized effects, such as on wetlands or local populations of plants and animals, and community concerns regarding compatibility with surrounding land uses. These factors are often best described in a qualitative way because they are not numerical items (e.g., a city's long range plan for use of a waterfront area, or a redevelopment area plan) or because of a lack of specific data.

Data and Information Collection

The staff may revise the list of units proposed as the study group based on comments received and new information discovered during the workshop process. Once the list for the selected group is finalized, the staff will gather data concerning the operational history of the plants, with emphasis on how they operated in the past two years, compared to how they operated during the "power emergency" of 2000-2001, which may provide predictive value for the intermediate term, when generation reserve margins may decline.

The staff also will collect information from various sources concerning the contracted services the plants provide. Such services would include any contracted energy and capacity sales, such as with the state's Department of Water Resources, as well as contracted reliability services – such as voltage or frequency support or spinning reserves – supplied to the CA ISO or other control area operators.

The staff will also collect data related to air emissions and other readily quantifiable parameters, and conduct a qualitative assessment of other environmental effects, such as the effects on biological resources from the once-through cooling systems used by some aging plants. The staff will also attempt to describe the potential cumulative environmental effects from the aging plants, to the extent that such effects can be readily ascertained. Finally, the staff will also identify regionally important issues, such as transmission bottlenecks and gas pipeline infrastructure limitations, that relate to the need for provision of reliability services from a particular plant or group of plants.

Future Role Analysis

The next step in the study will be to assess the role these plants may play in the California electricity generation system in the near to intermediate future. The staff is currently crafting a proposed methodology for conducting this part of the analysis, based on assigning risk factors for the retirement of groups of units and conducting supply/demand balance calculations under a wide variety of likely and theoretical maximum scenarios.

The staff intends to analyze a range of potential future scenarios, assuming a range of plant retirements, and will also likely create "perfect storm" scenarios – where several factors align to create the worst possible case related to both gas and electric reliability – to show the extreme end of the range of possibilities. The analysis will also take into account a range of possibilities concerning other development in the energy industry, as well as the effects of present policies concerning the continued use of these aging plants. Factors that could affect the analysis include the development of new electric transmission lines, and new or refurbished power plants, as well as the state's policies concerning renewable energy development and demand-side management.

Study Results
The final phase of the study will involve compilation and interpretation of the results of the analysis, with the goal of identifying potential issues related to both the continued reliance on aging power plants, as well as the potential effects from their retirement or extended shutdown for corrective maintenance. The staff will identify regions that are particularly vulnerable to supply problems because of the loss of one or more aging plants, as well as on the potential effects on the natural gas system from reliance on these plants. The staff will also place emphasis on identifying environmental concerns related to the continued operation of the plants, including air emissions, water quality, and biological resources. The results of the analysis will be documented in the Draft APPS. After considering all comments received on the draft document, and conducting any needed additional analysis, the staff will update the report at the Committee's direction, for inclusion in the *2004 IEPR Update*.

Study Schedule

The staff intends to complete a draft of the study in July 2004. To ensure continued participation in the study process, the IEPR Committee intends to hold a series of workshops throughout the process, beginning with a scheduled March 24, 2004, workshop. The purpose of this workshop is to provide an opportunity for all parties to participate in the Aging Power Plant Study process and to provide a forum for discussing the goals and mechanics of the study. The workshop will include presentations by staff to focus the discussion on four main points:

1. The major issues associated with aging plants that this study will focus on,

2. The criteria that was used initially to select the power plants for more detailed examination,

3. The information and analytical tools needed to adequately examine the issues associated with aging power plants, and

4. The methodology to be used in analyzing the potential effects of continued reliance on aging plants.

The Committee will revise the list of plants selected for study, and the proposed methodology for completing the study, following review of comments received from interested parties during and after the first workshop. The schedule and need for additional workshops will likely be revised during the process to fit the needs of the study participants. The staff intends to publish the Aging Power Plant Study in July 2004.

Comments

Comments from interested parties will be taken throughout the APPS process, beginning with comments on the four points of discussion listed above. In addition, the Committee is aware that work is ongoing at other agencies that will strongly influence the issues examined in the APPS, particularly the California Public Utilities Commission's proceedings on procurement and resource adequacy. The Committee is seeking comment from workshop participants as to what value the APPS can add to the debate. Specifically, the Committee is seeking comments on the topics outlined above, plus a list of questions contained in Attachment A. The Committee encourages interested parties to present their views either orally at the workshop or through written comments. Parties wishing to comment are requested to contact Matt Trask at (916) 654-4067 or by e-mail at: [mtrask@energy.state.ca.us].

Attachment A
Questions on Aging Power Plants

- Has the Committee captured the issues associated with aging plants that this study should focus on?
- What criteria should be considered for selecting power plants for the study?
- Should certain power plants be included or excluded from the initial selected group for study and why?
- What information should the Committee consider, and what data should the staff collect in conducting the APPS?
- What methodology should staff employ to assess the role these plants play in the state's power market accurately?
- What policies, plans, and practices are in place that might cause the retirement of these plants?
- What policies, plans, and practices are in place that might cause these plants to remain in operation?
- What are the best means to secure generation capacity, reduce uncertainty from operation, improve resource efficiency, and reduce environmental impacts at these plants?
- What are the potential environmental effects of any replacement units, and will there be an improvement?
- Will replacement units be available and reliable?
- What are the local fiscal impacts of aging plant retirement?

Proposed List of Plants for APPS Analysis

	Unit Identification			ER 94 ESPAR[1]		2002 Operating Data			Calculated Ratios			Other Information						
	EIA Plant ID	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 Redvlmnt Plan[6]	SCR Installed[7]	County
1	228	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	228	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	246	Humboldt Bay	1	1956	52	194,615	2,427,851	868,937	0.3579	12,475	0.427	RMR		NC	YES	NO	NO[b]	Humboldt
4	246	Humboldt Bay	2	1958	53	190,383	2,496,030	872,666	0.3496	13,111	0.410	RMR		NC	YES	NO	NO[b]	Humboldt
5	247	Hunters Point	4	1958	163	449,628	5,356,970			11,914	0.315	RMR		SF	YES	YES	NO[c]	San Francisco
6	259	Morro Bay Power Plant	1	1956	163	30,826	343,384	20,521	0.0598	11,140	0.022			SCC	YES	NO	NO[d]	San Luis Obispo
7	259	Morro Bay Power Plant	2	1955	163	80,218	852,057	51,193	0.0601	10,622	0.056			SCC	YES	NO	NO[d]	San Luis Obispo
8	259	Morro Bay Power Plant	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	259	Morro Bay Power Plant	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	260	Moss Landing Power Plant	6	1967	739	2,276,079	20,879,237	182,344	0.0087	9,173	0.352		ISO	NCC	YES	NO	YES	Monterey
11	260	Moss Landing Power Plant	7	1968	739	1,730,249	16,032,235	281,251	0.0175	9,266	0.267		ISO	NCC	YES	NO	YES	Monterey
12	271	Pittsburg Power	5	1960	325	547,082	5,652,989	132,775	0.0235	10,333	0.192	RMR		SF	YES	NO	YES	Contra Costa
13	271	Pittsburg Power	6	1961	325	703,877	7,523,108	88,369	0.0117	10,688	0.247	RMR		SF	YES	NO	YES	Contra Costa
14	271	Pittsburg Power	7	1972	720	2,760,981	27,536,340	1,113,654	0.0404	9,973	0.438	RMR		SF	YES	NO	NO[e]	Contra Costa
15	273	Potrero Power	3	1965	207	570,643	5,927,227	325,825	0.0550	10,387	0.315	RMR		SF	YES	NO	NO[e]	San Francisco
16	302	Encina	1	1954	107	152,068	1,671,418	34,264	0.0205	10,991	0.162	RMR		SD	YES	NO	YES	San Diego
17	302	Encina	2	1956	104	191,628	2,142,231	43,916	0.0205	11,179	0.210	RMR		SD	YES	NO	YES	San Diego
18	302	Encina	3	1958	110	195,769	2,143,917	43,950	0.0205	10,951	0.203	RMR		SD	YES	NO	YES	San Diego
19	302	Encina	4	1973	293	933,529	10,730,897	219,983	0.0205	11,495	0.364	RMR		SD	YES	NO	YES	San Diego
20	302	Encina	5	1978	315	1,051,716	10,982,456	225,140	0.0205	10,442	0.381	RMR		SD	YES	NO	YES	San Diego
21	310	South Bay Power Plant	1	1960	147	459,135	4,654,531	60,028	0.0129	10,138	0.357	RMR		SD	YES	YES	YES	San Diego
22	310	South Bay Power Plant	2	1962	150	466,098	4,400,057	52,738	0.0120	9,440	0.355	RMR		SD	YES	YES	YES	San Diego
23	310	South Bay Power Plant	3	1964	171	319,647	3,312,646	42,271	0.0128	10,357	0.214	RMR		SD	YES	YES	YES	San Diego
24	310	South Bay Power Plant	4	1971	222	84,940	1,023,633	42,206	0.0412	12,051	0.044	RMR		SD	YES	YES	YES	San Diego
25	315	AES Alamitos LLC	1	1956	175	142,973	1,809,301	56,448	0.0312	12,655	0.093			SC	YES	NO	YES	Los Angeles
26	315	AES Alamitos LLC	2	1957	175	167,808	2,164,441	52,874	0.0244	12,898	0.109			SC	YES	NO	YES	Los Angeles
27	315	AES Alamitos LLC	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	315	AES Alamitos LLC	4	1962	320	710,764	7,777,048	122,890	0.0158	10,942	0.254			SC	YES	NO	YES	Los Angeles
29	315	AES Alamitos LLC	5	1969	480	1,433,863	14,778,258	92,473	0.0063	10,307	0.341			SC	YES	NO	YES	Los Angeles
30	315	AES Alamitos LLC	6	1966	480	619,790	6,626,709	104,371	0.0158	10,692	0.147			SC	YES	NO	YES	Los Angeles
31	329	Coolwater	1	1961	65	84,534	531,461	45,130	0.0849	6,287	0.148		ISO	SDT	NO	NO	NO[e]	San Bernardino
32	329	Coolwater	2	1964	81	108,811	1,122,952	100,371	0.0894	10,320	0.153		ISO	SDT	NO	NO	NO[e]	San Bernardino
33	329	Coolwater	3	1978	241	1,250,643	9,079,014	934,507	0.1029	7,259	0.592			SDT	NO	NO	NO[e]	San Bernardino
34	329	Coolwater	4	1978	241	1,060,535	9,178,878	819,318	0.0893	8,655	0.502			SDT	NO	NO	NO[e]	San Bernardino
35	330	El Segundo Power	3	1964	335	1,061,387	10,399,010	58,862	0.0057	9,798	0.362			SC	YES	NO	YES	Los Angeles
36	330	El Segundo Power	4	1965	335	1,340,186	13,301,719	99,620	0.0075	9,925	0.457			SC	YES	NO	YES	Los Angeles
37	331	Etiwanda Generating Station	3	1963	320	543,179	5,969,559	69,468	0.0116	10,990	0.194			SC	NO	NO	YES	San Bernardino

Proposed List of Plants for APPS Analysis

	Unit Identification			ER 94 ESPAR[1]		2002 Operating Data			Calculated Ratios			Other Information						
	EIA Plant ID	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 Redvlmnt Plan[6]	SCR Installed[7]	County
38	331	Etiwanda Generating Station	4	1963	320	258,695	3,019,710	50,263	0.0166	11,673	0.092			SC	NO	NO	YES	San Bernardino
39	335	AES Huntington Beach LLC	1	1958	215	647,852	7,405,994	81,300	0.0110	11,432	0.344	RMR		SC	YES	NO	YES	Orange
40	335	AES Huntington Beach LLC	2	1958	215	699,436	7,633,953	87,194	0.0114	10,914	0.371	RMR		SC	YES	NO	YES	Orange
41	341	Long Beach Generation LLC	8	1976	303	81,883	939,891			11,478	0.031		ISO	SC	YES	NO	NO[f]	Los Angeles
42	341	Long Beach Generation LLC	9	1977	227	31,254	362,036			11,584	0.016		ISO	SC	YES	NO	NO[f]	Los Angeles
43	345	Mandalay	1	1959	215	499,331	4,710,452	23,304	0.0049	9,434	0.265			SCC	YES	NO	YES	Ventura
44	345	Mandalay	2	1959	215	564,964	5,144,509	31,252	0.0061	9,106	0.300			SCC	YES	NO	YES	Ventura
45	350	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	350	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	356	AES Redondo Beach LLC	5	1954	175	83,476	1,127,491	79,601	0.0706	13,507	0.054		ISO	SC	YES	YES	YES	Los Angeles
48	356	AES Redondo Beach LLC	6	1957	175	47,302	670,001	24,897	0.0372	14,164	0.031		ISO	SC	YES	YES	YES	Los Angeles
49	356	AES Redondo Beach LLC	7	1967	480	965,701	9,843,859	130,365	0.0132	10,193	0.230		ISO	SC	YES	YES	YES	Los Angeles
50	356	AES Redondo Beach LLC	8	1967	480	984,254	9,695,744	92,965	0.0096	9,851	0.234		ISO	SC	YES	YES	YES	Los Angeles
51	377	Grayson	3	1953	19								MUNI	SC	NO	NO	NO[h]	Los Angeles
52	377	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	377	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	377	Grayson	8	1977	95	8,385	134,416			16,031	0.010		MUNI	SC	NO	NO	YES	Los Angeles
55	389	El Centro	3	1952	44	47,419	585,886	96,064	0.1640	12,355	0.124		MUNI	SDT	YES	NO	NO[g]	Imperial
56	389	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	400	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	400	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	400	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	400	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	404	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	404	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	404	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	420	Broadway	B3	1965	66	70,886	849,285	19,605	0.0231	11,981	0.123		MUNI	SC	NO	NO	YES	Los Angeles
65	6013	Olive	1	1959	46	19,535	244,391	22,738	0.0930	12,511	0.048		MUNI	SC	NO	NO	YES	Los Angeles
66	6013	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	37,596,000	378,449,000	10,186,000										

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

[a] Bay Area APCD Rule 9-11 has a staggered implementation schedule. The owner, Mirant, of Potrero, Contra Costa, and Pittsburg boiler units have opted to comply via a "system cap, where all their boilers are held to an instantaneous cap. Currently some units are cleaner than other 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 IN.

[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. The owner, PG&E, of Hunters Point boiler opted to comply via a "system cap, where all the boilers unit is held to an instantaneous cap. Currently, the only operating boiler unit at Hunters Points in Unit 4. The final cap, in force 1/1/05, limits the unit to 0.018 lbs NOx/mm Btu IN. PG&E has purchased and surrendered to the district of Interchangeable Emission Reduction Credits (IERCs) to comply with the system cap.

[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 IN. Emission controls (e.g., SCR) or operations limits or some combination of the two could be used to compliance 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) are capped at 1,319 tons per year. SCR in not currently required to comply

[f] South Coast BARCT Rule 2009only requires steam injection on the 7 combustion turbines at the Long Beach combined cycle facility.

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

[h] Units 3, 4 and 5 burn landfill gas, which is incompatible with SCR. Grayson facility subject to District Rule 1135 - system cap of 0.2 lbs NOX/MWHR or 390 lbs NOx/day.

AGING NATURAL GAS POWER PLANTS IN CALIFORNIA

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California Energy Commission

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AGING NATURAL GAS POWER PLANTS IN CALIFORNIA

A summary of capacity, usage, and emission characteristics of older natural gas power plants in California

Summary

As previously reported, the Energy Commission staff has examined the adequacy of the state's electrical system reserve capacity for the summer of 2003 and determined that adequate capacity is expected be available to meet the summer peak demand. However, the age of the power plants in California has raised concerns that a significant number of older facilities may lack the reliability to be available when needed. In this report, the Energy Commission staff presents information on key characteristics of the state's natural gas power plants, including unit specific information on the 25 largest natural gas facilities in state. While some forced outages will occur among these units this summer, such outages have been incorporated into the Energy Commission staff's forecasts. The Energy Commission staff continues to believe that the state will have adequate reserves this summer despite the age distribution of its generation fleet, and that its forecasts appropriately incorporate consideration of the reliability of the generation facilities in the state.

Role of Natural Gas Power Plants in California's Electric System

The Energy Commission staff estimates that more than 60,000 MW of dependable capacity (including imports) will be on-line this summer, with almost 60,000 MW of that capacity expected to be available to meet peak demand at any time. Approximately 30,000 MW of the dependable capacity is provided by in-state natural gas power plants with a capacity of 50 MW or greater. These facilities play two key roles in the operation of the state's electric system: providing needed capacity to meet peak demand, and providing important swing capacity to meet annual electricity needs when imports or hydroelectric resources are low.

The full available capacity of the system needs to be called upon only to meet peak demand, which in California typically falls on hot summer afternoons. During those relatively few hours of the year, virtually all existing power plants are relied on to provide generating capacity or other reliability services. Given that natural gas units provide half of the available capacity, their availability at times of peak demand is an important aspect of system reliability. An overview of the age, emissions and efficiency characteristics, and recent operations of these natural gas power plants is presented below. While these characteristics are not direct measures of reliability, they do show that most of this capacity is from reasonably efficient units, and most of the older units have had recent investment from their owners in modern pollution control equipment.

The extent to which these facilities will be used to meet annual demand in California is governed by the hour-to-hour dispatch of generating resources by the operators of the different control areas over the course of the year. Power plants in California are dispatched to meet the demand for electricity in a 'merit order'. The merit order reflects each unit's relative variable costs of production, with hydro generation, as a rule, being least expensive, followed by nuclear and coal, then natural gas. Renewable resources and cogeneration are generally dispatched based on contractual or physical constraints. When available, these resources tend to be dispatched before most natural gas units. Natural gas-fired resources are generally dispatched according to their heat rates. Units with higher heat rates have higher positions in the merit order and are used less frequently. Other factors, such as transmission losses and costs are also factored into the merit order.

The system of constrained merit order dispatch is intended to ensure that electric supply and demand remain balanced throughout the year, including on days of peak demand, while attempting to minimize the overall costs of operating the system. The year-to-year variation in the availability of hydro resources due to changes in precipitation in California and the Pacific Northwest greatly influences the mix of resources called upon to meet California's demand during the year. The Western power system has been designed to accommodate variable hydro resources. When precipitation runoff is bountiful, hydroelectric generation is used and other generating plants, mostly gas-fired, are idled. When hydroelectric energy generation is low, a combination of increased imports, if they are available, and increased generation by in-state natural gas power plants will make up the difference. Differences in capacity factors between 2001 (low hydro and imports) and 2002 (relatively normal hydro and imports) for the 25 largest units (shown in **Table 1**, included at the end of the report) reflect this 'swing' role of the natural gas-fired capacity within the system.

The natural gas-fired facilities discussed below remain an important part of the overall system, providing both needed capacity for meeting peak demand and intermediate capacity to help meet annual energy requirements during low hydro years.

Natural Gas Power Plant Characteristics

Energy Commission staff has prepared the following overview of the age, emissions and efficiency characteristics, and recent operations of these natural gas power plants. While not direct measures of the reliability of these facilities, the fact that the vast majority of this capacity is from units that are relatively efficient provides an incentive for owners to keep the units available. The fact that the owners of a majority of this capacity have either built the facilities in recent years or invested in retrofitting with selective catalytic reduction (SCR) emission control equipment also suggests that owners are acting to keep the units available. While the Energy Commission staff recognizes that some forced outages will occur among these units this summer, such outages have been incorporated into the Energy Commission staff's forecasts. The Energy Commission staff continues to believe that the state will have adequate reserves this summer despite the age distribution of its generation fleet.

Table 1 provides unit-specific information for the 25 largest natural gas power plants in the state. This information includes the name, owner, and location of each facility, and the dependable capacity, the start-up or re-power date, the capacity factor (percent of time the unit operated during the year), efficiency (heat rate), and permitted emissions level of each set of units within those facilities. These 25 facilities, roughly those over 500 MW, represent approximately 80 percent of the in-state natural gas-fired capacity. The table has been color coded to distinguish among different categories of units, as summarized in **Table 2**. Of the 1,831 MW from older units without SCR that are not currently expected to shutdown, 1,036 MW are from Contra Costa unit 6 and Pittsburg unit 7. These units face deadlines to install SCR or shutdown by late 2004 and early 2005, respectively. The other units in this category do not face current regulatory deadlines to retrofit or stop operation.

Table 2. Summary of categories of the 25 largest natural gas power plants in California

Category	**MW**	**Table 1 Shading**
New unit with SCR	6,784	No shading
Older unit retrofit with SCR	12,783	Yellow
[illegible]	[illegible]	[illegible]
Older unit no SCR, shutdown expected	[illegible]	Blue
Total	**23,810**	

Figure 1 shows the age breakdown of the capacity from existing natural gas-fired facilities over 50 MW. While almost half of this capacity dates from the 1950s or 1960s, the data do not suggest that these older power plants are all dirty or inefficient. Though the overall age of these facilities raises a degree of concern, consideration of the efficiency and emissions profiles of these units suggests that the vast majority of this capacity is from units that have installed current emission control equipment and are reasonably efficient. In addition, more than 25 percent of the state's natural gas-fired-capacity either was built or repowered since 2000.

Figure 1. Age of Natural Gas Power Plant Capacity in California

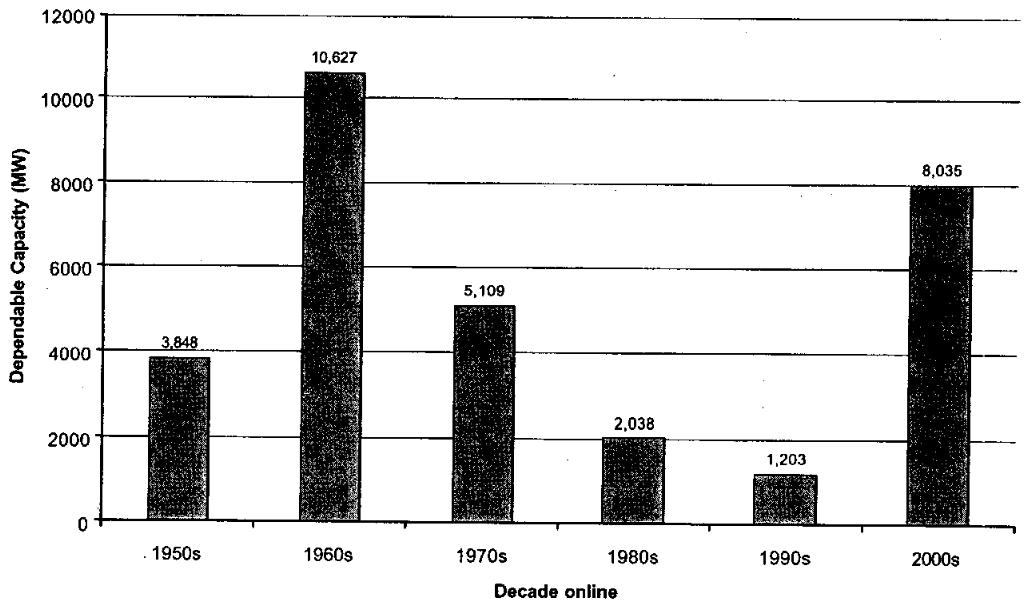


Table 3 shows the MW capacity of units in different emission categories based on NOx permit emission limits. **Figure 2** shows the emission characteristics for the capacity brought online in each decade. Almost one-third of the natural gas-fired capacity in California has a permit limit of 5 ppm NOx or less, and more than 75 percent are limited to 15 ppm or less. These facilities are in three categories. Combined-cycle and cogeneration facilities that have come on-line since the mid-1990s have permit limits below 5 ppm. Simple-cycle units ('peakers') that have come on-line in recent years are typically permitted at 5 ppm. Most of the steam boiler units built in the 1950s and 1960s have been retrofit with SCR and now have permit limits between 5 and 15 ppm. While these facilities could not control NOx emissions to that degree when they were initially constructed, most have opted to retrofit. Facilities with limits above 15 ppm are either steam boilers that have not been retrofit with SCR, or older simple-cycle units.

Table 3. Dependable Capacity by permitted NOx emission levels (all natural gas power plants 50 MW and larger)

NOx permit limit (ppm)	Capacity		Cumulative Capacity	
	MW	%	MW	%
<= 5	9,793	31.7	9,793	31.7
5.1 to 15	13,864	44.9	23,657	76.7
15.1 to 50	3,591	11.6	27,248	88.3
50.1 to 100	2,284	7.4	29,532	95.7
> 100	1,248	4.0	30,780	99.7
NA	80	0.3	30,860	100.0

The NOx permit limit was not readily available for one 80 MW unit.

Figure 2. Dependable capacity by decade online and NOx emission permit levels

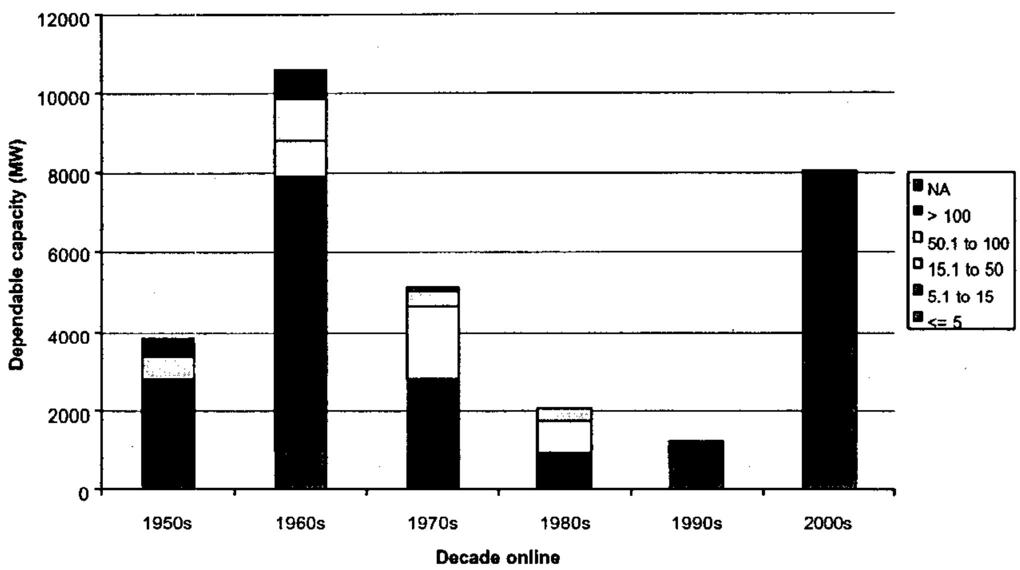
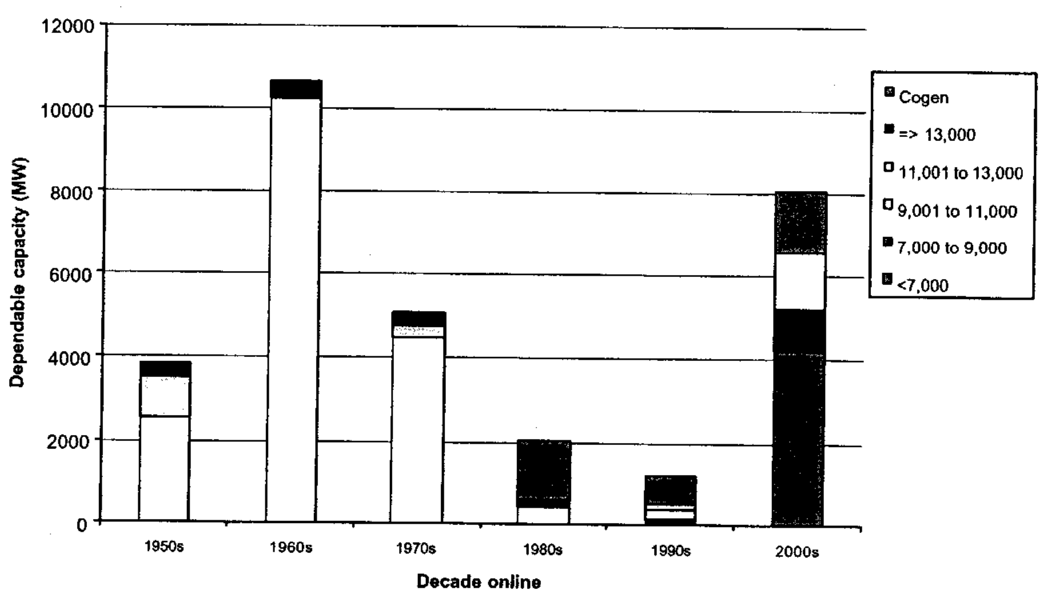


Table 4 shows the MW capacity of natural gas-fired units in different efficiency categories based on approximate heat rates. This table shows that the majority of capacity from these units generates electricity within a narrow heat rate range. This range, 9,000 to 11,000 Btu/kWh, is the general range in which relatively efficient older steam boilers and modern peaking combustion turbines both operate. **Figure 3** shows that the vast majority of capacity remaining online from the 1950s through 1970s operates in this range. Units that have come online this decade (or are expected to by August 2003) include more than 4,000 MW from modern combined cycle power plants that are significantly more efficient. Cogeneration units are presented separately, without an estimate of their heat rate. These units, in addition to generating electricity, also supply heat to host industrial facilities. This complicates the use of heat rate as a measure of efficiency. In addition, such facilities are often primarily designed to supply industrial heat to the host facility, with the generation of electricity to the grid a side-benefit.

Table 4. Dependable Capacity by approximate heat rate (all natural gas power plants 50 MW and larger)

Approximate heat rate (Btu/kWh)	Capacity		Cumulative Capacity	
	MW	%	MW	%
<7,000	4,186	13.6	4,186	13.6
7,000 to 9,000	1,135	3.7	5,321	17.2
9,001 to 11,000	19,259	62.4	24,580	79.7
11,001 to 13,000	1,453	4.7	26,033	84.4
=> 13,000	1,201	3.9	27,234	88.3
Cogeneration units	3,626	11.7	30,860	100.0

Figure 3. Dependable capacity by decade online and approximate heat rate (Btu/kWh)



Factors Affecting Power Plant Retirement Decisions

The information presented here cannot be used by itself to accurately predict future unit availability or retirements. Additional analysis and knowledge of power plant performance and usage characteristics would be needed to better evaluate the risk that capacity from older units would be unavailable in the future. Currently, with the information available to the state, it is not possible to predict with confidence how long units will remain sufficiently profitable to induce their owners to maintain their availability.

Power plants are operated to the economic advantage of their owners, whether the owners are independent power producers, investor-owned utilities or publicly owned utilities. However, power plant operations are constrained by utility practice and regulations that ensure the reliability of the electric system and avoid unacceptable economic, public health, and environmental impacts.

As noted in the tables and figures, some of these power plants are decades old, which can increase the cost of maintenance or make them unreliable. Whether these power plant units remain available to provide capacity and reliability services is an economic decision of the owner. This decision is usually determined by the expected net profitability of a unit (*i.e.* the difference between expected revenues and expected operation costs, which include fuel, maintenance, and any necessary capital costs). A number of units have been retired in recent years or are slated for retirement in the near term. These retirements have, for the most part, been associated with decisions by the facility owner to replace older, less efficient units that would have required emission control upgrades with new, more efficient and cleaner burning units.

Power plant owners will make investments to maintain a unit's availability as long as it is profitable to do so. Revenue guarantees, such as income from the California Department of Water Resources' long-term power purchase contracts or income from the California Independent System Operator's Reliability-Must-Run contracts, tend to encourage such investments, as do expectations of high electricity spot market prices. Expectations of low maintenance, fuel and going-forward capital costs also encourage owners to keep units available.

Conversely, the owner of a power plant unit may decline to invest in the maintenance necessary to maintain a unit's availability if faced with low or uncertain revenue expectations or high or uncertain cost expectations. If a plant is not efficient and does not have revenue guarantees for its output, it may not be dispatched often enough to recover its costs. If a plant requires extensive maintenance or capital costs to maintain its availability (*e.g.* boiler tube replacement, or SCR retrofit to control NOx emissions), higher revenues would be needed to maintain profitability.

The information most directly related to the owner's decision (*i.e.* expected revenues, costs, and profit expectations) is confidential, proprietary, or unknown. Indirect indicators of profitability such as historic annual capacity factor, annual energy generation, forced outage rates, and permitted NOx emissions rates could be examined and analyzed to provide more insight as to the potential for specific unit retirements. In addition, identifying which units have guaranteed revenue streams, Reliability-Must-Run contracts, or anticipated costly capital requirements, could help identify units less likely or more likely to retire. However, these analyses would still not be conclusive. As such, we have not attempted to make this kind of analysis in this report. The Energy Commission's near-term Electricity Supply/Demand Balance Assessments are an attempt to consider many of these factors, but a degree of uncertainty remains.

Conclusions

Energy Commission staff has provided an overview of the age, emissions and efficiency characteristics, and recent operations of the natural gas power plants in California. While this information cannot be used to predict future availability or retirement of specific units, most of the natural gas-fired capacity is from units that are relatively efficient, providing an incentive for owners to keep the units available. In addition, the owners of a majority of this capacity have either built the facilities in recent years or invested in retrofitting steam boiler units with current emission control technology, suggesting that owners are acting to keep the units available. While some forced outages will occur among these units this summer, such outages have been incorporated into the Energy Commission staff's forecasts. The Energy Commission staff continues to believe that the state will have adequate reserves this summer despite the age distribution of its generation fleet, and that its forecasts appropriately incorporate consideration of the reliability of the generation facilities in the state.

Table 1: Characteristics of the Twenty-five Largest Natural Gas Power Plants in California

Plant Name (Owner) Unit	County	Facility Dependable Capacity	Unit Dependable Capacity	Year Online/ Repowered	Capacity Factor (percent) 2001	Capacity Factor (percent) 2002	App. Heat Rate (Btu/Kwh)	NOx Permit Limit (ppm)	Comments
Moss Landing Power Plant									
(Duke Energy)	**Monterey**	**2,545**							
Steam units 6 & 7			1,485	1968	65	30	9,000	10	
Combined cycle units 1 & 2			1,060	2002	New units		7,000	2.5	
Alamitos									
(AES Corp)	**Los Angeles**	**2,087**							
Steam units 1 & 2			348	1956, 1957	13	10	13,000	9	
Steam units 3 & 4			642	1961, 1962	46	30	11,000	9	2003 RMR contract for Unit 3 only
Steam units 5 & 6			963	1964, 1966	58	26	10,000	9	
Peaker unit 7			134	1969	3	0.5	14,000	90	Shutdown expected 12/31/03
Haynes									
(LADWP)	**Los Angeles**	**1,570**							
Steam units 1 & 2			444	1959, 1962	33	27	10,000	9	
Steam units 3 & 4			444	1964, 1965	17	9	10,000	36	Shutdown of Unit 3 expected in 9/04 and of Unit 4 in 11/03
Steam units 5 & 6			682	1967	25	18	10,000	9	
Ormond Beach									
(Reliant Energy)	**Ventura**	**1,492**							
Steam units 1 & 2			1492	1971, 1973	42	18	10,000	9	
Pittsburg Power Plant									
(Mirant)	**Contra Costa**	**1,332**							
Steam units 5 & 6			632	1960, 1961	60	22	10,000	12	2003 RMR contract
Steam unit 7			700	1972	56	42	10,000	48	2003 RMR contract; retrofit with SCR expected by early 2005
Redondo Beach									
(AES Corp)	**Los Angeles**	**1,317**							
Steam units 5 & 6			350	1954, 1957	17	4	13,000	7	
Steam units 7 & 8			967	1967	44	23	10,000	5	
Morro Bay Power Plant	**San Luis**								
(Duke Energy)	**Obispo**	**1,021**							
Steam units 1 & 2			342	1955, 1956	30	4	11,000	150	Proposed replacement facility in review by Energy Commission; plans to retire Units 1 to 4 after replacement project is online
Steam units 3 & 4			679	1962, 1963	55	24	10,000	56	

Table 1: Characteristics of the Twenty-five Largest Natural Gas Power Plants in California

Plant Name (Owner) Unit	County	Facility Dependable Capacity	Unit Dependable Capacity	Year Online/ Repowered	Capacity Factor (percent) 2001	2002	App. Heat Rate (Btu/Kwh)	NOx Permit Limit (ppm)	Comments
Encina (Dynegy & NRG)	**San Diego**	**971**							
Steam units 1 to 3			320	1954-1958	40	18	11,000	12	2003 RMR contract
Steam units 4 & 5			635	1973, 1978	44	34	11,000	12	2003 RMR contract
Simple cycle unit			16	1968	17	1	10,000	42	dual fuel capability
La Paloma (PG&E National)	**Kern**	**968**							
units 1 to 4			968	2003	New units		6,000	2.5	
Huntington Beach (AES Corp)	**Orange**	**880**							
Steam units 1 & 2			430	1958	37	36	9,000	9	2003 RMR contract
Steam units 3 & 4			430	2002	Repowered in 2002 & 2003		9,000	5	Repowered Unit 4 expected online during 8/03
Delta LLC (Calpine)	**Contra Costa**	**861**							
Cogeneration unit			861	2002	New unit		Cogen unit	2.5	
Scattergood (LADWP)	**Los Angeles**	**803**							
Steam units 1 & 2			358	1958, 1959	28	31	10,000	7	
Steam unit 3			445	1974	25	7	10,000	7	
Etiwanda Generating Station (Reliant Energy)	**San Bernardino**	**770**							Units 1 and 2 currently unavailable due to need to install SCR
Steam units 3 & 4			640	1963	26	14	9,000	7	
Simple cycle unit 5			130	1968	7	2	15,000	74	Shutdown expected 12/31/03
High Desert (Constellation)	**San Bernardino**	**750**							
units 1 to 3			750	2003	New units		9,000	2.5	
El Segundo Power (Dynegy & NRG)	**Los Angeles**	**708**							Units 1 and 2 retired 12/31/02
Steam units 3 & 4			708	1964, 1965	37	38	10,000	9	
Contra Costa Power Plant (Mirant)	**Contra Costa**	**672**							
Steam unit 6			336	1964	63	29	10,000	175	2003 RMR contract; retrofit with SCR expected in late 2004
Steam unit 7			336	1964	52	38	10,000	15	2003 RMR contract

Table 1: Characteristics of the Twenty-five Largest Natural Gas Power Plants in California

Plant Name (Owner) Unit	County	Facility Dependable Capacity	Unit Dependable Capacity	Year Online / Repowered	Capacity Factor (percent) 2001	2002	App. Heat Rate (Btu/Kwh)	NOx Permit Limit (ppm)	Comments
South Bay Power Plant (Duke Energy)	**San Diego**	**661**							
Steam units 1 & 2			297	1960, 1962	43	34	10,000	12	2003 RMR contract
steam unit 3			176	1964	33	19	10,000	12	2003 RMR contract
steam unit 4			170	1971	12	5	12,000	10	no RMR contract for 2003; Unit 4 has SCR but has been mothballed
Simple cycle unit 5			18	1966	2	0.1	10,000	39	uses jet fuel, not natural gas
Coolwater Generating Station (Reliant Energy)	**San Bernardino**	**629**							
steam unit 1			65	1961	43	14	10,000	100	
steam unit 2			82	1964	57	14	10,000	100	
Combined cycle units 3 & 4			482	1978	53	39	9,000	42	
Mandalay Generating Station (Reliant Energy)	**Ventura**	**565**							
Steam units 1 & 2			433	1959	45	26	9,000	9	
Simple cycle units			132	1970	3	0.7	19,000	25	
Valley (LADWP)	**Los Angeles**	**563**							
Steam units 1 & 2			190	1954	0	0	12,000	70	LADWP is replacing existing boilers with new combined cycle facility. Units 1 through 4 expected to shut down in 4/04. Units 1 & 2 have not operated since early 1990s
Steam units 3 & 4			323	1955, 1956	6	2	11,000	60	
Simple cycle unit 5			50	2002	13	5	10,000	5	
Sunrise Cogeneration & Power (Texaco Edison Mission) Combined cycle cogeneration Unit	**Kern**	**560**	560	2001/2003	New unit		Cogen	2	Originally approved and built as a simple-cycle unit with permitted NOx limt of 9 ppm; conversion to combined cycle expected to be online by 7/03.
Elk Hills (Sempra and Occidental) Combined cycle unit	**Kern**	**550**	497	2003	New unit		6,000	2.5	Expected online 6/03.

Table 1: Characteristics of the Twenty-five Largest Natural Gas Power Plants in California

Plant Name (Owner) Unit	County	Facility Dependable Capacity	Unit Dependable Capacity	Year Online/ Repowered	Capacity Factor (percent) 2001	Capacity Factor (percent) 2002	App. Heat Rate (Btu/Kwh)	NOx Permit Limit (ppm)	Comments
Sutter (Calpine)	**Sutter**	**548**							
Combined cycle unit			548	2001	New unit		7,000	2.5	
Los Medanos (Calpine)	**Contra Costa**	**540**							
Combined cycle unit			540	2001	New unit		6,000	2.5	2003 RMR contract
Blythe I (Caithness Energy)	**Riverside**	**520**							
Combined cycle unit			520	2003	New unit		6,000	2.5	Expected to come online 6/03

Unit shut down or scheduled for shutdown	Unit retrofit with SCR
No SCR installed or other, but not currently scheduled for shutdown	New or repowered unit

Notes on data sources:

Dependable capacity figures are the Energy Commission Electricity Analysis Office's current input assumptions for modeling August, 2003, electricity supply, and includes four units (Elk Hills, Blythe 1, Huntington Beach Unit 4, and Sunrise Phase II) that were not online as of May 1, 2003, but are expected online by August. The accompanying figures also include two smaller units, Tracy Peaker and Woodland II, that are not online but are expected to be by August.

Year online/repowered represents the year the power plant was initially brought online, except for Huntington Beach, where Units 3 and 4 were substantially repowered. Unit 4 is expected to be online by August, 2003. Units that had air pollution control upgrades (*e.g.* the addition of SCR) but not a substantial repowering of the original equipment are shown with their original online date.

Capacity factors and heat rates are from the EPA Continuous Emission Monitoring System (CEMS) and Energy Information Agency Form 906 data. Heat rates provide a good measure of efficiency (the lower the value, the more efficient the unit), but vary based on operating and weather conditions. Therefore, only approximate heat rates, rounded to the nearest 1,000 Btu/KWh, are presented.

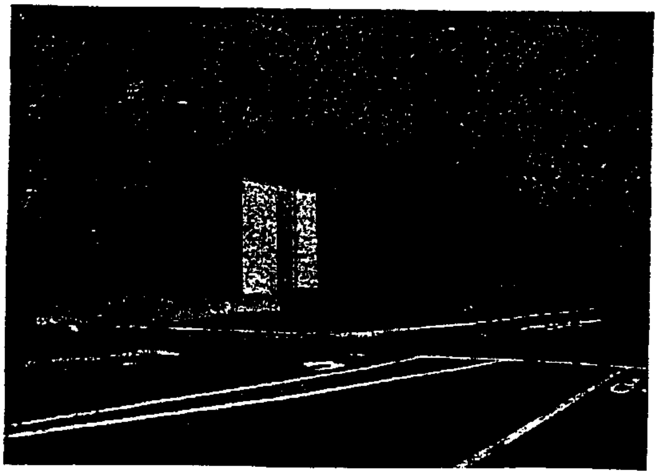
NOx permit limits are from the ARB's summary data and from local air districts. Some reported limits are estimated, with actual permits setting limits in terms of pounds per MWh rather than parts per million. Typically, NOx concentration values are normalized to 3% O2 for combustion turbines, and to 15% O2 for steam boiler units.

Independent System Operator Reliability-Must-Run contracts for 2003 are noted in the comments column.

AN APPRAISAL REPORT PREPARED FOR
AES REDONDO BEACH, LLC
OF THE PROPERTY LOCATED
1190 N. Harbor Drive
Redondo Beach, CA 90277

PREPARED BY
The Delahooke Appraisal Company
Scott D. Delahooke, MAI

THE EFFECTIVE DATE OF APPRAISAL IS
January 1, 2003



DELAHOOKE APPRAISAL COMPANY
VALUATION AND CONSULTATION

225 SOUTH FIRST AVENUE, SUITE 201
ARCADIA, CALIFORNIA 91006
PHONE (626) 445-0500 • FAX (626) 445-0599

SCOTT D. DELAHOOKE, MAI

July 31, 2003

AES Redondo Beach, LLC
c/o Rodi, Pollock, Pettker, Galbraith & Cahill
Mr. Wade Norwood, Esquire
444 Flower Street, Suite 1700
Los Angeles, CA 90071

Dear Mr. Norwood:

At your request, an appraisal has been completed of the AES power plant facility located at:

1190 N. Harbor Drive
Redondo Beach, California 90277

The report format includes this Letter of Transmittal which incorporates many items required by the Uniform Standards of Professional Appraisal Practice, a descriptive section which describes in greater detail regional, market area and physical property characteristics, and the valuation section.

Purpose: The purpose of the appraisal is to estimate the Fair Market Value for the subject site on an "as is" basis (excluding building value). The project includes ten P-GP (Plant Generating) zoned parcels totaling approximately 1,255,565 square feet or 28.82 acres. The subject site is improved with an electricity generating facility and is known as "AES Redondo".

Legal Description: A title report was not submitted for review. The APN's are 7503-013-004 through 010 and 7503-003-009 through 011. Public records describe the property as:

> A portion of the Ocean Beach Subdivision Redondo Beach M.B. 2-35 and the Townsite of Redondo Beach Tract, in the City of Redondo Beach, County of Los Angeles, State of California.

Market Value: This appraisal has been prepared in accordance with the following definition of Fair Market Value, per the California Revenue & Taxation Code, Section 110:

> The amount of cash or its equivalent that property would bring if exposed for sale in the open market under conditions in which neither buyer nor seller could take advantage of the exigencies of the other, and both the buyer and the seller have knowledge of all of the uses and purposes to which the property is adapted and for which it is capable of being used, and of the enforceable restrictions upon those uses and purposes.

The estimate of value is based on the definition as presented. The value conclusion represents a "cash" or "cash equivalent" value assuming no seller involvement in financing or terms of sale other than typical closing costs.

Market Value "As Is": Fair Market Value "as is" means an opinion of the market value of a property in the condition observed upon inspection and as it physically and legally exists without hypothetical conditions, assumptions, or qualifications as of the date of the appraisal. The effective date of the appraisal is January 1, 2003, and the date of inspection is July 9, 2003.

Marketing Time/Exposure Time: The value opinion is based on a normal marketing time, and is not a "quick sale" value. A normal sale marketing time would be approximately 9-12 months with proper exposure. The exposure time is estimated at 12-18 months. This is based on sales noted later in this report as well as other data held on file.

USPAP: This report conforms with the Uniform Standards of Professional Appraisal Practice. This report should be considered a Complete Appraisal (Standard Rule 1) written in a Summary Format (Standard Rule 2).

Intended Use/User of the Appraisal: This report has been prepared for Mr. Wade Norwood on behalf of the property owner (AES) for tax appeal purposes. This report may not be used or relied upon by any other entity without the express written permission of the appraiser.

Scope of the Assignment: In compliance with the Uniform Standards of Professional Appraisal Practice, the Scope of the appraisal is set forth in *The Appraisal Process, Methodology, Certification* and *The Assumptions and Limiting Conditions* section of this report. The subject involves a large site improved with a power generating facility. At the request of the client the assignment includes only the valuation of the site assuming it is vacant and available for development to its Highest and Best Use. The client has placed no other limitations on the Scope of this assignment

Sales History: The sales history for the subject property is noted below:

The subject has not sold in the prior three years. Reportedly this property was part of a $781,000,000 multi-property bulk purchase which transpired on 5/18/98.

Values Estimated: The appraisers were asked to provide a Fair Market Value opinion for the subject property.

Competency Provision: The property under being valued involves a site improved with a power generating plant (assignment includes land value only). The most probable future use would involve industrial and residential development. The appraisers comply with the Competency Provision of USPAP, and have valued numerous types and sizes of industrial and residential sites over the past twenty-one years.

Valuation Interests: The property is owner occupied. In accordance with the California Revenue & Taxation Code, the Fee Simple Estate rights are being valued.

Extraordinary Limiting Conditions: This report is subject to the extraordinary limiting conditions noted below:

1. The subject site is improved with a power generating plant. The appraisal assignment involves only the valuation of the underlying land based on its highest and best use. The improvements and FFE are not included in the appraisal. This is at the request of the client.

2. The demolition and environmental remediation costs used to determine the subject's "as is" value were taken from a Development Estimated submitted by Mar Ventures, Inc., a development company involved in the redevelopment of the subject property. These costs are assumed to be accurate. If the estimates prove inaccurate the appraisers reserve the right to amend the final value estimate.

As a result of the analysis of all available data and subject to the Assumptions and Limiting Conditions attached, the "as is" Fee Simple Estate Fair Market Value opinion for the subject property as of January 1, 2003 is:

FEE SIMPLE ESTATE VALUE
$25,670,000

Respectfully submitted,

Scott D. Delahooke, MAI
The Delahooke Appraisal Company
State Certification #AG002796
Expires 7/2/2004

TABLE OF CONTENTS

SUMMARY OF IMPORTANT FACTS AND CONCLUSIONS

In the following table, a summary of information regarding the subject property, the valuation process and the conclusions reached is presented. Support for the conclusions is contained later in this report.

EXECUTIVE SUMMARY	
General Information	
Property Address	1190 N. Harbor Drive, Redondo Beach, CA 90277
Current Property Ownership	AES Redondo, LLC
Census Tract	6212.02
Thomas Brothers Map Grid	762 G/H4
Date of Inspection	07/09/03
Date of Value	01/01/03
Physical Property Characteristics	
Flood Zone Information	Flood Zone X, Map Panel 0002 B, Map Date 9/15/83, #060150
Property Use	Power Generating Plant
Site Area	28.82 AC/1,255,565sf
Site Zone/Use Potential	PG-P/Generating Plant
Highest and Best Use Conclusion	Develop with a residential & industrial use
Land Valuation Information	
Fee Simple Sales Comparison Approach	$25,670,000
Conclusions	
Fee Simple Estate Value	$25,670,000

CERTIFICATION OF SCOTT D. DELAHOOKE, MAI

I certify that, to the best of my knowledge and belief:

The statements of fact contained in this report are true and correct.

The reported analyses, opinions and conclusions are limited only by the reported Assumptions and Limiting Conditions, and are my personal, impartial, and unbiased professional analyses, opinions and conclusions.

I have no present or prospective interest in the property that is the subject of this report, and I have no personal interest with respect to the parties involved. I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment.

My engagement in this assignment was not contingent upon developing or reporting predetermined results.

My compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.

My analyses, opinions and conclusions were developed and this report has been prepared in conformity with the Uniform Standards of Professional Appraisal Practice and the Regulations and Bylaws, as well as the Code of Professional Ethics of the Appraisal Institute.

Significant professional assistance was provided by Carmen Steele, including property inspection, data collection/verification and report writing. The appraisal assignment was not based on a requested minimum valuation, a specific valuation or the approval of a loan.

The property was personally inspected by the undersigned. No agent or employee exerted any undue pressure which could lead to a misleading or inaccurate appraisal.

As of the date of this appraisal, I have completed the requirements of the continuing education program of the Appraisal Institute (MAI). The use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.

Signed (AG002796)
Expires 7/2/2004

1-7-03
Dated

ASSUMPTIONS AND LIMITING CONDITIONS

1. The appraiser assumes no responsibility for matters of a legal nature affecting the property appraised or the title thereto, nor does the appraiser render any opinion as to the title, which is assumed to be good and marketable. The property is appraised as though under responsible ownership.

2. No survey has been made of the property and it is assumed that the improvement is well within the lot lines and in accordance with local zoning and building ordinances. This fact can only be ascertain by an engineering survey, which is beyond the appraiser's area of expertise.

3. Any sketch in the report may show approximate dimensions and is included to assist the reader in visualizing the property.

4. All information furnished by others are from reliable sources and are assumed to be true and correct. No responsibility is assumed for errors or omissions nor for information not disclosed by others which might otherwise affect the value estimate.

5. The appraiser assumes that there are no hidden or unapparent conditions of the property, subsoil or structures, which would render it more or less valuable. The appraiser assumes no responsibility for such conditions, or for engineering, which might be required to discover such factors. The appraiser can only report items which could be seen during the property inspection. The appraiser used due diligence in inspecting the property, however if access was limited for any reason the appraiser cannot be responsible for items which were hidden or unapparent due to the limited access.

6. The appraiser shall not be required to give testimony or appear in court by reason of this appraisal, unless prior arrangements have been made therefore. The client shall advise appraiser as to testimony required. If the appraiser is to provide expert testimony on behalf of the client, the client shall provide the appraiser with legal representation and pay for such legal representation as may be required.

7. Possession of this report does not carry with it the right of publication, nor may it or any part thereof, be used by anyone but the applicant without the previous written consent of the appraiser. The appraiser has no accountability, obligation or liability to any third party. If the client gives this report, or a copy of this report, to a third party, this limit of appraiser

liability should be fully explained and communicated. The report must always be observed in its entirety.

8. Neither all nor any part of the content or the report or copy thereof (including the conclusions as to the property value, the identity of the appraiser, professional designations, reference to any professional appraisal organizations, or the firm with which the appraiser is connected) shall be used for any purposes by anyone but the client specified in the report, the mortgagee or its successors and assigns, mortgage insurers, consultants, professional appraisal organizations, any state or federally approved financial institutions any department, agency or instrumentality of the United States or any state or the District of Columbia, without the previous written consent of the appraiser; nor shall it be conveyed by anyone to the public through advertising, public relations, news, sales or other media, without the written consent and approval of the appraiser. The appraiser assumes no obligation, liability or accountability to any third party. If this report is placed in the hands of anyone but the client, the client shall make such party aware of all of the assumptions and limiting conditions of this assignment.

9. The allocation of the total valuation in this report between land and improvements applies only under the existing utilization of the site. The separate valuations for land and improvements must not be used in conjunction with any other appraisal and are not valid if so used.

10. No search was made for insect infestation or rot in existing structures if any.

11. On all appraisals subject to satisfactory completion, repairs or alterations, the appraisal report and value conclusions are contingent upon completion of the improvements in a workmanlike manner.

12. In this appraisal assignment, the existence of potentially hazardous material used in the construction or maintenance of the building, such as the presence of urea formaldehyde foam insulation and/or existence of toxic waste (which may or may not be present on the property) was not observed by the appraiser nor does the appraiser have any knowledge of the existence of such materials on, in, or near the property. The appraiser, however, is not qualified to detect such substances. The existence of urea-formaldehyde insulation or other potentially hazardous waste material may have an effect on the value of the property. The client is urged to retain an expert in this field, if needed.

13. In April of 1992, the United States Congress passed landmark legislation known as the "Americans with Disabilities Act". It has unique and strong requirements on all property owners which is retroactive. At some point in the future, all buildings must provide adequate access to persons with disabilities. Due to the design of some structures, this could become extremely expensive and potentially alter property value. The appraiser is not an expert in architecture and can make no claims regarding the subject property's compliance with this act. The client should be aware that at some future date requirements may be made by governmental agencies for upgrades to the subject property.

14. The appraised value is based on the assumption all required licenses, certificates of occupancy, permits/conditional use permits or other operating approvals are in place and can be renewed in the future allowing reasonable property operation. In the event the subject site has been improved with legal, non-conforming structures, the appraiser assumes all such structures have been implemented with proper permits. It is also assumed that in the event of demolition, the building department having jurisdiction would allow reconstruction to the level of legal non-conforming use existing prior to destruction.

15. The appraised value is as of a specific date. The appraiser is not an economist and cannot predict or project future economic events which may impact the future value of the subject property. The appraiser can only take into account current and historic market information to estimate value.

16. If the client or any third party brings legal action against the appraiser and the appraiser prevails, the party initiating such legal action shall reimburse the appraiser for any and all costs of any nature, including attorney's fees, incurred during such legal action.

17. It is recommended that the client and/or any lienholder require, above and beyond the appropriate levels of liability and property damage insurance, a policy of rent abatement insurance to guarantee cash flow during periods of reconstruction. Most lease/rental agreements allow for tenant rent abatement during periods of repair/reconstruction, so the cash flow available for debt servicing is at substantial risk.

THE VALUATION PROCESS

The Valuation Process is defined in the Appraisal Terminology Handbook as:

> "A systematic procedure employed to provide the answer to a client's question about the value of real property."

It is a framework in which the appraiser gathers general and specific data needed to complete an appraisal assignment, and applies this data through the use of the three alternative approaches to value available to arrive at a final estimate of value by correlation and reconciliation of that data. The steps in the Valuation Process are typically as follows:

Identify the problem
Gather the Data
Analyze the Data
Develop Highest and Best Use
Apply the Data and Analysis to the Alternative Approaches
Reach a Final Estimate
Write the Appraisal Report

The alternative approaches to a value estimate available to the Appraiser include the Cost Approach, the Sales Comparison Approach and the Income Approach. Only the Sales Comparison has been analyzed in the body of this report. The Cost and Income Approaches are not used by buyers and sellers of this property type and were not developed. The Sales Comparison Approach is based on the Fee Simple Estate interest.

REGIONAL DATA

The City of Redondo Beach, located in Los Angeles County, is located within the so-called Sixty Mile Circle, which is an area within a radius of 60 miles of downtown Los Angeles. This 60-mile circle is comprised of about 11,310 square miles and encompasses almost all of the highly populated Counties of Los Angeles, Orange, Ventura, San Bernardino and Riverside.

Note: Most of the information contained in this section is from the Real Estate Research Council of Southern California report, which is a compilation from several sources of data including the Economic Development Department, Department of Finance and U.S. Census Bureau.

Population

Population for the region is over 12,000,000. For the County of Los Angeles, the January 2003 population now stands at 9,824,800, which is an increase from the January 2001 population of 9,802,780. Orange, Riverside and San Bernardino populations have increased by similar ratios over the past year. Projections are for a continuation of current trends.

Employment

It is interesting to note that while defense-related industry was the greatest employment sector in 1990, the most recent trends indicate that the entertainment industry had become the largest employment sector. In Los Angeles County, the largest employment field is in services, followed by trade and manufacturing. In the table below, the change in employment over the past several quarters is summarized.

MANUFACTURING EMPLOYMENT SUMMARY				
Period:	2nd Qtr. 2002	3rd Qtr. 2002	4th Qtr. 2002	1st Qtr. 2003
Total Regional Employment:	10,117,900	10,218,835	10,243,100	10,160,900
Change-Previous Year:	.017	.014	.009	-.001
Change-Previous Qtr.:	-.005	.010	.002	-.008
Regional Manufacturing Employment:	1,119,365	1,110,365	1,100,200	976,200
Change-Previous Year:	-.026	-.025	-.024	-.045
Change-Previous Qtr.:	-.003	-.008	-.009	-.113

The overall employment has been increasing starting in 1996 with manufacturing employment remaining relatively constant while other market segments improve. There was some erosion in manufacturing employment beginning in 2001 and increasing in 2002 although at a slower pace in the most recent quarters. For 2002 regional unemployment the national level and state levels. In the table below, the unemployment rates over the past several years have been summarized.

SUMMARY OF UNEMPLOYMENT RATES									
Period:	1994	1995	1996	1997	1998	1999	2000	2001	2002
Regional Unemployment:	8.4%	7.3%	7.0%	5.9%	5.4%	4.8%	4.5%	4.7%	5.7%
State Unemployment:	8.6%	7.8%	7.2%	6.3%	5.9%	5.2%	5.0%	5.3%	6.7%
National Unemployment:	6.1%	5.6%	5.4%	5.0%	4.5%	4.2%	4.0%	4.7%	5.8%

The lowest unemployment rate tends to be in Orange County, followed by San Diego County, Santa Barbara County, Ventura County, Los Angeles County and San Bernardino/Riverside Counties.

Development

The Southern California market has been considered one of the most dynamic real estate market areas in the world for several decades. Construction activity is summarized in the following table (in thousands for permit value).

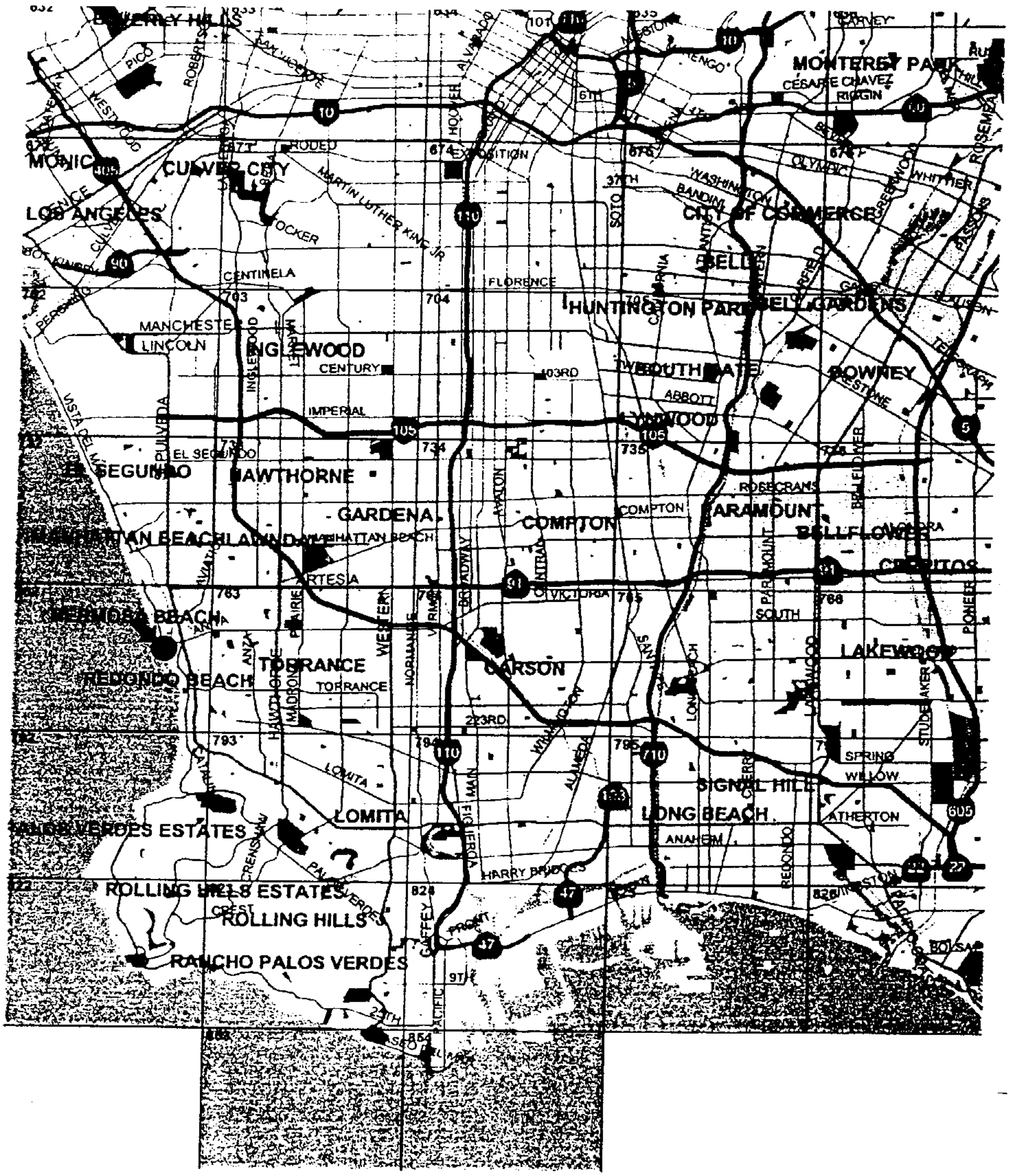
SUMMARY OF CONSTRUCTION ACTIVITY							
Residential Sector							
Time Period:	1996	1997	1998	1999	2000	2001	2002
Single Family Units:	32,785	36,762	43,411	49,054	47,599	50,903	56,005
Single Family Permit Value:	$5,467,000	$7,183,000	$8,462,000	$10,144,000	$10,182,000	$10,838,000	$11,872,000
Multi-Family Units:	8,338	12,869	13,525	20,851	24,651	23,802	26,868
Multi-Family Permit Value:	$604,000	$961,000	$1,084,000	$1,706,000	$2,183,000	$2,365,000	$2,591,000
Non-Residential Sector							
Time Period:	1996	1997	1998	1999	2000	2001	2002
Office Buildings:	$290,000	$465,000	$819,000	$959,000	$869,000	$996,000	$537,000
Retail Buildings:	$815,000	$915,000	$1,033,000	$1,235,000	$13,332,000	$1,225,000	$1,259,000
Industrial Buildings:	$510,000	$760,000	$1,239,000	$1,198,000	$1,173,000	$874,000	$776,000

As can be seen in the above table, single and multi-family development remained strong in 2001. While new office building construction increased from 2000 to 2001, retail and industrial building construction declined. In 2002 office and industrial construction declined but retail construction increased slightly. However, vacancy rates in all three property types remains at below 10% in most market areas.

Conclusion

In summary, the 60-Mile Circle and the Los Angeles area can expect future stability and slow growth in U.S. international trade not only as a shipping point but also as a service and financial hub because of its strategic position in the Pacific Basin, an area which contains nearly half of the world's population. By almost all accounts, the economy on a national basis is expected to grow at a 2.5% to 3.0% annual rate over the next two years. Southern California should expect to meet or exceed national growth expectations over the next few years according to most economists.

REGIONAL MAP



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MARKET AREA OVERVIEW

The City of Redondo Beach is situated 18 miles southwest of Los Angeles in the South Bay Area. Redondo Beach is bounded by the Pacific Ocean to the west and by the cities of Manhattan Beach, Hermosa Beach and Torrance. The city encompasses 6.35 square miles and has approximately two miles of beach frontage. The city is about four miles south of LAX. Access to the San Diego Freeway (405) is about four miles north east from Artesia Boulevard. The estimated 2002 population is 62,700. The city has convenient north/south access to other parts of the county from Pacific Coast Highway.

Redondo Beach is primarily a "bedroom community". The city reports a total of 29,543 housing units. Within the subject's census tract, Dataquick Information Systems reports the median single family price for the 1st Quarter of 2003 is $605,000. The median price of condominiums for the 1st Quarter of 2003 is $411,000. The reported median household income is $73,341. The city reports an unemployment rate of 2.4 percent.

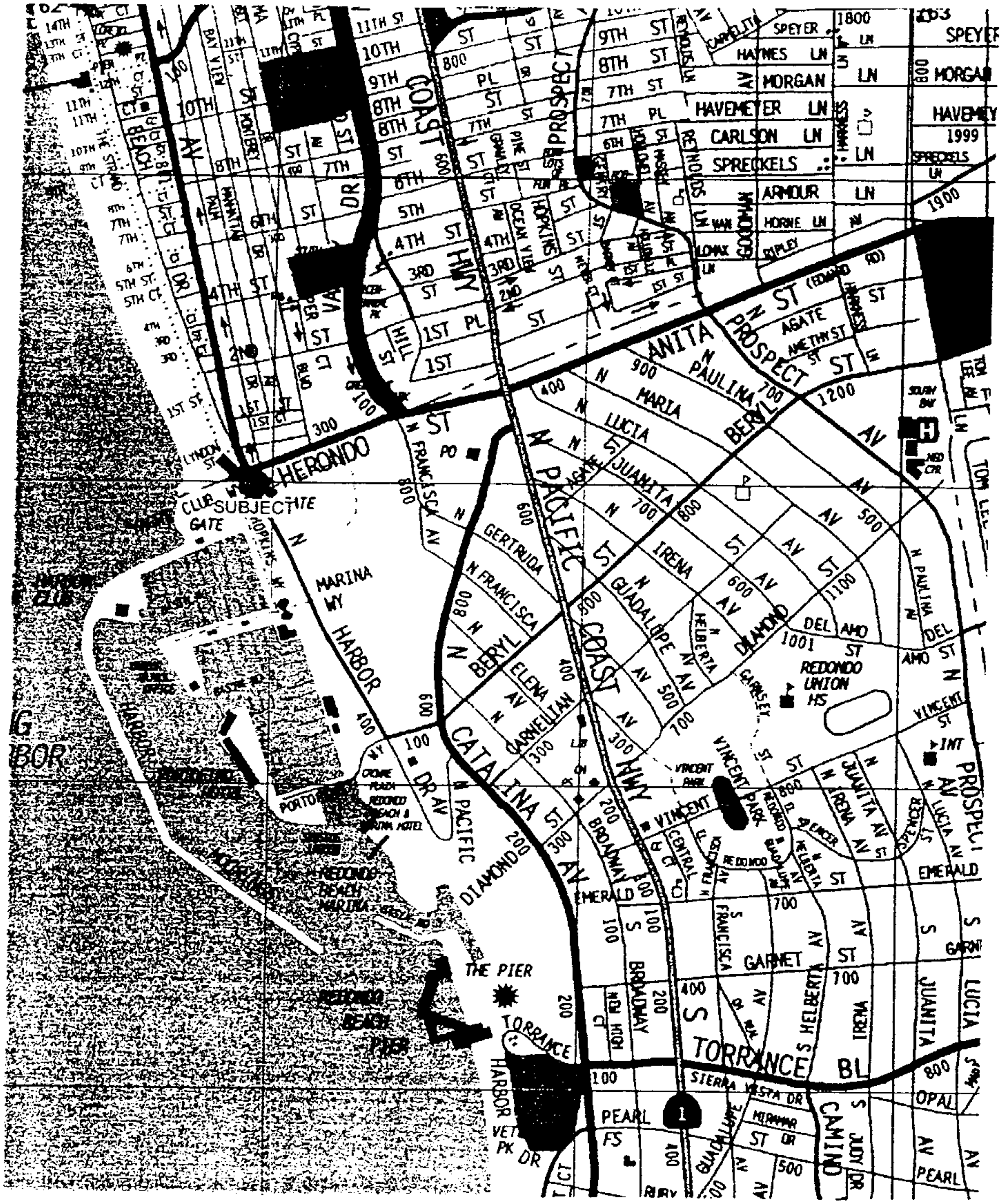
REDONDO BEACH MAJOR EMPLOYERS

Number of Employees	Company Name
500+	Northrop Grumman
200-499	Crowne Plaza Redondo Beach
	Cheesecake Factory
	Douglas Furniture
	Imperial Bank
	Mervyn's
	Nordstrom
	Robinson May
	South Bay Family Health
	United States Post Office
	Web Services Company
	The City of Redondo Beach
	The Redondo Beach Unified School District

Subject's Immediate Market Area

The subject is located on the south east corner of Herondo Street and Harbor Drive and on the south side of Harbor Drive between Yacht Club Way and Marina Way in the northwestern portion of Redondo Beach where it borders Hermosa Beach. The site fronts to the King Harbor Yacht Club and the Pacific Ocean beyond. Redondo Beach is bordered by Hermosa Beach, Manhattan Beach, Torrance and the Pacific Ocean. The immediate area is mostly commercial and residential with some industrial uses to the east. The site backs to a large mini-storage facility on Francisca Avenue. Along Harbor Drive uses include hotels/motels, restaurants and other commercial uses. Uses along Herondo Street include vacant land and industrial uses on the south side of the street and multi-residential uses on the north side of the street (Hermosa Beach). The subject's industrial use is considered non-conforming for the immediate market area.

