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CALIFORNIA ENERGY FLOW IN 1987

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ABSTRACT

California is noteworthy because of its diversity of energy supply and its proclivity to change and experiment in all matters relating to energy use and development. In many instances the state's approach has presaged national trends.

Overall energy use in the state increased 6% spread over almost all end-use sectors. The increase reflected a colder year than 1986 and a large population increase. On the supply side, the most impressive change in meeting demand was a substantial (23%) increase in the use of natural gas particularly for power production and in the industrial sector. The increase was fostered by drought conditions that limited hydropower, by the increased availability of out-of-state supplies, and by changes in regulations governing gas transmissions.

The number of cogenerators and self-generators grew faster than in the nation as a whole. The amount of power sold to the utilities by this group was double the amount sold in 1985 posing problems to utilities and regulatory agencies alike. Alternate sources of energy continued to grow. The state's windfarms and geothermal installations are the largest in the world. The state sponsored methanol program moved ahead with the introduction of flexible fueled automobiles into the state's fleet and installation of a large number of service stations selling the fuel. Nonetheless California's energy picture is dominated by the use of petroleum and natural gas, the bulk of which are imported.

INTRODUCTION

For the past ten years energy flow diagrams for the State of California have been prepared from available data by members of the Lawrence Livermore National Laboratory.[1-6] They have proven to be useful tools in graphically expressing energy supply and use in the State as well as illustrating the difference between particular years and between the State and the U.S. as a whole.

As far as is possible, similar data sources have been used to prepare the diagrams from year to year and identical assumptions[2] concerning conversion efficiencies have been made in order to minimize inconsistencies in the data and analyses. Sources of data used in this report are given in Appendix A and B; unavoidably the sources used over the 1976-1987 period have varied as some data bases are no longer available. In addition, we continue to see differences in specific data reported by different agencies for a given year. In particular, reported data on supply and usage in industrial/commercial/firm industrial/ residential end-use categories have shown variability amongst the data gathering agencies, which bars detailed comparisons from year to year. Nonetheless, taken overall some generalizations can be made concerning gross trends and changes.

CALIFORNIA ENERGY FLOW DIAGRAMS

Energy flow diagrams for 1987 and 1986 are shown in Figures 1 and 2 respectively. Energy sources are shown on the left and energy consumption is shown on the right. Also shown on the right are estimates of conversion efficiencies in the end-use sector, which result in a division between useful and rejected energy. The latter consists primarily of heat losses but also includes other sorts of losses such as line losses during electrical transmission. Inputs to total transmitted electricity such as nuclear, geothermal power, etc., are associated with estimated efficiencies of the conversion process to electricity. They vary from 90% in the case of hydroelectric power to 18% for geothermal energy. Assumptions concerning the conversion efficiencies are given in

Appendix C, and their rationale can be found in Ref 2. The box separating the energy source from the final electrical output represents the conversion process. In all cases, the quantities associated with the energy source are calculated based on assumed conversion efficiencies. While it is desirable to minimize the number of assumptions in preparing an energy flow diagram, it is also desirable to express as closely as possible the energy content of the sources used during the year. In this way changes and improvements in overall fuel conversions that occur over the course of time by virtue of fuel switching and use of renewable sources such as windpower or solar energy have an expression in the total energy consumption in the state.

Power from cogenerators and self-generators shown in the figures as inputs to total transmitted electricity appear without a box (representing the conversion process) that ordinarily would appear between the energy content of the fuel and the final product. In this instance, conversion losses are included in "rejected energy" from the industrial sector.

