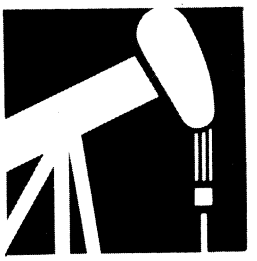
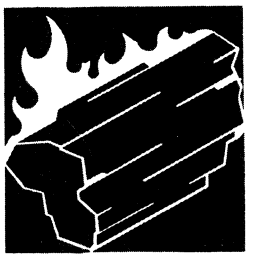
APPENDICES

BIENNIAL FUELS REPORT

CALIFORNIA ENERGY COMMISSION





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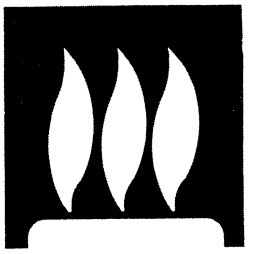

SEPTEMBER 1986

George Deukmejian, Governor

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BIENNIAL FUELS REPORT
September 1986

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APPENDIX A

STATE ENERGY SUPPLY AND DEMAND STATISTICS: HISTORIC AND FORECASTED

APPENDIX A

STATE ENERGY SUPPLY AND DEMAND STATISTICS: HISTORIC AND FORECASTED

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Table A-3 - Presents projected data on primary energy receipts and deliveries for the years 1985, 1990, 1997 and 2005.

Table A-4 - Presents projected data on energy deliveries by sector for the years 1985, 1990, 1997 and 2005.

The numbers in ( ) refer to the corresponding numbers in the data source documentation which follows the tables.

TABLE A-1

HISTORICAL
PRIMARY ENERGY RECEIPTS AND DELIVERIES
(Trillions of BTU)

ORIGIN	1976	1977	1978	1979	1980	1981	1982	1983	1984
ENERGY TYPE									
California Receipts									
Natural Gas(1)	346	350	344	374	346	388	397	421	464
Petroleum(2)	1,834	1,976	1,964	1,991	2,021	2,113	2,198	2,229	2,308
Natural Gas Plant Liquids(3)	59	57	60	62	64	59	54	48	51
Hydropower(4)	92	57	144	134	164	119	177	232	180
Geothermal and Other(5)	74	74	60	80	101	113	91	130	134
Subtotal California	2,405	2,514	2,572	2,641	2,696	2,792	2,917	3,060	3,137
Other States Receipts									
Natural Gas(6)	1,144	1,104	1,046	1,215	1,253	1,340	1,148	1,024	1,059
Petroleum(7)	433	637	1,377	1,701	1,708	1,718	1,363	1,342	1,476
Liquified Petroleum Gas(8)	5	6	6	6	4	5	2	6	16
Coal(9)	191	217	166	196	224	239	248	219	208
Hydropower(10)	118	52	93	57	100	134	207	216	271
Nuclear(11)	51	87	81	96	51	36	37	43	138
Subtotal Other States	1,942	2,103	2,769	3,271	3,340	3,472	3,005	2,850	3,168
Foreign Receipts									
Natural Gas(12)	395	392	352	396	324	269	319	293	283
Petroleum(13)	1,758	2,080	1,150	949	719	376	254	327	345
Liquified Petroleum Gas(14)	3	1	2	3	3	2	4	2	11
Subtotal Foreign	2,156	2,473	1,504	1,348	1,046	647	577	622	639
Total Receipts									
Natural Gas	1,885	1,846	1,742	1,985	1,923	1,997	1,864	1,738	1,806
Petroleum	4,025	4,693	4,491	4,641	4,448	4,207	3,815	3,898	4,129
Liquified Petroleum Gas	67	64	68	71	71	66	60	56	78
Coal	191	217	166	196	224	239	248	219	208
Hydropower	210	109	237	191	264	253	384	448	451
Nuclear	51	87	81	96	51	36	37	43	138
Geothermal and Other	74	74	60	80	101	113	91	130	134
Grand Total Receipts	6,503	7,090	6,845	7,260	7,082	6,911	6,499	6,532	6,944
EXPORT									
ENERGY TYPE									
Export									
Petroleum(16)	687	715	704	611	602	666	673	629	653
Liquified Petroleum Gas(17)	2	6	4	6	7	5	4	6	27
Total Export	689	721	708	617	609	671	677	635	680
STORAGE									
ENERGY TYPE									
Change									
Natural Gas(18)	43	33	-2	-40	-61	-59	-62	51	-19
Petroleum(19)	-68	121	-195	4	113	-107	-35	-77	-34
Coal(20)	-1	10	-4	-2	3	2	-4	5	--
Liquified Petroleum Gas(21)	-1	0	-1	1	2	0	-1	2	-1
Total Change	-27	164	-202	-37	57	-164	-102	-19	-54
DELIVERIES									
ENERGY TYPE									
Deliveries									
Natural Gas	1,842	1,813	1,744	2,025	1,984	2,056	1,926	1,687	1,825
Petroleum									
Motor Gasoline	1,307	1,397	1,405	1,447	1,372	1,321	1,340	1,415	1,415
Aviation Fuels	336	372	387	381	363	348	335	357	392
Distillate Fuels	303	381	410	404	386	424	411	464	489
Residual Fuels	915	1,144	1,023	1,081	929	798	519	467	523
Misc. Fuels	545	563	757	713	683	757	572	643	691
Subtotal Petroleum	3,406	3,857	3,982	4,026	3,733	3,648	3,177	3,346	3,510
Liquified Petroleum Gas	66	58	65	64	62	61	57	48	58
Coal	192	207	170	198	221	237	252	214	208
Hydropower	210	109	237	191	264	253	384	448	451
Nuclear	51	87	81	96	51	36	37	43	138
Geothermal and Other	74	74	60	80	101	113	91	130	134
Grand Total Deliveries	5,841	6,205	6,339	6,680	6,416	6,404	5,924	5,916	6,324

TABLE A-2

HISTORICAL
DELIVERIES BY SECTOR
(Trillions of Btu)

SECTOR/ENERGY TYPE	1976	1977	1978	1979	1980	1981	1982	1983	1984
Electric Utility									
Natural Gas(22)	302	364	312	458	534	678	571	486	599
Petroleum									
Distillate(24)	0	0	0	0	0	0	2	2	2
Residual(25)	596	774	619	640	391	284	99	65	22
Subtotal	596	774	619	640	391	284	101	67	24
Coal(26)	135	141	110	138	152	165	187	188	182
Hydropower(27)	210	109	237	191	264	253	384	448	451
Nuclear(11)	51	87	81	96	51	36	37	43	138
Geothermal and Other(12)	74	74	60	80	101	113	91	130	134
Total	1,368	1,549	1,419	1,603	1,493	1,529	1,371	1,362	1,528
Electricity Delivered(28)	520	527	545	567	566	591	578	584	611
Conversion Loss	800	976	821	983	870	893	754	704	797
Transmission Loss(29)	48	46	53	53	57	45	39	74	120
Total Loss	848	1,022	874	1,036	927	938	793	778	917
Residential End User									
Electricity(30)	154	162	174	182	176	183	179	187	200
Natural Gas(31)	610	569	584	621	557	518	559	515	502
Petroleum(35)									
Distillate Fuel Oil	5	7	7	7	1	1	1	1	1
Subtotal Petroleum	5	7	7	7	1	1	1	1	1
LPG(37)	9	9	14	18	18	16	16	15	15
Subtotal Residential	777	747	779	828	752	718	755	718	718
Commercial End User									
Electricity(30)	194	187	191	198	204	197	197	203	213
Natural Gas(31)	183	187	174	177	165	178	187	173	172
Petroleum(35)									
Motor Gasoline	11	13	16	14	10	8	8	8	8
Distillate Fuel Oil	9	13	13	10	21	30	29	27	27
Residual Fuel Oil	25	27	25	28	43	40	35	20	20
Subtotal Petroleum	45	53	54	52	74	78	72	55	55
LPG(37)	2	2	3	3	3	3	3	3	3
Subtotal Commercial	424	429	422	430	446	456	459	434	443
Industrial End User									
Electricity(30)	172	178	180	187	186	211	202	194	198
Natural Gas(31)	747	693	674	769	728	682	609	513	552
Petroleum(35)									
Motor Gasoline	8	6	5	6	9	7	7	7	7
Distillate Fuel Oil	78	104	110	138	105	112	127	103	103
Residual Fuel Oil	106	107	90	89	85	59	55	46	46
Other Petroleum	544	561	756	711	681	784	569	640	689
Subtotal Petroleum	736	778	961	944	880	962	758	796	845
LPG(37)	54	47	47	41	39	39	35	27	37
Coal(26)	57	66	60	60	69	72	65	26	26
Subtotal Industrial	1,766	1,762	1,922	2,001	1,902	1,966	1,669	1,556	1,658
Transportation End User									
Petroleum(35)									
Motor Gasoline	1,288	1,378	1,384	1,427	1,353	1,306	1,325	1,400	1,400
Aviation Fuels	336	372	387	381	363	348	335	357	392
Distillate Fuel Oil	211	257	280	249	259	281	252	331	356
Residual Fuel Oil	188	236	289	324	410	385	330	336	435
Lube Oil	1	1	1	2	2	3	3	3	2
Subtotal Petroleum	2,025	2,244	2,351	2,383	2,387	2,323	2,245	2,427	2,585
LPG(37)	1	1	1	2	2	3	3	3	3
Subtotal Transportation	2,026	2,245	2,352	2,385	2,389	2,326	2,248	2,430	2,588
Total End User	4,993	5,183	5,465	5,644	5,489	5,466	5,131	5,138	5,407
			TOTAL END USER DELIVERIES						
End User Deliveries									
Electricity	520	527	545	567	566	591	578	584	611
Natural Gas	1,540	1,449	1,432	1,567	1,450	1,378	1,355	1,201	1,226
Petroleum(34)									
Motor Gasoline	1,307	1,397	1,405	1,447	1,372	1,321	1,340	1,415	1,415
Aviation Fuels	336	372	387	381	363	348	335	357	392
Distillate Fuels	303	381	410	404	386	424	409	462	487
Residual Fuels	319	370	404	441	538	514	420	402	501
Misc. Fuels	545	563	757	713	683	757	572	643	691
Subtotal Petroleum	2,810	3,083	3,363	3,386	3,342	3,364	3,076	3,279	3,486
Liquified Petroleum Gas	66	58	65	64	62	61	57	48	58
Coal	57	66	60	60	69	72	65	26	26
Total End User	4,993	5,183	5,465	5,644	5,489	5,466	5,131	5,138	5,407

TABLE A-3

PROJECTED
PRIMARY ENERGY RECEIPTS AND DELIVERIES
(Trillions of Btu)

ORIGIN/ENERGY TYPE	1985	1990	1997	2005
California Receipts				
Natural Gas(1)	425	339	296	249
Petroleum(2)	2,318	2,474	2,472	1,908
Natural Gas Plant Liquids(3)	49	52	54	58
Hydropower(4)	150	214	224	236
Geothermal and Other(5)	170	632	780	1,035
Subtotal California	3,112	3,711	3,826	3,486
Other States Receipts				
Natural Gas(6)	1,083	1,015	995	818
Petroleum(7)	1,625	1,511	1,727	1,488
Liquified Petroleum Gas(8)	5	5	5	5
Coal(9)	251	303	362	425
Hydropower(10)	214	130	143	151
Nuclear(11)	350	394	395	364
Subtotal Other States	3,528	3,358	3,627	3,251
Foreign Receipts				
Natural Gas(12)	453	478	497	493
Petroleum(13)	309	265	265	1,301
Liquified Petroleum Gas(14)	2	2	2	2
Subtotal Foreign	764	745	764	1,796
Other Receipts				
Oil/Gas(15)	0	232	421	787
Total Receipts				
Natural Gas	1,961	1,832	1,779	1,558
Oil/Gas	0	232	421	787
Petroleum	4,252	4,250	4,464	4,697
Liquified Petroleum Gas	56	59	61	65
Coal	251	303	362	425
Hydropower	364	344	367	387
Nuclear	350	394	395	364
Geothermal and Other	170	632	780	1,035
Grand Total Receipts	7,404	8,046	8,638	9,320
EXPORT				
ENERGY TYPE				
Export				
Petroleum(16)	650	670	699	742
Liquified Petroleum Gas(17)	6	6	5	5
Total Export	656	676	704	747
STORAGE				
ENERGY TYPE				
Change				
Natural Gas(18)	--	--	--	--
Petroleum(19)	--	--	--	--
Coal(20)	--	--	--	--
Liquified Petroleum Gas(21)	--	--	--	--
Total Change	--	--	--	--
DELIVERIES				
ENERGY TYPE				
Deliveries				
Natural Gas	1,961	1,832	1,788	1,560
Oil/Gas	0	232	421	787
Petroleum				
Motor Gasoline	1,487	1,484	1,537	1,636
Aviation Fuels	405	462	507	563
Distillate Fuels	488	543	586	635
Residual Fuels	449	351	377	327
Misc. Fuels	774	740	758	794
Subtotal Petroleum	3,603	3,580	3,765	3,955
Liquified Petroleum Gas	50	53	56	60
Coal	251	303	362	425
Hydropower	364	344	367	387
Nuclear	350	394	395	364
Geothermal and Other	170	632	780	1,035
Grand Total Deliveries	6,748	7,370	7,934	8,573

TABLE A-4

PROJECTED
DELIVERIES BY SECTOR
(Trillions of Btu)

SECTOR / ENERGY TYPE	1985	1990	1997	2005
Electric Utility				
Natural Gas(22)	555	372	344	210
Oil/Gas(23)	0	0	40	220
Petroleum				
Distillate(24)	3	0	3	4
Residual(25)	22	0	84	22
Subtotal	25	0	87	26
Coal(26)	203	248	309	372
Hydropower(27)	364	344	367	387
Nuclear(11)	350	394	395	364
Geothermal and Other(5)	170	632	780	1,035
Total	1,667	1,990	2,322	2,614
Electricity Delivered(28)	612	694	796	876
Conversion Loss	964	1,192	1,407	1,607
Transmission Loss(29)	91	104	119	131
Total Loss	1,055	1,296	1,526	1,738
Residential End User				
Electricity(30)	193	218	253	284
Natural Gas(31)	590	571	584	593
Petroleum(35)				
Distillate Fuel Oil	6	6	6	6
Subtotal Petroleum	6	6	6	6
LPG(37)	15	15	15	15
Subtotal Residential	804	810	858	898
Commercial End User				
Electricity(30)	216	243	277	303
Natural Gas(31)	217	218	234	244
Petroleum(35)				
Motor Gasoline	8	8	8	9
Distillate Fuel Oil	13	13	14	15
Residual Fuel Oil	25	26	26	27
Subtotal Petroleum	46	47	48	51
LPG(37)	4	4	4	4
Subtotal Commercial	483	512	563	602
Industrial End User				
Electricity(30)	202	233	266	289
Natural Gas(31)	599	671	626	513
Oil/Gas(33)	0	232	381	567
Petroleum(35)				
Motor Gasoline	7	7	7	8
Distillate Fuel Oil	103	106	114	123
Residual Fuel Oil	55	46	46	46
Other Petroleum	771	737	755	791
Subtotal Petroleum	936	896	922	968
LPG(37)	28	31	34	38
Coal(26)	48	55	53	53
Subtotal Industrial	1,813	2,118	2,282	2,428
Transportation End User				
Petroleum(36)				
Motor Gasoline	1,472	1,469	1,522	1,619
Aviation Fuels	405	462	507	563
Distillate Fuel Oil	363	418	449	487
Residual Fuel Oil	347	279	221	232
Lube Oil	3	3	3	3
Subtotal Petroleum	2,590	2,631	2,702	2,904
LPG(37)	3	3	3	3
Subtotal Transportation	2,593	2,634	2,705	2,907
Total End User	5,693	6,074	6,408	6,835

TOTAL END USE DELIVERIES

End User Deliveries				
Electricity	612	694	796	876
Natural Gas	1,406	1,460	1,444	1,350
Oil/Gas	0	232	381	567
Petroleum(34)				
Motor Gasoline	1,487	1,484	1,537	1,636
Aviation Fuels	405	462	507	563
Distillate Fuels	485	543	583	630
Residual Fuels	427	351	293	305
Mis. Fuels	774	740	758	794
Subtotal Petroleum	3,578	3,580	3,678	3,929
Liquified Petroleum Gas	50	53	56	60
Coal	48	55	53	53
Total End User	5,693	6,074	6,408	6,835

DATA SOURCE DOCUMENTATION

(1) California Receipts of Natural Gas:

- o 1976 - 1984 - California Division of Oil and Gas annual net production of wet and dry gas.
- o 1985 - 2005 - CEC Natural Gas Supply and Price Forecast 1985-2005, July 1985, median case plus estimated natural gas direct deliveries to industry and use of gas by producers and natural gas processors based on historical pattern.

(2) California Receipts of Petroleum:

- o 1976 - 1984 - California Division of Oil and Gas annual gross production of crude oil and condensate.
- o 1985 - 2005 - CEC projected California oil production from Annual Petroleum Review, July 1983.

(3) California Receipts of Natural Gas Plant Liquids:

- o 1976 - 1982 - CEC Quarterly Fuel and Energy Reports annual interstate receipts from Liquefied Petroleum Gas Marketers Report (GM-02).
- o 1983 - 1984 - DOE Natural Gas Processors Report (EIA-816 also known as QFER Form 9) annual product output.
- o 1985 - 2005 - Estimated output based on historical ratio of wet gas processed to product produced.

(4) California Receipts of Hydropower:

- o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports annual hydrogeneration from Electric Utility Generation Report (EU-01).
- o 1983 - 1985 - CEC, Quarterly Fuel and Energy Report annual hydrogeneration from Electric Utility Generation Report (Form 1).
- o 1985 - 2005 - CFM V Resource Plan 1983-2004* Table 3.2-2 of The 1985 California Electricity Report, Appendices - Volume I hydroelectric generation.

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*In all cases where CFM V Resource Plan 1983-2004 forecasts were used, 1989 values were substituted for 1990 values, 1996 values were used for 1997 and 2004 values were used for 2005.

(5) California Receipts of Geothermal and Other:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual geothermal and other generation from Electric Utility Generation Report known as EU-01 prior to 1983 and Form 1 from then on.

- o 1985 - 2005 - CFM V Resource Plan 1983-2004 Table 3.2-2 of The 1985 California Electricity Report, Appendices - Volume I geothermal and other generation.

(6) Other States Receipts of Natural Gas:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual receipts of gas from federal offshore and other states from the Gas Utility Supply and Distribution Report known as GU-01 prior to 1983 and Form 6A from then on.

- o 1985 - 2005 - CEC, Natural Gas Supply and Price Forecast 1985-2005, July 1985.

(7) Other States Receipts of Petroleum:

- o 1976 - 1981 - CEC, Quarterly Fuel and Energy Reports annual interstate receipts of crude oil and unfinished oil from refineries origins of crude oil receipts (OR-02) and interstate receipts of petroleum products from Major Oil Marketers Finished Product Supply and Distribution Report (OM-01).

- o 1982 - 1984 - CEC, PIIRA annual domestic crude receipts less California receipts plus unfinished oil receipts from other states from California Refineries Annual Report (CEC-A04) plus petroleum product receipts from other states from California Major Petroleum Product Marketers Report (CEC-M07) and from California's Major Petroleum Product Storers Report (CEC-M12).

- o 1985 - 1997 - Total petroleum deliveries less California and foreign petroleum deliveries.

- o 1998 - 2005 - California OCS crude oil receipts, APR, June 1984, plus Alaska crude oil receipts based on William Wade, Dames and Moore, "Alaska 1985: Exploration Activity and Production Forecast to 2005," plus estimated amount of petroleum product import based on historical trends.

(8) Other States Receipts of Liquefied Petroleum Gas:

- o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports other states annual receipts of liquefied petroleum gas from Liquefied Petroleum Gas Marketers Report (GM-01).

o 1983 - 2005 - Estimated by CEC staff based on historical trends.