MARKET AREA MAP



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SITE DESCRIPTION

The subject is located in the northwestern portion of the city where Redondo Beach borders the city of Hermosa Beach and is approximately two blocks from the Pacific Ocean. The site consists of ten parcels situated on both sides of Harbor Drive and total 28.82 acres of gross land area. Two of the parcels are located on the east side of Harbor Drive. This is where the generating plant is located and total 1,215,293sf or 27.90 acres. The remaining eight parcels are located on the west side of Harbor Drive and total 40,272sf or .92 acres. The subject fronts to commercial and Marina uses on Harbor Drive. It backs to a large newer mini-storage facility on the west side of Francisca Avenue. Adjacently south on Harbor drive the AES Plant sides to a Best Western Redondo Motel and a Salvation Army facility adjacent north of the motel. There is metered parking on the south side of Herondo Street. A summary of the subject parcels is listed below.

SUMMARY OF SUBJECT PARCELS

Location	APN No.	Square Feet	Acres
1100 Harbor Drive	7503-013-004	1,214,017	27.87
1100 Harbor Drive	7503-013-005	1,276	0.03
Harbor Drive Between Yacht Way and 10th St.	7503-013-006	2,247	0.05
Harbor Drive Between Yacht Way and 10th St.	7503-013-007	5,606	0.13
Harbor Drive Between Yacht Way and 10th St.	7503-013-008	11,491	0.26
Harbor Drive Between Yacht Way and 10th St.	7503-013-009	2,238	0.05
Harbor Drive Between Yacht Way and 10th St.	7503-013-010	7,479	0.17
Harbor Drive Between 10th St. and Marina Way	7503-003-009	5,096	0.12
Harbor Drive Between 10th St. and Marina Way	7503-003-010	5,096	0.12
Harbor Drive Between 10th St. and Marina Way	7503-003-011	1,019	0.02
	Totals	**1,255,565**	**28.82**

The area is generally flat and the parcels are further described below.

<table>
<tr><th colspan="3">Site Summary</th></tr>
<tr><td>Total Site Area</td><td colspan="2">1,255,565sf/28.82 acres</td></tr>
<tr><td>Zoning</td><td colspan="2">CC-4/P-GP
The CC-4 (Costal Commercial Zone) provides for the continued use of the City's coastal-related commercial-recreational facilities and resources. It is designed to provide for development and enhancement of commercial retail and service facilities supporting recreational boating and fishing. All classifications in the coastal commercial zones are subject to approval of a Conditional Use Permit. Permitted uses under this classification include Commercial Recreation, Food and Beverage Sales, Hotels and Motels Marinas and Marina-related facilities, Services, Restaurants, Retail Sales, Cultural Institutions and Parking Lots. The maximum FAR is 0.35 and the maximum building height is 38 feet or two stories. Setbacks include a minimum 15 foot setback from Harbor Drive. Parking requirements depend and vary with use. Some of the parking requirements are listed below.</td></tr>
<tr><td></td><td>Restaurant Sit-down:</td><td>One space per 4 seats but not less than one space per 50sf of GBA.</td></tr>
<tr><td></td><td>Fast Food:</td><td>One Space per 75sf of GBA.</td></tr>
<tr><td></td><td>Hotels/Motels:</td><td>Hotels/Motels: One space for each guest room for motels and 1.5 space for each guest room for hotels.</td></tr>
<tr><td></td><td>Boat Slips:</td><td>Boat Slips: Three-fourth space for each boat slip.</td></tr>
<tr><td></td><td colspan="2">P-GP: See comments below.</td></tr>
<tr><td>Frontage</td><td colspan="2">2,149' on Harbor Drive±
1,160' on Herondo Street±</td></tr>
<tr><td>Site Topography</td><td colspan="2">Generally Level</td></tr>
<tr><td>Surrounding Uses</td><td colspan="2">Residential, multi-residential, industrial and commercial projects surround the subject.</td></tr>
</table>

Additional comments are noted below.

Zoning

The current zoning for the subject plant or the parcels located on the east side of Harbor Drive (7503-013-004 & 005) is difficult to determine. According to the 1992 General Plan the parcels are zoned P-GP (Generating Plant Zone). According to Mr. James Allen from the City's Harbor Department, at this time the only use allowed on the subject site is a power plant. The facility is an out-of-date electrical power generating plant with eight generating units. Units 1 through 4 are not operational. The remaining turbines employ steam turbine technology which is significantly less efficient than new combined cycle gas turbine technology. Typically, the plant operates only two of the four operational turbines.

In view of this, AES announced (when) that electrical production would not be expanded and did not need all of the owned land. City officials began working on a plan to develop the unused portion of the site. Over the past three years the City has worked on a redevelopment project for the AES site and surrounding area. Initially the project was known as the Heart of the City Specific Plan (HOCSP). The plan which provided for commercial and residential development on the AES site was adopted on 2/26/02. The plan met with such resistance from Redondo Beach citizens that the City Council was forced to rescind it in June of 2002. Redondo Beach Residents initiated a petition and collected 2,000 more than the 4,000 signatures needed to block the measure because they were concerned with the potential over-development of the site, and the non-specific nature of the proposed uses.

The Council has now revised the plan into what they hope will be acceptable to the public. The new plan is called the Catalina Redevelopment Project. The new plan provides for a smaller area and lower density. The City Council is now conducting public meetings in hopes that the public will find it more acceptable and the project can be adopted and implemented without further resistance. The first meeting was held on 7/12/03. The response from the public was not positive and the Council was forced to continue the hearing on 7/15/03. During the 7/15/03 meeting the Catalina Redevelopment Project still met with some resistance. The majority of the opposition appears to be that the presented project is not specific about density. After the meeting, the council agreed to answer all the questions posed by the public. Additionally, the City is being sued by Hermosa Beach with respect to aspects of the Catalina Redevelopment Project. The outcome of the Catalina Redevelopment Project is unknown at this time.

Under the Catalina Redevelopment Project the zoning was changed to HOCSP Catalina Corridor and HOCSP Waterfront (formerly CC-1 THROUGH CC-7, P-PRO, P-ROW, C-2A, C-3A, C-4B, C-F, MU-2 AND I-2A). However, determination of current zoning for the subject power plant site is further complicated because the Heart of the City Specific Plan was repealed but the associated zoning was left in place. This was due to legal restrictions related to the petition brought by the public which created conflicts that cannot be resolved until after a one-year moratorium on land use decisions related to the recission of the Specific Plan. At this time, the general types of uses intended for the subject site includes retail, commercial and residential with a density of 16 to 55 units per acre. According to the City's Senior Planner, Randy Berler, at this point it is unknown if and when the Catalina Redevelopment Project will be approved and what the allowed final uses will be. Mr. Berler confirmed that the primary use planned for the subject site is residential. Mr. Berler is of the opinion that it may six to twelve months before the Catalina Redevelopment Project is approved.

In view of the preceding facts and for the purpose of this appraisal, the concluded use for a portion of the site occupied by the electric generating plant is residential, with the potential for limited commercial along street frontage.

Easements A title report was not submitted for review. However, the client acknowledged an easement to Southern California Edison to allow access to their switching yards for transmission of the power generated.

Offsites Harbor Drive is a two-laned, two-way street which is asphalt paved. Herondo Street is a four-laned, asphalt paved, two way street. Both Streets are improved with concrete curbs/gutters/sidewalks and have storm drains and sewer systems in place.

Environmental The appraiser has valued the property assuming the site is free from all forms of environmental contamination. The field of environmental sciences is beyond the appraiser's area of expertise. The appraiser has been informed that the subject site may have some contamination (either on the subject site, or the tank farm site).

The following were interviewed for the investigation and determination of the subject's zoning classifications.

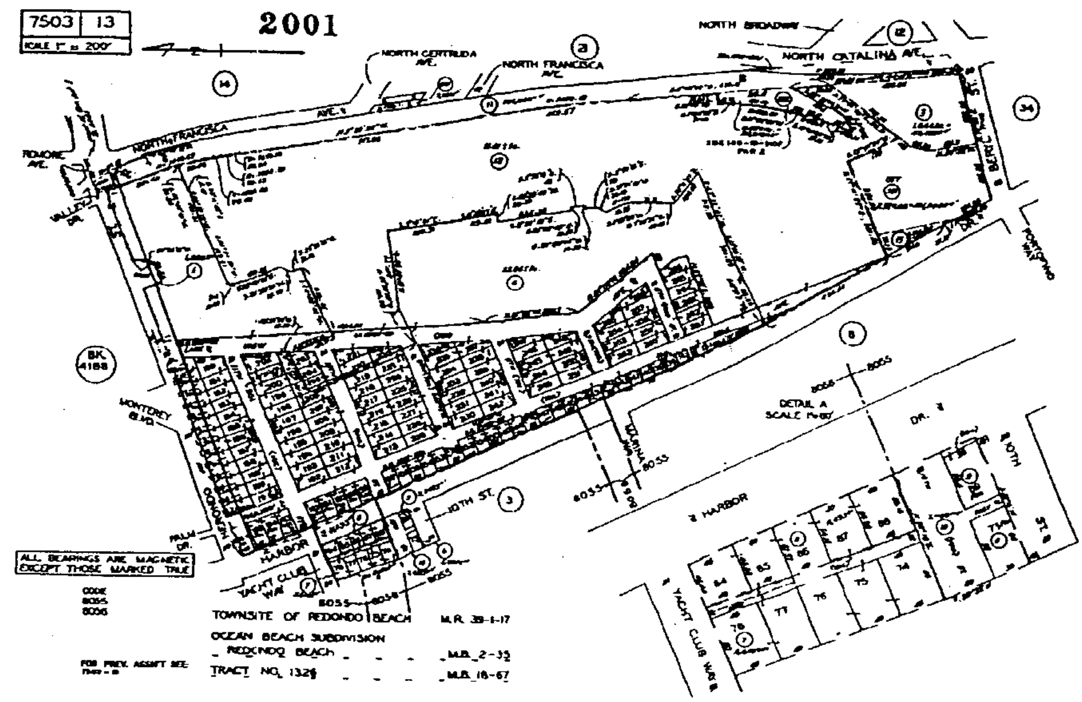
Randy Berler	Redondo Beach (Senior Planner) Redondo Beach Planning Dept.	310-318-0637
Sylvia	Redondo Beach Planning Department	310-318-0637
James Allen	Redondo Beach Harbor Department	310-318-0631
Gary Ohst	Appraiser/The Horizon Group	310-376-0616
Mary Delehanty	Redondo Beach Resident	310-937-4948

Improvement Description

The subject site is improved with a power generating plant with a capacity of 1,310 megawatts and employs 52 employees. The facility was built circa 1947 with additions made over the years. There is a four story frame and stucco office building and approximately 59 open concrete paved parking spaces.

There are seven units of which three are no longer operated. The Tank farm uses oil only (natural gas). The tanks and equipment are spread throughout the site.

PLAT MAP



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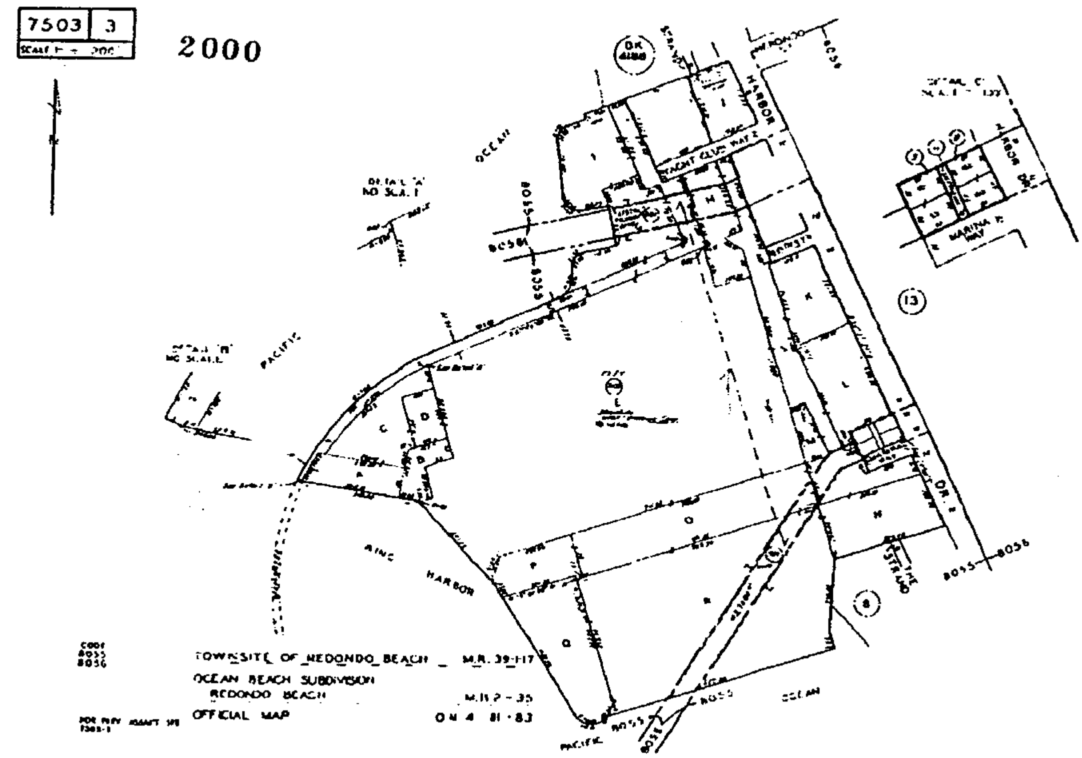
PLAT MAP



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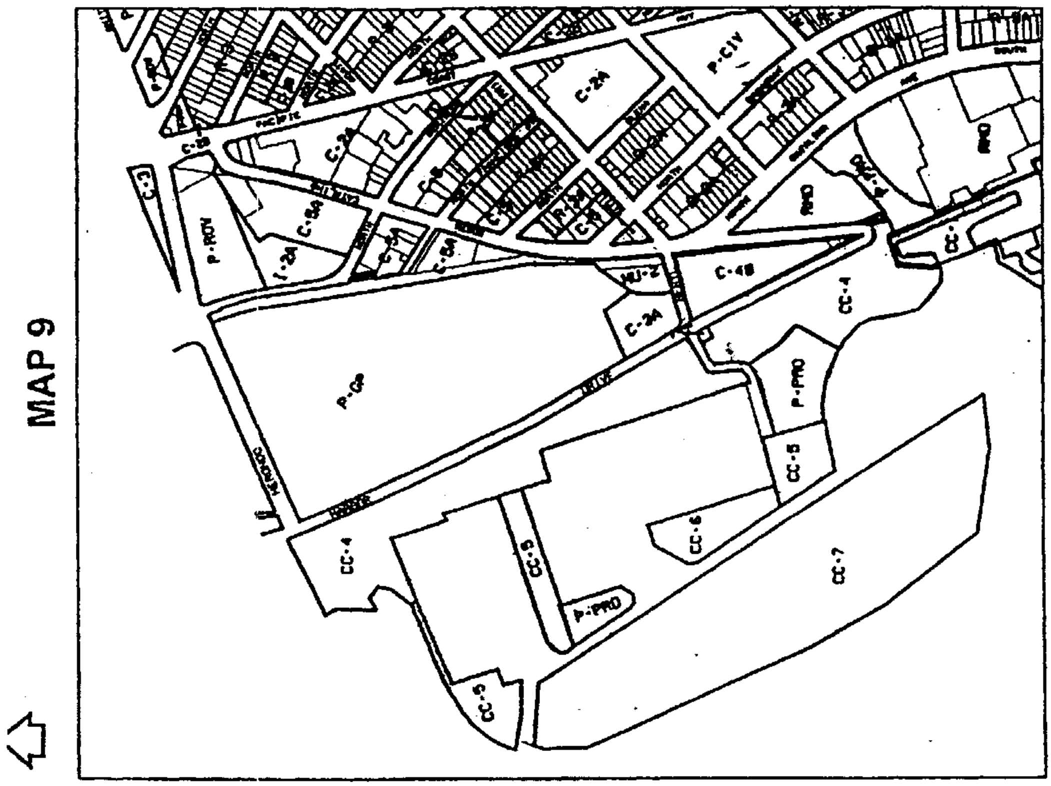
ZONING MAP

MAP 9



HIGHEST AND BEST USE ANALYSIS

Highest and Best Use is "The reasonably probable and legal use of vacant land or an improved property, which is physically possible, appropriately supported, financially feasible, and that results in the highest value. The four criteria the Highest and Best Use must meet are legal permissibility, physical possibility, financial feasibility, and maximum profitability." (The Dictionary of Real Estate Appraisal). In forming an opinion of Highest and Best Use, some of the factors to be considered are:

> Is the proposed use legally permissible or reasonably possible?
> Is the proposed use physically possible on the site?
> Is the proposed use economically and financially feasible under existing and projected market conditions?
> Is the proposed use estimated to be the most profitable among the alternatives that are legally permissible, physically possible and economically feasible?

Highest and best use analysis involves, in general, a study of the site as if vacant and ready to be put to its highest and best use, as well as the property as improved. Since only the land is being valued, only the Highest and Best Use "as if vacant" will be considered.

Highest and Best Use - As if Vacant

The subject site is zoned P-GP, which is a Generating Plant classification which allows primarily power plant use. The site consists of ten parcels totaling 28.82 acres. Approximately 40,000sf are located across the street from the power plant facility. Along Harbor Drive exists a wide range of uses including commercial and residential. Residential uses are found on most secondary streets in the area. The subject site fronts to the marina and the Pacific Ocean beyond. A portion of the subject site is not part of the Redevelopment Project as it is subject to a contract with 14 years remaining. The portion available for redevelopment is suitable for residential development

There has been a trend over the past three years toward development of industrial projects as rental rates and values have increased. According to CB Richard Ellis, the vacancy rate for industrial properties in the South Bay market for the 2nd Quarter of 2003 is 4.5% and the average asking monthly lease rate is \$0.53/sf. Still no new projects were noted as yet by the appraiser around the date of inspection in the immediate area. The Highest and Best Use of the subject site "as if vacant" would be to develop with a mixed use project (industrial and residential).

Sales of Generating Power Plants

To support the Highest and Best Use conclusion, a search was made for sales of power plant land. The only sales which could be confirmed involve two closed sales and one under contract which involve properties proximate to and with potential use as power plant land.

POWER PLANT SALES				
Address	Site Area/APN	Zoning	Sale Date/Price	Price/Acre
690 N. Studebaker Road Long Beach, CA	776,239sf/17.82 AC #7237-019-005	PD1	12/02-$2,500,000	$140,292
21732 Newland Avenue Huntington Beach, CA	831,168sf/19.08 AC #114-150-84	PS-O-CZ-FP2	05/01-$2,150,000	$112,683
21732 Newland Avenue Huntington Beach, CA	196,020sf/4.50 AC #114-150-84	PS-O-CZ-FP2	Pending-$300,000	$66,667

The first sale involves a 17.82 acre site sold by AES for $2,500,000 ($140,292/acre) with Doc. #3021327. The date of sale was 12/10/02. The site was purchased "as is" to hold for future development and sold for land value only.

The second property was purchased by AES from Southern California Edison on 5/7/01 for $2,150,000 ($112,683/acre) with Doc. #286988. The site was purchased to hold for future development and sold for land value only.

The third sale involves a portion of Sale #2. AES has a Letter of Agreement to sell 4.5 acres of this site to the City of Huntington Beach for development of a water reservoir facility. The agreed price is $300,000 or $66,667/acre. The site is being sold "as is". According to Rick Tripp from AES the sale should be finalized by the end of the fourth quarter of 2003. This is a smaller site on at the end of a dead -end 36'wide street. This site is inferior in utility and frontage. Mr. Tripp also confirmed that future plans for the remaining site may include leasing or selling the site to desalinating plant. At this time this is only in the planning stages and no other details have been set.

These properties involve sites formerly used as generating plants and sold "as is". The cost to clean up and remove existing equipment is to be paid by the buyers. According to Tom Kunde the cost to remove tanks is estimated at $50,000 plus scaffolding per tank. The price for these sites ranges from $66,667 to $140,292 per acre on an "as is" basis. This is below the range of value for industrial development sites, as noted later in this report.

VALUATION METHODOLOGY

In the appraisal process, there are three approaches to value which can be applied to income producing property. These include the Cost, Sales Comparison and Income Approaches to value. The importance of each approach is based on its use in the marketplace by active buyers and sellers and the data available to support the conclusion. Each approach is discussed in more detail below.

The Cost Approach

The Cost Approach is a technique which can be of primary importance in the analysis of special purpose property or as a check on a project's feasibility and measure of Highest and Best Use. The procedure involves estimating the cost new of the improvements, deduction of all forms of accumulated depreciation (physical, functional and external) and addition of land value. The indicated value represents what a property is worth based on the component parts and their corresponding cost or value. The land value estimate is based on sales of other parcels having a similar Highest and Best Use and is predicated on an "as if vacant" scenario. This approach is strongest in new construction but becomes difficult to support as the improvements deteriorate, functional or external obsolescence exists or other unique factors are present.

The Sales Comparison Approach

The Sales Comparison Approach or the Market Approach is based on the principal of substitution. It assumes that a potential buyer would not pay more for the property being analyzed than could be paid for a property of similar utility in a similar location. It requires a reasonable supply of property from which the buyer can make a prudent, rational decision. This approach is often used by buyers and sellers due to its simplicity in units of comparison (normally the price per square foot or income multiplier). It is most applicable when there are sufficient sales of similar property with verifiable income characteristics to analyze.

The Income Approach

This approach considers the income potential of the subject property. It is to be viewed from the investor's perspective, using rates of return being required in the market. The principal of substitution applies in that a sophisticated and prudent investor would pay no more for a cash flow, considering risk, management considerations and liquidity, than would be required for other similar income streams. The process involves estimating a potential market income for the property, deducting operating expenses to arrive at a net income before debt service, and capitalizing that income by an appropriate market-supported rate. This technique is applicable in all cases of income property analysis and is used by knowledgeable buyers and sellers in the market. If appropriate, the cash flows can be carried out over a period of years with each successive net income flow being discounted into a present worth estimate (Discounted Cash Flow Model). This technique must be based on investor expectations and should typically be used to support the first year income capitalization due to the number of inherent assumptions required.

Proper Use of Approaches: The subject property involves a site which is improved with a power generating facility. The Highest and Best Use would be for industrial and residential development. In this case, only the Sales Comparison Approach will be analyzed. The Cost and Income Approaches will not be analyzed as they are not typically used for land valuation.

Purpose of the Appraisal: The purpose of the appraisal is to estimate the Market Value of the subject property. The property rights appraised include the Fee Simple Estate, as the site is reportedly free from lease encumbrance. The analysis will include current market information based on recent sale comparable activity.

SALES COMPARABLE APPROACH

In the Market Data Approach or Sales Comparison Method, recently sold properties are compared with the subject for similarities and are adjusted for major differences. This Approach as used to estimate the value of real estate is based on the premise that an informed and prudent buyer would pay no more for a property than the cost of acquiring another property with the same utility. It is based on the principle of Substitution. This approach is based on an active market and the availability of other properties from which an investor can make a choice.

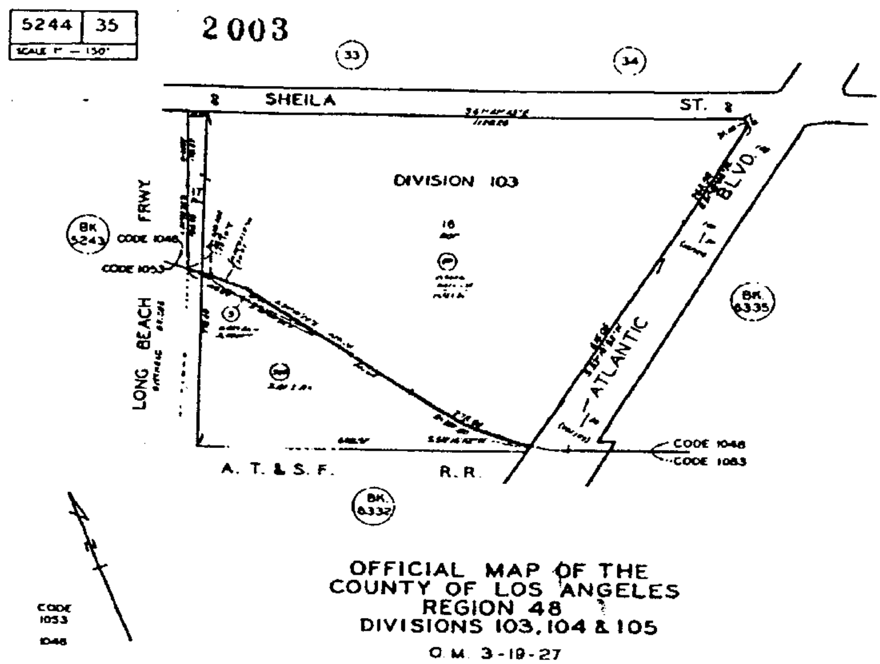
The subject site is zoned P-GP. Under this zoning classification only a generating plant can be developed. However, a redevelopment project is planned for the subject area. Under this redevelopment plan a portion of the subject site will be developed with a residential use. The remaining are will remain as power plan land. This portion of the site will be valued assuming an industrial use on this site. In all likelihood this use would be allowed on this site given the current P-GP zoning classification. In the analysis of industrial/residential land such as the subject, the primary unit of measure is either the price/square foot or price/acre. Due to the size of the subject, a price/acre will be utilized.

Site Valuation

To arrive at an estimate of value for the subject site as if vacant, a search for industrial and residential land sales of similar size to the subject was conducted in the same general area. The appraiser used several sources including MLS, Experian, Comps Inc. and public records. Neither industrial nor residential land sales of sites with more than ten acres in Redondo Beach and nearby areas were found. The search was expanded throughout competing areas of Los Angeles County. The search produced 35 industrial and seven residential land sales of more than ten acres that closed escrow since 2000. The most competitive properties which could be confirmed include four industrial and three residential properties which are analyzed. The results of this search are summarized on the following pages. Additional industrial land sales in competitive market areas are summarized below for further support.

ADDITIONAL INDUSTRIAL LAND SALES SUMMARY				
Address	**Site Area/APN**	**Zoning**	**Sale Date/Price**	**Price/Acre**
755 E. L Street Wilmington, CA	236,530sf/5.43 AC #7425-002-001	M2-1	04/02-$3,582,720	$659,801
Hamilton Ave. S/Knox St. Los Angeles, CA	260,924sf/5.99 AC #7351-033-040	Industrial	08/02-$3,300,000	$550,918
NE Harborgate/Francisco Los Angeles, CA	333,507sf/7.66 AC #7351-003-021	M3-1	12/01-$4,300,000	$561,358
5401 - 5599 Obispo Ave. Long Beach, CA	98,881sf/2.27 AC #7121-011-044	MG-ML	07/02-$888,030	$391,203
1495 Seabright Avenue Long Beach, CA	60,774sf/1.40 AC #7429-034-911, 914	MG	09/02-$668,514	$477,510
2121 E. Cover Street Long Beach, CA	32,200sf/0.74 AC #7149-004-028	MMR	06/02-$386,500	$522,297

LAND SALE #1



Property Information

Address:	4940 Sheila Street, City of Commerce, California
Legal/APN:	Portion of Lots 75 and 76, Rancho Laguna, Book 6387, Page 1/#5244-035-001 thru 003, #5243-014-005
Site Area/Zone:	657,756sf/15.10 Acres/M2 (Industrial)

Sale Information

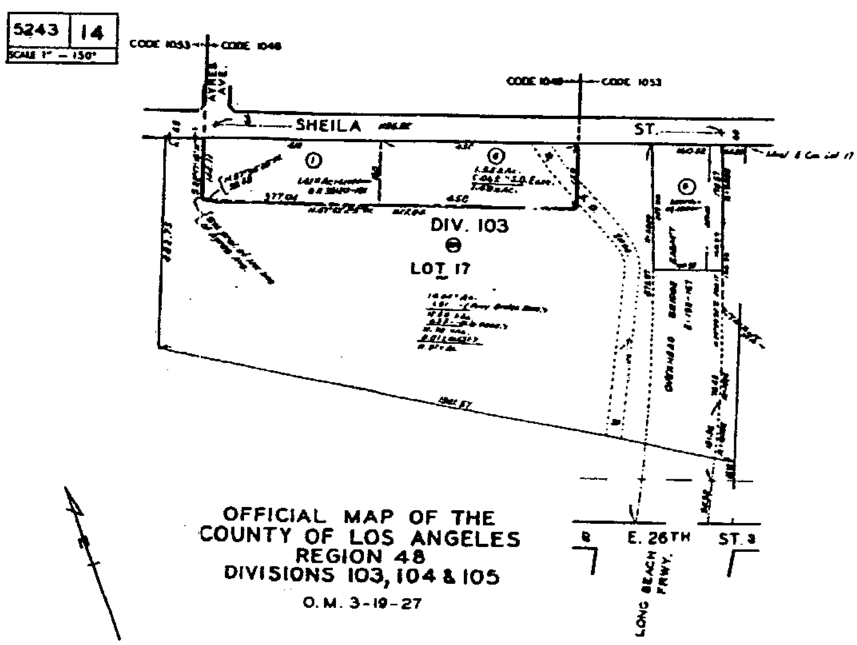
Sale Date:	12/11/02	**Document:**	#3025710
Buyer:	Burlington N. & Santa Fe Railway	**Seller:**	Ford Motor Company
Sale Price:	$10,450,000	**Cash Price:**	$10,450,000

Cash Price/Acre: $692,053

General Information

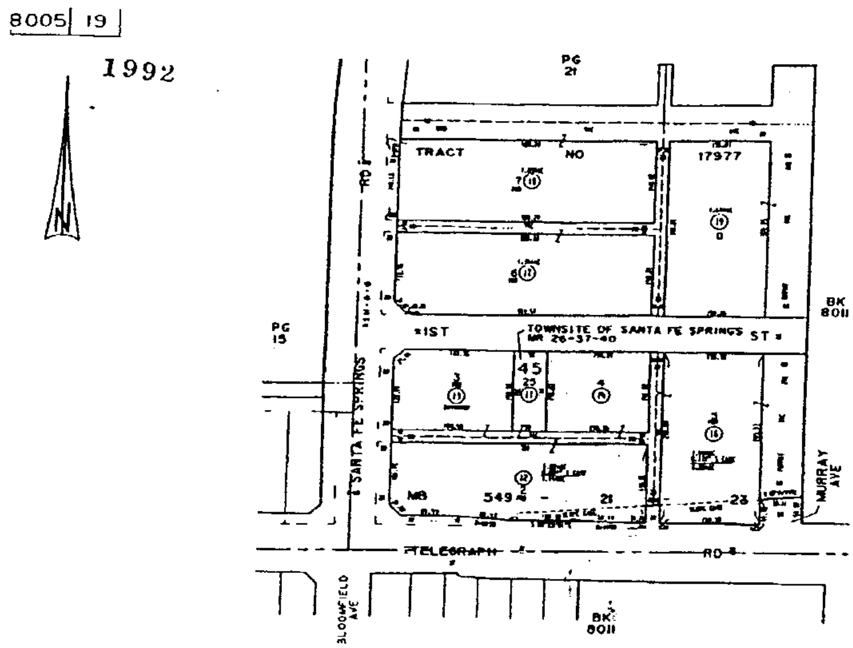
Financing:	All cash sale.
General Comments:	This sale involves several parcels totaling 15.10 acres of gross site area. The negotiated price was $11,000,000 less $550,000 for demolition of improvements. According to the listing broker there was no contamination on site and the property was never listed. The property was purchased to use as a storage yard.
Confirmed:	Broker, Michael Mitchell, #323-838-3100, Comps Inc., Public Records

SALE #1 ADDITIONAL PLAT MAPS



1759

LAND SALE #2



Property Information

Address:	Santa Fe Springs Rd. N/Telegraph Rd, Santa Fe Springs, California
Legal/APN:	Lots 4 thru 11, 14, 17, & Por. of Lots 2, 3, 12, 13, 15-16, Tract 17977, Book 549, Pages 21 thru 23/#8005-019-012, 013, 014, 016, 017, 018, 019; 8005-021-006, 007, 009, 010, 013; 8005-023-010, 012, 015, 016,; 8011-002-022.
Site Area/Zone:	958,320sf/22.00 Acres/M2 (Industrial)

Sale Information

Sale Date:	9/19/02	**Document:**	#2208446
Buyer:	Proficiency Heritage Crossing	**Seller:**	Bullet Parcel Fee (LLC)
Sale Price:	$9,000.000	**Cash Price:**	$9,000,000

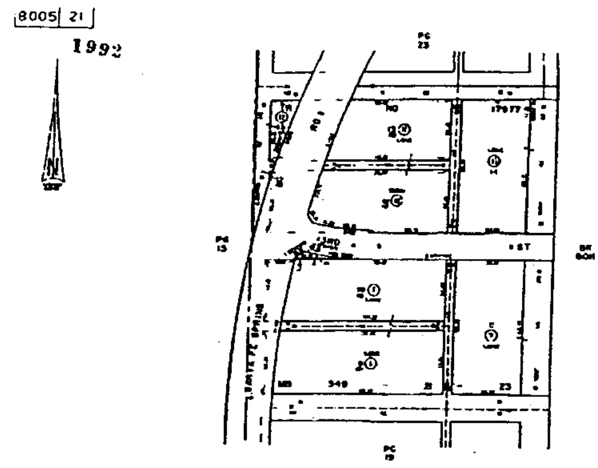
Cash Price/Acre: $409,091

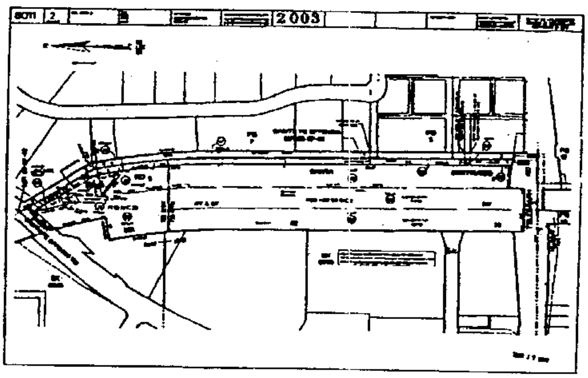
General Information

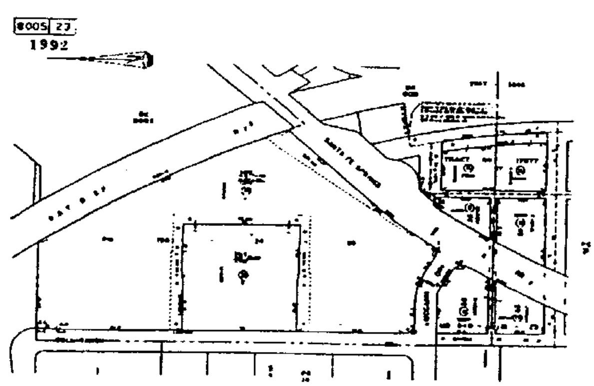
Financing:	All cash sale.
General Comments:	This sale involves eighteen vacant parcels stretching along Santa Fe Springs Road in the City of Santa Fe Springs. The site was purchased to develop with a seven building industrial project totaling 416,695sf. All utilities are to the site.
Confirmed:	Buyer, 310-914-7411, Comps Inc. & Public Records

1760

SALE #2 ADDITIONAL PLAT MAPS







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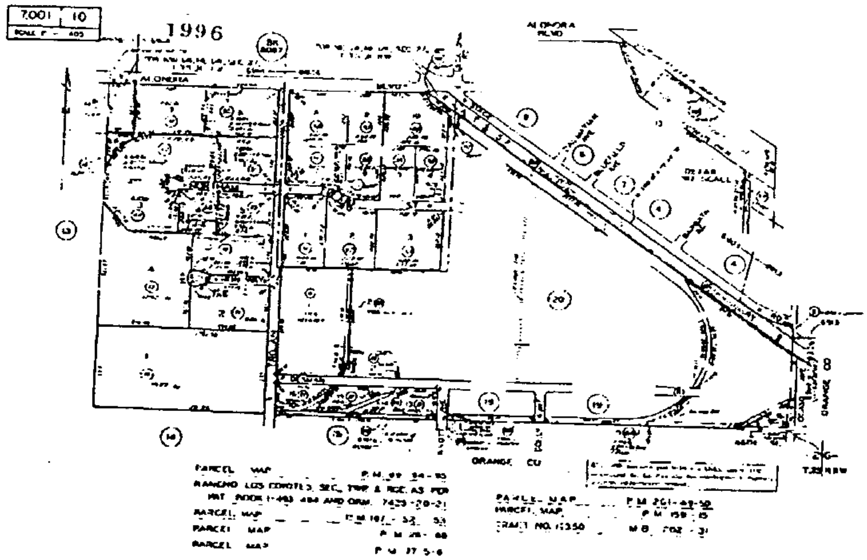
LAND SALE #3



Property Information	
Address:	16501 Trojan Way, La Mirada, California
Legal/APN:	P.M. #22527, Book 261, Pages 49-50/#7001-010-070
Site Area/Zone:	839,304sf/19.27Acres/M2

Sale Information			
Sale Date:	08/23/01	**Document:**	#1567772
Buyer:	MC & C/Fortis II (LLC)	**Seller:**	La Mirada Redevelopment
Sale Price:	$10,300,000	**Cash Price:**	$10,300,000

Cash Price/Acre: $534,510

General Information	
Financing:	$3,500,000 cash down and a $25,000,000 1st TD with City National Bank which includes construction costs.
General Comments:	This property involves a large rectangular site purchased to develop an industrial project totaling approximately 498,630sf. The project includes concrete tilt-up construction, 32' truss height, Phase 3 power, 800 amps, and 38 dock highs. Construction has been completed.
Confirmed:	Seller's representative, John Demerles, 562-943-0131, Comps, Public Records

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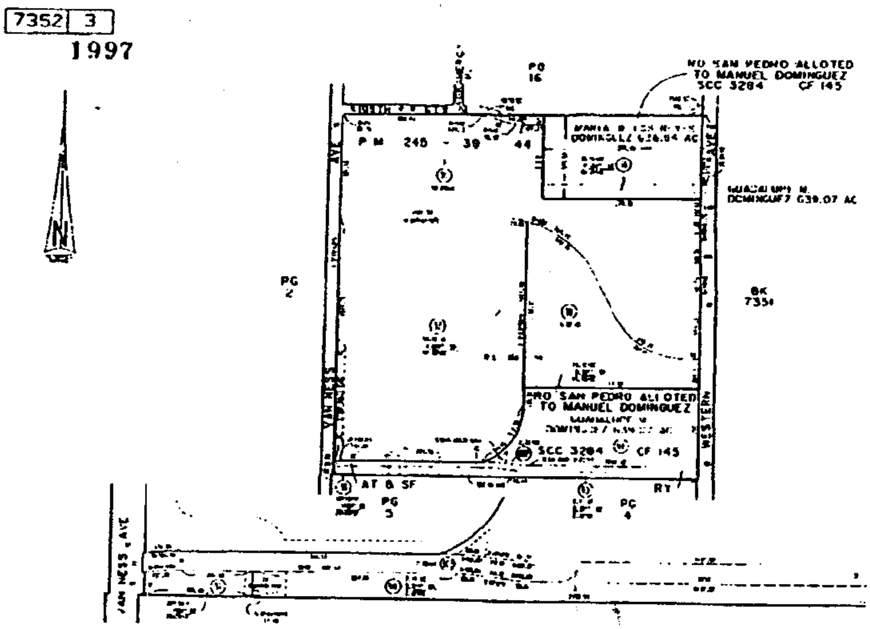
LAND SALE #4



Property Information

Address:	19700 - 19800 Van Ness Avenue, Torrance, California
Legal/APN:	Por. Parcel 2 PM 22909, Book 245, Pages 39-44/#7352-003-037
Site Area/Zone:	2,133,133sf/48.97 Acres/M2

Sale Information

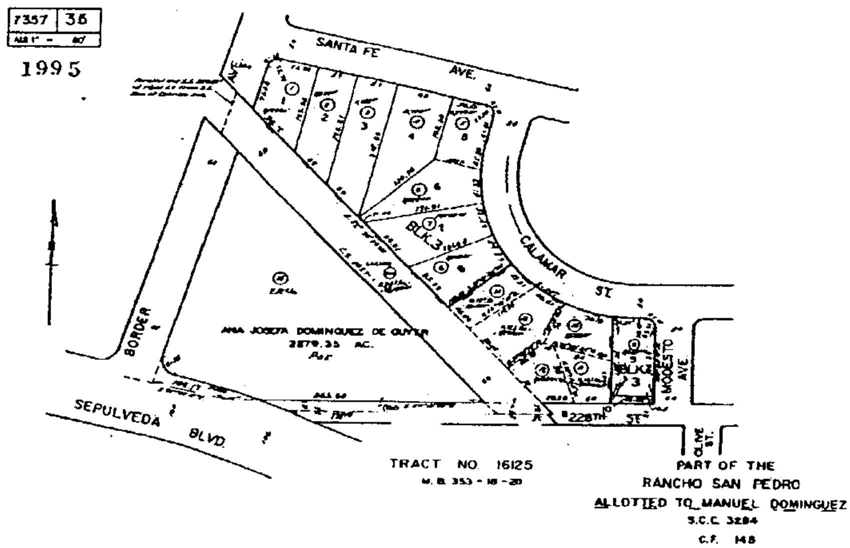
Sale Date:	06/05/00	**Document:**	#0862479
Buyer:	Prologis Dev. Services, Inc.	**Seller:**	Nissin Food Products Co.
Sale Price:	$24,829,769	**Cash Price:**	$24,829,769

Cash Price/Acre: $507,040

General Information

Financing:	All cash sale.
General Comments:	This property involves a large rectangular vacant site located in the City of Torrance. The site was purchased to develop with a large industrial project totaling approximately 1,084,194sf. The project includes concrete tilt-up construction, 30' truss height, Phase 3 power and dock highs doors. The project was completed in 2001.
Confirmed:	Broker, Roger Wile, 562-699-7500, Comps, Public Records

LAND SALE #5



Property Information

Address:	1827 W. 228th Street, Torrance, California
Legal/APN:	Part of the Rancho San Pedro Case allotted to Manuel Dominguez ½ vac street adj. and Lot commencing at intersection of SE line of Border Avenue line of AT and SF Railroad per CS8627-1 THSE on SD Ana Josefa Dominguez De Guyer 2279.35 AC/#7357-035-015.
Site Area/Zone:	92,347sf/2.12 Acres/C3

Sale Information

Sale Date:	11/05/02	**Document:**	#2642406
Buyer:	Watt Developers/Impressions, (LLC)	**Seller:**	Sepulveda Estates, (LLC)
Sale Price:	$4,613,000	**Cash Price:**	$4,613,000

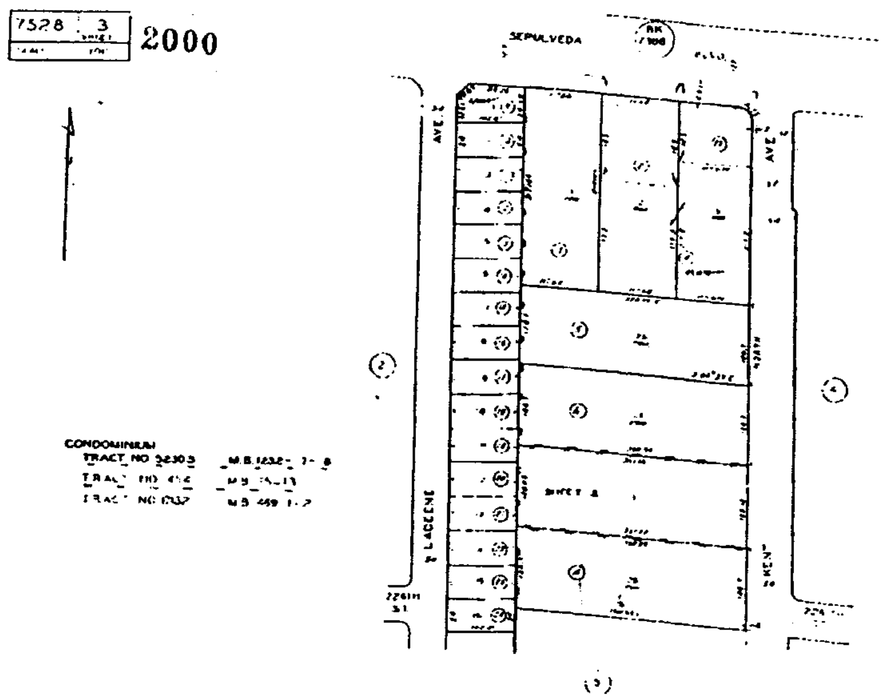
Cash Price/Acre: $2,175,943

General Information

Financing:	Seller, Greg Delgado, could not divulge down payment information because of an agreement between parties. Financing includes a $10,000,000 1st TD w/Comerica and a $1,820,000 2nd TD which includes a construction loan.
General Comments:	This property involves a somewhat triangular shaped vacant site located in the City of Torrance. The site has frontage on 228th Street, Sepulveda Boulevard and Border Avenue. It was purchased to develop with 28 single family dwellings with three and four bedrooms. The property sold with entitlements and permits.
Confirmed:	Seller, 310-540-3990, Comps, Public Records

1764

LAND SALE #6



Property Information

Address:	22525 Kent Avenue, Torrance, California
Legal/APN:	Lot 28, Tract 454, M.B. 245, Page 13/#7528-003-008
Site Area/Zone:	45,172sf/1.04 Acres/C1

Sale Information

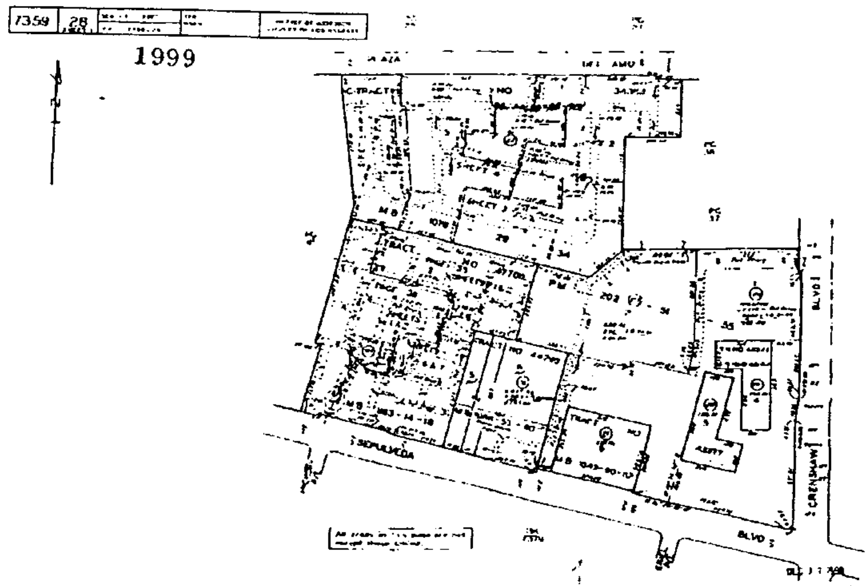
Sale Date:	04/03/02	**Document:**	#0862479
Buyer:	Anastasi Devlopment Co.	**Seller:**	Ling Liang World Wide Evangelistic
Sale Price:	$2,200,000	**Cash Price:**	$2,200,000

Cash Price/Acre: $2,115,385

General Information

Financing:	All cash sale.
General Comments:	This property involves a large rectangular site located on the west side of Kent Avenue. At the time of sale the site was improved with a religious building and was purchased to develop with 21 condominiums. The property sold without entitlements. According to the buyer the demolition cost was about $20,000.
Confirmed:	Buyer, 310-376-8077, Comps, Public Records

LAND SALE #7



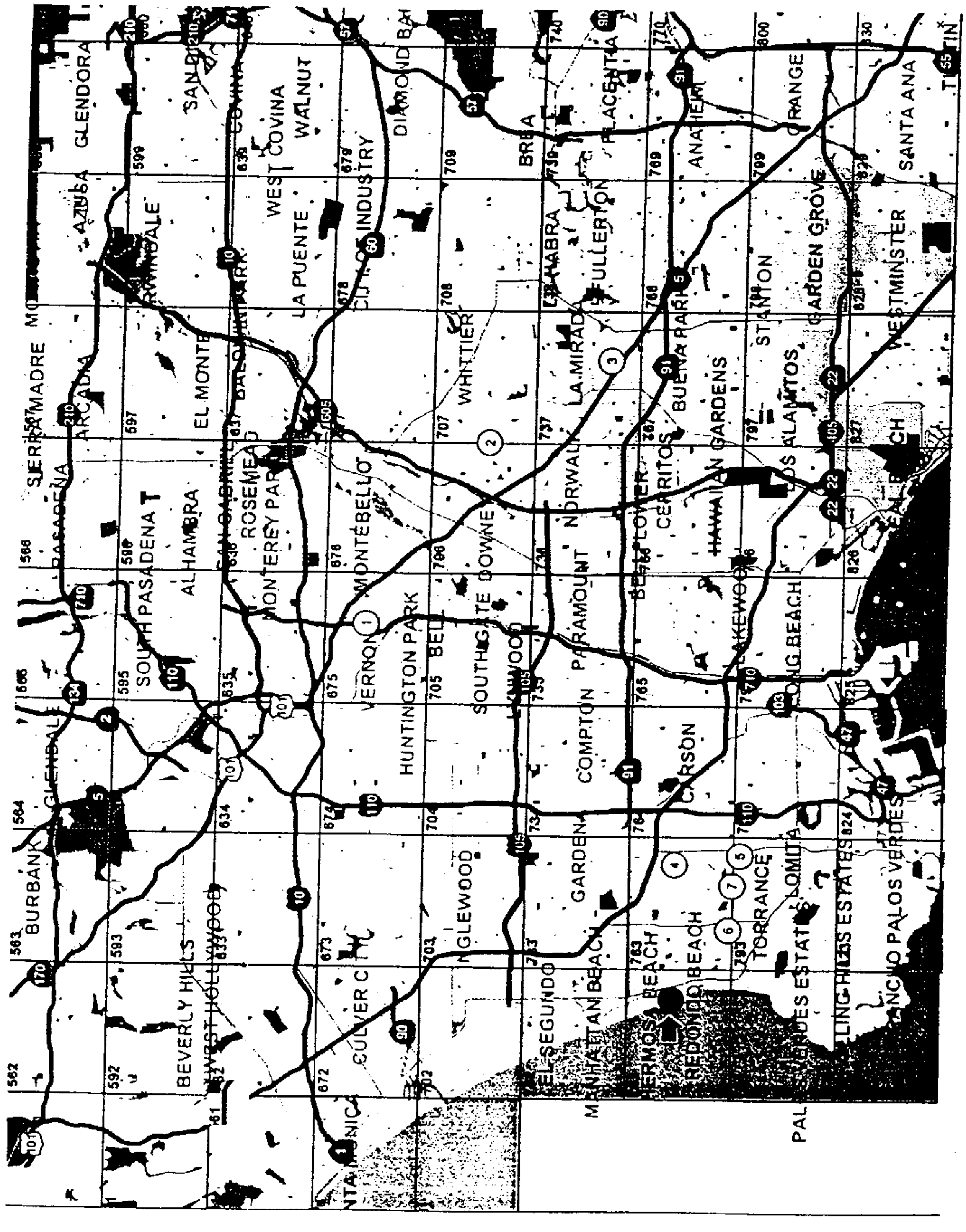
Property Information	
Address:	Sepulveda Bl./W/Crenshaw Bl., Torrance, California
Legal/APN:	Lot 6, Tract 43377, M.B. 1043, Pages 60-62/#7359-028-021.
Site Area/Zone:	82,328sf/1.89 Acres/PD

Sale Information			
Sale Date:	01/28/02	**Document:**	#0203041
Buyer:	Western Pacific Housing	**Seller:**	Torrance Sepulveda II Evangelistic
Sale Price:	$4,000,000	**Cash Price:**	$4,000,000

Cash Price/Acre: $2,116,402

General Information	
Financing:	All cash sale.
General Comments:	This property involves an infill rectangular vacant site located on the north side of Sepulveda Boulevard. The site was purchased to develop with a 91 condominium senior housing project. According to the buyer the property sold without entitlements.
Confirmed:	Buyer, 310-665-3700, Comps, Public Records

LAND SALES LOCATION MAP



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Land Value Analysis

The subject is part of a 50.43 acre power generating facility. The subject project totals 28.82 acres and a tank farm owned by Southern California Edison totals 21.61 acres. According to the city's redevelopment plan approximately two thirds (or 33.80 acres) of the 50.43 acre site is planned for redevelopment with residential uses. The 33.80 acres to be redeveloped generally includes the 21.61 acre tank farm and 12.20 acres of the subject site (33.80ac - 21.61ac = 12.19ac or say 12.20ac). The portion of the subject to be redevelop is located in the northwest portion of the site. This will be valued as residential land.

The AES power generating facility scheduled to remain is situated in the southwestern portion of the site and involves 16.62 acres (28.82ac - 12.20ac = 16.62ac). This portion of the site will be valued as industrial land.

Discussion of Industrial Land Sale Adjustments

Below, each industrial land sale is discussed in greater detail. An adjustment grid is presented at the end of this section.

Land Sale #1: This property involves a similar size industrially zoned site located in the City of Commerce. At the time of purchase the site was improved with a "tear down" 325,000sf industrial building. The cost to demolish was estimated at $550,000. Parcel #5244-035-002 has been changed to #5244-035-801. As compared to the subject property this site is similar in size, frontage and utility but superior in location.

Land Sale #2: This property involves an industrially zoned vacant site in the City of Santa Fe Springs. The site was purchased to develop with seven industrial buildings. Completion of construction is estimated in December of 2003. Construction is concrete tilt-up and will include sprinklers, Phase 3 and 4-wire power as well as amperage ranging from 800 to 2,200. According to the buyer the site sold free from contamination. As compared to the subject this property is in an inferior industrial location and utility but is similar in size and frontage.

Land Sale #3: This property involves a larger industrially zoned vacant site in La Mirada. The site was purchased to develop with a multi-tenant industrial project. Construction is concrete tilt-up and will include sprinklers, Phase 3 and 4-wire power and 800 amps. As compared to the subject this property is in a slightly superior industrial location but is similar in size and frontage.

Land Sale #4: This is the most proximate property to the subject and is also the most dated sale. It involves a similar size parcel located in Torrance. The site was previously improved and demolition costs were approximately $750,000. According to the broker the client does not wish to disclose sale details. Prior to sale the property had contamination and took approximately one year to clean. The cost of the clean up was not disclosed. The cost of clean-up was not disclosed but the sale price is net of the cost to clean. As compared to the subject this property is similar in location, superior in frontage and utility and is larger.

In the following table, adjustments for each industrial comparable sale are summarized.

INDUSTRIAL LAND SALES ADJUSTMENT GRID					
Sale #:	**Subject**	**#1**	**#2**	**#3**	**#4**
Sale Date	----	12/02	9/02	8/01	6/00
Gross Site Area:	16.62 Acres Net	15.10 Acres	22.00 Acres	19.27 Acres	48.97 Acres
Site Zoning:	Industrial	M2	M2	M2	M2
Price/Acre:	—	**$692,053**	**$409,091**	**$534,510**	**$507,040**
Primary Adjustments					
Financing:	---	0%	0%	0%	0%
Conditions of Sale:	---	0%	0%	0%	0%
Property Rights:	---	0%	0%	0%	0%
Market Conditions:	---	0%	0%	10%	20%
Listing Status:	---	0%	0%	0%	0%
Net Adjustment:	---	0%	0%	10%	20%
Adjusted Price:	---	**$692,053**	**$409,091**	**$587,961**	**$608,448**
Secondary/Physical Adjustments					
Location:	---	-15%	15%	-5%	0%
Size:	---	0%	0%	0%	5%
Utility:	---	0%	20%	0%	-5%
Zoning:	---	0%	0%	0%	0%
Offsite Improv.	---	0%	0%	0%	0%
Demolition Costs:	---	5%	0%	0%	5%
Clean Up Costs:	---	0%	0%	0%	0%
Frontage:	---	0%	0%	0%	-10%
Net Adjustment:	---	-10%	35%	-5%	-5%
Net Adjusted Price:	—	**$622,848**	**$552,273**	**$558,563**	**$578,026**

The adjusted range is from $552,273/acre to $657,450/acre with three sales ranging from $552,273 to $578,026. Most weight is placed on Sales #1 and #2 due to time of sale and size and to #4 due to location. The remaining sale supports the final value indication. Considering the data noted above, the estimated value for the subject's industrial site is $575,000/acre. Thus, the estimated "as if vacant" value of the industrial portion of the subject site is **$9,555,000** (16.62 x $575,000 = $9,556,500).

Discussion of Residential Land Sale Adjustments

Below, each residential land sale is discussed in greater detail. An adjustment grid is presented at the end of this section.

<u>Land Sale #5:</u> This property involves a smaller residential site in Torrence. The site was purchased to develop with a 28 townhome project. The seller would not disclose the cost of the entitlements but said the site was ready to develop at the time of sale. As compared to the subject this site is similar in location but smaller in size and inferior in utility and frontage.

<u>Land Sale #6:</u> This property involves a smaller site that was previously developed with a religious facility. According to the buyer the demolition cost was minimal. The site was purchased to develop with a 21 condominium project. As compared to the subject this property is similar in location, inferior in frontage and required adjustments for size and demolition costs.

<u>Land Sale #7:</u> This is property involves a smaller vacant site that was purchased to develop with a large senior housing project. As compared to the subject this property is similar in location but inferior in frontage and is smaller in size.

In the following table, adjustments for each residential comparable sale are summarized.

RESIDENTIAL LAND SALES ADJUSTMENT GRID				
Sale #:	Subject	#5	#6	#7
Sale Date	----	11/02	4/02	1/02
Gross Site Area:	12.20 Acres Net	2.12 Acres	1.04 Acres	1.89 Acres
Site Zoning:	Residential	C3	C1	PD
Price/Acre:	—	$2,175,943	$2,115,385	$2,116,402
Primary Adjustments				
Financing:	---	0%	0%	0%
Conditions of Sale:	---	0%	0%	0%
Property Rights:	---	0%	0%	0%
Market Conditions:	---	0%	0%	0%
Listing Status:	---	0%	0%	0%
Net Adjustment:	---	0%	0%	0%
Adjusted Price:	---	$2,175,943	$2,115,385	$2,116,402
Secondary/Physical Adjustments				
Location:	---	0%	0%	0%
Size:	---	-5%	-5%	-5%
Utility:	---	0%	0%	0%
Zoning:	---	0%	0%	0%
Offsite Improv.	---	0%	0%	0%
Demolition Costs:	---	0%	5%	0%
Clean Up Costs:	---	0%	0%	0%
Frontage:	---	5%	5%	5%
Net Adjustment:	---	0%	5%	0%
Net Adjusted Price:	---	$2,175,943	$2,221,154	$2,116,402

The adjusted range is from $2,116,402/acre to $2,221,154/acre. The three sales are considered good indicators of value for the subject. Considering the data noted above, the estimated value for the subject site is $2,180,000/acre. As presented previously the portion of the site to be redeveloped with residential uses is estimated at 12.20 acres. The estimated "as if vacant" value of the portion to be redeveloped with a residential use is **$26,595,000** (12.20 x $2,180,000 = $26,596,000).

Thus the total estimated "as if vacant" value of the subject site is summarized in the following table.

Land Value Summary						
Type of Land	**Size/AC**		**Price/Acre**		**Total**	**Rounded Value**
Industrial Land	16.62 Acres	x	$575,000	=	$9,556,500	$9,555,000
Residential Land	12.20 Acres	x	$2,180,000	=	$26,596,000	$26,595,000
					Total	**$36,150,000**

CORRELATION AND FINAL VALUE ESTIMATE

By use of the only approach analyzed in this case, the following value indication surfaced. It should be noted that this approach is based on the Fee Simple Estate rights as the property is reportedly free from lease encumbrance. The Cost and Income Approaches were not considered since they are not generally used by buyers and sellers of this property type (the motivation is almost entirely owner/occupant).

Value Indication	
Sales Comparison Approach	$36,150,000

The Sales Comparison Approach included seven sales (industrial and residential) of comparable sites. All sales were analyzed using an adjustment grid. Both industrial and residential sales and values were analyzed.

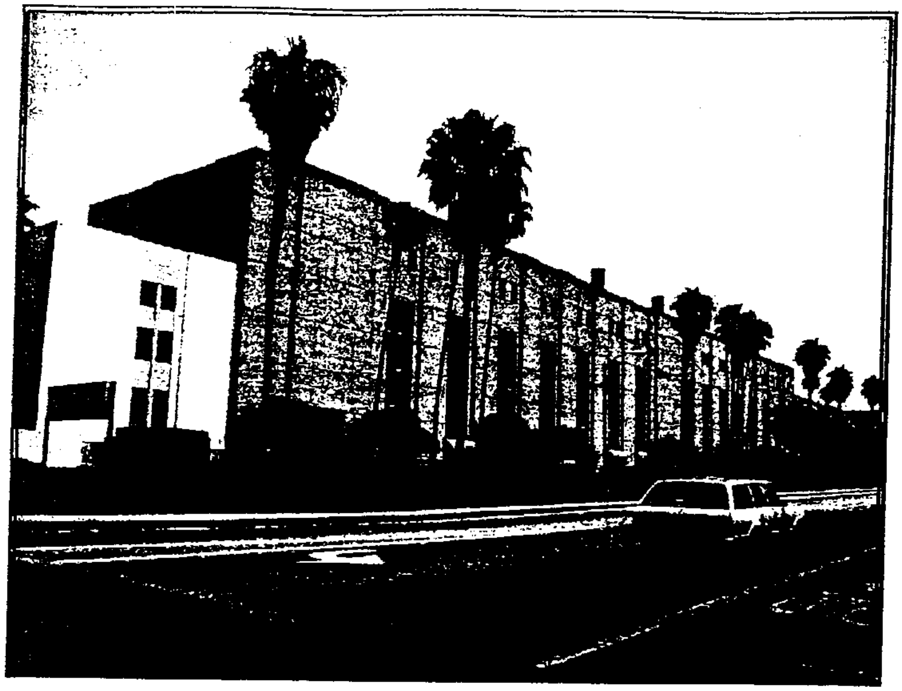
In determining the "as is" value of the subject site demolition and enviromental remediation costs were considered. Among developers and consultants engaged in the City's Redevelopment Project is Mar Ventures, Inc. Mr. Allan W. Mackenzie from Mar Ventures, Inc. provided a Development Cost Breakdown for the AES/Edison site. The demolition/salvage and environmental clean-up cost for the entire 50.43 acres totals $18,955,000. The subject site includes a large 1947 office building, four turbines to be razed and encompasses approximately 75% of the improvements to be demolished. The portion of the site to be redeveloped is 33% and requires environmental remediation. The costs attributed to the subject site total $10,480,000 and were subtracted from the "as if vacant" land value conclusion. The costs submitted by Mar Ventures, Inc. are assumed to be accurate. If the estimates prove inaccurate the appraisers reserve the right to amend the final value estimate.

Summary of Demolition/Remediation Costs		
Type of Cost	**Total Cost**	**Portion Attributed to Subject**
Demolition Costs @ 75%	$10,055,000	$7,540,000
Environmental Remediation @ 33%	$8,900,000	$2,940,000
Totals	$18,955,000	$10,480,000

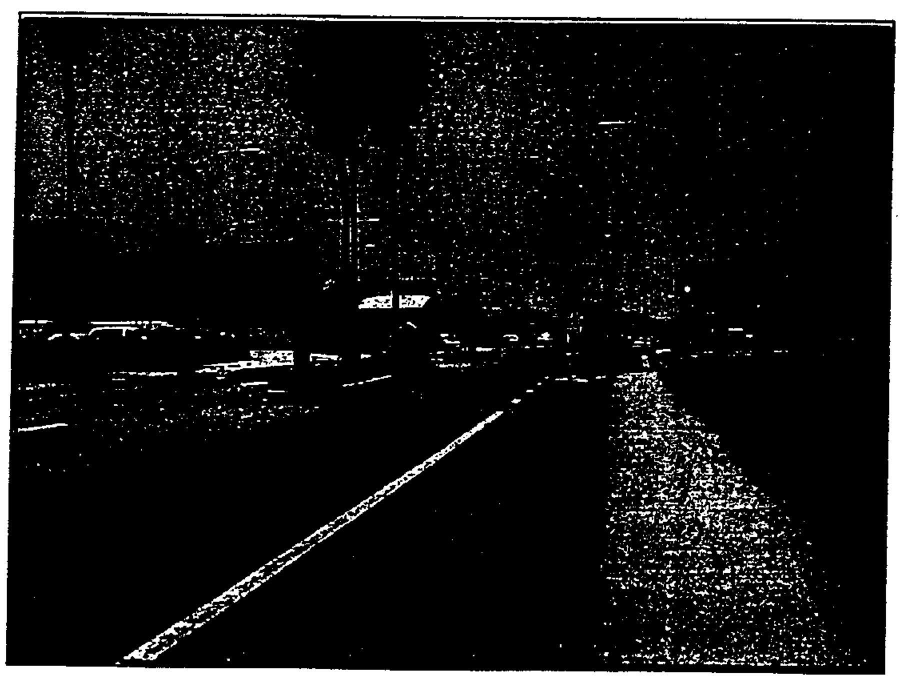
The final stage in estimating the "as is" value is to subtract the demolition/remediation costs from the estimated land value ($36,150,000 - $10,480,000 = $25,670,000). The final value estimate reflects the "as is" value of the subject site.

Therefore, Subject to the analysis incorporated in this report, and subject to the attached Assumptions and Limiting Conditions, the estimated "as is" Fee Simple Estate Market Value for the subject property as of January 1, 2003, is:

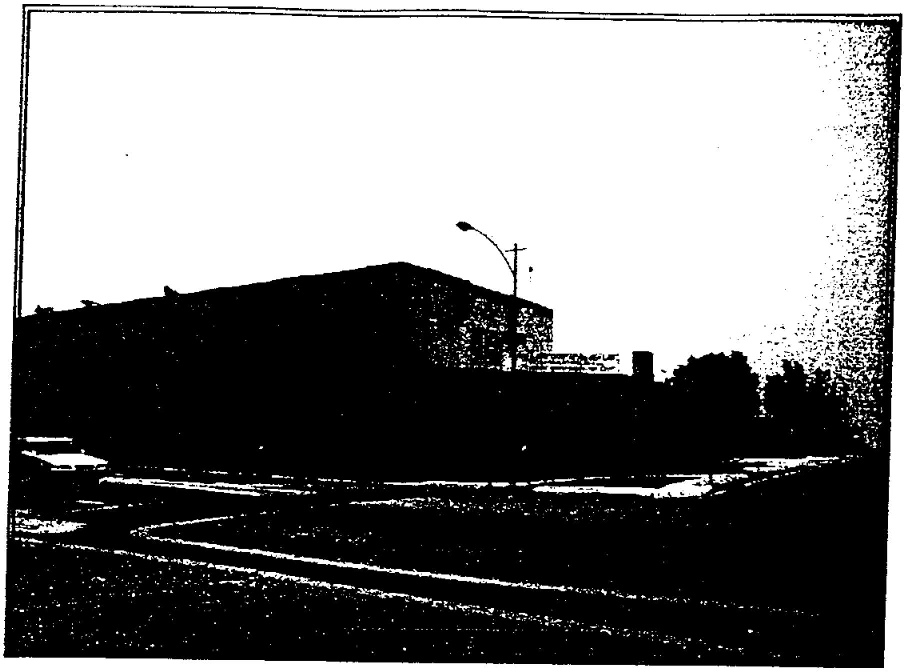
Twenty Five Million Six Hundred and Seventy Thousand Dollars
$25,670,000



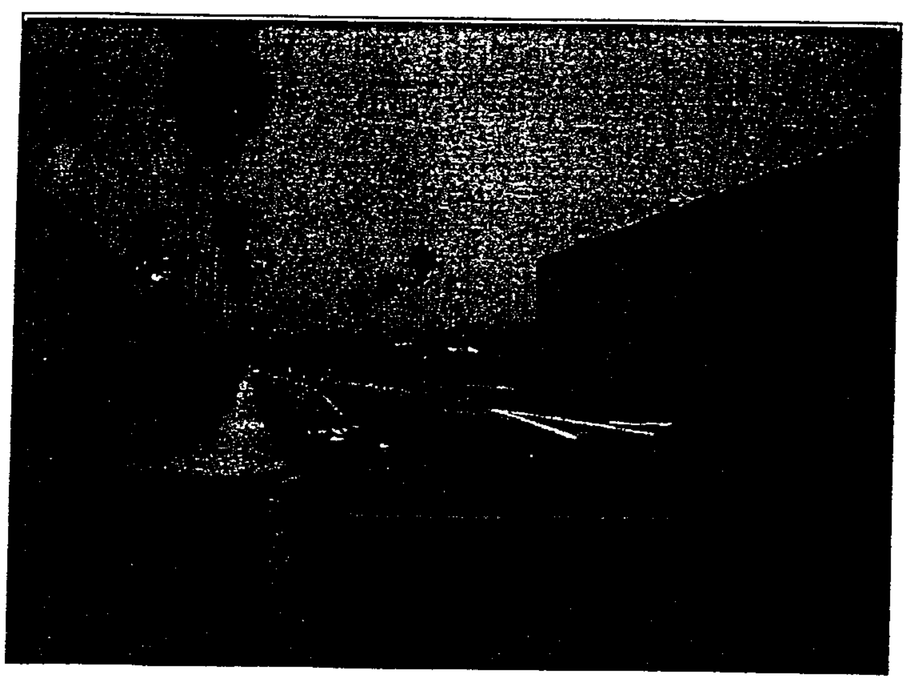
Southeasterly view of subject from Harbor Drive.