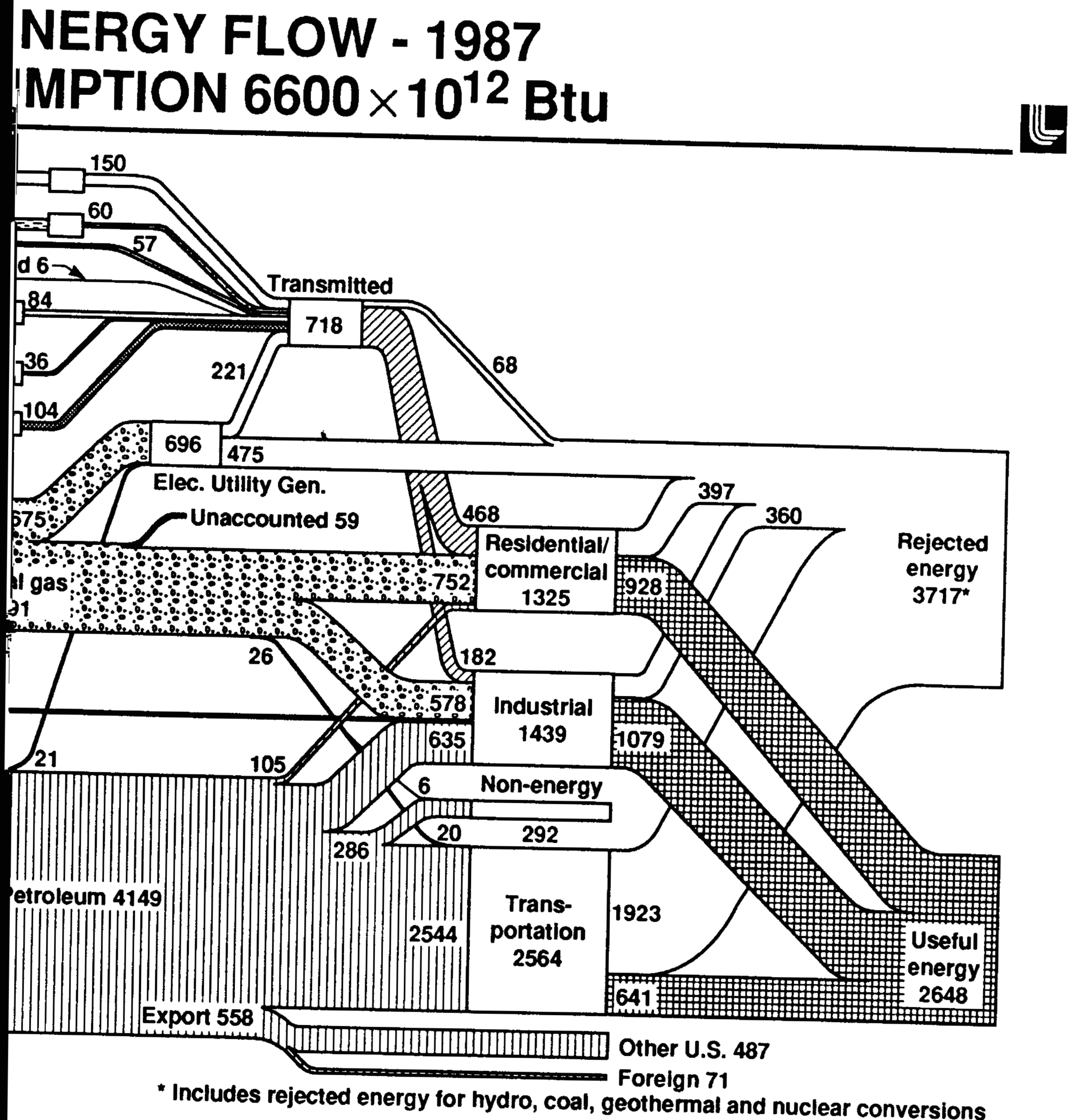
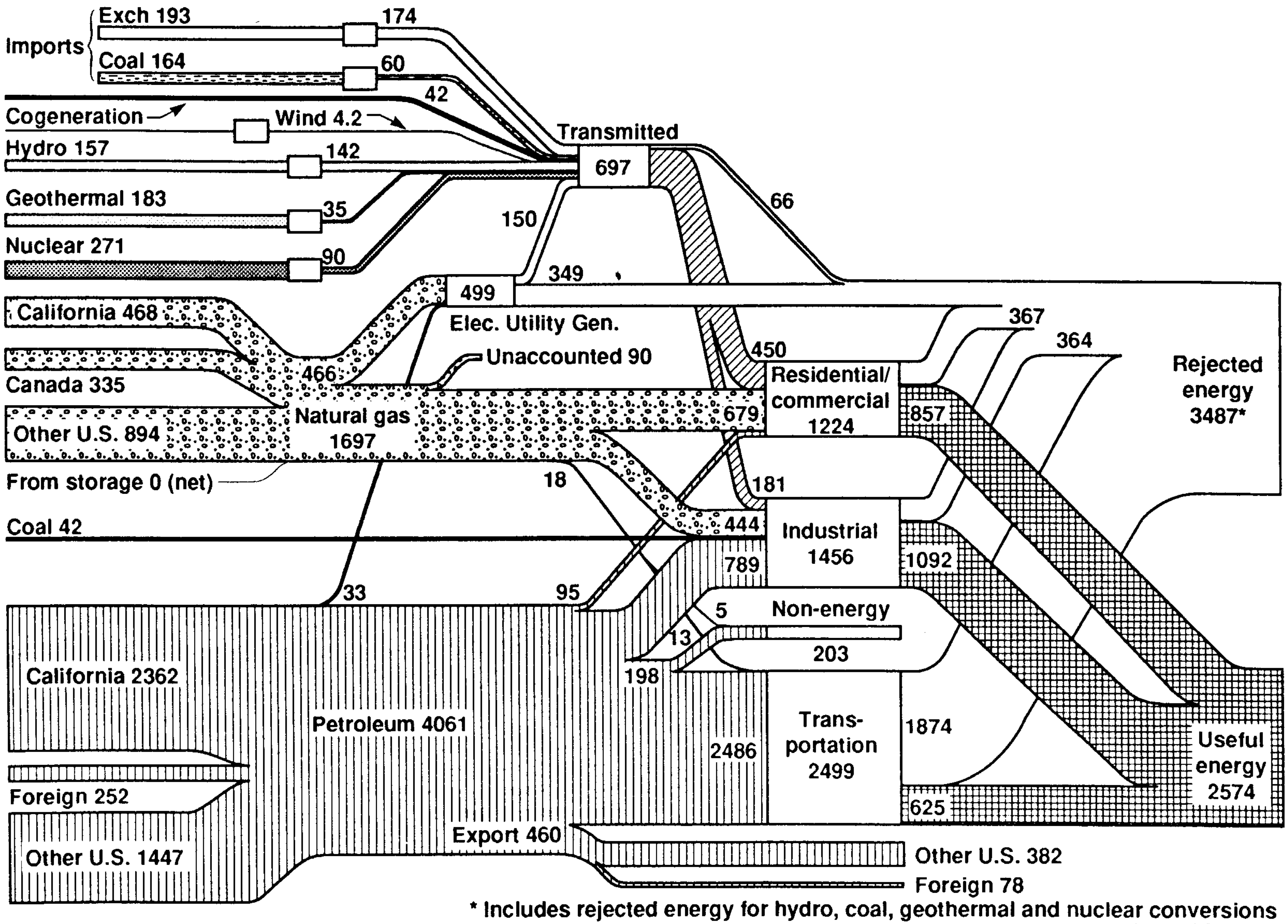