(9) Other State Receipts of Coal:

o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual coal receipts at coal plants generating electricity for California from Electric Utility, Coal Requirements Report (EU-05) prior to 1983 then from Electric Utility Fuel Data (Form 3). Plus annual coal use from California from DOE State Energy Data Report.

o 1985 - 2005 - CFM V Resource Plan 1983-2004 Table 3.2-2 of The 1985 California Electricity Report, Appendices - Volume I, coal generation plus estimated coal use by industry based on historical trends.

(10) Other States Receipts of Hydropower:

o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual net receipts of electricity from interstate sources from Electric Utility System Energy Report (EU-02) prior to 1983 then from Electric Utility Capacity and Energy Transaction Report (Form 2).

o 1985 - 2005 - CFM V Resource Plan 1983-2004, Table 3.2-2 of The 1985 California Electricity Report, Appendices - Volume I.

(11) Other States Receipts of Nuclear:

o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual electric generation at nuclear plants from Electric Utility Generation Report (EU-01) prior to 1983 then from Electric Utility Generation (Form 2).

o 1985 - 2005 - CFM V Resource Plan 1983-2004, Table 3.2-2 of The 1985 California Electricity Report, Appendices - Volume I.

(12) Foreign Receipts of Natural Gas:

o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual natural gas receipts from foreign sources from Gas Utility Supply and Distribution Report (GU-01) prior to 1983 then from Natural Gas Utility Supply (Form 6A).

o 1985 - 2005 - Natural Gas Supply and Price Forecast 1985-2005, July 1985.

(13) Foreign Receipts of Petroleum:

o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports annual crude oil and unfinished oil receipts from foreign sources from Refineries Origin of Crude Oil Receipts Report (OR-02)

plus foreign receipts of finished products from California Major Oil Marketers Finished Product Supply and Distribution Report (OM-01).

- o 1983 - 1984 - CEC, PIIRA foreign receipts of crude oil and unfinished oil from California Refiners Annual Report (CEC-A04) plus foreign imports from California Major Petroleum Product Marketers Report (CEC-M07) and from California Major Petroleum Product Storers Report (CEC-M12).

- o 1985 - 1997 Projected foreign receipts of crude oil and foreign imports of petroleum products assumed to remain constant.

- o 1998 - 2005 Total California petroleum deliveries less California petroleum deliveries and other states deliveries.

(14) Foreign Receipts of Liquefied Petroleum Gas:

- o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports annual foreign receipts of liquefied petroleum gas from the Liquefied Petroleum Gas Marketers Report (GM-02).

- o 1983 - 2005 - Estimated by CEC staff based on historical trends.

(15) Other Receipts Oil/Gas:

- o 1985 - 2005 - Difference between natural gas demand from Appendix B and Supply From Natural Gas Supply and Price Forecast 1985-2005, July 1985.

(16) Export of Petroleum:

- o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports annual export of petroleum products from Major Oil Marketer Finished Product Supply and Distribution Report (OM-01) and crude oil exported from Major Crude Oil Producers Production and Distribution Report (OP-01).

- o 1983 - 1984 - CEC, PIIRA annual product export from California Major Petroleum Product Marketers Report (CEC-M07) and Major Petroleum Product Storers Report (CEC-M12).

- o 1985 - 2005 - CEC estimated petroleum exports based on historical trends.

(17) Export of Liquefied Petroleum Gas:

- o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports annual export of liquefied petroleum gas from Major Liquefied Petroleum Gas Marketers Report (GM-02).

- o 1983 - 2005 - CEC estimated liquefied petroleum gas exports based on historical trends.

(18) Storage Change Natural Gas:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual gas to storage less gas from storage from Gas Utility Supply and Distribution Report (GU-01) prior to 1983 then from Natural Gas Utility Supply Report (Form 6A).

- o 1985 - 2005 - Assumed no change on annual basis.

(19) Storage Change Petroleum:

- o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports end-of-year stocks less beginning-of-year stocks of finished products from Major Oil Marketers Finished Product Supply and Distribution Report (OM-01) and crude oil stocks from Refiners Stocks Report (OR-06) and crude oil stocks from Major Crude Oil Producers Production and Distribution Report (OP-01) and petroleum product stocks from Electric Utility Oil Requirements Report (EU-03).

- o 1983 - 1984 - CEC, PIIRA end-of-year stocks less beginning-of-year stocks from California Major Petroleum Product Marketers Report (CEC-M07) and California Major Petroleum Product Storers Report (CEC-M12) and crude oil stocks from Monthly Refiners Report (DOE/EIA-810).

- o 1985 - 2005 - Assumes no change in stocks.

(20) Storage Change for Coal:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports end-of-year stocks of coal less beginning-of-year stocks from Electric Utility Coal Requirements Report (EU-05) prior to 1983 then from Electric Utility Fuel Data Report (Form 3).

- o 1985 - 2005 - Assumes no change in stocks.

(21) Storage Change for Liquefied Petroleum Gas:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports end-of-year stocks of liquefied petroleum gas less beginning-of-year stocks from Major Liquefied Petroleum Gas Marketers Report (GM-02) prior to 1982 then from DOE Natural Gas Processors Report (EIA-816) also known as QFER Form 9.

- o 1985 - 2005 Assumes no change in stocks.

(22) Electric Utility Gas Deliveries:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual gas burned from Electric Utility Gas Deliveries and Availability Report (EU-04) prior to 1983 then from Electric Utility Fuel Data Report (Form 3).

- o 1985 - 2005 - Natural Gas Supply and Price Forecast 1985-2005, July 1985.

(23) Electric Utility Oil/Gas Deliveries:

- o 1985 - 2005 - Natural gas demand from Appendix E less natural gas deliveries from Appendix F.

(24) Electric Utility Distillate Deliveries:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual distillate fuel burned from Electric Utility Oil Requirements Report (EU-03) prior to 1983 then from Electric Utility Fuel Data Report (Form 3).

- o 1985 - 2005 - CFM V Resource Plan 1983-2004 Table 3.2-2 of The 1985 California Electricity Report, Appendices - Volume I. distillate generation from combustion turbine and combined cycle.

(25) Electric Utility Residual Deliveries:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual residual fuel burned from Electric Utility Oil Requirements Report (EU-03) prior to 1983 then from Electric Utility Fuel Data Report (Form 3).

- o 1985 - 2005 - Potential natural gas curtailment to electric utilities from Natural Gas Supply and Price Forecast 1985-2005, July 1985.

(26) Electric Utility Coal Deliveries:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual coal burners from Electric Utility Coal Requirements Report (EU-05) prior to 1983 then from Electric Utility Fuel Data Report (Form 3).

- o 1985 - 2005 - CFM V Resource Plan 1983-2004 Table 3.2-2 of The 1985 California Electricity Report, Appendices - Volume I coal generation.

(27) Electric Utility Hydropower Deliveries:

- o 1976 - 1984 - California Deliveries (Footnote 4) plus other state deliveries (Footnote 10)
- o 1985 - 2005 - CFM V Resources Plan 1983-2004 Table 3.2-2 of The 1985 California Electricity Report, Appendices Volume I, hydrogeneration plus net exchange electricity.

(28) Electricity Delivered by Electric Utilities:

- o 1976 - 1984 - CEC, Quarterly Fuel and Energy Reports annual electricity delivered from Electric Utility Sales Report (EU-06) prior to 1983 then from Detailed Marketing Report (Form 4 and 4A).
- o 1985 - 2005 - CFM V committee directed demand forecast, January 1985.

(29) Electricity Utility Transmission Loss:

- o 1976 - 1982 - CEC, Quarterly Fuel and Energy Reports total electricity supplied from Electric Utility System Energy Report (EU-02) less total electricity delivered from Electric Utility Sales Report (EU-06).
- o 1983 - 1984 - CEC, Quarterly Fuel and Energy Reports total electricity supplied Electric Utility Capacity and Energy Transactions Report (Form 2) less total electricity delivered from Detailed Marketing Report (Form 4 and 4A).
- o 1985 - 2005 - Transmission losses in proportion to historical data trends.

(30) Residential, Commercial and Industrial Electricity Deliveries:

- o 1976 - 1984 CEC, Quarterly Fuel and Energy Reports.
  - 1976 - 1977 Annual electricity use from Electric Utility Sales Report (EU-06A Rate Schedule).
  - 1978 - 1980 Annual electricity use from Electric Utility Sales Report (EU-06B SIC).
  - 1981 - 1982 Annual electricity use from Electric Utility SIC Data Report (EU-07).
  - 1983 - 1984 Annual electricity use data from Detailed Marketing Report (Form 4 and 4A).
- o 1985 - 2005 CFM V Committee directed demand forecast, January 1985.

(31) Residential and Commercial Natural Gas Deliveries:

o 1976 - 1984 CEC, Quarterly Fuel and Energy Reports.

- 1976 - 1977 Annual gas use from Gas Utility Requirements and Deliveries Report (GU-07A Rate Schedule).

- 1978 - 1980 Annual gas use from Gas Utility Requirements and Deliveries Report (GU-07A SIC).

- 1981 - 1982 Annual Gas use from Gas Utility SIC Data Report (GU-05).

- 1983 - 1984 Annual gas use data from Detailed Marketing Report (Form 4 and 4A).

o 1985 - 2005 Natural Gas Supply and Price Forecast 1985-2005, July 1985.

(32) Industrial Natural Gas Deliveries:

o 1976 - 1984 CEC, Quarterly Fuel and Energy Reports.

- 1976 - 1977 Industrial deliveries from Gas Utility Requirements and Deliveries Report (GU-07A Rate Schedule) and gas used in production process and direct deliveries from Major Natural Gas Production Report (GP-01 and GP-03) and gas used by Nataural Gas Plant Operators Report (GP-02).

- 1978 - 1980 Industrial deliveries from Gas Utility Requirements and Deliveries Report (GU-07A SIC) and same data as above from GP-01, GP-02, and GP-03.

- 1981 - 1982 Industrial deliveries from Gas Utility SIC Data Report GU-05 plus same data from GP-01, GP-02 and GP-03.

o 1985 - 2005 Natural Gas Supply and Price Forecast 1985-2005, July 1985, plus estimated gas used in gas production and processing and direct deliveries by producers based on historical trends.

(33) Industrial Deliveries Oil/Gas:

o 1985 - 2005 - Difference between natural gas demand from Appendix E and natural gas supply from Natural Gas Supply and Price Forecast 1985-2005, July 1985.

(34) Petroleum Product Total End User Deliveries:

o 1976 - 1981 - CEC, Quarterly Fuel and Energy Reports total individual product use calculated as follows: Refinery output from Refinery Output Report (OR-04) plus imports plus beginning stocks minus exports minus ending stocks from

Major Oil Marketer Finished Product Supply and Distribution Report (OM-02).

- o 1982 - 1984 - CEC, PIIRA total individual product use calculated as follows: Refinery output from DOE Monthly Refiners Report (EIA-810) plus beginning stocks plus imports less exports less ending stocks from Major Petroleum Products Marketers Report (M07) and Major Petroleum Product Storer Report (M12).

- o 1985 - 2005 - Residential, commercial, industrial and electric utility energy demand and transportation energy demand plus additional demand, based on historical trends of fuel use for off road gasoline and diesel, residual used in shipping, aviation gasoline, and military jet fuel.

(35) Residential, Commercial and Industrial Petroleum Deliveries:

- o 1976 - 1982 - Adjusted U.S. DOE State Energy Data Report, consumption by sector for California.

- o 1983 - 2005 - Estimated by staff based on historical trends.

(36) Transportation Petroleum Deliveries:

- o 1976 - 2005 - Total end use deliveries less residential, commercial, industrial and electric utility use or demand.

(37) Liquified Petroleum Gas Deliveries:

- o 1976 - 1983 - U.S. DOE State Energy Data Report - consumption by sector for California.

- o 1984 - 2005 - Estimate based on historical trends.

APPENDIX B

ENERGY DEMAND

APPENDIX B

ENERGY DEMAND

I. Introduction

Despite many changes in energy use over the last decade, California is still heavily dependent on fossil fuels as a source of energy. Although the electric utility sector has decreased fossil fuel dependence by nearly 40 percent, the transportation sector is still almost 100 percent dependent on fossil fuels as an energy source.

In 1984 fossil fuels accounted for nearly 90 percent of the primary energy consumption (Figure B-1) in California. By comparison, in 1976 fossil fuels accounted for 94 percent of total energy consumption or 5,506 tBtus.[1] As the figure shows for 1984, petroleum accounted for 56 percent of all primary energy consumption, natural gas accounted for 29 percent and coal for another 3 percent.

California is not more dependent on fossil fuels than the nation as a whole but is more dependent on oil and gas. Nationally, petroleum accounts for 43 percent of primary energy consumption while natural gas takes 25 percent of national energy consumption.[2] Coal accounts for 23 percent nationally, a much higher level than in California.

II. Trends in Total Energy Demand

Figure B-2 shows the changes in total state energy consumption trends over the past decade and projections of state energy demand over the next 20 years.

Energy consumption in California rose at an average rate of 4.5 percent per year from 1976 until it peaked in 1979 at 6,680 tBtus. Beginning in 1980, the effects of rapidly increasing energy prices, conservation standards and incentives and a recessionary economy combined to cause energy use to decline. This decline lasted until 1983 when energy consumption in California was about 5,916 tBtus. In 1984, the effects of falling oil prices and a growing economy reversed the decline and energy consumption increased by 6.9 percent to 6,324 tBtus.

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1. The unit of measure used in this analysis is trillion British thermal units or "tBtus" annually. A "Btu" is a measurement of energy equivalent to raising the temperature of one pound of water one degree Fahrenheit.

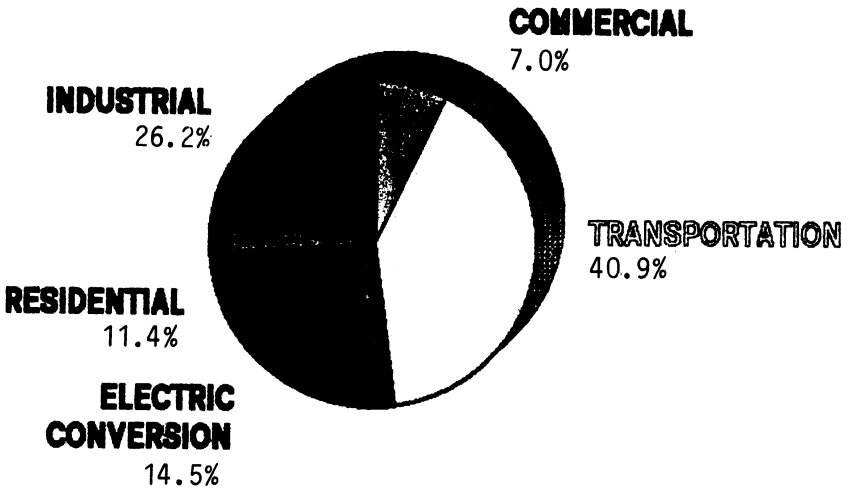
2. Energy Information Administration, State Energy Data Report, May 1985.

FIGURE B-1

1984 ENERGY CONSUMPTION

BY END USE (PERCENT)

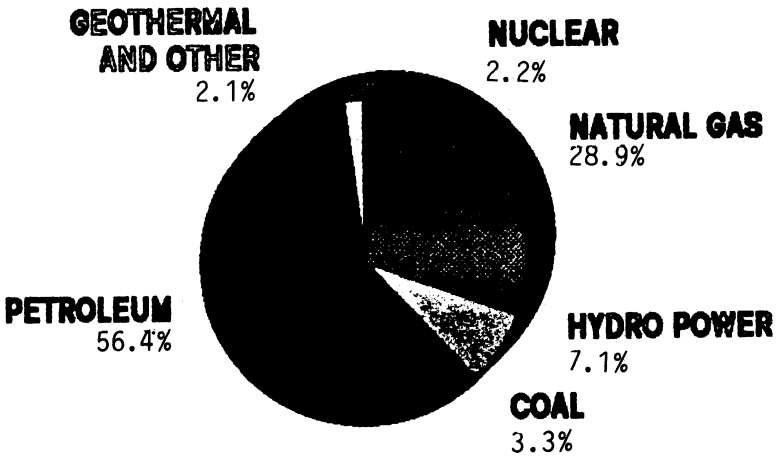
6,324 TBtu Total



1984 ENERGY CONSUMPTION

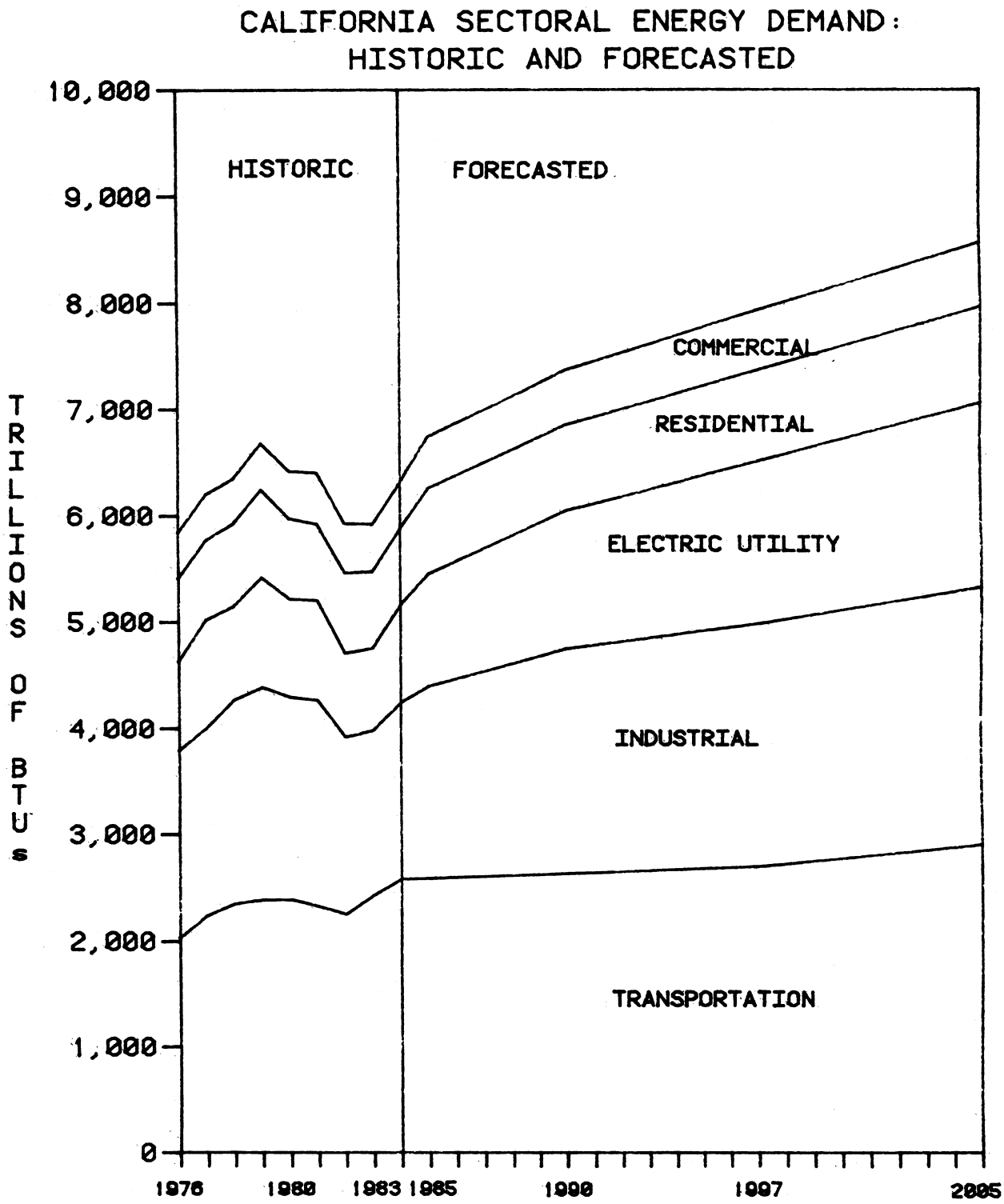
BY FUEL (PERCENT)

6,324 TBtu Total



Source: California Energy Commission 1985 Biennial Fuels Report, Appendix A.