South view of Harbor Drive

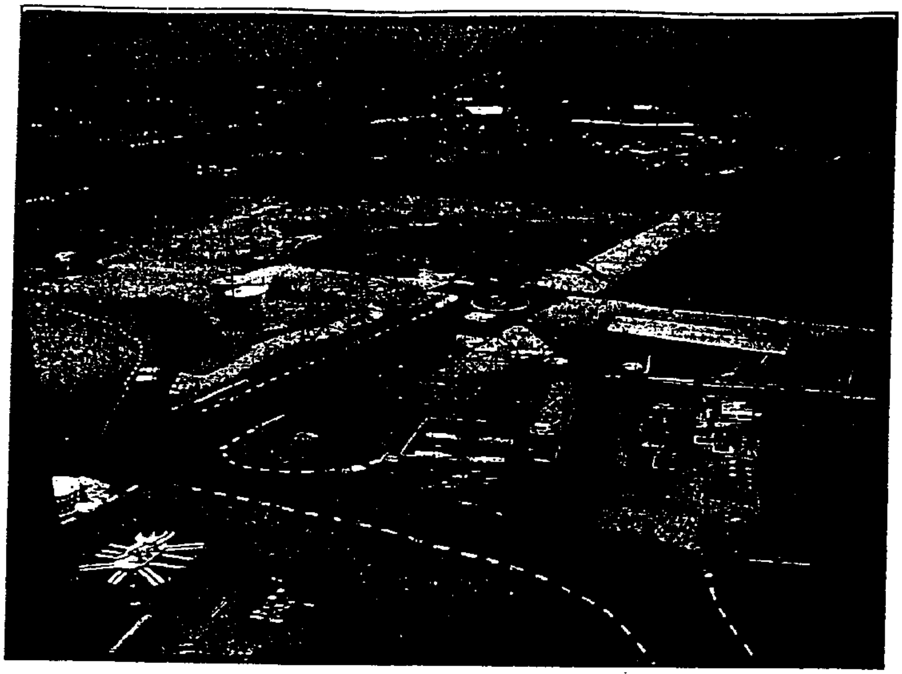


Subect Sea Lab Project on west side of Harbor Drive

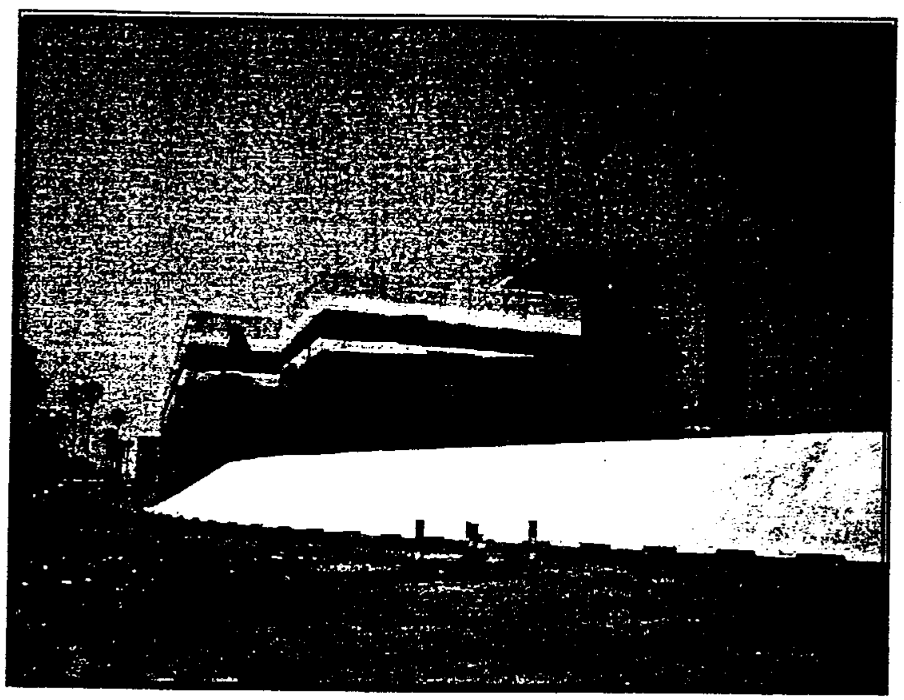


Harbor Drive south bound.

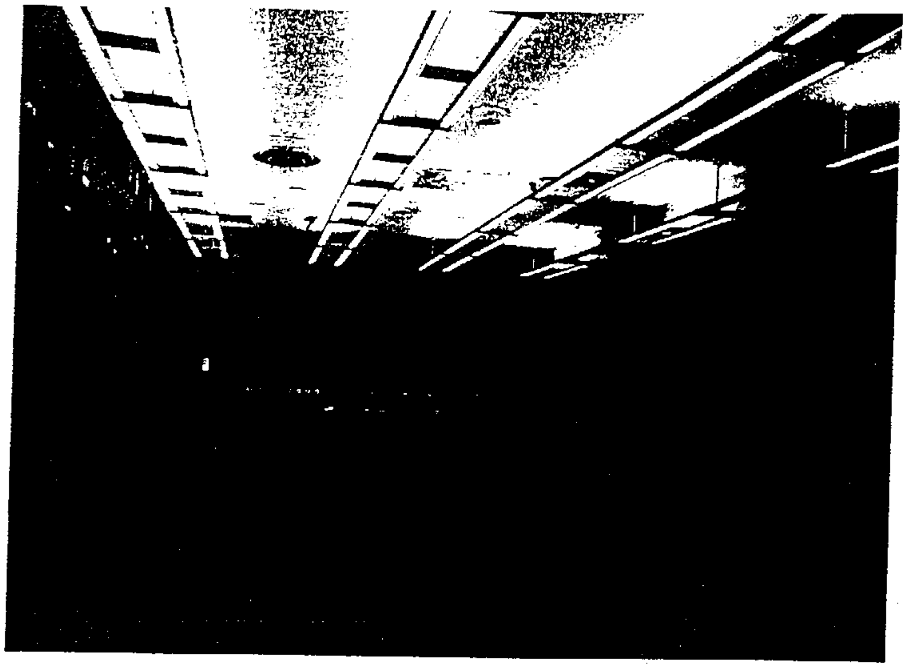
1778



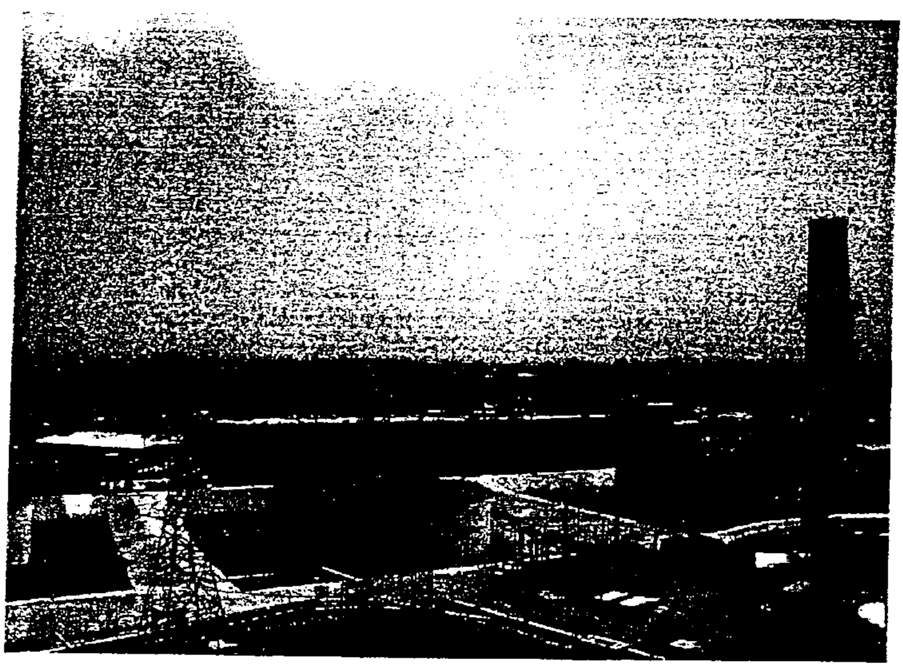
Over view of tank farm and power grid.



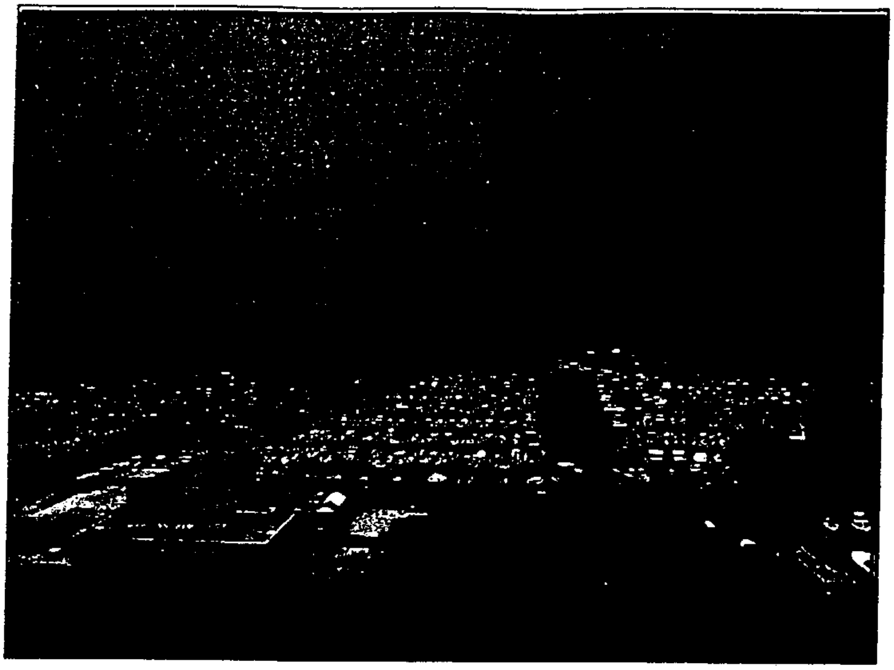
Northerly view of subject and access road.



Typical interior view.



View of tankfarm and residential properties along Herondo Street.



View of marina and Pacific Ocean from subject project.

Herondo Street east bound, the subject is to the right.

SCOTT D. DELAHOOKE, MAI
225 S. First Avenue, Suite #201
Arcadia, California 91006
(626)-445-0500

GENERAL EDUCATION

1981	University of Southern California, B.S., Business Administration Finance & Business Administration Program

APPRAISAL EDUCATION

1980	Real Estate Valuation-Courses 101/201 University of Southern California
1983	Society of Real Estate Appraisers-Course R-2
1984	Society of Real Estate Appraisers-Course 202
1991	Comprehensive Appraisal Workshop-Appraisal Institute

TEACHING EXPERIENCE

Course 110	Appraisal Institute (Introduction to Appraisal)
Course 310	Appraisal Institute (Capitalization- Theory)
Course 510	Appraisal Institute (Capitalization-Application)

APPRAISAL EXPERIENCE

Office	Includes valuation of office projects ranging in size from 1,500 sq.ft. to over 200,000 sq.ft., and from low-rise to mid-rise complexes.
Retail	Includes valuation of anchored and non-anchored centers ranging in size from 2,000 sq.ft. to over 150,000 sq.ft., with most being multi-tenant in use and from neighborhood to region in design.
Industrial	Includes valuation of single and multi-tenant industrial facilities, including incubator projects and business parks. Project sizes have ranged from 5,000 sq.ft. to over 150,000 sq.ft.
Apartment	Includes valuation of apartment projects ranging in size from 10 to over 250 units including conversion issues and feasibility.
Residential	Includes single family dwellings and residential subdivisions ranging in size from 10 sites to over 100 sites (both vacant and improved).
Vacant Land	A wide range of vacant sites have been valued, including land zoned for commercial, industrial, multi-residential and residential use.

SPECIAL PURPOSE PROPERTIES

Bowling Centers	Car Wash Facilities
Service Stations	Religious Facilities
Restaurants	Mobile Home Parks
Self Storage Facilities	Airport Fixed Base Operations

REAL ESTATE INTERESTS VALUED

Fee Simple Estate-Income and Non-Income
Leased Fee Estate
Leasehold Estate
Partial Interests

CONSULTATION ASSIGNMENTS

Feasibility Analysis
Developer Consultation
Loan Portfolio Analysis
Highest and Best Use Analysis

PARTIAL LIST OF CLIENTS

Financial Institution Clients

Cedars Bank
US Bank
Southern Pacific Bank
Quaker City Bank
Wells Fargo Bank
ChinaTrust Bank, USA
California State Bank
National Bank of Southern California
Bank Audi of New York
Imperial Bank
Broadway Federal, FSB
First Security Corporation
Southern California Bank
Capital Crossing Bank
Marathon National Bank
Tokai Bank
City National Bank
Preferred Bank
Farmers & Merchants Bank
Comerica Bank
Luther Burbank Savings
Fidelity Federal Bank
Coast Business Credit
Fremont Investment & Loan
Silvergate Thrift & Loan
Foothill Independent Bank
First Professional Bank
First Federal Bank
Deutsche Bank Securities
First Bank of Beverly Hills, FSB
Thai Farmers Bank
United Mizrahi Bank

General Lending Clients

Impac Commercial
George Elkins Mortgage Banking Company
Weyerhaeuser Financial Investments, Inc.
GMAC Mortgage
GE Capital Corporation
Imperial Commercial Capital Corporation
Int'l. Brotherhood of Electrical Workers
George Smith Partners

Client Summary

American Stores Properties, Inc.
State Farm Insurance Company
Scottsdale Insurance
Star Insurance Company
The John Alle Company
Community Housing Services
CIM Group
Aetna Casualty Insurers
The Travelers Insurance Company
TransAmerica Financial Services
North America Title Insurance Company
Savers Property & Casualty Insurance
TransAmerica Title Insurance

Public Agency Clients

L.A. Unified School District
Federal Deposit Insurance Corporation
City of El Monte
Housing/Urban Development
Metropolitan Transit Agency
City of Glendale
City of Pasadena
U.S. Department of Justice

Litigation

O'Melveny & Myers
Cooksey, Howard, Martin & Toolen
Driscoll & Associates
Jones, Bell, Abbott, Fleming & Fitzgerald
Greenberg & Bass
Gaglione & Dolan
Reed & Brown
Arkley, Butterfield & Swayne
Hughes, Hubbard & Reed, LLP
Nigro, Karlin & Segal
Law Offices of George W. Collins
Demetriou, Del Guercio, Springer & Moyer
Stringfellow & Associates
Dear & Kelley
Lewis, D'Amato, Brisbois & Bisgaard
Briedenbach, Swainston, Crispo & Way
Buchalter, Nemer, Fields & Younger
Hornberger, Ghazarians & Brewer
Marks & Murase
Verboon, Whitaker, Hartmann & Peter
Polk, Scheer & Prober
Hill, Wynne, Troop & Meisinger
Solomon, Grindle, Silverman & Spinella
Millikan & Thomas
Rosenfeld & Wolff
Hill, Farrer & Burrill
Hahn & Hahn
Oliver, Vose, Sandifer, Murphy & Lee
Law Offices of John F. Hertz
Rodi & Pollock

LITIGATION ASSIGNMENTS

Qualified Expert Witness:

County of Los Angeles, Superior Court
County of Orange, Superior Court
United States Bankruptcy Court,
Central District of California

PROFESSIONAL DESIGNATIONS

Appraisal Institute	MAI Designation

PROFESSIONAL AFFILIATIONS

Past President-	Los Angeles Chapter, Appraisal Institute
Board of Directors-	Pacific Chapter, Appraisal Institute

STATE CERTIFICATION

State of California-	Office of Real Estate Appraisers-#AG002796

Capacity payment worksheet

Calendar Year - Capacity Revenue ($000)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alamitos 1	5,439	5,668	5,725	5,782	5,840	5,898	5,957	6,017	6,077	6,138	6,225	6,270	6,270	6,270	6,270
Alamitos 2	5,432	5,662	5,718	5,775	5,833	5,891	5,950	6,010	6,070	6,131	6,218	6,262	6,262	6,262	6,262
Alamitos 3	10,535	10,980	11,090	11,200	11,312	11,428	11,540	11,655	11,772	11,889	12,059	12,145	12,145	12,145	12,145
Alamitos 4	10,205	10,635	10,742	10,849	10,958	11,067	11,178	11,290	11,403	11,517	11,681	11,764	11,764	11,764	11,764
Alamitos 5	20,634	21,504	21,720	21,937	22,156	22,378	22,601	22,827	23,056	23,288	23,618	23,786	23,786	23,786	23,786
Alamitos 6	20,634	21,504	21,720	21,937	22,156	22,378	22,601	22,827	23,056	23,286	23,618	23,786	23,786	23,788	23,788
Alamitos 7	3,177	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Huntington 1	7,998	8,335	8,419	8,503	8,588	8,674	8,760	8,848	8,937	9,026	9,155	9,220	9,220	9,220	9,220
Huntington 2	7,879	8,211	8,293	8,378	8,460	8,545	8,630	8,717	8,804	8,892	9,018	9,083	9,083	9,083	9,083
Huntington 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Redondo 5	5,548	5,783	5,840	5,899	5,958	6,017	6,078	6,138	6,200	6,262	6,351	6,396	6,396	6,396	6,396
Redondo 6	5,600	5,838	5,895	5,954	6,013	6,073	6,134	6,195	6,257	6,320	6,410	6,456	6,456	6,456	6,456
Redondo 7	20,014	20,859	21,068	21,278	21,491	21,706	21,923	22,142	22,364	22,587	22,909	23,072	23,072	23,072	23,072
Redondo 8	19,643	20,472	20,676	20,883	21,092	21,303	21,516	21,731	21,948	22,168	22,484	22,644	22,644	22,644	22,644
Total Capacity Revenue	142,737	145,450	146,905	148,374	149,858	151,356	152,870	154,399	155,943	157,502	159,747	160,885	160,885	160,885	160,885
Alamitos	76,055	75,954	76,714	77,481	78,256	79,038	79,828	80,627	81,433	82,247	83,420	84,014	84,014	84,014	84,014
Huntington Beach	15,876	16,547	16,712	16,879	17,048	17,218	17,391	17,565	17,740	17,918	18,173	18,302	18,302	18,302	18,302
Redondo Beach	50,805	52,950	53,479	54,014	54,554	55,100	55,651	56,207	56,769	57,337	58,154	58,568	58,568	58,568	58,568

Huntington Beach Units 3

Calendar Year - Capacity Revenue ($000)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Huntington 3	6,413	6,413	6,413	6,413	6,413										
Total Capacity Revenue	6,413	6,413	6,413	6,413	6,413	-	-	-	-	-	-	-	-	-	-

Variable revenue worksheet

INPUT	
Y02-03 Price	2.18824
Escalation Factor	2.50%
Capacity Factor	20%

May 20, 2003 - For Discussion Purposes Only

Contract Year - Price ($/MW-yr)	2.24	2.30	2.36	2.42	2.48	2.54	2.60	2.67	2.73	2.80	2.87	2.94	3.02	3.09	3.17
Calendar Year - Price ($/MWh)	2.21	2.27	2.32	2.38	2.44	2.50	2.56	2.63	2.69	2.76	2.83	2.90	2.97	3.05	3.12

Calendar Year - Variable Revenue	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alamitos 1	677,903	694,851	712,222	730,027	748,278	766,985	786,160	805,814	825,959	846,608	867,773	889,468	911,704	934,497	957,859
Alamitos 2	677,903	694,851	712,222	730,027	748,278	766,985	786,160	805,814	825,959	846,608	867,773	889,468	911,704	934,497	957,859
Alamitos 3	1,278,332	1,310,290	1,343,047	1,376,623	1,411,039	1,446,315	1,482,473	1,519,534	1,557,523	1,596,461	1,636,372	1,677,282	1,719,214	1,762,194	1,806,249
Alamitos 4	1,278,332	1,310,290	1,343,047	1,376,623	1,411,039	1,446,315	1,482,473	1,519,534	1,557,523	1,596,461	1,636,372	1,677,282	1,719,214	1,762,194	1,806,249
Alamitos 5	1,898,129	1,945,582	1,994,221	2,044,077	2,095,179	2,147,558	2,201,247	2,256,278	2,312,685	2,370,503	2,429,765	2,490,509	2,552,772	2,616,591	2,682,006
Alamitos 6	1,898,129	1,945,582	1,994,221	2,044,077	2,095,179	2,147,558	2,201,247	2,256,278	2,312,685	2,370,503	2,429,765	2,490,509	2,552,772	2,616,591	2,682,006
Alamitos 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Huntington 1	832,852	853,674	875,016	896,891	919,313	942,296	965,853	990,000	1,014,750	1,040,118	1,066,121	1,092,774	1,120,094	1,148,096	1,176,799
Huntington 2	832,852	853,674	875,016	896,891	919,313	942,296	965,853	990,000	1,014,750	1,040,118	1,066,121	1,092,774	1,120,094	1,148,096	1,176,799
Huntington 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Redondo 5	677,903	694,851	712,222	730,027	748,278	766,985	786,160	805,814	825,959	846,608	867,773	889,468	911,704	934,497	957,859
Redondo 6	677,903	694,851	712,222	730,027	748,278	766,985	786,160	805,814	825,959	846,608	867,773	889,468	911,704	934,497	957,859
Redondo 7	1,898,129	1,945,582	1,994,221	2,044,077	2,095,179	2,147,558	2,201,247	2,256,278	2,312,685	2,370,503	2,429,765	2,490,509	2,552,772	2,616,591	2,682,006
Redondo 8	1,898,129	1,945,582	1,994,221	2,044,077	2,095,179	2,147,558	2,201,247	2,256,278	2,312,685	2,370,503	2,429,765	2,490,509	2,552,772	2,616,591	2,682,006
Total Capacity Revenue	14,526,494	14,889,657	15,261,898	15,643,446	16,034,532	16,435,395	16,846,280	17,267,437	17,699,123	18,141,601	18,595,141	19,060,020	19,536,520	20,024,933	20,525,556
Alamitos	7,708,726	7,901,445	8,098,981	8,301,455	8,508,992	8,721,718	8,939,759	9,163,253	9,392,335	9,627,143	9,867,822	10,114,517	10,367,380	10,626,564	10,892,229
Huntington Beach	1,665,705	1,707,347	1,750,031	1,793,782	1,838,626	1,884,592	1,931,707	1,979,999	2,029,499	2,080,237	2,132,243	2,185,549	2,240,188	2,296,192	2,353,597
Redondo Beach	5,152,063	5,280,865	5,412,887	5,548,209	5,686,914	5,829,087	5,974,814	6,124,184	6,277,289	6,434,221	6,595,077	6,759,954	6,926,952	7,102,178	7,279,731

Dependable capacity (MW)															
Huntington 3	215	215	225	225	225	225	225	225	225	225					
Total output	215	215	225	225	225	225	225	225	225	225	-	-	-	-	-
Calendar Year - Price ($/MWh)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00					

Calendar Year - Variable Revenue	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Capacity Factor	15%	15%	15%	15%	15%										
Huntington 3	565,020	565,020	591,300	591,300	591,300						-	-	-	-	-
Total Capacity Revenue	565,020	565,020	591,300	591,300	591,300	-	-	-	-	-	-	-	-	-	-

PROOF OF SERVICE BY MAIL
(1013a, 2015.5 C.C.P.)

STATE OF CALIFORNIA)
)
COUNTY OF LOS ANGELES)

I am employed in the County of Los Angeles, State of California. I am over the age of eighteen years and not a party to the within action. My business address is 444 South Flower Street, Suite 1700, Los Angeles, California 90071-2901.

On August 5, 2003, I served the foregoing document described as **Petition for Reassessment for AES Redondo, L.L.C., (BOE Assessee #1101)** on the interested parties in this action by placing true copies thereof enclosed in a sealed box and addressed as follows:

State Board of Equalization
Attention: Joann Richmond
Board Proceedings Division
450 N Street
Sacramento CA 94279

I deposited each envelope in the mail at Los Angeles, California. The envelopes were mailed with postage thereon fully prepaid.

I am "readily familiar" with the firm's practice for collection and processing correspondence for mailing with the U.S. Postal Service. Under that practice it would be deposited with the U.S. Postal Service on that same day with postage thereon fully prepaid at Los Angeles, California in the ordinary course of business. I am aware that on motion of the party served, service is presumed invalid if postal cancellation date or postage meter date is more than one day after the date of deposit for mailing in affidavit.

Executed at Los Angeles, California on August 5, 2003.

☒ STATE I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

☐ FEDERAL I declare under penalty of perjury that the foregoing is true and correct.

Dean Simpson
Type or print name

Signature

262372_1.doc

RODI, POLLOCK, PETT[...] GALBRAITH & CAHILL
A LAW C[...]ATION
444 SOUTH FLOWER STREET, SUITE 1700
LOS ANGELES, CALIFORNIA 90071-2901
TELEPHONE: (213) 895-4900

AES REDONDO BEACH, LLC
AES REDONDO BEACH GENERATING STATION

FAIR MARKET VALUE REPORT
AS OF
JANUARY 1, 2003

AUS Consultants, Valuation Services Group

TABLE OF CONTENTS

AUS Consultants
8555 West Forest Home Avenue, Suite 201
Greenfield, WI 53228
414-529-5755 / FAX 414-529-5750
e-mail: auswest@execpc.com
INTERNET: http://www.ausinc.com

July 28, 2003

AES Redondo Beach, LLC
Redondo Beach, CA

Ladies and Gentlemen:

At your request, we have made an investigation and appraisal of the Fair Market Value of the real and tangible personal property, excluding land, ("Subject Property") of the AES Redondo Beach generating station for property tax purposes as of January 1, 2003, and herein submit our report and opinion of value.

Fair Market Value is defined as the amount at which the Subject Property might be expected to exchange between a willing buyer and a willing seller, each having reasonable knowledge of all relevant facts, with fairness to both parties, and assuming use of the property at its highest and best use. This definition of Fair Market Value is consistent with the requirements of Revenue and Taxation Code §110 and State Board of Equalization Rule 2.

Our report comprises this letter, Certificate of Appraisal, and the attached narrative with supporting exhibits and appendices. In conducting our analyses, we relied on information provided by AES Redondo Beach and data extracted from governmental publications and the trade and financial press. A specific listing of the information relied upon is found in the narrative report.

Based on our investigations as described in the attached narrative report, it is our opinion that the Fair Market Value of the Subject Property as put to beneficial or productive use, as of January 1, 2003, is reasonably represented by an amount of NINETY-FOUR MILLION EIGHT HUNDRED THOUSAND DOLLARS ($94,800,000).

We have made no investigation of nor express any opinion as to the title to this property appraised.

Respectfully submitted,

Michael J. Diedrich, P.E., ASA, CDP
Vice President

cfb
Enclosure

APPRAISAL CERTIFICATION

AES REDONDO BEACH, LLC
AES REDONDO BEACH GENERATING STATION

FAIR MARKET VALUE REPORT
AS OF
JANUARY 1, 2003

I certify that, to the best of our knowledge and belief:

- The statements of fact contained in this report are true and correct.
- The reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions, and are our unbiased professional analyses, opinions, and conclusions, and are our personal, impartial, and unbiased professional analyses, opinions and conclusions.
- My engagement in this assignment was not contingent upon developing or reporting predetermined results.
- Neither AUS Consultants, Valuation Services Group, or its professional staff has any present or prospective interest in the property that is the subject of this report, and has no interest or bias with respect to the parties involved.
- My compensation is not contingent upon development or reporting of a predetermined value or direction of value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result or the occurrence of a subsequent event directly related to the intended use of this appraisal.
- My analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the Uniform Standards of Professional Appraisal Practice.
- I have not made a personal inspection of the property that is the subject of this report.
- All individuals who participated in the preparation of this report and who are Senior Members of the American Society of Appraisers are recertified as required by the mandatory recertification as set out in the constitution by-laws and administrative rules of the American Society of Appraisers.
- No other individual provided significant professional assistance to the person signing this report.

Michael J. Diedrich, ASA, P.E., CDP
Vice President
AUS Consultants, Valuation Services Group
July 28, 2003

NARRATIVE REPORT

INTRODUCTION

Objective

The objective of this appraisal is to estimate the Fair Market Value of the real and tangible personal property excluding land (Subject Property) of the AES Redondo Beach Generating Station (Redondo Beach) located in Redondo Beach, Los Angeles County, California, as of January 1, 2003. The entire business enterprise conducted by Redondo Beach includes various tangible and intangible assets. The principal tangible assets consist of improvements (including fixtures), the associated personal property, spare parts and supplies, and the land. The intangible assets include contracts, agreements, emissions credits, workforce, computer software, elements of a going concern, among others. Because intangible property is exempt from property tax under California law, this appraisal will estimate fair market value for only the improvements and personal property as put to beneficial and productive use. The land was valued separately.

Fair Market Value, as used herein, is defined as the amount at which the subject property might be expected to exchange between a willing buyer and a willing seller, each having reasonable knowledge of all relevant facts, with fairness to both parties, and assuming use of the property at its highest and best use. This definition of fair market value is consistent with the requirements of Revenue and Taxation Code § 110 and Rule 2 of the Property Tax Rules of California (California Rules), the value definition appropriate for use in the appraisal of property for property tax purposes.

Property Description

The Redondo Beach Generating Station is located at 1100 Harbor Drive, Redondo Beach, California. Redondo Beach Generating Station is located in the City of Redondo Beach. It is bordered by Hermosa Avenue to the north, Fransisca Avenue to the east, Beryl Avenue to the south, and Harbor Drive and the Pacific Ocean to the west. Access to the station is from North Harbor Drive. Redondo Beach consists of eight generating units. Plant 1, Units 1 through 4, consists of four turbines which are delivered steam by way of a header system supplied by seven drum-type boilers. Plant 1, with the exclusion of boiler 17, was placed in long-term shutdown in 1987. Plant 1, boiler 17, is currently operated as an auxiliary boiler providing startup steam to Units 7 and 8. Units 5 and 6 are 175 MW conventional natural circulation steam drum units. Units 7 and 8 are 480 MW once-through supercritical units. Not including Plant 1, the Station has a maximum dependable operating capacity of 1,310 MW.

Units 5 through 8 each consists of a boiler, turbine, generator, control systems, and associated auxiliary equipment necessary to generate electric power. The units are arranged in pairs (5 and 6, and 7 and 8) with each pair having a separate control room. Auxiliary equipment associated with each unit consists of condensate and feedwater system piping, pumps and heaters, lubricating oil storage and pumping systems, generator cooling systems, fuel delivery systems, boiler lancing systems, instrumentation, electrical and compressed air systems, and pollution control systems (including Selective Catalytic Reduction (SCR) on Units 7 and 8). All of the units use natural gas as their primary fuel source and have backup fuel oil burning capability that is intended to be employed only in emergency situations.

Common systems that are associated with pairs of units or that provide service to the entire Station include closed equipment cooling water systems, condenser cooling water systems (including the intake and discharge channel), fire protection systems, irrigation and general use water systems, air compressor systems, water treatment systems, lubricating oil storage and filtration systems, water purification systems and storage, chemical storage and delivery systems, fuel delivery systems, wastewater storage and disposal systems, Station-specific communication systems, and switchyard equipment, including unit circuit breakers, associated relays and control, line dead ends, disconnects to the bus, step up transformers, associated switchrack, and a revenue metering system.

Redondo Beach 5 - 8 has been designated as Must-Run by the Independent System Operator ("ISO") as of the appraisal date. This means that Redondo Beach is needed for system reliability and stability due to transmission constraints in the southern California region. Redondo Beach will receive payments from the ISO when they are given dispatch notices indicating they are needed for reliability of the electrical grid system. It is currently anticipated that these payments will be for the benefit of the Tolling Party under the terms of the Tolling Agreement discussed below. The ISO has the right to terminate the Must-Run Agreement upon 90 days notice and can be extended on a 12-month basis. The Must-Run Agreement indicated that the ISO will be inclined to extend the term of the Must-Run Agreement until such time that the system reliability can be provided for through market mechanisms.

Sale of Redondo Beach to AES from Southern California Edison

On November 24, 1997, the proposed sale of three Southern California Edison (SCE) generating stations was announced. The sale included Alamitos, Redondo Beach, and Huntington Beach with a prospective purchase price of $781 million for all three stations. The sale closed under essentially the announced terms on May 18, 1998.

Concurrent with the purchase of Redondo Beach, AES entered into a Tolling Agreement with Williams Energy Services Company (Williams). Under the Tolling Agreement, Redondo Beach will be provided with capacity payments and variable operations and maintenance payments in exchange for giving Williams the exclusive right to toll fuel gas through Redondo Beach at a guaranteed heat rate and to market and dispatch the power generated. The Tolling Agreement is for a term of 15 years with an option for either party to extend the term for an additional five years. There is currently 15 years remaining, at most, on the tolling agreement. Redondo Beach will make available to Williams on an exclusive basis the dependable capacity shown in the table below:

Redondo Beach Unit	Guaranteed Availability
5	78.9%
6	78.9%
7	86.0%
8	86.0%

Provision is made for a Major Maintenance Cycle (MMC) each six years that will result in a maximum planned outage of 3,600 hours per MMC.

Redondo Beach will receive a fixed payment pursuant to the Tolling Agreement stated in dollars per KW per year in accord with the below schedule:

Unit Cost Per Contract Year
$/kW/Year

Year	Cost
1	35.00
2	35.00
3	35.00
4	35.00
5	35.00
6	38.20
7	38.58
8	38.97
9	39.36
10	39.75
11	40.15
12	40.55
13	40.96
14	41.37
15	41.78
16	42.50
17	42.50
18	42.50
19	42.50
20	42.50

In addition, Williams will make a variable payment of $2.00 per megawatt hour for net electric energy dispatched and delivered for market transactions.

Appraisal Unit

The relationship between the intangible and the tangible property at the facility is particularly important in performing an appraisal of the real and personal property for California property tax assessments. California Revenue and Taxation Code ("Cal. Tax Code") section 110, which provides the definition of "full cash value" and "market value," states in relevant part:

> (d) Except as provided in subdivision (e), for purposes of determining "full cash value" or "market value" of any taxable property, all of the following shall apply:
>
> > (1) The value of intangible assets and rights relating to the going concern value of a business using taxable property shall not enhance or be reflected in the value of the taxable property.
> >
> > (2) If the principle of unit valuation is used to value properties that are operated as a unit and the unit includes intangible assets and rights, then the market value of the taxable property contained within the unit shall be determined by removing from the value of the unit the market value of the intangible assets and rights contained within the unit.
> >
> > (3) The exclusive nature of a concession, franchise, or similar agreement, whether de jure or de facto, is an intangible asset that shall not enhance the value of the property, including real property.
>
> (e) Taxable property may be assessed and valued by assuming the presence of intangible assets or rights necessary to put the taxable property to beneficial or productive use.
>
> (f) For purposes of determining the "full cash value" or "market value" of real property, intangible attributes of real property shall be reflected in the value of the real property. These intangible attributes of real property include zoning, location, and other such attributes that relate directly to the real property involved.

Based on our examination of the Tolling Agreement and Cal. Tax Code section 110, and based on our discussions with Redondo Beach's counsel regarding the relevant legal authorities governing the treatment of intangibles for property tax purposes, we have appraised the real and tangible personal property at Redondo Beach considering the presence of intangible assets and rights held by Redondo Beach that are necessary to put the tangible property to a beneficial and productive use. We have also included in the value of the improvements and fixtures that comprise the real property at the facility the intangible attributes of that property, such as location and zoning. However, the value of identifiable intangible assets has been excluded from the final value conclusion.

The Assessor's Handbook Section 502, Advanced Appraisal, December 1998 (AH502) further clarifies the valuation methods to be used to ensure that non-taxable intangible assets are not captured in the appraisal of the tangible assets. Chapter 6 of AH502 at pages 150 to 165 entitled "Treatment of Intangible Assets and Rights" directly addresses the appraisal methods that ensure that intangible assets are not captured in the valuation of the tangibles.

At page 159 under the subject of "Selecting the Appropriate Appraisal Unit," AH502 states: "If the appraisal unit consists only of taxable property, the appraiser does not have to remove the non-taxable assets and rights, including intangible assets and rights." The recommendation is that, if possible, limit the appraisal unit to taxable property only. This suggests that a cost approach that does not include the intangibles, other than the intangible attributes of real property, is the preferred appraisal method. In AH501, page 73 states: "The most universally applied approach for property tax purposes is the cost approach." (See AH502, page 160, Footnote 129.) At page 164, AH502 states "Valuation approaches which value only the taxable property are generally favored over approaches which value the business enterprise that contains the taxable property." At page 151, AH502 states: "Section 212 states the general rule that intangible assets and rights are exempt from property taxation and that the value of intangible assets and rights shall not enhance or be reflected in the value of taxable property. However, this general rule is subject to the last sentence of section 212(c), which states that taxable property may be assessed and valued by assuming the presence of intangible assets or rights necessary to put the taxable property to beneficial or productive use."

At page 152, AH502 states: "Sections 110(e) and 212(c) do not authorize adding an increment to the value of taxable property to reflect the value of intangible assets and rights necessary to put the taxable property to beneficial or productive use. Instead, these sections indicate that, in valuing taxable property, it is appropriate to assume the presence of the intangible assets and rights which are necessary to put taxable property to beneficial or productive use. For example, a business which owns taxable property may need working capital and other intangible assets in order to productively use its tangible property. Although the presence of the intangible assets are assumed in the valuation of the tangible property, this does not mean that their values are included in that valuation."

It is clear from this discussion that the appraisal methods and procedures used by the appraiser ensure that non-taxable intangible assets **must not** be included in the valuation of the property of Redondo Beach subject to appraisal for property tax purposes.

To reliably measure the value of the Redondo Beach **tangible** property, we have prepared a series of analyses that use the cost and income approaches to value.

First, we have prepared a traditional cost approach valuation. Included in this approach are all of the costs necessary to replace Redondo Beach with property of equal capacity and utility, less all forms of depreciation that exist in Redondo Beach. We have included all hard and soft costs necessary to put the property to its highest and best use as an up and running electric generation facility capable of producing electricity. The soft costs include permits required to operate and all legal and architectural fees necessary to construct the Subject Property. Because it focuses on the value of the tangible assets, this approach does not include any value for the intangible assets. As noted above, AH502 supports this under the subject of Selecting the Appropriate Appraisal Unit.

Second, we have developed an income approach that assumes the Subject Property was to receive market-level income as a "merchant plant," i.e., an electricity producing plant that is able to obtain market rates for its electricity by selling it into the Power Exchange. This approach does not include any value associated with the Tolling Agreement to the extent that the Tolling Agreement provides Redondo Beach a premium income over and above the income it could obtain operating the Subject Property in the market as a merchant plant. It does, however, include business enterprise value associated with operating the Subject Property as a merchant plant.

Finally, we have not investigated the sales comparison approach to Redondo Beach utilizing sales of the Subject as well as other plants in California as comparables. Not only are these sales over four years old, but also we recognize the infirmities of applying the sales comparison approach because the sales price of the comparables and the Subject Property represent "investment value" rather than "fair market value" for property tax purposes. Investment value is defined in the Dictionary of Real Estate Appraisal, Third Edition, as "The specific value of an investment to a particular investor or class of investors based on individual investment requirements; distinguished from market value, which is impersonal and detached." As such, we have not relied on the sales comparison approach to value.

Highest and Best Use

The Subject Property is to be valued at its highest and best use. It is obvious that the only physical use of the Subject Property is the conversion of the energy in natural gas to electricity for sale in the market. We have concluded that, upon a sale of the Subject Property, its highest and best use would continue to be the production and sale of electricity and steam as a "merchant plant," selling electricity to the market at the best price obtainable.

Data Sources

In the development of this appraisal, data was gathered from various sources including:

- Historical operating cost and electric and steam production data for Redondo Beach from 1993 through 1997 as contained in the FERC Form 1.
- Historical operating cost and electric and steam production data for Redondo Beach from 1998 through 2002 as provided by AES.
- Projected operating cost and electric and steam production data for Redondo Beach as forecast by AES.
- Design characteristics, including capital cost and efficiency, of a state-of-the-art combined cycle gas turbine electric generating facility that could be constructed as of the appraisal date as published in the 2001-2002 Gas Turbine World Handbook.
- The Asset Sale Agreement between SCE and AES as it pertains to AES Redondo Beach.
- The Capacity Sale and Tolling Agreement by Redondo Beach (and others) with Williams

- Forecast of market prices for merchant plant sales of electricity and prices of natural gas in California as developed by the United States Department of Energy's Energy Information Administration in the Annual Energy Outlook 2003.

- Independent Technical Review of the AES California for the Benefit of the Project Lenders prepared by Stone & Webster Management Consultants, Inc. (S&W Report)

- Market data used in the development of a discount rate, including:

  - Stocks, Bonds, Bills, and Inflation, 2002 Yearbook, published by Ibbotson Associates;

  - Value Line Selection and Opinion, January 2, 2003;

  - Value Line Investment Survey, October 11, 2002.

APPRAISAL METHOD

Property to be Appraised

As described above, the objective of the appraisal is to estimate the fair market value of the real and tangible personal property of Redondo Beach (excluding land) put to beneficial and productive use as of January 1, 2003. Intangible assets are excluded from our value conclusion because these represent assets not subject to property tax.

The Three Approaches to Value: Sales Comparison, Income and Cost

In the development of an appraisal, and in accord with the State Board of Equalization (SBE) Property Tax Rule 3, there are three generally accepted approaches to value that should be investigated and applied, if possible, to the appraisal subject.

The sales comparison approach indicates value through analysis of recent sales or asking prices of comparable property. Prices are adjusted to reflect differences in age, physical condition, size, and utility between the subject and the market comparables.

The income approach is based on the present value of anticipated future earnings or cash flow. It requires projections of earnings and cash flows and the discounting of the cash flow to present value at rates based on the business risk and time value of money.

The cost approach is used to estimate the value of property based on the cost of reproducing or replacing the property less an allowance for existing depreciation or loss in value from physical deterioration, functional obsolescence, and external obsolescence.

The three approaches (if all can be calculated) are then correlated to a final value conclusion based on the judgement of the appraiser as to the reliance to be placed on each of the calculated value indicators.

Sales Comparison Approach (SBE Rule 4)

In the classical sales comparison approach, the indication of fair market value is derived from an analysis of the prices of similar properties in an active, open market similar in nature to that of the subject. These prices must be drawn from actual transactions involving similar property.

An active, open market for property similar in nature to that of the subject is specified because a single isolated sale of similar property may or may not be representative of the price that the appraised property would bring if offered on the market in the locale of the subject. As related to the securities market, this is the situation where there is a very "thin" market with very few trades being made. The "open market" concept refers to the fact that the prices to be used in the sales comparison approach should reflect arms-length transactions between willing buyers and willing sellers and not transactions in which there is compulsion on the part of either party that would tend to influence the amount paid. In order for a sale to be comparable, it must be similar to the subject in physical attributes, such as capacity, design, etc., and have similar income levels and patterns. In order for the market in which the sale took place to be comparable, it must be similar to that of the subject in that there must be the same demand for that type of property or the product it produces.

The strengths of the sales comparison approach are that it represents the best evidence when strong comparables are available and it is easily explained and understood. The weaknesses of this approach stem from the difficulty often experienced in finding appropriate comparable sales, and discovering the motives of buyer and seller. In general, this approach is not appropriate for unique special purpose property (such as electric generating plants) because of the adjustments that must be made to any suggested comparables to extract the value of a single plant from a multiple plant transaction, extract intangible elements in the sale, and extract "Fair Market Value" from the "Investment Value" evidenced in the market price.

Throughout the country, and particularly in California and the Northeast, the traditional regulated utilities were thoroughly restructured several years ago, especially in their sectors that generate electricity. Electric generating plants were divested by the utilities by sale of generating assets. Since these sales took place over four years ago, very few sales have occurred. Due to the age of these sales and the turbulence that has shaken the merchant power plants industry in the past several years, we will not rely on the sales comparison approach to value. **In our reconciliation of value indications, no weight is given to the comparable sales analysis.**

Income Approach (SBE Rule 8)

The income approach measures fair market value as the present worth of the anticipated monetary benefits to be derived in the future by the ownership of the asset. The monetary benefits are measured by the income stream which is expected to be available to the owner of the assets. The present worth of these future monetary benefits is measured by the duration and pattern of the projected income stream and by the risk attendant in the realization of that income stream. The duration and pattern of the projected income stream is based on estimates that take into consideration the type of property, its remaining economic life, future market conditions, and such. The risk element is recognized by discounting the projected income stream at a rate commensurate with the risk perceived by a prospective investor as compared to other investment opportunities. The discount rate is the result of a prospective investor's evaluation of the relative risk of the investment in question.

In a less risky investment, the investors, more confident of the return of their investment and the income to be derived from it, are willing to accept a lower rate of return. On the other hand, the investors will require a very high rate of return in situations where there is a considerably higher degree of risk or uncertainty as to the realization of earnings and/or the return of their original investment.

In this appraisal, we have developed an income approach to value that assumes that the Subject Property is used to produce electricity to be sold in the deregulated power market at market rates (the "merchant plant" income approach). As an economic matter, this approach plainly includes the value of the intangible assets, and, without adjustment, does not meet the dictates of Cal. Tax Code sections 110 and 212 cited earlier in this report. The income approach includes the value of all of the tangible and intangible assets of the business enterprise including the underlying land.

Cost Approach (SBE Rule 6)

The cost approach seeks an indication of value based on the amount of money required to replace the property at the time of the appraisal. It is based on the principle of substitution which says that one would not pay more for a property than the cost to construct improvements of equal desirability and utility without undue delay. It is assumed that the buyer is going to buy the subject property and will measure how much he or she will pay for the subject by considering his or her other alternatives. One alternative is to build and operate a different facility that produces the same output as the subject. This cost of building and operating a substitute facility sets the upper limit for how much the buyer will pay for the subject.

The development of fair market value by the cost approach involves the following formula:

Start:	Reproduction Cost New (RCN) Less: Excess Capital Costs
Result:	Cost of Replacement (COR) Less: Physical Deterioration Functional Obsolescence (Excess Operating Costs) External Obsolescence
Result:	Reproduction Cost New Less All Elements of Depreciation (RCNLD)
Result:	Fair Market Value

As utilized above, the Reproduction Cost New (RCN) is the amount required to reproduce the subject property in like kind, utility, and material at current market prices and assumes a creation of the entire property at one time. RCN is also described as the current cost of an identical but unused asset. If identical properties are still being produced at the time of the appraisal, the current cost of the identical property is the best indication of RCN at that time. When a property is new and of current design, RCN is a preferred cost methodology.

Cost of Replacement (COR), as used in the above formula, implies the replacement of the productive capacity of the property in question using modern materials and available technology at current market prices at the time of the appraisal. Stated another way, this is the current market price of a property that provides an equivalent service. An example of "the equivalent service" in the electric industry would be the number of kilowatt hours (kWh) of electricity to be produced over a future time period.

The difference between these two measures (RCN and COR), termed "excess capital cost" in the formula, reflects the fact that, where there has been a significant change in the basic design or function of a property, the current cost to reproduce the outmoded design, if it could be reproduced at all, will usually be higher than the current cost to replace the property's productive capacity. This is one element of functional obsolescence (see definition section below). As demonstrated on the next page, RCN less depreciation approach and a COR less depreciation approach will arrive at the same conclusion of value. The excess construction cost element of functional obsolescence is measured by RCN minus COR. The source for the next page is The Appraisal of Real Estate, 10th Edition, at page 347. (The same concept is discussed in the 11th Edition but without the demonstrative table.)

PROPER APPLICATION OF RCNLD APPROACH TO REFLECT FUNCTIONAL OBSOLESCENCE REQUIRES ANALYSIS OF A REPLACEMENT PLANT

Source: Page 347, The Appraisal of Real Estate

Item	Reproduction Cost (RCN)	Replacement Cost (COR)
Physical deterioration		
Incurable	Physical age-life or economic age-life (with effective age adjusted)	Physical age-life or economic age-life (with effective age adjusted)
Functional obsolescence		
Incurable Superadequacy	Excess construction cost	**Already recognized in replacement cost**
	Present value of excess operating costs	Present value of excess operating costs
External Obsolescence	Capitalization of property's net income loss due to external obsolescence	Capitalization of property's net income loss due to external obsolescence
	equals	equals
	Reproduction Cost less Depreciation	Replacement Cost less Depreciation

Both Cost Approaches Arrive at the same Conclusion of Value.

The three depreciation elements contained in the formula above and referenced in SBE Rule 6(e) – physical deterioration, functional obsolescence, and external obsolescence – reflect a reduction in value when the asset being appraised is not as desirable as its new, unused replacement because of either age, utility, excess operating costs, or outside economic factors.

Physical Deterioration is the loss in value caused by wear and tear in operation and exposure to the elements. The Subject Property has an average age in excess of thirty-four years and has endured wear and tear in operation and exposure to the elements.

Functional Obsolescence is the loss in value within the property as a result of the development of improved technology. This includes such things as changes in design, materials, or process resulting in overcapacity, inadequacy, excess construction, lack of utility, or excess variable operating costs in the subject. At the Subject Property, excess construction exists because of the availability of similar facilities at lower capital costs. Excess operating costs also exist at the Subject Property because newer facilities can convert natural gas into electricity at higher efficiencies than does the Subject Property.

External Obsolescence is the loss in value resulting from influences external to the property itself such as the political climate; the economics of the industry in which the property is used and the extent to which it is usable in another industry; inferior quality of raw materials, labor, utilities, and transportation service; changes in the local economy; legal changes including legislation, ordinances, zoning, and administrative orders. Even new property can exhibit external obsolescence.

For use in determining the value of the tangible assets of Redondo Beach, the cost approach is highly applicable because:

- The cost approach clearly excludes the exempt intangible assets held by a property owner and values only tangible real and personal property.

- The principle of substitution as applied in the cost approach is an evaluation method that would be used by buyers and sellers in the open market because it would be feasible to build a replacement in the vicinity.

- A highly supportable estimate of the capital cost to replace the productive capacity of Redondo Beach with the most modern substitute is readily available.

- The approach to developing the functional obsolescence caused by excess operating costs is simple and straightforward. The difference in the efficiencies with which Redondo Beach and a modern substitute can convert the energy in natural gas to electricity is readily measurable.

- Physical deterioration is measurable by a review of operating history.

The cost approach is applicable to the Subject Property and will be developed for Redondo Beach.

VALUATION

We will now proceed with the valuation of the Subject Property using the cost and income approaches to value.

Discount Rate

The discount rate is used in both the income and cost approaches to value.

The required return on an investment or discount rate was derived by the band-of-investment method. This method develops a capitalization or discount rate by summing the proportionate cost of debt and equity financing using appropriate component weightings of the various sources of capital.

In determining an appropriate capital structure to be used in this appraisal, we considered the relatively leveraged capital structure typical of the independent power industry. Schedule 1, page 1, to this report shows our conclusion that an appropriate capital structure for Redondo Beach as of January 1, 2003, is:

Common Equity	50%
Long Term Debt	50%

The next step is the determination of market costs of long term debt and common equity for Redondo Beach as of January 1, 2003. Schedule 1, page 1, shows the development of costs of capital and their weighting into a weighted average cost of capital (WACC).

The Capital Asset Pricing Model (CAPM) was used to develop the equity return requirement. This method starts with a "riskless" rate established by long term U.S. Government bonds followed by an adjustment to reflect the additional risk resulting from an equity investment considering both the general market, specific industry risks, and the fact that Redondo Beach would be classified as a Small Company. As shown on page 1 of Schedule 1, an indicated market cost of equity is 24.32%. A second estimate of the equity return requirements adds a size premium to the equity rate developed using Large Company Stock Total Returns. Redondo Beach as a standalone facility is in the micro-capitalization range resulting in an indicated equity return of 20.26%. Based on the above, we conclude the required return on equity to be 22.0% as shown at the middle of page 1 of Schedule 1.

For the cost of long term debt, a market rate as of January 1, 2003, for utility debt rated Baa/BBB was used. We conclude a reasonable estimate of Redondo Beach' cost of long term debt as of January 1, 2003, would be not less than 7.43% as developed in the top box on Schedule 1, page 1.

At the bottom of Schedule 1, page 1, the weighted average cost of capital is calculated by applying the capital structure weights to the concluded costs for the elements of capital. The WACC is concluded to be 14.72% using an after-tax cost of equity of 22.0%.

The 14.72% as originally developed is appropriate to apply to after-tax cash flows with taxes calculated considering the tax sheltering effects of debt payments. In the income approach, we apply a 40.75% income tax rate to a taxable income **not** adjusted for such tax sheltering. At the bottom of Schedule 1, page 1, we adjust the 14.72% WACC to 13.20%; this rate is applicable to income calculated assuming no tax sheltering of interest payments. It is also applicable in the calculation of an excess operating cost penalty in the cost approach because the operating costs are deductible in calculating taxable income.

SBE Tax Rule 8 specifies that income before deductions for income taxes and property taxes be used in the development of an income indicator of value. Therefore, a WACC must be constructed consistent with makeup of the income to which it is applied. At Schedule 1, page 2, we calculate such a rate by determining a pre-income tax required equity return to be 37.1%. A pre-income tax WACC at January 1, 2003, is calculated to be 22.27%. A further adjustment must be made for the lack of a deduction for property taxes in the income forecast. Property taxes in Los Angeles County approximate 1.07% of fair market value; therefore, we add 1.07% to the 22.27% pre-income tax WACC resulting in a pre-income tax and pre-property tax WACC of 23.34%, say 23.3%.

Schedule1, page 1, also shows the development of the 3.10% inflation rate expected in the future based on an analysis of market data at January 1, 2003.

Data used in the development of the WACC is in Appendix A.

Data Analysis Inputs

Certain data particular to Redondo Beach and, in general, from market sources are required for the various approaches to value.

Redondo Beach Generation and Operating Cost Data

Schedule 2, Page 1, is a listing of the Redondo Beach generating plant statistics for the years 1994 through 1997. Schedule 2, Pages 2 and 3 show the Redondo Beach generating plant statistics under AES ownership. We must point out that in the 1994 to 1997 period the plant was owned by Southern California Edison (SCE) and regulated by the California Public Service Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). During this time period, SCE was required to report information to FERC in a certain format. Also during this time, the subject plant did not operate under a tolling agreement. Therefore, comparing the 1994 through 1997 period to the 1998 to current period is difficult.

As can be seen in Schedule 2, the capacity factor went up under AES ownership from around 27% to around 33%. This could have been caused by two factors – the recent energy crisis in California and the tolling agreement. The California Energy Commission's 2002 - 2012 Electricity Outlook Report predicts capacity factors for large existing gas-fired units, such as the subject, to drop capacity factors to around 10% by 2005.

From this data we have forecast the heat rate, the operating and maintenance (O&M) costs per KWH of production, and a capacity factor which permits the forecast of future generation in MWH. On Schedule 2, Page 1 we adjust the labor costs to add loadings for benefits that are not included in FERC data. Based on the data in Schedule 2, we summarize the following for Redondo Beach:

Capacity Factor	15%
Heat Rate	10,200 BTU per KWH
O&M Cost per KWH Loaded	$.0060 per KWH

Redondo Beach Prospective Revenue From Power Sales

The forecast of revenues that could be expected from the sale of capacity and energy in from Redondo Beach was derived from a publication provided by the United States Department of Energy's Energy Information Administration entitled Annual Energy Outlook 2003. The revenue forecast in the Annual Energy Outlook 2003 is an average revenue for the year. Because Redondo Beach operates a lower capacity factor, it will be generating higher revenues than forecast. Therefore, we have increased the energy forecast by 10% to reflect this. The revenue in cents per kilowatt-hour is specific to California.

Income Tax, Capital Recovery, and Property Tax Rates

It was assumed that any potential buyer of the plant would continue to operate the plant in an electric power generating business. This means that this prospective purchaser would have to pay income taxes on the taxable income generated from the subject plant. The federal income tax rate is 35% for this type of income. The California state income tax rate is 9.3%; however, the state income tax is a deduction for federal tax purposes. Therefore, we assumed a composite federal and state income tax rate of 40.75%.

The prospective purchaser of the subject plant would be able to recover its investment in the plant and calculate depreciation for a deduction from taxable income. We have used the Modified Accelerated Cost Recovery System (MACRS) Table A-1 for 20-year property for this purpose.

The property tax rate for Redondo Beach is 1.07% of fair market value.

Redondo Beach Future Capital Investment

As noted above, we have relied on AES's forecast of capital expenditures for this plant.

Cost Approach

The cost approach was discussed above as having the following components:

	Reproduction Cost New (RCN)
Less:	Excess Construction
Equals:	Replacement Cost (COR)
Less:	Physical Deterioration
Less:	Excess Operating Costs
Equals:	RCN Less Physical and Functional Depreciation

An additional deduction from RCN in the cost approach is external obsolescence.

Reproduction Cost New (RCN)

Earlier in this report, we demonstrated that a cost approach can start with either Reproduction Cost or Replacement Cost because the difference between these two measures is excess construction. Given this, we develop a cost approach to value starting with Replacement Cost.

Cost of Replacement

The technology used at Redondo Beach converts the energy in gas to steam which is used to drive a turbine which, in turn, drives an electric generator. This older technology has been replaced by a combined-cycle gas turbine (CCGT).

A CCGT combines combustion turbines (similar to aircraft jet engines) that drive an electric generator(s) with the waste heat being recovered and converted into steam to drive a steam turbine which drives its own electric generator. An overwhelming majority of plants under development as of 2003 were CCGTs. The efficiency of the CCGT is much improved over the older technology.

CCGT Capital Cost - The Gas Turbine World 2001-2002 Handbook (GTW) presents the overnight construction costs for CCGTs. At Schedule 3, page 1, we summarize the overnight capital costs for CCGTs that could be utilized in the development of the substitute plant. In addition, we extract data from GTW pertaining to the heat rate at which the CCGT can operate. The heat rate in GTW is stated in terms of lower heating value (LHV) and must be converted to the higher heating value (HHV) heat rate to account for energy lost in the combustion process. The GTW data is included in Appendix C.

The capital cost and heat rate for a CCGT at January 1, 2003, concluded on Schedule 3, page 1, are:

	January 1, 2003
$/KW	$425
Heat Rate	6,771

These amounts must be adjusted for indirect and other costs not included in the GTW data. These include administrative and warehouse buildings, permits, construction management, start-up, spares and consumables, legal and miscellaneous equipment costs as shown on Schedule 3, page 2.

Buildings – This component is a 10,000 square foot administrative building and a 20,000 square foot warehouse/maintenance building priced in Los Angeles in January 1, 2003.

Permits, Environmental and CEC Liaison – This includes consultant costs for permitting application, interface with the CEC, owner's costs concerning permitting. This data was provided by URS/Woodward - Clyde Consultants and legal costs were added.

Construction Management – Black & Veatch developed an estimate of the total cost for a 1,422 MW CCGT. We ratioed the cost of construction management for this plant on the basis of the size of Redondo Beach to that model.

Start-up Costs and Spares/consumables – Same procedure as described for construction management.

Miscellaneous Equipment Cost – The addition of SCRs to the replacement model adds $8.60 per KW. The Miscellaneous Equipment Cost includes $8.60 times 1,310,000 KW, or $11,300,000 for these SCRs.

The sum of the GTW and other costs for Redondo Beach total $638,900,000 as shown in the top box of Schedule 3, page 2. To this amount we add a contingency of 5% resulting in a total cost of $670,800,000, or $512 per KW of capacity.

Overnight costs assume essentially instantaneous construction of the plant. The plant cannot be constructed instantly and, therefore, interest during construction, or construction financing costs, must be added to account for the borrowing costs. This addition at the second box on Schedule 3, page 2, results in the total installed cost per KW at January 1, 2003 of $543. Applying the $543 per KW to a CCGT with the net capacity of Redondo Beach at 1,310,000 KW results in a replacement cost for Redondo Beach as of January 1, 2003 in the amount of $711,800,000.

CCGT Operating Costs

The fixed and variable operating costs as of January 1, 2003, for the CCGT are developed on Schedule 3, pages 3 and 4.

To develop a fuel cost per KWH, the cost of gas is required. The cost of gas is derived from the EIA's Electric Power Monthly January 2003. The cost of natural gas delivered to electric power generators in the state of California. The forecast of natural gas prices was derived from the Annual Energy Outlook 2003. The fuel cost per MMBTU is converted into fuel cost per KWH by reference to the CCGT heat rate.

At Schedule 3, page 3, the starting CCGT fuel cost per KWH is calculated to be $0.02719 stated in 2003 dollars ($2003). At Schedule 3, page 4, we calculate the operating and maintenance (O&M) cost per KWH for the CCGT stated in $2003. The fixed O&M cost per KWH is calculated to be $0.00992 per KWH assuming that Redondo Beach operates at a 15% capacity factor. The variable O&M per KWH is calculated to be $0.00217 per KW. The total O&M costs per KWH are $0.01209 per KWH.

Excess Operating Costs

To develop an adjustment for the differential in operating costs between Redondo Beach and the CCGT, we must examine the operating costs expected for Redondo Beach based on its historical performance.

The CCGT O&M costs per KWH and fuel costs per KWH were developed on Schedule 3, pages 3 and 4, as explained above.

Schedule 2 displays the historical performance of Redondo Beach using data extracted from SCE reports to the Federal Energy Regulatory Commission as well as data from AES. Our analysis of the data for use in forecasting future performance for Redondo Beach is summarized above.

On Schedule 4, page 1 and 2, we calculate the present value of the difference in operating cost between Redondo Beach and the CCGT as follows:

- **Lines 1 and 2** - The fixed and variable O&M costs per KWH for Redondo Beach is assumed to increase in future years at inflation.

- **Lines 3 and 4** - The O&M costs per KWH for the CCGT are extracted from Schedule 3, page 4, and are assumed to increase at inflation.

- **Lines 5 through 7** - The discount rate and inflation estimate calculated on Schedule 1 is shown at lines 5 and 6. At line 7, we extract inflation from the discount rate because all data for all future years will be stated in terms of $2003.

- **Lines 8 through 12** - The operating costs per KWH for Redondo Beach are calculated by adding the O&M costs per KWH to the fuel cost per KWH. At lines 9 through 11, we utilize the gas price forecast in constant 2003 dollars (line 9) and the heat rate of Redondo Beach (line 10) to calculate the Redondo Beach fuel cost per KWH (line 11). At line 12, we sum the O&M and fuel costs per KWH.

- **Lines 13 through 17** - In a manner similar to that described for Redondo Beach (lines 8 through 12), we calculate the combined O&M and fuel cost per KWH for the CCGT on line 17.

- **Line 18** - The total operating costs per KWH for Redondo Beach and the CCGT are compared, and the difference is stated on line 18 for each future year. Note that line 18 is positive, indicating that Redondo Beach has higher operating costs than does the CCGT.

- **Lines 19 through 22** - The MWH to be generated at each year in the future is calculated by reference to the 1,310 MW capacity of Redondo Beach and the 15% capacity factor. The MWH production is multiplied by the differential operating cost from line 18, resulting in the pretax excess operating cost assignable to Redondo Beach.

- **Line 23** - Because operating costs are deductible for tax purposes, the dollar amount of excess operating costs is adjusted for the implicit tax shelter by multiplying line 22 by (100% minus the tax rate of 40.75%).

- **Lines 24 through 26** - A present value factor for the differential operating costs in each year is calculated using the disinflated discount rate and the discount period.

- **Line 27** - At line 27, the present value of the differential operating costs for each of the years 2003 through 2017 is calculated.

- **Line 28** - Line 28 summarizes the total differential operating costs for line 27 for the entire period 2003 through 2017 in the amount of $90,300,000 for Redondo Beach.

This calculation indicates that Redondo Beach is subject to a $90.3 million penalty for functional obsolescence due to excess operating costs.

Physical Deterioration

In Chapter 16, The Appraisal of Real Estate, 12th Edition (AORE), describes methods to develop estimates of total and physical-only depreciation percentages. Several definitions in AORE are important to understand the concept and application of age to life techniques in measuring depreciation.

> *"In estimating the total depreciation of an improvement, the age-life concepts most important to the market extraction and age-life methods are:*
>
> - *Economic Life*
> - *Effective Age*
> - *Remaining Economic Life*

The concepts of economic life, effective age, and remaining economic life expectancy consider all elements of depreciation in one overall calculation. Therefore, the effective age estimate considers not only physical wear and tear but also any loss in value for functional and external considerations. This type of analysis is characteristic of the market extraction and age-life depreciation methods. However, the age-life method can be modified to reflect the presence of any known items of curable physical depreciation or incurable deterioration in short-lived building components.

When estimating physical deterioration in the breakdown method, the most important age-life concepts are:

- *Useful Life*
- *Actual Age*
- *Remaining Useful Life*

The use of these terms in the breakdown method relates to the separation of physical depreciation from functional and external obsolescence. Economic life considers all three components of depreciation in one age-life estimate, whereas useful life considers only the depreciation of the physical components of a property. A building's useful life would probably be longer than the economic life of the same building. In spite of that difference, the application of useful life in the breakdown method and economic life in the market extraction and age-life methods should yield the same approximate estimate of total depreciation." AORE, pages 384 through 385

"Economic Life: The period over which improvements to real property contribute to property value; the term relates to the market extraction and age-life methods of estimating depreciation." AORE, page 386

"Effective age is the age indicated by the condition and utility of a structure and is based on an appraiser's judgment and interpretation of market perceptions." AORE, page 385

"Remaining economic life is the estimated period over which existing improvements are expected to continue to contribute to property value." AORE, page 386

"Useful Life: The period of time over which a structure may reasonably be expected to perform the function for which it was designed." AORE, page 387

"Actual age, which is sometimes called ***historical age*** *or* ***chronological age****, is the number of years that have elapsed since building construction was completed."* AORE, page 385

"In the breakdown method, remaining useful life is the estimated period from the actual age of a component to the end of its total useful life expectancy. The remaining useful life of any long-lived component is equal to or, typically, greater than its remaining economic life." AORE, page 388

"The deterioration of long-lived items is measured by estimating an age-life ratio and applying it to all components of cost that have not already been treated for physical deterioration.

As an example, consider a small industrial building with a total cost of $700,000. It is 35 years old and has a total useful life expectancy of 100 years. The cost to cure the curable items (deferred maintenance) is $10,000. Short-lived building components include the boiler, roof cover, and floor covering. The cost to replace the boiler is $40,000, the cost to replace the roof covering is $60,000, and the cost to replace the floor finish is $20,000. There are no other short-lived items. The age-life ratio is calculated to be 35% (35-year actual age divided by 100-year useful life = 0.35). Physical deterioration in the long-lived items is estimated by deducting te cost to cure the curable items and the sum of the costs to replace the short-lived items from the cost of the structure ($700,000 - $10,000 - [$40,000 + $60,000 + $20,000] = $570,000). The age-life ratio is applied to the untreated costs (0.35 x $570,000) and the resulting amount of deterioration attributable to the long-lived items is $199,500." AORE, page 400.

It is clear from the above extracts from AORE that physical depreciation of long-lived property under the breakdown method is measured by application of an age-to-life ratio. The "age" is the chronological age of the property and the "life" is the useful life of the property. The useful life is the chronological age plus the remaining useful life. This is the method we have used in the appraisal.

AH502 in Chapter 2 confirms the applicability of the AORE methods to measure physical depreciation. AH502, Chapter 2, states at page 27:

> *"Incurable physical deterioration is physical deterioration that is not economical to repair as of the valuation date – that is, the cost to cure the defect exceeds the added value of the repair. Incurable physical deterioration includes both short-lived and long-lived physical components. As discussed earlier, a short-lived component (e.g., roof covering, exterior paint, interior decorating, floor covering, water heater, furnace, and kitchen appliances) has a remaining useful life shorter than the remaining economic life of the primary improvement (such as a building). Most short-lived items will become deferred maintenance items before the end of the primary improvement's remaining economic life expectancy. A long-lived component (e.g., a building's structural and electrical systems) has a remaining useful life at least as long as the remaining economic life of the primary improvement. Since it is normally not economically feasible to replace such components before the economic life of the primary improvement ends, physical deterioration incurred by long-lived components is considered incurable.*
>
> *To measure the loss in value caused by physical deterioration for each short-lived component, the appraiser calculates an age-life ratio from its actual age and total useful life expectancy. The age-life ratio is then applied to the cost new to replace each item as of the valuation date. A similar procedure is followed for long-lived components; however, the actual age and useful life expectancy of the primary improvement may be assigned to all long-lived items. Thus, all long-lived items are analyzed together."*

We now proceed to measure the physical depreciation existent in Redondo Beach as of the appraisal date.

The total useful life of Redondo Beach is developed by adding the expected remaining useful life to its age. The remaining useful life as of January 1, 2003, is estimated at 15 years. In developing this estimate of remaining useful life, we relied on our experience, the tolling agreement, and discussions with plant staff.

Redondo Beach was built in the late 1950s to the mid 1960s. Schedule 5, Page 1 weights the ages by the capacity of each unit to arrive at a weighted age of 42.3 years for Redondo Beach.

As discussed above, physical depreciation is measured by relating age to total useful life. The capacity-weighted chronological age of Redondo Beach is 42.3 years, and the remaining useful life is 15 years. The physical depreciation percentage is calculated below:

		January 1, 2003
1	Physical Age (Yrs)	42.3
2	Remaining Useful Life (Yrs)	15.0
3 = 1 + 2	Total Useful Life (Yrs)	57.3
4 = 1 ÷ 3	% Physical Depreciation	74.0%

Applying the 74.0% physical depreciation to the Cost of Replacement of $711,800,000 results in a physical deterioration amount of, say, $526,700,000.