NERGY FLOW - 1987
MPTION 6600×10^12 Btu
150
60
57
d 6
84
36
104
Transmitted
718
221
68
696
475
Elec. Utility Gen.
Unaccounted 59
397
360
468
Residential/
commercial
1325
752
928
Rejected
energy
3717*
26
182
578
Industrial
1439
635
1079
21
105
6
Non-energy
20
292
286
Petroleum 4149
2544
Trans-
portation
2564
1923
Useful
energy
2648
641
Export 558
Other U.S. 487
Foreign 71
* Includes rejected energy for hydro, coal, geothermal and nuclear conversions

Figure 1

CALIFORNIA ENERGY FLOW - 1986
TOTAL CONSUMPTION 6200 $\times 10^{12}$ Btu



I. Borg/C. Briggs
FL-032-U-2615-01

Revised December 1988

Figure 2

CALIFORNIA'S ENERGY FLOW IN 1987 COMPARED TO 1986

Energy consumption in the state increased approximately 6% in 1987 (Table 1) which is almost twice the national record over the same timespan. Part of the increase is due to a colder year as judged by climatic records of urban centers. A larger number of annual heating degree days (Table 2) is reflected in a substantial increase (8%) in residential and commercial use. Another important factor influencing greater energy consumption was a population increase which at mid-year was estimated to be 662,000 or 2.5% for the year.[7] It was the largest increase in 40 years. It is due largely to migration particularly into the southern part of the state. The state's birth rate also exceeds national average which is attributed to migrants, who tend to consist of young adults of child-bearing age.

Table 1

Comparison of Annual Energy Use in California

(in 10^{12} Btu)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Natural Gas	1831	1724	1971	1910	2010	1893	1769	1865	2034	1697	2091
Crude Oil (net)	3720	3781	3967	3834	3650	3327	3329	3477	3580	3601	3591
Transmitted Electricity	574	597	617	622	620	642	622	700	673	697	718
Residential/Commercial	1253	1321	1398	1334	1370	1225	1268	1176	1325	1224	1325
Industrial	1248	1088	1216	1294	1400	1570	1395	1493	1648	1456	1439
Non-energy	221	239	304	298	165	158	183	185	208	203	292
Transportation	2199	2438	2478	2471	2430	2265	2313	2464	2384	2499	2564
Total Energy Consumption†	6000	6050	6500	6400	6300	6000	5900	6200	6400	6200	6600

† Total is not sum of above figures because of rounding and inclusion of losses associated with conversion to electrical energy.

Table 2

<u>Weather Comparison</u>
1958 - 1987
Annual Heating Degree Days**

	San Francisco Federal Office Building	Los Angeles Civic Center	San Diego Lindbergh Field
1958	2332	849	805
1967	2978	1040	1380
1968	2942	850	1052
1969	3066	1032	1145
1970	3006	941	1137
1971	3468	1424	1657
1972	3240	918	1166
1973	3161	1066	1137
1974	3182	1084	1123
1975	3313	1548	1416
1976	2665	1128	793
1977	2888	911	747
1978	2599	1208	736
1979	2545	1160	902
1980	2799	597	590
1981	2819	506	573
1982	3195	975	913
1983	2386	602	623
1984	2648*	704	713
1985	2486	921	1079
1986	1842	473	843
1987	2150	979	1201
Normal 1951-80	3071	1204	1284

*CA. Mission Dolores - same historical data as for Federal Office Building
Source: Local Climatological Data for San Francisco, Los Angeles and San Diego.

** A "degree day" is a term that describes the relationship of energy consumption to outdoor temperatures. "Heating or cooling degree days" are deviations of the mean daily temperature from 65° F. For example for a day with a mean temperature of 40°F., the "heating degree days" would be 25 and the "cooling degree days" 0. Annual heating degree days are the sum for the year. Greater number of heating degree days means greater fuel requirements.