FIGURE B-2



Source: California Energy Commission
1985 Biennial Fuels Report, Appendix A

The CEC projects that total energy demand in California will grow at an average annual rate of about 1.5 percent over the next 20 years reaching a total of 8,573 tBtus by 2005.[3] This forecast assumes healthy economic and population growth as well as moderate increases in energy prices.

III. Energy Demand by End Use

To better understand the trends in energy use, energy demand is often separated into categories defined by the type of use or end-use. The major end-use sectors in California include transportation, electric utility, residential, commercial and industrial. Included in the "industrial" category is energy use for Thermal Enhanced Oil Recovery projects.

In 1984 the transportation sector represented 40.9 percent of total energy consumption. By 2005 this sector's energy demand will decline to 33.9 percent of total energy consumption. On the other hand, the electric generation sector's share of net energy consumption is expected to increase from 14.5 percent in 1984 to 20.3 percent in 2005.

Following is an overview of each sector and an analysis of past and expected future trends.

A. Transportation Demand

Overview. Transportation energy use in the state comprises 40.9 percent of the state's total energy consumption.[4] Fuels included in this category are motor gasoline, diesel used in trucks, trains and farming, jet fuel and residual oil for shipping. Gasoline usage alone is greater in total Btus than the energy consumed in the state's residential and commercial sectors combined. The importance of this sector is further underlined by the fact that over 99 percent of the transportation fuel used is refined from crude oil. In fact, the transportation sector accounted for 73.7 percent of all petroleum consumed in California in 1984.

Trends. During the past nine years energy consumption in the transportation sector has increased from a low of 2,026 tBtus in 1976 to 2,588 tBtus in 1984 or an increase of 28 percent. However the rate of increase has not been steady. As shown in Figure B-3, the period between 1976 and 1984 was characterized by dramatic shifts in consumption trends.

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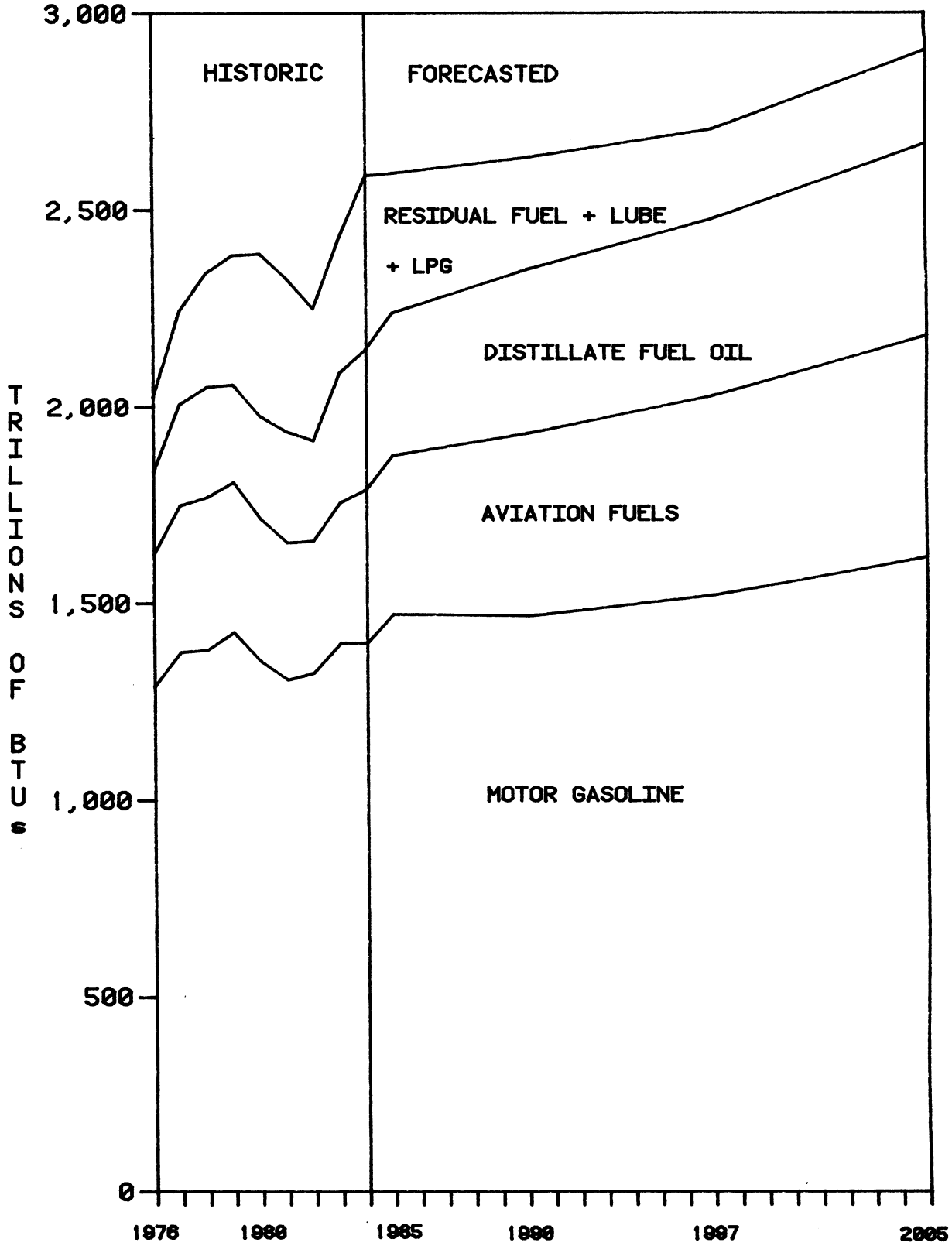
3. Historic and forecasted changes in energy demand and fuel use contained in this chapter are derived from various existing CEC forecasts. Appendix A provides basic data and documentation.

4. Excludes electricity losses from conversion and transmission.

FIGURE B-3

CALIFORNIA TRANSPORTATION SECTOR ENERGY DEMAND:
HISTORIC AND FORECASTED



Source: California Energy Commission 1985 Biennial Fuels Report, Appendix A.

From 1976 to 1979, transportation fuel use increased sharply. Consumption declined markedly from 1979-1981 as the effect of higher mileage cars and higher fuel prices caused by the Iranian oil crisis combined to reduce fuel demand. Since then, the trend has been upward, spurred by decreasing gasoline prices and increasing population and economic growth.

The CEC projects that transportation energy demand will continue to increase throughout the forecast period, as the California economy continues to grow. From its current level of 2,588 tBtus, annual consumption will increase to 2,907 tBtus in 2005. During the period 1984-2005 gasoline demand is expected to increase by a total of 16 percent, while aviation and diesel fuel demand use are projected to increase by 44 percent and 37 percent, respectively.

These projections are based on assumptions of only a moderate increase in fuel prices coupled with continued economic and population growth. Moderate fuel price increases are expected to have the effect of decreasing the share of high fuel efficiency automobile purchases while increasing annual vehicle miles traveled. These trends, however, will be partially offset by increased auto fleet efficiency due to replacement of older, less efficient vehicles since today's fuel efficient automobiles are considerably more efficient than the older vehicles they replace.

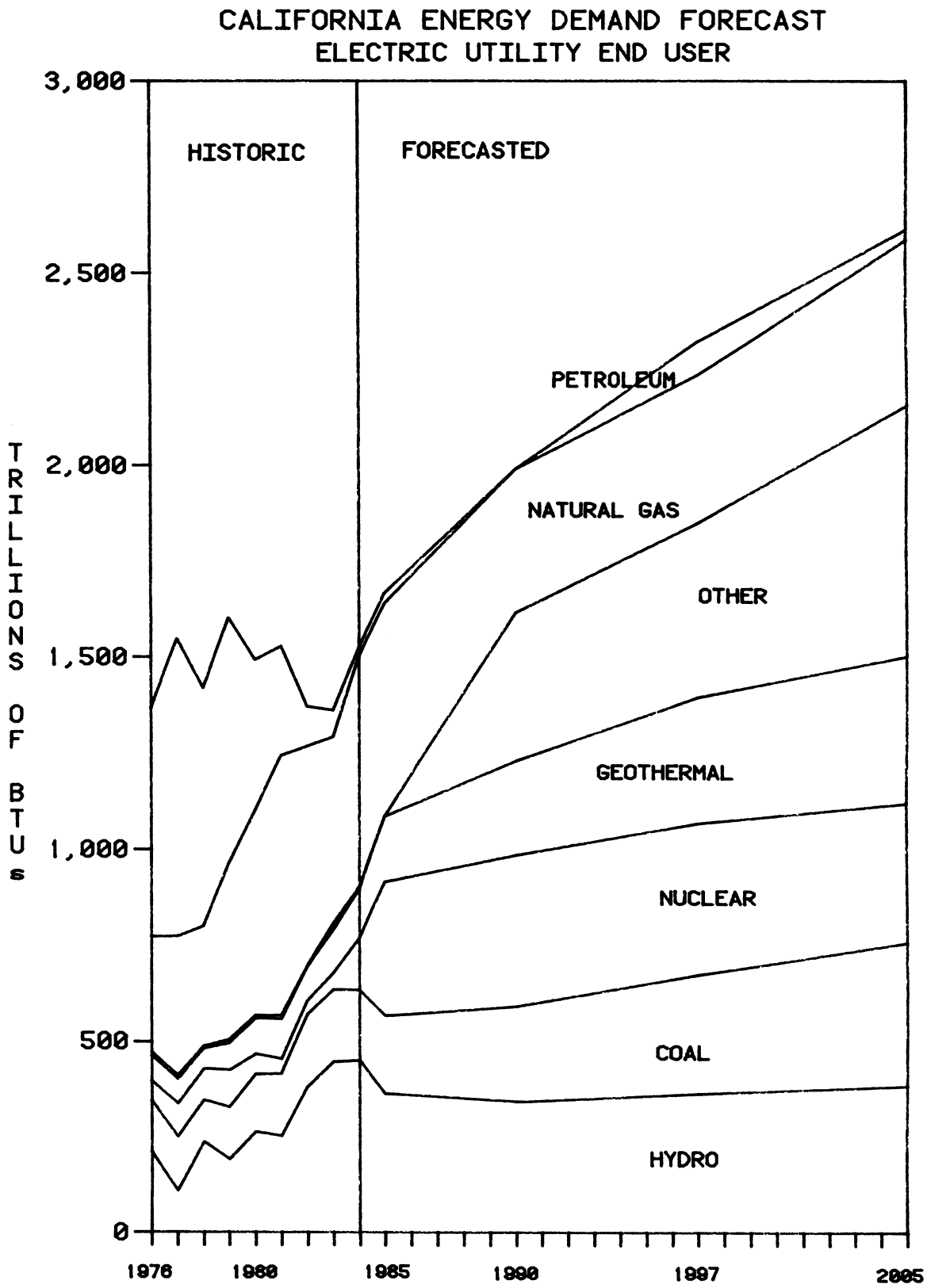
B. Electric Utility Demand

Overview. In 1984, the electricity utility sector consumed 1,528 tBtus of energy. This means that almost 25 percent of the primary energy used in California was used to make electricity. Almost two-thirds of that energy, however, was lost as a result of energy conversion and transmission losses. This sector relies on a variety of different energy sources to meet its needs, including natural gas, oil, hydropower, nuclear, coal and geothermal.

Trends. Between 1976 and 1984 energy consumption in the electricity sector increased from 1,368 tBtus to 1,528 tBtus, an increase of 12 percent (Figure B-4). By the end of the forecast period energy demand for this sector is projected to increase to 2,614 tBtus. This 71 percent increase is due to a 43 percent increase in demand for electrical energy in California resulting from projected increases in population and economic growth. Additionally, expected continued reliance on natural gas in steam electric boilers rather than other more efficient methods of electric generation will also contribute to increased energy demand.

As noted above, past energy requirements for the system have been met by a variety of energy sources. In 1976, for example, two-thirds of the system's needs were met by oil and gas; hydro, coal, nuclear, and geothermal made up the rest of the requirements. By 1980, this fuel mix had changed only slightly, with oil and gas contributing 62 percent of the mix. In 1984, however, oil and gas contributed only about 41 percent of total system energy needs. This change was due primarily to increased hydro generation resulting from above average rainfall, the addition of major nuclear units to the system and additional power from nonutility electric generators (QF). After 1990, increasing energy requirements are projected to be met by new geothermal plants, coal facilities and QFs, many of which will use natural gas.

FIGURE B-4



Source: California Energy Commission 1985 Biennial Fuels Report, Appendix A.

As Figure B-4, shows, electric generation natural gas requirements are expected to decrease by about 28 percent over current levels. "Geothermal and Other" sources of generation which include wind, solar and unidentified generation, will increase their share. These projections are consistent with the CEC adopted demand forecast and the CFM VI resource plans of electric utilities.

C. Industrial Demand

Overview. The industrial sector uses 31 percent of the total end-use energy consumed in the state in three basic areas--process industries, assembly industries, and mining. These subsectors rely on petroleum to meet 52 percent of their energy and feedstock needs, natural gas for 33 percent of their energy requirements and electricity for about 11 percent of their energy needs. Coal and LPG make up the remaining 4 percent. The largest portion of the mining subsector is Thermally Enhanced Oil Recovery (TEOR) which is discussed in detail in the next section.

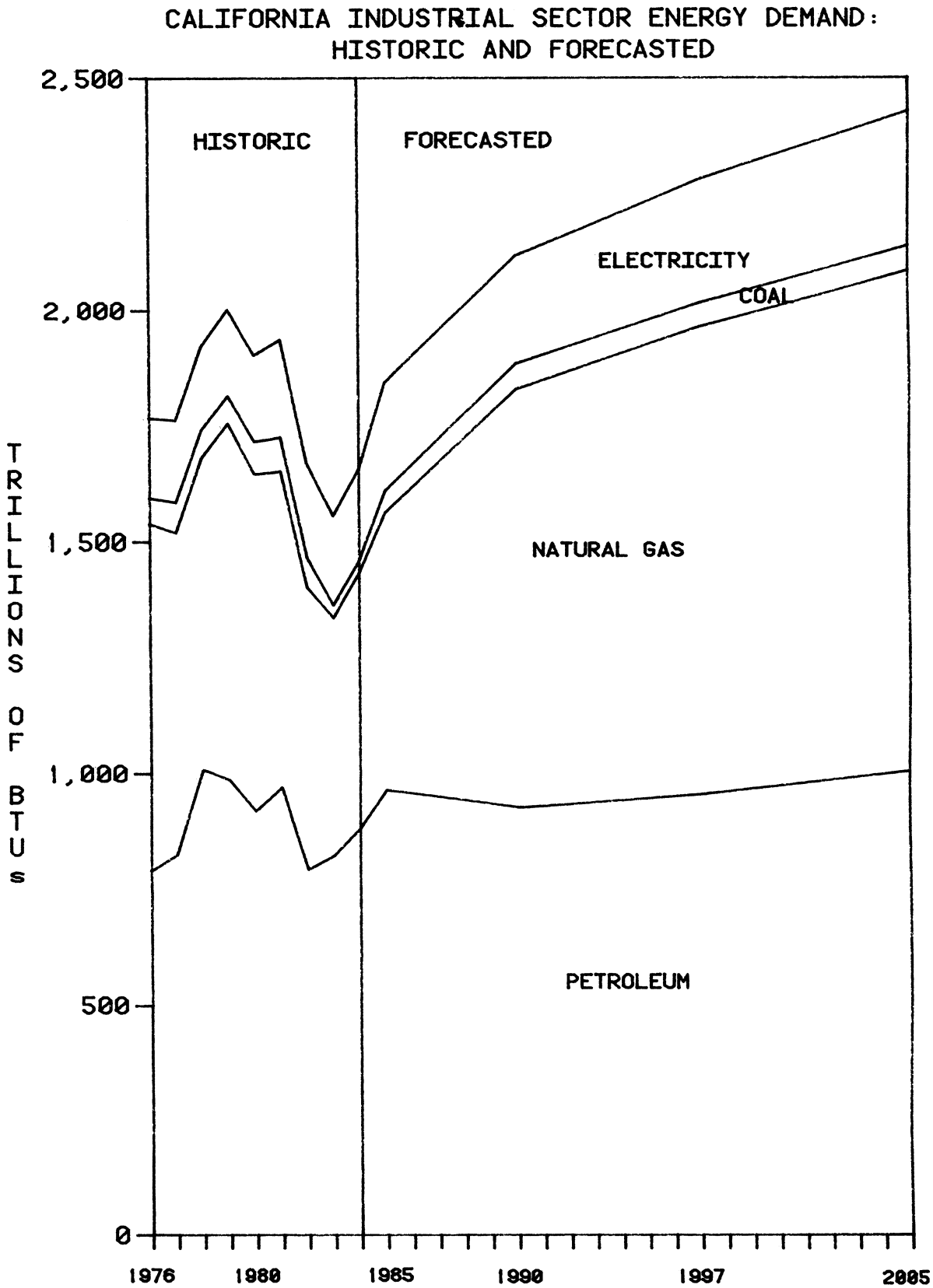
Trends. Total energy consumption in the industrial sector from 1976 to 1984 mirrored usage patterns in other sectors. Consumption increased sharply between 1976 and 1979 and then declined rapidly until 1983 (Figure B-5). Reduced economic activity and conservation induced by high energy costs led to the abrupt decline. In 1984 consumption increased by 7.0 percent--from 1,556 tBtus in 1983 to 1,658 tBtus. The CEC projects that total energy consumption will increase by about 28 percent between 1984 and 1990 (to 2,118 tBtus) and an additional 15 percent by 2005.

Oil/gas consumption patterns in the industrial sector over the next 20 years will principally depend on fuel availability; if natural gas supplies are limited, petroleum is typically used in lieu of gas in a number of applications, particularly in thermally enhanced oil recovery (TEOR). The trends presented here represent the industrial sector's choice of natural gas without regard to its availability.

D. Thermally Enhanced Oil Recovery

Overview. Thermally enhanced oil recovery (TEOR) operations add an element of uncertainty to projecting fuel demand during the forecast period. This is because both the level of development and the mix of fuels that will be used are uncertain. TEOR development is expected to increase significantly during the forecast period and it is expected that a portion of this development will utilize cogeneration for the coproduction of steam (for TEOR) and electricity for sale to electric utilities. If natural gas is the primary fuel, the projected increase in TEOR operations could increase the overall demand for natural gas in the state by more than 20 percent over projected demand levels in the traditional end-use sectors (see Table B-3). However, natural gas requirements in the electric generation sector would be offset to a certain degree (but not completely) because of reduced utility generating requirements permitted by TEOR cogeneration.

FIGURE B-5



Source: California Energy Commission 1985 Biennial Fuels Report, Appendix A.

Trends. Between 1976 and 1984 energy use in TEOR increased by 44 percent from 160 tBtus to 230 tBtus.[5] The CEC projects that continued development of the heavy oil fields and the consequent expansion of TEOR projects will cause fuel demand for meeting steaming requirements to increase to 351 tBtus in 1990. This level of fuel requirements is expected to gradually increase to 390 tBtus by 2005. The CEC forecasts were prepared using an enhanced oil recovery model that simulates production from known California oil production areas.[6]

Natural gas is the preferred fuel of TEOR operators because of its clean combustion characteristics and cost. However, the CEC believes that oil will continue to supply about 20 percent of TEOR energy needs.[7] Oil use will occur where gas conversion is noneconomic due to location, size of the resource or expected life of the project.