Cost Approach Summary

The cost approach for Redondo Beach before external obsolescence is:

Replacement Cost	$711,800,000
Physical Depreciation	($526,700,000)
Excess Operating Costs (Functional Obsolescence)	($ 90,300,000)
Cost Approach Before External Obsolescence	$ 94,800,000

Discounted Cash Flow - Income Approach - After-Tax Cash Flows

Schedule 6 displays the forecasting of revenues and expenses and development of after-tax net cash flows from Redondo Beach, for all units, annually for the years 2003 through 2017.

Each line number on Schedule 6 will now be addressed:

- **Line 1** - Forecast of annual MWH of electric deliveries developed by using the 15% capacity factor for the combined plant and the Redondo Beach net capacity of 1,310 MW is calculated. The full year MWH is calculated by multiplying 15% x 1,310 MW x 8,760 hours per year = 1,721,340 MWH.

- **Line 2** - Capacity and Energy Revenue as developed in the Annual Energy Outlook 2003.

- **Line 3** - Total electric revenue is the product of capacity and energy revenue and electric deliveries.

- **Line 4** - The operating and maintenance expenses per KWH for the year 2003 were developed previously, in the amount of $.00600 per KWH. For each future year, these O&M expenses are stated in nominal dollars.

- **Line 5** - The total O&M costs are the O&M costs per KWH times the electric deliveries restated to KWH.

- **Line 6** - The fuel cost will be developed on lines 7 and 8.

- **Line 7** - The Redondo Beach natural gas cost was developed previously in 2003 dollars. This gas cost is then escalated to reflect normal inflation.

- **Line 8** - The total fuel cost is the product of the MWH and the gas cost per KWH times 1,000.

- **Line 9** - The total operating cost is the sum of the O&M cost and the fuel cost.

- **Line 10** - The variable margin is the revenue less the total operating costs.

- **Lines 11 and 12** - Recognition is given to the general and administrative (G&A) expenses required to operate Redondo Beach in a merchant plant business. Based on an analysis of data in reports provided by AES, these G&A expenses are established at 33% of the O&M expenses. On line 11, the 33% rate is applied to the O&M expenses.

- **Line 13** - The pretax operating cash flow – revenues less operating expenses less G&A expenses – is calculated.

- **Line 14** - Recognition is given to the fact that future capital expenditures will be required to permit the forecast of MWH to be actually produced. The capital expenditure forecast was prepared by AES.

- **Line 15** - The property tax rate for Redondo Beach is 1.07% of fair market value.

- **Lines 16 through 20** - Income taxes are deducted at 40.75% of taxable income to reflect state and federal income taxes that will be paid. Note that tax depreciation is deducted in the calculation of income taxes, but no consideration is given to the tax sheltering effect of interest expense on borrowed funds. On Schedule 1, page 1, we calculated a discount rate that reflects the tax shelter implicit in debt service costs.

- **Lines 21 through 23** - This is the after-tax net cash flow that is estimated to be received by the owner of the subject assets over the next 15 years. This cash flow is discounted to January 1, 2003 dollars.

- **Line 24** - Line 24 sums the present value of the cash flows from 2003 through 2017. The total DCF for Redondo Beach calculated on an after-tax basis is $152,400,000 as of January 1, 2003. This DCF includes the value of all tangible and intangible assets, including land, that are part of the business enterprise.

Discounted Cash Flow - Income Approach - Pre-Tax Cash Flow

Schedule 6, Page 2, displays the forecasting of revenues and expenses and development of the pre-tax net cash flows from Redondo Beach annually for the years 2003 through 2017.

Each line number on Schedule 6, Page 2, will now be addressed.

Lines 1 through 14 - this data is exactly the same as that presented for the discounting of after-tax net flow on Schedule 6, page 1.

Line 15 through 17 - The pre-tax net cash flow is the pre-tax operating cash flow less the capital expenditures that Redondo Beach is estimated to produce over the next 15 years.

Line 18 - Line 18 sums the present value of the pre-tax cash flows from 2003 through 2017.

The total DCF for Redondo Beach calculated on a pre-tax basis is $174,300,000 as of January 1, 2003.

Identifiable and Measurable Intangible Assets

Certain Identifiable and measurable intangible assets within the Redondo Beach business enterprise will now be addressed.

Tolling Agreement

The Tolling Agreement is an intangible asset that may have value if the contract revenues are in excess of the revenues in the open market. If the total electric revenues under the Tolling Agreement are in excess of the revenues developed using the Annual Energy Outlook 2003 electricity prices less the cost of the gas, then the Tolling Agreement could have value as an intangible asset. Stated another way:

If
Tolling Agreement Electric Revenues
Less
Annual Energy Outlook 2003 Revenues Less Cost of Gas
Equals
An Amount Greater Than Zero
Then
Tolling Agreement May Have Value.

We investigated this and determined that the present values of revenues under the Tolling Agreement are less than the net revenues using the Annual Energy Outlook 2003 data. Therefore, the Tolling Agreement has no positive value as an intangible asset itself but has a direct influence on financing costs as discussed below. In addition, its existence influences the purchase price because of the multiple plants purchased by AES and because it permits immediate entry to the market for merchant plant power.

Emissions Credits

Air emissions credits are an intangible asset included in the income approach. These sulfur dioxide (SO_2) and nitrogen oxide credits are tradeable in the market and have a determinable fair market value. AES has not been able to determine the emissions credits assignable to Redondo Beach. However, this is an intangible asset with some value that we know exists.

Workforce

It is our opinion that AES has another intangible asset in the form of a trained workforce. This workforce is a valuable intangible asset, bringing with it significant expertise and experience in operating Redondo Beach.

Utilizing information concerning the salary and loading for the employees at AES Redondo Beach, we were able to derive the cost to replace this intangible asset. On Schedule 7, we utilize this information to infer a value for the AES Redondo Beach staff in the amount of $1,300,000.

Favorable Financing

In our opinion, the purchase of the plants by AES from SCE, along with the concurrent establishment of the Tolling Agreement, provides evidence of a favorable financing opportunity for AES.

The lender of the debt capital – 70% of the total purchase price – would recognize the lower risk in financing a plant purchased with a Tolling Agreement from a major company. The Tolling Agreement provides an assured revenue source for the plants.

With a Tolling Agreement in place, the lender would require a mortgage interest rate much less than the rate required for an investment in a pure merchant plant with no Purchase Power Agreement or Tolling Agreement in place.

Recognizing the reduced default risk because of the Tolling Agreement, the lender would provide funds at a rate equivalent to A or Aa bonds. For a pure merchant plant, with no agreements in place, the lender would require a significantly higher rate equivalent to junk bonds such as B or BB grade.

Assuming a 20-year mortgage period with 70% of the $781 million purchase price financed and A rates of 6.89% and Baa/BBB rates of 7.43% at January 1, 2003, we can calculate the required mortgage payments. The present value at January 1, 2003, of the differential in the mortgage payments over the 20 years represents the value of this favorable financing intangible asset.

Schedule 8 displays the development of the value favorable financing asset at $24,400,000. This asset is shared by the other two properties – Huntington Beach and Alamitos – acquired by AES from SCE. At the bottom of Schedule 8, we develop factors to assign portions of the favorable financing asset value to each of the properties. Redondo Beach is allocated 28.8% of the total, or $7,000,000.

Reconciliation of Value Indicators

Page 33 of this report summarizes the indicators of value calculated. This data is then adjusted to ensure that all identifiable intangible assets (and land value) are removed, leaving a residual for the tangible assets of Redondo Beach but also including other elements of value in the business enterprise including unmeasured intangibles and going concern value.

Lines 1 through 8 analyze the DCFs calculated utilizing the revenue forecast for merchant plants prepared by the EIA. After removal of the land and direct intangibles – favorable financing and workforce summarized on lines 2 and 6 – the residual to the tangible assets, unmeasured intangibles and going concern value of Redondo Beach is $140.3 million using the pre-tax DCF.

Line 9 states the value indication developed by use of the cost approach. Because no non-realty-related intangibles were captured in the cost approach, the $94.8 million is indicative of the value of the tangible assets of Redondo Beach (excluding land) when put to beneficial and productive use. We did not identify any external obsolescence in Redondo Beach as evidenced by the income indicator of value exceeding the cost approach before adjustment for external obsolescence. Considering the fact that not all intangible assets have been removed from the income approach to value, we would expect them to be higher than the cost approach.

Lines 10 through 13 state the calculated values for the direct intangible assets and the value of the land, as indicated in the land value appraisal from The Delahooke Appraisal Company.

Chapter 6 of the AH502 at pages 150 to 165 provides guidance in the reconciliation of the value indicators. If the appraisal unit consists of only tangible property, the intangible assets and rights do not have to be removed. AH502 goes on to state at page 164 "Valuation approaches which value only the taxable property are generally favored over approaches which value the business enterprise that contains the taxable property." This guidance leads us to the conclusion that the cost approach to value is the relevant and most reliable indicator of value for Redondo Beach.

Based on our investigations as described herein, it is our opinion that the Fair Market Value of the real and personal tangible property (excluding land) of Redondo Beach as put to beneficial and productive use, as of January 1, 2003, is reasonably represented by an amount of NINETY-FOUR MILLION EIGHT HUNDRED THOUSAND DOLLARS ($94,800,000).

REDONDO BEACH RECONCILIATION OF VALUE INDICATORS

1	DCF REV AFTER TAX	$152,400,000	INCL DIRECT INTANGIBLES AND LAND AND ELEMENTS OF BUSINESS ENTERPRISE
2	LESS DIRECT INTANGIBLES	-$8,300,000	
3	LESS LAND	-$25,670,000	
4	RESIDUAL TO TANGIBLE ASSETS	$118,430,000	INCL ELEMENTS OF THE BUSINESS ENTERPRISE
5	DCF REV PRE TAX	$174,300,000	INCL DIRECT INTANGIBLES AND LAND AND ELEMENTS OF BUSINESS ENTERPRISE
6	LESS DIRECT INTANGIBLES	-$8,300,000	
7	LESS LAND	-$25,670,000	
8	RESIDUAL TO TANGIBLE ASSETS	$140,330,000	INCL ELEMENTS OF THE BUSINESS ENTERPRISE
9	COST APPROACH	$94,800,000	INCLUDES ONLY TANGIBLE ASSETS BUT NOT LAND
10	WORKFORCE	$1,300,000	
11	FAVORABLE FINANCING	$7,000,000	
12	DIRECT INTANGIBLES	$8,300,000	
13	LAND	$25,670,000	

SCHEDULES

AES Redondo Beach
Development of Weighted Average Cost of Capital (WACC)
as of 1/1/03

Market Data: (Source: Valueline 10/11/02)

Merchant Plant Developers/Operators			
Valueline:	AES Corp.	Calpine	Average
Beta	1.45	1.55	1.50
LTD %	85%	78%	82%

Both reflect a portfolio of plants; single plant would have higher risk
USE Beta of 1.60 and Capital Structure of higher equity

Capital Structure:

Debt:	50%
Equity:	50%
Total	100%

Debt Rate:
Considering the risk associated with operating a single plant
Utility Baa/BBB rated bonds were used.

1/2/03 7.43%

Equity Rate:
Using the Capital Asset Pricing Model:

Risk-Free Rate	30-Yr Government Bonds		Jan-03	4.96%	Valueline Selection and Opinion
Beta				1.60	
Equity Risk Premium	Small Company Stock Total Returns			17.3%	SBBI 2002 Yearbook Table 2-1
	Long-Term Government Bond Income Returns			5.2%	SBBI 2002 Yearbook Table 2-1
	Risk Premium			12.1%	
Equity Rate =	4.96% + (	1.60	x	12.1%)	
				24.32%	
Alternate:					
Equity Risk Premium	Large Company Stock Total Returns			12.7%	SBBI 2002 Yearbook Table 2-1
	Long-Term Government Bond Income Returns			5.2%	SBBI 2002 Yearbook Table 2-1
	Risk Premium			7.5%	
Equity Rate =	4.96% + (	1.60	x	7.5%)	
				16.96%	
	Micro-cap size premium			3.30%	SBBI 2002 Yearbook Table 2-1
	Equity Rate			20.26%	
			SAY	22.00%	

Weighted Average Cost of Capital

Debt =	50%	x	7.43%		=	3.72%
Equity =	50%	x	22.00%		=	11.00%
Total						**14.72%**

Tax Affected Weighted Average Cost of Capital

Debt =	50%	x	7.43%	x (1-40.75%)	=	2.20%
Equity =	50%	x	22.00%		=	11.00%
Total						**13.20%**

1551 ation: Long-Term Average 3.10%

AES Redondo Beach
Development of Weighted Average Cost of Capital (WACC)
Pre-Income and Pre-Property Tax WACC
as of 1/1/2003

After-Tax Market Cost of Equity	22.00%	
Combined Federal and State Income Tax	40.75%	
Implicit Pre-Tax Cost of Equity	37.13%	After-Tax Rate/(1-Tax Rate)
Use	**37.10%**	

Weighted Average Cost of Capital					
Debt =	50%	x	7.43%	=	3.72%
Equity =	50%	x	37.10%	=	18.55%
Total					22.27%
Property Tax at 1.07% of FMV					1.07%
Weighted Average Cost of Capital					23.34%
				Use	**23.30%**

SOUTHERN CALIFORNIA EDISON COMPANY
Redondo Beach
Historical Operating Statistics From FERC Form 1, Page 403

Line Number	Item	12/31/1994	12/31/1995	12/31/1996	12/31/1997	Average		
1	Kind of Plant	Steam	Steam	Steam	Steam			
2	Type of Plant	Outdoor/Conventional	Outdoor/Conventional	Outdoor/Conventional	Outdoor/Conventional			
3	Yr Originally Constr	1948	1948	1948	1948			
4	Yr Last Unit Inst	1967	1967	1967	1967			
5	Nameplate Cap (MW)	1,579.5	1,579.5	1,579.5	1,579.50	1,579.5		
6	Net Peak Demand-MW (60 Min)	1,107.0	1,192.0	1,118.0	1,111	1,132.0		
7	Plant Hrs Connected to Load	8,604	8,114	8,784	8,413			
8	Net Continuous Pl Capability (MW)	0	0	0	-			
9	When Not Ltd by Cond Water	1,602.0	1,602.0	1,602.0	1,602	1,602.0		
10	When Ltd by Cond Water	0.0	0.0	0.0	-			
11	Avg # Empl	97	90	68	68			
12	Net Gen (KWH)	3,438,558,000	2,347,771,000	2,861,770,000	2,657,486,200	2,826,396,300		
13	Cost: Land	$646,979	$646,979	$646,979	646,979			
14	Str	$19,279,429	$18,703,845	$18,870,608	19,536,270			
15	Eq	$244,338,559	$258,201,660	$263,203,053	267,617,399			
16	Total Cost	$264,264,967	$277,552,484	$282,720,640	$287,800,648			
17	Cost/KW	$167.31	$175.72	$178.99	$182.21	AVG 94..97	LABOR	AVG 94..97 LABOR $
18	Prod Exp: Op Supv/Engr	2,275,469	1,586,699	1,980,895	720,014	1,640,769	100.0%	1,640,769
19	Fuel	89,487,254	54,171,197	85,832,923	92,010,742	80,375,529	0.0%	
20	Coolants	0	0	0	-			
21	Steam	2,848,306	2,583,938	2,469,902	2,712,827	2,653,743	0.0%	-
22	Steam from Other Sources	0	0	0	-			
23	Steam Xferred	0	0	0	-			
24	Electric Exp	986,481	847,042	874,269	1,200,128	976,980	0.0%	
25	Misc Steam Pwr Exp	1,519,588	1,731,903	1,563,967	1,642,791	1,614,562	0.0%	
26	Rents	0	18,301	4,285	13,020	8,902	0.0%	-
27	Allowances	0	0	0	-	0	0.0%	-
28	Maint Super/Eng	2,687,402	2,585,004	2,205,773	1,325,007	2,200,797	100.0%	2,200,797
29	Maint Str	1,137,956	806,779	459,027	646,155	762,479	80.0%	609,983
30	Maint Boiler	2,752,997	5,840,121	3,481,196	3,533,044	3,901,840	80.0%	3,121,472
31	Maint El Pl	2,272,484	9,560,347	1,512,531	1,564,745	3,727,527	80.0%	2,982,021
32	Maint Misc	3,135,977	1,707,481	1,111,226	1,402,023	1,839,177	80.0%	1,471,341
33	Tot Prod Exp	109,103,914	81,438,812	101,495,994	106,770,496	99,702,304		12,026,384
33A	Prod. Exp less Fuel	19,616,660	27,267,615	15,663,071	14,759,754	19,326,775		62.2%
34	Exp/KWH	0.0317	0.0347	0.0355	0.0402	0.0355		
35	Fuel: Gas	Gas	Gas	Gas	Gas			
36	MCF	MCF	MCF	MCF	MCF			
37	Qty Burned	32,858,812	23,231,101	27,049,363	26,155,457			
38	BTU/MCF	1,035	1,038	1,035	1,019			
39	Avg Cost of Fuel/Unit Deld	2.723	2.332	3.173 $	3.518			
40	Avg Cost of Fuel/Unit Burned	2.72	2.33	3.17 $	3.518			
41	Avg Cost of Fuel/Unit MMBTU	2.63	2.25	3.07 $	3.451	2.85		
42	Avg Cost of Fuel/Unit KWH	0.026	0.023	0.03 $	0.035			
43	Avg BTU/KWH	9,894	10,273	9,787	10,032	9,997		
	MMBTU Burned	34,009	24,114	27,996	26,652			
	% of Total Prod	100.00%	100.00%	100.00%	100.00%			

UNITS OPERATING AS OF MAY 1998	
UNIT	CAPY (MW
5	17
6	17
7	48
8	48
TOTAL	1,31

Line	Item	12/31/1994	12/31/1995	12/31/1996	12/31/1997			
43A								
43B							% OF O&M TO LABOR	62.2%
43C							AES BENEFIT LOAD ON DIRECT LABOR	44.0%
43D	**Capacity Factor-Net Cont. Cpy.**	24.50%	16.73%	20.39%	18.94%	**20%**	ADDITIONAL O&M/KWH FOR BENEFITS	27.0%
43E	**Heat Rate**	9,894	10,273	9,787	10,032	**10,000**		
43F	O&M Cost/KWH (FERC Form)	0.0057	0.0116	0.0055	0.0056	**0.00558**		
43G	**O&M Cost/KWH Adj for Benefits**					**0.00708**		

AES Redondo Beach, L.L.C.

Statement of Earnings

	1998	1999	2000	2001	2002
Costs and expenses:					
Utilities	1,560,948	883,930	923,961	1,832,005	752,507
Replacement Power				753,835	0
Raw Materials			371,270	975,569	361,762
NOX				3,118,877	0
Maintenance	8,497,373	12,173,009	13,566,866	7,212,598	3,653,226
Wages & Benefits	259,574	585,676	3,426,538	5,742,839	5,484,098
Administrative	66,859	431,964	1,333,277	2,675,570	2,084,413
Charitable Contributions	7,931	20,195	13,732	40,809	19,645
Meals & Entertainment		5,331	2,141	1,370	428
Taxes	521,683	2,610,283	2,342,969	2,714,857	2,327,225
Insurance	793,775	1,029,097	903,413	1,367,445	2,523,136
Corporate Fee	0	0	1,146,723	2,474,399	2,275,701
Penalties and Fines	0	0	0	272,985	0
	11,708,144	17,739,485	24,030,890	29,183,156	19,482,140
Earnings (loss) from operations	19,303,126	32,397,572	5,735,389	28,236,860	35,834,925

1999	2000	2001	2002	Average
0.0007	0.0003	0.0003	0.0004	0.0004
0.0000	0.0000	0.0001	0.0000	0.0000
0.0000	0.0001	0.0002	0.0002	0.0001
0.0000	0.0000	0.0005	0.0000	0.0001
0.0092	0.0042	0.0012	0.0018	0.0041
0.0004	0.0010	0.0009	0.0026	0.0013
0.0003	0.0004	0.0004	0.0010	0.0005
0.0000	0.0000	0.0000	0.0000	0.0000
0.0000	0.0000	0.0000	0.0000	0.0000
0.0020	0.0007	0.0004	0.0011	0.0011
0.0008	0.0003	0.0002	0.0012	0.0006
0.0000	0.0004	0.0004	0.0011	0.0005
0.0000	0.0000	0.0000	0.0000	0.0000
0.0134	0.0074	0.0048	0.0094	0.0087
0.0103	0.0056	0.0026	0.0049	0.0059

Utilities, raw materials, maintenance, and wages & benefits only

AES Redondo Beach LLC Operating Information

1. MW-hrs Sold by unit from 1998-2002:

Year	RB Unit 5 (MW-hr)	RB Unit 6 (MW-hr)	RB Unit 7 (MW-hr)	RB Unit 8 (MW-hr)	Station (MW-hr)	Capacity Factor
1998	87,620.0	41,930.0	988,036.0	1,098,138.0	2,215,724.0	
1999	102,060.0	37,670.0	405,339.0	774,271.0	1,319,340.0	11.50%
2000	116,320.0	282,922.0	1,812,937.0	1,055,360.0	3,267,539.0	28.47%
2001	165,674.0	372,642.0	2,789,625.0	2,802,695.0	6,130,636.0	53.42%
2002	78,940.0	46,720.0	964,260.0	985,653.0	2,075,573.0	18.09%
Total	550,614.0	781,884.0	6,960,197.0	6,716,117.0	15,008,812.0	
Average	115,748.5	184,988.5	1,493,040.3	1,404,494.8	3,198,272.0	27.87%

2. Average Unit Heat Rate from 1998-2002:

Year	RB Unit 5 (BTU/kw-hr)	RB Unit 6 (BTU/kw-hr)	RB Unit 7 (BTU/kw-hr)	RB Unit 8 (BTU/kw-hr)	Station (BTU/kw-hr)
1998	16,818.0	16,372.0	9,843.0	9,903.0	10,853.0
1999	13,889.1	16,432.5	9,652.7	9,820.5	10,429.0
2000	13,756.1	13,081.4	10,121.0	9,859.2	9,980.0
2001	14,572.5	12,777.9	9,904.4	9,724.7	9,888.0
2002	14,361.0	14,419.0	10,135.0	9,730.0	9,946.0
Average	14,679.3	14,616.6	9,931.2	9,807.5	10,219.2

Gas Turbine World
2001-2002 Handbook
2001$

Subject Plant:	1,310 MW	Net Continuous Capacity	
Assumed replacement model is		437 MW	blocks
+/- 25%:	328 to	546 MW	

Net Plant Output	LHV Heat Rate	$/KW
346.9	6,740	455
365.0	5,880	434
378.0	5,985	416
390.8	6,020	402
392.2	5,945	396
397.7	5,988	395
400.0	5,690	500
426.6	6,610	427
466.6	6,590	389
477.9	6,506	383
480.0	6,450	387
517.0	6,550	383
529.8	6,040	390
Mean	6,230	412
Median	6,040	396
Say	6,100	400

11% Adjustment to LHV for HHV

Say	6,771	400

Handy-Whitman	408	7/1/01 Gas Turbogenerators
	415	1/1/02 Gas Turbogenerators
	433	1/1/03 Gas Turbogenerators
1/1/2002$	407	
1/1/2003$	425	

COMBINED CYCLE GAS TURBINE 7/15/2003
ANALYSIS OF MODEL PLANT CAPITAL COST DATA

COMBINED CYCLE GAS TURBINE			SOURCE	TOTAL COST	
CAPITAL COSTS PER KW OF CAPACITY-OVERNIGHT	$	425	GTW	$ 556,750,000	1/1/03
CONSTRUCTION MANAGEMENT			B&V MODEL	$ 7,000,000	1/1/03
START-UP COSTS			B&V MODEL	$ 2,300,000	1/1/03
SPARES AND CONSUMABLES			B&V MODEL	$ 9,000,000	1/1/03
MISC LEGAL COSTS AT 1.0% OF OVERNIGHT CAPITAL COSTS				$ 5,567,500	1/1/03
MISC EQUIPMENT COSTS AT $8.60/KW FOR SCR'S				$ 11,300,000	1/1/03
SUBTOTAL				$ 591,917,500	1/1/03
LOCATIONAL MULTIPLIER			EIA/AEO2003	1.058	1/1/03
LOCATIONALLY ADJUSTED SUBTOTAL				$626,200,000	1/1/03
OFFICE, MNTCE., AND WHSE BUILDINGS			AUS CALC	$ 1,900,000	1/1/03
PERMITS, ENVIRO, CEC LIAISON, LEGAL			URS WOODWARD	$ 10,800,000	1/1/03
TOTAL CAPITAL AND OTHER COSTS BEFORE CONTINGENCY				$638,900,000	1/1/03
CONTINGENCY AT 5.0% OF CAPITAL AND OTHER COSTS				$ 31,900,000	1/1/03
TOTAL CAPITAL COST INCL CONTINGENCY				$ 670,800,000	
TOTAL CAPITAL COST/KW	$	512			1/1/03

AUS CALCULATIONS FROM DATA

CONSTRUCTION FINANCING COST 6.3% PRIME + 2%

DISTRIBUTION OF CAPITAL COSTS PER KW

	% IN YEAR	OVERNITE $ IN YEAR	PERIODS FOR CFC	CFC	COST WITH CFC
YEAR 1	40%	$ 205	1.5	$ 21	$ 226
YEAR 2	60%	$ 307	0.5	$ 10	$ 317

CAPITAL COST PER KW WITH CONSTRUCTION FINANCING COSTS $ 543
1/1/03

SUBJECT PLANT 1,310,000 KW 711,800,000

ANALYSIS OF COMBINED CYCLE GAS TURBINE MODEL DATA
CALCULATION OF FUEL COST PER KWH AT 1-1-03

FUEL COSTS PER KWH PRODUCED			CALCULATED BELOW	
HEAT RATE - GAS	BTU/KWH		6,771	
FUEL COSTS				
GAS	PER MMBTU		$ 4.02	$1-1-03
FUEL COST PER KWH				
6,771 BTU/KWH	**x**	**4.0150 $/MMBTU =**	**$ 0.02719**	**$1-1-03**

SUMMARY OF CCGT MODEL OPERATING COSTS AT 1-1-2000		
FUEL COST PER KWH PRODUCED	**$ 0.02719**	**$1-1-03**

FUEL COST PER KWH					
10,200	**0**	**x**	**4.0150 $/MMBTU =**	**$ 0.04095**	**$1-1-03**

OPERATING COSTS FOR COMBINED CYCLE GAS TURBINE MODEL PLANT

CCGT OPERATING COST DATA				
UNIT RATING:			1,310	MW
CAPACITY FACTOR			15%	
KWH OUTPUT - (8760 HR/YR x GROSS CAPY x CAPY FACTOR)			1,721,340,000	KWH
FIXED O&M COST PER KW OF CAPACITY ($2001).....	$	12.26	AEO 2003	
FIXED O&M COST PER KW OF CAPACITY ($2003)......	$	13.03	3.1%	INFLATION
CAPACITY (KW)..		1,310,000		
TOTAL FIXED O&M COSTS..	$	17,069,300		
VARIABLE O&M COSTS ($2001)................................	$	0.00204	AEO 2003	
VARIABLE O&M COSTS ($2003)................................	$	0.00217		
FIXED O&M COSTS PER KWH..	**$**		**0.00992**	**$1-1-2003**
VARIABLE O&M COSTS PER KWH..	**$**		**0.00217**	**$1-1-2003**
TOTAL O&M COSTS PER KWH..	**$**		**0.01209**	**$1-1-2003**

7/22/2003

REDONDO BEACH
CALCULATION OF EXCESS OPERATING COST PENALTY
AS OF JANUARY 1, 2003
(CCGT = COMBINED CYCLE GAS TURBINE)

REDONDO BEACH HEAT RATE 10,200
CCGT HEAT RATE 6,771

FACILITY TO BE REPLACED
REDONDO BEACH
1 FIXED AND VARIABLE O&M COST($/KWH)($1-1-03) — $ 0.00600 O&M ADJ FOR BENEFITS
2 REAL O&M ESCALATION PER YEAR — 0.00% ASSUMED TO RISE AT INFLATION

REPLACING FACILITY
COMBINED CYCLE GAS TURBINE
3 FIXED O&M AND VARIABLE COST($/KWH)($1-1-03) — $ 0.01209
4 REAL O&M ESCALATION PER YEAR — 0.00% ASSUMED TO RISE AT INFLATION

DISINFLATED DISCOUNT RATE
5 INFLATION FORECAST — 3.10%
6 INFLATED DISCOUNT RATE — 13.20% WACCI
7 DISINFLATED DISCOUNT RATE — 9.80%

CALCULATION OF EXCESS OPERATING COSTS PER KWH	2003 ($1-1-03)	2004 ($1-1-03)	2005 ($1-1-03)	2006 ($1-1-03)	2007 ($1-1-03)	2008 ($1-1-03)	2009 ($1-1-03)	2010 ($1-1-03)
8 SUBJECT O&M/KWH (L1)	$0.00600	$0.00600	$0.00600	$0.00600	$0.00600	$0.00600	$0.00600	$0.00600
9 GAS COST IN $/MMBTU ($1-1-02)	$4.02	$4.13	$4.28	$4.32	$4.38	$4.67	$4.82	$4.97
10 SUBJECT HEAT RATE	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200
11 SUBJECT VARIABLE FUEL/KWH	$0.04095	$0.04213	$0.04366	$0.04406	$0.04468	$0.04763	$0.04916	$0.05069
12 TOTAL SUBJECT OPERATING COSTS / KWH (L8+L11)	$0.04695	$0.04813	$0.04966	$0.05006	$0.05068	$0.05363	$0.05516	$0.05669
13 CCGT FIXED AND VARIABLE O&M/KWH (L3)	$0.01209	$0.01209	$0.01209	$0.01209	$0.01209	$0.01209	$0.01209	$0.01209
14 GAS COST IN $/MMBTU ($1-1-03)	$4.02	$4.13	$4.28	$4.32	$4.38	$4.67	$4.82	$4.97
15 CCGT HEAT RATE	6,771	6,771	6,771	6,771	6,771	6,771	6,771	6,771
16 CCGT VARIABLE FUEL/KWH	$0.02719	$0.02796	$0.02898	$0.02925	$0.02966	$0.03162	$0.03264	$0.03365
17 TOTAL CCGT OPER COSTS / KWH (L13+L16)	$0.03927	$0.04005	$0.04107	$0.04134	$0.04174	$0.04371	$0.04472	$0.04574
18 SUBJECT OPER COSTS/KWH IN EXCESS OF MODEL (L18 = L12 - L17)	$0.00768	$0.00808	$0.00859	$0.00873	$0.00893	$0.00993	$0.01044	$0.01096

CALCULATION OF EXCESS OPERATING COSTS PER KWH	2011 ($1-1-03)	2012 ($1-1-03)	2013 ($1-1-03)	2014 ($1-1-03)	2015 ($1-1-03)	2016 ($1-1-03)	2017 ($1-1-03)
8 SUBJECT O&M/KWH (L1)	$0.00600	$0.00600	$0.00600	$0.00600	$0.00600	$0.00600	$0.00600
9 GAS COST IN $/MMBTU ($1-1-02)	$5.03	$5.08	$5.07	$5.25	$5.34	$5.43	$5.37
10 SUBJECT HEAT RATE	10,200	10,200	10,200	10,200	10,200	10,200	10,200
11 SUBJECT VARIABLE FUEL/KWH	$0.05131	$0.05182	$0.05171	$0.05355	$0.05447	$0.05539	$0.05477
12 TOTAL SUBJECT OPERATING COSTS / KWH (L8+L11)	$0.05731	$0.05782	$0.05771	$0.05955	$0.06047	$0.06139	$0.06077
13 CCGT FIXED AND VARIABLE O&M/KWH (L3)	$0.01209	$0.01209	$0.01209	$0.01209	$0.01209	$0.01209	$0.01209
14 GAS COST IN $/MMBTU ($1-1-03)	$5.03	$5.08	$5.07	$5.25	$5.34	$5.43	$5.37
15 CCGT HEAT RATE	6,771	6,771	6,771	6,771	6,771	6,771	6,771
16 CCGT VARIABLE FUEL/KWH	$0.03406	$0.03440	$0.03433	$0.03555	$0.03616	$0.03677	$0.03636
17 TOTAL CCGT OPER COSTS / KWH (L13+L16)	$0.04614	$0.04648	$0.04642	$0.04763	$0.04824	$0.04885	$0.04845
18 SUBJECT OPER COSTS/KWH IN EXCESS OF MODEL (L18 = L12 - L17)	$0.01116	$0.01133	$0.01130	$0.01192	$0.01222	$0.01253	$0.01233

REDONDO BEACH
CALCULATION OF EXCESS OPERATING COST PENALTY
AS OF JANUARY 1, 2003

	2003 ($1-1-03)	2004 ($1-1-03)	2005 ($1-1-03)	2006 ($1-1-03)	2007 ($1-1-03)	2008 ($1-1-03)	2009 ($1-1-03)	2010 ($1-1-03)	2011 ($1-1-03)	2012 ($1-1-03)	2013 ($1-1-03)	2014 ($1-1-03)	2015 ($1-1-03)	2016 ($1-1-03)	2017 ($1-1-03)
19 SUBJECT OPER COSTS/KWH IN EXCESS OF MODEL	$0.00768	$0 00808	$0.00859	$0.00873	$0.00893	$0 00993	$0.01044	$0.01096	$0.01116	$0.01133	$0.01130	$0.01192	$0 01222	$0.01253	$0 01233
L20 =1,310MWAT CAPACITY FACTOR OF 15%															
20 MW REQUIRED AT SUBJECT CAPACITY FACTOR	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5
21 MWHR OUTPUT AT SUBJECT CAPY FACTOR (L21 = L20 x 8760 HOURS)	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340
22 TOTAL SUBJECT EXCESS OPER COSTS IN 1-1-03 $000 (L22 = L19 x L21)	13,222	13,901	14,786	15,022	15,376	17,088	17,973	18,859	19,213	19,508	19,449	20,511	21,043	21,574	21,220
23 AFTER TAX COST OF SUBIECT EXCESS OPER COSTS (L23 = (100% - 40.75%) x L22)	7,834	8,236	8,761	8,901	9,110	10,125	10,649	11,174	11,384	11,558	11,524	12,153	12,468	12,783	12,573
24 DISCOUNT PERIOD TO JAN 2003 IN YEARS n =	0.5	1.5	2.5	3.5	4.5	5 5	6.5	7.5	8.5	9 5	10.5	11.5	12.5	13.5	14.5
25 DISINFLATED DISCOUNT RATE =	9.80%														
26 PRESENT VALUE FACTOR	0.9627	0.8922	0.8269	0.7663	0.7102	0.6582	0.6100	0.5654	0.5240	0.4856	0 4501	0.4171	0.3866	0.3583	0.3320
27 PV OF YEARLY AFTER TAX EXCESS OPER COSTS ($000)	7,542	7,348	7,244	6,821	6,470	6,664	6,496	6,318	5,965	5,613	5,187	5,069	4,820	4,580	4,174
28 TOTAL PV OF EXCESS OPER COSTS 2002 THROUGH 2017	90,311														
SAY	$90,300														

AES
REDONDO BEACH
CALCULATION OF AVERAGE AGE

UNIT	IN SERVICE DATE	1/1/2003 AGE	CAPACITY	1/1/2003 WEIGHTED AGE
UNIT 5	1956.5	46.5	175	8,138
UNIT 6	1957.5	45.5	175	7,963
UNIT 7	1961.5	41.5	480	19,920
UNIT 8	1962.5	40.5	480	19,440
TOTAL		42.3	1,310	55,460

HUNTINGTON BEACH NET CAPY (KW) 1,310,000 DATE PREPARED = 7/22/2003
DISCOUNTED CASH FLOW ANALYSIS AT JANUARY 1, 2003 ANNUAL INFLATION ASSUMPTION = 3.10%
AEO 2003 FORECAST OF REVENUE
CAPACITY FACTOR = 15.0%

				2003	2004	2005	2006	2007	2008	2009	2010
	REVENUES										
1	ELECTRIC DELIVERIES (MWH)			1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340
2	CAPACITY/ENERGY REVENUE ($/MWH)		AEO2003	83.02	78.35	79.54	79.44	81.91	84.45	87.07	89.77
3	TOTAL ELECTRIC REVENUE		L1*L2	$142,900,483	$134,872,153	$136,917,105	$136,746,692	$140,988,074	$145,361,999	$149,868,467	$154,526,413
	OPERATING COSTS										
4	O&M COSTS/KWH	$ 0.00600 | $2003		$0.00600	$0.00619	$0.00638	$0.00658	$0.00678	$0.00699	$0.00721	$0.00743
5	TOTAL O&M COSTS		L1*L4*1000	$10,328,040	$10,655,095	$10,982,149	$11,326,417	$11,670,685	$12,032,167	$12,410,861	$12,789,556
6	FUEL COSTS										
7	GAS COST ($/KWH)			$0.0410	0.0434	0.0464	0.0483	0.0505	0.0555	0.0590	0.0628
8	TOTAL FUEL COST		L1*L7	$70,494,037	$74,761,077	$79,878,138	$83,124,027	$86,891,162	$95,516,201	$101,640,282	$108,052,266
9	TOTAL OPERATING COSTS		L5+L8	$80,822,077	$85,416,172	$90,860,287	$94,450,444	$98,561,847	$107,548,368	$114,051,143	$120,841,822
10	VARIABLE MARGIN		L3-L9	$62,078,406	$49,455,981	$46,056,818	$42,296,248	$42,426,227	$37,813,631	$35,817,324	$33,684,591
11	GEN. AND ADMIN. EXP.	33.0% OF O&M COSTS									
12	TOTAL GEN ADMIN EXP		L11*L5	$3,408,253	$3,516,181	$3,624,109	$3,737,718	$3,851,326	$3,970,615	$4,095,584	$4,220,553
13	PRE-TAX OPERATING CASHFLOW		L10-L12	$58,670,153	$45,939,800	$42,432,709	$38,558,530	$38,574,901	$33,843,016	$31,721,740	$29,464,038
14	TOTAL CAPITAL EXPENDITURES			$0	$0	$1,850,000	$3,300,000	$3,750,000	$4,020,000	$3,130,000	$920,000
15	PROP TAX AS % OF FMV	1.07%	RATE*L25	$1,630,680	$1,630,680	$1,630,680	$1,630,680	$1,630,680	$1,630,680	$1,630,680	$1,630,680
16	PRE-FIT NET CASH FLOW		L13-L14-L15	$57,039,473	$44,309,120	$38,952,029	$33,627,850	$33,194,221	$28,192,336	$26,961,060	$26,913,358
17	MACRS DEPR. RATE TABLE A-1 20 YR			3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%
18	TAX DEPRECIATION (MACRS)		L16*L17	$5,715,000	$11,001,756	$10,175,748	$9,413,748	$8,706,612	$8,054,340	$7,449,312	$6,891,528
19	TAXABLE INCOME		L16-L18	$51,324,473	$33,307,364	$28,776,281	$24,214,102	$24,487,609	$20,137,996	$19,511,748	$20,021,830
20	FIT AND SIT AT.................	40.75%	RATE*L19	$20,914,723	$13,572,751	$11,726,335	$9,867,247	$9,978,701	$8,208,233	$7,951,037	$8,158,896
21	AFTER-TAX NET CASH FLOW		L16-L20	$36,124,750	$30,736,369	$27,225,694	$23,760,603	$23,215,520	$19,986,103	$19,010,023	$18,754,462
22	DISCOUNT PERIODS		n =	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5
23	PV OF AFTER-TAX NCF AT	13.20%	PV L21 @ JAN-03	$33,953,102	$25,519,748	$19,968,801	$15,395,000	$13,287,701	$10,105,290	$8,490,876	$7,399,863
24	SUM OF 2003 - 2017 PV OF NCF		SUM L23	$152,448,501							
25			152,400,000	$152,400,000							

	Item	2011	2012	2013	2014	2015	2016	2017
1	ELECTRIC DELIVERIES (MWH)	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340
2	CAPACITY/ENERGY REVENUE ($/MWH)	91.06	89.27	90.44	93.25	96.14	99.12	102.19
3	TOTAL ELECTRIC REVENUE	$156,741,778	$153,655,415	$155,681,432	$160,509,791	$165,489,628	$170,620,942	$175,903,735
4	O&M COSTS/KWH	$0.00766	$0.00790	$0.00814	$0.00839	$0.00865	$0.00892	$0.00920
5	TOTAL O&M COSTS	$13,185,464	$13,598,586	$14,011,708	$14,442,043	$14,889,591	$15,354,353	$15,836,328
7	GAS COST ($/KWH)	0.0655	0.0682	0.0702	0.0749	0.0786	0.0824	0.0840
8	TOTAL FUEL COST	$112,746,778	$117,397,415	$120,798,473	$128,964,879	$135,242,152	$141,784,681	$144,564,758
9	TOTAL OPERATING COSTS	$125,932,242	$130,996,001	$134,810,181	$143,406,922	$150,131,743	$157,139,034	$160,401,086
10	VARIABLE MARGIN	$30,809,536	$22,659,414	$20,871,251	$17,102,869	$15,357,885	$13,481,908	$15,502,649
12	TOTAL GEN ADMIN EXP	$4,351,203	$4,487,533	$4,623,864	$4,765,874	$4,913,565	$5,066,936	$5,225,988
13	PRE-TAX OPERATING CASHFLOW	$26,458,333	$18,171,881	$16,247,387	$12,336,995	$10,444,320	$8,414,972	$10,276,661
14	TOTAL CAPITAL EXPENDITURES	$2,600,000	$2,440,000	$1,325,000	$0	$85,000	$55,000	$0
15	PROP TAX AS % OF FMV	$1,630,680	$1,630,680	$1,630,680	$1,630,680	$1,630,680	$1,630,680	$1,630,680
16	PRE-FIT NET CASH FLOW	$22,227,653	$14,101,201	$13,291,707	$10,706,315	$8,728,640	$6,729,292	$8,645,981
17	MACRS DEPR. RATE TABLE A-1 20 YR	4.462%	4.461%	4.462%	4.461%	4.462%	4.462%	4.462%
18	TAX DEPRECIATION (MACRS)	$6,800,088	$6,798,564	$6,800,088	$6,798,564	$6,800,088	$6,800,088	$6,800,088
19	TAXABLE INCOME	$15,427,565	$7,302,637	$6,491,619	$3,907,751	$1,928,552	-$70,796	$1,845,893
20	FIT AND SIT AT	$6,286,733	$2,975,825	$2,645,335	$1,592,409	$785,885	-$28,849	$752,201
21	AFTER-TAX NET CASH FLOW	$15,940,920	$11,125,376	$10,646,372	$9,113,906	$7,942,755	$6,758,141	$7,893,780
22	DISCOUNT PERIODS	8.5	9.5	10.5	11.5	12.5	13.5	14.5
23	PV OF AFTER-TAX NCF AT	$5,556,248	$3,425,565	$2,895,798	$2,189,881	$1,685,917	$1,267,190	$1,307,521

1564

HUNTINGTON BEACH NET CAPY (KW) = 1,310,000 DATE PREPARED = 7/22/2003

DISCOUNTED CASH FLOW ANILYSIS AT JANUARY 1, 2003 ANNUAL INFLATION ASSUMPTION = 3.10%

AEO 2003 FORECAST OF REVINUE

CAPACITY IACTOR = 15.0%

			2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	REVENUES																
1	ELECTRIC DELIVERIES (MWH)		1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340	1,721,340
2	CAPACITY/ENERGY REVENUE($/MWH)	AEO2003	83.02	78.35	79.54	79.44	81.91	84.45	87.07	89.77	91.06	89.27	90.44	93.25	96.14	99.12	102.19
3	TOTAL ELECTRIC REVENUE	L1*L2	$142,900,483	$134,872,153	$136,917,105	$136,746,692	$140,988,074	$145,361,999	$149,868,467	$154,526,413	$156,741,778	$153,655,415	$155,681,432	$160,509,791	$165,489,628	$170,620,942	$175,903,735
	OPERATING COSTS																
4	O&M COSTS/KWH	$ 0.00600 $2003	$0.00600	$0.00619	$0.00638	$0.00658	$0.00678	$0.00699	$0.00721	$0.00743	$0.00766	$0.00790	$0.00814	$0.00839	$0.00865	$0.00892	$0.00920
5	TOTAL O&M COSTS	L1*L4*1000	$10,328,040	$10,655,095	$10,982,149	$11,326,417	$11,670,685	$12,032,167	$12,410,861	$12,789,556	$13,185,464	$13,598,586	$14,011,708	$14,442,043	$14,889,591	$15,354,353	$15,836,328
6	FUEL COSTS																
7	GAS COST ($/KWH)		$0.0410	$0.0434	$0.0464	$0.0483	$0.0505	$0.0555	$0.0590	$0.0628	$0.0655	$0.0682	$0.0702	$0.0749	$0.0786	$0.0824	$0.0840
8	TOTAL FUEL COST	L1*L7*1000	$70,494,037	$74,761,077	$79,878,138	$83,124,027	$86,891,162	$95,516,201	$101,640,282	$108,052,266	$112,746,778	$117,397,416	$120,798,473	$128,964,878	$135,242,152	$141,784,681	$144,564,768
9	TOTAL OPERATING COSTS	L5+L8	$80,822,077	$85,416,172	$90,860,287	$94,450,444	$98,561,847	$107,548,367	$114,051,144	$120,841,822	$125,932,242	$130,996,001	$134,810,181	$143,406,921	$150,131,743	$157,139,034	$160,401,096
10	VARIABLE MARGIN	L3-L9	$62,078,406	$49,455,981	$46,056,818	$42,296,248	$42,426,227	$37,813,632	$35,817,323	$33,684,591	$30,809,535	$22,659,416	$20,871,252	$17,102,870	$15,357,884	$13,481,908	$15,502,649
11	GEN. AND ADMIN. EXP.	33.0% OF O&M COSTS															
12	TOTAL GEN ADMIN EXP	L15*L11	$3,408,253	$3,516,181	$3,624,109	$3,737,718	$3,851,326	$3,970,616	$4,095,584	$4,220,654	$4,351,203	$4,487,533	$4,623,864	$4,765,874	$4,913,565	$5,066,936	$5,225,988
13	PRE-TAX OPERATING CASH FLOW	L10-L12	$58,670,153	$45,939,800	$42,432,709	$38,558,530	$38,574,901	$33,843,017	$31,721,739	$29,464,038	$26,458,332	$18,171,881	$16,247,388	$12,336,996	$10,444,319	$8,414,972	$10,276,661
14	TOTAL CAPITAL EXPENDITURES	0	$0	$0	$1,850,000	$3,300,000	$3,750,000	$4,020,000	$3,130,000	$920,000	$2,600,000	$2,440,000	$1,325,000	$0	$85,000	$55,000	$0
15	PRE-TAX NET CASH FLOW	L13-L14	$58,670,153	$45,939,800	$40,582,709	$35,258,530	$34,824,901	$29,823,017	$28,591,739	$28,544,038	$23,858,332	$15,731,881	$14,922,388	$12,336,996	$10,444,319	$8,414,972	$10,276,661
16	DISCOUNT PERIODS	n =	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5
17	PV OF PRE-TAX NCF AT 23.30%	PV L15 @ JAN-03	$52,836,699	$33,554,014	$24,039,938	$16,939,221	$13,569,256	$9,424,420	$7,327,916	$5,933,246	$4,022,110	$2,150,956	$1,654,726	$1,109,817	$761,801	$497,796	$493,046
18	SUM OF 2003 - 2017 PV OF NCF	SUM L23	$174,314,664														
19	SAY	0	$174,300,000														

REDONDO BEACH POWER PLANT
WORKFORCE COST APPROACH

	Annual Rate	Hiring Cost	Training Cost	Total Cost	Quantity	Total
Operators	72,561	21,768	6,047	27,815	21	584,117
Maintenance	59,008	17,702	4,917	22,620	12	271,435
Support	72,710	21,813	6,059	27,872	6	167,234
Administration	50,499	1,000	12,625	13,625	3	40,874
Supervision	93,917	28,175	7,826	36,001	6	216,008
Total						1,300,000

Note 1: Individual hiring cost for Administration employees equals the cost of placing an ad and interviewing prospective employees. Individual hiring cost for all other positions equals 30% of the loaded annual salary for the position.

Note 2: Individual training cost for Administration employees equals 3 months loaded salary. Individual training cost of all other positions equals 1 month loaded salary.

FAVORABLE FINANCING INTANGIBLE ASSET

PURCHASE OF ALAMITOS, REDONDO BEACH, AND HUNTINGTON BEACH FROM SCE		
GIVEN OR ASSUMED DATA		
PURCHASE PRICE	$781,000,000	
PURCHASE DATE	5/18/1998	
TOLLING AGREEMENT	15 YRS + 5 YR OPTION	
PRIME RATE	4.25%	1/2/2003
A-RATED UTILITY BONDS	6.89%	1/2/2003
BAA/BBB-RATED UTILITY BONDS	7.43%	1/2/2003
% PP FINANCED WITH DEBT	70.00%	

CALCULATIONS	
PURCHASE PRICE	$781,000,000
% PP FINANCED WITH DEBT	70.00%
AMOUNT FINANCED	$546,700,000
RATE WITH TOLLING AGREEMENT	6.89%
RATE WITHOUT TOLLING AGREEMENT	7.43%
MORTGAGE TERM	20 YEARS
MORTGAGE PAYMENT WITH TOLLING	$51,164,252
MORTGAGE PAYMENT WITHOUT TOLLING	$53,341,842
DIFFERENTIAL IN ANNUAL PAYMENT	$2,177,590
PW AT 1/1/03 OF PAYMENT DIFFERENTIAL	$24,400,000

PLANTS PURCHASED	KW NET	HEAT RATE	O&M/KWH	FUEL/KWH	TOT/KWH	CF	NET GEN MWH	NET GEN %
ALAMITOS	2,085,000	9999	$0.00421	$0.02890	$0.03311	27%	4,931,442	64.1%
REDONDO BEACH	1,310,000	9997	$0.00558	$0.02994	$0.03552	20%	2,311,223	30.0%
HUNTINGTON BEACH	430,000	10623	$0.00854	$0.02948	$0.03802	12%	452,016	5.9%
					$0.03555		7,694,681	100.0%
HUNTINGTON BEACH GT	133,000							
ALAMITOS GAS TURBINE	133,000							

	NET GEN %	ALL PLANTS AS % OF SPECIFIC	NET GEN COST WGHTED	RATIO TO 100%	ALLOCATED FAVORABLE FINANCING
ALAMITOS	64.1%	107.4%	68.8%	65.9%	$16,100,000
REDONDO BEACH	30.0%	100.1%	30.1%	28.8%	$7,000,000
HUNTINGTON BEACH	5.9%	93.5%	5.5%	5.3%	$1,300,000
	100.0%		104.4%	100.0%	$24,400,000

APPENDIX A

COST OF CAPITAL DATA

AUS Consultants, Valuation Services Group

AES CORP NYSE-AES

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
2.57	2.7 (Trailing: 2.2 Median: 23.0)	0.18	Nil	974

TIMELINESS 5 Lowered 8/2/02

SAFETY 4 Lowered 7/12/02

TECHNICAL 4 Lowered 9/13/02

BETA 1.45 (1.00 = Market)

2005-07 PROJECTIONS	Price	Gain	Ann'l Total Return
High	25	(+875%)	75%
Low	15	(+485%)	55%

Insider Decisions

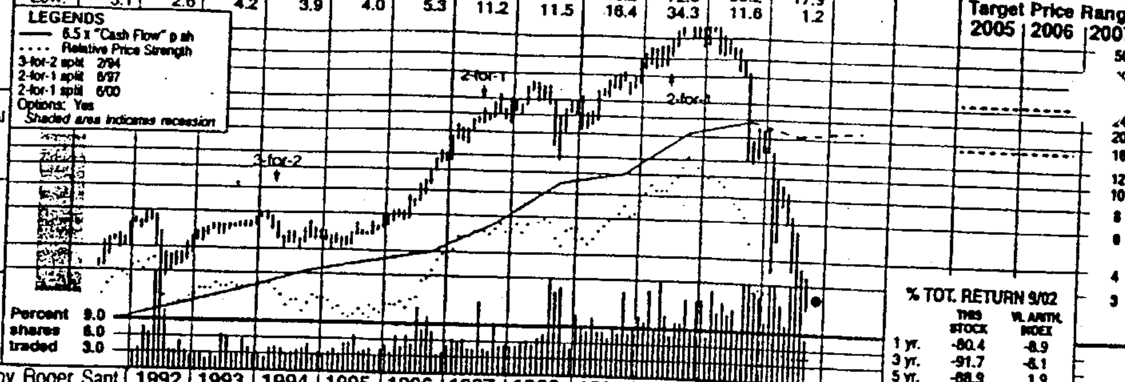
	N	D	J	F	M	A	M	J	J
to Buy	1	1	0	2	0	0	0	0	0
Options	0	2	0	1	0	3	0	0	0
to Sell	0	2	0	5	0	0	0	0	0

Institutional Decisions

	4Q2001	1Q2002	2Q2002
to Buy	201	166	161
to Sell	259	233	179
Hld's(000)	345844	359965	360453

High:	5.2	6.0	5.7	6.1	6.0	12.5	24.8	29.0	38.2	72.8	60.2	17.9
Low:	3.1	2.6	4.2	3.9	4.0	5.3	11.2	11.5	16.4	34.3	11.6	1.2

Target Price Range 2005 | 2006 | 2007



% TOT. RETURN 9/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	-80.4	-8.9
3 yr.	-91.7	-6.1
5 yr.	-88.9	1.9

AES Corp. was co-founded by Roger Sant and Dennis Bakke in 1981, under the original name Applied Energy Services. Initially the company provided energy consulting services before becoming a power producer. Went public, under the present title, in 1991, at which time 4,770,000 shares were issued at $2.535, after adjusting for stock splits. The lead underwriter was Donaldson, Lufkin & Jenrette Sec. Corp.

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
1.48	1.79	1.78	2.29	2.70	4.04	6.65	7.87	13.91	17.50	17.85	18.90	Revenues per sh	23.65
.33	.39	.47	.54	.61	.86	1.40	1.58	2.56	2.99	2.55	2.70	"Cash Flow" per sh	3.70
.20	.25	.33	.35	.41	.56	.84	.96	1.48	1.35	1.05	1.15	Earnings per sh A	1.70
.10	.15	--	--	--	--	--	--	--	--	Nil	Nil	Div'ds Decl'd per sh B	Nil
.45	.05	.09	.65	1.69	1.58	1.59	2.02	4.47	5.95	2.75	2.75	Cap'l Spending per sh	3.65
.65	1.07	1.34	1.83	2.33	3.92	4.68	5.81	10.00	10.38	7.35	8.50	Book Value per sh	12.80
274.01	289.14	298.60	299.20	309.60	349.60	360.40	413.60	481.00	533.00	543.00	543.00	Common Shs Outst'g C	550.00
17.9	19.8	14.9	13.3	19.9	32.6	26.5	27.2	33.4	27.1	Bold figures are		Avg Ann'l P/E Ratio	12.0
1.09	1.17	.98	.89	1.25	1.88	1.38	1.55	2.17	1.39	Value Line		Relative P/E Ratio	.80
2.7%	2.9%	--	--	--	--	--	--	--	--	estimates		Avg Ann'l Div'd Yield	Nil
401.0	518.7	532.7	685.0	835.0	1411.0	2398.0	3253.0	6691.0	9327.0	9700	10250	Revenues ($mill)	13000
46.5%	49.5%	51.7%	44.2%	43.5%	35.4%	39.7%	37.0%	32.8%	32.6%	29.0%	29.5%	Operating Margin	31.0%
33.7	41.7	43.4	55.0	65.0	114.0	196.0	278.0	582.0	859.0	800	850	Depreciation ($mill)	1100
55.8	71.3	98.3	107.0	125.0	188.0	307.0	378.0	648.0	733.7	575	625	Net Profit ($mill)	945
14.2%	20.3%	30.1%	34.1%	31.1%	21.3%	26.6%	29.4%	24.7%	28.7%	30.0%	30.0%	Income Tax Rate	30.0%
13.9%	13.7%	18.5%	15.6%	15.0%	13.3%	12.8%	11.6%	9.7%	7.9%	5.9%	6.1%	Net Profit Margin	7.3%
16.2	99.8	328.2	197.0	120.0	d14.0	d722.0	17.0	691.0	d388.0	d1000	d1200	Working Cap'l ($mill)	d1500
1196.4	1199.6	1144.1	1223.0	2006.0	4585.0	5241.0	10818	16927	20564	20000	19000	Long-Term Debt ($mill)	17500
177.2	309.3	401.0	549.0	721.0	2031.0	2344.0	3955.0	4811.0	5535.0	4000	4625	Shr. Equity ($mill)	7045
7.6%	8.9%	10.3%	9.5%	7.2%	4.6%	6.7%	4.1%	5.2%	5.4%	3.0%	3.5%	Return on Total Cap'l	4
31.5%	23.0%	24.5%	19.5%	17.3%	9.3%	13.1%	9.5%	13.5%	13.3%	14.5%	13.5%	Return on Shr. Equity	1
22.3%	18.4%	24.5%	19.5%	17.3%	13.7%	18.2%	15.6%	13.5%	13.3%	14.5%	13.5%	Retained to Com Eq	13
29%	20%	--	--	--	--	--	--	--	--	Nil	Nil	All Div'ds to Net Prof	Nil

CAPITAL STRUCTURE as of 6/30/02
Total Debt $24519 mill. Due in 5 Yrs $9452.0 mill.
LT Debt $20184 mill. LT Interest $1400.0 mill.
(Includes $978.0 mill. in trust-preferred securities)
(LT interest earned: 1.6x; Total interest coverage: 1.5x) (85% of Cap'l)

Leases, Uncapitalized Annual rentals $107.0 mill.
Pension Liability None
Pfd Stock None

Common Stock 542,721,411 shs. (15% of Cap'l) as of 8/01/02

Market Cap: $1.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2000	2001	6/30/02
Cash Assets	2178	1510	1616
Receivables	1498	1588	1987
Inventory (FIFO)	499	626	1485
Other	1398	929	317
Current Assets	5573	4653	5405
Accts Payable	708	819	1258
Debt Due	2465	2672	4335
Other	1709	1550	2365
Current Liab.	4882	5041	7958

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Revenues	31.5%	42.0%	10.5%
"Cash Flow"	31.5%	34.5%	7.5%
Earnings	31.5%	28.5%	5.0%
Dividends	--	--	Nil
Book Value	42.5%	36.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	638.0	640.0	847.0	1128	3253.0
2000	1476	1538	1781	1916	6691.0
2001	2495	2184	2261	2387	9327.0
2002	2719	2131	2325	2525	9700
2003	2750	2350	2450	2700	10250

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	.20	.22	.25	.29	.96
2000	.42	.25	.29	.50	1.46
2001	.42	.33	.27	.28	1.35d
2002	.36	.26	.20	.23	1.05
2003	.25	.25	.30	.35	1.15

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	NO CASH DIVIDENDS BEING PAID				
1999					
2000					
2001					
2002					

BUSINESS: AES Corp. is a global power company with 179 generating facilities in operation or under construction, totaling 62,852 megawatts of output. The company's four primary lines of business include contract generation, competitive supply, large utilities, and growth distribution, which accounted for 27%, 29%, 26%, and 18% of tot. revenues in '01, respectively. Plant locations incl.: U.S., Australia, Argentina, Brazil, Canada, Pakistan, Hungary, Kazakhstan, China, Dominican Republic, Netherlands, and the United Kingdom. Employees: roughly 38,000. Insiders control 16.0% of common stock (3/02 proxy). Chmn.: Roger W. Sant. Pres. & CEO: Paul T. Hanrahan. Inc.: Delaware. Address: 1001 North 19th St. Arlington, Virginia 22209. Tel.: 703-522-1315. Internet: www.aesc.com.

Asset sales will play a vital role in the restoration of AES to financial health. Last month, it completed the sale of FirstEnergy to Constellation Energy for $260 million, and is expected to close the sale of CILCORP for $510 million in the fourth quarter. Meanwhile, AES is auctioning off its Australian power assets. It is entertaining bids for either individual assets or the whole portfolio. This includes four power facilities with a combined generating capacity of nearly 1,750 megawatts.

AES is taking additional measures to improve liquidity. It seeks to roll over an $850 million corporate revolver that comes due next March, and possibly another $425 million in debt that matures in August, 2003. We believe that the prospects of AES reaching an agreement on these rollovers is good, especially since it has little in the way of debt maturing in the 2004-2006 time period.

Exposure to Latin America continues to be a burden on earnings. AES lowered share-net guidance for the full-year 2002 to a range of $1.00 to $1.10, from a previous level around $1.35. The main culprits are weak local currencies and poor economic activity in Brazil and Venezuela. AES is particularly frustrated in Brazil, where it has halted additional investment. The leftist Workers' Party was leading the polls for the presidential election, scheduled for October 6th. That increased the political risks facing foreign energy companies in Brazil. AES is considering an exit strategy for its operations in Brazil, including asset sales, spinoffs, or writedowns of nonperforming assets.

These shares are untimely for the year ahead. AES' need to focus on liquidity and the balance sheet will detract from potential earnings growth, as the company has drastically reduced capital expenditures and looks to divest assets. Our 3- to 5-year price projections assume that the company can overcome its current challenges and can get back on track with a less aggressive capital structure, but that is uncertain.

Michael P. Maloney *October 11, 2002*

CASH POSITION	5-Year Av'g	6/30/02
Current Assets to Current Liabilities:	177%	68%
Cash & Equiv's to Current Liabilities:	114%	13%
Working Capital to Sales:	15%	NMF

(A) Primary earnings through 1996, diluted thereafter. Excludes net nonrecur. charges in '99, (76¢); '00, (4¢); '01, (84¢). Next earnings report due late October. (B) 3% stock dividend was paid in March 1994. (C) In millions, adjusted for stock splits. (D) Quarterly EPS figures in '01 do not sum to yearend due to change in shares outstanding.

Company's Financial Strength	C++
Stock's Price Stability	15
Price Growth Persistence	65
Earnings Predictability	75

1569

CALPINE CORP. NYSE-CPN

RECENT PRICE	2.43	P/E RATIO	2.7 (Trailing: 1.6 Median: NMF)	RELATIVE P/E RATIO	0.18	DIV'D YLD	Nil	VALUE LINE	979

	1996	1997	1998	1999	2000	2001	2002
High:	2.5	2.9	3.5	16.4	53.0	58.0	17.3
Low:	2.0	1.5	1.6	3.1	16.4	10.0	2.4

Target Price Range 2005 | 2006 | 2007

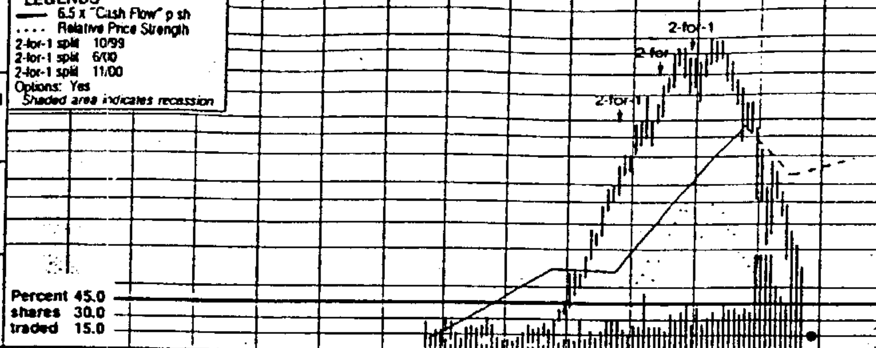
TIMELINESS 5 Lowered 1/25/02

SAFETY 4 Lowered 4/12/02

TECHNICAL 4 Lowered 9/27/02

BETA 1.55 (1.00 = Market)

LEGENDS
— 6.5 x "Cash Flow" p sh
.... Relative Price Strength
2-for-1 split 10/99
2-for-1 split 6/00
2-for-1 split 11/00
Options: Yes
Shaded area indicates recession



% TOT. RETURN 9/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	-89.2	-8.9
3 yr.	-77.5	-6.1
5 yr.	-7.1	1.9

2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+930%)	80%
Low	16	(+560%)	60%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	1	0	0	1	0	0
Options	1	0	0	1	0	1	1	1	2
to Sell	1	0	0	1	0	1	1	1	2

Institutional Decisions

	4Q2001	1Q2002	2Q2002
to Buy	282	219	233
to Sell	267	268	183
Hld's(000)	249413	252029	272068

Calpine began operations in 1984 in San Jose, California. It went public on November 19, 1996. The initial public offering of 18,045,000 shares was underwritten by CS First Boston, Morgan Stanley, Paine Webber, and Salomon Brothers. The initial share price was $16.00, or $2.00 on a stock-split adjusted basis. The company aims to take advantage of growing deregulation in the power industry.

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
--	--	--	--	1.35	1.72	3.45	3.36	8.05	24.72	21.20	23.85	Revenues per sh	29.20
--	--	--	--	.35	.51	.75	.73	1.69	3.46	2.05	2.40	"Cash Flow" per sh	3.65
--	--	--	--	.16	.21	.27	.43	1.11	1.95	.90	1.00	Earnings per sh A	1.45
--	--	--	--	--	--	--	--	--	--	Nil	Nil	Div'ds Decl'd per sh	Nil
--	--	--	--	.15	.67	.61	3.69	10.46	20.10	6.65	6.65	Cap'l Spending per sh	9.75
--	--	--	--	1.28	1.50	1.78	3.82	7.88	9.80	10.50	11.50	Book Value per sh B	16.30
--	--	--	--	158.75	160.49	161.29	252.22	283.72	307.06	377.00	377.00	Common Shs Outst'g C	385.00
--	--	--	--	13.9	11.2	8.8	19.7	29.4	18.9	Bold figures are	Value Line	Avg Ann'l P/E Ratio	15.0
--	--	--	--	.87	.65	.46	1.12	1.91	.97	estimates		Relative P/E Ratio	1.00
--	--	--	--	--	--	--	--	--	--			Avg Ann'l Div'd Yield	Nil
--	--	--	--	214.6	276.3	556.0	847.7	2282.8	7590.0	8000	9000	Revenues ($mill)	11250
--	--	--	--	48.2%	52.1%	39.7%	37.0%	33.1%	19.9%	19.0%	21.0%	Operating Margin	22.0%
--	--	--	--	36.6	46.8	74.3	87.2	154.3	338.2	425	525	Depreciation ($mill)	825
--	--	--	--	18.7	34.7	46.3	96.2	324.7	725.6	345	385	Net Profit ($mill)	580
--	--	--	--	32.7%	34.7%	36.9%	39.2%	40.3%	34.9%	35.0%	35.0%	Income Tax Rate	35.0%
--	--	--	--	8.7%	12.6%	8.3%	11.4%	14.2%	9.6%	4.3%	4.3%	Net Profit Margin	5.0%
--	--	--	--	96.2	d12.0	86.9	251.1	174.5	778.9	225	150	Working Cap'l ($mill)	50.0
--	--	--	--	285.0	742.9	1065.9	2006.2	5552.9	12947	11945	10945	Long-Term Debt ($mill)	14450
--	--	--	--	203.1	240.0	287.0	964.6	2236.8	3010.6	3950	4335	Shr. Equity ($mill)	6270
--	--	--	--	8.5%	6.7%	6.6%	4.8%	4.5%	5.0%	2.5%	2.5%	Return on Total Cap'l	3.0%
--	--	--	--	9.2%	14.5%	16.1%	10.0%	14.5%	24.1%	8.5%	9.0%	Return on Shr. Equity	9.0%
--	--	--	--	9.2%	14.5%	16.1%	10.0%	14.5%	24.1%	8.5%	9.0%	Retained to Com Eq	9.0%
--	--	--	--	--	--	--	--	--	--	Nil	Nil	All Div'ds to Net Prof	Nil

CAPITAL STRUCTURE as of 6/30/02
Total Debt $14.3 bill. Due in 5 Yrs $6.1 bill.
LT Debt $14.1 bill. LT Interest $.9 bill.
(Includes $1123.5 mill. in trust-preferred securities, and $209.0 mill. in capital leases.)
(LT interest earned: 2.6x; total interest coverage: 2.5x) (78% of Cap'l)

Leases, Uncapitalized: Ann. rentals $23.5 mill.
Pension Liability None
Pfd Stock None

Common Stock 376,699,769 shs. (22% of Cap'l)
MARKET CAP: $925 million (Small Cap)

CURRENT POSITION ($MILL.)	2000	2001	6/30/02
Cash Assets	588.7	1525.4	528.8
Receivables	649.4	966.1	1000.0
Inventory (FIFO)	36.9	78.9	96.7
Other	68.7	1437.3	1065.8
Current Assets	1343.7	4007.7	2691.3
Accts Payable	765.6	1283.8	1250.4
Debt Due	61.6	903.4	160.2
Other	342.0	1041.6	911.7
Current Liab.	1169.2	3228.8	2322.3

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Revenues	--	55.0%	16.0%
"Cash Flow"	--	41.5%	11.0%
Earnings	--	49.0%	3.5%
Dividends	--	--	Nil
Book Value	--	41.0%	14.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1999	145.9	190.7	263.6	247.5	847.7
2000	235.4	363.7	678.9	1004	2282.8
2001	1229	1724	2916	1721	7590.0
2002	1738	1583	2890	1789	8000
2003	1750	1800	3250	2200	9000

Calendar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1999	.02	.08	.19	.12	.43
2000	.09	.20	.48	.34	1.11
2001	.30	.39	.95	.31	1.95
2002	.10	.19	.50	.11	.90
2003	.10	.20	.55	.15	1.00

Calendar	QUARTERLY DIVIDENDS PAID Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	NO CASH DIVIDENDS BEING PAID				
1999					
2000					
2001					
2002					

BUSINESS: Calpine is a leading independent power company engaged in the development, acquisition, ownership, and operation of power generation facilities. Its sells electricity predominantly in the United States. As of 12/01, it owned interests in 84 power plants having an aggregate capacity of 12,090 megawatts. Upon the completion of its current construction projects in progress, Calpine will have interests in 88 plants with an aggregate capacity in excess of 26,232 megawatts. Mellon Financial owns 5.6% of outstanding comm. stock, and Massachusetts Finl. Svs. owns 5.1%. Officers/dirs. hold 4.7% (4/02 proxy). Chairman & CEO: Peter Cartwright. Address: 50 West San Fernando St., San Jose, CA 95113. Telephone: (408) 995-5115. Internet: www.calpine.com.