Table 3

California Transportation End Use

(in 10^{12} Btu)

	1980	1981	1982	1983	1984	1985	1986	1987
Net gasoline	1375	1384	1345	1418	1413	1445	1543	1576
Net aviation fuel	346	335	298	318	348	379	392	390
Taxable diesel fuel-public highways	160	166	161	168	201	207	218	174
Rail diesel	43	46	42	41	27	31	31	30
Net bunkering fuel	430	412	346	316	390	274	267	347
Military	32	42	36	35	40	33	35	28
Natural gas (pipeline fuel)	n.a.	n.a.	n.a.	11.	12.	15	13	20
Total	2386	2385	2228	2307	2431	2384	2499	2565

n.a.: not available

The growth in energy use in the transportation end-use sector (Table 3) continued albeit at a slower pace than during the 1985-86 period. Consumption of transportation fuels reached an all time high in the state as a consequence of low fuel prices following the 1986 break in the world price of crude oil and California's steady population increase. Industrial consumption of energy remained close to 1986 levels although the slate of fuels used continued to change.

From the standpoint of supply the most impressive change in California's energy picture is the dramatic increase (23%) in the use of natural gas in the industrial sector and for power production. This was possible because of the gas surplus existing in the southwest, availability of Canadian gas, and changes in pipeline regulations that made both more accessible to potentially large users. Starting in 1986 large users could choose between gas utility contracts or elect to have the utility transport customer-owned gas to their facilities. In 1987 the amount of gas transported by the utilities for others reached record levels. The end-use to which this gas was put is not always a matter of record; however the principal users are self-generating electrical installations, cogenerators and enhanced oil recovery (EOR) operations, some of which are also cogenerators. In 1987 more than 20% of the gas moving through the state was customer-owned.[8]

More than forty percent of California's oil production requires steam stimulation.[9] EOR operators traditionally have used lease crude and low grade oils to raise steam for injection into California heavy oil fields. The rule of thumb is that it requires one barrel of oil to fuel boilers in order to recover two to four barrels of oil. The cost of pollution abatement associated with use of the low quality, typically sulfurous oils, has made natural gas economically attractive as an alternative fuel for steam generation given its current availability. In EOR installations, as well as in other industrial activities such as canning and refining, concomitant cogeneration of electricity has proven profitable. The electricity is either used on site or sold to the utilities under the Public Utilities Regulatory Policies Act of 1978 (PURPA).

The utilities themselves turned to natural gas for power production in 1987 to compensate for the drop in hydropower available on the Pacific Coast due to a dry 1986-87 winter. Imported power from the Pacific Northwest, principally from the Bonneville Dam, was substantially down during the year as was power from California dams. Use of natural gas by the utilities for electrical generation increased 45%. At the same time total transmitted power from all sources showed only a small (3%) increase. Oil, which is used as a peaking fuel, made a very small contribution to electrical generation.

OIL AND GAS PRODUCTION

California's oil production, which is about one million barrels per day, fell for the second year.[9] This occurred despite a halt in the five year production decline at Elk Hills field (Naval Petroleum Reserve No. 1), the fourth largest producer in the state after the South Belridge, Midway-Sunset, and Kern River fields. The decline in output was attributed to depressed oil prices which affected marginal producers. Where increases in onshore fields were recorded, they were due to enhanced oil recovery using steam injection.

Offshore production from federal offshore fields showed an increase for the year although the two largest installations (the Honda and Beta fields) recorded declines. The first offshore production from the Santa Maria Basin occurred in the Point Pedernales field near Point Arguello on leases acquired in 1981 (OCS Sale No. 53). Discoveries made on southern and central California OCS leases acquired in four sales in the 1982-4 period have yet to produce any oil or gas due to protracted litigation on environmental impacts.

Controversy reached new heights over the proposed Federal Outer Continental lease sales (OCS Sales No. 90 and 119) in the next few years in northern and central California. There has been insistence on the preservation of what is pristine coastal areas from both environmental groups as well as local inhabitants who do not want an oil industry in their area. The areas particularly in the north do not appear from all pre-sale assessments to be important oil provinces. Some thirty exploratory holes were drilled and abandoned in the late sixties in federal waters following an earlier sale (OCS Sale P-1 in 1963).

Production of both onshore associated and nonassociated natural gas declined in 1987. These two sources essentially contribute equally to the total; offshore production in both state and federal waters is small. Combined state production meets 21% of demand.

NATURAL GAS SUPPLY

The growing use of natural gas has encouraged many large users - utilities, cogenerators and enhanced oil recovery operators - to look for new sources of supply. Because in most cases this involves interstate transfers, the Federal Energy Regulatory Agency (FERC) has been the critical regulating body whose stated objective is to insure the most efficient transportation of the lowest priced gas. Large users propose to negotiate their own contracts with producers and look to the interstate gas transmission companies, who in some cases are subsidiaries of the utilities, and gas utilities to deliver the gas. Thus at the same time the pipelines lose end-use customers and are still bound by "take or pay" contracts to buy gas from gas producers. FERC Order 500, which became effective January 1, 1988, is an interim rule that would allow pipelines to make transportation of gas conditional on producers granting them some relief from their "take or pay" contracts.