Coal for TEOR. Advanced coal-based technologies may be a realistic alternative to using natural gas for TEOR operations. The United States has abundant coal reserves and domestic coal suppliers are willing to enter into long-term supply contracts. Current delivered coal costs to California industry ($2.60/ mmBtu) are lower than current natural gas costs to cogenerators ($3.60-4.40/ mmBtu). No major constraints associated with transport of up to 100 million tons per year of coal into California have been identified.[8]

The CEC staff has concluded that AFBC (a method of utilizing coal in a TEOR application using atmospheric fluidized bed combustion technology) plants up to 500 MW in size could be available for commercial order as early as 1988.[9] In the past, two atmospheric fluidized bed combustion plants have operated in California, one of which was specifically devoted to TEOR activities. General Electric Company, a major supplier of combustion turbines, has a joint venture with Pyropower, a supplier of circulating AFBC systems, to develop AFBC technology using a variety of solid fuels such as coal, petroleum coke, biomass, and municipal solid waste.

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5. Historic TEOR fuel use through 1983 is based on steam injection data published by the Division of Oil and Gas in its Annual Report of the State Oil and Gas Supervisor. TEOR fuel use for 1984 is based on data collected through the Petroleum Industry Information Reporting Act. (See Appendix N.)

6. See Appendix I.

7. Staff presented its assumption of 20 percent continued oil use in TEOR at the August 20, 1985 hearing. No alternative was presented. See Chapter 5 and Appendix I.

8. Radian Corporation, Availability of Western Coal for California Use.

9. CEC Staff Report, Commercial Status of Electrical Generation Technologies (P300-85-003) June 1985, p. 80.

Achievable AFBC nitrogen oxide emissions are comparable to those for gas fired facilities. The CEC will continue to investigate coal as a potential fuel from TEOR development.[10,11]

E. Commercial Demand

Overview. Energy use in the commercial sector accounts for about 8 percent of total end-use energy consumption in California. This sector uses energy primarily for lighting, space conditioning, water heating, office machinery, and refrigeration. Natural gas and electricity are the major sources of energy used.

Trends. Figure B-6 shows that total energy consumption in the commercial sector increased from 424 tBtus in 1976 to 486 tBtus in 1981 and then declined to the current level of 443 tBtus.[12] The CEC projects total demand to increase by 36 percent to 602 tBtus in 2005. Commercial energy demand growth is a function of floor space growth, moderated by mandated and price-induced conservation. Growth in floor space is the result of expected economic growth over the forecast period. Appendix E contains a more detailed description of forecasted natural gas use in the commercial sector.

F. Residential Demand

Overview. The residential sector uses 13 percent of the end-use energy consumed in California. Primary residential energy end uses are for space heating and cooling, lighting, refrigeration, water heating, and powering of appliances. In 1984 natural gas accounted for 70 percent of all residential energy use, electricity accounted for 28 percent, and petroleum and LPG accounted for 2 percent.

Trends. Since 1976, total residential energy use has dropped from 828 tBtus in 1979 to 718 tBtus in 1984 even though the number of residential customers has increased 15.7 percent. New appliance and building standards and price-induced conservation have reduced individual residential use considerably. This is evidenced by the average residential customer's annual gas consumption dropping from 953 therms[13] of gas in 1976 to 680 therms in 1984 while the average residential electrical consumption edged upward from 19.4 million Btus equivalent (5,700 kWh) in 1976 to 20.4 million Btus equivalent (6,000 kWh) in 1984.

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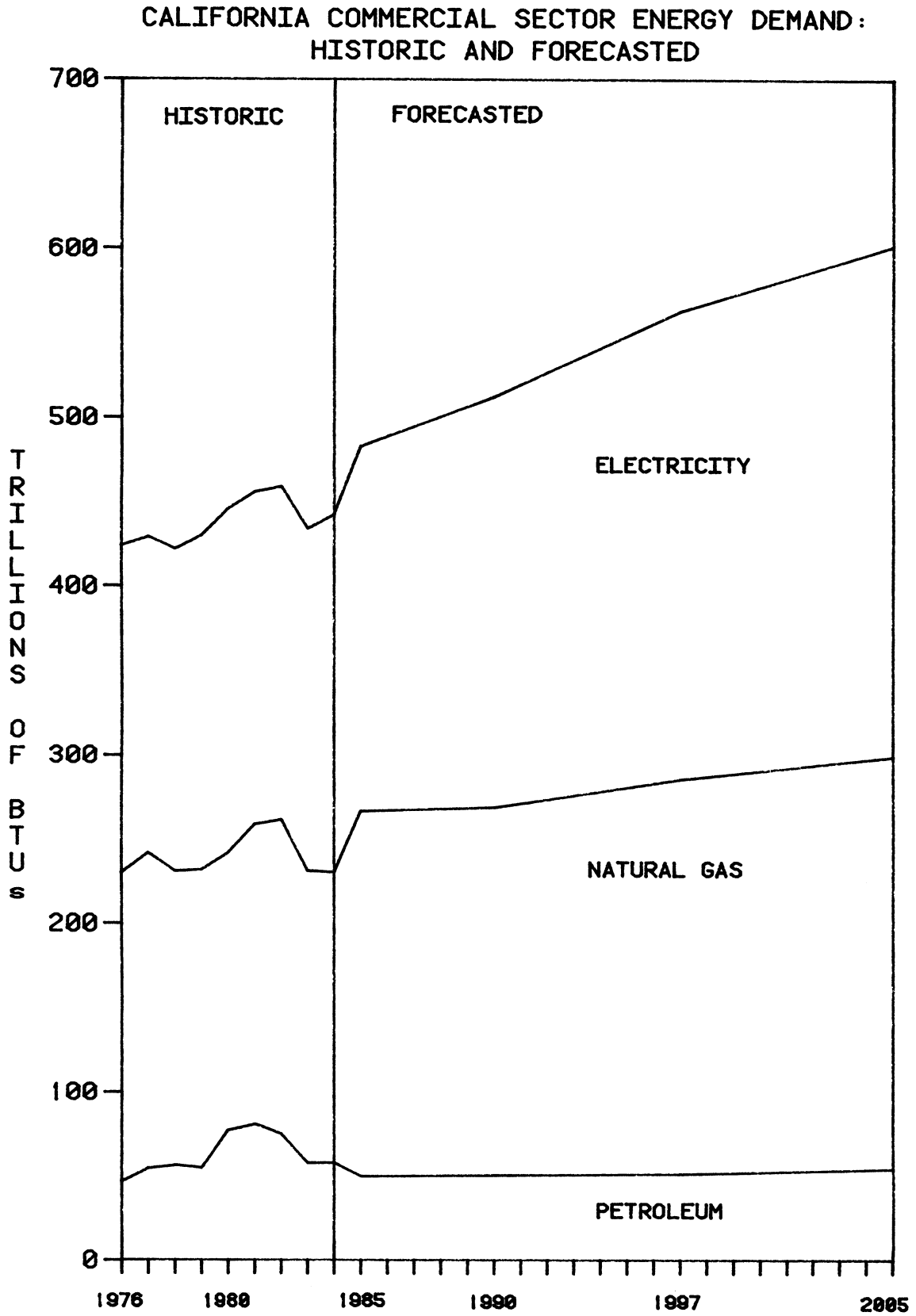
10. Ibid, page 81.

11. CEC Staff Report, Technical Assessment Manual, Vol. I, Edition II, Appendices, June 1984, page H-13.

12. The 1980-1982 peak in commercial petroleum use is an unexplained anomaly in federal statistics.

13. One therm equals 100,000 Btus.

FIGURE B-6



Source: California Energy Commission 1985 Biennial Fuels Report, Appendix A.

Warm weather accounted for a portion of the reduced gas use, but individual home owner conservation also played a role. Weatherization of existing homes, new buildings standards, solar installation and thermostat set backs have each contributed to reduced use.

The CEC projects (Figure B-7) that residential energy consumption will increase gradually from current level of 718 tBtus to 898 tBtus by 2005--an increase of 25 percent. Energy savings from building and appliance standards and other conservation practices are not expected to be sufficient to overcome all the increased demand fostered by more residences. Electricity deliveries, projected to increase by 42 percent, will supply most of this increased energy demand.

Natural gas as a percent of total residential energy use is expected to decline from its present share of 70 percent to 66 percent in 2005. Electricity's share of the residential energy market is expected to increase from 28 percent now, to 32 percent by 2005.

G. Cogeneration Demand

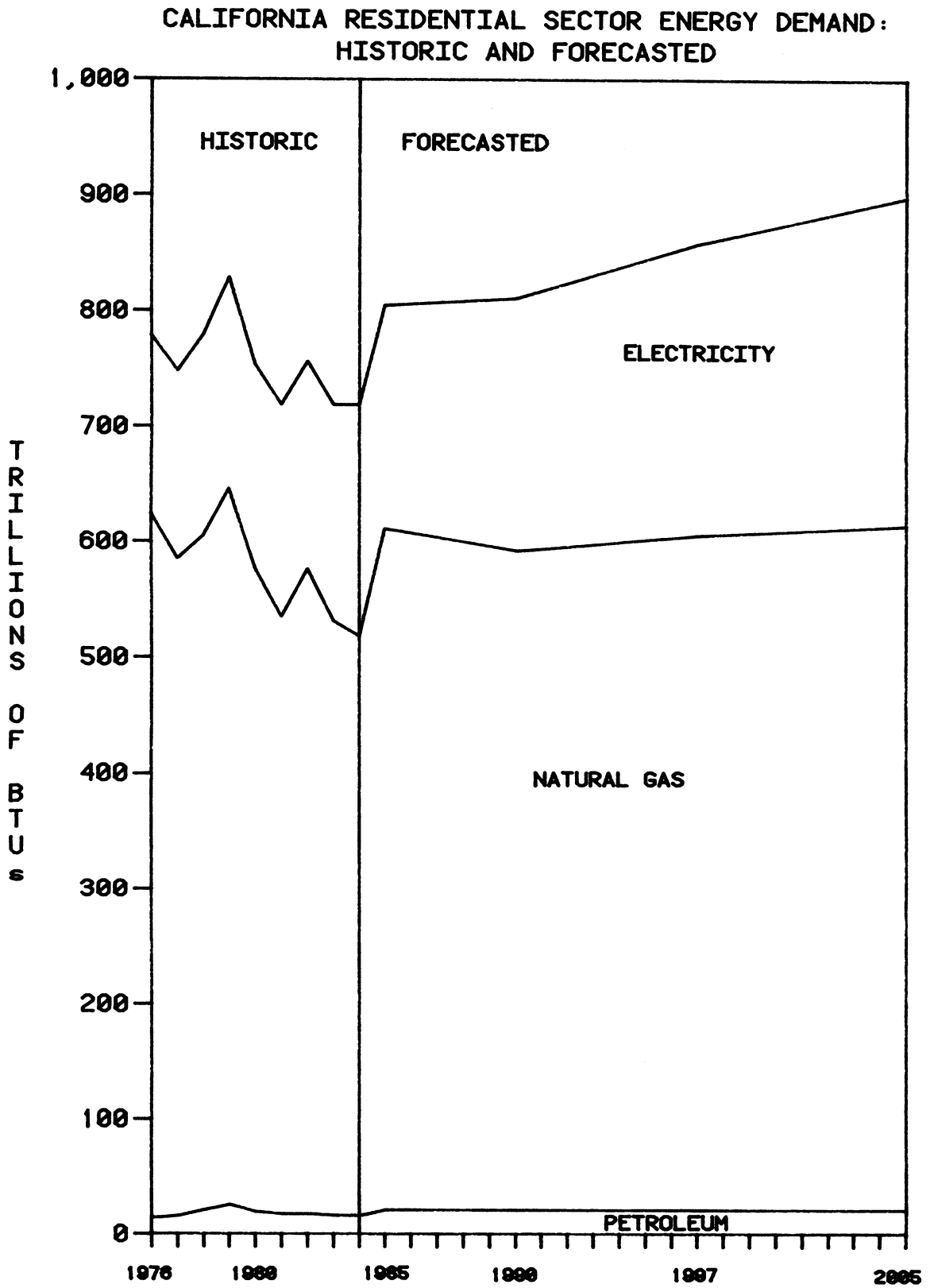
Overview. Cogeneration refers to the sequential use of energy for production of electricity and industrial process heat. For the purposes of energy demand forecasting, cogeneration is not considered to be an energy end use in itself. Energy use for cogeneration is included in the industrial, commercial and electric utility demand accounting. A portion of the total fuel consumed may be attributed to electric power production and the remainder to industrial process needs.

The technology of cogeneration can be implemented using a variety of fuels, combustion, and electric power generation equipment. The most prevalent form is use of natural gas to fire a combustion turbine. A substantial portion of the turbine exhaust heat is recovered and converted to a form useful to industrial processes: steam, hot water, or heated air. This section projects natural gas demand for the electricity production component of cogeneration applications. Other fuel types, which may be utilized in cogeneration facilities, are treated in later sections. Fuel demand to satisfy industrial process needs is calculated in the industrial demand section.

Many existing and planned industrial cogeneration installations produce electric power in excess of their own needs. The excess is sold to electric utilities for resale to other customers. Thus, increased natural gas demand for fuel cogeneration is offset to some extent by a reduction in the need for electric utility use of natural gas for electric power production.

Gas demand attributable to the electricity production component of cogeneration depends on (1) the amount of overall cogeneration present and likely to develop; (2) the extent of operation and the efficiency of the cogeneration process; and (3) the gas savings from not operating utility gas-fired power plants.

FIGURE B-7



Source: California Energy Commission 1985 Biennial Fuels Report, Appendix A.

There are a large number of potential cogeneration projects under consideration in California. As a means for determining the amounts of cogeneration that would be built and associated gas demand, staff assumed existing and projects under construction as identified in electric utility CFM 6 filings, would operate.[14]

The composition of an electric utility system will largely determine whether or not cogenerated electric power will replace utility natural gas-fired or coal, nuclear, hydroelectric, geothermal or other sources of electricity. If an electric utility relies on natural gas or oil for the bulk of its electric power production, there is a strong likelihood that an increment of cogenerated power will substitute, or "displace," a nearly equal amount of utility gas or oil-based generation. However, California's utilities vary in the degree to which they rely on gas or oil for electric power generation.

In 1983, San Diego Gas and Electric Company produced 82 percent of electricity from oil or gas, while Pacific Gas and Electric relied on oil and gas for only 20 percent of production. In a dry year such as 1977, oil and gas provided 73 percent of the energy used by utilities to generate electricity. In general, utilities expect oil/gas use to decline in future years in all service areas.

Predicting the way a given utility system will operate in response to a given level of customer demand for electricity is complex. The CEC and utilities generally predict operation in future years using computer simulations. Analysis of the Southern California Edison system was done to predict the degree to which increasing additions of natural gas-fired cogeneration would reduce the need to operate utility gas-fired power plants.

The simulation results are presented in Table B-1. The first 1,500 MW of incremental cogeneration reduces the need for utility use of oil/gas generation by 88 percent of the amount of cogenerated electricity. As greater amounts of cogeneration are added to a utility system, less utility owned gas-fired generation is displaced. This results in a smaller drop in gas consumption than a one-to-one displacement of utility resources by cogenerators would suggest.

This declining offset will be more pronounced in the PGandE service area because of its lesser dependence on oil/gas. The SDG&E service area, in contrast, will have a higher degree of displacement due to its relatively higher use of oil/gas. The interplay between cogeneration and utility gas use is reflected in the calculation of total gas demand for electric power production.

IV. Energy Demand by Fuel Type

California currently relies on petroleum to meet about 57 percent of the state's primary energy requirements. Natural gas supplies 29 percent of the

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14. See Appendix E.

TABLE B-1

SCE COGENERATION SCENARIOS
UTILITY OIL/GAS GENERATION DISPLACEMENT

Scenario	Oil/Gas Generation (GWh)	Cogeneration Generation (GWh)	Incremental Oil/Gas Displacement[1]
Basecase	21,344	613	--
+500 MW Cogen	18,272	4,124	.88
+1,000 MW Cogen	15,181	7,635	.88
+1,500 MW Cogen	12,906	11,145	.65
+2,000 MW Cogen	11,357	14,656	.44
+2,500 MW Cogen	10,400	18,167	.27
+3,000 MW Cogen	10,031	21,678	.11
+3,500 MW Cogen	9,880	25,182	.04
+4,000 MW Cogen	9,732	28,492	.04

[1] $\frac{\text{Change in oil/gas generation (kWh)}}{\text{Change in cogen generation (kWh)}}$

Source: Utility Offset Credit Concept Application in Southern California, David Maul, CEC Staff, October 1985.

state's energy needs. The remaining balance is supplied by hydropower, nuclear, coal, geothermal, solar and a variety of renewable fuels. While this last group is expected to increase its share of energy supplied, oil and gas will still account for about 76 percent of California's energy consumption in 2005 (Figure B-8).

In several end use sectors oil and gas are partially interchangeable fuels. These sectors include the industrial sector, including TEOR, cogeneration, and the electric utility sector. Gas is frequently the preferred fuel. However, if gas is unavailable or oil is cheaper some portion of the energy need can be met by oil. Situations where natural gas is used as a feedstock or to meet environmental regulations may restrict the full substitution of oil for natural gas. Occasional shortages of natural gas in the 1970s led to creation of the California Public Utility Commission's priority system which provides a basis for preferentially allocating gas among customer groups if gas is unavailable.

A. Petroleum and Petroleum Products Demand

Major petroleum fuels consumed in California include motor gasoline, distillates (diesel), jet fuel, and residual oils. In general, petroleum is converted in a refinery into these fuels before being consumed as products. However, a large volume of crude oil, about 64 thousand barrels per day (mb/d) in 1984, is consumed directly in the oil fields as fuel used to produce steam for thermal enhanced oil recovery (TEOR) operations. A discussion of each petroleum fuel as well as crude oil consumption follows.

Motor Gasoline. Motor gasoline is used almost exclusively in the transportation sector. It accounts for 41 percent of all petroleum use in California and 26 percent of all end use deliveries of energy.

Between 1976 and 1979 gasoline consumption increased by 11 percent, from 679 mb/d (1307 tBtus/yr) to 756 mb/d (1447 tBtus/yr). The rapid increase in prices during 1979 and 1980 caused gasoline usage in the state to decline to 689 mb/d (1321 tBtus/yr) in 1981. However, after 1981 gasoline consumption began to increase again and by 1984, consumption was back up to 729 mb/d (1415 tBtus/yr).

The expectation of soft oil prices in the near term combined with a continuation of current CAFE standards,[15] an increase in the driving population and less emphasis on the fuel saving aspects of automobiles is expected to cause a gradual increase in gasoline consumption over the forecast period. By 1997, gasoline consumption is projected to be about 9 percent higher than current levels and by 2005, 16 percent higher.