Calpine has laid out its new strategic objectives. Its top priority is to strengthen the balance sheet and ensure sufficient liquidity. It has cut or delayed spending on a significant number of development contracts, and has also begun to sell noncore assets to raise cash. At the same time, Calpine is focused on completing those plants already under construction, and continues to pursue attractive projects that have long-term power sales contracts in place with access to favorable financing. **The company has been aggressively shedding assets.** It most recently completed the sale of substantially all of its British Columbia oil and gas properties to Pengrowth Corp. for $243.7 million. Calpine received just over $155 million of that amount in cash; the remainder came from the assumption of about $88 million in Calpine debt by Pengrowth. Previously, the company completed the disposal of another $81 million of nonstrategic Canadian oil and gas properties, and terminated a Canadian power development partnership that resulted in a $14 million reimbursement. Further, Calpine announced plans to sell a $120 million Wisconsin peaking facility, as well as a letter of intent to sell two of its combustion turbines.

But Calpine also continues to bring new plants online. Over the last few months, it put a new 300-megawatt (mw) facility into service in Illinois, as well as a 1,000 mw plant in Texas, a 1,160 mw energy center in Louisiana, and a 630 mw project in Oregon. Too, Calpine has completed financing for a new $150 million peaking facility to be built in Colorado. **This issue continues to hold our lowest ranking (5) for Timeliness.** There appears to be no stimulus for the share price in the year ahead, as earnings guidance has moved downward (currently between $0.80 and $1.00 a share for 2002). Also, spark spreads (power revenues minus fuel costs) remain challenging. At the current share price, 3- to 5-year capital appreciation potential is wide if the company can rise above its current obstacles.

Michael P. Maloney *October 11, 2002*

CASH POSITION	5-Year Av'g	6/30/02
Current Assets to Current Liabilities:	100%	116%
Cash & Equiv's to Current Liabilities:	84%	23%
Working Capital to Sales:	19%	23%

(A) Diluted earnings. Excludes nonrecurring items: '99, d1¢; '00, d1¢, '01, d8¢. Quarterly figures do not sum to yearend number in '99 due to stock split and large change in shares outstanding. Next earnings report due late Oct.
(B) Includes deferred financing costs. In '01: $210.8 million; $0.69/sh.
(C) In millions, adjusted for stock splits.

Company's Financial Strength	C++
Stock's Price Stability	15
Price Growth Persistence	60
Earnings Predictability	60

AES CORP NYSE-AES

RECENT PRICE 13.10 | P/E RATIO 10.7 (Trailing: 8.5, Median: 23.0) | RELATIVE P/E RATIO 0.65 | DIV'D YLD Nil | VALUE LINE 979

TIMELINESS 5 Lowered 10/5/01
SAFETY 3 New 3/3/95
TECHNICAL 3 Raised 8/17/01
BETA 1.15 (1.00 = Market)

2004-06 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+360%)	47%
Low	40	(+205%)	32%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	1	0	0	1	0	1	0	1	0
Options	5	2	1	1	1	1	4	1	0
to Sell	5	1	0	3	0	0	5	2	0

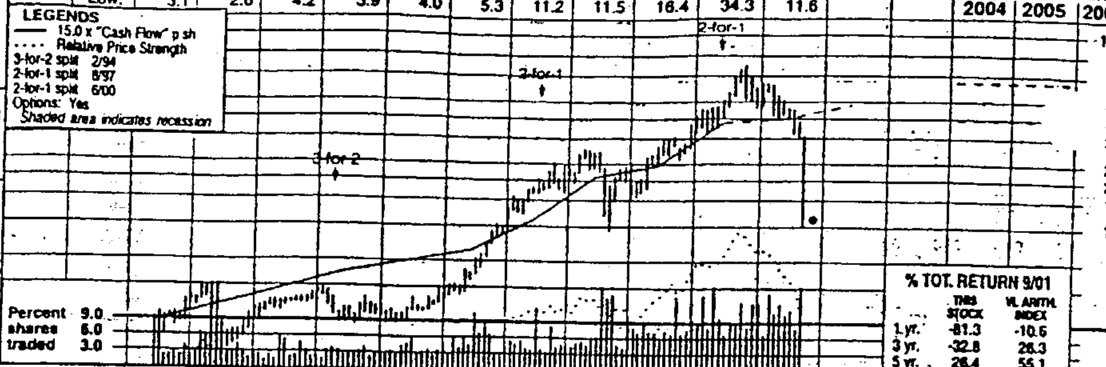
Institutional Decisions

	4Q2000	1Q2001	2Q2001
to Buy	263	322	309
to Sell	202	235	222
Hld's(000)	315021	339518	330585

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
High:	5.2	6.0	5.7	6.1	6.0	12.5	24.8	29.0	38.2	72.8	60.2
Low:	3.1	2.6	4.2	3.9	4.0	5.3	11.2	11.5	16.4	34.3	11.6

LEGENDS
—— 15.0 x "Cash Flow" p sh
.... Relative Price Strength
3-for-2 split 2/94
2-for-1 split 8/97
2-for-1 split 6/00
Options: Yes
Shaded area indicates recession

Target Price Range 2004 | 2005 | 2006



% TOT. RETURN 9/01

	THIS STOCK	VL ARITH. INDEX
1 yr.	-81.3	-10.6
3 yr.	-32.8	26.3
5 yr.	26.4	55.1

AES Corp. was co-founded by Roger Sant and Dennis Bakke in 1981, under the original name Applied Energy Services. Initially the company provided energy consulting services before becoming a power producer. Went public, under the present title, in 1991, at which time 4,770,000 shares were issued at $2.535, after adjusting for stock splits. The lead underwriter was Donaldson, Lufkin & Jenrette Sec. Corp.

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	© VALUE LINE PUB., INC.	04-06
1.25	1.46	1.79	1.78	2.29	2.70	4.04	6.65	7.87	13.91	17.95	20.55	Revenues per sh	27.90
.27	.33	.39	.47	.54	.61	.86	1.40	1.58	2.56	2.70	3.10	"Cash Flow" per sh	3.95
.17	.20	.25	.33	.35	.41	.58	.84	.96	1.46	1.30	1.60	Earnings per sh A	2.35
.03	.10	.15	--	--	--	--	--	--	--	Nil	Nil	Div'ds Decl'd per sh B	Nil
.89	.45	.05	.09	.65	1.69	1.56	1.59	2.02	4.47	4.65	5.60	Cap'l Spending per sh	6.90
.53	.65	1.07	1.34	1.83	2.33	3.92	4.68	5.81	10.00	12.50	14.15	Book Value per sh	21.15
265.85	274.01	289.14	298.80	299.20	309.60	349.60	360.40	413.60	481.00	535.00	535.00	Common Shs Outst'g C	545.00
24.3	17.9	19.8	14.9	13.3	19.9	32.6	26.5	27.2	33.4	Bold figures are		Avg Ann'l P/E Ratio	21.0
1.55	1.09	1.17	.98	.89	1.25	1.88	1.38	1.55	2.22	Value Line		Relative P/E Ratio	1.40
.8%	2.7%	2.9%	--	--	--	--	--	--	--	estimates		Avg Ann'l Div'd Yield	Nil
333.5	401.0	518.7	532.7	685.0	835.0	1411.0	2398.0	3253.0	6691.0	9600	11000	Revenues ($mill)	15200
48.4%	46.5%	49.5%	51.7%	44.2%	43.5%	35.4%	39.7%	37.0%	32.8%	28.0%	29.0%	Operating Margin	32.0%
29.2	33.7	41.7	43.4	55.0	65.0	114.0	196.0	278.0	582.0	750	800	Depreciation ($mill)	850
42.6	55.8	71.3	98.3	107.0	125.0	188.0	307.0	376.0	648.0	690	855	Net Profit ($mill)	1295
14.7%	14.2%	20.3%	30.1%	34.1%	31.1%	21.3%	26.6%	29.4%	24.7%	35.0%	35.0%	Income Tax Rate	35.0%
12.8%	13.9%	13.7%	18.5%	15.6%	15.0%	13.3%	12.8%	11.6%	9.7%	7.2%	7.8%	Net Profit Margin	8.5%
d3.4	16.2	99.8	328.2	197.0	120.0	d14.0	d722.0	17.0	691.0	d95.0	d390	Working Cap'l ($mill)	d1170
1159.5	1196.4	1199.6	1144.1	1223.0	2008.0	4585.0	5241.0	10818	16927	19500	21000	Long-Term Debt ($mill)	23500
140.9	177.2	309.3	401.0	549.0	721.0	2031.0	2344.0	3955.0	4811.0	6700	7555	Shr. Equity ($mill)	11535
6.5%	7.6%	8.9%	10.3%	9.5%	7.2%	4.6%	6.7%	4.1%	5.2%	2.5%	3.0%	Return on Total Cap'l	3.5%
30.3%	31.5%	23.0%	24.5%	19.5%	17.3%	9.3%	13.1%	9.5%	13.5%	10.5%	11.5%	Return on Shr. Equity	11.0%
21.2%	22.3%	18.4%	24.5%	19.5%	17.3%	13.7%	18.2%	15.6%	13.5%	10.5%	11.5%	Retained to Com Eq	%
30%	29%	20%	--	--	--	--	--	--	--	Nil	Nil	All Div'ds to Net Prof	Nil

CAPITAL STRUCTURE as of 6/30/01
Total Debt $21926 mill. Due in 5 Yrs $8561.0 mill.
LT Debt $19126 mill. LT Interest $1340.0 mill.
(Includes $1228.0 mill. in trust-preferred securities)
(LT interest earned: 1.6x; Total interest coverage: 1.5x) (77% of Cap'l)

Leases, Uncapitalized Annual rentals $13.0 mill.
Pension Liability $95 million in '00 vs. none in '99
Pfd Stock None

Common Stock 532,324,037 shs. (23% of Cap'l) as of 8/01/01.

Market Cap: $6.9 billion (Large Cap)

CURRENT POSITION ($MILL.)	1999	2000	6/30/01
Cash Assets	833	2178	1617
Receivables	934	1498	1569
Inventory (FIFO)	307	499	542
Other	513	1398	697
Current Assets	2587	5573	4425
Accts Payable	381	708	769
Debt Due	1216	2465	2800
Other	973	1709	2000
Current Liab.	2570	4882	5569

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '98-'00 to '04-'06
Revenues	31.5%	37.0%	19.5%
"Cash Flow"	35.0%	31.5%	13.5%
Earnings	38.5%	28.5%	13.5%
Dividends	--	--	Nil
Book Value	51.0%	37.0%	20.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	575.0	565.0	612.0	646.0	2398.0
1999	638.0	640.0	847.0	1128	3253.0
2000	1476	1538	1761	1916	6691.0
2001	2545	2215	2370	2470	9600
2002	2650	2500	2800	3050	11000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	.19	.20	.22	.23	.84
1999	.20	.22	.25	.29	.96
2000	.42	.25	.29	.50	1.46
2001	.42	.33	.25	.30	1.30
2002	.35	.40	.40	.45	1.60

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1997	NO CASH DIVIDENDS				
1998	BEING PAID				
1999					
2000					
2001					

BUSINESS: AES Corp. builds, owns, and operates cogeneration plants. As an international independent (non-utility) power producer, the company owns or has an interest in 134 power facilities totaling over 48,000 megawatts (MW) of generation capacity, and has numerous projects that are under construction or in various stages of development. Plant locations incl.: United States, Australia, Argentina, Brazil, Canada, Pakistan, Hungary, Kazakhstan, China, Dominican Republic, Netherlands, and the United Kingdom. Employees: roughly 16,000. Insiders control 26.0% of common stock (3/01 proxy). Chrmn.: Roger W. Sant. Pres. & CEO: Dennis W. Bakke. Inc.: Delaware. Address: 1001 North 19th St. Arlington, Virginia 22209. Telephone: 703-522-1315. Internet: www.aesc.com.

AES warned of a wide earnings shortfall for 2001. It revised share net downward to between $1.25 and $1.45 for the year, from a previous range of $1.75 to $1.95. One reason for lower guidance has been the company's extensive exposure to Brazil, where that nation's currency, the real, has slid about 40% against the dollar since January. Also, AES has been hurt by lower-than-expected electricity prices in the U.K., where much of its output is sold in the spot market. In addition, an agreement to buy a power plant in Nevada was cancelled, putting a further dent into AES's earnings estimates. The company expects that these three items will combine to lower EPS by $0.50 in 2001. Accordingly, we have lowered our share-net estimate to $1.30, from $1.80, for the year. **AES continues to have an appetite for acquisitions.** It purchased substantially all the energy assets of Thermo Ecotek in July for about $257 million. Aside from assets in the Czech Republic and Germany, the deal include three power plants in California with a total generating capacity of $330 megawatts (mw). It also paid about $70 million for a 56% stake in SONEL, an electric utility with 800 mw of capacity in Cameroon. Then, in late August, AES bought PSEG's global interests in five jointly held businesses in Argentina for $376 million, which includes stakes in three distribution and two generating companies. At present, the company seeks to acquire a roughly 43% stake in CANTV, a Venezuelan telecom company. AES has offered about $1.4 billion, which will stand until October 29th.

This now untimely issue has been under heavy pressure of late. The share price declined nearly 50% the day of the earnings revision. While we do not expect much from these shares in the year ahead, the selloff has left a good entry point for venturesome investors over the 3- to 5-year pull. As the global economy recovers from its current doldrums, AES's growth-through-acquisitions strategy should support double-digit share-net advances.

Michael P. Maloney *October 12, 2001*

CASH POSITION	5-Year Avg	6/30/01
Current Assets to Current Liabilities:	177%	79%
Cash & Equiv's to Current Liabilities:	114%	29%
Working Capital to Revenues:	15%	NMF

(A) Primary earnings through 1996, diluted thereafter. Excludes net nonrecur. charges in '99, (76¢); '00, (4¢). Next earnings report due late October.
(B) 3% stock dividend was paid in March 1994.
(C) In millions, adjusted for stock splits.

Company's Financial Strength —
Stock's Price Stability —
Price Growth Persistence 85
Earnings Predictability 85

CALPINE CORP. NYSE-CPN

RECENT PRICE	26.90	P/E RATIO	12.8 (Trailing: 17.8 / Median: NMF)	RELATIVE P/E RATIO	0.78	DIV'D YLD	Nil	VALUE LINE	985

TIMELINESS 3 Lowered 10/5/01
SAFETY 3 New 1/12/01
TECHNICAL 4 Lowered 10/12/01
BETA .90 (1.00 = Market)

	1996	1997	1998	1999	2000	2001
High:	2.5	2.9	3.5	16.4	53.0	58.0
Low:	2.0	1.5	1.6	3.1	16.4	18.9

Target Price Range 2004 | 2005 | 20

2004-06 PROJECTIONS

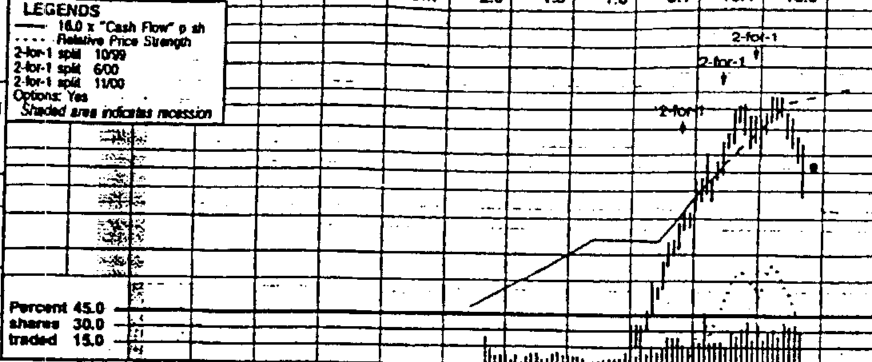
	Price	Gain	Ann'l Total Return
High	80	(+195%)	31%
Low	55	(+105%)	19%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	1	0	0	0	0	0	0	0	2
Options	3	3	0	2	2	0	2	1	0
to Sell	3	3	0	2	2	0	2	0	0

Institutional Decisions

	4Q2000	1Q2001	2Q2001
to Buy	244	322	315
to Sell	166	168	201
Hld's(000)	261950	269338	257703



% TOT. RETURN 9/01

	THIS STOCK	VL ARITH. INDEX
1 yr.	-56.3	-10.8
3 yr.	771.0	28.3
5 yr.	1002.3	55.1

Calpine began operations in 1984 in San Jose, California. It went public on November 19, 1996. The initial public offering of 18,045,000 shares was underwritten by CS First Boston, Morgan Stanley, Paine Webber, and Salomon Brothers. The initial share price was $16.00, or $2.00 on a stock-split adjusted basis. The company aims to take advantage of growing deregulation in the power industry.

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	© VALUE LINE PUB., INC.	04-06
--	--	--	--	--	1.35	1.72	3.45	3.38	8.05	18.05	22.75	Revenues per sh	30.
--	--	--	--	--	.35	.51	.75	.73	1.69	3.35	3.95	"Cash Flow" per sh	4.
--	--	--	--	--	.16	.21	.27	.43	1.11	2.10	2.50	Earnings per sh [A]	3.
--	--	--	--	--	--	--	--	--	--	Nil	Nil	Div'ds Decl'd per sh	N
--	--	--	--	--	.15	.67	.61	3.69	10.46	14.30	13.65	Cap'l Spending per sh	12.
--	--	--	--	--	1.28	1.50	1.78	3.82	7.88	11.90	15.20	Book Value per sh [B]	25.
--	--	--	--	--	158.75	160.49	161.29	252.22	283.72	315.00	330.00	Common Shs Outst'g [C]	350.
--	--	--	--	--	13.9	11.2	8.8	19.7	29.4	Bold figures are		Avg Ann'l P/E Ratio	20.
--	--	--	--	--	.87	.65	.46	1.12	1.95	Value Line		Relative P/E Ratio	1.
--	--	--	--	--	--	--	--	--	--	estimates		Avg Ann'l Div'd Yield	N
--	--	--	--	--	214.6	276.3	558.0	847.7	2282.8	6000	7500	Revenues ($mill)	1050
--	--	--	--	--	48.2%	52.1%	39.7%	37.0%	33.1%	34.0%	34.0%	Operating Margin	34.0
--	--	--	--	--	36.6	46.8	74.3	87.2	154.3	300	400	Depreciation ($mill)	50
--	--	--	--	--	18.7	34.7	46.3	98.2	324.7	780	900	Net Profit ($mill)	119
--	--	--	--	--	32.7%	34.7%	36.9%	39.2%	40.3%	40.0%	40.0%	Income Tax Rate	40.0
--	--	--	--	--	8.7%	12.6%	8.3%	11.4%	14.2%	12.7%	12.0%	Net Profit Margin	11.5
--	--	--	--	--	96.2	d12.0	88.9	251.1	174.5	100	d25.0	Working Cap'l ($mill)	.15
--	--	--	--	--	285.0	742.9	1065.9	2006.2	5552.9	8500	10000	Long-Term Debt ($mill)	1550
--	--	--	--	--	203.1	240.0	287.0	964.6	2236.8	3745	5020	Shr. Equity ($mill)	898
--	--	--	--	--	8.5%	6.7%	6.6%	4.8%	4.5%	5.5%	5.5%	Return on Total Cap'l	5.0
--	--	--	--	--	9.2%	14.5%	16.1%	10.0%	14.5%	20.5%	18.0%	Return on Shr. Equity	13.5
--	--	--	--	--	9.2%	14.5%	16.1%	10.0%	14.5%	20.5%	18.0%	Retained to Com Eq	13.5
--	--	--	--	--	--	--	--	--	--	Nil	Nil	All Div'ds to Net Prof	N

CAPITAL STRUCTURE as of 6/30/01
Total Debt $9218.0 mill. Due in 5 Yrs $1416 mill.
LT Debt $8215.3 mill. LT Interest $515.0 mill.
(Includes $1122.7 mill. in trust-preferred securities, and $208.8 mill in capital leases.)
(LT interest earned: 2.5x; total interest coverage: 2.4x) (74% of Cap'l)

Leases, Uncapitalized: Ann. rentals $174.0 mill.
Pension Liability None
Pfd Stock None

Common Stock 304,986,024 shs. (26% of Cap'l)
MARKET CAP: $8.2 billion (Large Cap)

CURRENT POSITION ($MILL.)	1999	2000	6/30/01
Cash Assets	349.4	588.7	1241.5
Receivables	127.5	849.4	1046.1
Inventory (FIFO)	16.4	36.9	56.6
Other	33.1	68.7	714.9
Current Assets	526.4	1343.7	3059.1
Accts Payable	84.4	765.6	915.0
Debt Due	47.4	61.6	1002.7
Other	143.5	342.0	1082.6
Current Liab.	275.3	1169.2	3000.3

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '98-'00 to '04-'06
Revenues	--	--	35.0%
"Cash Flow"	--	--	29.0%
Earnings	--	--	33.0%
Dividends	--	--	Nil
Book Value	--	--	33.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1998	55.1	141.6	186.2	173.1	556.0
1999	145.9	190.7	263.6	247.5	847.7
2000	235.4	363.7	678.9	1004.8	2282.8
2001	1229	1613	1900	1258	6000
2002	1500	1950	2350	1700	7500

Cal-endar	EARNINGS PER SHARE [A] Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1998	d.02	.07	.14	.08	.27
1999	.02	.08	.19	.12	.43
2000	.09	.20	.48	.34	1.11
2001	.30	.39	.85	.56	2.10
2002	.30	.40	1.25	.55	2.50

Cal-endar	QUARTERLY DIVIDENDS PAID Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1997	NO CASH DIVIDENDS BEING PAID				
1998					
1999					
2000					
2001					

BUSINESS: Calpine is a leading independent power company engaged in the development, acquisition, ownership, and operation of power generation facilities. Its sells electricity predominantly in the United States. As of 12/00, it owned interests in 50 power plants having an aggregate capacity of 5,849 megawatts. Upon the completion of its current construction projects in progress, Calpine will have interests in 74 plants with an aggregate capacity in exces of 19,800 megawatts. Has 1,883 employees. Putnam Investments own 6.1% of out. comm. stock, and Wellington Mgmt. owns 5.8%. Officers/dirs. hold 5.7% (4/01 proxy). Chairman & CEO: Peter Cartwright. Address: 50 West San Fernando St., San Jose, CA 95113. Telephone: (408) 995-5115. Internet: www.calpine.com.

Calpine is standing by its previously stated growth targets. It still intends to generate 70,000 megawatts (mw) of power by 2005. The company has brought a few new plants on line in recent months. Its new 213 mw Pine Bluff Energy Center in Arkansas began operations in late September. Calpine also completed a 250 mw capacity addition to its Broad River Energy Center in South Carolina, which now generates about 890 mw. Too, it began production at the RockGen Energy Center in Wisconsin, a 460 mw peaking facility. Meanwhile, the company received regulatory approval to build a 600 mw plant in San Jose, CA, and began construction on the 550 mw facility in South Carolina.

Acquisitions are also playing a role in Calpine's expansion initiative. In late August, it bought the Saltend Energy Center, a 1,200 mw natural-gas fired facility in England. The company paid approximately $810 million for the plant, and the deal marks its entry into the U.K. market. Elsewhere, Calpine completed the purchase of two power facilities from WestCoast Energy, for a total of $255 million. The plants, located in western Canada, add 275 mw to its generating portfolio.

The company appears to be well-situated in California, where energy deregulation has been under fire. It has minimal exposure to the FERC refund order that requires energy sellers to reimburse the state for overcharging on their power sales. Also, Calpine has signed a plan to get its $267 million receivable balance that it is owed from financially strapped PG&E. Calpine is committed to California, where it plans to have 15,000 mw of capacity by 2005. Already, it has sold 90% of its California output forward in 2001, 80% for 2002, and 65% for 2003.

Calpine stock has dropped in Timeliness. We believe that its recent selloff is a reflection of broader industry concerns and and a general downturn in the economy. The company has reaffirmed its guidance for strong share-net growth both this year and next ($2.00-$2.60 in 2001, $2.45-$2.60 in 2002). Another positive for this issue is PG&E's commitment to pay back its liabilities to Calpine in full with interest. These shares have good 3- to 5-year capital gains potential.

Michael P. Maloney *October 12, 2001*

(A) Diluted earnings. Excludes nonrecurring items: '99, d1¢; '00, d1¢. Quarterly figures do not sum to yearend number in '99 due to stock split and large change in shares outstanding.
Next earnings report due late Oct.
(B) Includes deferred financing costs. In '00: $0.49/sh.
(C) In millions, adjusted for stock splits.

Company's Financial Strength	B+
Stock's Price Stability	35
Price Growth Persistence	65
Earnings Predictability	55

AES CORP NYSE-AES

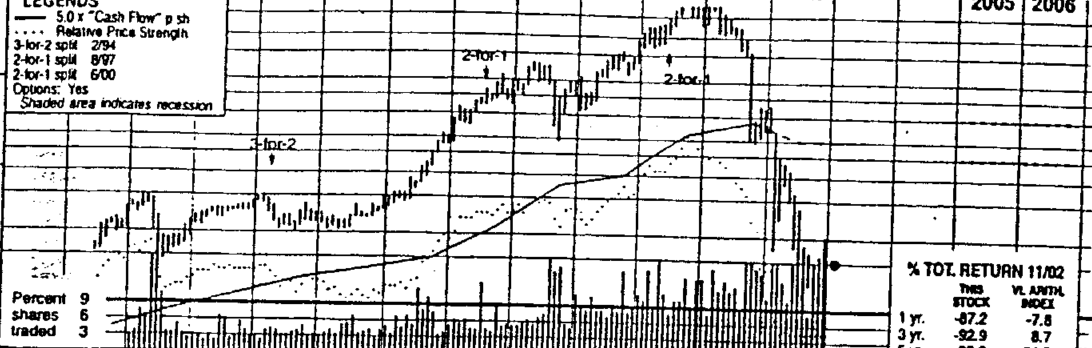
RECENT PRICE 3.02 | P/E RATIO 4.1 (Trailing: 2.8; Median: 23.0) | RELATIVE P/E RATIO 0.26 | DIV'D YLD Nil | VALUE LINE 974

TIMELINESS 4 Raised 12/27/02
SAFETY 4 Lowered 7/12/02
TECHNICAL 5 Lowered 1/10/03
BETA 1.75 (1.00 = Market)

High:	5.2	6.0	5.7	6.1	6.0	12.5	24.8	29.0	38.2	72.8	60.2	17.9
Low:	3.1	2.6	4.2	3.9	4.0	5.3	11.2	11.5	16.4	34.3	11.6	0.9

Target Price Range 2005 | 2006 | 2007

LEGENDS
— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
3-for-2 split 2/94
2-for-1 split 8/97
2-for-1 split 6/00
Options: Yes
Shaded area indicates recession



% TOT. RETURN 11/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	-87.2	-7.8
3 yr.	-92.9	8.7
5 yr.	-88.8	24.2

2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	16	(+430%)	50%
Low	10	(+230%)	35%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	2	0	0	0	0	0	3	0	0
Options	1	0	3	0	0	0	0	0	0
to Sell	5	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2002	2Q2002	3Q2002
to Buy	166	161	119
to Sell	233	179	178
Hld's(000)	359965	360453	362472

AES Corp. was co-founded by Roger Sant and Dennis Bakke in 1981, under the original name Applied Energy Services. Initially the company provided energy consulting services before becoming a power producer. Went public, under the present title, in 1991, at which time 4,770,000 shares were issued at $2.535, after adjusting for stock splits. The lead underwriter was Donaldson, Lufkin & Jenrette Sec. Corp.

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
1.46	1.79	1.78	2.29	2.70	4.04	6.65	7.87	13.91	17.50	17.20	17.65	Revenues per sh	20.45
.33	.39	.47	.54	.61	.86	1.40	1.58	2.56	2.99	2.40	2.45	"Cash Flow" per sh	3.05
.20	.25	.33	.35	.41	.58	.84	.96	1.46	1.35	.95	.90	Earnings per sh A	1.00
.10	.15	--	--	--	--	--	--	--	--	--	Nil	Div'ds Decl'd per sh B	Nil
.45	.05	.09	.65	1.69	1.56	1.59	2.02	4.47	5.95	3.40	3.40	Cap'l Spending per sh	4.10
.65	1.07	1.34	1.83	2.33	3.92	4.68	5.81	10.00	10.38	4.60	5.50	Book Value per sh	8.40
274.01	289.14	298.80	299.20	309.60	349.60	360.40	413.60	481.00	533.00	544.00	544.00	Common Shs Outst'g C	550.00
17.9	19.8	14.9	13.3	19.9	32.8	26.5	27.2	33.4	27.1	5.9		Avg Ann'l P/E Ratio	12.0
1.09	1.17	.98	.89	1.25	1.88	1.38	1.55	2.17	1.39	.30		Relative P/E Ratio	.80
2.7%	2.9%	--	--	--	--	--	--	--	--	--		Avg Ann'l Div'd Yield	Nil
401.0	518.7	532.7	685.0	835.0	1411.0	2398.0	3253.0	6691.0	9327.0	9350	9600	Revenues ($mill)	11250
46.5%	49.5%	51.7%	44.2%	43.5%	35.4%	39.7%	37.0%	32.8%	32.6%	29.0%	29.5%	Operating Margin	31.0%
33.7	41.7	43.4	55.0	65.0	114.0	196.0	278.0	582.0	859.0	800	850	Depreciation ($mill)	1100
55.8	71.3	98.3	107.0	125.0	188.0	307.0	376.0	648.0	733.7	510	490	Net Profit ($mill)	565
14.2%	20.3%	30.1%	34.1%	31.1%	21.3%	26.6%	29.4%	24.7%	28.7%	30.0%	30.0%	Income Tax Rate	30.0%
13.9%	13.7%	18.5%	15.6%	15.0%	13.3%	12.8%	11.6%	9.7%	7.9%	5.4%	5.1%	Net Profit Margin	5.0%
16.2	99.8	328.2	197.0	120.0	d14.0	d722.0	17.0	691.0	d388.0	d2425	d2000	Working Cap'l ($mill)	d1500
1196.4	1199.6	1144.1	1223.0	2008.0	4585.0	5241.0	10818	16927	20564	19000	18000	Long-Term Debt ($mill)	16500
177.2	309.3	401.0	549.0	721.0	2031.0	2344.0	3955.0	4811.0	5535.0	2500	2990	Shr. Equity ($mill)	4605
7.6%	8.9%	10.3%	9.5%	7.2%	4.6%	6.7%	4.1%	5.2%	5.4%	3.0%	3.0%	Return on Total Cap'l	3.[illegible]
31.5%	23.0%	24.5%	19.5%	17.3%	9.3%	13.1%	9.5%	13.5%	13.3%	20.5%	16.5%	Return on Shr. Equity	12.[illegible]
22.3%	18.4%	24.5%	19.5%	17.3%	13.7%	18.2%	15.6%	13.5%	13.3%	20.5%	16.5%	Retained to Com Eq	12.5%
29%	20%	--	--	--	--	--	--	--	--	--	Nil	All Div'ds to Net Prof	Nil

CAPITAL STRUCTURE as of 9/30/02
Total Debt $24129 mill. Due in 5 Yrs $9452.0 mill.
LT Debt $19110 mill. LT Interest $1400.0 mill.
(Includes $978.0 mill. in trust-preferred securities)
(LT interest earned: 1.6x; Total interest coverage: 1.5x) (89% of Cap'l)

Leases, Uncapitalized Annual rentals $107.0 mill.
Pension Liability None
Pfd Stock None

Common Stock 543,800,891 shs. (11% of Cap'l) as of 11/01/02

Market Cap: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2000	2001	9/30/02
Cash Assets	2178	1510	1651
Receivables	1498	1588	1292
Inventory (FIFO)	499	626	503
Other	1398	929	1596
Current Assets	5573	4653	5042
Accts Payable	708	819	1085
Debt Due	2465	2672	5019
Other	1709	1550	2155
Current Liab.	4882	5041	8259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Revenues	31.5%	42.0%	7.5%
"Cash Flow"	31.5%	34.5%	4.5%
Earnings	31.5%	28.5%	NMF
Dividends	--	--	Nil
Book Value	42.5%	36.5%	NMF

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	638.0	640.0	847.0	1128	3253.0
2000	1476	1538	1761	1916	6691.0
2001	2495	2184	2261	2387	9327.0
2002	2719	2131	2138	2362	9350
2003	2650	2250	2250	2450	9600

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	.20	.22	.25	.29	.96
2000	.42	.25	.29	.50	1.46
2001	.42	.33	.27	.28	1.35D
2002	.36	.26	.17	.16	.95
2003	.20	.20	.25	.25	.90

Calendar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999					
2000	NO CASH DIVIDENDS BEING PAID				
2001					
2002					
2003					

BUSINESS: AES Corp. is a global power company with 179 generating facilities in operation or under construction, totaling 62,852 megawatts of output. The company's four primary lines of business include contract generation, competitive supply, large utilities, and growth distribution, which accounted for 27%, 29%, 26%, and 18% of tot. revenues in '01, respectively. Plant locations incl.: U.S., Australia, Argentina, Brazil, Canada, Pakistan, Hungary, Kazakhstan, China, Dominican Republic, Netherlands, and the United Kingdom. Employees: roughly 38,000. Insiders control 18.0% of common stock (3/02 proxy). Chrmn.: Roger W. Sant. Pres. & CEO: Paul T. Hanrahan. Inc.: Delaware. Address: 1001 North 19th St. Arlington, Virginia 22209. Tel.: 703-522-1315. Internet: www.aesc.com.

AES has been rescheduling its short-term financial obligations. In December, it completed a $500 million bond exchange offer to refinance debt just days before $300 million in notes came due. The new secured notes, bearing a hefty 10% coupon, will not mature until July 15, 2005, and could be extended to December 12, 2005 if certain conditions are met. Elsewhere, AES has been negotiating with the Brazil National Bank for Economic Development (BNDES) regarding money AES owes for an electricity distribution company it purchased in Sao Paulo. The BNDES allowed AES to defer an $85 million past-due payment until January 30th. Meanwhile, AES Drax, a struggling subsidiary in the United Kingdom, signed a six-month contract whereby lenders will waive certain defaults and give it time to restructure.

AES is aggressively selling assets to increase liquidity. Last month, the company reached an agreement to sell two African generating businesses to a single buyer in a transaction valued at about $329 million, including cash and the assumption of project debt. The transactions, expected to close in the current quarter, are subject to bank and regulatory approval. Separately, AES made arrangements to divest two other generating businesses, located in Australia, to different parties. These sales, with an aggregate value of approximately $165 million, are also expected to close during the first quarter and are dependent on external approvals.

Investors should avoid untimely AES shares in the year ahead. The company has been under financial stress, relying on asset sales and debt refinancing to remain solvent. We believe that AES' pressing needs to strengthen the balance sheet will stifle earnings growth for at least the next year or two. Our 3- to 5- year projections, though downward revised, assume that the company will make some headway on the difficulties it faces, making the stock a speculative choice.

Michael P. Maloney *January 10, 2003*

CASH POSITION	5-Year Av'g	9/30/02
Current Assets to Current Liabilities:	177%	61%
Cash & Equiv's to Current Liabilities:	114%	20%
Working Capital to Sales:	15%	NMF

(A) Primary earnings through 1996, diluted thereafter. Excludes net nonrecur. items in '99, 76¢; '00, (4¢); '01, (84¢). Next earnings report due late January. (B) 3% stock dividend was paid in March 1994. (C) In millions, adjusted for stock splits. (D) Quarterly EPS figures in '01 do not sum to yearend due to change in shares outstanding.

Company's Financial Strength	C++
Stock's Price Stability	10
Price Growth Persistence	60
Earnings Predictability	70

CALPINE CORP. NYSE-CPN

RECENT PRICE	3.26	P/E RATIO	4.6 (Trailing: 3.3 Median: NMF)	RELATIVE P/E RATIO	0.29	DIV'D YLD	Nil	VALUE LINE:	979

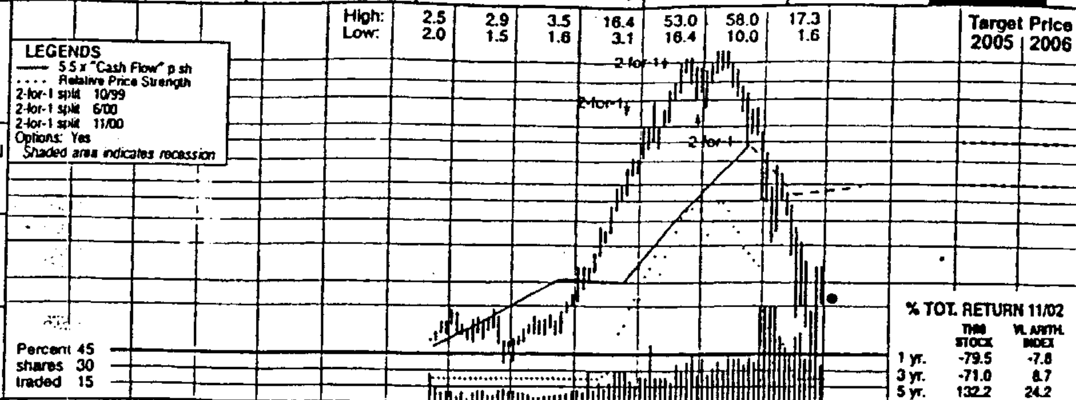
TIMELINESS 5 Lowered 1/25/02

SAFETY 4 Lowered 4/12/02

TECHNICAL 5 Lowered 1/3/03

BETA 1.75 (1.00 = Market)

High:	2.5 (1996)	2.9 (1997)	3.5 (1998)	16.4 (1999)	53.0 (2000)	58.0 (2001)	17.3 (2002)
Low:	2.0	1.5	1.6	3.1	16.4	10.0	1.6



2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	20	(+515%)	60%
Low	12	(+270%)	39%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	1	0	0	1	0	0	1	0	0
Options	1	0	1	1	1	2	2	1	1
to Sell	1	0	1	1	1	2	2	1	1

Institutional Decisions

	1Q2002	2Q2002	3Q2002
to Buy	219	233	143
to Sell	268	183	215
Hld's(000)	252029	272068	246328

% TOT. RETURN 11/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	-79.5	-7.8
3 yr.	-71.0	8.7
5 yr.	132.2	24.2

Calpine began operations in 1984 in San Jose, California. It went public on November 19, 1996. The initial public offering of 18,045,000 shares was underwritten by CS First Boston, Morgan Stanley, Paine Webber, and Salomon Brothers. The initial share price was $16.00, or $2.00 on a stock-split adjusted basis. The company aims to take advantage of growing deregulation in the power industry.

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
--	--	--	--	1.35	1.72	3.45	3.36	8.05	24.72	19.85	21.85	Revenues per sh	27.90
--	--	--	--	.35	.51	.75	.73	1.69	3.46	1.85	2.15	"Cash Flow" per sh	3.45
--	--	--	--	.16	.21	.27	.43	1.11	1.95	.70	.75	Earnings per sh A	1.25
--	--	--	--	--	--	--	--	--	--	--	Nil	Div'ds Decl'd per sh	Nil
--	--	--	--	.15	.67	.61	3.69	10.46	20.10	10.60	10.60	Cap'l Spending per sh	10.40
--	--	--	--	1.28	1.50	1.78	3.82	7.88	9.80	10.45	11.25	Book Value per sh B	15.55
--	--	--	--	158.75	160.49	161.29	252.22	283.72	307.06	378.00	378.00	Common Shs Outst'g C	385.00
--	--	--	--	13.9	11.2	8.8	19.7	29.4	18.9	9.4		Avg Ann'l P/E Ratio	13.0
--	--	--	--	.87	.65	.46	1.12	1.91	.97	.48		Relative P/E Ratio	.85
--	--	--	--	--	--	--	--	--	--	--		Avg Ann'l Div'd Yield	Nil
--	--	--	--	214.6	276.3	556.0	847.7	2282.8	7590.0	7500	8250	Revenues ($mill)	10750
--	--	--	--	48.2%	52.1%	39.7%	37.0%	33.1%	19.9%	18.0%	18.5%	Operating Margin	22.0%
--	--	--	--	36.6	46.8	74.3	87.2	154.3	338.2	425	525	Depreciation ($mill)	825
--	--	--	--	18.7	34.7	46.3	96.2	324.7	725.6	270	295	Net Profit ($mill)	495
--	--	--	--	32.7%	34.7%	36.9%	39.2%	40.3%	34.9%	35.0%	35.0%	Income Tax Rate	35.0%
--	--	--	--	8.7%	12.6%	8.3%	11.4%	14.2%	9.6%	3.6%	3.6%	Net Profit Margin	4.6%
--	--	--	--	96.2	d12.0	86.9	251.1	174.5	778.9	185	110	Working Cap'l ($mill)	55.0
--	--	--	--	285.0	742.9	1065.9	2006.2	5552.9	12947	13000	12000	Long-Term Debt ($mill)	14500
--	--	--	--	203.1	240.0	287.0	964.6	2236.8	3010.6	3950	4245	Shr. Equity ($mill)	5985
--	--	--	--	8.5%	6.7%	6.6%	4.8%	4.5%	5.0%	2.0%	2.0%	Return on Total Cap'l	2.5%
--	--	--	--	9.2%	14.5%	16.1%	10.0%	14.5%	24.1%	7.0%	7.0%	Return on Shr. Equity	8.5%
--	--	--	--	9.2%	14.5%	16.1%	10.0%	14.5%	24.1%	7.0%	7.0%	Retained to Com Eq	8.5%
--	--	--	--	--	--	--	--	--	--	--	Nil	All Div'ds to Net Prof	Nil

CAPITAL STRUCTURE as of 9/30/02
Total Debt $14.5 bill. Due in 5 Yrs $6.1 bill.
LT Debt $14.1 bill. LT Interest $.8 bill.
(Includes $1123.8 mill. in trust-preferred securities, and $208.1 mill. in capital leases.)
(LT interest earned: 2.6x; total interest coverage: 2.5x) (78% of Cap'l)

Leases, Uncapitalized: Ann. rentals $23.5 mill.
Pension Liability None
Pfd Stock None

Common Stock 377,999,176 shs. (22% of Cap'l)
MARKET CAP: $1.2 million (Mid Cap)

CURRENT POSITION ($MILL.)	2000	2001	9/30/02
Cash Assets	588.7	1525.4	659.7
Receivables	649.4	966.1	838.6
Inventory (FIFO)	36.9	78.9	104.8
Other	68.7	1437.3	1074.0
Current Assets	1343.7	4007.7	2677.1
Accts Payable	765.6	1283.8	1117.8
Debt Due	61.6	903.4	420.9
Other	342.0	1041.6	896.5
Current Liab.	1169.2	3228.8	2435.2

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Revenues	--	55.0%	16.0%
"Cash Flow"	--	41.5%	11.0%
Earnings	--	49.0%	3.5%
Dividends	--	--	Nil
Book Value	--	41.0%	14.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1999	145.9	190.7	263.6	247.5	847.7
2000	235.4	363.7	678.9	1004	2282.8
2001	1229	1724	2916	1721	7590.0
2002	1738	1583	2495	1684	7500
2003	1700	1650	3000	1900	8250

Calendar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1999	.02	.08	.19	.12	.43
2000	.09	.20	.48	.34	1.11
2001	.30	.39	.95	.31	1.95
2002	.10	.19	.38	.13	.70
2003	.05	.15	.45	.10	.75

Calendar	QUARTERLY DIVIDENDS PAID Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	NO CASH DIVIDENDS BEING PAID				
2000					
2001					
2002					
2003					

BUSINESS: Calpine is a leading independent power company engaged in the development, acquisition, ownership, and operation of power generation facilities. Its sells electricity predominantly in the United States. As of 12/01, it owned interests in 64 power plants having an aggregate capacity of 12,090 megewatts. Upon the completion of its current construction projects in progress, Calpine will have interests in 88 plants with an aggregate capacity in excess of 26,232 megawatts. Mellon Financial owns 5.6% of outstanding comm. stock, and Massachusetts Finl. Svs. owns 5.1%. Officers/dirs. hold 4.7% (4/02 proxy). Chairman & CEO: Peter Cartwright. Address: 50 West San Fernando St., San Jose, CA 95113. Telephone: (408) 995-5115. Internet: www. calpine.com.

Calpine shares are ranked 5 (Lowest) for Timeliness, with an above-average risk profile. Although the stock is trading at a significant discount to historical levels (P/E multiple is below five times our current earnings projections), we believe there is limited opportunity for significant profit gains in the next 12 months. Meaningful earnings improvement will be constrained by prevailing low spark spreads (power revenues minus fuel costs) and the company's need to focus on liquidity and debt reduction. We have lowered our share-net estimates by $0.20, to $0.70 for the year just ended, and by $0.25, to $0.75 for 2003.

Calpine continues to sell off assets for cash. In its latest move, the company sold a 180-megawatt plant in Wisconsin for $72 million in cash and a $48.4 million payment due in December, 2003. Calpine then sold the receivable to a third party for $46 million in cash. Elsewhere, the company is receiving money from a power contract breech by the city of Lodi, California. In a negotiated settlement, Lodi agreed to make installment payments to Calpine over the next nine years to fulfill its obligations. Calpine subsequently monetized the installments for $33.2 million in cash up front, along with up to an additional $8.3 million payment at a later date.

This issue's potential for 3- to 5-year capital appreciation is speculative. We lowered our price range to $12-$20 from $16-$25, reflecting reduced earnings estimates and a lower P/E multiple. From 1998-2001, Calpine stock surged as deregulation and the expanding economy brought incentive for massive power construction. Too, financing was abundant. But the stock soon collapsed behind industry scandals, economic malaise, and a huge debt burden. Our view is that both the fervor fueling these shares and the cynicism later ravaging them were excessive. Given the nation's longer-term prospects for energy demand growth, patient investors accepting the risks may be well rewarded here.

Michael P. Maloney *January 10, 2003*

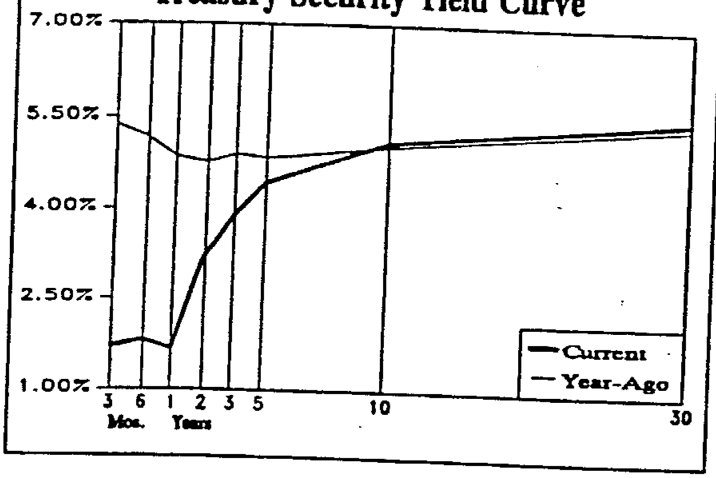
CASH POSITION	5-Year Av'g	9/30/02
Current Assets to Current Liabilities:	160%	100%
Cash & Equiv's to Current Liabilities:	84%	27%
Working Capital to Sales:	19%	10%

(A) Diluted earnings. Excludes nonrecurring items: '99, d1¢; '00, d1¢, '01, d8¢. Quarterly figures do not sum to yearend number in '99 due to stock split and large change in shares outstanding. Next earnings report due late Jan.
(B) Includes deferred financing costs. In '01: $210.8 million; $0.69/sh.
(C) In millions, adjusted for stock splits.

Company's Financial Strength	C++
Stock's Price Stability	15
Price Growth Persistence	60
Earnings Predictability	50

Selected Yields

	Recent (1/3/02)	3 Months Ago (10/4/01)	Year Ago (1/4/01)
TAXABLE			
Market Rates			
Discount Rate	1.25	2.00	5.50
Federal Funds	1.75	2.50	6.00
Prime Rate	4.75	5.50	9.00
30-day CP (A1/P1)	1.77	2.48	5.89
3-month LIBOR	1.87	2.48	5.87
Bank CDs			
6-month	1.61	2.37	5.06
1-year	1.92	2.54	5.21
5-year	4.11	4.04	5.45
U.S. Treasury Securities			
3-month	1.71	2.20	5.37
6-month	1.81	2.20	5.18
1-year	1.67	2.16	4.85
5-year	4.43	3.73	4.83
10-year	5.11	4.50	5.03
30-year	5.53	5.30	5.44
30-year Zero	5.74	5.36	5.52



Treasury Security Yield Curve

	Recent (1/3/02)	3 Months Ago (10/4/01)	Year Ago '01
Mortgage-Backed Securities			
GNMA 8%	5.93	5.44	7.09
FHLMC 8%	5.67	5.34	7.00
FNMA 8%	5.70	5.08	6.97
FNMA ARM	4.52	5.23	6.91
Corporate Bonds			
Financial (10-year) A	6.79	6.32	7.17
Industrial (25/30-year) A	6.93	6.97	7.64
Utility (25/30-year) A	7.22	7.52	7.66
Utility (25/30-year) Baa/BBB	7.63	7.92	7.87
Foreign Bonds (10-Year)			
Canada	5.09	4.96	5.34
Germany	4.91	4.68	4.73
Japan	1.37	1.38	1.63
United Kingdom	4.96	4.76	4.80
Preferred Stocks			
Utility A	6.88	6.88	6.88
Financial A	6.56	6.51	6.80
Financial Adjustable A	4.98	4.98	4.97
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.26	5.03	5.09
25-Bond Index (Revs)	5.57	5.32	5.40
General Obligation Bonds (GOs)			
1-year Aaa	1.70	2.03	3.70
1-year A	1.95	2.22	[illegible]
5-year Aaa	3.80	3.09	
5-year A	4.06	3.32	[illegible]
10-year Aaa	4.50	3.89	4.33
10-year A	4.78	4.13	4.55
25/30-year Aaa	5.22	4.99	5.17
25/30-year A	5.46	5.20	5.29
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.38	5.11	5.24
Electric AA	5.39	5.15	5.26
Housing AA	5.37	5.40	5.70
Hospital AA	5.51	5.40	5.87
Toll Road Aaa	5.44	5.15	5.30

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

Recent Levels	12/26/01	12/12/01	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1858	1374	484	1491	4054	2722
Borrowed Reserves	60	60	0	151	649	394
Net Free/Borrowed Reserves	1798	1314	484	1340	3405	2328

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 12/24/01	12/17/01	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1181.2	1172.3	8.9	-6.5%	10.5%	8.0%
M2 (M1+savings+small time deposits)	5448.0	5467.7	-19.7	3.4%	8.9%	9.9%
M3 (M2+large time deposits)	8077.4	8106.2	-28.8	8.8%	11.8%	13.2%

Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes
Summary Statistics of Annual Returns

from 1926 to 2001

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Serial Correlation
Large Company Stocks				
Total Returns	10.7%	12.7%	20.2%	0.02
Income	4.4	4.4	1.5	0.87
Capital Appreciation	6.1	8.0	19.6	0.03
Ibbotson Small Company Stocks				
Total Returns	12.5	17.3	33.2	0.08
Mid-Cap Stocks*				
Total Returns	11.4	14.2	25.0	-0.02
Income	4.2	4.2	1.6	0.87
Capital Appreciation	7.0	9.8	24.2	-0.02
Low-Cap Stocks*				
Total Returns	11.7	15.7	29.8	0.04
Income	3.9	3.9	1.9	0.88
Capital Appreciation	7.7	11.8	29.1	0.04
Micro-Cap Stocks*				
Total Returns	12.5	18.6	39.4	0.11
Income	2.7	2.7	1.8	0.90
Capital Appreciation	9.7	15.8	38.8	0.10
Long-Term Corporate Bonds				
Total Returns	5.8	6.1	8.6	0.07
Long-Term Government Bonds				
Total Returns	5.3	5.7	9.4	-0.07
Income	5.2	5.2	2.8	0.96
Capital Appreciation	-0.1	0.2	8.1	-0.22
Intermediate-Term Government Bonds				
Total Returns	5.3	5.5	5.7	0.15
Income	4.8	4.8	3.0	0.96
Capital Appreciation	0.4	0.5	4.4	-0.22
Treasury Bills				
Total Returns	3.8	3.9	3.2	0.92
Inflation	3.1	3.1	4.4	0.65

Total return is equal to the sum of three component returns; income return, capital appreciation return, and reinvestment return.

*Source: Center for Research in Security Prices, University of Chicago. See Chapter 7 for details on decile construction.

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Key Variables in Estimating the Cost of Capital

Yields (Riskless Rates)[1]	**Value**
Long-term (20-year) U.S. Treasury Coupon Bond Yield	5.8%
Intermediate-term (5-year) U.S. Treasury Coupon Note Yield	4.4
Short-term (30-day) U.S. Treasury Bill Yield	1.6
Fixed Income Risk Premia[2]	
Expected default premium: long-term corporate bond total returns minus long-term government bond total returns	0.1
Expected long-term horizon premium: long-term government bond income returns minus U.S. Treasury bill total returns†	1.4
Expected intermediate-term horizon premium: intermediate-term government bond income returns minus U.S. Treasury bill total returns†	1.0

	Market Benchmark	
Equity Risk Premia[3]	**S&P 500**	**NYSE 1-2**
Long-horizon expected equity risk premium: large company stock total returns minus long-term government bond income returns	7.4%	6.6%
Intermediate-horizon expected equity risk premium: large company stock total returns minus intermediate-term government bond income returns	7.8	7.1
Short-horizon expected equity risk premium: large company stock total returns minus U.S. Treasury bill total returns†	8.8	8.0
Size Premia[4]		
Expected mid-capitalization equity size premium: capitalization between $1,115 and $5,252 million	0.7	1.2
Expected low-capitalization equity size premium: capitalization between $269 and $1,115 million	1.4	1.8
Expected micro-capitalization equity size premium: capitalization below $269 million	3.3	3.7

[1] As of December 31, 2001. Maturities are approximate.

[2] Expected risk premia for fixed income are based on the differences of historical arithmetic mean returns from 1970–2001.

[3] Expected risk premia for equities are based on the differences of historical arithmetic mean returns from 1926–2001.

[4] See Chapter 7 for complete methodology.

† For U.S. Treasury bills, the income return and total return are the same.

Note: Examples of how these variables can be used are found in Chapters 3 and 4.

APPENDIX B

ENERGY PRICE FORECAST DATA

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Table 72. Electric Power Projections for EMM Region
Western Electricty Coordinating Council/California

Electricity Supply and Demand	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Industrial	7.4	10.5	7.2	6.7	6.3	6.2	6.1	6.2	6.2	6.2	6.3	6.2	6.0
Transportation	10.1	10.6	11.0	9.6	9.6	9.6	9.5	9.4	9.5	9.4	9.3	9.2	8.9
All Sectors Average	9.9	13.4	10.9	10.0	9.5	9.4	9.3	9.4	9.4	9.5	9.5	9.4	9.1
Prices by Service Category													
(2001 cents per kilowatthour)													
Generation	6.7	10.5	8.0	7.1	6.5	6.4	6.2	6.2	6.2	6.2	6.2	6.1	5.8
Transmission	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8
Distribution	2.5	2.4	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5
Fuel Consumption (quadrillion Btu) 9/													
Coal	0.30	0.30	0.37	0.36	0.38	0.38	0.43	0.49	0.48	0.48	0.48	0.48	0.48
Natural Gas	0.91	1.00	0.93	0.78	0.85	0.87	0.87	0.86	0.92	0.94	0.99	1.02	1.12
Oil	0.24	0.25	0.38	0.37	0.37	0.36	0.36	0.33	0.33	0.32	0.33	0.33	0.31
Total	1.45	1.55	1.67	1.51	1.59	1.61	1.66	1.68	1.73	1.75	1.80	1.84	1.91
Emissions (million tons) 10/													
Total Carbon	25.46	26.67	25.34	22.78	24.26	24.72	26.03	27.52	28.27	28.70	29.66	30.52	31.76
Carbon Dioxide	93.36	97.79	92.90	83.51	88.95	90.65	95.45	100.91	103.65	105.23	108.76	111.90	116.47
Sulfur Dioxide	0.08	0.08	0.07	0.06	0.07	0.07	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Nitrogen Oxide	0.13	0.13	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09

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Table 72. Electric Power Projections for EMM Region
Western Electricty Coordinating Council/California

Electricity Supply and Demand	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2001-2025
Industrial	5.9	5.9	6.0	6.0	6.0	6.0	5.9	5.9	5.9	5.9	5.9	6.0	6.0	-2.3%
Transportation	8.8	8.7	8.7	8.7	8.6	8.4	8.3	8.2	8.1	8.0	7.9	7.9	7.9	-1.2%
All Sectors Average	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.0	9.0	9.0	9.1	9.1	9.2	-1.6%
Prices by Service Category (2001 cents per kilowatthour)														
Generation	5.7	5.7	5.7	5.7	5.7	5.7	5.6	5.6	5.6	5.6	5.6	5.7	5.8	-2.4%
Transmission	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.5%
Distribution	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6	0.3%
Fuel Consumption (quadrillion Btu) 9/														
Coal	0.48	0.51	0.53	0.55	0.57	0.59	0.61	0.62	0.64	0.66	0.68	0.70	0.71	3.7%
Natural Gas	1.19	1.21	1.24	1.31	1.34	1.42	1.47	1.53	1.54	1.64	1.64	1.66	1.67	2.1%
Oil	0.29	0.31	0.31	0.31	0.30	0.29	0.29	0.30	0.32	0.29	0.31	0.35	0.36	1.5%
Total	1.97	2.03	2.09	2.17	2.21	2.31	2.36	2.45	2.50	2.59	2.64	2.70	2.74	2.4%
Emissions (million tons) 10/														
Total Carbon	32.74	34.05	35.31	36.87	37.89	39.62	40.69	42.19	43.59	45.00	46.09	47.59	48.54	2.5%
Carbon Dioxide	120.05	124.86	129.46	135.18	138.94	145.28	149.21	154.71	159.81	165.00	169.00	174.50	177.99	2.5%
Sulfur Dioxide	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-2.5%
Nitrogen Oxide	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	-0.2%

Table 42. Receipts and Average Cost of Gas Delivered to Electric Utilities by Census Division and State

Census Division and State	September 2002 Receipts (thousand Mcf)	September 2002 Receipts (billion Btu)	September 2001 Receipts (thousand Mcf)	September 2001 Receipts (billion Btu)	Year to Date Receipts (billion Btu) 2002	Year to Date Receipts (billion Btu) 2001	Year to Date Average Cost (cents/million Btu)[1] 2002	Year to Date Average Cost (cents/million Btu)[1] 2001
New England	**681**	**705**	**1,163**	**1,206**	**3,956**	**3,940**	**367.3**	**365.8**
Connecticut	-	-	-	-	-	-	-	-
Maine	-	-	-	-	-	-	-	-
Massachusetts	481	496	980	1,011	3,228	3,623	372.0	370.1
New Hampshire	200	209	183	196	719	217	346.8	241.2
Rode Island	-	-	-	-	-	-	-	-
Vermont	-	-	-	-	9	100	315.5	477.6
Middle Atlantic	**8,930**	**9,082**	**12,589**	**12,799**	**64,902**	**64,111**	**362.0**	**451.6**
New Jersey	-	-	-	-	-	-	-	-
New York	8,930	9,082	12,589	12,799	64,902	63,986	362.0	450.8
Pennsylvania	-	-	-	-	-	125	-	851.4
East North Central	**2,755**	**2,130**	**2,331**	**2,158**	**21,525**	**22,861**	**342.9**	**440.1**
Illinois	42	43	163	168	3,525	2,370	337.6	447.7
Indiana	51	51	52	53	392	1,280	362.9	524.1
Michigan	2,347	1,721	1,939	1,760	14,880	16,192	338.2	412.6
Ohio	14	15	17	18	184	390	485.4	835.8
Wisconsin	300	301	159	160	2,543	2,629	364.8	502.8
West North Central	**3,192**	**3,215**	**1,346**	**1,372**	**29,319**	**24,736**	**324.1**	**418.1**
Iowa	343	343	162	163	2,713	2,331	362.0	511.6
Kansas	1,391	1,403	898	922	13,183	16,088	300.9	369.4
Minnesota	434	436	30	30	2,383	1,244	372.7	553.0
Missouri	938	946	205	206	10,038	4,365	329.9	501.8
Nebraska	87	88	50	51	1,001	708	353.8	461.9
North Dakota	-	-	*	*	0	1	257.4	687.5
South Dakota	-	-	-	-	-	-	-	-
South Atlantic	**37,522**	**38,849**	**34,971**	**36,353**	**308,861**	**198,697**	**384.9**	**511.6**
Delaware	15	16	-	-	244	178	346.0	452.2
District of Columbia	-	-	-	-	-	-	-	-
Florida	35,393	36,656	32,361	33,654	295,067	188,189	382.7	516.0
Georgia	4	4	330	338	265	1,226	328.6	329.5
Maryland	-	-	-	-	-	-	-	-
North Carolina	269	277	22	22	2,419	549	413.5	454.9
South Carolina	3	4	*	*	29	55	485.7	626.5
Virginia	1,829	1,884	2,252	2,332	10,688	8,380	442.3	439.9
West Virginia	9	9	7	7	149	119	401.2	766.8
East South Central	**14,777**	**15,289**	**10,513**	**10,817**	**148,971**	**58,407**	**318.7**	**436.3**
Alabama	6,279	6,534	60	62	55,481	7,651	319.4	693.0
Kentucky	70	72	40	41	658	194	406.3	560.6
Mississippi	8,428	8,683	10,412	10,713	92,831	50,561	317.7	396.9
Tennessee	-	-	-	-	-	-	-	-
West South Central	**68,207**	**70,258**	**121,808**	**124,725**	**549,546**	**1,137,964**	**328.8**	**447.3**
Arkansas	1,774	1,805	1,612	1,642	15,549	17,962	343.9	454.1
Louisiana	23,992	24,871	23,945	24,789	207,967	192,973	335.0	445.6
Oklahoma	15,712	16,144	14,609	15,053	133,467	129,326	331.8	469.3
Texas	26,728	27,438	81,643	83,241	192,563	797,704	318.9	444.0
Mountain	**16,326**	**16,599**	**13,873**	**14,090**	**127,573**	**166,957**	**376.9**	**546.8**
Arizona	4,194	4,273	4,158	4,236	32,475	56,225	302.5	492.7
Colorado	3,330	3,298	3,693	3,694	30,131	30,191	247.9	410.3
Idaho	-	-	-	-	-	-	-	-
Montana	1	1	1	1	12	10	432.7	704.1
Nevada	5,612	5,741	2,232	2,272	38,505	38,299	568.1	845.9
New Mexico	2,213	2,254	2,850	2,902	21,569	31,075	304.5	447.6
Utah	938	992	939	986	4,711	10,762	483.7	440.2
Wyoming	39	41	-	-	170	396	396.6	384.1
Pacific Contiguous	**11,569**	**11,699**	**7,835**	**7,944**	**71,266**	**110,314**	**387.2**	**804.0**
California	10,027	10,126	4,398	4,438	62,191	74,964	401.5	1,002.7
Oregon	1,542	1,573	3,437	3,506	9,075	35,350	289.2	382.5
Washington	-	-	-	-	-	-	-	-
Pacific Noncontiguous	**1,149**	**1,149**	**1,064**	**1,064**	**14,115**	**12,807**	**239.2**	**226.5**
Alaska	1,149	1,149	1,064	1,064	14,115	12,807	239.2	226.5
Hawaii	-	-	-	-	-	-	-	-
U.S. Total	**165,108**	**168,974**	**207,491**	**212,528**	**1,340,034**	**1,800,794**	**349.2**	**483.0**

[1] Monetary values are expressed in nominal terms.

* = For detailed data, the absolute value is less than 0.5, for percentage calculations, the absolute value is less than 0.05 percent

Notes: • Data for 2002 and 2001 are preliminary. • Total may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Includes small quantities of coke-oven, refinery, and blast-furnace gas. • Mcf=thousand cubic feet. • Due to restructuring of the electric power industry, electric utilities are selling/transferring plants to the nonutility sector. This will affect comparisons of current and historical data.

Source: • Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

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Table 3. Energy Prices by Sector and Source (2001 Dollars per Million Btu, Unless Otherwise Needed)

Sector and Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	14.58	15.80	14.15	13.99	13.83	13.74	13.54	13.55	13.59	13.75	13.84	13.97	14.02
Primary Energy 1/	8.50	9.73	7.84	8.18	7.97	7.82	7.72	7.74	7.81	7.86	7.96	8.01	8.05
Petroleum Products 2/	11.12	10.85	9.77	10.35	10.14	9.74	9.58	9.66	9.71	9.76	9.90	10.00	10.06
Distillate Fuel	9.67	8.99	8.14	9.08	8.43	7.88	7.81	7.81	7.85	7.89	7.96	8.05	8.11
Liquefied Petroleum Gas	13.85	14.84	12.73	13.16	13.79	13.70	13.37	13.62	13.68	13.74	14.01	14.09	14.12
Natural Gas	7.75	9.41	7.29	7.58	7.39	7.31	7.23	7.25	7.32	7.38	7.48	7.52	7.56
Electricity	24.49	25.35	23.96	23.10	22.96	22.83	22.43	22.28	22.17	22.38	22.34	22.51	22.49
Commercial	14.14	15.47	14.13	13.56	13.29	13.16	12.92	12.92	13.02	13.24	13.35	13.49	13.57
Primary Energy 1/	6.74	7.81	6.11	6.28	6.06	6.00	5.95	6.01	6.12	6.21	6.34	6.40	6.46
Petroleum Products 2/	7.82	7.27	7.10	7.42	6.83	6.67	6.57	6.61	6.67	6.70	6.78	6.87	6.91
Distillate Fuel	7.27	6.40	6.08	6.51	5.75	5.57	5.50	5.51	5.55	5.59	5.66	5.76	5.82
Residual Fuel	3.53	3.46	4.15	4.41	4.01	3.91	3.93	3.95	3.97	3.98	4.01	4.03	4.06
Natural Gas	6.64	8.09	6.04	6.19	6.03	5.99	5.95	6.02	6.14	6.24	6.38	6.44	6.50
Electricity	21.86	23.22	21.90	20.73	20.39	20.12	19.63	19.48	19.48	19.72	19.73	19.85	19.86
Industrial 3/	7.08	7.10	5.74	6.07	6.05	5.97	5.89	5.97	6.07	6.16	6.26	6.34	6.40
Primary Energy	5.91	5.83	4.55	4.90	4.86	4.77	4.70	4.78	4.86	4.93	5.07	5.15	5.22
Petroleum Products 2/	8.21	7.72	6.27	6.76	6.79	6.66	6.58	6.67	6.73	6.78	6.94	7.04	7.10
Distillate Fuel	7.38	6.55	6.14	6.57	5.79	5.62	5.55	5.56	5.62	5.66	5.73	5.87	5.92
Liquefied Petroleum Gas	12.03	12.34	8.20	8.62	9.41	9.33	8.99	9.23	9.28	9.32	9.59	9.66	9.70
Residual Fuel	3.34	3.28	3.85	4.14	3.72	3.60	3.62	3.64	3.67	3.69	3.71	3.73	3.75
Natural Gas4/	4.62	4.87	3.40	3.72	3.58	3.52	3.46	3.53	3.64	3.75	3.89	3.96	4.05
Metallurgical Coal	1.66	1.69	1.62	1.61	1.59	1.57	1.57	1.55	1.53	1.52	1.51	1.49	1.48
Steam Coal	1.43	1.46	1.48	1.47	1.45	1.44	1.43	1.42	1.41	1.39	1.38	1.37	1.36
Electricity	13.46	14.10	12.99	12.88	12.82	12.75	12.55	12.56	12.63	12.75	12.64	12.62	12.61
Transportation	11.11	10.28	9.73	10.33	10.06	9.93	10.01	10.15	10.15	10.24	10.28	10.25	10.22
Primary Energy	11.08	10.25	9.70	10.30	10.03	9.90	9.99	10.13	10.12	10.21	10.25	10.23	10.19
Petroleum Products 2/	11.08	10.25	9.70	10.30	10.03	9.91	9.99	10.13	10.13	10.22	10.26	10.23	10.20
Distillate Fuel 5/	10.99	10.05	9.31	9.95	9.60	9.36	9.56	10.07	9.98	10.11	10.22	10.32	10.20
Jet Fuel 6/	7.26	6.20	5.90	6.33	5.81	5.61	5.49	5.56	5.58	5.61	5.62	5.76	5.78
Motor Gasoline 7/	12.42	11.57	10.96	11.58	11.38	11.30	11.38	11.41	11.42	11.50	11.53	11.42	11.39
Residual Fuel	4.48	3.90	3.73	4.01	3.58	3.45	3.48	3.49	3.51	3.53	3.55	3.58	3.60
Liquefied Petroleum Gas 8/	16.45	16.93	14.83	15.25	15.02	14.89	14.62	14.79	14.88	14.92	15.21	15.32	15.25
Natural Gas9/	6.76	7.65	6.01	6.36	6.17	6.12	6.21	6.42	6.67	6.88	7.08	7.21	7.33
Ethanol (E85) 10/	17.72	17.72	17.72	20.13	19.36	19.50	19.84	21.01	21.23	21.53	21.32	21.32	22.17
Electricity	22.07	21.84	20.81	20.09	19.99	19.72	19.24	19.03	18.97	19.02	18.99	18.97	18.90
Average End-Use Energy	10.63	10.74	9.65	9.92	9.76	9.67	9.62	9.70	9.74	9.85	9.92	9.97	9.99
Primary Energy	8.65	8.52	7.47	7.93	7.76	7.67	7.69	7.80	7.86	7.95	8.05	8.08	8.10
Electricity	20.17	21.30	20.21	19.41	19.22	19.06	18.68	18.55	18.52	18.70	18.65	18.73	18.71
Electric Generators 11/													
Fossil Fuel Average	2.01	2.14	1.66	1.74	1.71	1.71	1.68	1.68	1.74	1.77	1.82	1.85	1.89
Petroleum Products	4.62	4.73	4.28	4.74	4.26	4.13	4.14	4.15	4.14	4.23	4.27	4.36	4.33
Distillate Fuel	6.73	6.20	5.60	6.04	5.20	5.01	4.95	4.96	5.00	5.04	5.13	5.23	5.29
Residual Fuel	4.39	4.50	4.01	4.35	3.99	3.85	3.89	3.90	3.88	3.96	3.97	4.01	4.01
Natural Gas	4.42	4.78	3.07	3.42	3.29	3.27	3.24	3.32	3.48	3.62	3.79	3.88	3.98

Industry Pricing Factors

Combined Cycle Power Plants

Project engineers figure turnkey supply and installation prices for large plants have increased by at least 10 percent over the last year

In the last year or so, turnkey prices for large utility-scale and merchant combined cycle power plant installations have increased by around 10% to 13% overall.