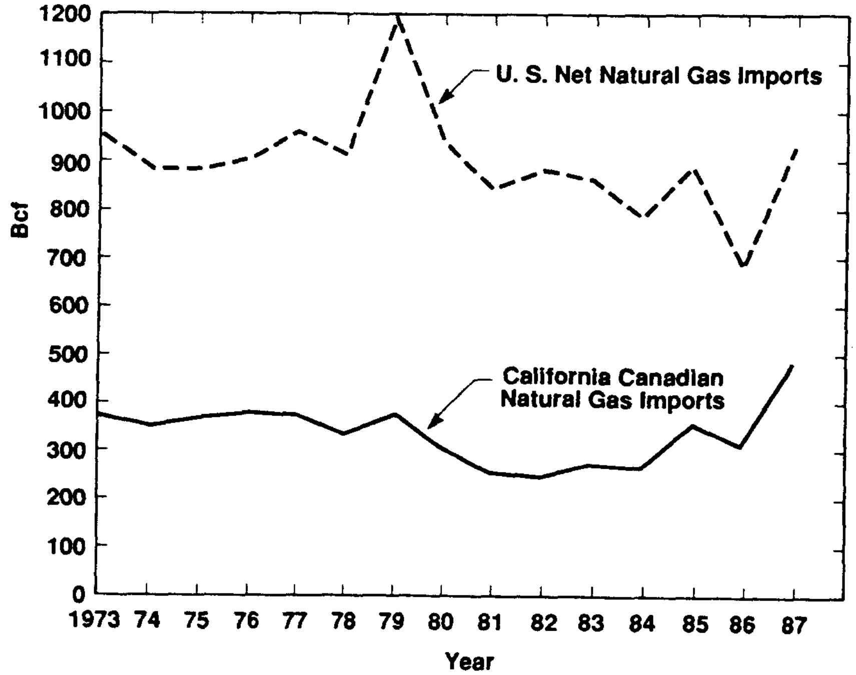
The growth in the number of so-called "non-core" gas customers has posed numerous problems for the gas utilities, who in the past have relied on long term contracts with producers to meet demand. Their large customers can remain "core" customers with a guaranteed supply, become "non core" customers and rely on the gas purchased by the utilities on short term basis, or look to the utility to transport gas that they have independently purchased. Even with the most astute planning the utilities are facing increased financial risk in their operations since the numbers of customers in the last two categories are increasing.

The quantities of natural gas planned for enlarged EOR projects have fostered at least three gas pipeline proposals (Mojave Pipeline Co., Kern River Transmission Co. and Wyoming-California Pipeline Co.) which are before FERC. A fourth, El Dorado Pipeline Co., at one time was also competing for the market. Not surprisingly, the utilities who currently service EOR activities have testified against the proposals since loss of these large consumers would require that a larger share of their fixed costs be passed on to the residential and commercial core customers. They argue that existing transmission services are adequate and that the principal reason for the proposals is to avoid regulation by the California Public Utilities Commission (CPUC).[10]

Nonetheless, Southern California Gas Co. was forced to curtail deliveries to its large industrial customers at the end of the year for the first time in 10 years. Pipeline proponents blamed a shortage of gas pipeline capacity, and the utility blamed the cold weather elsewhere that cut gas supplies for delivery to California. As a matter of record, demand in December 1987 was 25% more than in December 1986[11], suggesting that there were several contributing factors leading to the curtailment.

For the last several years almost half of the total natural gas imports from Canada (Figure 3) have come to California. Relaxation of Canadian price and export restrictions starting in 1983 and culminating in the free trade agreement negotiated between the U.S. and Canada in 1988 has reversed the decline in gas exports from Canada and promises to increase volumes imported into the U.S. in the next decade especially to the northeast U.S.[12] The actual volume of Canadian gas imported to California increased 34% in 1987 and will probably only be limited in the future by pipeline capacity to the state. Increases reflect the objectives of natural gas trade groups and an emerging priority in state and federal governmental agencies to promote natural gas as an alternative to oil imports. Some fraction of the increased use in California however, is for power generation by self generators, cogenerators and utilities who must operate in regions of the state that cannot meet federal air control standards.

Figure 3 Net Natural Gas Imports



Source: U. S. Department of Energy, EIA, Natural Gas Monthly and Ref. 12.