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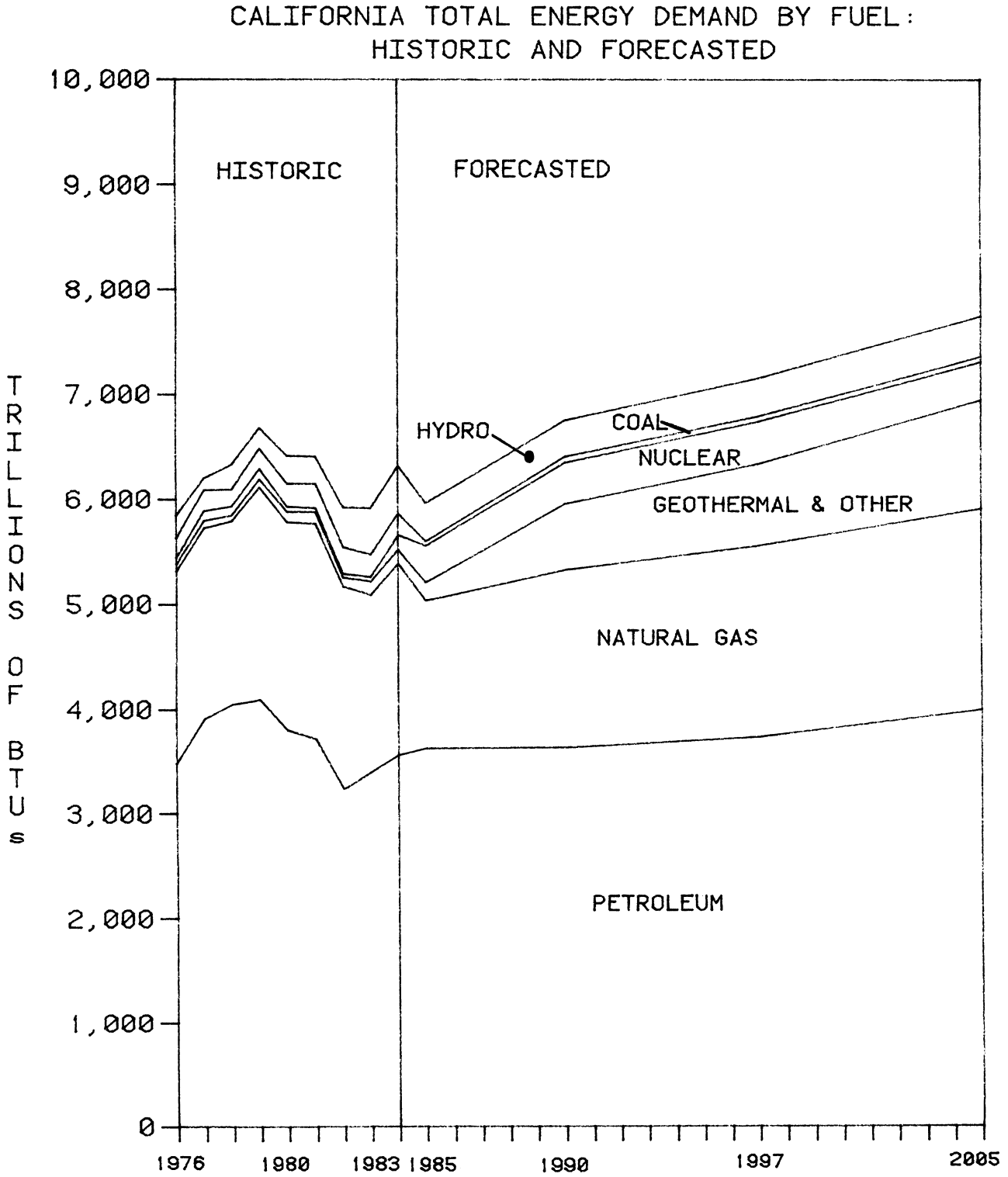
15. Staff has calculated that the roll back of the standard from 27.5 mpg to 26 mpg would have the effect of increasing gasoline consumption by only 0.1 percent in the late 1980s.

FIGURE B-8



Source: California Energy Commission
1985 Biennial Fuels Report, Appendix A

Aviation Fuels. Aviation fuels accounted for 11 percent of total petroleum consumption in 1984 or 189 mb/d (392 tBtus). About 75 percent of this total was consumed by private and commercial aviation. The remaining 25 percent was for military use.

Aviation fuel consumption reached a high in 1978 of 187 mb/d (387 tBtu/yr) before declining to 162 mb/d (335 tBtu/yr) in 1982. Consumption has since risen to 189 mb/d (392 tBtus/yr).

Although airplane fuel efficiencies are expected to be upgraded, aviation fuel use is projected to increase by 44 percent between 1984 and 2005 to about 272 mb/d (563 tBtus/yr), due to growth both in the economy and population.

Distillate Fuels. While 73 percent of the distillate fuel used in California is sold as diesel for transportation use, the commercial and industrial sectors also consume a significant amount for heating and boiler fuel. Depending on price, distillate fuels often compete with natural gas. As a result, some fuel switching occurs in industrial and commercial applications.

Distillate fuel consumption in California has fluctuated up and down more than the consumption of most other petroleum products. Overall distillate use rose from 142 mb/d (303 tBtus/yr) in 1976 to 228 mb/d (487 tBtus/yr) in 1984. Distillate demand is expected to remain strong increasing by 29 percent during the forecast period to almost 300 mb/d (630 tBtus/yr) in 2005. Growing transportation use accounts for most of the expected increase in distillate fuel demand.

Residual Fuel Oil. Residual fuel consumption accounted for 22 percent of total petroleum consumption in 1981, down from a high of 30 percent in 1977. The decline in residual oil use for electric generation is the major reason for this change. In 1977 electric generation used 68 percent of the residual oil consumed in California. By 1984 electric generation accounted for only 4 percent. Residual oil is also used as an industrial boiler fuel, as fuel for ships, and as a feedstock to produce other refinery products.

Residual fuel use in California peaked in 1977 at almost 500 mb/d (1144 tBtus/yr) before steadily declining to 228 mb/d (523 tBtus/yr) in 1984. During this period, use for electric generation declined from 336 mb/d (774 tBtus/yr) to 10 mb/d (22 tBtus/yr).

Residual oil use is projected to decline gradually to about 143 mb/d (327 tBtus/yr). Oil is not expected to be commonly used for electric generation.

Crude Oil. Although most crude oil goes to refineries for processing into petroleum products, some crude oil is used as a fuel in Thermal Enhanced Oil Recovery (TEOR) operations in California. In 1984, about 64 mb/d (137 tBtus/yr) of crude oil were used in this fashion. The CEC projects that total fuel use in TEOR will increase to the equivalent of 166 mb/d (351 tBtus/yr) by 1990 (Table B-2). However, natural gas use has become and is expected to continue to be more common in TEOR operations. This means that crude oil use in TEOR will decline reaching 33 mb/d (70 tBtus/ yr) in 1990. After 2000 TEOR production is expected to increase slightly, and crude oil demand for TEOR fuel will increase to 37 mb/d (78 tBtus/yr) by 2005.

TABLE B-2
PROJECTED TEOR FUEL CONSUMPTION
(Thousand Barrels Per Day of Oil Equivalent)

Fuel Type	Actual 1984	Projected 1990	1997	2005
Crude Oil	64	33	36	37
Natural Gas	44	133	143	147
Total	108	166	179	184

Source: Actual PIIRA, Projected Annual Petroleum Review, July 1983.
CEC, "Forecast of California TEOR Production 1986-2006," July, 1986.

B. Natural Gas Demand

The trend for future natural gas demand in California is characterized by a high degree of uncertainty. The major areas of uncertainty are future natural gas requirements for TEOR, cogeneration and electric utility use. Projections for the residential, commercial and nonTEOR industrial sectors' consumption are subject to less uncertainty due to their more direct historical relationship to population and economic growth, and the CEC's ability to quantify the effect of conservation programs and consumer actions. A more complete discussion of utility natural gas demand and underlying assumptions is presented in Appendix E.

Table B-3 shows that total natural gas demand for nonutility and gas utility service is projected to increase from 5,015 mmcfd in 1984 to 5,990 mmcfd in 2005.[16]

This forecast is composed of a number of separate trends in the various sectors. The table shows that:

- Residential demand is expected to increase by 18 percent from 1,309 mmcfd in 1984 to 1,547 mmcfd in 2005.
- Commercial demand is expected to increase by 28 percent over the forecast period from 499 mmcfd in 1984 to 637 mmcfd in 2005.
- Industrial demand, not including cogeneration or TEOR, is expected to increase by 25 percent from 1,440 mmcfd in 1984 to 1,803 mmcfd in 2005, due to strong economic growth.

16. The demand forecast presented in Table B-3 summarizes natural gas demand depicted in figures found earlier in this chapter and are consistent with Appendices A and E.

TABLE B-3

STATEWIDE NATURAL GAS DEMAND PROJECTIONS
mmcf/d

	Actual		Projected		
	1983	1984	1990	1997	2005
Residential	1,340	1,309	1,491	1,524	1,547
Commercial	480	499	569	611	637
Industrial[a]	1,128	1,440	1,436	1,632	1,803
Cogeneration[b,d]	35	50	297	376	453
TEOR[c]	204	204	736	790	812
Electric Generation[d]	1,396	1,563	673	853	738
TOTAL	4,641	5,015	5,201	5,786	5,990

Source

1983: QFER and PIIRA Data
1984: Preliminary QFER and PIIRA Data
Projected: CEC Staff Forecast

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a. Includes both utility and nonutility demand.

b. Cogeneration demand represents the incremental fuel requirement needed to generate electricity.

c. Projected TEOR fuel requirements are 80 percent of forecasted TEOR fuel needs for steaming. (See Footnote 7.)

d. Projected gas use for electric generation and cogeneration is based on model simulations of electric utility CFM 6 resource plans.

- Incremental demand for natural gas in cogeneration is expected to increase eight fold between 1984 and 1990 from 50 mmcfd to 453 mmcfd in 2005.

- TEOR gas demand for steaming only is projected to increase from its current level of 204 mmcfd to 812 mmcfd by 2005. This increase is due to a combination of fuel switching from oil to gas and increased heavy oil development.

- Natural gas usage in electric generation is projected to drop sharply between now and 1990. After 1990, natural gas use in this sector will gradually increase to 853 mmcfd in 1997 then decline to 735 mmcfd in 2005.

The above projections are consistent with the July, 1986 CEC adopted electricity demand forecast and the CFM 6 resource plans of electric utilities.

C. Coal Demand

Coal is used to a limited degree by California industry and for electrical generation in out-of-state power plants. The demand for coal in the state's industrial sector is expected to remain relatively constant throughout the forecast period. Coal is used in cement production, in the chemical industry and in the cogeneration of steam and electricity. The current use of 48 tBtus of coal annually is expected to increase only slightly, to around 53 tBtus by 2005.

Coal comprises approximately 12 percent of the fuel used to supply electricity for California. California's coal use for electric generation is in out-of-state power plants which deliver electricity to California utilities. In 1984, coal contributed some 182 tBtus for California electricity use. This use is expected to increase to 372 tBtus by 2005 as new out-of-state coal plants are constructed.

D. Alternative Fuels Demand

Alternatives to conventional fossil fuels offer a substitute source of energy to meet demand typically met in California by petroleum or natural gas fuels. The use of alternative fuels results particularly when their consumption offers economic, environmental, or other advantages.

Biomass. The majority of biomass fuel currently converted to energy is wood used for industrial purposes to produce process steam and electrical power. In 1983, California used about 3.6 million dry tons (58 tBtus) to generate process steam and electricity (with 200 megawatts [MW] installed capacity). Most of the fuel was used by cogenerators in the forest products industry that burned wood processing waste, predominantly generated on site. A relatively small amount of biomass fuel, derived from agricultural and urban woodwaste, was used by a few newer facilities. Since 1983, another 5 tBtus or 30 MW of generation capacity have come on line. Currently, 99 MW of cogeneration are under construction which will use an additional 16 tBtus of biomass.

For home heating, about 45 tBtus per year of wood are used. The future domestic use is estimated to increase to about 59 tBtus annually with the primary increase in rural regions where low cost natural gas is not available.

Municipal Solid Waste. In general, municipal solid waste (MSW) is a poor quality fuel for direct burning because it is difficult and expensive to use compared to other types of fuels. In addition, several environmental issues associated with direct burning of MSW have not been completely resolved. Therefore, the primary reason for direct burning of MSW in a MSW-to-energy plant is to dispose of the refuse. Steam and electricity are produced and sold to energy users to provide a revenue source which can be used to help pay for MSW disposal costs.

Currently the only operational MSW-to-energy plant in California burns less that 0.3 million tons per year. However, planned MSW-to-energy plants contemplate use of eight million tons or 72 tBtus per year. These plants are expected to have an electrical generating capacity of 537 MW.

In contrast, landfill gas is an easy to use, relatively high quality fuel. Collection is relatively simple and the gas can be used in conventional combustion devices. In addition, landfill gas use poses fewer environmental concerns than does direct burning of MSW. Landfill gas collection systems are being installed not only to prevent gas migration, but also to recover the gas for use as a fuel.

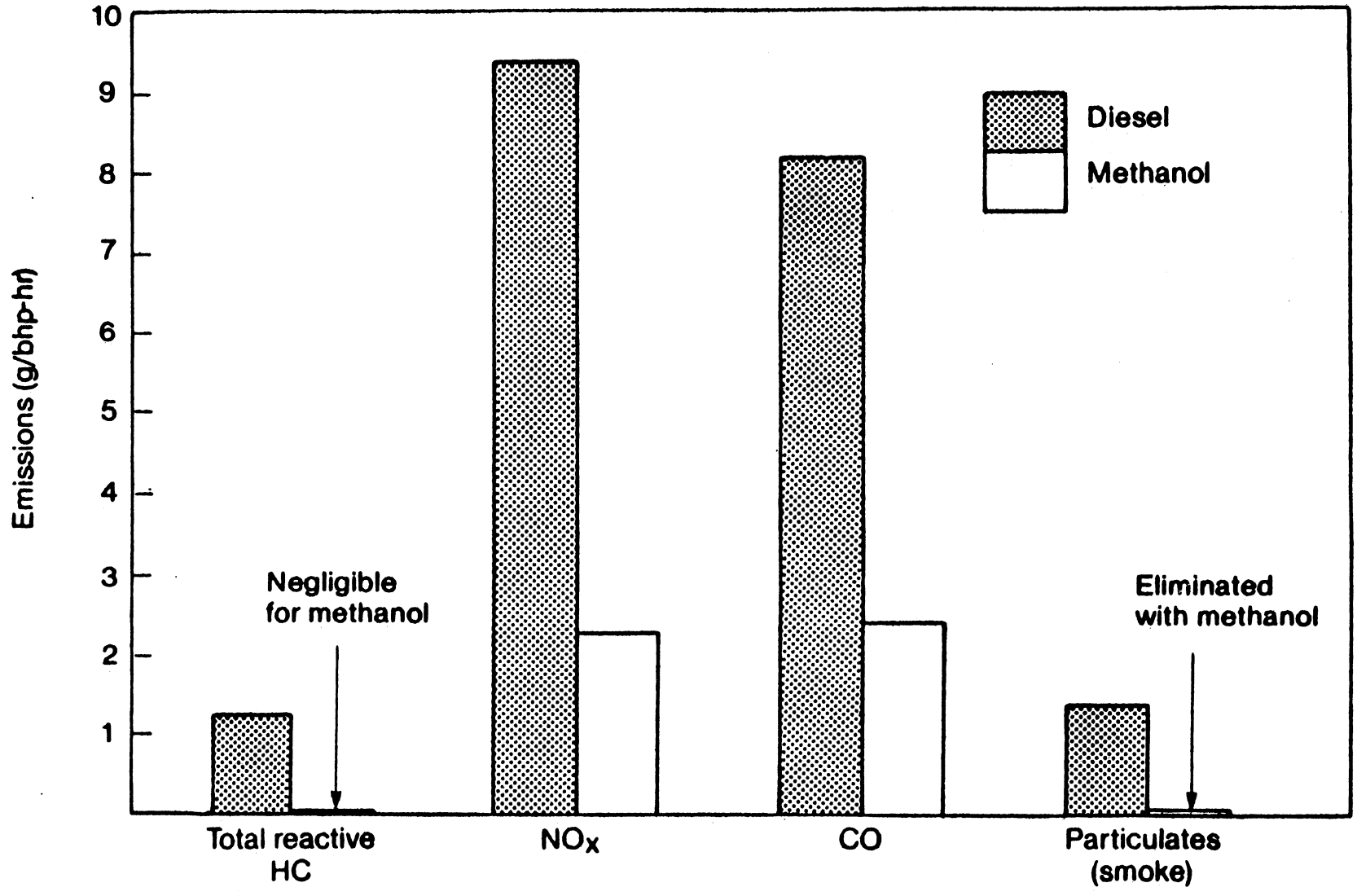
There are 25 landfill gas recovery facilities operating in California producing only 35 million mmcf/d (6 tBtus per year). The use of landfill gas is expected to increase by 46 mmcf/d during the next five years in the major urban areas in the state, due to regulatory requirements to install gas collection systems at landfills and economic use factors that favor the gas as a fuel.

In the 1985 California Electricity Report, the Commission expressed preference for the type of resource to meet future electrical needs. For electrical generation additions from 1984 through 1996, the Commission established a reserve need of 1,064 MW for biomass and MSW projects.

Methanol. As a liquid fuel, methanol offers several advantages particularly for transportation in California. It offers reduced air quality impacts when compared to petroleum fuels and other competing fuel options. For example, Figure B-9 shows an estimate by the Acurex Corporation, manager of the CEC's methanol bus demonstration program, of the emission improvements achievable with methanol in diesel engines. Another attribute of methanol is the ability to produce it from various energy resources. While nearly all methanol in the U.S. is now produced from natural gas, there is one coal based production facility.

EMISSION ADVANTAGES WITH HEAVY-DUTY METHANOL ENGINES

S-291



Source: Acurex Corporation - Based on emission information supplied by Detroit Diesel Allison and M.A.N. 1982.

FIGURE B-9

Methanol demand in California today is limited to vehicle fleet tests and other transportation demonstrations. Currently there is an ongoing fleet test of over 500 methanol Ford Escorts operated by state and local government agencies in fleets throughout the state. The fleet is served by a network of 18 methanol fueling stations with seven additional stations planned. Other private sector fleets--including a program being conducted by Bank of America--also contribute to demand for methanol as an automotive fuel.

Testing and demonstration is also continuing with heavy-duty (diesel engine) vehicles. Two methanol-fueled buses built by General Motors and by a West German company, M.A.N., are in daily transit service in the Golden Gate Transit District in a CEC-sponsored demonstration. Another heavy-duty vehicle demonstration is underway at the California State University, Chico, where a methanol-fueled farm tractor built by Komatsu of Japan has been operated for over a year.

The future demand for methanol as a transportation fuel is uncertain. The demand will particularly depend on the cost competitiveness of methanol with petroleum fuels. Although presently more costly on an energy equivalency basis, methanol could potentially be cost competitive with gasoline in the future. Methanol from existing excess production capacity and from worldwide remote natural gas not connected to pipelines may allow cost competitive methanol to be delivered to California. Staff assumed that remote natural gas would provide a cost competitive feedstock for methanol production since this gas does not have another economic use.

In addition, a coordinated program would be needed to develop the necessary infrastructure. Fuel companies would need to provide a network of methanol service stations and manufacturers would need to provide vehicles for methanol use. Ford is developing fuel flexible vehicles, perhaps for production by 1990. These vehicles could use methanol or gasoline in any combination. With projected petroleum fuel price increases, methanol from coal may provide a competitive fuel to meet demand by about 2005.

Programs for methanol use are likely to be increasingly stimulated by methanol's potential to enable improved air quality. Several investigations have generally demonstrated a potential for reducing ozone smog-forming emissions through substitution of methanol for petroleum fuels. In addition, methanol combustion produces no emission of sulfur compounds and reduces particulate emission to negligible levels. Diesel engines operating on methanol yield significant reductions in emissions, with no visible smoke and highly reduced oxides of nitrogen (NO_x).

APPENDIX C

FUEL SUPPLIES

APPENDIX C

FUEL SUPPLIES

I. Introduction

The previous appendix discussed historical and forecasted trends in demand for energy in California and noted that 90 percent of California's present energy comes from fossil fuels. This appendix discusses the sources of these fuels and analyzes the factors which are likely to impact the future availability of petroleum, natural gas and coal to California. Also included in this chapter is a discussion of the contribution that alternative fuels such as methanol, biomass, and municipal solid waste, could make in meeting California's energy needs.

II. Petroleum Supplies

A. Overview

In 1984, California end-users consumed about 601 million barrels of oil, 96 percent in the form of petroleum products. These products were largely produced by in-state refineries. In 1984 California's refineries received 631.1 million barrels of crude oil. Of this total 58 percent came from in-state production, 33 percent was imported from Alaska, and the remaining 9 percent was supplied by foreign sources (Table C-1).