Understandably, turnkey prices vary widely from one project to another depending on the need for access roads, fuel gas pipeline extensions, training centers, repair facilities, site location, and the like.

For budgetary pricing purposes we have focused on projects with comparable requirements and scope of supply. We have excluded cost items such as overseas shipment, catalytic NOx and CO reduction systems, water treatment, power augmentation, etc.

Turnkey projects include supply and installation of gas turbine, heat recovery steam generator, steam turbine, and electric generator equipment; associated balance of plant components; plant engineering, design; and construction services; plant startup and commissioning.

We are quoting combined cycle plant prices in year 2001 U.S. dollars for turnkey supply and construction of standard 1x1 and 2x1 modular designs equipped with basic balance of plant equipment and controls needed for an operational installation:

Gas turbine. Skid mounted, with minimal enclosure, generally for indoors installation. Standard starting and controls. No steam or water injection for NOx and no inlet air heating or chilling. Includes reduction gearing for smaller engines.

Steam turbine. Condensing, subcritical, single or dual-pressure level; some units triple pressure with reheat. Axial or radial exhaust and water cooled heat rejection.

Unfired HRSG. Outdoors mounted heat recovery steam generator with ductwork, but no bypass damper or catalytic section. Dual-pressure level, some units triple pressure with reheat. Short exhaust stack.

Electric generators. Generally air-cooled on smaller machines, hydrogen cooling on larger units. Main step-up transformer, neutral grounding cubicle, and non-segregated bus included.

Balance of plant. Standard controls (not DCS) and auxiliaries. Does not include substation, pipeline, fuel gas compressor. Includes minimal tank storage for liquid fuels but no treatment system. Office and workshop buildings, special tools, operational spares, consumables, black start generator not included.

$ per kW pricing

Industry practice is to evaluate and compare combined cycle plant prices on the basis of net plant output and efficiency at 59°F (15C) seal level and 60% relative humidity on natural gas fuel with system losses.

Calculated $ per kW cost figures are based on net plant power output measured across the electric generator terminals.

These dollar figures are designed for scoping studies and preliminary project assessment. They do not include indirect costs that add considerably to project budgets.

Prices can vary considerably depending on the scope of equipment supply, site specifics, geographic location, currency valuations, and competitive market conditions.

Construction costs also can vary dramatically as a function of labor rates and specific construction requirements at different site locations worldwide.

Fuel cost is also a factor. There is a first-cost premium for high efficiency gas turbines and steam turbines. For example, a more efficient (and more complex) steam cycle will increase the overall plant cost.

Triple pressure heat recovery boilers cost more. So do units with reheat, and the multi-casing steam turbines that match these boilers also are more expensive.

Efficiency effects

In mid-range to base load service up to 8000 hours per year, typically how these plants operate, the higher efficiency units produce equipment payback years faster than lower-efficiency counterparts, justifying their greater initial cost.

For a typical plant installation that is expected to be in service 20 to 30 years, fuel costs are still the biggest single cost of running a power plant.

Figure that over the roughly 25-year life of a base load combined cycle, up to 70 percent of total plant costs—including acquisition, owning and operating costs and debt service—are for fuel alone. It's easy to see why efficiency is so important.

One OEM notes that "an increase of ever single percentage point in efficiency can reduce operating costs by $15-20 million over the life of a typical gas-fired combined cycle plant in the 400-500 MW range."

The relative value of thermal efficiency is specific to each site. It depends on equipment, price of fuel, size of plant, and operational profile, among others.

Pricing roller coaster

Prices for large IPP and utility-scale combined cycles plummeted over a five to six year period to hit historic low levels around 1997-98.

Compared to the early 1990s, these plants were selling for 45-50% less than earlier models installed at the beginning of the decade. But, around mid-1998, prices started turning around.

Industry analysts point to the North

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American gas turbine 'buying spree' starting mid-summer 1998 as the key to the rising price trend.

The release of pent-up demand, particularly for large 60-Hz 'F' technology gas turbines, resulted in the production pipeline for most OEMs currently being full.

This has resulted in customers queuing up for delivery slots and putting up with longer lead times before equipment is delivered. More recently, economic downturn has caused a number of power project postponements and cancellations.

Multi-unit buys and delivery slots are changing hands, and OEM vendors are reportedly looking at speeding up deliveries on certain models. Prices are falling, fast.

Pre-packaged designs

EPC firms and OEMs have dramatically cut plant building schedules, sometime in half, by developing standardized, pre-engineered and easily replicated package modules to simplify plant design.

These 'reference plants' are designed for and built with maximized factory production and packaging for minimum on-site work.

Computerized overall plant design cuts materials and labor costs and jobsite problems and delays by allowing a complete plant, down to the piping and wiring, to be designed and reviewed before any earth is moved.

Today's pre-engineered complete combined cycle power plants can routinely be installed in well under two years from contract signing to commissioning.

Dollars per kilowatt

Standardized combined cycle plant $ per kW prices are a function of size (output) of the gas and steam turbines.

Prices vary according to multiples of units that make up the plant—as well as the design configuration of both the plant and its components.

Multi-shaft plants, where each gas turbine and steam turbine drives its own electric generator, are generally more costly than single shaft designs.

The single-shaft combined cycle—with the gas and steam turbine together driving opposite ends of an electric generator in a single power train—eliminates one complete electric generator and its attendant auxiliaries.

Any reduction in power equipment usually reduces price. However, some single-shaft plant designs fit an overrunning clutch between the steam turbine and generator.

This allows running the gas turbine simple cycle on its own without the steam cycle. However, it increases cost so that the single-shaft configuration ends up only about 3 to 5% cheaper than a multi-shaft unit.

Fudge factors

As noted, turnkey prices for large plants have increased substantially. Part of the reason is these plants have grown through higher technology designs which can include air cooled condensers and tighter emissions control.

One power plant developer notes that the steam turbines have also increased in price over the past 12 months. He indicates that now they are also paying premiums for shipment slots for steam turbines, just as they are for gas turbines.

An industry analyst claims that the increase in combined cycle prices is primarily due to non-OEM components that make up the balance of the plant and which are not actually manufactured by the OEMs.

In order to maximize production the OEMs have farmed out much of the combined cycle equipment as modules, he claims.

"If you look at a combined cycle plant layout it is really made up of about 10 modules: gas turbine, electric generator(s), steam turbine, heat recovery boiler, condenser, cooling, lube oil, fuel, controls, fire suppression, water treatment, and probably one or two more," he says.

"All these modules are supplied by an outside source and put together by a contractor. Modules and contracting costs make up approximately 50 to 55 percent of the total plant's cost."

In addition, there has been a shift to go to dry cooling to conserve water (makes permitting easier) and putting the combined cycle power modules inside a building on raised pedestals.

"This would be called a dry indoor plant and adds anywhere from 3 to 5 percent to the total cost over a comparable wet, outdoor plant."

There is another factor which he calls 'hidden costs'. "This is an advance payment required in order to secure a production space in the current schedule.

"If the down payment (not recoverable) is say, three percent, that gives you at least a 1% price increase based on the interest cost of the down payment."

Advanced technology

Manufacturers have improved both gas and steam turbine technologies and performance. Increased power density reduces costs on the gas turbine and steam turbine portions.

For a given amount of labor and materials, the advanced technology designs produce many more kW of power than their predecessors of only a decade ago.

Optimizing the gas turbine-to-steam turbine size and design has produced economies and boosted overall plant performance.

Precise matching of the gas turbine design performance parameters to the HRSG and steam turbine design greatly improves overall plant performance.

Scoping studies

As noted, the $ figures quoted in the GTW Handbook are designed for scoping studies and preliminary project assessment. They are not 'sticker prices'.

While equipment prices listed reflect an average level, there is a fairly wide range—usually upward, rarely downward.

This results from OEM or packager competitive position, geographical area, marketing strategies, currency valuations and production capabilities.

As noted, currently many order books are filled, boosting prices for the foreseeable future unless market conditions change dramatically.

Excluded costs

These turnkey price levels are for no-frills plants with minimal equipment and services.

Extended site work such as cogenerated process steam or utility plant tie-ins are not covered, nor are extensive buildings, workshops, substations.

Special tools and operational spares such as combustor baskets, blades and vanes, etc., are also not inluded.

Additional costs must be added to these prices for emission controls which can include water or steam injection for NOx treatment in the combustor.

If post-firing treatment with selective catalytic reduction is applied to meet tight regulatory levels, this will add substantially to the plant initial capital costs (and operational expenses).

For example, one project developer in the U.S. is budgeting an additional $5 million per 44-MW unit to pay for combustion water injection and downstream catalytic reduction to remove post-combustion NOx and a CO emissions.

Also not included are the indirect costs for items such as interest during construction, financing and legal fees, licensing and permitting, insurance and bonding, workman's compensation, sales tax, extensive inland freight, owner's cost and overhead, and project contingency funds.

It is up to you and your engineering consultants to review and evaluate all these factors during the bidding process when shopping for new gas turbine combined cycle generating capacity.

Industry Price Levels

Combined Cycle Power Plants

Budget prices in year 2001 U.S. dollars for turnkey equipment supply and installation of modular plants powered by natural gas-fired gas turbine, unfired multi-pressure HRSG without a bypass stack, condensing multi-pressure steam turbine, electric generators, associated balance of plant equipment, engineering procurement construction services, plant startup and commissioning.

Plant Model	Net Plant Output	Heat Rate Btu/kWh	Net Effic	Gas Turbines	Steam Turbines	Budget Price	$ per kW
STAC 60	7.3 MW	8620 Btu	39.6%	1xTaurus 60	1x1.8 MW, 1P	$5,475,000	$750
GPCS 80	7.9 MW	8470 Btu	40.3%	1xM7A-01	1x2.4 MW, 1P	$7,900,000	$1000
STAC 70	9.5 MW	8180 Btu	41.7%	1xTaurus 70	1x2.0 MW, 1P	$7,125,000	$750
STAC 100	13.8 MW	8380 Btu	40.7%	1xMars 100	1x3.0 MW, 1P	$10,350,000	$750
S-LM1600PA	17.4 MW	7280 Btu	46.8%	1xLM1600	1x4.6 MW, 2P	$15,900,000	$912
STAC 130	17.7 MW	8000 Btu	42.7%	1xTitan 130	1x3.7 MW, 1P	$12,900,000	$730
KA35-1	22.8 MW	7880 Btu	43.3%	1xGT35	1x6.2 MW, 2P	$19,100,000	$840
CC-201	28.3 MW	7670 Btu	44.5%	2xPGT10	1x10 MW, 2P	$24,100,000	$852
CC1-2500	31.7 MW	6850 Btu	49.8%	1xLM2500	1x8.4 MW, 2P	$25,600,000	$808
THM1304-11	32.9 MW	7497 Btu	45.5%	2x1304-11	1x11 MW, 2P	$26,000,000	$790
FT8	32.9 MW	6865 Btu	49.7%	1xFT8	1x8.8 MW, 2P	$25,800,000	$740
KA10B-1	36.1 MW	6760 Btu	50.5%	1xGT10B	1x12 MW, 2P	$28,340,000	$785
1 x RB211-6556	36.7 MW	6725 Btu	50.7%	1xRB211	1x11 MW, 2P	$24,400,000	$665
CC1-2500+	38.4 MW	6570 Btu	51.9%	1xLM2500+	1x12 MW, 2P	$27,300,000	$710
CC105P	38.5 MW	8180 Btu	41.7%	1xFr.5PA	1x18 MW, 2P	$24,260,000	$630
1 x RB211-6562	40.6 MW	6535 Btu	52.2%	1xRB211	1x12 MW, 2P	$27,000,000	$665
1 x RB211-6762	41.5 MW	6435 Btu	53.0%	1xRB211	1x12 MW, 2P	$27,200,000	$657
1 x RB211-6761DLE	44.2 MW	6275 Btu	54.4%	1xRB211	1x12 MW, 2P	$28,700,000	$650
CC1-6000	55.6 MW	6620 Btu	52.5%	1xLM6000PC	1x13 MW, 2P	$36,975,000	$665

Plant Model	Net Plant Output	Heat Rate Btu/kWh	Net Effic	Gas Turbines	Steam Turbines	Budget Price	$ per kW
KAX100-1	62.0 MW	6320 Btu	54.0%	1xGTX100	1x21 MW, 2P	$41,000,000	$661
S-106B	64.3 MW	6970 Btu	49.0%	1xFr. 6B	1x24 MW, 2P	$41,800,000	$650
1 x Trent-DLE	66.0 MW	6285 Btu	54.3%	1xTrent	1x16 MW, 2P	$42,900,000	$650
FT8 Twin	66.7 MW	6770 Btu	50.4%	2xFT8	1x18 MW, 2P	$42,200,000	$630
1.W251B	71.5 MW	7140 Btu	47.8%	1xW251B11/12	1x25 MW, 2P	$55,600,000	$777
KA10B-2	73.2 MW	6730 Btu	50.7%	2xGT10B	1x25 MW, 2P	$48,500,000	$663
2 x RB211-6556	73.5 MW	6725 Btu	50.7%	2xRB211	1x23 MW, 2P	$46,300,000	$630
1 x Trent	74.2 MW	6470 Btu	52.7%	1xTrent	1x16 MW, 2P	$44,500,000	$600
KA8C-1	77.4 MW	6740 Btu	50.6%	1xGT8C	1x25 MW, 2P	$52,300,000	$630
CC205P	77.8 MW	8110 Btu	42.1%	2xFr.5PA	1x27 MW, 2P	$47,850,000	$615
2025	80.5 MW	6890 Btu	49.5%	2xH-25	1x28 MW, 2P	$49,500,000	$615
2 x RB211-6562	81.3 MW	6530 Btu	52.2%	2xRB211	1x24 MW, 2P	$51,200,000	$630
KA8C2-1S	82.0 MW	6825 Btu	50.0%	1xGT8C2	1x26 MW, 2P	$52,000,000	$634
2 x RB211-6762.	82.8 MW	6355 Btu	53.7%	2xRB211	1x24 MW, 2P	$52,200,000	$630
KA10C-2	83.6 MW	6590 Btu	51.8%	2xGT10C	1x27 MW, 2P	$53,000,000	$634
2 x RB211-6761DLE	88.4 MW	6270 Btu	54.4%	2xRB211	1x25 MW, 2P	$55,700,000	$630
1S.64.3A	99.8 MW	6540 Btu	52.2%	1xV64.3A	1x31 MW, 2P	$83,300,000	$832
1xP200-PFBC	100.0 MW	8030 Btu	42.5%	1xGT35P	1x83 MW, Cond.	$110,000,000	$1100
CC2-6000	106.5 MW	6610 Btu	51.6%	2xLM6000PC	1x22 MW, 2P	$69,760,000	$655
S-106FA	107.1 MW	6440 Btu	53.0%	1xFr.6FA	1x40 MW, 3P, RH	$88,400,000	$825
KAX100-2	124.5 MW	6285 Btu	54.3%	2xGTX100	1x42 MW, 2P	$75,000,000	$602
S-107EA	130.2 MW	6800 Btu	50.2%	1xFr. 7EA	1x48 MW, 3P	$79.100,000	$607
S-206B	130.7 MW	6850 Btu	49.8%	2xFr. 6B	1x49 MW, 2P	$84,800,000	$648
2 x Trent-DLE	132.0 MW	6285 Btu	54.3%	2xTrent	1x32 MW, 2P	$85,000,000	$644
2.W251B	143.5 MW	7110 Btu	48.0%	2x251B11/12	1x51 MW, 2P	$96,000,000	$669
KA13D-1	147.1 MW	6920 Btu	48.6%	1xGT13D	1x53 MW, 1P	$83,100,000	$565
2 x Trent	148.2 MW	6470 Btu	52,7%	2xTrent	1x32 MW, 2P	$85,000,000	$573

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Plant Model	Net Plant Output	Heat Rate Btu/kWh	Net Effic	Gas Turbines	Steam Turbines	Budget Price	$ per kW
1.84.2	163.0 MW	6630 Btu	51.5%	1xV84.2	1x60 MW, 2P	$89,900,000	$551
KA11N2-1	168.0 MW	6860 Btu	49.7%	1xGT11N2	1x56 MW, 2P	$91,600,000	$545
1.W501D5A	173.0 MW	6760 Btu	50.5%	1x501D5A	1x59 MW, 2P	$95,900,000	$554
Cobra 264.3	183.4 MW	6595 Btu	51.7%	2xV64.3	1x64 MW, 2P	$96,600,000	$528
S-109E	189.2 MW	6570 Btu	52.0%	1xFr. 9E	1x70 MW, 2P	$101,695,000	$537
2.64.3A.	201.1 MW	6490 Btu	52.6%	2xV64.3A	1x75 MW, 2P	$108,270,000	$538
MPCP1-M701D	212.5 MW	6635 Btu	51.4%	1xM701D	1x70 MW, 2P	$110,860,000	$522
S-206FA	218.7 MW	6305 Btu	54.1%	2xFr. 6FA	1x84 MW, 3P, R	$119,500,000	$548
1.V94.2	232.9 MW	6600 Btu	51.7%	1xV94.2	1x86 MW, 2P	$118,100,000	$508
1S84.3A	260.0 MW	5980 Btu	57.1%	1xV84.3A	1x84 MW, 3P, R	$126,440,000	$486
KA24-1 ICS	260.0 MW	6040 Btu	56.5%	1xGT24	1x102 MW, 2P	$126,300,000	$485
S-107FA	262.6 MW	6090 Btu	56.0%	1xFr. 7FA	1x95 MW, 3P, R	$130,960,000	$499
S-207EA	263.6 MW	6700 Btu	50.9%	2xFr. 7EA	1x101 MW, 3P	$130,800,000	$
1.W501F	283.3 MW	6090 Btu	56.0%	1xW501F	1x103 MW, 3P, R	$133,150,000	$470
1S.94.2A	294.3 MW	6190 Btu	55.1%	1xV94.2A	1x95 MW, 3P, R	$128,900,000	$438
2.W501D5A	346.9 MW	6740 Btu	50.6%	2x501D5A	1x118 MW, 2P	$157,800,000	$455
1S.W501G	365.0 MW	5880 Btu	58.0%	1xW501G	1x125 MW, 3P, R	$158,400,000	$434
KA26-1	378.0 MW	5985 Btu	57.0%	1xGT26	1x140 MW, 3P, R	$157,360,000	$416
S-109FA	390.8 MW	6020 Btu	56.7%	1xFr. 9FA	1x142 MW, 3P, R	$157,200,000	$402
1S.V94.3A	392.2 MW	5945 Btu	57.4%	1xV94.3A	1x120 MW, 3P, R	$155,230,000	$396
MPCP1-M701F..	397.7 MW	5988 Btu	57.0%	1xM701F	1x132 MW, 3P, R	$157,300,000	$395
S107H	400.0 MW	5690 Btu	60.0%	1xMS7001H	1x140 MW, 3P, R	$200,000,000	$500
MPCP2-M701D..	426.6 MW	6610 Btu	51.6%	2xM701D	1x142 MW, 2P	$182,200,000	$427
2.V94.2	466.6 MW	6590 Btu	51.8%	2xV94.2	1x173 MW, 2P	$181,500,000	$389
Cobra 294.2	477.9 MW	6506 Btu	52.4%	2xV94.2	1x178 MW, 2P	$183,000,000	$383
KA13E2-2	480.0 MW	6450 Btu	52.9%	2xGT13E2	1x167 MW, 2P	$185,900,000	$3[illegible]
KA11N2-3	517.0 MW	6550 Btu	52.1%	3xGT11N2	1x172 MW, 2P	$198,000,000	$383

Plant Model	Net Plant Output	Heat Rate Btu/kWh	Net Effic	Gas Turbines	Steam Turbines	Budget Price	$ per kW
S-207FA.	529.8 MW	6040 Btu	56.5%	2xFr. 7FA	1x196 MW, 3P, R	$206,600,000	$390
S-207FB.	562.5 MW	5920Btu	57.5%	2xFr. 7FB	1x204 MW, 3P, R	$216,400,000	$385
2.W501F	568.5 MW	6060 Btu	56.3%	2x501F	1x207 MW, 3P, R	$214,890,000	$378
2.V94.2A	587.6 MW	6200 Btu	55.0%	2xV94.2A	1x230 MW, 3P, R	$201,555,000	$355
S-507EA.	620.0 MW	6800 Btu	50.2%	5xFr. 7EA	3x68 MW, 3P	$232,620,000	$375
3.V94.2	719.5 MW	6490 Btu	52.6%	3xV94.2	1x270 MW, 2P	$271,600,000	$377
KA13E2-3	720.0 MW	6450 Btu	52.9%	3xGT13E2	1x250 MW, 2P	$271,370,000	$377
2.W501G	735.0 MW	5880 Btu	58.0%	2xW501G	1x245 MW, 3P, R	$310,170,000	$422
2.V94.3A	783.9 MW	5980 Btu	57.1%	2xV94.3A	1x282 MW, 3P, R	$268,100,000	$342
S-209FA	786.9 MW	5980 Btu	57.1%	2xFr. 9FA	1x289 MW, 3P, R	$273,600,000	$348
MPCP2-M701F	799.6 MW	5955 Btu	57.3%	2xM701F	1x267 MW, 3P, R	$267,700,000	$335

Keep in mind the difference between LHV and HHV in making fuel calculations

Gas turbine performance is calculated on the basis of the lower heating value (LHV) of the fuel to be burned, whereas fuel supply and purchase contracts are figured on the basis of higher heating value (HHV).

The difference between them is Btu content you pay for but do not see as power output. Technically it is difficult to explain. But it relates to fuel-bound hydrogen which forms water as a byproduct of combustion and is wasted in the exhaust.

HHV is measured on the basis of the chemical energy in the fuel which accounts for the total heat given up when the fuel is burned (including formation of water vapor) while LHV measures the useable energy.

In practical terms, some 6% by weight of liquid fuels is "wasted" versus 11 % for natural gas fuel. Or, put another way, you must increase LHV fuel consumption by a factor of 1.06 for liquid fuels and by 1.11 for gas.

Cycle studies for gas turbine projects are done on an LHV basis and fuel requirement on an HHV basis. This means you must figure on supplying more fuel than called for in the specifications and performance calculations.

Bulk weight of liquid fuels. This table lists the weights of various liquid fuels. For gaseous fuel 3500 cubic feet of still gas is equivalent to one 42-gallon barrel of liquid fuel.

Type Fuel	Gravity at 60'F (Average)	Gallons per Pound	Pounds per Gallon	Pounds 42-Gal Barrel	Barrels per Short Ton (2000 Lbs)	Barrels per Metric Ton (2205 Lbs)
Crude Oil (U.S. imports)	25.6	0.13333	7.500 lb	315 lb	6.349 bbl	6.998 bbl
Crude Oil (U.S. domestic)	36.0	0.14217	7.034 lb	295 lb	6.770 bbl	7.463 bbl
Distillate Oil	31.3	0.13817	7.237 lb	304 lb	6.580 bbl	7.253 bbl
Residual Oil	18.0	0.12687	7.882 lb	331 lb	6.041 bbl	6.660 bbl
Liquefied Petroleum Gas	—	0.22104	4.524 lb	190 lb	10.526 bbl	11.603 bbl

Cross index to Btu content of fuels (HHV). This table lists HHV values of various liquid fuels. For approximate performance calculations, figure on an LHV of 18,400 Btu/lb for distillate or crude oil.

Fuel Type and Bulk	42-Gal Bbl Crude Oil	1000-Cu Ft Natural Gas	42-Gal Bbl Distillate	42-Gal Bbl Residual	42-Gal Bbl LPG
Btu Content x 10^6	5.800 Btu	1.035 Btu	5.825 Btu	6.287 Btu	4.011 Btu
Crude Oi l(42-gal barrel)	1.000	5.604	0.996	0.923	1.446
Dry Natural Gas (l000 cu ft)	0.178	1.000	0.178	0.165	0.258
Distillate Oil (42-gal barrel)	1.004	5.628	1.000	0.927	1.452
Residual Oil (42-gal barrel)	1.084	6.074	1.079	1.000	1.567
Liquefied Gas(42-gal barrel)	0.692	3.875	0.689	0.638	1.000

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Industry Pricing Factors

Simple Cycle Power Plants

Quoted price levels are arrived at as a consensus of users and suppliers on what they consider 'reasonable' for budgeting purposes

Budget price levels reported in the Gas Turbine World Handbook are derived from a number of different sources including owner-operators, consulting firms, packagers, and gas turbine builders.

The individual prices sometimes vary considerably. We adjust the results of our field research to arrive at a consensus price that the majority of industry contacts consider reasonable for a single unit purchase.

In the case of simple cycle gensets and packaged plants, the budget prices quoted are F.O.B. the factory in year 2001 U.S. dollars for basic gas turbine packages without the bells and whistles or accessory systems.

Based on 'bare bones' gas turbine and electric generator package equipped with basic systems and controls needed for an operational installation:

Genset package. Skid mounted single-fuel gas turbine and driven electric generator. Includes regular gas turbine start, fuel forwarding and lube oil systems, standard controls.

Electric generator. Primarily air-cooled designs (TEWAC) for generators below 150 MW output and hydrogen-cooled designs over 150 MW. Even for the larger units, however, air cooling is becoming more popular as a lower priced alternative.

Balance of plant. Air inlet filter and intake silencer, stack with exhaust silencing, vibration monitoring system and controls. Packaged gensets are normally housed outdoors in acoustic enclosures with ventilation and fire protection systems. Fuel gas compressor not included.

Emissions control. Dry low NOx combustion is included when it is a standard design feature of the specified gas turbine model.

But the budget prices do not include NOx water or steam injection, nor post-firing treatment such as NOx or CO catalytic reduction.

$ per kW pricing

It is important to evaluate and compare gas turbine genset and power plant prices on the same basis.

Industry practice is to relate the total price to base load output on natural gas fuel at 59F (15C) ambient sea level site conditions and 60% relative humidity, without water or steam injection for NOx or power augmentation unless otherwise specified, and without duct losses.

Gas turbine models identified as steam injected designs are an exception. In this case, the output rating is quoted for base load operation with steam injection—but without inlet or exhaust duct losses.

For electric gensets, the quoted nominal ISO rating represents the gross power output measured across the electric generator terminals. As such it includes electric generator efficiency and any reduction gearing losses.

Installation extra

The prices shown in the GTW Handbook do not reflect associated plant costs such as site engineering and installation services that typically can more than double equipment-only acquisition costs.

Complete turnkey plant outlay such as transportation and taxes, engineering procurement and construction services, legal and financial fees, start-up, commissioning, spares and operator training can add tremendously to project costs.

For steam and water injected gas turbine units, the quoted price includes all of the on-engine components and hardware necessary to run steam or water through the machine.

But it does not include the off-engine steam production equipment such as heat recovery boiler or once-through steam generator, nor any water treatment hardware and supplies.

Depending on the number of units ordered, scope of equipment supply, site specific requirements, geographic location, and competitive market conditions, prices vary considerably.

As the past two years have shown, market demand and supply inevitably are the most important factors in determining price levels. Under all scenarios, however, big buys for multiple unit installations can reduce the unit cost substantially.

Changes in currency valuations also play an important role, sometimes dramatically, since competitive suppliers must take into account their impact on profit margins and costs.

Fuel efficiency

In areas of premium fuel prices, the better thermal efficiency designs almost always command higher first cost than lower-efficiency models in the same output range.

This reflects the increased engineering, manufacturing and materials costs that suppliers of advanced gas turbine designs must recover through higher equipment prices.

In the long run, however, the level of natural gas pricing (primary fuel for most of these machines) determines the value of thermal efficiency relative to fuel costs and number of hours the plant will operate.

For mid-range to base load service, higher efficiency plants can produce equipment payback periods many years faster than lower-efficiency competitors, justifying their increased first cost.

By contrast, fuel efficiency is relatively unimportant for peaking machines that run less than a few hundred hours a year. Availability, reliability and start time take precedence over thermal efficiency.

This is especially true in grid areas where daily, hourly or seasonal price swings are high.

Low emissions

Increasingly stringent emissions regulations are spreading beyond industrialized countries to developing nations and even remote offshore platform operations.

Depending on fuel type and allowable emission levels, the cost of gas turbine emissions controls and post combustion treatment systems can add substantially to the base price of a plant.

In general, the tighter the air quality emission regulations, the more you will have to spend on gas turbine and plant equipment.

Basic emission control systems include water or steam injection for NOx reduction on natural gas or distillate fuels.

Some installations also add post-firing treatment with NOx and CO catalytic reduction, adding substantially to balance-of-plant and operating costs.

One extreme example is an LM6000 peaking station project in the U.S. northeast that is budgeting an additional $5 million per unit for NOx and CO reduction.

This covers the costs of an engine water injection system, a downstream selective catalytic reduction system to reduce NOx, and a separate CO removal system.

Today, several gas turbines are being equipped with dry low-NOx/CO combustors for operation on natural gas fuel. However, a few systems are coming out with dry low emissions on distillate as well.

On the larger frame engines, dry NOx systems are often provided as standard equipment, and the $ per kW levels do not increase that much due to the production volume of the fuel system equipment.

This is generally true of DLE system designs that are relatively simple to engineer and install. (There is more room in the combustion section.)

In other cases, especially on the aeroderivative machines, complex dry low emissions systems can add up to 10% or more to the engine cost.

In most cases, these DLE units are completely new replacements of the original aircraft propulsion designs that are fully annular units designed for liquid fuel only.

Extras cost more

Not covered in the prices quoted are the electrical substation, switchyard, pipeline connections, fuel gas compressor skid.

Nor are fuel storage and treatment systems for liquid fuel included. No black start generator sets. Administrative offices, separate modular control room, workshops, storage buildings, spares and consumables are not included.

Also not covered: water or steam injection systems for NOx control; complex multi-level inlet filtration, inlet chillers or anti-ice systems; tall exhaust stacks or chimneys; electrical distribution or main step-up transformers and switchgear and motor control centers; poured concrete foundations and foundation bolting.

Pricing factors

Bulk purchases can create significant volume discounts, affecting unit price levels. How badly an OEM wants to enter or succeed in a particular market makes a difference.

Trade tariffs set up to tax imported equipment can significantly add to the packaged price at rates of 3% and higher.

Similarly, attractive financing packages and low-interest (or no interest) loan availability can affect the budget price of the gas turbine generator set.

Age of the gas turbine design can also be a factor in setting prices. New machines are often heavily discounted to get production prototypes out into the field.

Some are downright 'giveaways' to accumulate operating hours (field experience) and provide a showcase for prospective customers.

Later, as the design is accepted into the marketplace, prices are increased to normal levels.

Older machines, besides being less efficient, can often be steeply discounted since the original costs of engineering design, product development and production tooling and facilities have long since been repaid.

Unit upratings also tend to reduce $ per kW levels. An uprated machine, for example, can carry exactly the same equipment price as its predecessor. But, because of its higher output, it will show up with lower $ per kW cost in comparative evaluations.

Gross versus net plant ratings will also have an impact on $ per kW pricing. In the GTW Handbook, we try as much as possible to quote net plant ratings where available.

Scoping studies

Budgetary $ per kW prices are intended for preliminary project assessment and evaluation of power generating equipment.

Installed and complete turnkey plant costs can conservatively add between 60 and 100% to the equipment-only prices shown here.

While equipment prices listed reflect an average level, there is a fairly wide range—upward and downward—resulting from OEM or packager competitive position, geographical area, marketing strategies and production capabilities.

Most important price factor is supply and demand. In a seller's market for the 180-MW-class 'F' technology units, price sometimes takes a back seat to product availability.

Industry analysts note that, despite major price increases, buyers are paying full retail for these machines, and are queuing up for 'delivery slots' some of which stretch out through 2005.

As a project developer, owner or operator, it is up to you and your engineering consultants to evaluate all these factors during the bid process when shopping for new gas turbine generating capacity.

RFP Bid Specifications for Six 50-MW Peaking Plants

Two years ago, the City Department of Water and Power in Los Angeles, California invited sealed proposals to furnish and deliver approximately 300 MW of gas turbine peaking capacity.

DWP bid documents insisted that "time is of the essence" in the resulting contract. Units were to be installed before June 1, 2001, requiring delivery at the Department by March 15, 2001.

"All equipment shall be completed and delivered by the contractual dates. Late delivery will face substantial liquidated damages based upon the Department's anticipated loss of revenue caused by late delivery.

"Proposers are requested to furnish and deliver, F.O.B. Department facilities within a radius of 75 miles of Los Angeles, six new (combustion) gas turbine generators, each unit not to exceed 49 MW in capacity, complete with all equipment and systems necessary for a continuously functional installation, which also meets Best Achievable Control Technology criteria."

Scope of supply

Each unit was to include, but not be limited to, (combustion) gas turbine with generator, dual fuel capability for natural gas and distillate oil, dry low NOx combustors, base plate mountings, access ladders and walkways, inlet filter and intake silencer with structural supports.

Also to include starting system, compressor wash system, lube oil systems, fire protection system, acoustic enclosures, space conditioning, internal lighting, (fuel) gas compressors, generator breaker, step up transformer, power system stabilizer, ducting and stack.

The specifications called for a CO and NOx selective catalytic reduction system for each machine, including structural supports, housing, reactors, catalyst, and ammonia supply, transfer, conditioning and injection equipment.

Engine protection equipment included monitoring instruments, vibration monitoring system and controls, and drawings, service manuals, operating manuals, and operator training for each piece of equipment furnished.

Extras

The Department requested separate prices for specific optional equipment: black start capability per unit; inlet air cooling system; modular control room; switchgear; motor control center; synchronous condensing capability.

It also requested separate, itemized pricing for recommended spare parts and special tools, and left the door open to vendor recommendations: "The Department will consider other optional equipment and alternate proposals."

RFP submittals were required to include (for each piece of equipment furnished) "all information necessary to obtain regulatory permits, including; guaranteed performance characteristics; all operating characteristics; process, system and equipment descriptions; schematic system process drawings."

Also to itemize "component installation requirements, including space, weight, handling, dimensions and locations of all interface connections; maintenance requirements, including access, lifting, handling, inspection and service intervals; and component life expectancies."

Site work

The cost of assembly on a foundation provided by the Department was to be included as an optional item in the proposal.

Proposals were also to include daily charges for field engineering services, applicable if another entity (other than the selected vendor) was selected for the installation of the equipment.

Bid award

On September 5, 2000 the DWP awarded GE Packaged Power Inc. a $149,363,000 contract for six LM6000 enhanced Sprint gas turbine gensets and balance of plant equipment. At a nominal ISO base load output rating of 47 MW each on natural gas fuel, this works out to $530 per kW.

Industry Price Levels

Simple Cycle Power Plants

Budget prices in year 2001 U.S. dollars for basic electric power generator packages including a single-fuel gas turbine, air cooled electric generator (some larger units hydrogen cooled), skid and enclosure, inlet and exhaust ducts with silencers, standard control and starting systems, conventional combustion system unless otherwise designated as dry low emissions (DLE) models.

Plant Model	Base Load Output	Heat Rate Btu/kWh	Efficiency	Budget Price	$ per kW
VPS1	496 kW	16,570 Btu	20.6%	$435,000	$877
ST6L-813	848 kW	13,125 Btu	26.0%	$677,500	$799
Makila TI	1050 kW	12,580 Btu	27.1%	$880,000	$838
Saturn 20	1210 kW	14,025 Btu	24.3%	$675,000	$558
KG2-3C	1450 kW	21,620 Btu	15.8%	$1,070,000	$738
M1A13D	1473 kW	14,230 Btu	24.0%	$940,000	$638
KG2-3E	1830 kW	21,070 Btu	16.2%	$1,200,000	$656
ST18A	1960 kW	11,300 Btu	30.2%	$1,200,000	$611
OGT2500	2730 kW	12,515 Btu	27.3%	$1,435,000	$526
UGT-2500	2850 kW	12,430 Btu	27.5%	$1,390,000	$488
M1T13D	2900 kW	14,460 Btu	23.6%	$1,625,000	$560
VPS3	3105 kW	12,775 Btu	26.7%	$1,520,000	$490
ST30	3340 kW	10,660 Btu	32.0%	$1,600,000	$479
Centaur 40	3515 kW	12,240 Btu	27.9%	$1,400,000	$398
VPS4	3570 kW	11,800 Btu	28.9%	$1,601,000	$449
501-KB5S	3950 kW	11,765 Btu	29.0%	$1,600,000	$405
GTES-4	4100 kW	14,130 Btu	24.1%	$1,230,000	$300
ST40	4040 kW	10,310 Btu	33.1%	$1,800,000	$446

Plant Model	Base Load Output	Heat Rate Btu/kWh	Efficiency	Budget Price	$ per kW
Centaur 50	4600 kW	11,630 Btu	29.3%	$1,600,000	$348
GTES-5	5200 kW	13,050 Btu	26.1%	$1,534,000	$295
Taurus 60	5200 kW	11,225 Btu	30.4%	$1,800,000	$346
PGT5	5220 kW	12,720 Btu	26.8%	$1,900,000	$364
Typhoon 5.25	5250 kW	11,200 Btu	30.5%	$1,850,000	$352
501-KB7	5275 kW	11,200 Btu	30.5%	$1,750,000	$332
M7A-01	5840 kW	11,230 Btu	30.4%	$2,310,000	$396
PGT5B	5900 kW	10,700 Btu	31.9%	$2,050,000	$347
GTES-6	6200 kW	12,780 Btu	26.7%	$1,705,000	$275
501-KH5 (steam injection)	6420 kW	8560 Btu	39.9%	$2,300,000	$358
601-KB9	6450 kW	10,615 Btu	32.1%	$2,450,000	$380
GT6001	6700 kW	10,840 Btu	31.5%	$2,700,000	$403
UGT-6000	6700 kW	11,270 Btu	30.3%	$2,100,000	$313
Tornado	6750 kW	10,820 Btu	31.5%	$2,650,000	$393
M7A-02	6960 kW	11,050 Btu	30.9%	$2,700,000	$388
Taurus 70	7520 kW	10,100 Btu	33.8%	$2,670,000	$355
Tempest	7910 kW	10,940 Btu	31.2%	$2,750,000	$348
601-KB11	7920 kW	10,350 Btu	33.0%	$3,200,000	$404
UGT-6000+	8300 kW	10,650 Btu	32.0%	$2,350,000	$283
THM1304-10	9320 kW	12,170 Btu	28.0%	$3,520,000	$378
UGT-10000	10,000 kW	10,220 Btu	34.2%	$3,350,000	$335
G3142J	10,450 kW	13,320 Btu	25.6%	$3,750,000	$359
Mars 100	10,690 kW	10,520 Btu	32.4%	$4,000,000	$374
THM1304-11	10,760 kW	11,460 Btu	29.8%	$3,730,000	$347
PGT10B	11,700 kW	10,660 Btu	32.0%	$4,700,000	$402

Plant Model	Base Load Output	Heat Rate Btu/kWh	Efficiency	Budget Price	$ per kW
GTES-12	12,000 kW	10,240 Btu	33.3%	$3,000,000	$250
Cyclone DLE	12,875 kW	9820 Btu	34.8%	$4,650,000	$361
Titan 130	13,500 kW	10,250 Btu	33.3%	$4,500,000	$335
SB60-1	13,570 kW	11,490 Btu	29.7%	$5,930,000	$437
PGT16	13,750 kW	9670 Btu	35.3%	$6,750,000	$491
LM1600PA	13,750 kW	9865 Btu	34.6%	$8,000,000	$582
LM1600DLE	13,750 kW	9865 Btu	34.6%	$8,500,000	$618
H-15	13,800 kW	11,010 Btu	31.0%	$6,300,000	$456
MF111B	14,570 kW	11,020 Btu	31.0%	$6,200,000	$425
Avon	14,580 kW	12,100 Btu	28.2%	$5,200,000	$357
GTES-16	16,000 kW	9790 Btu	34.9%	$4,000,000	$250
UGT-10000 STIG. (steam injection)	16,000 kW	7950 Btu	43.0%	$4,500,000	$281
UGT-16000	16,300 kW	11,230 Btu	30.4%	$3,950,000	$242
LM1600-PB STIG (steam injection)	16,900 kW	8605 Btu	39.7%	$8,280,000	$490
GT35	17,000 kW	10,600 Btu	32.2%	$5,914,000	$348
L20A	17,000 kW	10,040 Btu	34.0%	$6,665,000	$392
UGT-15000.	17,500 kW	9750 Btu	35.0%	$6,275,000	$359
LM2000	18,000 kW	9615 Btu	35.5%	$7,950,000	$440
UGT-15000+.	20,000 kW	9480 Btu	36.0%	$6,500,000	$325
PGT25	22,450 kW	9395 Btu	36.3%	$9,900,000	$441
LM2500PE	22,800 kW	9280 Btu	36.8%	$9,575,000	$420
GT10B	24,770 kW	8985 Btu	34.2%	$7,495,000	$303
UGT-15000 STIG (steam injection)	25,000 kW	8100 Btu	42.1%	$7,250,000	$290
RB211-6556	25,360 kW	9745 Btu	35.0%	$7,900,000	$311

Plant Model	Base Load Output	Heat Rate Btu/kWh	Efficiency	Budget Price	$ per kW
FT8	25,490 kW	8950 Btu	38.1%	$9,725,000	$382
UGT-25000	26,200 kW	9550 Btu	35.7%	$6,800,000	$260
PG5371PA	26,300 kW	11,990 Btu	28.5%	$7,680,000	$292
H-25	26,900 kW	10,280 Btu	33.2%	$8,300,000	$309
LM2500PH (steam injection)	28,280 kW	8325 Btu	41.0%	$11,500,000	$407
LM2500+PK	28,600 kW	8860 Btu	38.5%	$10,500,000	$367
RB211-6562	28,775 kW	9225 Btu	37.0%	$8,900,000	$309
GT10C	29,060 kW	9480 Btu	36.0%	$8,495,000	$292
RB211-6762DLE	29,430 kW	9030 Btu	37.8%	$9,600,000	$326
MF-221	30,000 kW	10,670 Btu	32.0%	$10,000,000	$333
RB211-6761DLE	31,750 kW	8735 Btu	39.1%	$10,300,000	$324
IM5000	33,550 kW	9210 Btu	37.1%	$12,900,000	$384
PG6561B	39,620 kW	10,710 Btu	31.9%	$13,100,000	$331
UGT-25000 STIG (steam injection)	40,100 kW	7990 Btu	42.7%	$8,200,000	$204
PG6581B	42,100 kW	10,640 Btu	32.1%	$14,600,000	$348
GTX100	43,000 kW	9215 Btu	37.0%	$11,828,000	$275
LM6000PD	42,330 kW	8310 Btu	41.1%	$14,600,000	$345
LM6000PD(DLE)	42,400 kW	8200 Btu	41.6%	$15,400,000	$363
LM6000PC	43,700 kW	8105 Btu	42.1%	$14,200,000	$325
LM6000PC Sprint (water injection)	48,060 kW	8430 Btu	40.5%	$16,100,000	$335
W251B11/12	49,500 kW	10,450 Btu	32.6%	$14,000,000	$284
IM5000-STIG(steam injection)	50,100 kW	7950 Btu	42.9%	$15,150,000	$303
Trent DLE	51,190 kW	8210 Btu	41.6%	$16,000,000	$312
FT8 Twin	51,350 kW	8890 Btu	38.4%	$16,500,000	$322
GT8C2	57,000 kW	10,100 Btu	33.8%	$16,100,000	$281

Plant Model	Base Load Output	Heat Rate Btu/kWh	Efficiency	Budget Price	$ per kW
Trent	58,000 kW	8528 Btu	40.0%	$17,350,000	$299
V64.3	63,000 kW	9640 Btu	35.4%	$17,700,000	$281
V64.3A	67,100 kW	9810 Btu	34.8%	$20,600,000	$308
PG6101FA	70,140 kW	9980 Btu	34.2%	$22,200,000	$317
PG7121EA	85,400 kW	10,420 Btu	32.8%	$21,200,000	$248
UGT-110000	114,500 kW	9480 Btu	35.0%	$14,000,000	$122
GT11N2	116,500 kW	10,050 Btu	33.9%	$24,100,000	$207
W501D5A	120,500 kW	9840 Btu	34.7%	$25,800,000	$214
PG9171E	123,400 kW	10,100 Btu	33.8%	$25,900,000	$210
M701DA	144,100 kW	9810 Btu	34.8%	$29,400,000	$204
V94.2	157,000 kW	9920 Btu	34.4%	$30,500,000	$194
GT13E2	165,100 kW	9560 Btu	35.7%	$35,200,000	$213
PG9231EC	169,200 kW	9770 Btu	34.9%	$35,200,000	$208
PG7241FA	171,700 kW	9420 Btu	36.2%	$40,500,000	$236
GT24	179,000 kW	9098 Btu	37.5%	$39,300,000	$219
V84.3A	180,000 kW	8980 Btu	38.0%	$39,700,000	$220
W501F	186,500 kW	9130 Btu	37.4%	$40,400,000	$217
V94.2A	190,700 kW	9660 Btu	35.3%	$37,500,000	$197
PG9311FA	243,000 kW	9360 Btu	36.4%	$47,100,000	$194
W501G	253,000 kW	8760 Btu	38.5%	$49,700,000	$196
PG9351FA	255,600 kW	9250 Btu	36.9%	$51,000,000	$199
GT26	262,000 kW	8930 Btu	38.2%	$51,900,000	$198
V94.3A	265,900 kW	8840 Btu	38.6%	$50,400,000	$190
M701F	270,300 kW	8930 Btu	38.2%	$51,000,000	$189
M701G	334,000 kW	8630 Btu	39.5%	$60,700,000	$182

Keep in mind the difference between LHV and HHV in making fuel calculations

Gas turbine performance is calculated on the basis of the lower heating value (LHV) of the fuel to be burned, whereas fuel supply and purchase contracts are figured on the basis of higher heating value (HHV).

The difference between them is Btu content you pay for but do not see as power output. Technically it is difficult to explain. But it relates to fuel-bound hydrogen which forms water as a byproduct of combustion and is wasted in the exhaust.

HHV is measured on the basis of the chemical energy in the fuel which accounts for the total heat given up when the fuel is burned (including formation of water vapor) while LHV measures the useable energy.

In practical terms, some 6% by weight of liquid fuels is "wasted" versus 11 % for natural gas fuel. Or, put another way, you must increase LHV fuel consumption by a factor of 1.06 for liquid fuels and by 1.11 for gas.

Cycle studies for gas turbine projects are done on an LHV basis and fuel requirement on an HHV basis. This means you must figure on supplying more fuel than called for in the specifications and performance calculations.

Bulk weight of liquid fuels. This table lists the weights of various liquid fuels. For gaseous fuel 3500 cubic feet of still gas is equivalent to one 42-gallon barrel of liquid fuel.

Type Fuel	Gravity at 60°F (Average)	Gallons per Pound	Pounds per Gallon	Pounds 42-Gal Barrel	Barrels per Short Ton (2000 Lbs)	Barrels per Metric Ton (2205 Lbs)
Crude Oil (U.S. imports)	25.6	0.13333	7.500 lb	315 lb	6.349 bbl	6.998 bbl
Crude Oil (U.S. domestic)	36.0	0.14217	7.034 lb	295 lb	6.770 bbl	7.463 bbl
Distillate Oil	31.3	0.13817	7.237 lb	304 lb	6.580 bbl	7.253 bbl
Residual Oil	18.0	0.12687	7.882 lb	331 lb	6.041 bbl	6.660 bbl
Liquefied Petroleum Gas	—	0.22104	4.524 lb	190 lb	10.526 bbl	11.603 bbl

Cross index to Btu content of fuels (HHV). This table lists HHV values of various liquid fuels. For approximate performance calculations, figure on an LHV of 18,400 Btu/lb for distillate or crude oil.

Fuel Type and Bulk	42-Gal Bbl Crude Oil	1000-Cu Ft Natural Gas	42-Gal Bbl Distillate	42-Gal Bbl Residual	42-Gal Bbl LPG
Btu Content x 10^6	5.800 Btu	1.035 Btu	5.825 Btu	6.287 Btu	4.011 Btu
Crude Oil (42-gal barrel)	1.000	5.604	0.996	0.923	1.446
Dry Natural Gas (1000 cu ft)	0.178	1.000	0.178	0.165	0.258
Distillate Oil (42-gal barrel)	1.004	5.628	1.000	0.927	1.452
Residual Oil (42-gal barrel)	1.084	6.074	1.079	1.000	1.567
Liquefied Gas(42-gal barrel)	0.692	3.875	0.689	0.638	1.000

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS 1999 Jan. 1	1999 Jul. 1	2000 Jan. 1	2000 Jul. 1	2001 Jan. 1	2001 Jul. 1	2002 Jan. 1	2002 Jul. 1	2003 Jan. 1	2003 Jul. 1	2004 Jan. 1	2004 Jul. 1	2005 Jan. 1	2005 Jul. 1
1	Total Plant-All Steam Generation		366	365	369	382	387	386	398	403	412					
2	Total Plant-All Steam & Nuclear Gen.		365	364	368	382	386	386	398	403	411					
3	Total Plant-All Steam & Hydro Gen.		359	357	361	374	378	378	389	393	401					
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		388	391	397	414	419	416	424	434	445					
7	Structures & Improvements-Indoor	311	347	346	351	369	374	375	382	391	397					
8	Structures & Improvements-Semi-Outdoor	311	338	341	350	355	358	363	367	369	372					
9	Boiler Plant Equipment-Coal Fired	312	404	406	410	430	434	435	441	453	457					
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-					
11	Boiler Plant Piping Installed		352	350	348	358	362	361	368	375	381					
12	Turbogenerator Units	314	369	373	383	396	400	389	399	409	431					
13	Accessory Electrical Equipment	315	421	428	434	461	472	472	493	511	522					
14	Misc. Power Plant Equipment	316	416	420	426	442	445	446	455	464	469					
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		368	372	377	392	397	395	405	414	424					
18	Structures & Improvements	321	327	331	334	349	351	354	359	369	373					
19	Reactor Plant Equipment	322	361	361	365	377	380	380	387	394	399					
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		333	337	342	346	349	349	354	356	359					
23	Structures & Improvements	331	347	346	351	369	374	375	382	391	397					
24	Reservoirs, Dams & Waterways	332	319	323	327	330	333	336	339	342	344					
25	Water Wheels, Turbines & Generators	333	382	386	395	396	400	386	398	392	399					
26																
27	**Other Production Plant**															
28	Total Other Production Plant		387	390	396	421	427	402	409	420	427					
29	Fuel Holders, Producers & Accessories	342	374	370	372	383	384	386	391	399	404					
30	Gas Turbogenerators	344	398	401	408	394	401	408	415	426	433					
31																
32	**Transmission Plant**															
33	Total Transmission Plant		376	369	373	395	398	401	411	411	415					
34	Station Equipment	353	384	388	391	415	419	421	429	434	438					
35	Towers & Fixtures	354	353	354	365	368	373	377	384	385	388					
36	Poles & Fixtures	355	418	419	413	422	425	432	450	448	454					
37	Overhead Conductors & Devices	356	389	354	356	398	399	403	416	406	411					
38	Underground Conduit	357	354	346	348	355	358	360	374	381	390					
39	Underground Conductors & Devices	358	453	463	453	458	468	447	462	466	474					
40																
41	**Distribution Plant**															
42	Total Distribution Plant		339	336	338	346	350	351	366	369	376					
43	Station Equipment	362	374	375	377	379	382	383	391	383	388					
44	Poles, Towers & Fixtures	364	390	391	391	398	400	403	420	426	434					
45	Overhead Conductors & Devices	365	393	377	381	410	413	416	438	437	449					
46	Underground Conduit	366	343	347	353	356	361	362	377	389	397					
47	Underground Conductors & Devices	367	325	329	326	335	342	327	342	343	347					
48	Line Transformers	368	234	228	229	231	234	238	247	250	252					
49	Pad Mounted Transformers	368	329	329	330	332	333	351	357	365	362					
50	Services-Overhead	369	332	330	334	343	345	343	366	363	375					
51	Services-Underground	369	238	236	243	252	253	248	259	265	269					
52	Meters Installed	370	226	212	208	210	222	237	263	275	287					
53	Street Lighting-Overhead	373	402	402	405	410	415	419	435	450	474					
54	Mast Arms & Luminaires Installed	373	413	413	413	419	423	424	438	440	445					
55	Street Lighting-Underground	373	404	405	409	414	419	424	439	459	489					
56																

Electricity Market Module

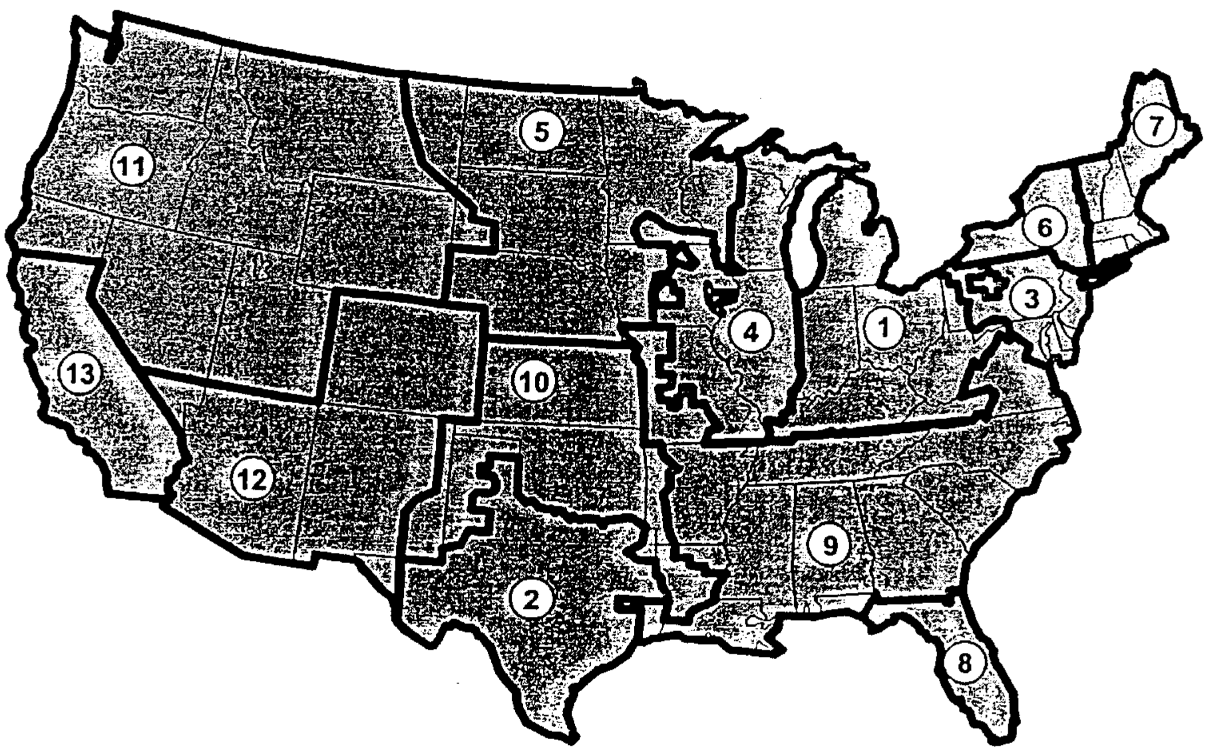
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand-side management, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, *Electricity Market Module of the National Energy Modeling System 2003*, DOE/EIA-M068(2003) April 2003.

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM Regions

The supply regions used in EMM are based on the North American Electric Reliability Councils shown in Figure 4.

Figure 4. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement
2 Electric Reliability Council of Texas
3 Mid-Atlantic Area Council
4 Mid-America Interconnected Network
5 Mid-Continent Area Power Pool
6. New York
7 New England
8 Florida Reliability Coordinating Council
9 Southeastern Electric Reliability Council
10 Southwest Power Pool
11 Northwest Power Pool
12 Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada
13 California

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 39. Assumptions for the renewable technologies are discussed in a later chapter.

Table 39. Generating Capacity Types Represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Integrated Gasification Combined-Cycle
Solar Thermal - Central Receiver
Solar Photovoltaic - Single Axis Flat Plate
Wind

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of No_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

New Generating Plant Characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 40). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for fossil-fueled technologies decline linearly through 2010.

The overnight costs shown in Table 40 are the cost estimates to build a plant in a typical region of the country *(Middletown, U.S.A)*. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers (Table 41) that represent variations in the cost of labor. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost used for the capacity choice decision.

Table 40. Cost and Performance Characteristics of New Electricity Generating Technologies

Technology	Online Years[1]	Size (mW)	Leadtimes (Years)	Overnight Costs[2] in 2002 ($2001/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost including Contingencies in 2002[4] (2001 $/kW)	Variable O&M[5] ($2001 mills/kWh)	Fixed O&M[5] ($2001/kW)	Heatrate in 2002 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New	2006	600	4	1,079	1.07	1.00	1,154	3.07	24.52	9,000	8,600
Integrated Coal-Gasification Combined Cycle	2006	550	4	1,277	1.07	1.00	1,367	2.04	33.72	8,000	7,200
Conventional Gas/Oil Combined Cycle	2005	250	3	510	1.05	1.00	536	2.04	12.26	7,500	7,000
Adv Gas/Oil Combined Cycle	2005	400	3	563	1.08	1.00	608	2.04	10.22	7,000	6,350
Conv Combustion Turbine[6]	2004	160	2	389	1.05	1.00	409	4.09	10.22	10,939	10,450
Adv Combustion Turbine	2004	230	2	439	1.05	1.00	460	3.07	10.22	10,939	10,450
Fuel Cells	2005	10	3	1,850	1.05	1.10	2,137	20.43	8.17	9,394	8,550
Advanced Nuclear	2007	1000	5	1,750	1.10	1.10	2,117	0.43	58.48	7,500	6,750
Distributed Generation - Base	2005	2	3	766	1.05	1.00	804	6.13	13.79	9,400	8,900
Distributed Generation - Peak	2004	1	2	919	1.05	1.00	965	6.13	13.79	10,400	9,880
Biomass	2006	100	4	1,569	1.07	1.05	1,763	2.96	45.94	8,911	8,911
MSW - Landfill Gas	2005	30	3	1,365	1.07	1.00	1,460	0.01	98.42	13,648	13,648
Geothermal[7,8]	2006	50	4	1,681	1.05	1.00	1,766	0.00	71.75	32,320	31,797
Wind	2005	50	3	938	1.07	1.00	1,003	0.00	26.10	10,280	10,280
Solar Thermal[8]	2005	100	3	2,204	1.07	1.10	2,594	0.00	48.91	10,280	10,280
Solar Photovoltaic[8]	2004	5	2	3,389	1.05	1.10	3,915	0.00	10.06	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2002.

[2]Costs reflect market status and penetration as of 2002.

[3]The technological optimism factor is applied to the first four units of a new, unproven design. It reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2002.

[5]O&M = Operation and maintenance.

[6]Combustion turbine units can be built by the model prior to 2004 if necessary to meet a given region's reserve margin.

[7]Because geothermal cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[8]Capital costs for geothermal and solar technologies are net of (reduced by) the ten percent investment tax credit.

Source: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed

Table 41. Regional Multipliers for Construction of Fossil-Fueled, Nuclear, and Renewable[1] Generating Technologies

EMM Region	NE, NY	MAAC	STV	MAPP, ECAR, MAIN	SPP
	1.043	0.996	0.96	1.004	0.997
EMM Region	**RA**	**NWP**	**FL**	**CNV**	**ERCOT**
	1.003	1.026	0.961	1.058	0.986

[1]Regional multipliers are not applied to geothermal technologies because costs are site specific.

Source: Argonne National Laboratory, *Cost and Performance Database for Electric Power Generating Technologies*..

Technological Optimism and Learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors. For each generating technology available for new capacity in a region, the overnight cost used by the model is calculated using the base cost, technological optimism and contingency factors for the technology from Table 40, the regional factors from Table 41, and the learning parameters from Table 42.

Table 42. Learning Parameters for New Generating Technologies

Technology	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2020
Conventional Pulverized Coal	-	-	0.01	-	-	0.05
Integrated Coal-Gasification Combined Cycle	-	0.05	0.01	-	5	0.10
Gas/Oil Steam Turbine	-	-	0.01	-	-	0.05
Conv Gas/Oil Combined Cycle	-	-	0.01	-	-	0.05
Adv Gas/Oil Combined Cycle	-	0.05	0.01	-	5	0.10
Conv Combustion Turbine	-	-	0.01	-	-	0.05
Adv Combustion Turbine	-	0.05	0.01	-	5	0.10
Fuel Cells	0.1	0.05	0.01	3	5	0.20
Adv Nuclear	-	0.05	0.01	-	5	0.10
Distributed Generation - Base	-	0.05	0.01	-	5	0.10
Distributed Generation - Peak	-	0.05	0.01	-	5	0.10
Biomass	0.1	0.05	0.01	3	5	0.20
MSW - Landfill Gas	-	-	0	-	-	0.05
Geothermal	-	0.05	0.01	-	5	0.10
Wind	-	-	0.01	-	-	0.01
Solar Thermal	0.1	0.05	0.01	3	5	0.20
Photovoltaic	0.1	0.05	0.01	3	5	0.20

Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function has the nonlinear form:

$$OC(C) = a^{*}C^{-b},$$

where C is the cumulative capacity for the technology.

The progress ratio (*pr*) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (f) is an exogenous parameter input for each technology Table 42. Consequently, the progress ratio and *f* are related by:

$$pr = 2^{-b} = (1 - f)$$

The parameter "b" is calculated by $(b = -(\ln(1-f)/\ln(2))$. The parameter "a" can be found from initial conditions. That is,

$$a = OC(C0)/C0^{-b}$$

where C0 is the cumulative initial capacity. Thus, once the rates of learning (f) and the cumulative capacity (C0) are known for each interval, the corresponding parameters (a and b) of the nonlinear function are known. Three learning steps were developed, to reflect different stages of learning as a new design is introduced to the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. All technologies receive a minimal amount of learning, even if new capacity additions are not projected. This could represent cost reductions due to future international development or increased research and development.

International Learning. In *AEO2003*, capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the U.S. market, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the domestic learning effects calculation.

AEO2003 includes 784 megawatts of advanced coal gasification combined-cycle capacity, 4,199 megawatts of advanced combined-cycle natural gas capacity, and 11 megawatts of biomass capacity to be built outside the United States from 2001 through 2003.

Distributed Generation

Distributed generation is modeled in the end-use sectors as well as in the EMM, which is described in the appropriate chapters. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). Use Table 40 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Representation of Electricity Demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Council regions and subregions) using historical hourly load data. However, unlike traditional load duration curves where the demands for an entire period would be ordered from highest to lowest, losing their chronological order, the load duration curves in the EMM are segmented into the 9 time periods shown in Table 43. The summer and winter peak periods are represented in the model by 2 vertical slices each (a peak slice and an off-peak slice) while the remaining 7 periods are represented by 1 vertical slice each, resulting in a total of 11 vertical slices. The time periods shown were chosen to accommodate intermittent generating technologies (i.e., solar and wind facilities) and demand-side management programs.

Table 43. Load Segments in the Electricity Market Module

Season	Months	Period	Hours
Summer	June-September	Daytime	0700-1800
		Morning/Evening	0500-0700 and 1800-2400
		Night	0000-0500
Winter	December-March	Daytime	0800-1600
		Morning/Evening	0500-0800 and 1600-2400
		Night	0000-0500
Off-peak	April-May	Daytime	0700-1700
	October-November	Morning/Evening	0500-0700 and 1700-2400
		Night	0000-0500

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are also assumed for each regulated EMM region. A 13 percent reserve margin is assumed for MAPP and STV, 9 percent for FL, 15 percent for NWP, and 14 percent for CNV. In the other regions where competition has replaced regulation in all or a majority of the region, the EMM determines the reserve margin by equating the marginal cost of capacity and the cost of unserved energy.

Fossil Fuel-Fired and Nuclear Steam Plant Retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operating of existing plants. If the expected revenues from these plants are not sufficient to cover the annual going forward costs, the plant is assumed to retire if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant specific based on historical data. The average capital additions for existing plants are $11 per kilowatt (kW) for oil and gas steam plants, $6/kW for combined-cycle plants, and combustion turbines, $16/kW for coal plants and $18/kW for nuclear plants. These costs are added to existing plants regardless of their age. Beyond 30 years of age an additional $5/KW capital charge for fossil plants, and $50/kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased maintenance costs to mitigate the effects of aging.

Biomass Co-firing

Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $100 to $200 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional supply.

New Nuclear Plant Orders

A new nuclear technology competes with other fossil-fired and renewable technologies as new generating capacity is needed to meet increasing demand, or replace retiring capacity, throughout the forecast period. The cost assumptions for new nuclear units are based on an analysis of recent cost estimates for nuclear designs available in the United States and worldwide. The capital cost assumptions in the reference case are meant to represent the expense of building a new single unit nuclear plant of approximately 1,000 megawatts at a new "Greenfield" site. Since no new nuclear plants have been built in the US in many years, there is a great deal of uncertainty about the true costs of a new unit. The EIA accounts for this uncertainty by requiring that the capital cost estimates be symmetric in the sense that there is an equal probability that they could turn out to be either "too high" or "too low." For that reason, the estimate used for AEO2003 is an average of the ones reviewed from various sources (See 'Notes and Sources' at the end of the Chapter for a full list of sources reviewed).

It is also important to note that there is a great deal of uncertainty about how the nuclear technology will evolve over the next 20 years. Currently, two conventional light water reactors along with the smaller, passively safe, Westinghouse AP600 power plant have had their designs certified by the NRC. A larger version of the Westinghouse design is also under review with the NRC. Additionally, the process to certify a number of more revolutionary reactor designs is just beginning. Thus, it is quite possible that within the next 20 years there will be wide range of designs that have been licensed by the NRC and could be built. Rather than attempting to "pick the winners" the cost estimates used here are more general, and do not deal with any one design.

Interregional Electricity Trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the NERC and WSCC Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's *Electricity Supply and Demand Database 2000*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2010 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2010, they are assumed to be phased out by 2020. In addition, in certain regions where data show an established commitment to build plants to serve another region, new plants are permitted to be built to serve the other region's needs. This option is available to compete with other resource options.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are allowed to exchange power.

International Electricity Trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Existing and planned transactions are obtained from the North American Electric Reliability Council's *Electricity Supply and Demand Database 2000*. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report *Northern Lights: The Economic and Practical Potential of Imported Power from Canada*, (DOE/PE-0079).

International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections as reported in the Canadian National Energy Board report *Energy Supply and Demand to 2025.*

Electricity Pricing

The reference case assumes a transition to full competitive pricing in New York, New England, Mid-Atlantic Area Council, and Texas. California is assumed to return to fully regulated pricing in 2002, after beginning to transition to completion in 1998. In addition electricity prices in the East Central Area Reliability Council, the Mid-American Interconnected Network (Illinois, plus parts of Missouri, Michigan and Wisconsin), the Southwest Power Pool, and the Rocky Mountain Power Area/ Arizona are a weighted average of both competitive and regulated prices. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. The price for the region will be a weighted average of the competitive price and the regulated price, with the weight based on the percent of the region that has taken action to deregulate. The reference case assumes that State-mandated price freezes or reductions during a specified transition period will occur based on the terms of the legislation. In general, the transition period is assumed to occur over a ten-year period from the effective date of restructuring, with a gradual shift to marginal cost pricing. In regions where none of the states in the region or where states representing less than half of regional electricity sales have introduced competition, electricity prices are assumed to remain regulated. The cost-of-service calculation is used to determine electricity prices in regulated regions.

The price of electricity to the consumer is comprised of the price of generation, transmission and distribution including applicable taxes. Transmission and distribution are considered to remain regulated in the *AEO*; that is, the price of transmission and distribution is based on the average cost for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The marginal cost includes fuel, operating and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. Therefore, the price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. The price of electricity in the four regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution. In the four partially competitive regions the price is a combination of cost-of-service pricing and marginal pricing weighted by the share of sales.

In recent years, the move towards competition in the electricity business has led utilities to make efforts to reduce costs to improve their market position. These cost reduction efforts are reflected in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and these trends have been incorporated in the *AEO2002*. The key trends are discussed below:

- Reduced General and Administrative Expenses (G&A) - Over the 1990 through 1999 period, utilities have reduced their employment at fossil steam plants at a rate of 4 percent per year. This trend has been incorporated by reducing total G&A expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

- Reduced Fossil Plant Operations Expenditures (O&M) - Again, over the 1990 through 1999 period, utility fossil plant operation and maintenance costs (all operating costs other than fuel) fell at a rate of about 3 percent annually. As with G&A, this trend has been incorporated by reducing fossil O&M expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

Fuel Price Expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 20-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas, and oil are derived using adaptive expectations, in which future prices are extrapolated from recent historical trends.[92] For each oil product, future prices are estimated by applying a constant markup to an external forecast of world oil prices. The markups are calculated by taking the differences between the regional product prices and the world oil price for the previous forecast year. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on expected demand changes throughout the forecast horizon, resulting in updated mining utilization and different supply curves.

For natural gas, expected wellhead prices are based on a nonlinear function that relates the expected price to the expected cumulative domestic gas production. Delivered prices are developed by applying a constant markup, which represents the difference between the delivered and wellhead prices from the prior forecast year.

The approach for natural gas was developed to have the following properties:

1. The natural gas wellhead price should be upward sloping as a function of cumulative gas production.

2. The rate of change in wellhead prices should increase as fewer economical reserves remain to be discovered and produced.