ELECTRIC POWER

Source of supply

Nameplate electrical generating capacity in the state is a poor guide to the source of electricity as can be ascertained by comparing generating capacity (Table 4) with sources of supply (Table 5). This is not unusual because some fuels are used primarily to meet peak loads and because California relies heavily on out-of-state electrical supplies. Peak demand was approximately 45 GWe in 1987.[13]

Table 4

California Electrical Generating Capacity[13, 14]

Primary energy source	Capacity (GWe)
Utility*	
Petroleum	3.14
Gas	21.25
Water	12.44
Nuclear	5.61
Other (principally geothermal)	1.99
SUB-TOTAL	44.44
Cogeneration	3.56
Wind	1.35
Biomass	0.21
Landfill gas	0.19
Small Hydro	0.18
Solar	0.18
Municipal solid waste	0.02
TOTAL	50.13

* Summer capability as of December 31, 1987

Table 5

Sources of California Utilities' Electricity- 1987

Source	Net electrical energy (trillion Btu)	
Imports		210
Out-of-state coal facilities	60	
Purchases	150	
Fossil fuels		221
Natural gas	214	
Oil	7	
Nuclear power		104
Hydropower		84
Geothermal power		36
Windpower		6
Cogeneration		57
TOTAL		718

Cogeneration

Cogeneration of electricity in California continued to grow faster than in the nation as a whole. The growth reflects the heavy oil industry in the state that depends heavily on steam EOR processes. Some fraction of the power produced by the industrial sectors that have built cogenerating plants is used by the producer so that the amount of electricity purchased and transmitted to ultimate consumers by the utilities (Table 6) has to be an understatement of the power produced and used. In 1987 it was on the order of 10% of the electricity used in the state. Qualified facilities* selling electricity to the principal utilities received a weighted average price of 2.9 cents per kWh during the year, less than half of the price five years earlier; however the utilities are locked into many long term contracts at higher prices which were negotiated prior to the 1986 worldwide drop in oil prices.

Table 6

Utility purchases of electricity from cogenerators and self-generators (Million MWh)

1983	2.2	1986	12.4
1984	4.7	1987	16.7
1985	7.7		

Source: Dennis Smith, California Energy Commission, personal communication, November 1988.

The growth of the small producers has led to some concern by the principal utilities since it represents loss of customers that until this decade were among their largest. Recovery of fixed costs of the utilities base load generating plants is thus born increasingly by the residential

* A qualified facility under PURPA is a small power producer who produces less than 80 MWe of electricity from solid waste or renewable resources. Also included in the group are cogenerators that meet minimum size, fuel use and fuel efficiency requirements prescribed by rule by FERC.

and commercial customers. During 1987 Pacific Gas and Electric Co. (PG&E) persuaded its largest customer, Chevron, to defer construction of a 100 MWe cogenerating plant to serve its oil refinery by offering to lower its rates; however the agreement has yet to be approved by the CPUC.[15] Such inducements have also been successful with other customers, who like Chevron view their decision to stay on the system as deferral of their plans to become either cogenerators or self-generators. In a particularly bizarre example, the CPUC allowed PG&E to make a nonrefundable payment of $14 million to Crockett Cogeneration for delaying for five years the construction of a 240 MWe gas-fired plant.[16] The rationale was that if it were built, the utility would have to pay anywhere from $25 to $100 million more for electricity it does not need. Nonetheless, the northern California utility has lost 99 customers by year-end, and expects the trend to continue.

On the positive side, with the loss of customers the utilities are able to meet the overall growth in demand for power in the state without building additional base load facilities. As current growth is equivalent to approximately 1000 MWe per year and because approximately 13 GWe of the 55 GWe (includes self-generators) available capacity was considered surplus in 1987, there will be no need for new plants for at least a decade.[17]

Nuclear Power

California utilities operate six nuclear plants at three sites with a combined capacity of 5.6 GWe, and Southern California Edison Co. has a partial interest in the Palo Verde nuclear complex in Arizona. One of the six, Rancho Seco near Sacramento (913 MWe), was shut down in 1985 after a cooling malfunction and remained closed throughout 1987. Its performance as judged by capacity factors had been subaverage since its opening in 1974. Concerns about its safety led to a referendum in 1988 to decide whether it should be allowed to operate on a trial basis following the $400 million repairs made after the 1985 incident. It survived by a very narrow margin.

The controversial Diablo Canyon nuclear plant, while performing well, continued to pose serious problems for its owner since discussions continued with the CPUC on how much of its $5.8 billion cost should be incorporated into the rate base. By year-end a tentative settlement was considered whereby the utility's revenues would depend on how well the plant performs over its 30-year lifetime. This "performance-based pricing" obviates prudency hearings and disallowances. The unique proposal could set a precedent for solution of similar impasses in prudency disputes elsewhere in the country.

Renewable sources of electricity

Geothermal Energy

California's Geysers geothermal field is the largest producing field in the world with a net, generating capacity of 1773 MWe.[18] Although no new power plants came on line during 1987 steam production - hence electrical production - rose a few percent. An additional 177 MWe of generating capacity was either under construction or in the planning stage at year-end.

The Geysers geothermal system is dominated at depth by steam as contrasted to other geothermal systems elsewhere in the state that are predominantly hot water systems. Although more difficult to develop and often involving brine-rich waters, water-dominated geothermal resources in the state are enormous. Their development is underway in the southern part of the state at the Salton Sea where 42 MWe is operating and 112 MWe is under construction, at East Mesa where there is 60 MWe operating and 74 MWe in the planning stage, at Coso with 25 MWe, and at Heber with 92 MWe. In other parts of the state, e.g. at Susanville, use of geothermal resources for district heating are being explored.