TABLE C-1

PROJECTED CRUDE OIL RECEIPTS
BY CALIFORNIA REFINERIES
(Thousand Barrels per Day)

Source	Actual 1984	Projected 1990	1997	2005
California	1,009	1,035	1,040	959
OCS	a	225	225	125
Alaska	575	378	475	400
Foreign	145	125	125	473
TOTAL	1,729	1,763	1,865	1,957

Source: Actual-PIIRA; Projected-CEC staff estimates (see Tables C-2 and C-3 and Figures C-1, and C-2.)

a. Included in California figures since OCS receipts are not reported as a separate category.

By the end of the forecast period, the CEC projects that annual refinery crude oil receipts will increase to over 714 million barrels in 2005. The CEC also projects that because California and Alaska production will begin to decline in the 1990s, increasing reliance will be placed on foreign oil supplies to make up the difference.

The reasons for these changes are discussed in the subsequent supply sections.

B. Petroleum Product Supplies

Table C-2 displays projected California refinery outputs needed to meet the expected demand for petroleum products described Chapter 2. California refineries also produce some products which are exported to neighboring states and, in the case of residual oil, to Pacific Rim countries.

TABLE C-2
PROJECTED CALIFORNIA
REFINERY OUTPUTS
(Thousands Barrels per Day)

Source	Actual 1984	Projected 1990	1997	2005
Motor Gasoline	822	844	882	924
Aviation Fuels	223	230	257	315
Distillates	286	299	323	349
Residual	254	230	234	191
LSFO	35	30	30	30
HSFO	219	200	204	161
Other*	323	328	347	364
Total	1,908	1,931	2,043	2,143

Source: Actual - PIIRA, Projected - CEC staff estimates.

*Other includes lubricating oil, asphalt and road oil, wax, petroleum coke, still gas, LPG, and unfinished oils.

Total refinery outputs are expected to increase by 12 percent from 1,908 mb/d in 1984 to 2,143 mb/d in 2005. Both motor gasoline and other refinery outputs

will increase by about the same amount. Aviation fuel and distillate fuel outputs are expected to increase by 41 and 21 percent, respectively, to meet the increased demand for these products. Residual oil production is expected to decline by 25 percent reflecting declining demand for this product.

Current refinery capacity of about 2,300 mb/d should be sufficient to handle the increase in total output. However it is expected that the trend towards conversion of the crude oil bottoms (residual oil) to lighter products will continue. This will require some additional investments in refinery modifications.

C. Crude Oil Supplies

Over the past decade California's sources of crude oil have changed dramatically. Prior to the opening of the Trans Alaskan Pipeline (TAPS), California was heavily dependent on foreign crude oil. However, the availability of Alaska oil combined with increased California heavy oil production and the opening of the Elk Hills Naval Petroleum Reserve served to back out most foreign imports. A new source of crude, the federal Outer Continental Shelf (OCS) off California's coast, is now being developed which may further change the mix of supplies available to California refineries.

The following discussion of crude oil supplies is divided into sections on California, federal OCS, Alaska and foreign.

California. California crude oil production (not including federal OCS} has increased during each of the past ten years, except in 1978. Production increased 28 percent over this period from 816 mb/d to 1,046 mb/d. The increase has been due largely to increased development of heavy oil fields and federally sanctioned production from Elk Hills Naval Petroleum Reserve.

Future production as shown in Table C-3 is expected to increase above the 1984 level of 1,046 mb/d to 1,064 mb/d in 1990 through 1995. Thereafter, production is expected to decline through the end of the forecast period, falling to 968 mb/d in 2005.

This projected trend is shaped by trends in conventional onshore production, production from thermally enhanced oil recovery (TEOR) and state tidelands production. Conventional production including onshore and state tidelands is expected to decrease gradually throughout the forecast period to 438 mb/d in 2005. TEOR is expected to increase from 431 mb/d in 1984 to 530 mb/d in 2000 and remain at this level through 2005. However, without continued investment and development TEOR would also decline over this period.

Air quality standards may limit the expansion of TEOR production if crude oil is the primary fuel. The substitution of natural gas for crude oil as a fuel in TEOR operations allows more fuel to be burned before reaching air quality limits. This increases significantly the amount of California crude oil available to be used by California refineries. In the future, approximately, 80 percent of the fuel needs for raising steam are expected to be provided by natural gas compared to about 40 percent in 1984.

Production from the state's tidelands currently accounts for around 10.5 percent of total state production or 109 mb/d in 1984. By the early 1990s this source could contribute up to an additional 100 mb/d, before declining in the mid-1990s.

TABLE C-3
PROJECTED CALIFORNIA OIL PRODUCTION
(Not Including Federal OCS)
(mb/d)

Source	Actual 1984	Projected 1990	1995	2000	2005
TEOR	431	490	525	530	530
Other	696	574	539	501	438
	1,127	1,064	1,064	1,031	968

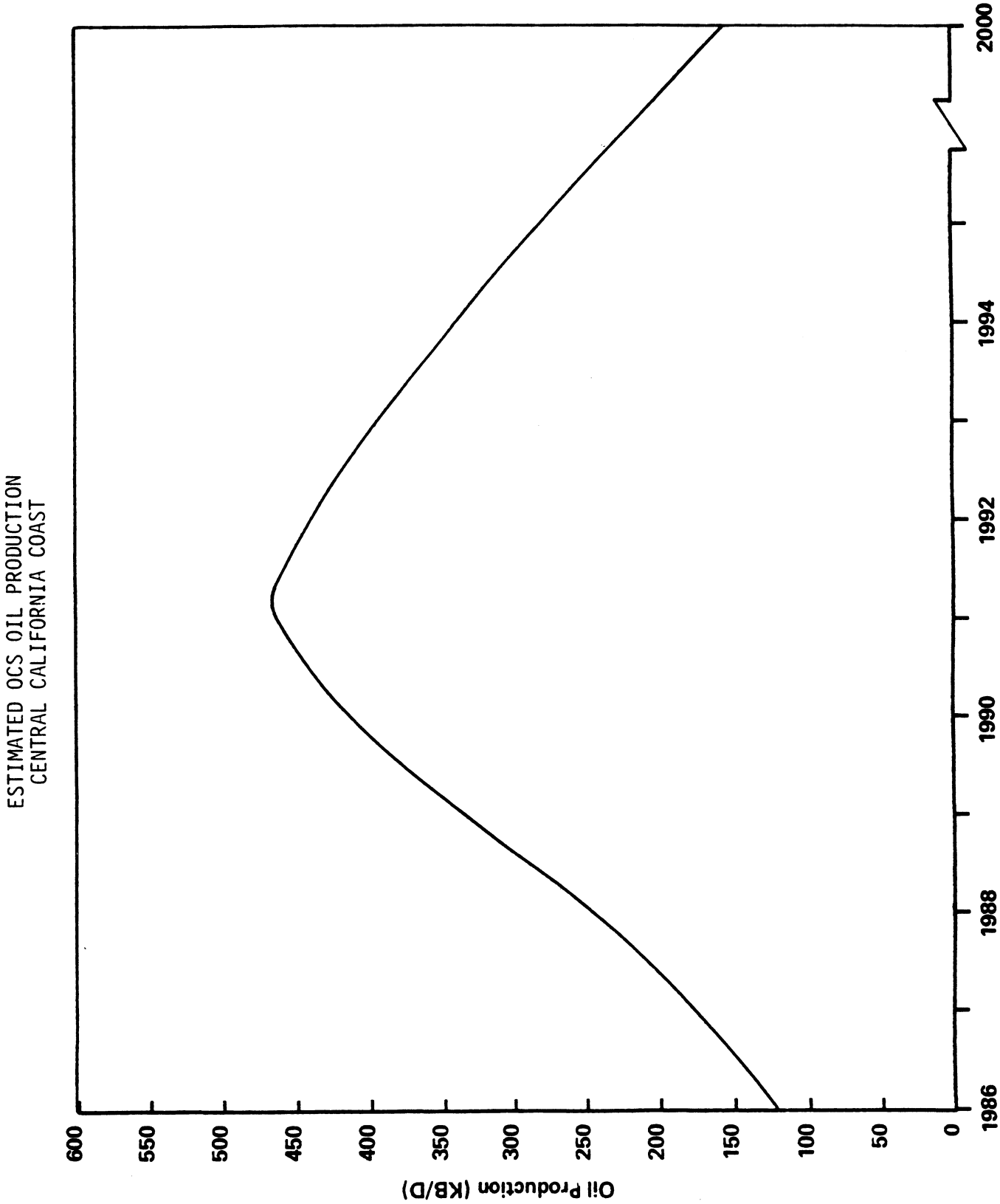
Source: Actual - Division of Oil and Gas; projected - CEC staff.

A discussion of this Thermally Enhanced Oil Recovery (TEOR) forecast is presented in Appendix I.

Federal OCS. In 1984, 83 mb/d of oil were produced in OCS waters. The Hondo field, operated by Exxon, accounted for 34 mb/d, the bulk of which was shipped to the Gulf Coast. Federal OCS production off central California could increase to 450 mb/d[1] in the early 1990s (Figure C-1). However, reaching this level of production depends upon resolving a variety of environmental, production and transportation related issues. (These issues are discussed in Chapter 7.) Transportation restrictions will limit the amount of OCS oil available to California refineries to about 225 mb/d during the 1990s. This amount is equal to the capacity of the proposed Southern California pipeline system to the Los Angeles refinery region plus expected OCS production from other areas not served by the pipeline. OCS production above this amount is expected to be transported to the Gulf Coast by either ship or pipeline.

1. John F. Peirson, Jr., Arthur D. Little, Inc., Outlook for OCS Production: Central California Coast.

FIGURE C-1



Source: A. D. Little, "Outlook for OCS Production: Central California Coast."

Alaska Oil. Alaska is the second most important supply source for California refineries. Alaska production in 1984 was 1,722 mb/d, of which some 575 mb/d were shipped to California. Without significant new discoveries Alaska production is expected to peak in the early to mid-1990s and thereafter decline (Figure C-2).[2] Since 1977 oil from Alaska has functioned as the marginal supply of oil to California. That is, instate production is used first and then Alaska oil is used to meet the remaining difference between supply and demand. Alaska oil is projected to continue to be the marginal supply until the late 1990s when Alaska production is forecasted to drop below West Coast needs. Any foreign export of Alaska crude oil would further reduce the availability of this crude to California. Chapter 9 contains a more in depth discussion of Alaska crude oil exports.

Foreign Oil. Oil from foreign sources represented California's marginal supply source until oil from Alaska became available in the mid-1970s. Foreign oil is now imported either because of favorable cost or special product needs. The CEC projection shows that from 1984 levels of 145 mb/d, foreign imports are expected to decline slightly to around 125 mb/d by 1990 and hold there until the late 1990s. However, as production levels from instate and Alaska sources decline in the late 1990s increased foreign supplies will be needed to meet refinery crude oil needs. The source of these supplies is uncertain.

III. Natural Gas Supplies

A. Overview

Currently, natural gas supplies available to California exceed demand. Including nonutility gas, the CEC estimates that in 1984 5,638 mmcfd could have been delivered compared to actual consumption of 4,903 mmcfd. Figure C-3 shows that during the forecast period natural gas supplies available to gas utilities from traditional or current sources for California utilities will decline to 3,664 mmcf/d by 2005. Nonutility gas supplies produced in California are expected to decline from 620 mmcfd in 1984 to 399 mmcfd in 2005.

California utilities currently obtain natural gas from four sources--Southwestern U.S., Canada, instate production, and the Rocky Mountain region. At present the Southwest accounts for 66 percent of supply, Canada 18 percent, and California 16 percent. The Rocky Mountain Region contributes less than 1 percent of current supplies.

In the next 20 years a shift in these proportions will occur as supplies from the Southwest and California decline and supplies from other areas increase to partially offset those declines (Table C-4). However, supplies from the Southwest will continue to be the major source of gas.

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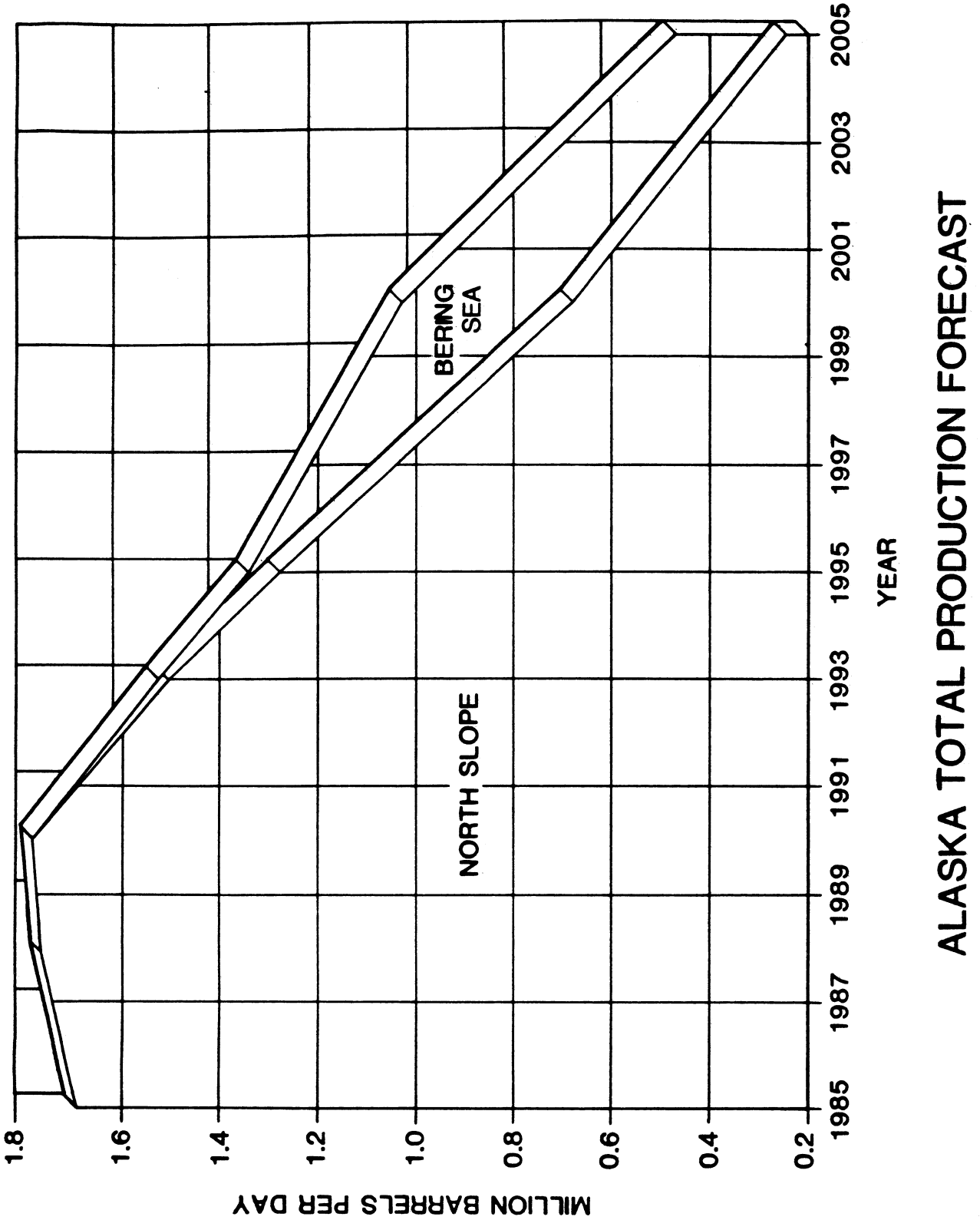
2. William Wade, Dames and Moore, Alaska 1985: Exploration Activity and Production Forecast to 2005.

FIGURE C-2

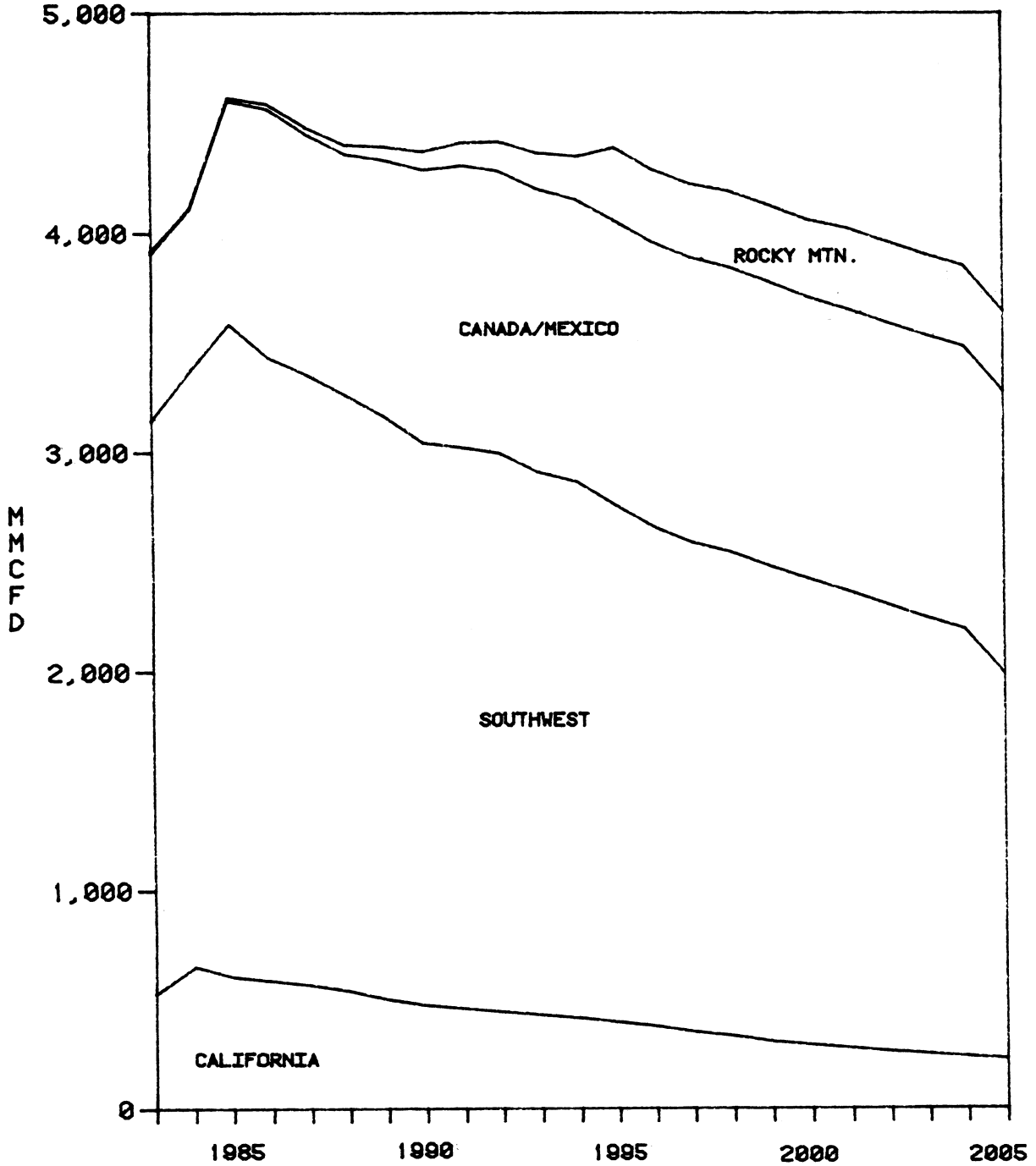


Source: Dames and Moore "Alaska 1985: Exploration Activity and Production Forecast to 2005." August, 1985.

Source: Dames and Moore "Alaska 1985: Exploration Activity and Production Forecast to 2005."