The approach assumes that at some point in the future a given target price, PF, results when cumulative gas production reaches a given level, QF. The target values for PF and QF were assumed to be $7.00 per thousand cubic feet (1995 dollars) and 2000 trillion cubic feet (tcf), respectively. Gas hydrates are included in the resource base at a level of 60 tcf, and geopressurized aquifers are included at 500 tcf. The future annual production is assumed to be constant at the prior year's level. There is also the flexibility to assume a different path in the short term and longer term by choosing an inflection price at which new competitors would enter the market.

The expected wellhead gas price equation is of the following form:

$$P_k = A * Q_k^{exp} + B$$

where P is the wellhead price for year k, Q_k is the cumulative production from 1991 to year k, and A and B are determined each year such that the price equation will intersect the future target point (PF, QF). The exponent, exp, is assumed to be 0.70 as long as P_k is below an assumed inflection price of $3.50. Above this price, the exponent is assumed to be 1.30. The cumulative production calculation assumes that future growth in production will be equal to most recent 3 year average growth rate.

The point (P_k , Q_k) therefore represents the expected wellhead price given the expected cumulative production. A series of supply steps are then developed around this point to represent changes in the expected price that could occur if the cumulative production differs from the expected value. The expected quantity is varied by assuming different levels of consumption, which could result from capacity additions, fuel switching, or other operating decisions. After determining the relative change from the expected production for each step, the corresponding price is derived by applying an elasticity to the expected wellhead price.

Legislation and Regulations

Clean Air Act Amendments of 1990 (CAAA90)

It is assumed that electricity producers comply with the CAAA90, which mandate a limit of 8.95 million tons by 2010. Utilities are assumed to comply with the limits on sulfur emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. It is assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NOx) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000 (Table 44). Dry bottom wall-fired, and tangential fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet their Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NO_x regulations. All new fossil units are required to meet standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. All of these NO_x limits are incorporated in EMM.

Table 44. NO_x Emissions Standards
(Pounds per million Btu)

Boiler Type	# Boilers	Phase I Limit	Phase II Limit
Group 1 Boilers			
Dry Bottom Wall-Fired	284	0.50	0.45
Tangential	296	0.45	0.38
Group 2 Boilers			
Cell Burners	35	NA	0.68
Cyclones	88	NA	0.94
Wet Bottom Wall-Fired	38	NA	0.86
Vertically Fired	29	NA	0.80
Fluidized Bed	5	NA	0.29

NA = Not Applicable.

Source: Environmental Protection Agency, Nitrogen Oxide Emission Reduction Program.

In addition, the EPA has issued rules to limit the emissions of NOx, specifically calling for capping emissions during the summer season in 22 Eastern and Midwestern states. After an initial challenge, these rules have been upheld, and emissions limits have been finalized for 19 states and the District of Columbia (Table 45). Within EMM, electric generators in these 19 states must comply with the limit either by reducing their own emissions or purchasing allowances from others who have more than they need.

Table 45. Summer Season NO_x Emissions Budgets for 2004 and Beyond
(Thousand tons per season)

State	Emissions Cap
Alabama	29.02
Connecticut	2.65
Delaware	5.25
District of Columbia	0.21
Illinois	32.37
Indiana	47.73
Kentucky	36.50
Maryland	14.66
Massachusetts	15.15
Michigan	32.23
New Jersey	10.25
New York	31.04
North Carolina	31.82
Ohio	48.99
Pennsylvania	47.47
Rhode Island	1.00
South Carolina	16.77
Tennessee	25.81
Virginia	17.19
West Virginia	26.86

Source: U.S. Environmental Protection Agency, Federal Register, Vol. 65, number 42 (March 2, 2002) pages 11222-11231.

The costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO_2)and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NO_x) are given below for 300, 500, and 700-megawatt coal plants. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NO_x. The costs per megawatt of capacity tend to decline with plant size and this is shown in table 46.

Table 46. Coal Plant Retrofit Costs
(2001 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	267	93
500	204	82
700	168	74

Source: CUECOST3.xls model (as updated 2/9/2000) developed for the Environmental Protection Agency by Raytheon Engineers and Constructors, Inc. EPA Contract number 68-D7-0001.

Note: The model was run for each individual plant assuming a 1.3 retrofit factor.

Planned FGD (SO2 scrubber) Additions

In recent years, in response to state emission reduction programs and compliance agreements with the Environmental Protection Agency, some companies have announced plans to add scrubbers to their plants to reduce sulfur dioxide and particulate emissions. Where firm commitments appear to have been made these plans have been represented in NEMS. Based on EIA analysis of announced plans, nearly 23,000 megawatts of capacity are assumed to add these controls (Table 47). The greatest number of retrofits is expected to occur in Region 9 because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 47. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Megawatts)
1	1,715
2	1,160
3	1,906
4	173
5	0
6	105
7	837
8	524
9	12,638
10	0
11	1,340
12	2,421
13	0
Total	22,819

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Energy Policy Act of 1992 (EPACT)

The provisions of the EPACT include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs).

The Public Utility Holding Company Act of 1935 (PUHCA)

Prior to the passage of EPACT, PUHCA required that utility holding companies register with the Securities and Exchange Commission (SEC) and restricted their business activities and corporate structures.[93] Entities that wished to develop facilities in several States were regulated under PUHCA. To avoid the stringent SEC regulation, nonutilities had to limit their development to a single State or limit their ownership share of projects to less than 10 percent. EPACT changed this by creating a class of generators that, under certain conditions, are exempt from PUHCA restrictions. These EWGs can be affiliated with an existing utility (affiliated power producers) or independently owned (independent power producers). In general, subject to State commission approval, these facilities are free to sell their generation to any electric utility, but they cannot sell to a retail consumer. These EWGs are represented in NEMS.

FERC Orders 888 and 889

FERC has issued two related rules (Orders 888 and 889) designed to bring low cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and a Open Access Same-time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make it economic to do so.

Electricity and Technology Cases

High Electricity Demand Case

The *high electricity demand case* assumes that electricity demand grows at 2.5 percent annually between 2001 and 2025. In the reference case, electricity demand is projected to grow 1.8 percent annually between 2001 and 2025. No attempt was made to determine the changes needed in the end-use sectors to result in the stronger demand growth.

The *high electricity demand case* is a partially integrated run. The end-use demand modules are not operated, but all of the electricity end-use demands from the reference case are multiplied by the same factor to achieve the higher growth rate. Using the higher electricity demand and all other reference case demand projections as inputs, the EMM, Petroleum Marketing, Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact.

Low and High Fossil Cases

The *low fossil case* assumes that the costs of advanced fossil generating technologies (integrated coal-gasification combined-cycle, advanced natural gas combined-cycle and turbines) will remain at current costs during the projection period, that is, no learning reductions are applied to the cost. Operating efficiencies for advanced technologies are assumed to be constant at 2002 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 48).

In the *high fossil case*, efficiencies of advanced fossil generating technologies are higher than the reference case, based on the Department of Energy, Office of Fossil Energy's Vision 21 program goals, while efficiencies of conventional technologies are the same as used in the reference case. The costs of advanced coal are also assumed to be lower than in the reference case.

In the high fossil case, the efficiency improvements may be achieved through a new design, for example, inlcuding a fuel cell in addition to a combined cycle. It is assumed that research and development will bring the costs of these new designs down to the levels of the current technology.

The *low and high fossil* runs are partially-integrated runs, i.e., the reference case values for the Macroeconomic Activity, Petroleum Market, International Energy, and end-use demand modules are used and are not affected by changes in generating capacity mix. Conversely, the Oil and Gas Supply, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the EMM in the *low and high fossil cases.*

Advanced Nuclear Cost Case

An advanced nuclear cost case was used to analyze the sensitivity of the projections to lower costs for new nuclear plants. The cost assumptions are consistent with the goals endorsed by the Department of Energy's Office of Nuclear Energy and indicated as requirements for cost-competitiveness by the Offices Near-Term Deployment Working Group. In this case, the overnight capital cost, including contingencies, of a new advanced nuclear unit is assumed to be $1500/kilowatt initially, and to fall to $1200/kilowatt by 2020, (costs in year 2000 dollars)[94] (Table 49). The cost and performance characteristics for all other technologies are as assumed in the reference case.

Table 48. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2002 (Reference)	Total Overnight Cost			Heatrate in 2002 (Reference)	Heat Rate		
		Reference	High Fossil	Low Fossil		Reference	High Fossil	Low Fossil
	(2001$/kW)	(2001$/kW)	(2001$/kW)	(2001$/kW)	Btu/kWhr	Btu/kWhr	Btu/kWhr	Btu/kWhr
Pulverized Coal	1155				9000			
2010		1128	1134	1128		8689	8689	8689
2015		1101	1022	1095		8600	8600	8600
2020		1086	1109	1079		8600	8600	8600
2025		1080	1097	1072		8600	8600	8600
Adv. Coal	1367				8000			
2010		1320	1023	1367		7378	6799	7911
2015		1290	998	1367		7200	6104	7911
2020		1260	973	1367		7200	5687	7911
2025		1231	949	1367		7200	5687	7911
Conv Combined Cycle	536				7500			
2010		527	527	527		7056	7056	7056
2015		521	521	521		7000	7000	7000
2020		515	515	515		7000	7000	7000
2025		509	509	509		7000	7000	7000
Adv. Gas Technology	608				7000			
2010		549	549	608		6422	5717	6928
2015		513	513	608		6350	4960	6928
2020		503	503	608		6350	4960	6928
2025		494	494	608		6350	4960	6928
Conv. Combustion Turbine	409				10939			
2010		402	402	402		10450	10450	10450
2015		397	397	397		10450	10450	10450
2020		393	393	393		10450	10450	10450
2025		388	388	388		10450	10450	10450
Adv. Combustion Turbine	461				9394			
2010		391	391	461		8550	6669	9394
2015		355	355	461		8550	6669	9394
2020		351	351	461		8550	6669	9394
2025		348	348	461		8550	6669	9394

[1]. Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects initiated in the given year.

Source: AEO2003 National Energy Modeling System runs: AEO2003.D110502C, HFOSS03.D110602A, LFOSS03.D110602A.

Table 49. Cost Characteristics for Advanced Nuclear Technology: Two Cases

Advanced Nuclear	Overnight Cost in 2002 (Reference) (2001$/kW)	Total Overnight Cost[1]	
		Reference Case (2001$/kW)	Adv Nuclear Case (2001$/kW)
	2118		
2010		2044	1535
2015		1998	1380
2020		1952	1228
2025		1906	1228

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects initiated in the given year.

Source: AEO2003 National Energy Modeling System runs: AEO2003.D110502C, ADVNUC03.D110602A.

APPENDIX D

EXCERPTS FROM 2002 - 2012 ELECTRICITY OUTLOOK REPORT
CALIFORNIA ENERGY COMMISSION

CALIFORNIA
ENERGY
COMMISSION

2002 - 2012 Electricity Outlook Report

COMMISSION FINAL

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Gray Davis, *Governor*

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Executive Summary

This report assesses California's electricity system over the next ten years, focusing on supply and demand forecasts, reliability, wholesale spot market and retail prices, demand responsiveness, renewable generation initiatives, and environmental issues. Part I, Setting the Stage, includes background information to understand the electricity market developments over the last three years and a supply adequacy assessment for the next three years. Part II, California's Electricity Demand and Supply Balance, discusses how key uncertainties affect our ability to make longer-term forecasts of electricity demand, supply adequacy, and wholesale electricity prices. Part III, Issues Analyses, explores how the current state of the electricity market is affecting prospects for sustaining adequate generating capacity, retail electricity rates, the development of demand responsive loads and renewable generation, and the environmental review of proposed power plants.

Scope and Purpose

The *2002-2012 Electricity Outlook Report* is a product of the Energy Commission's ongoing responsibilities to evaluate California's electricity demand and supply and to assess electricity system issues. Its purpose is to provide the Governor and Legislature an assessment of the state's electricity system over the next ten years and information on issues impacting state electricity issues. In addition, the results of this report will be available within the timeframe needed to meet the Energy Commission's obligation, under Section 3369 of the Public Utilities Code, to coordinate with the California Consumer Power and Financing Authority's development of its Energy Resources Investment Plan. This obligation was enacted in Senate Bill Number 6X, which was signed into law by Governor Davis. (Stats. 2001, 1st Ex. Sess. 2000 - 2001, ch. 10.)

This study helps to inform generation and demand decisions that could be made within the next two years by analyzing their possible intended and unintended consequences through the rest of the decade. The study necessarily examines the entire West, but focuses on electricity market trends and issues within California.

This report provides analyses that will help identify the choices and constraints, alternatives, implications and proposed actions that will further the goal of balancing electricity system reliability, reasonable prices and environmental protection. To meet this goal in a sustainable fashion, the long-term impact on suppliers, consumers and the environment must be carefully considered. Based on current supply and demand assessments, the Energy Commission believes that the near-term outlook for supply adequacy is promising. This gives California breathing room to examine the opportunities and choices for meeting its environmental, efficiency, and renewable resource investment goals.

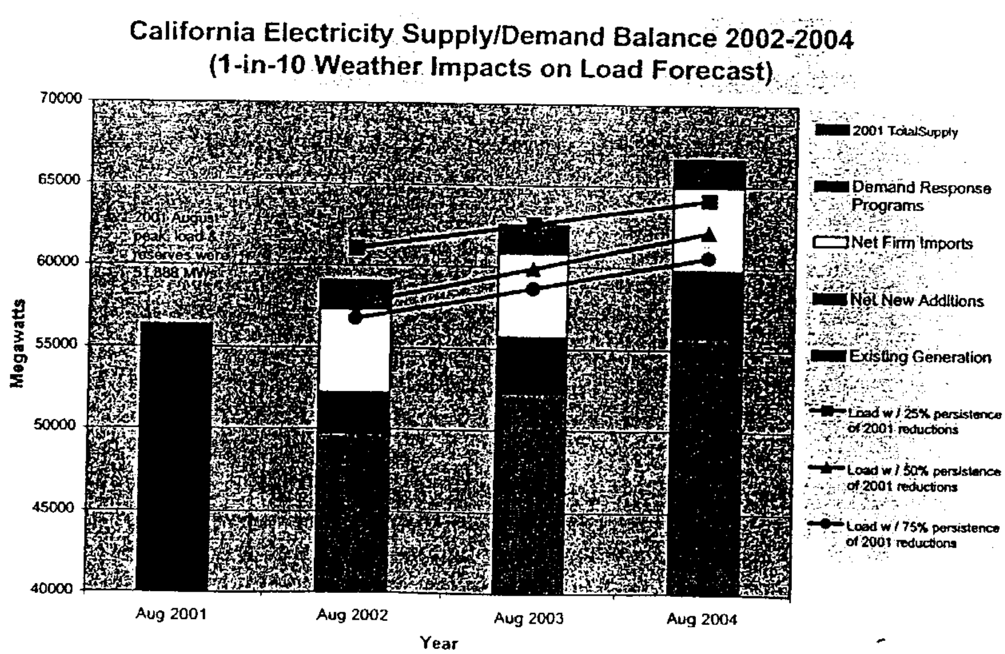
The remainder of this "Executive Summary" summarizes the analyses, findings and conclusions discussed in the report.

Part I: Electricity Market Developments - Setting the Stage

Part I summarizes the factors that have created the market volatility of the last several years and the events that have allowed the market to stabilize this summer. In addition, this chapter provides an electricity supply outlook of the expected near-term trends.

Based on the Commission's analysis, the electricity outlook for the next several years is more favorable for maintaining system reliability and moderating wholesale prices. **Figure ES-1** highlights the near-term capacity supply outlook. Although the outlook has improved for maintaining system reliability through 2004, several issues still need to be resolved. Many of the market structure changes made to avert the near-term crisis actually compromised some of the intended long-term goals of restructuring and have raised issues about the long-term sustainability of system reliability and moderate electricity prices.

Figure ES-1



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The market structure that currently exists is an *ad hoc* arrangement, created to respond to the immediate needs of the crisis that was averted. If pending electricity related financial issues are not resolved and positive steps towards fixing the market structure are delayed, California will most likely face long-term system problems. Policy makers now have to choose what market organization and market structure will best serve California. What should the new market look like? Will it still have a strong competitive flavor or will the State assume a larger role in procuring future power supplies? Does the State need to have a "reserve," and if so, what form should it take and how large should it be? These questions need to be carefully analyzed and thoughtfully addressed.

Part II: California Electricity Demand and Supply Balance

This chapter presents the component analyses comprising the overall electricity supply and demand assessment for the next decade. Chapter II-1, California Electricity Demand, examines the uncertainties associated with forecasting the California electrical system peak demand and energy requirements, given the substantial reduction in consumer demand in response to the recent electricity crisis.

Chapter II-2, Energy Market Simulations, examines the uncertainties associated with forecasting energy spot market prices and new power plant completions under a variety of supply and demand scenarios. Even with much of the energy demand served under bilateral contracts, spot market prices remain an important price signal for developers of new supply- or demand-side electricity resources. The goal of this analysis is to estimate spot market prices, which can be used to assess the likelihood of additional capacity expansion and the retirement of existing power plants.

Chapter II-3, Putting the Risks of Capacity Shortages in Perspective, presents a probabilistic analysis of the potential risks that near-term (2003) capacity resources may be inadequate to meet demand and reserve requirements. This chapter's goal is to understand how robust is the more deterministic supply adequacy assessment found in Part I. This chapter also examines the differences in supply adequacy risks among the various transmission-constrained areas of the state (this was not a feature of the Part I supply assessment).

Chapter II-1: California Electricity Demand

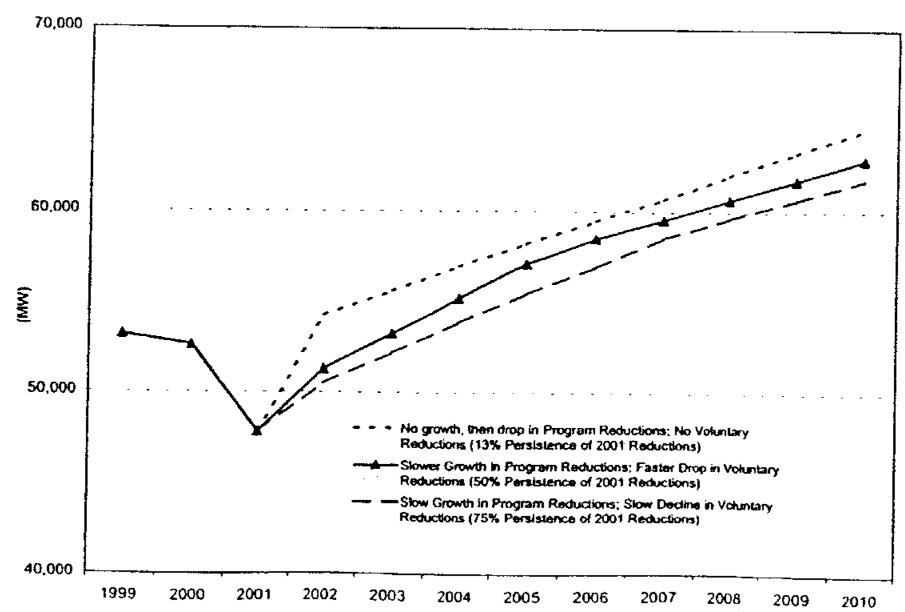
The summer of 2001 saw an extraordinary reduction in peak demand. Even though the summer of 2000 and 2001 were equally hot, actual summer peak demand in 2001 was substantially lower than in 2000. There were 29 days during the summer of 2000 when demand exceeded 40,000 MW. There were only 6 of these high demand days during the summer of 2001.

The following summarizes our analysis of expected California energy consumption over the coming decade:

- Uncertainty about future economic conditions makes forecasting highly uncertain.
- There is uncertainty regarding why summer of 2001 demand reductions occurred although electricity price increases, programs, and volunteerism are factors reducing summer 2001 demand.
- Impacts of demand reduction programs may increase slightly but, unless there are new campaigns or crises, voluntary demand reductions will likely decrease over time.
- The full impact of rate surcharges and newly legislated programs have not yet been seen.
- It is not clear what, if any, effect recent events will have on economic growth in the state — and on energy growth.

To capture this uncertainty about future electricity use, the Commission Staff developed several possible patterns of future trends for the persistence of summer 2001 demand reductions. These patterns are based on alternative assumptions about the level and persistence of voluntary impacts and permanent, program impacts (**Figure ES-2**). These three demand scenarios provide the demand forecast for the different analyses throughout this report.

Figure ES-2
California Electricity Consumption Scenarios



As well as detailed data about customer use, information is needed to determine why customers did what they did. Surveys need to be done to analyze how much of the reduction was due to customer behavioral and permanent response to legislated programs, how much was due to media campaigns, and how much to other factors. A better understanding of 2001 will reduce some of the uncertainty in the projections of future demand reduction.

Chapter II-2: Energy Market Simulations

This chapter presents five different scenarios simulating the wholesale spot market for electricity. The goal of this analysis is to obtain estimates of spot market prices, which can be used to assess the likelihood of additional capacity expansion (beyond what is already very likely to occur) and the retirement of existing power plants. The scenarios are differentiated by their assumptions about demand growth and new power plant additions during the next four years. The assumptions that characterize each scenario are discussed in detail. The simulation results are presented and discussed, including the spot market prices yielded by the five scenario simulations and the impact of power plant additions on the hours of operation of new combined cycles, peaking units, and the older and larger gas-fired plants. The chapter concludes with a discussion of the implications of the findings for the construction and retirement of capacity during the second half of the decade.

The long-term power contracts signed by the California Department of Water Resources to supply customers of the three largest investor-owned utilities, together with energy from utility-owned nuclear and hydroelectric generation and QF contracts, greatly reduce the share of energy to meet IOU customer demand purchased in spot markets. Accordingly, spot market electricity prices will play a significantly smaller role in determining the wholesale cost of energy for IOU customers. Spot market prices will continue, however, to have a major influence on the decisions to build new generation capacity and to retire existing facilities.

Low spot market prices, those that do not result in profits high enough to warrant investment in new plants, deter capacity expansion. If low enough, spot prices encourage the retirement of plants that cannot cover operating costs. High prices signal the need for new capacity and its profitability. Our results tend to indicate that the addition of expected new capacity during 2002 - 2005 is apt to drive spot market prices to levels that will render many existing power plants unprofitable and discourage further construction. However, there are factors that may encourage building even in the face of low prices in the short-term.

The simulation results also indicate that low prices from 2003 onward may be an incentive to retire existing units. It is unlikely, however, that a substantial amount of capacity will be completely retired and dismantled in the WSCC during 2002 – 2004. Uncertainties related to the amount of new capacity coming on-line, the return of electricity demand to previous trend levels, and regulation and market structure will contribute to uncertainty regarding spot market electricity prices, and discourage the closure of generation facilities. Owners are apt to incur the costs required to keep less-efficient plants available for operation given the *possibility* of adequate revenues during the next couple of years, if not long-run profitability. Low prices in 2003 and 2004, would lead to reduced operation for many plants. This reduction in their competitiveness will encourage their placement into long-term reserve, and increased consideration being given to their retirement

As gas-fired power plants become an increasingly large share of the generation resources in California and the WSCC, the price of natural gas will have an increasingly larger role in determining the spot market price of electricity.

Overbuilding and delays in retiring older facilities are part of a "boom-bust" dynamic that is an inherent part of the structure of the market. The amplitude and length of these cycles cannot be known in advance, but must be considered in market design.

Chapter II-3: Quantifying the Risk of Capacity Shortages

Generally, the power system is said to have adequate capacity if it has enough generation and transmission resources to meet the customer demand and to maintain a reserve of capacity for contingencies. But it would be prohibitively expensive to build an electric generation and transmission system that would *never* experience a service outage. Instead, we seek to minimize outages within a constraint of reasonable cost, thereby accepting some risk of outages.

The goal of this chapter is to understand how robust is the more deterministic supply adequacy assessment for 2003, found in Part I, by applying more probabilistic risk assessment techniques. In doing so, we illustrate the risk issues that are central to the questions: What risk of supply shortages are we facing in the near term? Do we have "enough" capacity? How much additional risk will the next increment of capacity avoid? What are our options for managing the risk, and how do their risk management performances compare? In addition, the risk assessment in this chapter examines the differences in supply adequacy risks among the various transmission-constrained areas of the state, which was not a feature of the previous supply assessments.

This chapter specifically illustrates how uncertainties associated with specific key risks that affect supply adequacy contribute to the overall risk of supply shortages. (By "shortage" we mean failing to maintain a seven-percent reserve; we do not mean experiencing a service outage of firm load.) We assessed one demand-side risk to supply adequacy: the effect of temperature variations on peak demand. We assessed three supply-side risks: the effect of hydrological conditions on the availability of hydroelectric generation capacity, the effect of potential construction delays on the availability of new power plant capacity, and the effect of aging on the rates at which generation and transmission facilities are forced out of service. We selected the summer of 2003 as the time period to illustrate the risk assessment because the supply balance was tightest that year and sufficient time remains to take additional action, should that be warranted.

Generally we have found that our probabilistic risk assessment gives us a measure of confidence in the near-term supply adequacy outlook in Part I. Although this work does identify the *possibility* of shortages in excess of those identified in Part I, the probability of their occurrence is generally small. The risks of power supply shortages in 2003 vary for different parts of the state: from little to no risk for Northern and Central California and the largest municipal utilities- LADWP and SMUD, to low risk (about 1 percent) for Southern California, to a noticeable level of risk (7 percent) for San Diego, and to a significant level of risk (about 14 percent) for San Francisco.

Depending on the cost to society of such shortages, actions in addition to those anticipated in the Part I near-term supply analysis might be taken (and their associated expense incurred) to avoid the additional risk of shortages. A cost-benefit analysis of available "supply adequacy insurance" options has not been attempted in this report. However, we do make the case that, if supply adequacy insurance is sought, then the full range of demand- and supply-side options for mitigating that risk should be considered.

Part III: Issues Analyses

This part presents discussions and analyses of a variety of issues important to the development of a workable electricity market. Chapter III-1, Electricity Markets and Capacity Supply, deals with the fundamental question of how well the existing energy market can be expected to maintain the adequacy of the electricity system at reasonable prices, and what market changes might better achieve that goal. Chapter III-2, Retail Electricity Price Outlook, provides an assessment of future retail electricity rates by utility and customer class, showing how the various components of costs each contribute to the total rate. Chapter III-3, Developing Demand Responsive Loads, examines the characteristics of the demand response potential, and suggests a specific mix of load curtailment programs to ensure reliability in the year 2002. Chapter III-4, Effects of Renewable Generation Initiatives, discusses how recent events and the current *ad hoc* market arrangements have affected the renewable generation industry and issues related to incentive programs for developing renewable generation resources. Chapter III-5, Siting Issues, describes the progress the Energy Commission has made in licensing new power plants, issues that may affect the ability of power plant developers to obtain timely approval; and measures needed to address these siting issues.

Chapter III-1: Electricity Markets and Capacity Supply

This chapter examines what structure will motivate the addition of timely new supply to reduce price volatility and contribute to reliable service. Three options for revising the supply market for capacity are introduced and evaluated. This chapter also finds that modifications to retail pricing and to the wholesale market are also necessary for a sustainable generation market. Unless modifications are made, by 2005 California will be headed back into supply and demand conditions likely to produce tight supplies, price volatility, reliability concerns, and consumer dissatisfaction.

Choosing a method to ensure future adequate supply, is a major element of the 2002 market redesign. Tight capacity supplies were one of the principal conditions that allowed the California market to destabilize. The current market structure must be changed, because it cannot produce adequate generation in a timely and efficient manner. Under the current market structure California is doomed to boom and bust cycles, price spikes, price volatility, and higher prices due to the need to hedge against the risks inherent in a faulty market design. A good market design will provide benefits to consumers and suppliers, allow for efficient market monitoring, reduce the need for government intervention, and promote competitive innovation. Policy-makers now have to choose what market structures will best serve California.

Three supply designs are evaluated: incentive payments for reserves, installed capacity requirements and a regulated, cost-of-service capacity reserve. Of the three, the installed capacity requirement is the most promising. But its actual effectiveness is dependent on complicated implementation rules. Hundreds of millions of dollars are at stake in these design details. Further exploration is needed to determine the most effective capacity payment options

The wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of price responsiveness in the retail market. Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability.

Generation adequacy will be facilitated if the wholesale day-ahead, hour-ahead, and real time spot markets use commercial models that reflect physical constraints and efficient dispatch. Generators must have an obligation to perform according to schedules. Accurate locational prices are needed.

The market structure must be compatible with other market designs in the Western United States. California is an integral part of a regional market. A coherent market design will need to be advocated in multiple forums, including FERC, the ISO, CPUC, CPA, and DWR. New California laws will be needed to facilitate a new design.

Chapter III-2: Retail Electricity Price Outlook

This chapter presents the Energy Commission's outlook of electricity retail rates for California Investor- and Publicly-Owned Utilities for the years 2002-2012. In this outlook, the Commission provides estimates of the retail electricity rates that typical consumers may pay, given projected energy prices, utility plans and programs, and regulatory decisions. This outlook provides consumers, market participants, and policy makers with a basic understanding of the determinants of future electricity rates.

This outlook is not an absolute prediction of what the future electricity rates will be, since future regulatory actions, technology development, or market changes may alter key fundamental assumptions. Retail electricity rates detailed in this chapter reflect the best available information to Commission staff up to mid-November 2001 and a set of assumptions the authors believe probable and realistic. Since then, the California Public Utilities Commission has rendered some decisions that have a direct impact on the IOU price outlook. In addition, Southern California Edison provided comments and data to Commission staff that could also change the outlook. The Commission has directed the Staff to incorporate relevant data and information in an update of retail electricity prices within the next two months.

Under the circumstances specified in this chapter, retail rates for investor-owned utility (IOU) customers will most likely increase in the 2002-2003 period. A rate decrease is unlikely, unless the Federal Energy Regulatory Commission (FERC) orders merchant generators and energy traders to refund the State utilities for overcharges incurred during the fall 2000 and the winter 2001. However, a small rate decrease is possible after 2003 for most IOU customers. Municipal utilities are likely to maintain constant retail electricity rates for their customers during the 2002-2003 period. Rates for municipal customers after 2003 would most likely reflect the utilities' cost of generation, which under current projections will increase slightly every year through 2012.

Future retail electricity rates for the IOUs depend to a certain extent on the regulatory decisions of the FERC, the State Legislature, the Governor, and the CPUC, rather than the spot market prices. Most of the IOU electricity rate components are relatively set for the next ten years. Therefore, major rate fluctuations are unlikely.

Because municipal utilities have long-term contracts for energy, their rates depend more directly on the price of natural gas and to some extent the need to replenish their rate stabilization funds.

Chapter III-3: Developing Demand Responsive Loads

This chapter discusses the characteristics of the demand responsive potential, and suggests a specific mix of load curtailment programs to facilitate ensuring reliability in the year 2002. As Chapter III-1 of this report noted, the wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of the retail market. Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability. Further, in assessing the tradeoffs between demand response and peaking generators, the Commission believes that large amounts of DR loads can be acquired that are cheaper than peaking generators. This chapter assesses different types of demand responsiveness options and recommends pursuit of an aggregate capability of 2,500 MW through new and/or revised program designs.

Reducing exposure to excessive market prices is likely to be more cost-effective through time than avoiding markets entirely by relying upon command and control decision-making. Reducing exposure is not the same as eliminating exposure. Reducing exposure to excessive prices admits that an occasional dose of high prices in the right circumstances might be the most cost-effective way to satisfy net electricity demand with generation.

Demand response can come from real-time price (RTP) tariffs or dispatchable load curtailment programs that enable end-users to respond to market prices or to adverse system conditions by reducing loads, respectively. Customers on real-time price tariffs either save money by reducing consumption in high-priced periods or shifting loads from high- to lower-price periods. Customers on load curtailment programs respond to incentives to reduce loads when system conditions trigger load curtailment program operation. Both forms of demand responsiveness reduce loads when market prices and/or system conditions warrant this action.

Much remains to be determined about end-users' willingness to participate in demand responsive programs and tariffs. Unfortunately, we learned nothing in the summer of 2001 except that constantly changing program designs create great confusion in end-user minds and greatly increases the difficulty of marketing any programs. Our experience base with end-user response to demand responsive programs and rates is simply insufficient to be able to guarantee response. However, recent experience shows that at least some customers are perfectly willing to trade off reliability for reduced costs. Making short term commitments to load curtailment programs achieves the overall goal of 2,500 MW of demand responsive capability, and can lead eventually to greater reliance upon RTP tariffs and less reliance upon load curtailment programs. The Energy Commission has already proposed specific modifications to two existing, CPUC-authorized load curtailment programs that would enable this 1,000 MW of increased load curtailment program capability to be achieved.

Chapter III-4: Effects of Renewable Generation Initiatives

This chapter discusses renewable energy issues arising from the recent changes in the electricity market conditions. Despite substantial Energy Commission *contingent* funding for new renewable facilities through the Public Goods Charge, the current absence of a market for the output of those facilities is threatening the long-term viability of the renewable industry. The Commission's Renewable Energy Program presently has agreements to provide production payments to 1,300 MW of new renewable capacity, *but only after projects come on-line.* How much of that capacity comes to fruition, however, is dependent on whether project developers can find a buyer for their power.

As a result of the electricity crisis, the market opportunities available to renewable facilities have been dramatically altered. The Power Exchange has disappeared. Utilities are either unable or unwilling to buy. Direct Access has been suspended, so selling to a "Green" Electric Service Provider is no longer an option. The Department of Water Resources contracted for only small amounts of renewable energy, and has ceased making long-term commitments. The newly created Power Authority is not yet in a position to finance or acquire renewable resources.

There are a number of activities underway in various forums that could potentially alleviate the no-market dilemma. The Legislature may enact a Renewable Portfolio Standard, the California Public Utility Commission's current utility procurement proceeding could result in a renewable purchase requirement, a renewable-only form of direct access may be restored, or proposals emanating from the California Consumer Power and Conservation Financing Authority might provide a remedy. But until suitable buyers for renewable energy materialize, there will continue to be a cloud over the future development of new renewable facilities.

The legislation extending the Energy Commission's renewables program stated renewables would add needed generating capacity while promoting diversity and reducing the need to burn fossil fuels. The Energy Commission has established a target of meeting 17 percent of California's energy demand with renewables by 2006. To respond effectively to changing conditions, the Energy

Commission needs to maintain its flexibility in determining the allocation and distribution of funds for its efforts in renewable energy.

Chapter III-5: Siting Issues

In response to the energy crisis, the Energy Commission has taken steps to expedite the licensing of new power plants. This chapter discusses these recent changes to the licensing process, current trends in licensing power plants, the interactions of transmission constraints with power plant licensing, the outcome of the new expedited review process, and remaining constraints to power plant licensing. This chapter finishes with suggestions to help alleviate some of the licensing constraints.

During the electricity emergency, the Energy Commission was successful in bringing new capacity on line by conducting early site screening for the emergency projects, assisting developers in processing project compliance amendments, and overcoming roadblocks to completing construction.

The Energy Commission will support efforts to improve planning for new generation and transmission lines to address congestion, system reliability and efficiency issues. Forecasting the electricity supply and demand balance requires more than a calculation of demand and supply. It also requires the assessment of the locations of demand increases and of new generation resource additions to avoid local transmission system congestion and generation deficiencies. Integrated electricity planning, which considers both transmission and capacity solutions should continue so the most economically efficient and reliable supply/demand balance has a better chance of being achieved.

The Energy Commission will continue to support consolidation of transmission line permitting in California. Although the Energy Commission licenses transmission lines needed to interconnect a power plant under its review to the transmission system, other transmission projects are permitted by multiple agencies. The overlap, inconsistency and inefficiency created by such permitting pose potential constraints to expedited licensing of new generation and transmission projects.

Environmental and permitting issues potentially constrain the Energy Commission's ability to site new capacity additions efficiently without resulting in contested proceedings or potentially significant adverse impacts. These issues include the availability of emission offsets, water supply and water quality impacts, the timing of federal permits, land use conflicts, transmission congestion, and natural gas supply constraints. Working with other agencies, the Energy Commission directs its Policy Committees and Staff to provide guidance or assistance regarding these constraints on licensing new capacity.

Part I Electricity Market Developments – Setting the Stage

Part 1 summarizes the factors that created the volatile electricity market fluctuations of the last several years. It describes the market volatility since 1996, actions taken to stabilize the market in the summer of 2001, the electricity supply outlook for expected near-term trends, and long-term considerations for maintaining a reliable, reasonably priced, and sustainable electricity system.

Market Volatility Since 1998

Assembly Bill 1890, Monopolies to Competition

The California Legislature passed Assembly Bill 1890 (AB 1890 – Statutes of 1996, Chapter 854) to restructure the electricity industry. The State restructuring law dramatically changed the market system that was in place for more than eighty years for serving the electricity needs of California homes, businesses, industry and farms. AB 1890 establishes the Legislature's intent to:

- Ensure that California's transition to a more competitive electricity market structure allows its citizens and businesses to achieve the economic benefits of industry restructuring at the earliest possible date.
- Create a new market structure that provides competitive, low-cost and reliable electric service.
- Provide assurances that electric customers in the new market will have sufficient information and protections.
- Preserve California's commitment to developing diverse, environmentally sensitive electricity resources.

AB 1890 made fundamental changes to the structure of the electricity market to increase reliance on competitive market forces. Municipal utilities were not required under AB1890 to participate in the restructured electricity market and most continue to serve the needs of their customers by generating their own power or with other market transactions initiated at their own discretion.

One of the intended features of electricity industry restructuring in California was that consumers who previously purchased electricity from investor-owned electric utilities could then choose their electricity provider. AB 1890 also created a new market structure featuring two state-chartered, nonprofit market institutions. The Power Exchange (PX) was charged with providing an efficient, competitive auction to meet electricity loads of exchange customers, open on a nondiscriminatory basis to all electricity providers. An Independent System Operator (ISO) was given centralized control of the investor-owned utilities' transmission grid and charged with ensuring the efficient use and reliable operation of the transmission system. These evolving market institutions and merchant facilities presented new and different issues for policy makers.

Market Transformation

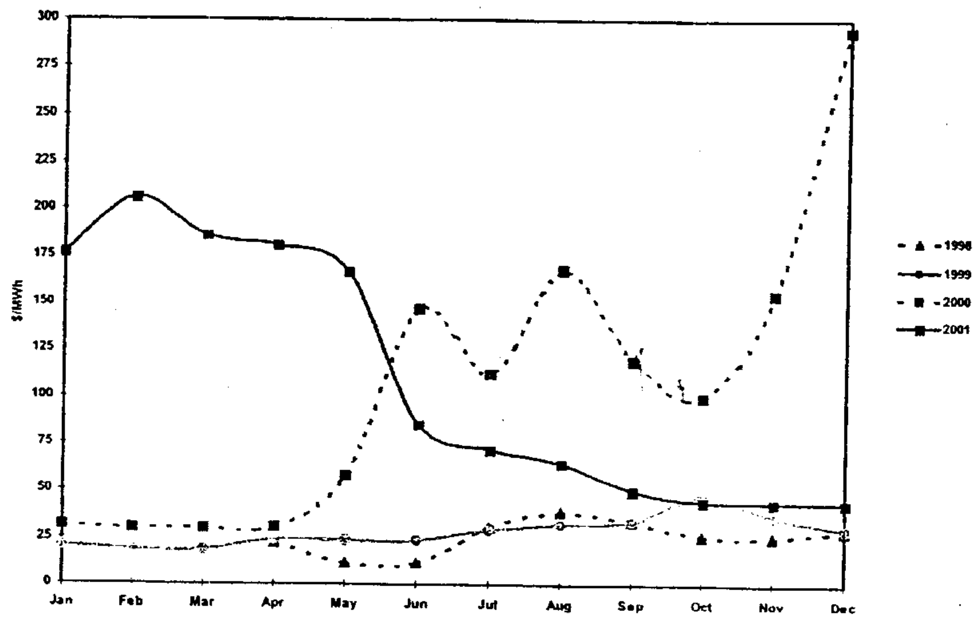
The restructured electricity industry took form in early 1998 and the new market appeared to be off to a good start. Wholesale electricity prices initially tracked expectations averaging $33 per megawatt-hour, which was close to the marginal cost of power production. Unfortunately, many implementation problems developed over time to jeopardize the original goals of establishing a competitive electricity market. Ultimately, these unanticipated problems escalated to "energy crisis" levels in 2000, inducing serious near-term financial and reliability risks throughout the West. Whatever the causes, California's efforts to substitute competition for cost-based regulation in the generation sector of the electricity industry have fallen substantially short of expectations.

Market occurrences in 2000 raised serious questions about the ability of the market structure to provide affordable and reliable electricity supplies for California's residents and businesses. Electricity market problems include the following:

- Extremely high electricity costs,
- Decreased reliability in the form on ISO Emergencies and rotating outages,
- Very high profits by generators and wholesale power sellers,
- Large debt incurred by utility distributions companies on behalf of retail customers, and
- Large amount of revenue flowing from California consumers to a few sellers.

Wholesale electricity cost the ISO's customers $27.1 billion in 2000, more than triple the amount spent during 1999 ($7.4 billion) and five times 1998 expenditures ($5.5 billion, excluding the first quarter)[1]. The estimates include the costs for Power Exchange energy, bilateral contracts, real time purchases, and ancillary service requirements; these estimates, however, do not include any additional costs that other California municipal utilities incurred over the period. **Figure I-1** shows the average monthly wholesale costs incurred in 1998 through the first half of 2001. Average costs significantly declined in 2001 as the market stabilized.

Figure I-1
Monthly Average CAISO Wholesale Electricity Costs
($ per MWh)



Sources: 1998-1999 Power Exchange Market Clearing Price
2000-2001 ISO Market Analysis Report, Sept 20, 2001

Most retail customers have not seen the high wholesale costs reflected in their monthly bills. Customers of the investor-owned utilities (IOUs) had their rates frozen as part of the overall legislative design for restructuring. During the summer of 2000, the electricity that the utilities purchased in the Power Exchange doubled and then even tripled in price. Because of the rate freeze, the utilities could not pass these expenses to their customers, leaving PG&E and Edison with negative balances in their revenue accounts. PG&E ultimately declared bankruptcy on April 6, 2001. Although Edison is in the same situation as PG&E with a revenue deficit approaching $3.8 billion dollars, the utility has been working with the California Public Utilities Commission to solve its problems without declaring bankruptcy.

The severe and volatile price fluctuations that occurred in 2000 and 2001 affected consumers and other sectors of the state economy. The results of the energy crisis ultimately brought about a public outcry for change. To address the energy crisis, the Legislature implemented a number of changes to restructure the electricity market, but some of these changes compromised some intended goals of AB 1890. For example, customer choice opportunities provided by direct access and the transparent pricing system that the Power Exchange provided have been terminated.

Causes of Market Problems in 2000-2001

During the debate about the cause of California's electricity problems, some have argued that price volatility is an inevitable characteristic of markets run by the ISO and Power Exchange. From this perspective, high prices experienced in electricity markets in 2000 were not a totally unexpected phenomenon. It is true that periods of price spikes and supply shortages are common in commodity markets, particularly in markets like electricity that require significant capital investments. Collapsing prices and excess supplies have historically been common in such markets as well.

Commodity markets use high prices to induce investments in new production capacity. Generally speaking, rising prices from shortages of capacity encourage the construction of new power plants and/or expansion of existing facilities. In most markets, as these additional resources come on-line, prices tend to decline. As a consequence, idle capacity may lead to temporary plant shutdowns, and investors planning to construct new facilities may defer those plans to await higher prices.

However, the electricity market may be inherently different from other commodity markets due to a number of factors. First of all, electricity is a critical service to maintain public health and safety. Furthermore, the generation, transmission and distribution system is complex given the physical reality that coordination of the system is absolutely critical.[2] In addition, the demand for electricity is highly variable due to the weather changes, which can exacerbate the cyclic nature described above. Another distinguishing characteristic of electricity markets is the limited ability to store or stockpile the product. Large inventories help other markets control exposure to wide price swings.

Notwithstanding the nature of commodity markets, many entities have concluded that flaws in market design and rules are a major factor in the excessively high prices for electricity.[3] Some of the major flaws in the market structure and rules that have been identified include the following:

- Sole reliance on the Power Exchange spot market to meet demand and balance reliability needs,
- Exercise of market power to raise wholesale electricity costs,
- Lack of demand responsiveness,
- Out-of-market purchases above price caps,
- Limited ability of the utilities to use forward contracts,
- Conflicts of interest for the ISO Stakeholder Board, and
- Unintended consequences of RECLAIM on the electricity market.

Other factors such as weather conditions, tight supplies, increased costs of natural gas and high emission credit prices also contributed to higher costs for electricity this summer. These other factors alone do not adequately explain the levels of prices seen in the ISO and Power Exchange markets from the summer of 2000 through the winter of 2001.

Supply Adequacy Developments

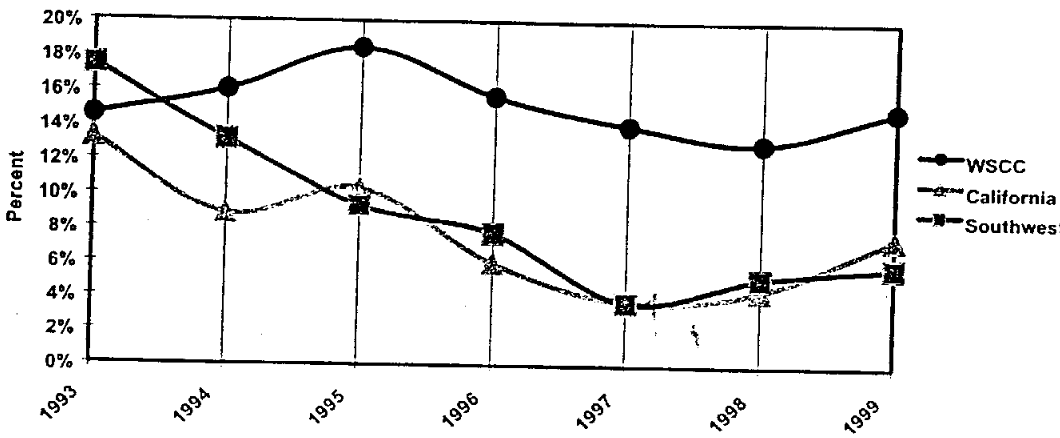
The nation's economy expanded throughout the 1990s. Likewise, so did the electricity consumption in the Western United States. Because power plant development did not keep pace with load growth, reserve margins throughout the Western Systems Coordinating Council (WSCC) and especially in California declined over time. A reserve margin is the percentage of extra generation capacity available at a moment's notice and used by the system operator to adjust for fluctuations in load or other contingencies. Potential problems include a plant going off-line or a transmission line being unexpectedly unavailable.

Figure I-2, shows the peak reserve margins for California, the Southwest and for the WSCC as a whole. The recorded reserves include operational generation, not those facilities that were down for maintenance. While the entire WSCC has maintained double-digit margins, both California and the Southwest had declining reserve throughout the 1990s.

Current reserve margins are not included in **Figure I-2** since the method for calculating the margins that the ISO now reports each day differs from the WSCC estimated peak reserves. The ISO daily reserves are a function of the generation that is contractually scheduled for dispatch and does not measure the actual physical availability of total generation in the system. The ISO scheduled reserve margins dropped below 1.5 percent several times during the 2000/2001-winter period. Part of the reason why reserves dropped to this level was due to financial concerns.

California's rate of load growth was matched by load growth throughout the WSCC. One effect was that a relatively large pool of non-firm capacity, once available on the spot market had begun to dry up. This capacity had enabled California to meet increasing load growth without building new matching capacity.

Figure I-2
Non-Coincident Peak Demand Reserve Margins
1993-1999



Source: Western Systems Coordinating Council, *10-Year Coordinating Plan Summary 1999-2008*, October 1999.

In 1999, the Energy Commission issued a study known as the "Heat Storm" report[4]. Staff predicted that California would face a statewide capacity short fall on the order of 5,000 MW during the summer of 2000 and 2001, based upon a 1-in-10 hot year scenario. Other agencies such as the ISO said that shortages, including rotating outages, were inevitable. A similar capacity shortage was expected on a WSCC region-wide scale. The market appeared to be responding as plant developers throughout the west submitted licensing applications to build new generation facilities. Even though the market did respond to the peak-time-capacity shortage, it was too late to avoid a short-term crunch since power plants take years to bring on line.

The rotating outages that occurred in December 2000 and again in February and March 2001 were attributable to several factors, especially that a larger-than-normal amount of capacity that was not generating. As a rule, generators plan to do maintenance and repairs during the fall and winter because the demand is less and prices are lower. A much higher amount of generation capacity was unavailable during this period. Other factors contributing to outages were generating units being down for retrofits of emission controls. Less power was available for imports to California from other areas of the Western Systems Coordinating Council region as a result of high demand growth and declining reserve margins in these areas. Many Qualifying Facilities were not paid as a result of the IOUs experiencing cash flow problems, and thus these facilities were not producing electricity. **Table I-1** provides a summary of the statewide outages that occurred over the past several years.

Table I-1
Monthly California Generation Outages

	Outage (MW)			
	Minimum Daily	Maximum Daily	Monthly Average	Recorded Peak Demand
1999				
Jan	2,116	3,829	3,180	36,892
Feb	2,416	6,980	5,067	36,490
Mar	3,963	6,196	5,311	36,143
Apr	3,810	6,973	5,647	35,742
May	1,495	4,617	2,839	39,309
Jun	411	1,952	1,290	47,420
Jul	719	1,630	1,031	53,392
Aug	777	1,507	931	50,347
Sep	777	1,955	1,045	44,904
Oct	447	3,037	1,636	44,871
Nov	1,778	3,832	2,817	37,841
Dec	1,525	3,381	2,463	39,689
2000				
Jan	1,279	3,687	2,228	37,922
Feb	2,324	3,962	3,244	37,068
Mar	1,790	5,307	3,265	37,260
Apr	1,611	4,387	3,203	38,351
May	2,346	5,805	3,872	46,898
Jun	1,660	3,806	2,784	52,480
Jul	1,273	3,564	2,253	52,608
Aug	1,960	3,532	2,680	51,945
Sep	2,754	5,049	3,621	52,367
Oct	2,731	10,457	7,478	41,513
Nov	7,851	13,020	10,343	38,679
Dec	7,114	14,014	8,988	39,679
2001				
Jan	6,894	15,846	9,940	38,811
Feb	7,985	12,744	10,895	36,497
Mar	12,510	16,088	13,737	35,156
Apr	12,744	17,558	14,911	36,017
May	10,533	16,383	13,431	43,458
Jun	4,821	11,787	6,758	47,175
Jul	3,146	7,845	5,044	46,566
Aug	3,069	6,205	4,229	48,066
Sep	3,132	7,501	5,278	44,649
Oct	6,132	10,580	8,905	45,923
Nov	9,046	14,847	12,199	36,768
Dec	7,806	14,441	11,112	38,741

*Includes both forced and planned outages

The electricity outages disrupted activities at businesses, schools, and residences. Traffic was snarled by inoperative traffic signals. Realizing the potential for serious consequences, the ISO made a concerted effort when enacting the outages to minimize the affect on critical services, such as hospitals and emergency support services. These outages came in the fall and winter, during the off-peak period. As such, these outages served to illustrate that a large potential existed for frequent rotating outages during the summer of 2001.

Actions to Mitigate Market Volatility

The consequences of the energy crisis were due to flaws in the market design and electricity system infrastructure limitations. It became clear by December 2000 that stronger government involvement was required to protect the interests of California citizens. To address this need, the Governor developed an energy plan and numerous Legislative bills were passed to stabilize the market. The California Independent System Operator also worked with stakeholders to resolve a number of market design problems. The Federal Energy Regulatory Commission later imposed a number of changes to the market structure to mitigate price and reliability problems. These structural changes, together with the negotiation of new long-term contracts, increased electricity generation facility construction, mandated efficiency programs and reduced energy consumption patterns have moderated the market volatility that was anticipated for 2001.

Governor Gray Davis responded to the market challenge by announcing the primary components of the Energy Stabilization Plan in February 2001. Part of the plan involved issuing a series of executive orders designed to accomplish two objectives: increase near-term supply availability and decrease peak demand. Considering that the Energy Commission identified a 5,000 MW gap between demand and supply, the Governor established two teams, a Generation Team and Conservation Team, to address the problem.

Using a multi-faceted strategy, the Governor's Generation Team put forth a plan designed to use every possible megawatt out of the system. This entailed boosting output from existing plants, restarting other plants that were in short-term retirement, accelerating the review process for plants under consideration and providing incentives to developers to bring plants online sooner than planned.

A number of private and public entities, at all levels of government, cooperated and coordinated the plan. Many lessons were learned along the way. The Generation Team was successful because it attacked the capacity gap problem with the assistance of these entities and a broad set of key players in the electricity market.

The other major effort to bridge the gap was to encourage consumers to reduce electricity demand. The Conservation Team addressed the problem from several different angles. Voluntary conservation was encouraged through public service announcements on radio and television. Californian's were asked to "Flex your Power" by eliminating unnecessary uses of electricity and shifting certain electricity uses, such as doing the laundry, to off-peak times. One of the most successful programs, known as "20/20,"used the promise of a 20 percent rate reduction to those consumers who reduced their electricity demand by 20 percent or more. Californians did "Flex" their power by reducing electricity demand more than 4,828 MW in July 2001.

Other conservation programs were enacted by special legislation such as SB5X, AB29X, and AB970. The legislation employed a variety of methods to reduce consumption, such as time-of-use/real-time meters, rebates for more efficient air-conditioners and appliances, cycling on/off of HVAC systems, replacing traffic signals with more efficient LED type. State Office buildings and public universities were required to reduce HVAC costs by 2 percent. Another significant source of electricity use reductions came from the ISO and CPUC interruptible programs where consumers are given a better rate if they agree to have their power interrupted at times of peak demand. All of these programs, along with the impacts of other voluntary reductions and rate increases, combined to save 7,613 MW.

Federal actions were also taken to mitigate market problems. Electric generation prices paid in the spring and summer of 2001 were as much as 100 times greater than in 1999. Consumer advocacy groups made allegations of unfair market practices and gaming. California was not the only market affected, soaring electricity prices were being paid throughout the WSCC. Prices rose so high that governors of several western states joined Governor Gray Davis in petitioning the FERC to impose WSCC-wide wholesale price caps. After refusing to do so on several occasions, the FERC finally agreed in June 2001 to impose price caps whenever the ISO declares a state of energy emergency (Stage 1 or higher).

Summer of 2001 Developments

Summer 2001 came and went and the power stayed on despite many predictions that the market would continue to be volatile. What happened? Was there ever a real crisis? Or were we saved by the mild weather? Even though the summer of 2001 was a relatively hot summer, as hot as 2000, analysis has shown that Californians pulled together and reduced demand far in excess of what could be expected historically under those weather conditions. It was the culmination of many efforts that "kept the lights on."

Conservation programs and new interruptible power programs created permanent peak load reductions. California consumers heeded the call to reduce demand during peak demand periods.

As implemented, the Governor's Energy Stabilization Plan also had a real measurable effect. A number of new state-of-the-art generation dedicated to California load was brought online this year. Restrictions on how some peaker plants operated were modified. There were 42 projects representing 2,236 MW of new generation that became operational through October of 2001. About 60 percent of these new additions include four large generation facilities that were licensed by the Energy Commission. The other additions include California Independent System Operator peaker projects, several biomass projects coming back online, a peaker facility approved by the Energy Commission, new renewable facilities, and re-rate projects.

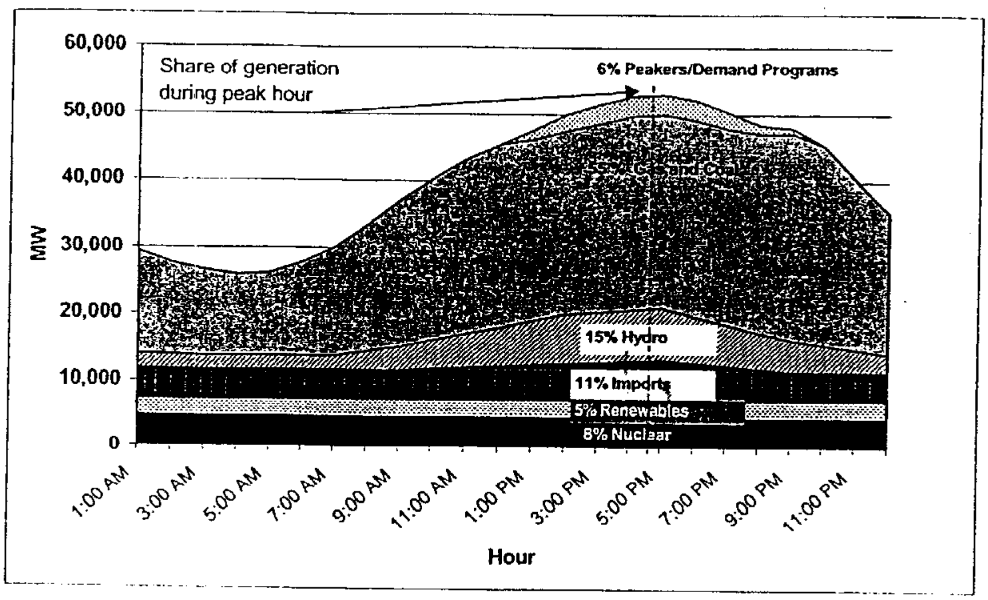
Figure I-3 illustrates the electricity supply and demand profile for a typical hot California summer day. This figure demonstrates the importance of demand responsiveness programs, photovoltaic technology, and load management programs and, if necessary, peaking power plants for providing peak capacity resources for a short amount of time during high demand periods. There is generally sufficient generation capacity available during the shoulder and off-peak periods on a hot day with a one-in-ten probability of occurrence. Demand reduction, photovoltaics technologies and load management programs can also help to reduce the need to produce electricity during the critical peak periods.

Other factors, which did not stem from the Governor's plan, contributed to keeping the lights on during the summer of 2001. Natural gas prices began to fall which lowered generator costs. The Department of Water Resources had firmed-up a large amount of capacity by signing a variety of short-term and long-term contracts, and as a result the price volatility in the spot market declined. Wholesale price caps also factored into decreased price volatility. BPA also agreed to increase generation from its hydro facilities.

Near-term Electricity Supply Outlook

Demand reduction by California's electricity consumers and new generation sources averted predicted outages during the summer 2001 and brought market stability. The electricity supply outlook for the next several years is even more favorable for maintaining reliability and moderating wholesale market price fluctuations. The assessment is based on the assumption that many of the market-related problems that exacerbated the earlier supply problems will be successfully resolved.

Figure I-3
The Electricity Supply and Demand Profile
For a Typical Hot Summer Day



The staff anticipates the addition of 2,703 MW of new generation that have a 75 percent probability of becoming operational by August 1, 2002. This includes renewable projects sponsored by Energy Commission programs. The new generation additions considered for 2002 are already under construction and should be operational to meet the upcoming summer peak demand. There is also a significant amount of new generation capacity that should be operational throughout the West and be available for spot market sales to California.

Predicting the amount of additional new generation development will become more uncertain after 2002. Although there are several thousand megawatts of new power plant capacity currently under review in the Commission's siting process, owners of the plants may decide not to proceed immediately with construction for a number of reasons. For example, the increase in the number of new generation capacity that will become operational in 2002 may depress spot market prices below the level needed by potential new generators to recover their revenue requirement. Because of this possibility, the availability of surplus power beyond firm commitments was not factored into this assessment.

Table I-2 provides a list of probable generation additions over the next several years. Most of these projects are currently under construction or have

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committed to financial agreements for development. Although there are many more projects under review in the Commission's siting process, only a small fraction of these applications are conservatively considered to be available in the forecast period.

Table I-2
Expected Net new Generation Additions

Year	Status	New Generation
2002	Construction	2,538
	Financing	0
	CEC Review	0
	Renewables	165
	Sub Total	2,703
2003	Construction	2,997
	Financing	77
	CEC Review	391
	Renewables	55
	Sub Total	3,520
2004	Construction	2,687
	Financing	1,070
	CEC Review	360
	Renewables	0
	Sub Total	4,117
2002-2004	**Total MW**	**10,340**

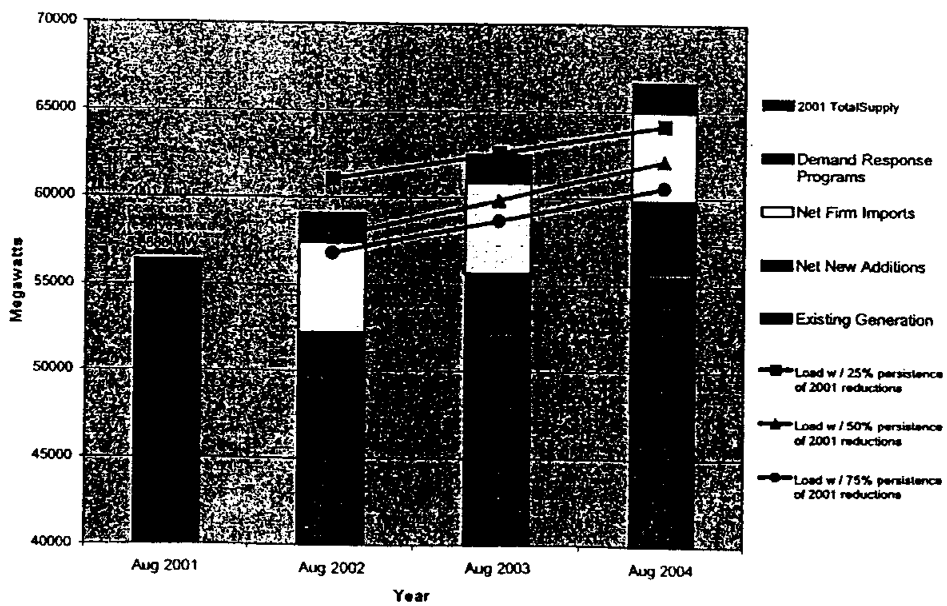
California electricity peak demand levels generally fluctuates with summer temperature variations. Air conditioning contributes to a large portion of the California summer peak demand. Using historical temperature data collected since 1959, the Commission staff classifies temperature conditions according to their probability of occurrence. The summer with hottest average temperatures equals a 1-in-40 year probability. A very hot year has a 1-in-10 year probability and a typical summer season has a 1-in-2 year probability. The Commission staff uses the 1-in-10 year temperature probabilities to estimate future peak demand levels to assess a conservative electricity supply scenario.

The impacts of the energy crisis will be felt by Californians well into the future. It is difficult to determine how many of the actions taken by electricity consumers over the last twelve months will continue into 2002 and beyond. Monthly peak demand in 2001 was significantly lower than would be expected due to voluntary conservation activities and state-sponsored demand responsiveness programs. Determining the amount of this reduction that was a result of permanent technological improvements and how much was due to temporary behavioral changes will continue to be a difficult task into the next few years.

The 2002 summer peak demand is expected to be 54, 248 MW, assuming a 1-in-10 hot summer and a decrease in the voluntary consumer reductions experienced in 2001. The staff also assumes that state-sponsored demand responsiveness programs will successfully reduce 1,744 MW of demand during the summer peak period in 2002[5].

Figure I-4 provides a summary of the "most likely" resource balance scenario assuming a 1-in-10 hot summer peak period. The staff assessment shows that there will likely be sufficient resources available in the next several years to meet statewide electricity peak loads and required operating reserves in the event of a hot summer (1-in-10 probability). The assessment includes the construction of new gas-fired and renewable resources that are expected to be online at the specified periods. The outlook does not address the transmission problem of moving the electricity to the major load centers, therefore local area reliability issues may continue to exist during the forecast period.

Figure I-4
California Electricity Supply and Demand Balance 2002-2004
(1-in-10 Weather Impacts on Load Forecast)



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The commission staff has developed several peak demand scenarios to consider varying levels of consumer conservation behavior. The demand scenarios are based on assumptions that there are several decreasing levels in voluntary consumer reductions compared to levels experienced in 2001. The demand levels may vary depending on whether the 2001 consumption reductions were mostly due actual consumer investments in more efficient appliances (i.e. compact florescent lamps or new refrigerators) that will continue to provide savings or simply from household conservation responses to the well publicized energy crisis. The demand scenario with the moderate drop in conservation is considered to have a 75 percent probability of occurring during the next several years.

The staff finds that there will most likely be sufficient electricity supplies to maintain system reliability requirements through 2004. The following chapters further examine the system reliability risks considering varying levels of development uncertainties.

Long Term Considerations

While the outlook has improved, critical issues need to be resolved to maintain a reliable, reasonably priced, and sustainable electricity system. The market structure that currently exists is an *ad hoc* arrangement, created to respond to the immediate needs of the crisis that was averted. Policy makers now have to choose what kind of market organization and market structure will best serve California.

What should the new market look like? Will it still have a strong competitive flavor or will the State assume a larger role in procuring future power supplies? Does the state need to have a "reserve," and if so, what form should it take and how large should it be? These are questions that need to be addressed, but require thoughtful analysis.

Endnotes

1 Anjali Sheffrin, *ISO Market Analysis Report*, January 16, 2001, Folsom, CA.

2 *Electricity Market Reform in California*, November 22, 2000, John D. Chandley, Scott M. Harvey, and William W. Hogan, provides the following description of the need for system coordination: "Over short horizons of a day or less, generating facilities must work through the transmission network to provide the multiple products of energy, reserves and ancillary services. These same generating facilities must provide all of these products, in the right amounts, and with very limited tolerances."

3 Including the California Public Utilities Commission (CPUC), the Electricity Oversight Board (EOB), the Federal Energy Regulatory Commission (FERC) and the ISO's Market Surveillance Committee (MSC)

4 High Temperature and Electricity Demand: An Assessment of Supply Adequacy in California Trends and Outlook, www.energy.ca.gov/electricity/1999-07-20_heat_rpt.pdf.

5 Staff Report: 2002 Monthly Electricity Forecast, California Supply/Demand Capacity Balance for January to September 2002; Publication Number 700-01-002 www.energy.ca.gov/reports/2001-11-20_700-01-002.pdf.

Part II California Electricity Demand and Supply Balance

This part of the report presents the component analyses comprising the overall electricity supply and demand assessment for the next decade. The first chapter, Chapter II-1, examines the uncertainties associated with forecasting the California electrical system peak demand and energy requirements, given the substantial reduction in consumer demand in response to the recent electricity crisis.

Chapter II-2 examines the uncertainties associated with forecasting energy spot market prices and new power plant completions under a variety of supply and demand scenarios. Even with much of the energy demand served under bilateral contracts, spot market prices remain an important price signal for developers of new supply- or demand-side electricity resources. The goal of this analysis is to estimate spot market prices, which can be used to assess the likelihood of additional capacity expansion and the retirement of existing power plants.

Chapter II-3 examines the potential risks that near-term (2003) capacity resources may be inadequate to meet demand. This chapter explains the probabilistic nature of supply adequacy and attempts to quantify the relative risks associated with key uncertainties that affect supply adequacy.

Chapter II-1 California Electricity Demand

An accurate picture of electricity consumption and demand trends is necessary to determine whether there will be adequate supplies of electricity. According to the North American Reliability Council (NERC) "a credible load forecast is necessary when planning and operating transmission and generation facilities...Even in a market environment, demand forecasts will continue to be crucial for ... those responsible for assessing and maintaining reliability."

Chapter II-1 examines California's electricity demand between 2002 and 2012 according to the following topics:

- Misconceptions about demand growth since restructuring.
- Recent California electricity demand trends.
- The current electricity demand situation.
- Future electricity demand scenarios.
- Patterns of electricity use.
- Recent trends in western states' electricity use.
- Electricity prices and electricity use.
- Energy efficiency resources and the impacts of demand reduction programs.
- The importance of data to demand analysis.

The critical demand forecast issue is uncertainty. Forecasting demand is always uncertain; however, the recent events in California and the nation increase the range of uncertainty in the forecasts presented here. At this point, the Commission cannot predict whether the demand reductions of the summer of 2001 will continue. Nor can it predict the impact from various programs. Other factors add uncertainty to these demand forecasts: the full impact of rate surcharges and newly legislated programs have yet to be seen. Nor is it clear what effect the tragic events of September 11, 2001 will have on economic growth in the state — and on energy growth.

Misconceptions about California Electricity

In addition to uncertainty about the future, there has been some confusion about the past. Numerous assertions about California demand trends and impact of those trends on electricity emergencies and resource scarcity have been made. This chapter starts by looking at several of these misconceptions.

As the summer of 2001 approached, media coverage of the electricity crisis increased along with fears of rotating outages. At the same time several misconceptions about California's electricity demand situation also appeared. The demand situation was characterized as "unprecedented", "resulting from extraordinary growth", and "unexpected". These characterizations were not accurate.

Not Unprecedented Growth

Growth of 3.5 percent in 1999 and 3.7 percent in 2000 was no higher than growth in recent years (1996 and 1997) and growth around a decade ago. During the 70s and 80s the growth rate was three percent per year. In the 90s, growth in electricity use slowed to one percent per year.

Not Extraordinary Growth

As seen in **Figure II-1-2**, growth in peak and energy in the last few years is not greater than growth in earlier years.

For the three years preceding restructuring (1995-1997), overall electricity demand grew by seven percent — the same as the growth in the three years after restructuring. Furthermore, summer peak demand fell by two percent after restructuring, compared to a nine-percent increase before.