Windpower

Despite loss of federal and state tax credits, the wind industry continued to grow in 1987 (Table 7). There is a nominal 1.3 GWe installed capacity at seven sites in California, an increase of 68 MWe. Capacity factors were low for the year - 16% - but somewhat higher than the 13% recorded in the previous two years.[19] The capacity factor is the ratio of actual output to the amount of energy a project would produce if it operated at full rated power, 24 hours a day over a given period. They do not reflect nonoperational turbines. Most studies suggest 20-30% as within the reach of wind technology. Coupled with the low capacity factors achieved, the actual output in kWh was 40% below projections. The statewide total was 1.73 billion kWh produced primarily during the summer and fall months. In a somewhat misleading statement, the California Energy Commission (CEC) equates the output to "power to meet the annual electricity needs of approximately 285,000 typical California homes."[19] The statement implies 500 kWh/month consumption, which may be the average use for all types of living units served, but it is not typical use in a fully occupied home. Further, the statement suggests that windpower could supplant conventional power production whereas in fact, a back-up system is required since windpower is only available 16% of the year.

Turbines in the 50-100 kW size account for almost two-thirds of total wind capacity, and turbines of foreign manufacture continue to make up a large portion (44%) of the total. There are no plans to build more multi-megawatt turbines, and the two in operation are scheduled to be dismantled.[20] The weighted average cost for new capacity installed during 1987 was $1070/kWh, down 43% from two years earlier.[19]

Table 7

Windpower Installations in California as of January I

Location	Capacity (MWe)				Number of turbines			
	1985	1986	1987	1988	1985	1986	1987	1988
Altamont Pass area, 45 miles east of San Francisco	318	524	584	654	3900	5175	6219	6615
San Gorgonio Pass, Riverside Co. near Palm Springs	150	197	295	254	2450	2945	4155	3830
Tehachapi Pass, Kern Co.	132	188	355	393	1950	2733	4175	4480
Mojave Desert, Kern Co.	7	(n.a.)	0	0	150	(n.a.)	0	0
Boulevard, San Diego Co.	4	1.25	0.8	0.8	16	51	36	36
Carquinez Strait, Solano Co.	3	.63	0	0.63	10	6	0	6
Pacheco Pass, San Benito Co.	0	(n.a.)	0.5	0.5	0	(n.a.)	20	20
Salinas Valley	0	0.1	0.16	0.16	0	4	4	4
TOTAL	609	911	1235	1304	8476	10914	14609	14991

n.a. = not available

Source: California Energy Commission, Results from the Wind Project Performance Reporting, System 4th Q (1984, 1985, 1986); Results from the Wind Project Performance System 1985 Annual Report, August 1986, 1987.

Solar

Solar contribution to the total electrical supply provided by utilities remained small - 3,812 MWh out of a total of 152 million MWh, which was slightly greater than in the previous year.[21] The source of the solar electricity was divided between solar thermal involving the use of parabolic collectors and photovoltaic panels. All projects in the state are demonstrations supported in large part by public agencies.

METHANOL AS A TRANSPORTATION FUEL IN CALIFORNIA

There about 700 methanol-fueled vehicles in use in California by private companies and public agencies. In 1987 the first flexible fueled vehicles, mid-size Fords, were acquired for testing by the CEC, the Air Resources Board and the South Coast Air Quality Management District.[22] These vehicles have an optical fuel sensor which determines the percentage of methanol in the fuel and adjusts the fuel injection system and ignition timing for optimum performance of the engine. In cooperation with the CEC, Atlantic Richfield Co has agreed to install methanol pumps at 25 retail gasoline outlets in southern California, which would bring to 45 the number of service stations in the state selling methanol. Chevron, U.S.A. is contemplating joining the group. The pumps dispense a fuel consisting of 85 percent methanol and 15 percent premium unleaded gasoline. To encourage the use, the Governor of the state has signed legislation to authorize the purchase of several thousand flexible fueled cars and light trucks as part of an expanded demonstration program. Apart from the advantage of moving away from depleting oil products, use of methanol can provide substantial emission reductions in areas of the state with extreme air pollution problems.

IMPORTS AS A FRACTION OF STATE CONSUMPTION

California is notable for its diversity of sources of energy supply - particularly its electrical supply. Many alternate forms of energy have been developed in the state to the point of being the largest in the world, for example its wind farms and geothermal fields. Other novel energy supplies, such as methanol as an alternate automotive fuel, have been given their first widespread trial within the state. Cogeneration has flourished because of the need for steam on the part of major indigenous industries, such as EOR, oil refining, and food processing and the favorable economics associated with the sale of electricity to the utilities stemming from the passage of PURPA. The state's penchant for dynamic change has penetrated the regulatory sector of the state as well leading to adjustments designed to foster conservation, energy efficiency, alternate fuels and energy sources as well as utilization of out-of-state gas that has been search of markets.