FIGURE C-3

CALIFORNIA UTILITY NATURAL GAS SUPPLY
FROM TRADITIONAL SOURCES: HISTORIC AND PROJECTED
(Millions of Cubic Feet Per Day)



Source: Historic QFER Form 6A
Projected CEC Staff Estimates

TABLE C-4
PERCENT OF TOTAL UTILITY NATURAL GAS SUPPLY BY SOURCE

	1984	2005
California	16	7
Southwest	66	48
Rocky Mtns.	0	10
Canada	18	33
Mexico	--	2
Total	100	100

The CEC uses four criteria to determine whether specific gas supplies should be included in its gas supply forecast:

- The resource can be identified, and amongst competitors for its use, allocated to California.
- The wellhead cost can be estimated.
- A means of transportation can be identified and cost estimated.
- The estimated delivered cost to California is below the projected residual fuel oil price.

The CEC's natural gas supply forecast differs from the gas supply picture presented by the gas utilities in the 1985 California Gas Report. The utilities' forecasts are significantly higher by 523 mmcf/d in 1990 and 1360 mmcf/d in 2000. Their gas supply forecasting methodology differs considerably from the CEC's.

The gas utilities have apparently not made resource evaluations as a basis for long-term supply planning. As an example PGandE has used the results of preliminary contract negotiations with El Paso Natural Gas Company as the basis for its long-term supply forecast, not resource evaluation. In 2000, this results in 452 mmcfd more supply from El Paso to PGandE than staff's estimate.

For 2000, unspecified resources called supplemental supplies provide 43 percent of SoCal Gas' natural gas supply forecast. Supplemental supplies includes supplies from a number of different sources without specifying individual quantities or sources. From supplemental supplies the SoCal forecast draws sufficient gas to meet the required supply need. Informal discussion with SoCal Gas indicates the principal supplemental supplies in the SoCal forecast are additional Canadian supply above current contract levels and more California offshore production.

Staff is in agreement with SoCal Gas that Canada has sufficient resources to increase exports to California, but is reluctant to include this supply in its forecast. The method of transport has not been identified. Without identified transportation, a cost evaluation cannot properly be made.

Staff believes additional California offshore supplies in the latter years of the forecast period are truly speculative. Review of environmental impact statements for offshore production platforms and related process equipment leads staff to a gas production estimate considerably less than the SoCal estimate.

In determining costs of supply for a number of gas sources included in their forecasts, the utilities assumed, rather than demonstrated, that the delivered price would be competitive with residual fuel. There was no attempt to identify wellhead costs and transportation availability and related costs for these sources.

Based on these evaluations, staff believes its forecast provides a sounder supply planning method. Appendix F presents additional information on the CEC gas supply forecast methodology.

B. Southwest Supplies

California's two major sources of supply from the Southwest are the El Paso Natural Gas Company and the Transwestern Pipeline Company; together these sources have the capability to supply 3,700 mmcfd annually to California gas distributors. Because of reduced demand during 1984, only about 2,721 mmcfd were taken. During the forecast period, the CEC expects that supplies from these sources will decline to 1,757 mmcfd in 2005, a decline of about 35 percent due to resource depletion and inadequate reserve replacement. This forecast is consistent with forecasts published by the two pipeline systems.

C. California Supplies

California production from instate natural gas resources are also projected to decline from current levels of 1,270 mmcfd to only 650 mmcfd by the close of the forecast period, due again to resource depletion without adequate reserve additions. Even with higher wellhead prices, California producers have not been able to completely replace produced gas with new reserves. Utilities receipts from instate production are anticipated to decline from present levels of 650 mmcfd to 251 mmcfd by 2005.

D. Rocky Mountain Supplies

While gas supplies to California from the Rocky Mountain Region are currently insignificant, the CEC projects that substantial increases in natural gas from this source will be available during the next 20 years. Thus, by 1997, the Commission expects supplies from the Rocky Mountain Region totaling 335 mmcfd, increasing to 369 mmcfd by 2005. This projection is based on CEC estimates of the potential reserves in this area available from California suppliers' lease holdings that have been purchased for future gas exploration and

development. The projection also assumes completion of a Rocky Mountain pipeline to deliver this additional supply to utilities.[3]

E. Foreign Supplies

Natural gas supplies from foreign sources are projected to be stable or increasing during the forecast period. The CEC projects full license amounts of gas from Canada, increasing from current levels of 738 mmcfd to around 1,197 mmcfd by 1997, and remaining at that level through 2005.[4] A renewal of natural gas deliveries from Mexico at a level of 75 mmcfd is projected beginning in the late 1980s. Consistent with staff's previous supply forecasts, gas supply from Mexico will increase to 100 mmcfd in the late 1990s before decreasing to 90 mmcfd in 2000.[5]

F. Supplemental Supplies

There are significant potential gas resources in the United States and Canada that have been excluded from the CEC forecast of supplies available to California. The exclusion is based on the staff analysis in Appendix F that either transportation is unavailable, resources have not been identified or the delivered price of gas would not be competitive with alternative fuels available to marginal fuel users. Under the current CPUC curtailment system supplemental supplies would be obtained only to serve interruptible users. These supplies would be unable to compete on a price basis with alternative fuels, thus preventing these supplies from coming to California. A more complete discussion of the factors involved in gas prices is contained in Appendix D -III and Appendix F.

The FERC recently adopted Order Number 436 which provides for nondiscriminative transport regulations for interstate pipelines. These regulations should make it easier to obtain transportation for gas from nontraditional areas. On the other hand there may be increased costs associated with the new regulations. Because these regulatory developments have only recently occurred, their long-term effects are still speculative.

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3. For further detail on staff's Rocky Mountain assumption see CEC, California Energy Demand: 1984-2005, Prepared in Consideration in the Electricity Report V Proceedings, Volume II Technical Appendix Forecasting Methodology Updates (P300-84-004), August 1984, pages E.35-E.36.

4. Testimony of Canadian producers, and Provincial officials at hearings held on March 13, 1985 for the Biennial Report and August 9, 1985 for the Biennial Fuels Report, support the concept that their resources could maintain current export license levels of 1,200 mmcfd for the study period.

5. CEC, California Energy Demand: 1984-2004, Vol. II: Technical Appendix, Forecasting Methodology Updates, (P300-84-004) August 1984, pp. E.35 and E.74.

For this reason it is not currently possible to quantify with any precision the additional supplemental supplies that might be available to California. However, the levels of additional supply needed to supplement traditional supplies have been quantified. These are identified as gas/oil demand in Appendix A.

G. Pipeline Capacity Considerations

Under present pipeline configurations additional out-of-state utility supply for increased TEOR sales would have to be delivered through the El Paso Natural Gas Company and Transwestern Pipeline Company systems. In 1984 there was a total of 990 mmcfd of average daily unused capacity on the two pipelines. However, the capacity to deliver an extra 990 mmcfd is not always available throughout the year. During the winter gas use increases significantly because of building heating requirements, substantially reducing unused pipeline capacity.

Table C-5 provides data on surplus capacity for the past two winters. The table indicates that much of the time during the past two winters there would not have been sufficient capacity available on the combined pipeline systems to provide the supply to meet both the existing utility requirements and an additional projected TEOR need of 736 mmcfd.

TABLE C-5
SURPLUS CAPACITY ON EL PASO AND TRANSWESTERN
PIPELINES DURING WINTER MONTHS 1983 and 1984
(mmcfd)

	December 1983	January 1984	December 1984	January 1985
El Paso	584	1,013	217	242
Transwestern	129	150	10	163
Total Unused Capacity	713	1,163	227	405

Source: Based on Quarterly Fuel and Energy Report data reported to the CEC.

There are three supply options available to overcome seasonal interstate capacity limitations. First, instate storage capability could be increased. Both PGandE and SoCal Gas maintain underground natural gas storage facilities to meet high winter gas needs. These existing facilities could be upgraded to accommodate increased supply requirements. Second, more delivery capacity could be added to the existing El Paso and Transwestern systems. The third option would be the construction of a new interstate pipeline to California.

IV. Coal Supplies

California does not have significant domestic reserves of coal. Therefore, its industries and utilities must depend on other states for their coal supplies.

The five western coal producing states from which California now obtains coal produce over 200 million tons per year and have more than 100 billion tons of reserves. Coal reserves in Montana and Wyoming alone are estimated to have an energy content equal to 1.75 times the oil reserves of Saudi Arabia and about 40 percent of the total world oil reserves.

Wyoming mines currently produce over 15 million tons per mine per year. This rate is expected to double by 1990. A single mine producing 30 million tons per year could supply nearly three times the current coal needs for California's industrial and out-of-state utility coal needs.

The abundance and security of coal supplies and the relatively low price of coal when compared to oil and gas will ensure that coal continues to hold and even enhance its place as the major fuel for electric generation in the U.S. New and emerging technologies to burn coal more efficiently, cheaper, and with fewer emissions will displace oil and gas in industrial applications and a resurgence of coal use in transportation (locomotives and ships) is currently underway.

It is a widely held belief that coal is too dirty to be burned in California industry and electric generating facilities. However, based on air quality constraints, a Commission staff report found that at least 4,000 MW and perhaps as much as 6,000 MW of direct-fired coal power plant capacity could be sited in California in the 1990 timeframe.[6] Currently, at least 450 MW of coal-fired cogeneration projects are being planned for the SCE and PGandE service areas.[7]

California, however, is much more likely to benefit indirectly than directly from coal use. The cost and price uncertainty for transporting coal 700 to 2,000 miles from the western coal producing states to California is a major obstacle that will have to be overcome for coal-fired facilities to flourish here. Instead, California will benefit by increased reliance on coal in the rest of the country and the resulting oil and gas that will be displaced for new uses or to extend current uses for oil and gas in noncoal using states.

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6. CEC Staff Report, Air Quality Statewide Coal Plant Area Screening Study February 1979.

7. Each quarter the electric utilities file with the CPUC a report entitled Cogeneration and Small Power Production Quarterly Report to the California Public Utilities Commission. From these reports a total of 450 MW of proposed coal-fired cogeneration was determined.

V. Alternative Fuels Supplies

A. Biomass

Nearly all of the state's biomass fuel is derived from California forest resources. Fuel for domestic home heating use is extracted directly from forests in the form of cord wood while industrial fuels are for the most part waste products of the forest products industry. Most new facilities continue to be associated with the forest products industry; however, stand-alone power plants have become significant in the use of agricultural biomass fuel for electrical generation purposes. Growth in industrial fuel use beyond 110 tBtus, 1.3 percent of 2005 total energy demand, will be hampered by fuel availability issues.

B. Municipal Solid Waste (MSW)

The theoretical potential supply of MSW available to burn in MSW-to-energy plants is essentially the quantity of MSW collected and transported to California landfills that accept 100 tons per day or more of refuse. This current supply is estimated to be 35 million tons per day or 315 tBtus per year. Assuming current MSW disposal practices do not change, California future supply of MSW is projected to increase primarily as a result of increasing state population. If, by the year 2005, MSW were used as fuel in all communities facing landfill closure, about 47 percent of all MSW collected in California for disposal might be burned in MSW-to-energy plants. This amount of fuel could support 1,100 MW of electrical generation capacity.

Future supply of MSW as fuel may be reduced by barriers to new plant development resulting from citizen opposition, environmental concerns, regulatory requirements, and changes in plant financing procedures and tax incentives.

The supply of landfill gas will increase over the next 20 years as a result of (1) continued gas collection from MSW already in place in existing landfills, (2) new gas collection systems installed at existing landfills, and (3) additional gas generated from MSW projected to be disposed of at new landfills.

The theoretical potential supply of landfill gas currently available in California is 275 million standard cubic feet per day (scf/d). This is equivalent to approximately 50 tBtus per year. Future supply of landfill gas will depend on amounts and organic matter content of MSW disposed of in landfills. Direct use of MSW at MSW-to-energy facilities will reduce the amount of MSW going to landfills, and thereby reduce potential landfill gas supplies. Similarly, reductions in the organic matter content of MSW due to expanded resource recycling programs may also decrease the future supply of landfill gas.

C. Methanol

Methanol as an alternative fuel can be used in transportation and electric generation. Methanol is primarily used today as a petrochemical feedstock.

Current sources of methanol are mainly from the conversion of natural gas. Existing methanol production facilities are underutilized providing the basis for greatly increasing production for alternative fuel use. Presently about 50 thousand b/d oil equivalent of excess methanol capacity exists worldwide.[8]

Potential new sources for methanol include conversion from coal and the use of remote natural gas. While the U.S. has vast quantities of underdeveloped coal resources, (see Section IV above), only one small commercial scale coal to methanol conversion facility is currently operating. The plant processes 900 tons of coal per day. Present coal resources in the United States which can be economically mined today are probably sufficient to meet the nation's transportation fuel demand for over 200 years. The most likely sources of coal-based methanol for California would be the Western United States--particularly Montana, Wyoming, Colorado, North Dakota, and New Mexico--and Alaska.

The production of methanol from coal raises various environmental issues. Although air emissions and other effluent streams can be closely controlled at the production sites, environmental impacts are likely to be assessed carefully by state and local regulatory agencies. The production of methanol requires large amounts of water. Diverting water to energy-producing activities is the center of controversy in many water-critical regions of the West where coal is located. Pipelines would also be needed to transport the methanol to California.

Remote fields of natural gas not connected to pipelines, such as fields in Alaska and the South Pacific, are also potential resources for methanol production. The methanol would be produced at the gas site and then delivered by tanker. On the basis of the size of proven gas reserves in remote areas, perhaps 2.6 mmb/d oil equivalent of methanol could be produced from world supplies of remote gas.[9]

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8. Charles A. Stokes, The Near- and Long-Term Fuel Methanol Supply and Price Outlook and Suggested Supply-Inducing Strategies for California, Consultant study for CEC August 20, 1985.

9. Ibid.

APPENDIX D

CALIFORNIA ENERGY PRICES: TRENDS AND FORECASTS

APPENDIX D

CALIFORNIA ENERGY PRICES: TRENDS AND FORECASTS

I. Introduction

The CEC regularly develops 20-year fuel price forecasts in recognition that fossil fuel prices are a major determinant of the price of electricity, the demand for natural gas and petroleum products and the cost-effectiveness of conservation programs and alternative energy sources. Following are price projections for the period 1986-2005 for crude oil and petroleum products, natural gas and coal. A discussion of projected alternative fuel prices is also included.

II. Petroleum Prices Forecasts

A. Crude Oil Price Forecast

The large decline in oil prices during the first half of 1986 has increased substantially the uncertainty surrounding the level of future oil prices. As a result of this uncertainty two alternative price scenarios were considered: a high price growth scenario and a low price growth scenario.

The high price growth scenario is based on expectations that exploration and development of nonOPEC reserves will be severely reduced by current low level of oil prices leading to reduced production and increased reliance on OPEC production. This, combined with increased oil and energy consumption, due to lower prices, will cause a rapid increase in prices as the current world "surplus" of crude oil is eliminated.

The low price growth scenario assumes that despite low oil prices the reduction in nonOPEC production will be less severe, that energy efficiency gains in the last decade will persist thus limiting demand growth, that the substitution of the other fuels for oil will continue and that OPEC infighting will keep OPEC production levels high relative to demand.

While both scenarios are plausible the high growth scenario better represents staff's understanding of how the world oil market has historically functioned. On the other hand, the low growth scenario implies a substantial revision to the traditional view of the impacts of low prices on the world oil market. There does not yet appear to be adequate evidence available to support a low price growth scenario.

The CEC's 20-year crude oil price forecast projects that inflation adjusted (real) international oil prices will increase rapidly from current levels to

$26.71 per barrel in 1990.[1] After, that prices will increase at a more moderate rate before increasing at a more rapid rate toward the end of the forecast period (Table D-1). It will require about 10 years for oil prices to again reach 1985 levels, barring unanticipated major international disruptions. However, even by the end of the forecast period real oil prices are not expected to be as high as their 1981 peak.

TABLE D-1

FORECASTED ANNUAL RATES OF CHANGE IN WORLD CRUDE OIL PRICES

Period	Rate of Change
1986-1990	15.4%/yr
1991-1994	1.6%/yr
1995-2005	2.5%/yr

This forecast is consistent with current understanding and expectations about how world supply and demand for oil interact in an international market to determine the price of oil (Table D-2 and Figure D-1 show the projected prices by year).

The primary reason for declining oil prices and ample supplies has been the response of both oil consumers and suppliers to high oil prices. Rapidly increasing oil prices between 1973 and 1981 encouraged world oil exploration and discouraged energy use through improved efficiency and increasing substitution of other energy sources, such as coal, gas and nuclear power, for oil. Between 1979 and 1982 oil industry capital expenditures increased from $87.0 billion to $149 billion.[2] During this same period the number of exploratory wells completed increased from 14,315 in 1979 to 21,299 in 1982.[3] In the United States, the combination of exploration, efficiency improvements and fuel substitution had the effect of reducing 1983 oil imports by 4 million barrels per day from 1979 oil import levels of 8.8 mmb/d (Figure D-2).

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1. The CEC forecast was developed from a statistical analysis of the results of a survey of energy experts on their opinions concerning the future oil prices. This analysis was adjusted to reflect the significant change in price levels since the survey was completed. A more detailed discussion of the forecast methodology is contained in Appendix G.

2. Chase Manhattan Bank, Capital Investments of the World Petroleum Industry, Annual.

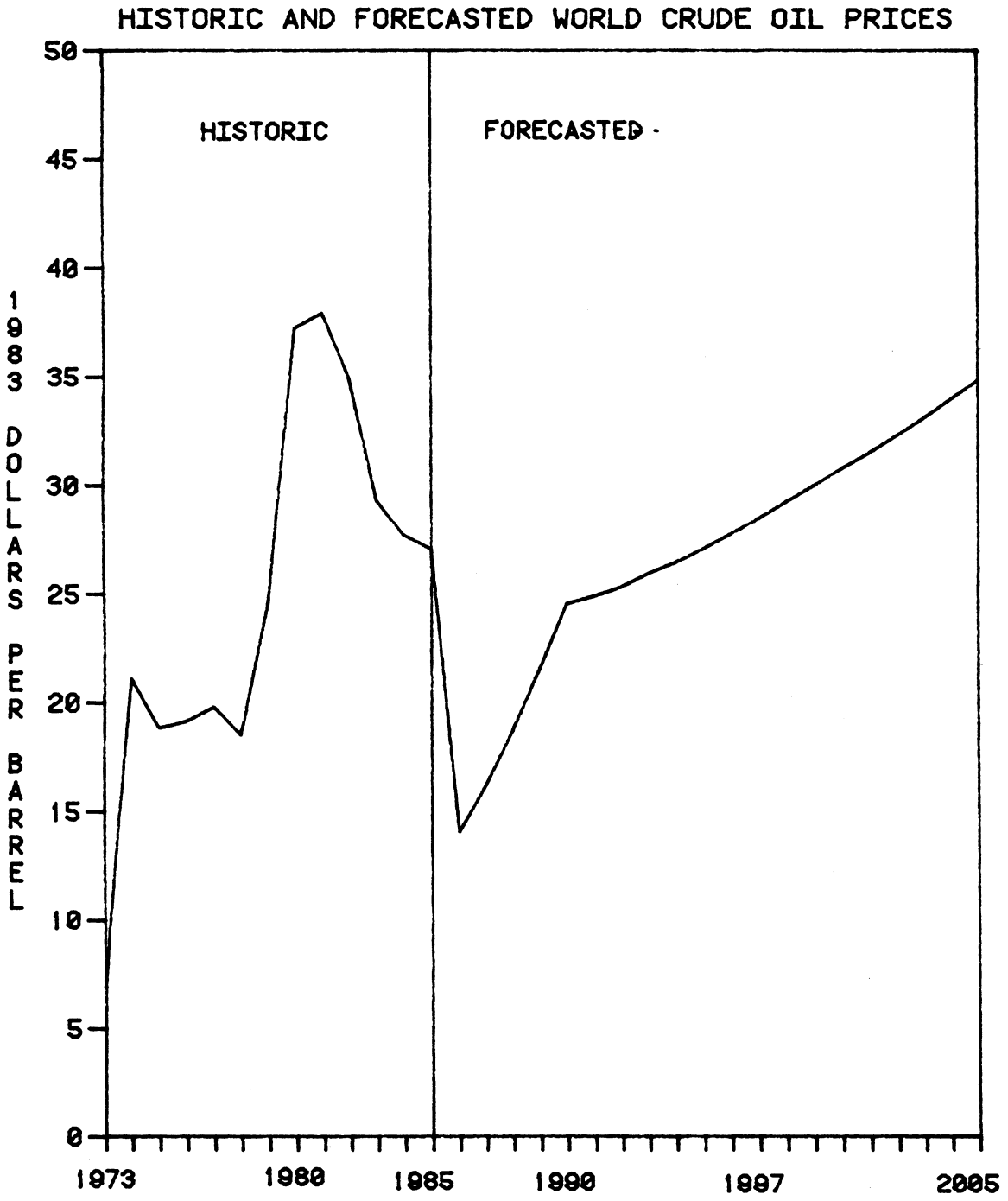
3. United States, American Association of Petroleum Geologists and American Petroleum Institute - Other, Oil and Gas Journal.