Figure II-1-1
California Electricity Consumption not Unprecedented

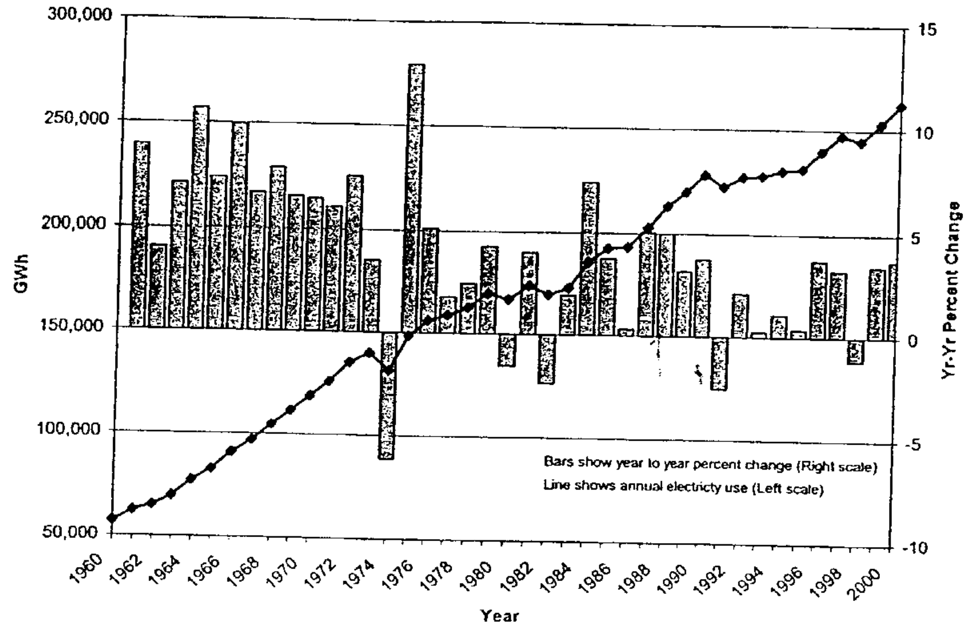

Figure II-1-2
Growth in California Electricity Use not Extraordinary

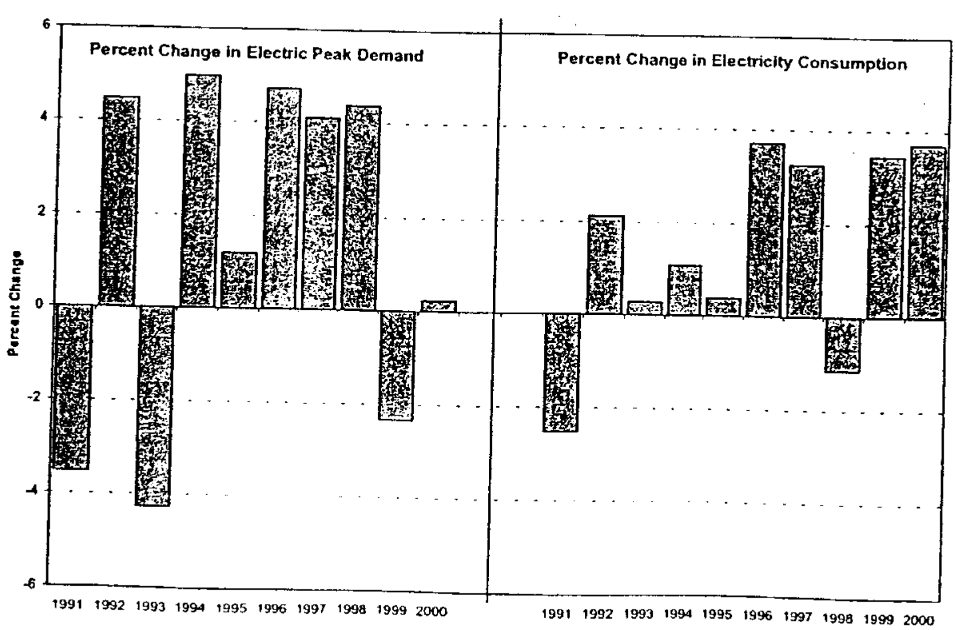

Figure II-1-3 compares actual peak demand to several Energy Commission forecasts of peak demand. If anything, the forecasts are too high; they overestimate actual peaks. This error on the high side did not contribute to lack of sufficient resources.

Recent California Electricity Trends

Recent trends in electricity use are driven by economics and population growth, while average consumption per customer has not changed much.

Increasing economic activity and increasing population are factors contributing to increasing use of electricity. Long term overall electricity use is shown in **Figure II-1-4**. The shaded columns in the figure represent national economic recessions. It is clear that periods of declining electricity use are associated with declines in economic activity. Conversely, economic and electricity growth are related.

Figure II-1-3
California Peak Demand Growth not Unexpected

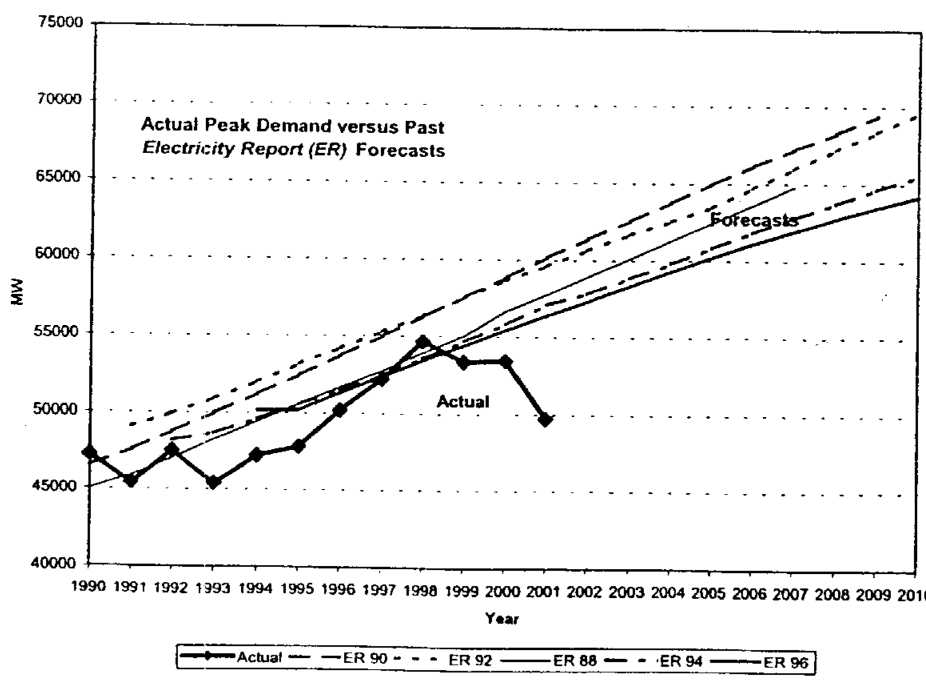

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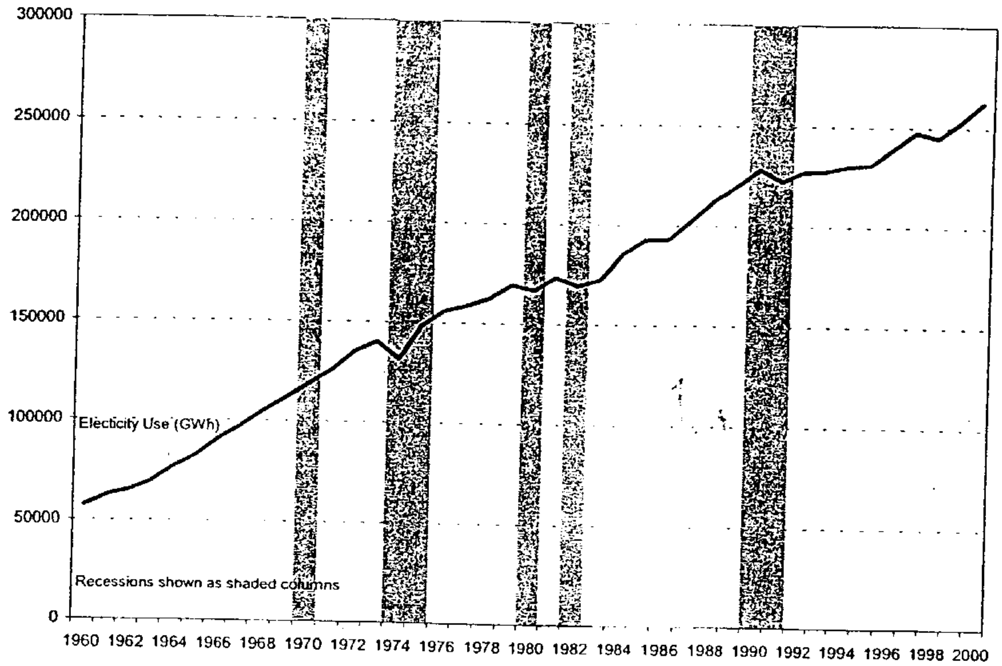
Figure II-1-4
California Electricity Use is Influenced by Economic Conditions



Other factors contributing to growth in electricity use are how much electricity each business and person uses—how efficiently they use electricity—and how that efficiency changes over time. As seen in **Figure II-1-5**, total electricity use per person grew between 1960 and 1974. Use per person grew by 4.3 percent per year in California, by 5.1 percent per year for the nation, and 5.2 percent per year for the western states.

After 1974 use per person patterns changed. As a result of various actions, including Energy Commission building and appliance standards, use per person in California has been relatively flat since 1974, growing only at 0.1 percent per year. In contrast, although growth slowed in the nation and west relative to pre-1974, growth in use per person continued to increase in both the nation (1.7 percent per year) and the west (1.2 percent per year).

Another important factor influencing electricity use, particularly peak demand, is weather. Hot weather causes increased use in air conditioning and increased peak demand.

Figure II-1-5
California Use per Person is Not Increasing

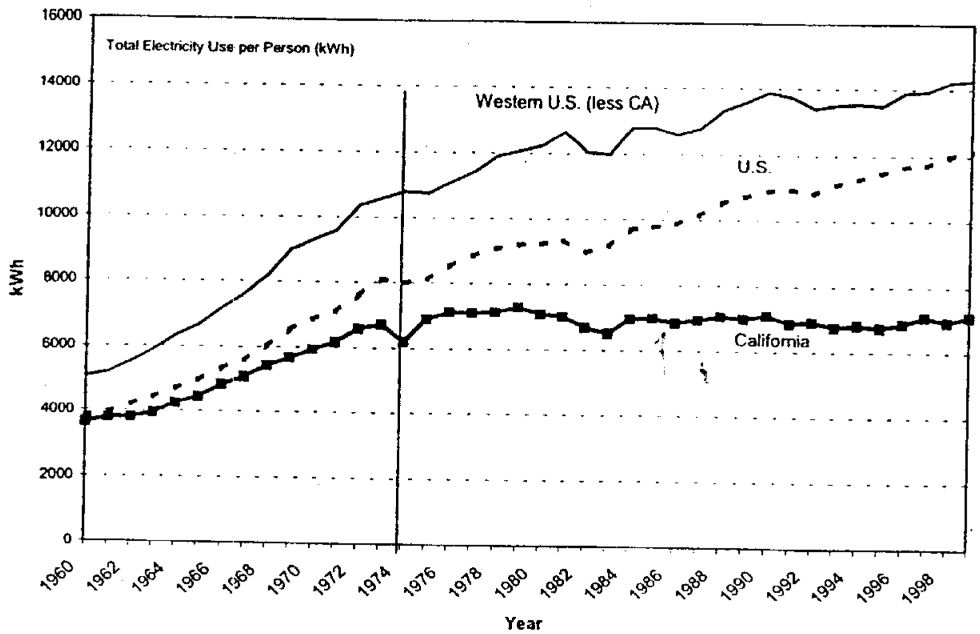
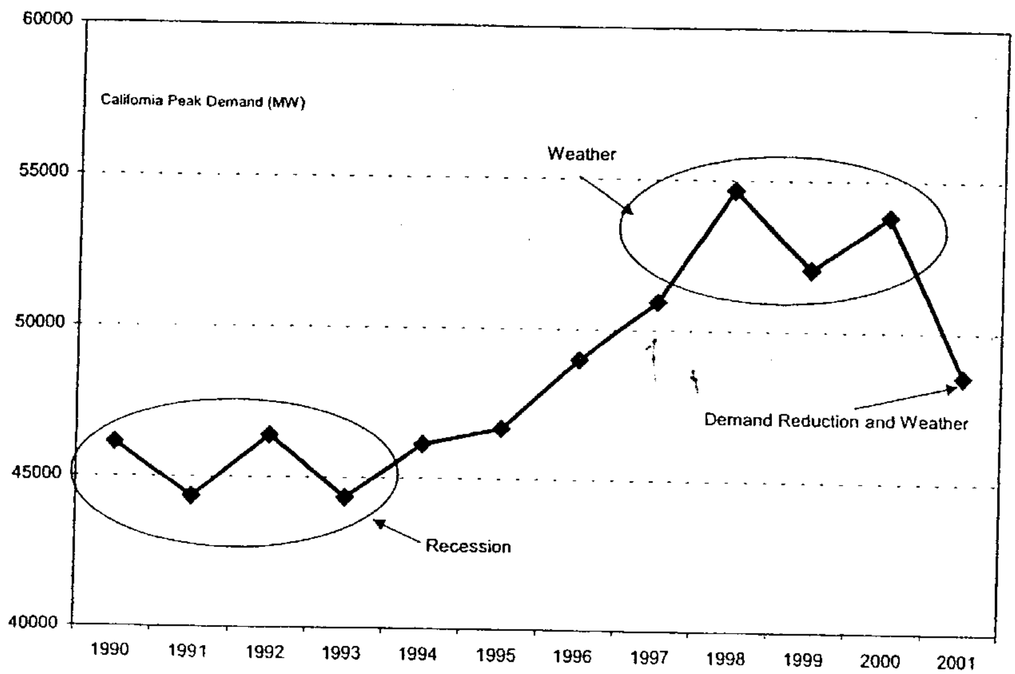


Figure II-1-6 shows the influence of economics and weather on peak demand. The no-growth period of the early 90s was caused by an extended recession in the state. Peak demand growth in the mid-90s reflects the state's economic recovery. In addition, some small weather fluctuations can be seen—1995 was relatively mild, 1996 hot, and 1997 mild.

In the late 1990s weather fluctuations obscure any economic growth trends. August 1998 was the 6th hottest month ever in the state, leading to a very high peak demand. Peak demand in 1999 occurred in July which was much cooler than normal.

The summer of 2000 was hot again, the 25th hottest out of 106 years, leading to an increase in peak demand. The summer of 2001 was as hot as the summer of 2000, the 25th hottest out of 107 years. Looking at heat waves, there were fourteen days in 2001 that the temperature in the Central Valley was 100 degrees or higher compared to only ten days in 2000. In addition, the temperature on the peak day in 2001 was 102 degrees while in 2000 it was 100 degrees. Even though both years have similar temperature patterns, peak demand in 2001 was lower than in the previous three years. This reduction is the result of efforts of citizens of the state to reduce demand and conserve electricity.

Figure II-1-6
Peak Demand Influenced by Economics and Weather



Current Electricity Demand Situation

This section looks at the current electricity demand situation in the state. First, California is compared to other nations and state. Next, there is a discussion of the demand reduction in the summer of 2001.

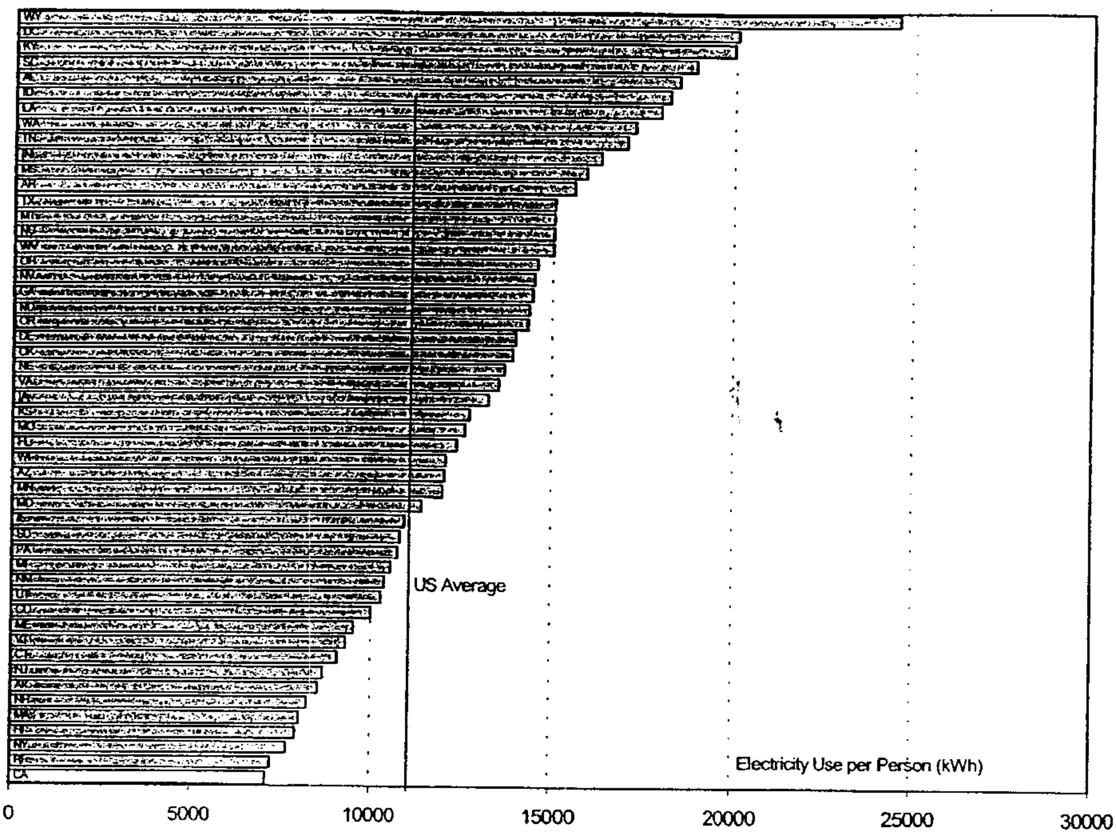
California's Electricity Ranking

If California were a separate country, it would be the fifth largest economy in the world, surpassed only by the United Kingdom, Germany, Japan, and the United States. In addition, it would be the 12th largest consumer of electricity, using slightly more than South Korea and less than Italy.

Among the 50 states, California is the second largest consumer of electricity, surpassed only by Texas. California's 12 percent of the nations' population uses 7 percent of the electricity.

As measured by use per person, California is the most energy efficient state in the nation, ranking 50th lowest out of the 50 states in electricity use per capita **(Figure II-1-7.)**

Figure II-1-7
California is the Most Electricity Efficient State



Summer of 2001

The summer of 2001 was remarkable for what did not happen and for what did happen. What did not happen was frequent system emergencies. Various sources forecast hundreds of hours of rotating outages across the state during the summer of 2001. These outages did not occur. Furthermore, there were far fewer minor emergencies during the summer of 2001. During the summer of 2000, the California Independent System Operator declared 24 stage 1 electricity emergencies and 13 stage 2 emergencies. In contrast, during the summer of 2001, only 2 stage 1 and 2 stage 2 emergencies were declared.

What did happen during the summer of 2001 was an extraordinary reduction in peak demand. Even though the summer of 2000 and 2001 were both the 25th hottest (with high ranks denoting hotter conditions, 2000 was ranked 82nd out of 106 years and 2001 was 83rd out of 107 years), actual peak demand in 2001 was substantially lower than the summer 2000 peak demand. There were 29 days during the summer of 2000 when demand in the California

Independent System Operator's area exceeded 40,000 MW. There were only 6 of these high demand days during the summer of 2001.

The actual peak demand in the summer of 2001 in the Independent System operator area was 41,155 MW. This is about 2,300 MW (or 5.4 percent) lower than the 43,509 MW peak demand in 2000. After adjusting for weather and economic growth, the summer 2001 peak was almost 9 percent lower than the 2000 peak demand.

In addition to summer demand reduction, peak demand was also lower during the winter and spring of 2001. These demand reductions during 2001 are the result of several factors. Unfortunately it is not yet possible to attribute specific levels of demand reduction to specific factors or programs.

The factors contributing to the 2001 demand reduction include:

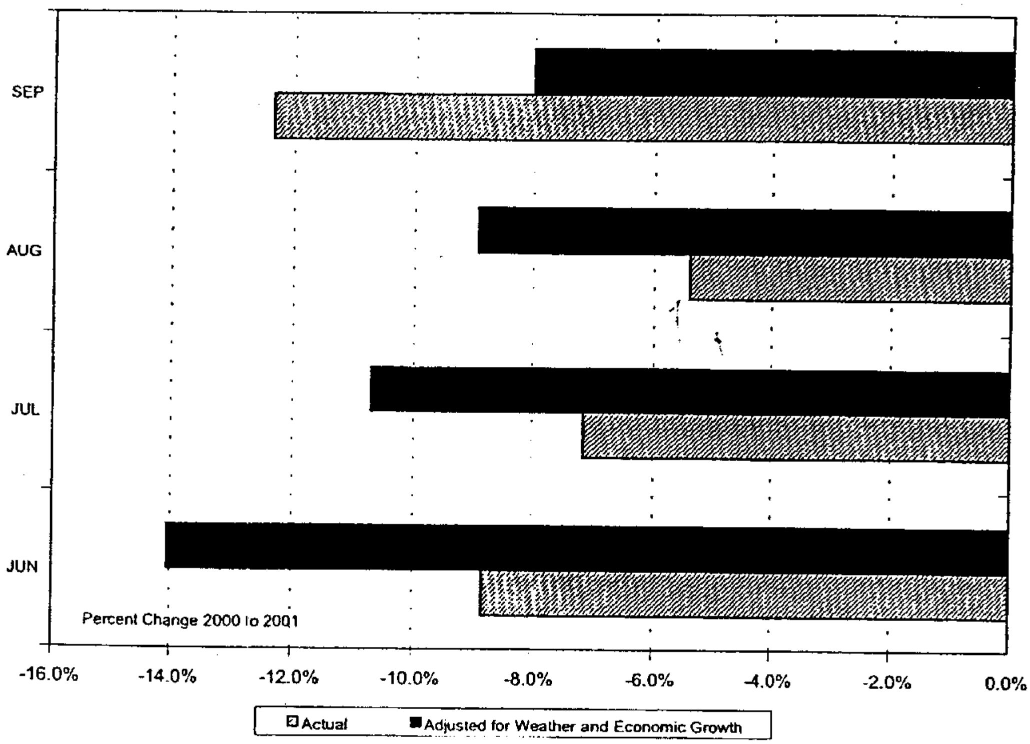
- Demand reduction programs
- Electricity price increases
- The 20/20 program
- Public awareness and voluntary conservation
- Response to crisis, winter rolling outages, and media exposure

Demand reduction programs and customer response to electricity price increases are discussed in more detail later in this chapter.

Over the summer of 2001, there was a reduction of over 3,000 MW in peak demand compared to expected demand levels. This reduction is a result of the factors listed above. In addition to not being able to determine how much of those savings are due to individual factors, it is also not yet possible to determine whether different customers saved different amounts. Data are not yet available to analyze the different savings of residential, commercial, and industrial customers.

It is also not yet possible to determine how much of the demand reduction is due to changes in behavior (e.g., turning up the thermostat to reduce air conditioning use) as opposed to changes in equipment (installing an Energy Star refrigerator). If the reductions are due to changes in behavior, then the savings may disappear in the future if customers return to previous behavior. However, if the reductions are due to equipment changes, these savings should continue into the future.

Figure II-1-8
Summer 2001 Peak Demand Reductions



Electricity Demand Scenarios

The uncertainty about what caused the demand reduction in the summer of 2001, in particular, the uncertainty about how much was due to temporary, behavioral changes and how much was due to permanent, equipment changes contributes to increased uncertainty about future electricity use trends. The three scenarios discussed in this chapter were developed to provide a range of possible electricity futures that account for the demand reductions of the summer of 2001 and uncertainties about future demand reductions and future economic growth. These scenarios combine different levels of temporary and permanent reductions to capture a reasonable range of possible electricity futures.

A two-step process was used to develop the three scenarios shown here. First, the Energy Commission's existing end-use electricity demand forecasting models were used to develop a "raw model output" case. This case was based on forecasts of economic growth. Although these forecasts are reasonably current, they were not prepared in time to capture the slowing growth in California in the early part of 2001 and did not capture any effects of the September 11 tragedy. The case also included the impacts of conservation programs that had been put in place before the summer of 2001. The "raw model output" case did not include the impacts of summer 2001 reductions.

Second, several possible patterns of future trends in summer 2001 demand reductions were developed. These patterns are based on alternative assumptions about the level and persistence of voluntary impacts and permanent, program impacts. These demand reduction patterns were applied to the "raw model output" case to develop three scenarios. One of these scenarios was selected as the most likely case. The other two scenarios represent higher and lower cases. The "raw model output" case from the end-use models is outside of the reasonable range of forecasts bounded by the "high" and "low" scenario and has not been used in any further analysis.

Figure II-1-9 is a chart of the three peak demand scenarios and **Figure II-1-10** shows the scenarios for overall electricity use—the data from the scenarios are shown in **Tables II-1-1** and **II-1-2**.

Figure II-1-9
California Peak Demand Scenarios

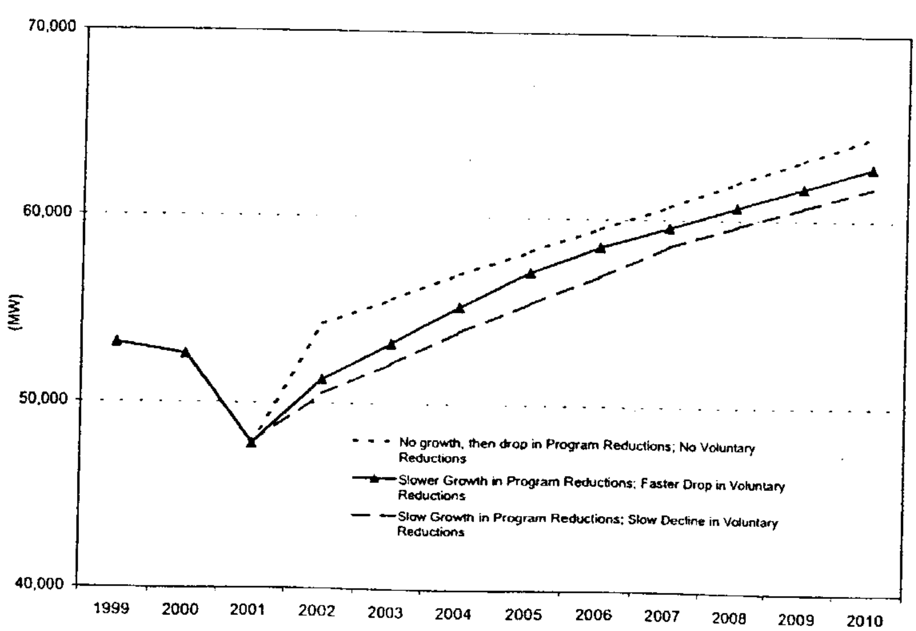


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Figure II-1-10
California Electricity Consumption Scenarios

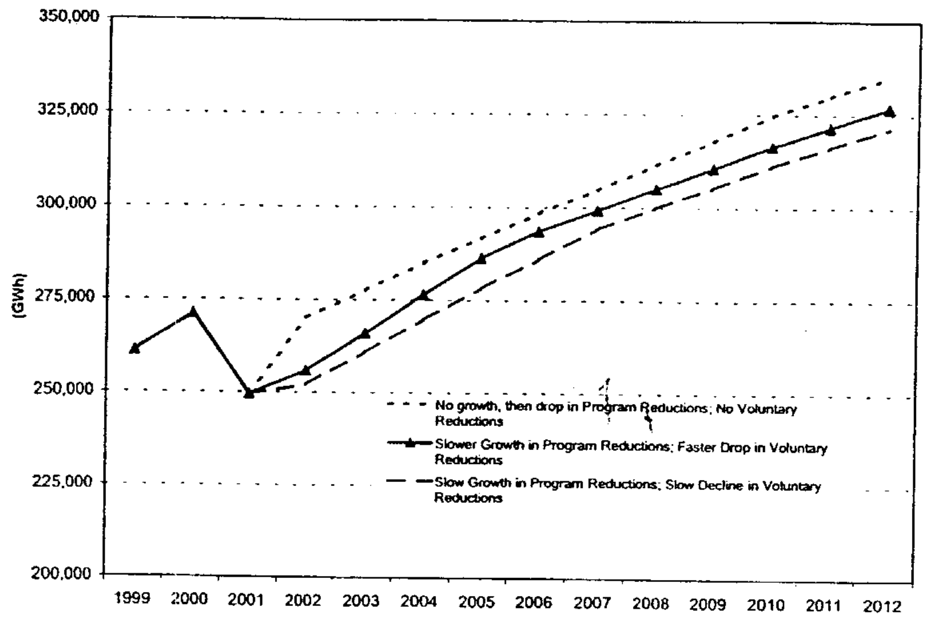


Table II-1-1
California Peak Demand Scenarios
(MW)

Year	Low	Most Likely	High
2002	50,501	51,277	54,255
2003	52,150	53,211	55,600
2004	53,846	55,206	56,973
2005	55,452	57,120	58,232
2006	56,952	58,510	59,502
2007	58,570	59,581	60,735
2008	59,659	60,688	62,011
2009	60,681	61,727	63,223
2010	61,772	62,838	64,512
2011	62,768	63,850	65,552
2012	63,745	64,845	66,573

Table II-1-2
California Electricity Consumption Scenarios
(GWh)

Year	Low	Most Likely	High
2002	252,070	255,829	270,236
2003	260,860	266,011	277,601
2004	269,800	276,414	285,012
2005	278,230	286,359	291,778
2006	286,018	293,625	298,466
2007	294,328	299,263	304,904
2008	300,098	305,132	311,604
2009	305,528	310,655	317,978
2010	311,320	316,546	324,757
2011	316,407	321,718	330,065
2012	321,399	326,796	335,277

The most likely scenario--labeled "Slower Growth in Program Reductions, Faster Drop in Voluntary Reductions"--in **Figures II-1-9** and **II-1-10**, assumes that program impacts increase in 2002 but stay constant after that, while voluntary impacts decrease more rapidly starting with a drop of 1,500 MW in 2002.

The lower scenario--labeled "Slow Growth in Program Reductions, Slow Decline in Voluntary Reductions"--assumes that program impacts grow from 2001 to 2006 while impacts of voluntary reductions drop slowly over the period after a drop of 1,000 MW in 2002.

The higher scenario--labeled "No growth, then drop in Program Reductions, No Voluntary Reductions"--assumes that there are no impacts from voluntary actions in 2002 and after, while impacts of programs stay constant until 2005 and then start declining.

Table II-1-3 shows the demand reduction data used in the three scenarios. In the low scenario, program impacts stay constant at 500 MW from 2002 to 2005. After that program impacts decrease, falling to 0 MW in 2009. The impacts of voluntary programs are assumed to be zero in 2002 and remain so over the forecast period.

In the most likely scenario, program impacts increase to 1,000 MW in 2000 and remain at that level. Voluntary impacts drop from 3,300 MW in 2001 to 1,800 MW in 2002 and continue to fall, reaching 1000 MW in 2006.

Program impacts increase in the high case, growing from 500 MW in 2001 to 2006 MW in 2006. Also, the impacts of voluntary programs drop relatively slowly, falling from 3,800 MW in 2001 to 1,800 MW in 2007.

Table II-1-3
Demand Reductions Used in Scenarios

Year	Scenario								
	Low			Most Likely			High		
	Program	Voluntary	Total	Program	Voluntary	Total	Program	Voluntary	Total
2001	500	3300	3800	500	3300	3800	500	3300	3800
2002	500	0	500	1000	1800	2800	1100	2300	3400
2003	500	0	500	1000	1300	2300	1200	1900	3100
2004	500	0	500	1000	800	1800	1300	1500	2800
2005	500	0	500	1000	300	1300	1400	1100	2500
2006	400	0	400	1000	100	1100	1500	700	2200
2007	300	0	300	1000	100	1100	1500	300	1800
2008	200	0	200	1000	100	1100	1500	300	1800
2009	100	0	100	1000	100	1100	1500	300	1800
2010	0	0	0	1000	100	1100	1500	300	1800
2011	0	0	0	1000	100	1100	1500	300	1800
2012	0	0	0	1000	100	1100	1500	300	1800

Recent Trends in Western States Electricity Use

In addition to information about California trends, it is also important to monitor and analyze trends and forecasts for the western states. Different states have different growth patterns. Uncertainty about future patterns of growth in the west adds to the uncertainty about California electricity supply/demand balances.

Table II-1-4 shows growth from 1989 to 1999 in electricity use, population, and use per person for 11 western states. Growth in electricity use ranges from a low of 0.2 percent per year in Montana to a high of 5.8 percent annually in Nevada.

Table II-1-4
Growth in Western States
1989 to 1999 Average Annual Growth Rate (%)

		Electricity Use	Population	Use per Capita
1	Nevada	5.8	4.8	1.0
2	Utah	3.9	2.2	1.6
3	Arizona	3.5	2.8	0.7
4	Colorado	3.0	2.2	0.8
5	Texas	2.8	1.8	1.0
6	Idaho	2.5	2.3	0.1
7	California	1.4	1.3	0.1
8	Washington	1.3	1.9	-0.6
9	Oregon	1.3	1.7	-0.4
10	Wyoming	0.5	0.5	0.0
11	Montana	0.2	1.0	-0.8

Six states have annual growth in electricity greater than 2 percent. The remaining 5 states have growth in electricity use well below 2 percent per year. The high growth states are characterized by rapid growth in population as well as. Except for Idaho, rapid growth in use per person. On the other hand, the low growth states all have low or declining use per person.

Patterns of Electricity Use

Analyses of electricity resource issues require monthly, daily, or hourly electricity demand data. Hourly data can indicate how long the extreme peak demand period is, influencing how long peaker units will be required to operate or what kind of demand reduction program might best substitute for peaking generation. There are two ways of looking at load data: (1) sorted by day and (2) sorted by maximum value.

Figure II-1-11 shows daily peak demand sorted by day. Relatively stable patterns can be seen in the winter, spring, and fall—in contrast to the load volatility in the summer. While loads are high on weekdays, weekends consistently feature low loads.

Figure II-1-11
Patterns of Daily Peak Demand

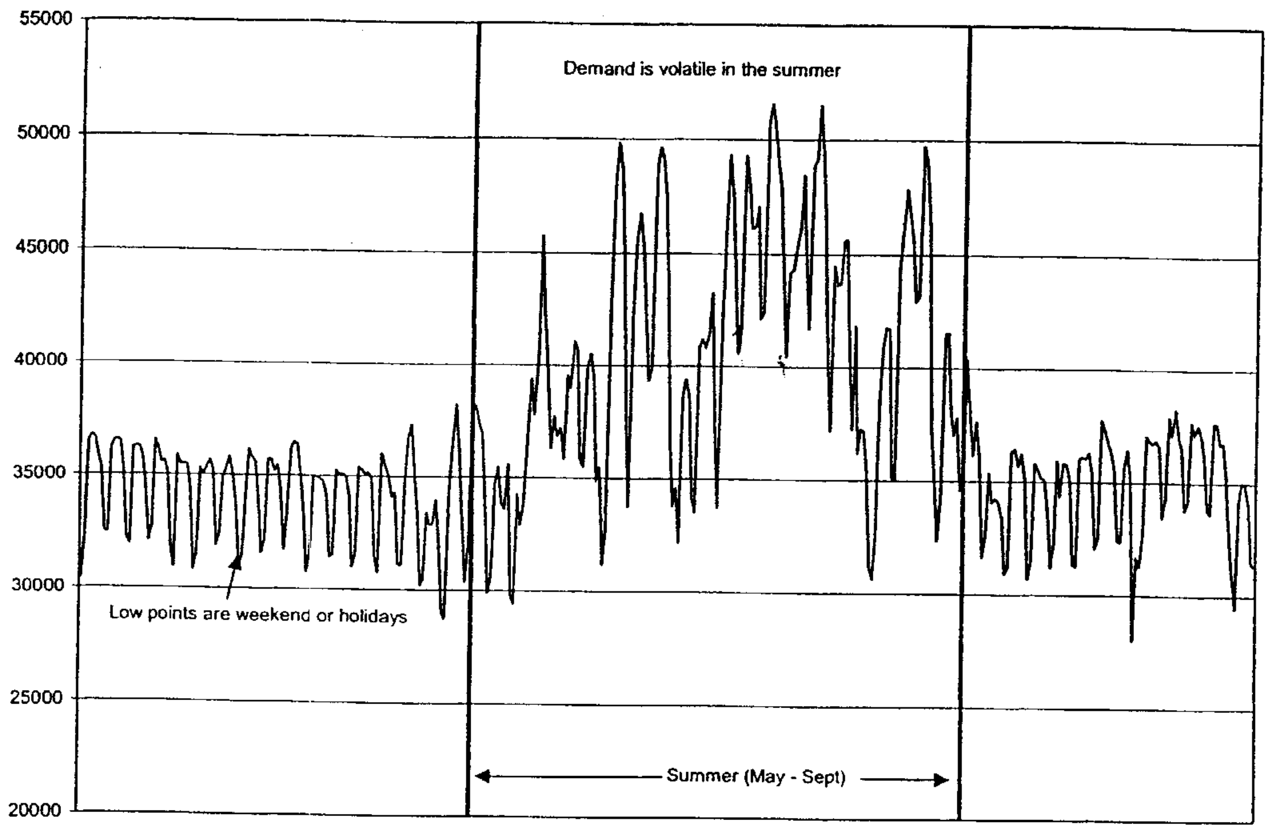
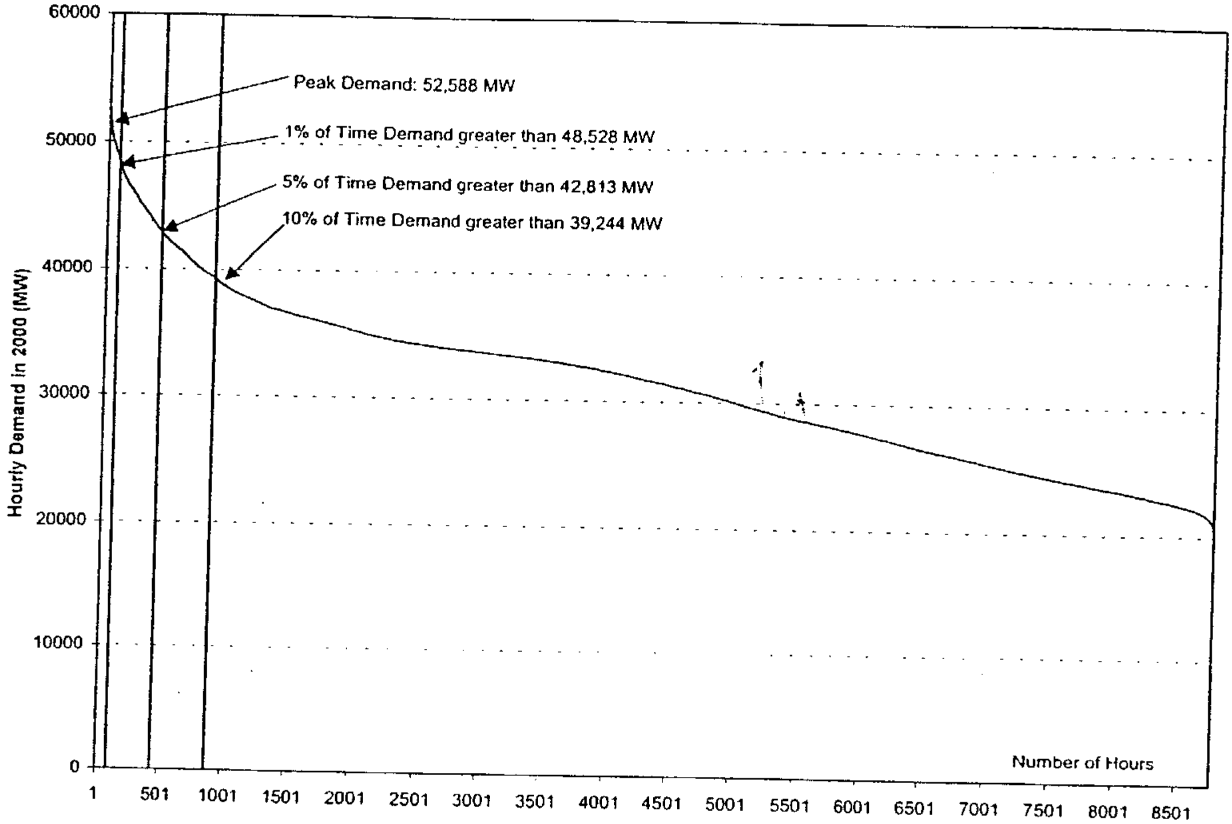


Figure II-1-12 shows hourly demand sorted high to low; this chart is also referred to as a "load duration curve". This figure is useful in determining the number of hours when the loads will be high.

Figure II-1-12
How Many Hours Will Demand Be High



Electricity Prices and Electricity Use

As mentioned earlier, increases in the price of electricity were a factor in the demand reductions seen this year. Until January 2001, electricity prices for PG&E and SCE customers had been frozen. The California Public Utilities Commission approved a 1¢ per kWh rate increase in January 2001 and an even more substantial rate increase in July 2001.

As the price of electricity increases, consumers would be expected to try to reduce their electricity use. The term "price elasticity" is used to measure how much consumers change their use in response to prices. If prices were to increase by 10 percent and electricity use decrease by only 1 percent, this response would be called inelastic, since use did not decrease as much as prices increased. Demand is inelastic if the price elasticity is less than 1.

However, if the response to a 10 percent increase was a 20 percent decrease in use, this would be an elastic response, since use decreased more than price increased. Demand is elastic if the price elasticity is greater than 1.

Table II-1-5 shows ranges of elasticity estimates for electricity prices. These estimates indicate that increases in prices do decrease use since all of the elasticity estimates are greater than zero. Over the short run, electricity use is relatively inelastic—large changes in price produce only small changes in use. As the length of time to respond increases, price elasticity increases. Over the long run, consumers have greater opportunity to adjust their behavior and appliances to changes in prices.

Table II-1-5
Elasticity Estimates

	Short Run	Long Run
Residential	0.06 to 0.49	0.45 to 1.89
Commercial	0.17 to 0.25	1.00 to 1.60
Industrial	0.04 to 0.22	0.51 to 1.82

Energy Efficiency Resources

Energy efficiency programs reduce the energy dependence of California's economy, make businesses more competitive, and allow consumers to save money and live more comfortably. In addition, energy efficiency programs defer the need for new generation or transmission capacity, prevent environmental degradation, and help consumers control their utility bills.

While the fundamental goal of California's efficiency programs and standards continues to be to promote cost-effective energy efficiency and conservation, the strategies emphasized to meet this goal have varied with the regulatory and market environment. Before the restructuring of electricity markets, utilities and state agencies invested in energy efficiency as a cost-effective alternative to generation. With the passage of AB 1890, the focus shifted to achieving longer-term energy savings that would be sustainable after public subsidies ended. The first section of this chapter looks at past savings from energy efficiency programs.

However, with recent electricity market strains, state and utility energy efficiency programs are refocusing on end uses with the largest peak impacts to help prevent shortages and price spikes. In addition, legislation has been recently enacted to provide immediate relief in the summers of 2001 and 2002. This new legislation is AB 970, SB 5x, and AB 29x. Although these programs target demand reductions during the summer peak demand period, many programs will also produce year-round savings through improvements to lighting, water pumping, and heating and cooling system efficiency.

Past Energy Savings from Energy Efficiency

Demand-side management (DSM) has included a variety of approaches, including energy efficiency and conservation, building and appliance standards, load management, and fuel substitution. Since 1975, the displaced peak demand from all of these efforts has been roughly the equivalent of eighteen 500-megawatt power plants.

The annual impact of building and appliance standards has increased steadily, from 600 MW in 1980 to 5,400 MW in 2000, as more new buildings and homes are built under increasingly efficient standards.

Savings from energy efficiency programs run by utilities and state agencies have also increased, from 750 in 1980 to 3,300 MW in 2000.

Summer 2001 Peak Load Reduction Programs

Several programs were implemented to quickly bring about energy conservation and peak load reduction to mitigate possible supply-demand imbalances during the summer of 2001 summer. In July 2000, the CPUC directed utilities to implement new peak load programs in the summer of 2001. In August 2000, the California Legislature and Governor approved AB 970, which directed both the Energy Commission and the CPUC to implement cost-effective energy conservation and demand-side management programs.

In April 2001, the California Legislature and the Governor approved SB 5x and AB 29x, which direct the Commission, CPUC, and other state agencies to implemented, as quickly as possible, peak load reduction programs. These two bills create a landmark energy efficiency and demand reduction program that represent the largest conservation effort ever launched by a single state.

Table II-1-6 summarizes the peak reduction programs put in place to help avoid electricity emergencies during the summer of 2001 and beyond.

Table II-1-6
Peak Demand Reduction Programs

Funding Source	Agency	Measure	Funding Source	Total Appropriated ($ million)	Summer 2001 Peak Reduction Goal (MW)
SB 5X	CPUC	Residential Incentives and Rebates	SB 5X	$50.0	61
SB 5X	CPUC	Increase CARE program	SB 5X	$100.0	
SB 5X	CPUC	Low-Income Weatherization	SB 5X	$20.0	8
SB 5X	CPUC	Oil and Gas Pumping Efficiency	SB 5X	$12.0	16
SB 5X	CPUC	Incentives for High Efficiency Lighting	SB 5X	$60.0	44
AB 970	Energy Commission	Light Emitting Diode Traffic Signals	AB 970	$10.0	6
AB 970		Innovative Efficiency and Renewables	AB 970	$8.0	32
AB 970		Demand Response Systems	AB 970	$10.0	65
AB 970		Cool Roofs	AB 970	$10.0	25
AB 970		State Buildings and Public Universities	AB 970	$5.5	200
AB 970		Water and Wastewater Treatment	AB 970	$5.0	20
SB 5X		Municipal Utility District Programs	SB 5X	$40.0	35
SB 5X		Demand Responsive Systems	SB 5X	$35.0	120
SB 5X		Cool Roofs	SB 5X	$30.0	15
SB 5X		Innovative Peak Programs	SB 5X	$50.0	90
SB 5X		Agriculture Programs	SB 5X	$70.0	22
SB 5X		Municipal water district generation retrofit	SB 5X	$10.0	25
AB 29X		Time of Use and Real Time Meters	AB 29X	$35.0	500
AB 29X		Local government loans and grants	AB 29X	$50.0	20
AB 29X		Geysers Injection System	AB 29X	$4.5	0
AB 29X		Emerging Renewable Account	AB 29X	$15.0	0
AB 29X		Transfer from Renewable Trust Fund	AB 29X	$15.0	0
SB 5X	Dept. Of Consumer Affairs	Public Awareness Initiatives	SB 5X	$10.0	1,000
SB 5X	Dept of General Services	State Energy Projects	SB 5X	$40.0	30
SB 5X	Dept of Community Services and Development	Low-Income Assistance	SB 5X	$120.0	–
AB 29X	Technology, Trade and Commerce Agency	Renewable Loan Guarantee Program	AB 29X	$40.0	10
AB 29X	Ca Conservation Corps	Mobile Efficiency Brigade	AB 29X	$20.0	10
AB 29X	Ca Alt Energy and Adv Transportation Financing Authority	Renewable energy financial assistance	AB 29X	$25.0	

The demand scenarios discussed above include the impacts of pre-2001 programs as well as the programs enacted to reduce demand in the summer of 2001. The scenarios do not include the impacts of possible future programs. In addition, the forecasts do not assume that additional money will be allocated to AB 970, AB 5X, and AB 29X programs in the future resulting in impacts above and beyond those already accounted for.

Importance of Data to Demand Analysis

It is important to better understand what caused the summer 2001 demand reduction. Data are needed to understand which customers reduced demand, including disaggregating data into residential, commercial, industrial, agricultural, and government categories. Within each category, data are needed to see which groups of customers saved the most.

As well as detailed data about customer use, information is needed to determine why customers did what they did. Surveys need to be done to analyze how much of the reduction was due to customer behavioral and permanent response to legislated programs, how much was due to media campaigns, and how other factors.

Although analysis of the summer of 2001 will help reduce uncertainty, uncertainty about future trends in demand reduction trends will continue as the full impact of rate surcharges and newly-legislated programs impact customers. Even if the summer of 2001 were well understood, other factors contribute to uncertainty about future electricity use. The primary factor is uncertainty about economic growth. It is not clear what impact the events of September 11th will have on a California economy that has seen growth slowing since the first of the year.

Chapter II-2 Energy Market Simulations

Introduction

This chapter presents five different scenarios simulating the wholesale spot market for electricity. The scenarios are differentiated by their assumptions about demand growth and new power plant additions during the next four years. The assumptions that characterize each scenario are discussed in detail. The simulation results are presented and discussed, including the spot market prices yielded by the five scenario simulations and the impact of power plant additions on the hours of operation of new combined cycles, peaking units, and the older and larger gas-fired plants. The chapter concludes with a discussion of the implications of the findings for the construction and retirement of capacity during the second half of the decade.

The goal of this analysis is to obtain estimates of spot market prices, which can be used to assess the likelihood of additional capacity expansion (beyond what is already very likely to occur) and the retirement of existing power plants. From April 1998 until January 2001, wholesale spot market prices for electricity largely determined the cost of meeting the energy needs of the customers of California's three investor-owned utilities (IOUs). During the first half of 2001, the California Department of Water Resources signed long-term contracts for wholesale power that will meet a substantial share of the energy needs of IOU customers. These contracts, together with energy from utility-owned nuclear and hydroelectric generation and QF contracts, greatly reduce the share of energy to meet IOU customer demand purchased in spot markets. Accordingly, spot market electricity prices will play a significantly smaller role in determining the wholesale cost of energy for IOU customers.

Spot market prices will continue, however, to have a major influence on the decisions to build new generation capacity and to retire existing facilities. Low spot market prices, those that do not result in profits high enough to warrant investment in new plants, deter capacity expansion. If low enough, spot prices encourage the retirement of plants that cannot cover operating costs. High prices signal the need for new capacity and its profitability. Our results tend to indicate that the addition of new capacity during 2002 - 2005 is apt to drive spot market prices to levels that will render many existing power plants unprofitable and discourage further construction.

Overall Study Design

Staff simulated the inter-connected western wholesale electricity market during the period 2002 – 2012 under different assumptions regarding electricity demand, capacity additions and natural gas prices. Five scenarios were developed, characterized by the rate of demand growth and the amount of new capacity added, and titled according to the resulting reserve margin (Baseline, High, Low, Lower and Lowest). Each of the scenarios was evaluated using "expected" and "high" prices for natural gas. The simulations yield wholesale spot prices for a range of possible reserve margins during the next ten years.

Multisym™, a market simulation model produced by Henwood Energy Services, Inc., was used for this analysis. Given the operating characteristics of each power plant in the Western Systems Coordinating Council, forecasts of electricity demand, fuel prices, available hydroelectric energy and transmission constraints, the model produces estimates of wholesale spot prices across the western U.S. for each hour during the period simulated. It also provides estimates of hourly output and fuel use for each of the plants in the region.

Assumptions Used in Simulations

This section describes the assumptions used in the market simulations and how variations in those assumptions define the five separate scenarios. The assumptions described below include the following:

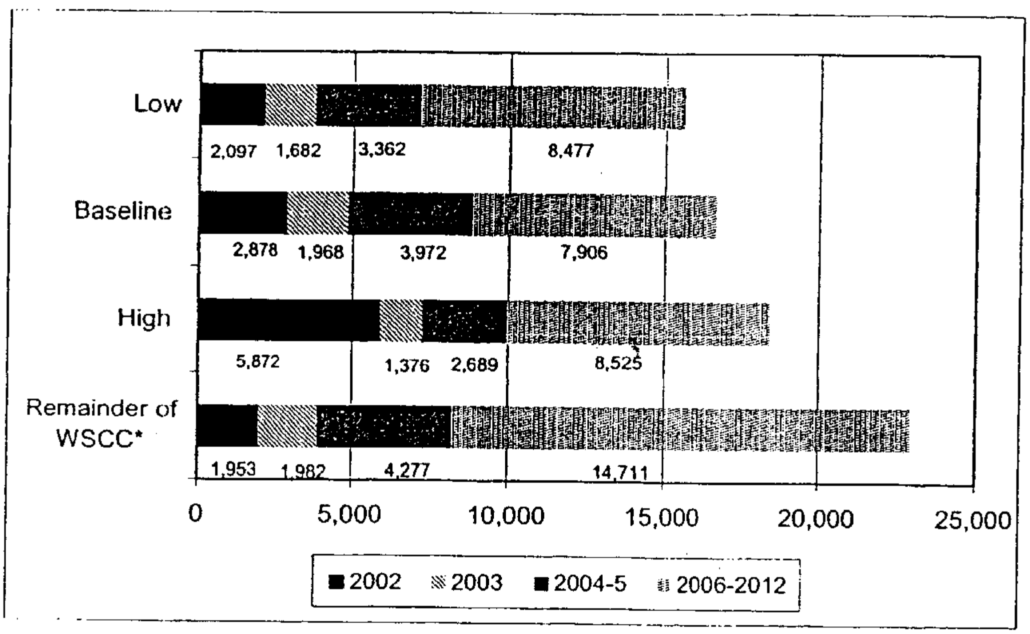
- Demand growth over the 2002-2012 period for California and the other WSCC areas.
- Capacity additions and retirements assumed over the next four years for California and the other WSCC areas.
- Reserve margins that directly result from the demand growth and capacity addition assumptions (these define and scenarios and help explain the results).
- Cost of a new entry into the generation market.
- Hydrological conditions and resulting amounts of hydroelectric generation.
- Long-run natural gas prices.
- Transmission upgrades that are assumed to be constructed during the study period.
- Competitive spot market conditions.

A discussion of the results of the scenario analyses immediately follows the description of assumptions.

Demand Growth

In the market simulation scenarios, the Staff used the three peak demand and energy consumption growth scenarios presented in **Figures II-1-9** and **II-1-10**, respectively. For greater simplicity, these demand scenarios are renamed in this chapter with respect to the trend in demand growth over the decade--Low, Baseline, and High demand growth. As explained in Chapter II, the differences in the increase in demand assumed to occur in 2002 and 2003 reflect uncertainty regarding the persistence of conservation during the next two years; the highest rate of growth used assumes it all but disappears.

Figure II-2-1
Demand Growth Uncertain
Annual Peak Demand Growth (MW)



* The same rate of growth elsewhere in the WSCC was assumed for all scenarios

Capacity Additions and Retirements

The staff has simulated the market under several assumptions regarding the quantity and timing of new additions; the amount of capacity added in each scenario is presented in **Table II-2-1.** All the information available to the Staff regarding new generation capacity planned for construction and operation during 2002 - 2005 indicates that a substantial amount of capacity will be added during the period. A large number of new power plants are being built throughout the western United States; the construction and operation of additional facilities have been approved, but ground has yet to be broken. Beyond these, the number of pending applications for certification and pronouncements by developers indicate that even more capacity is being contemplated. Not all of the new capacity under consideration during this period will be built; there is obviously even greater uncertainty regarding additions during 2006 - 2012.

Table II-2-1
A Boom in Generation Capacity
Cumulative Capacity Additions (MW)

Region	Scenario	Year			
		2002	2003	2005	2012
California ISO	High			17,990	23,347
	Baseline			16,362	21,719
	Low	5,371	9,753	14,270	20,324
	Lower			10,125	16,829
	Lowest			10,125	14,034
WSCC	High			51,023	69,333
	Baseline			47,141	65,451
	Low	10,909	28,305	41,458	61,396
	Lower			35,051	55,638
	Lowest			35,051	46,334

Net capacity additions during 2002 – 2005 were based on information compiled by the Staff regarding facilities under construction, permitted for construction and operation, applications under review, and announced for development. Plants currently under construction were assumed to be completed, as were most permitted plants. A share of the plants with pending applications were included, as were a smaller share of announced plants. The additions prior to August 2003 are the same for each scenario; the capacity assumed to come on line thereafter varies. Events since these scenarios were developed suggest that the 2002 estimate is high for generation additions. However, if regarded as a combination of generation and dispatchable demand reductions, it is reasonable. As reserve margins were increased substantially in every scenario during 2002 - 2005, net additions during 2006 - 2012 were assumed not to keep pace with demand growth.

Retirements were limited to those announced to date and those that were assumed to occur in conjunction with the appearance of new facilities at the same site. The estimates in **Table II-2-1** do not reflect the repowering of 1900 MW of existing capacity in California assumed to occur in 2009.

Almost all new generation was assumed to be efficient natural gas-fired combined cycle plants; the major exception being gas-fired peaking facilities added in 2002. A share of the latter – those facilities permitted for temporary operation – were assumed to retire at the end of the summer of 2003.

Resulting Reserve Margins Define the Five Scenarios

The demand growth and resource additions assumed in each scenario yield a corresponding change in reserve margins, for which the scenarios are named. **Table II-2-2** shows the reserve margins for the California ISO control area and the WSCC for each of the scenarios.

<table>
<tr><th colspan="6">Table II-2-2
Reserve Margins Increase</th></tr>
<tr><th rowspan="2">Region</th><th rowspan="2">Scenario</th><th colspan="4">Year</th></tr>
<tr><th>2002</th><th>2003</th><th>2005</th><th>2012</th></tr>
<tr><td rowspan="5">CAISO</td><td>High</td><td>20.6%</td><td>26.9%</td><td>36.4%</td><td>27.7%</td></tr>
<tr><td>Baseline</td><td>18.7%</td><td>24.3%</td><td>29.1%</td><td>22.6%</td></tr>
<tr><td>Low</td><td rowspan="3">12.2%</td><td rowspan="3">19.0%</td><td>22.3%</td><td>16.9%</td></tr>
<tr><td>Lower</td><td rowspan="2">13.9%</td><td>10.7%</td></tr>
<tr><td>Lowest</td><td>5.8%</td></tr>
<tr><td rowspan="5">WSCC</td><td>High</td><td>29.5%</td><td>38.8%</td><td>47.3%</td><td>37.8%</td></tr>
<tr><td>Baseline</td><td>28.7%</td><td>37.8%</td><td>42.9%</td><td>34.5%</td></tr>
<tr><td>Low</td><td rowspan="3">25.9%</td><td rowspan="3">35.4%</td><td>38.0%</td><td>30.8%</td></tr>
<tr><td>Lower</td><td rowspan="2">33.6%</td><td>27.4%</td></tr>
<tr><td>Lowest</td><td>21.8%</td></tr>
</table>

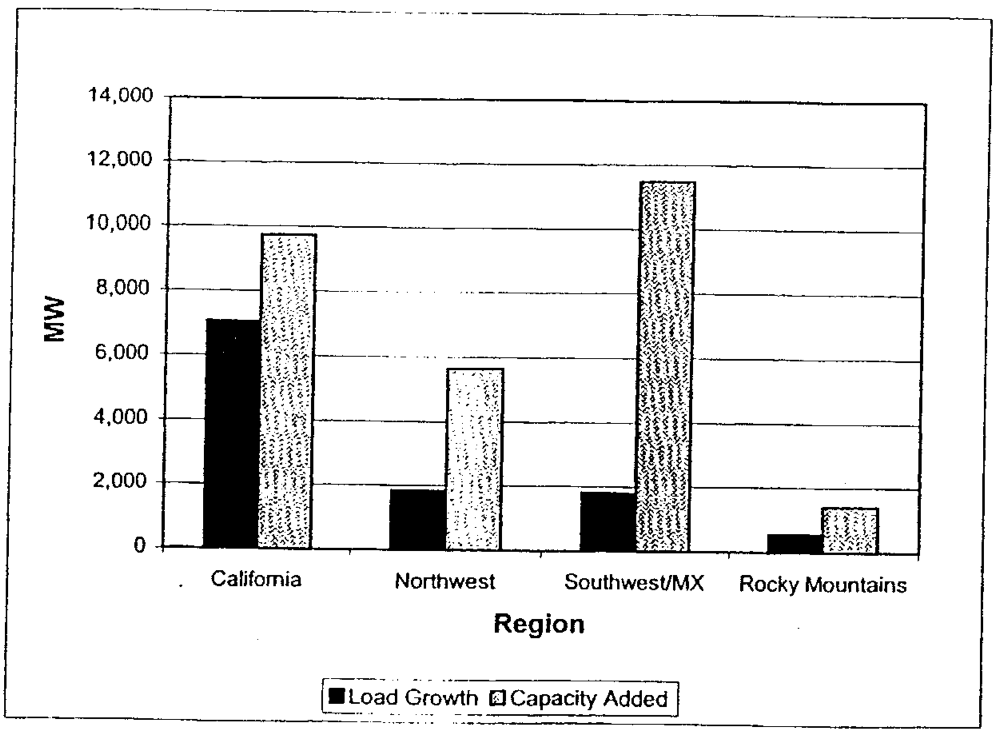
Note: CAISO values include capacity located out-of-state, but owned by investor-owned or public utilities in California

In the High Reserve Margin scenario, demand growth in California is slow in 2002 - 2003; a substantial amount of new capacity is added during 2004 - 2012. In the Low and Lower Reserve Margin scenarios, a large share of the conservation witnessed in California in 2001 is not observed in 2002 and the construction of new capacity is increasingly limited during 2004 - 2012. Finally, in the Lowest Reserve Margin scenario, construction is curtailed even further in

2006 - 2012. In this scenario, the reserve margin in the CAISO control area in 2012 has actually fallen by almost 2,000 MW compared to 2001; this has been offset, however, by an increase in the reserve margin elsewhere in the WSCC of almost 7,000 MW.

Throughout the West, more generation is being added than is necessary to match demand growth. **Figure II-2-2** illustrates additions to capacity reserves from 2001 - 2003 in the WSCC regions under the scenarios with high peak demand assumptions. Capacity additions exceed peak load growth by 2,700 MW in California and a total of 14,400 MW in the Northwest, Southwest and Rocky Mountain regions.

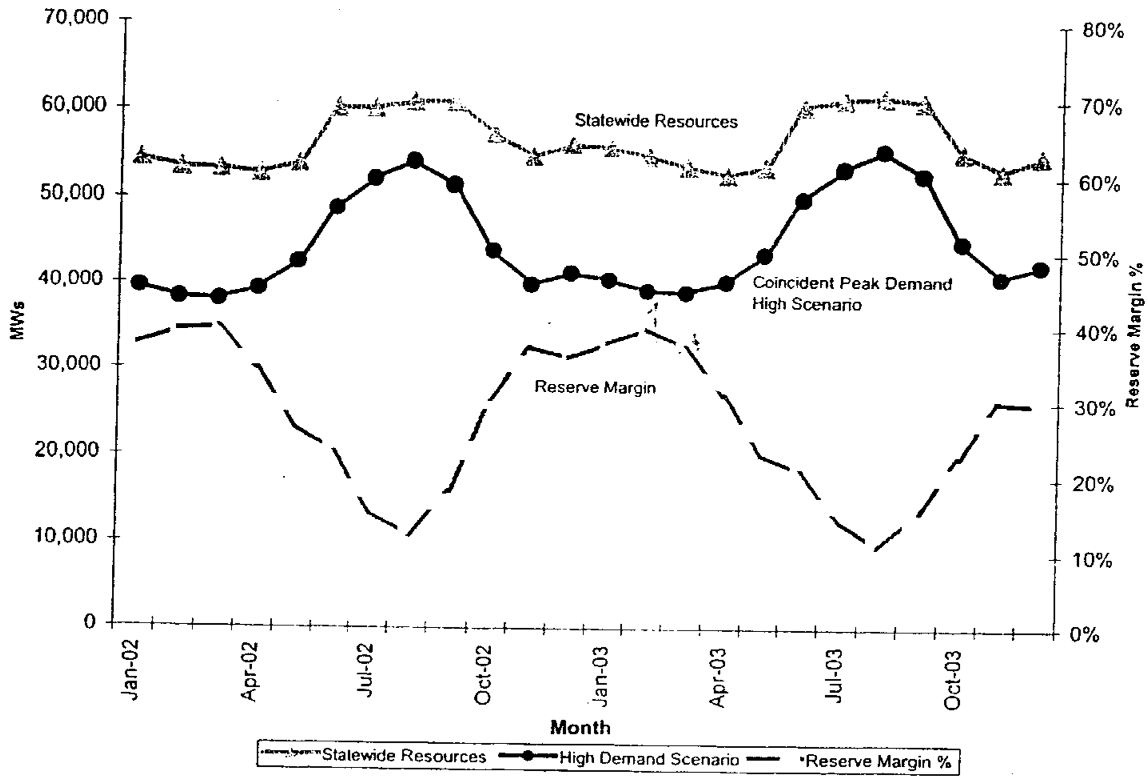
Figure II-2-2
Reserve Capacity Increases,
Peak Load Growth and Capacity Additions, 2001-2003,
High Peak Demand Case (MW)



Reliability requires that sufficient in-state generation and imports be available given possible plant and transmission line outages and adverse water conditions, which limit hydro generation in both California and the Northwest. Industry standards have historically set reserve margins so that the inability to meet peak demand be no greater than one day in ten years. This reliability performance target has required planning reserve margins of about 15 – 22 percent, depending on the nature of demand and the mix of capacity resources in a control area. These planning reserve levels have been necessary to guarantee that operators will have 7 percent reserves at all times. On any given day, some installed generating capacity will be unavailable due to operating restrictions, age, a need for maintenance, or water conditions which prevent hydroelectric facilities from operating at full output. Demand may be greater than anticipated; the probability of one-day-in-ten-year temperatures, for example, can drive peak electricity demand above its forecast level. In addition, capacity equal to seven percent of demand must be set aside to ensure system stability in the event of the sudden loss of a power plant or major transmission line.

The simulations suggest that reserve margins will be adequate in the fall through spring in 2002-2003, but will decline to minimum levels in the summer, potentially triggering calls for interruptible load curtailments. **Figure II-2-3** compares expected available capacity to monthly peak demand for California under the low reserve margin scenario. The Staff thinks that this scenario is the most appropriate for capacity planning. A detailed enumeration of the assumptions which underlies the figure appears in **the Appendix, A-1.**

Figure II-2-3
Monthly Load-Resource Balance
High Demand/Low Resources Case



Cost of New Entry

Under deregulation new capacity is constructed in response to market conditions rather than regulatory fiat. In the long run, reserve margins will tend towards levels that yield prices for wholesale electricity sufficient (in conjunction with earnings in ancillary services markets and from "must-run" contracts for local reliability) to adequately compensate investors in new facilities for the risks that they assume. This "revenue requirement" is expressed in $/kW/yr and represents the revenue stream at which investment in new capacity is warranted.

Fixed operating and capital costs for a new combined cycle facility are project-specific. They are also proprietary information of strategic value. Estimates of fixed operating costs range from $7 - $15/kW/yr. Capital costs include construction costs, debt costs, the returns desired by investors and repayment period, debt-equity ratio, tax rate, etc. The Staff estimates that the revenue requirement for most new combined cycle projects is between $85-$100/kW/yr.

As revenue from other sources is apt to be minimal for new power plants, revenues from energy markets must be nearly equal to the revenue requirement. Energy prices must cover much of the variable operating costs, fixed operating costs, and capital costs. The expected annual hours of operation of a new plant, jointly with the revenue requirement, determine the required spread between average wholesale price and variable operating costs. For example, a plant with a revenue requirement of $85/kW/yr, expected to operate 90 percent of the time (8000 hours) requires an average spread of ($85*1000/8000) $10.62/MWh between its operating costs and the wholesale price during the hours that it operates. A plant with a revenue requirement of $100/kW/yr expected to operate 60 percent of the time (5250 hours) requires a spread of ($100*1000/5250) $19.04/MWh.

Hydro Conditions

Staff assumed slightly adverse hydro conditions in the Northwest for the first nine months of 2002; available energy in each month was set at roughly 95 percent of normal. For all other areas and all other periods during the simulation, hydro conditions were assumed to be normal.

Natural Gas Prices

The average annual gas prices in California for 2002 are assumed to be between $3.05 and $3.25/mmbtu; they fall to $2.70 - $2.80 in the summer and rise to $3.50 - $3.60 in the winter. They escalate each year by approximately 2 percent in real terms. **Appendix A-2** includes the annual average real natural gas prices and monthly natural gas price multipliers used in the simulation for each hub in the WSCC, and GDP implicit price deflator series.

Long-run natural gas prices were estimated using the North American Regional Gas Model ™, licensed from Altos Management Partners, Ltd. The model was used to estimate annual average market prices for 2002, 2007 and 2012 for twenty-one hubs in the WSCC. Prices at five additional locations were then derived using estimates of transportation adders. Averages for interim years were interpolated. Location-specific monthly multipliers derived from historical price data were then used to capture seasonal variations in the spot prices.

Transmission Upgrades

The Staff assumed that several major transmission upgrades will take place in California during the simulation horizon. The transfer capability on Path 15 was assumed to increase to 4,400 MW in June,2003, and then to 5400 MW in June, 2005. The transfer capability on the South of SONGS link between the Southern California Edison and San Diego Gas & Electric service areas

(Path 44) was assumed to increase by 450 and 650 MW in January 2003 and 2005, respectively. Finally, upgrades to the southern portions of the West of River and East of River systems were assumed to result in an increase of approximately 800 MW in transfer capability along various paths from Palo Verde to San Diego in January, 2005.

A Competitive Market is Assumed

From summer 2000 until spring 2001, the wholesale electricity market in California was not competitive. During most hours, constraints on supply (due to the need for maintenance, poor hydro conditions, concerns regarding the creditworthiness of the IOUs, and the strategic withholding of capacity), as well as the absence of a price signal that would have reduced consumption, allowed generators to sustain market clearing prices well above their operating costs.

The Staff's simulation of the wholesale electricity market during 2002 - 2012 assumes that it is competitive during all but peak hours, *i.e.*, it is not possible during other hours for the market price to be sustained above the variable costs of the most expensive unit that is operating. Yet it acknowledges that less-efficient generators will only continue operating if they can recover non-variable operating costs such as start-up, no-load and fixed operating costs. Accordingly, these generators, totaling 45 percent of the capacity in the WSCC, were assumed to include these costs in their offers in the spot market during peak hours, with a corresponding effect on the market clearing price. When reserve margins are high, inclusion of these costs will not have a substantial effect on the clearing price, as less-efficient generators operate infrequently. These generators are called upon more often when reserve margins are low; including non-variable costs leads to a larger increase in the average clearing price.

Scenario Results

The remainder of this chapter presents, and then discusses, the results of the market simulation scenarios. Among the quantitative results are the following:

- Average annual and monthly on- and off-peak energy spot market clearing prices.
- Annual capacity factors for new combined cycle, existing large steam boilers, and peaking units.

Spot Market Prices

The annual average wholesale market prices for California are presented in **Table II-2-3** for each scenario.

Table II-2-3