Nonetheless, 49 percent of the energy consumed* in the state was from out-of-state sources (cf Figure 1) - 36% of the petroleum, 78% of the gas and 29% of transmitted electricity. California oil and gas production accounted for 41% of the remaining energy consumed.

* Of the 6600 x 10^{12} Btu consumed, imports (less exports) comprised 1288 x 10^{12} Btu petroleum, 1631 x 10^{12} Btu natural gas, and 330 x 10^{12} Btu electricity for a total of 3249 x 10^{12} Btu.

Appendix A

Data Sources for California Energy Supply (1987)

Production	Source
Crude Oil including Federal Offshore and Lease Condensate	Ref. 9.
Associated and Nonassociated Natural Gas (Dry)	Ref. 23, Table 42. Summary Statistics for Natural Gas - California.
Electric Utility Fuel Data	Ref. 24, Table 33. Total Petroleum Consumption by Census Division and State. Table 34. Total Gas Consumption by Census Division & State.
Electrical Generation Oil, gas, hydro, nuclear, geothermal	Ref. 24, Tables 16, 17, 18, 19, 20. Total Petroleum (Gas, Hydroelectric, Nuclear, Other) by Census Division & State.
Wind	Ref. 19.
Cogeneration	Ref. 25.
Imports	
Natural Gas	
Foreign	Ref. 25.
Domestic	Ref. 23, Table 42.
Crude Oil Foreign and Domestic	Ref. 26, Table 1. California Petroleum Summary.
Oil Products Foreign and Domestic	Ref. 26, Fourth Quarter, Table A-1. California Petroleum Fuels Market Activity.

Coal	Ref. 27, Table 24. Coal Consumption by Census Division and State.
Electrical Power	
Net Exchange	Ref. 25.
Coal	Ref. 25.

<u>Exports</u>

Oil Products	
Foreign and Domestic (not including bunkering fuel supplied at California ports)	Ref. 26. Fourth Quarter, Table A-1.

Appendix B

Data Sources for California End Uses (1987)

Net Storage	
Natural Gas	Ref. 23, Table 42.
Unaccounted for Natural Gas	Ref. 23, Table 42.
Transportation	
Crude Oil	
Gasoline, aviation and jet fuels	Ref. 26, Fourth Quarter, Table A-1. (CA supplied).
Taxable Diesel Fuel (for public highways)	Ref. 28, Table A-11. Sales of Distillate Fuel Oil by End Use.
Vessel Bunkering (includes international bunkering)	Ibid.
Rail Diesel	Ibid.
Military Use	Ibid.
Natural Gas	
Pipeline fuel	Ref. 23, Table 13. Consumption of Natural Gas.
Industrial, Government, Agriculture, etc.	
Natural Gas (includes lease and plant fuel)	Ref. 23, Table 42.
Coal	Ref. 27, Table 24.
Electricity	Ref. 24, Table 88. Industrial Sales of Electricity to Ultimate Consumers by Census Division and State.
Crude Oil	By Difference.

Non Energy Applications	
Crude Oil and LPG	
Asphalt	Ref. 29
Petrochemical feedstock	Ref. 30, Table 8. PAD District V, Supply and Disposition of Crude Oil and Petroleum Products, 1987.
Waxes, lubricating oils, medicinal uses, cleaning	Ref. 26, Table A-5. California Refinery Activity by Type and Area.
Natural Gas	
Fertilizer	Ref. 31
Residential and Small Commercial	
Natural Gas	Ref. 23, Table 42.
Crude Oil and Other Oils (kerosene, residual, and distillate)	Ref. 28, Table A-6. Sales of Kerosene by End Use. Table A-5.Sales of Residual Fuel Oil by End Use. Table A-4.Sales of Distillate Fuel Oil by End Use.
LPG	Ref. 30, loc. cit.
Miscellaneous "off highway" Diesel	Ref. 28, Table A-4.
Electricity	Ref. 24, Table 86. Residential Sales of Electricity by End Use. Table 87. Commercial Sales of Electricity by End Use. Table 89. Other Sales of Electricity by End Use.

Appendix C

Conversion Units

Energy Source	Conversion factor, 10^6 Btu
Electricity	3.415 per MW.h
Coal	22.6 per short ton
Natural Gas	1.05 per Mcf
Crude Oil	5.80 per barrel
Fuel Oil	
Residual	6.287 per barrel
Distillate, including diesel	5.825 per barrel
Gasoline and Aviation Fuel	5.248 per barrel
Kerosene	5.67 per barrel
Asphalt	6.636 per barrel
Road Oil	6.636 per barrel
Synthetic Rubber and Miscellaneous LPG Products	4.01 per barrel

Assumed Conversion Efficiencies of Primary Energy Supply

Electric Power Generation	
Hydro Power	90%
Coal	30%
Geothermal	18%
Oil and Gas	33%
Uranium	32%
Transportation Use	25%
Residential/Commercial Use	70%
Industrial Use	75%

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