TABLE D-2

WORLD OIL PRICE PROJECTIONS

	1983 Dollars	
	$/bbl	$/MMBtu
1983	29.31	5.05
1984	27.71	4.78
1985	27.04	4.66
	Projected	
1986	14.06	2.42
1987	16.22	2.79
1988	18.72	3.23
1989	21.60	3.72
1990	24.93	4.30
1991	25.33	4.37
1992	25.74	4.44
1993	26.15	4.51
1994	26.57	4.58
1995	27.23	4.69
1996	27.91	4.81
1997	28.61	4.93
1998	29.33	5.06
1999	30.06	5.18
2000	30.81	5.31
2001	31.58	5.44
2002	32.37	5.58
2003	33.18	5.72
2004	34.01	5.86
2005	34.86	6.01

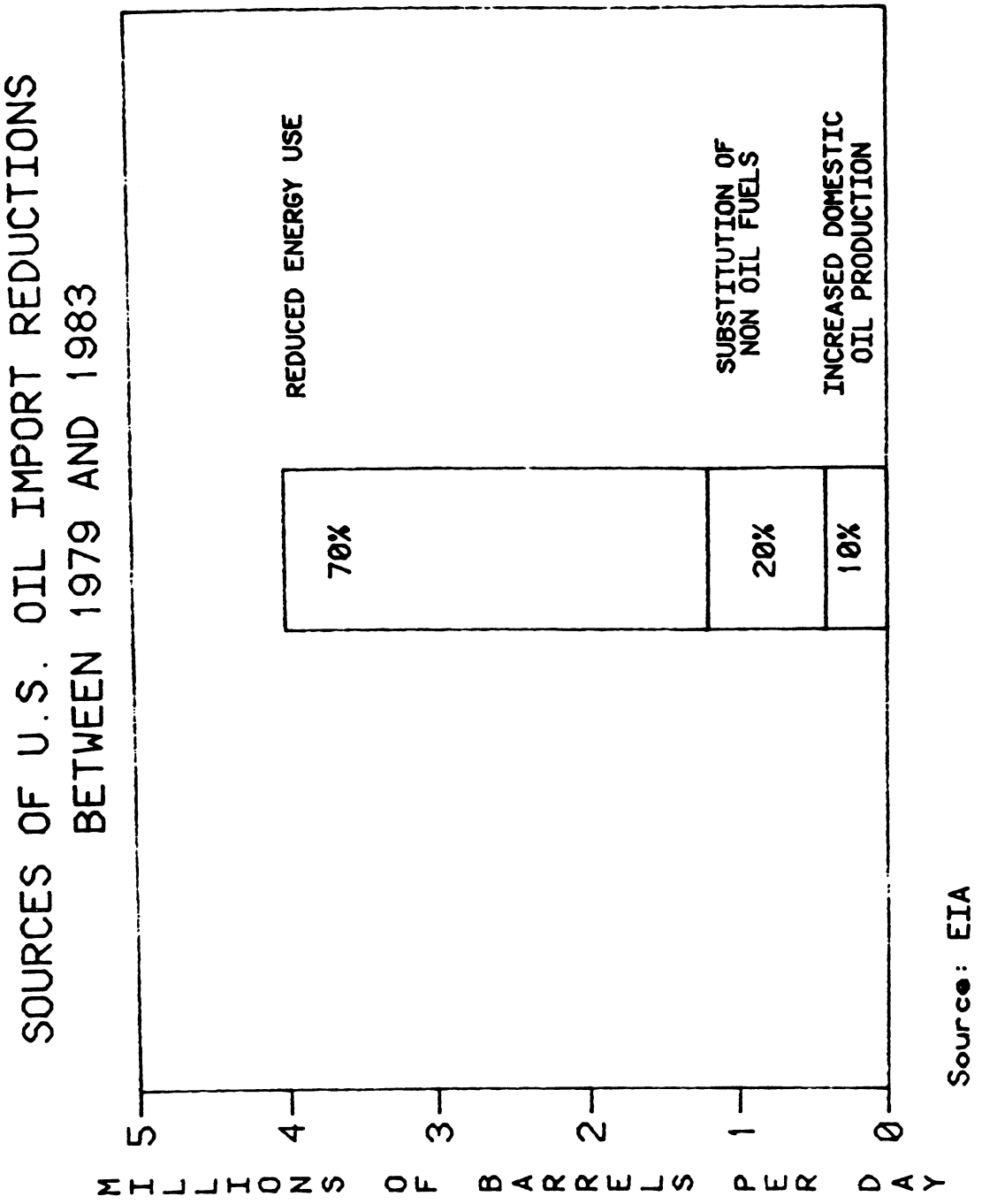
FIGURE D-1



Historic - U.S. Dept. of Energy, Weekly Petroleum Status Report, Various Issues, 1973-1985, (Average Price of Internationally Traded Oils)

Forecasted - California Energy Commission
1985 Biennial Fuels Report, Appendix A

FIGURE D-2


SOURCES OF U.S. OIL IMPORT REDUCTIONS
BETWEEN 1979 AND 1983
MILLIONS OF BARRELS PER DAY
5
4
3
2
1
0
70%
20%
10%
REDUCED ENERGY USE
SUBSTITUTION OF NON OIL FUELS
INCREASED DOMESTIC OIL PRODUCTION
Source: EIA

Similar price effects also occurred on a world wide basis. Between 1979 and 1983 total world petroleum consumption dropped by 25 percent while nonOPEC oil production increased by 16 percent. The joint effect of these two trends was to drastically reduce the need for oil imports from OPEC countries (Figure D-3). This has resulted in OPEC production declining from its 1979 peak of 31 mmb/d to only half that amount today.

However, future prices will be responsive to demand and supply conditions spawned by today's depressed prices. Current trends already foreshadow this development. California's total automobile fuel use, responsible for 70 percent of the state's petroleum consumption, has increased by 12 percent since 1981. At the same time, inhibited by falling prices, U.S. oil exploration and development capital outlays are down 60 percent from the peak year of 1981.

These trends toward increased consumption and declining expenditures for exploration and development will eventually cause demand to increase toward the limits of world oil production capacity which, in turn, will lead to increasing oil prices during the 1990s. Thus, the long term prospect is for higher oil prices. The most recent price decreases are the result of short-term market responses to overly rapid and earlier OPEC induced price shocks, not because the potential for the depletion of world oil resources has in any way changed.

B. Petroleum Product Price Forecasts

The Commission's petroleum product price forecast assumes that over the long run, stable historic relationships between crude oil prices and selected petroleum product prices will continue. The combination of EPA lead reduction rules and the continuing replacement of vehicles fueled with leaded gasoline with unleaded fueled vehicles should result in the phaseout of leaded regular gasoline. Therefore, no price projections for leaded gasoline have been made. Tables D-3 and D-4 present the resultant price projections for the major products in California for the period 1986-2005.

The assumption that historic price relationships will continue may not provide the best predictions of California petroleum product prices. There are a number of regulatory initiatives directed toward improving the environmental characteristics of certain fuels that could increase fuel production costs for California refiners.[4] It is not clear, however, how large these potential increased costs might be or to what extent they would be reflected in consumer fuel prices. This is because not all costs can be passed by oil refiners on to consumers. A recent trade journal article noted that "the effects on gasoline prices for consumers, widely predicted at the time the lead reduction went into effect, have failed to materialize."[5]

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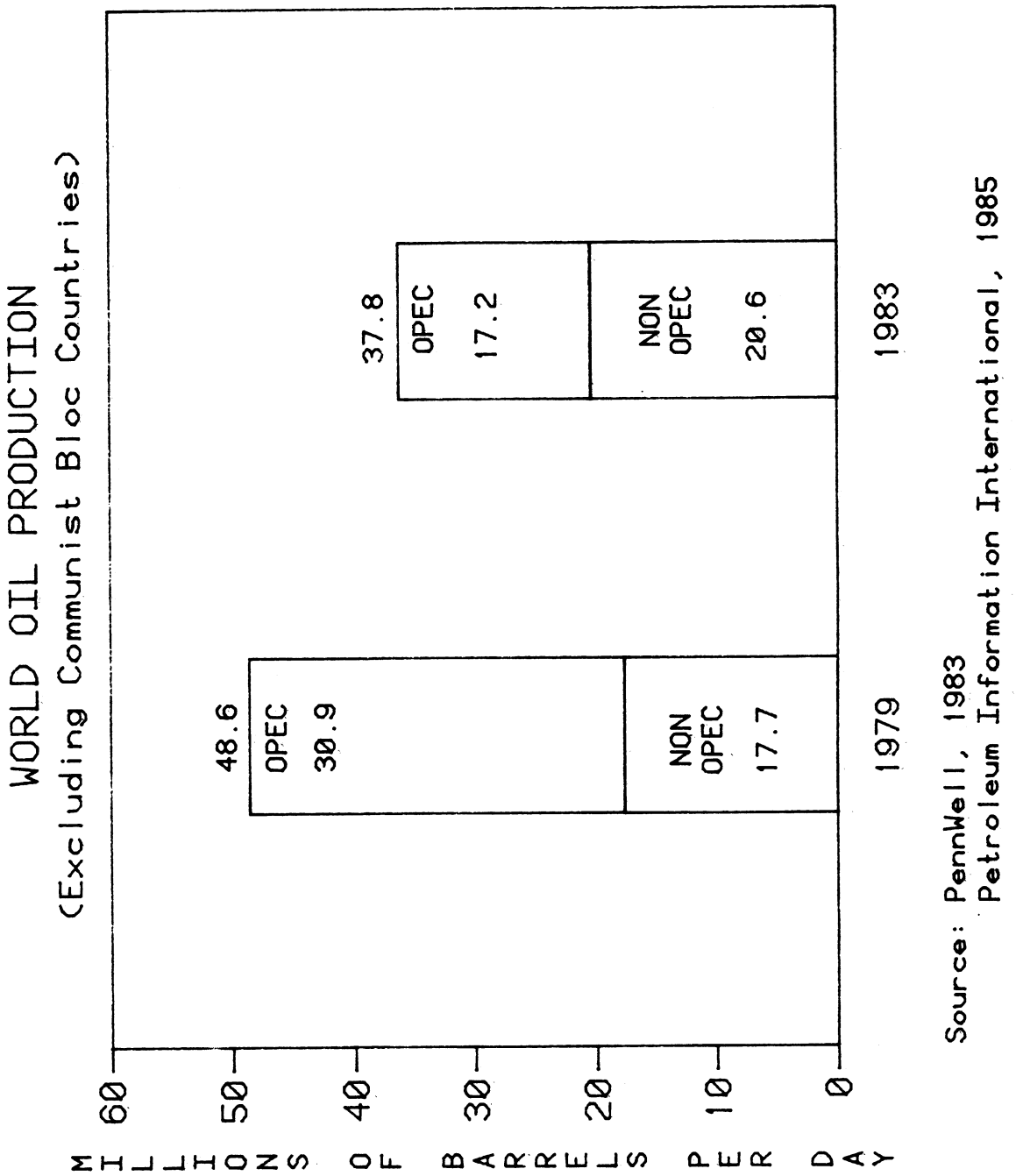
4. See Appendix L for further details.

5. Western Energy Update, Western Interstate Energy Board Newsletter, October 4, 1985, p.9.

FIGURE D-3



Source: PennWell, 1983
Petroleum Information International, 1985

TABLE D-3

PETROLEUM PRODUCT PRICE PROJECTIONS
1983 $/Gallon - Excluding Taxes

	Regular Unleaded	Premium Unleaded	Diesel	Wholesale Propane Prices	Aviation Gasoline	Kerosene-Type Jet Fuel
Actual						
1983	.93	1.08	.92	.54	1.27	0.90
1984	.92	1.06	.82	.49	1.22	0.83
1985	.90	1.03	.80	.48	1.19	0.81
Projected						
1986	.47	0.54	.42	.25	0.62	0.43
1987	.54	0.62	.48	.29	0.71	0.49
1988	.62	0.71	.55	.33	0.82	0.56
1989	.72	0.82	.64	.38	0.95	0.65
1990	.83	0.95	.74	.44	1.10	0.75
1991	.84	0.97	.75	.45	1.12	0.76
1992	.85	0.98	.76	.46	1.13	0.77
1993	.87	1.00	.77	.46	1.15	0.78
1994	.88	1.02	.79	.47	1.17	0.80
1995	.90	1.05	.81	.48	1.20	0.82
1996	.93	1.07	.83	.49	1.23	0.84
1997	.95	1.10	.85	.51	1.26	0.86
1998	.97	1.13	.87	.52	1.29	0.88
1999	1.00	1.15	.89	.53	1.32	0.91
2000	1.02	1.18	.92	.54	1.36	0.93
2001	1.05	1.21	.94	.56	1.39	0.95
2002	1.07	1.24	.94	.56	1.43	0.97
2003	1.10	1.27	.99	.59	1.46	1.00
2004	1.13	1.31	1.01	.60	1.50	1.02
2005	1.16	1.34	1.04	.62	1.54	1.05

Table D-4

PETROLEUM PRODUCT PRICE PROJECTIONS
(1983 $/MMBtu)

	Electric Utility Prices-Residual Oil*		Retail (Excluding Taxes) Transportation Prices			Wholesale Propane
	1/4% Sulfur	1/2% Sulfur	Regular Unleaded	Premium Unleaded	Diesel	Prices
Actual						
1983	4.84	4.60	7.44	8.64	6.63	5.65
1984	4.67	4.45	7.36	8.48	5.91	5.13
1985	4.56	4.34	7.20	8.24	5.77	5.03
Projected						
1986	2.37	2.25	3.66	4.28	3.00	2.61
1987	2.73	2.60	4.21	4.93	3.45	3.01
1988	3.16	3.01	4.88	5.71	4.00	3.49
1989	3.64	3.46	5.62	6.58	4.61	4.01
1990	4.20	4.00	6.64	7.60	5.34	4.61
1991	4.27	4.07	6.72	7.76	5.41	4.71
1992	4.34	4.13	6.80	7.84	5.48	4.82
1993	4.41	4.20	6.96	8.00	5.55	4.82
1994	4.48	4.27	7.04	8.16	5.70	4.92
1995	4.59	4.38	7.20	8.40	5.84	5.03
1996	4.70	4.49	7.44	8.56	5.98	5.13
1997	4.82	4.60	7.60	8.79	6.13	5.34
1998	4.94	4.71	7.76	9.03	6.27	5.45
1999	5.07	4.83	8.00	9.19	6.42	5.55
2000	5.19	4.95	8.16	9.43	6.63	5.65
2001	5.32	5.08	8.40	9.67	6.78	5.86
2002	5.46	5.20	8.56	9.91	6.92	5.97
2003	5.59	5.33	8.79	10.15	7.14	6.18
2004	5.73	5.47	9.03	10.47	7.28	6.28
2005	5.87	5.60	9.27	10.71	7.50	6.49

*Base residual oil prices reflect the annual average low sulfur waxy resid price in Singapore plus a $3.00 per barrel transportation charge to California.

In fact PIIRA data[6] shows that California gasoline prices were 4 cents per gallon lower in the third quarter of 1985, after the new lead phasedown rules went into effect, than in the second quarter of 1985. A more complete discussion of these initiatives is presented in Appendix L, Oil Industry Issues.

III. Natural Gas Price Forecasts

After seven years of continuing increases, averaging about 11 percent per year above inflation, system average gas prices peaked in 1983 at $5.37 per mmBtu in constant 1983 dollars. The decline that began in 1984 has continued through 1985 and into 1986. Real gas prices will not change for a few years before again increasing. By 2005 average gas prices are expected to increase to $6.95 per mmBtu, an annual average increase of 2.1 percent beginning in 1985. The following narrative discusses the components and factors influencing gas prices and their effects on the CEC's natural gas price forecast. A more detailed discussion may be found in Appendix F.

A. Natural Gas Price Forecast Components

There are three basic cost components that make up average delivered gas prices: wellhead, transport, and distribution costs.

The wellhead cost is the price paid to the gas producer. This covers the producer's exploration, drilling, and development costs, and a margin of profit. Since January 1, 1985 only about 50 percent of the prices at the wellhead are controlled by the federal government. The prices for remaining 50 percent of production are freely negotiated between the producer and the purchaser.

As 90 percent of California's gas is purchased outside the state, a part of its cost includes transportation expenses to California. Three pipeline companies supply gas to California, principally from Canada and the Southwestern United States. Generally the pipeline companies purchase the gas and transport it from the production area to California. Included in transportation costs are costs for gas conditioning, fuel for pumps and installation, maintenance and operation of the pipeline and return on investment. Transportation costs and wellhead costs combined make up the California gas utility purchase cost.

Gas utilities take the gas from their point of purchase from pipeline companies and distribute it to the various customers. Their costs include gas purchase, fuel, installation, distribution system maintenance and operation expenses, and return on investment.

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6. CEC, Third Quarter Oil Report, December 1985.

B. Factors Affecting Gas Prices to Various End-users

There are three general factors which affect the price of gas to various end-users. These are alternative fuel prices, volumes of gas being sold, and federal and state regulatory policy. Each may affect one or more of the gas price components.

Alternative fuels such as fuel oil set a cap on gas prices for certain customers. As many gas customers have alternative fuel capability, gas prices to these customers, higher than the alternative fuel price, would lead to switching from gas to the alternative fuel.

Fuel oil prices in the market in which the gas will be sold often determine how much a gas producer will receive for the gas at the wellhead. On a netback basis, the wellhead price will equal the fuel oil price less gas transportation and distribution costs. However, if the netback wellhead price of gas is too low in a particular market because of high transportation and distribution costs, a producer will look for better, closer markets in which to sell the gas.

Total volumes of gas delivered by pipelines and utilities affect the customer's cost for gas. Pipeline and gas utilities have fixed costs which do not vary significantly with the quantity of gas delivered. The more gas a particular pipeline or gas utility carries or distributes, the smaller the unit cost. For instance, if fixed unit costs average 50 cents per thousand cubic feet (mcf) at delivery levels of 100 million cubic per day (mmcfd), deliveries of 200 mmcfd would reduce unit costs to 25 cents/mcf. Similarly a reduction in deliveries to 50 mmcfd would increase units cost to $1/mcf.

Costs or availability of transportation can affect the volumes of gas received. If there is no transportation available or if the cost of gas or its transportation is too high, gas supplies that would otherwise be shipped to California will not be available.

Federal and state regulatory policies affect all components of the gas price. About 50 percent of domestic gas production is still under federal regulation at the wellhead. Additionally, for gas imported from other countries, the price set at the international border must be approved by a federal agency.

Federal regulations also affect transportation costs. Interstate pipeline companies must receive approval from a federal agency before building a new pipeline. Also the companies' costs to operate the pipeline are examined at least once every three years and based on this examination its transportation rates are set. Pipelines may also request, no more frequently than once every six months, rate changes to recover or refund money to its customers based on the company's increased or decreased costs to purchase gas.

Through federal laws and regulations the federal government also regulates the prices certain classes of customers must pay to the gas utility. Other federal regulations prohibit the sale of gas to other classes of customers, thereby affecting the volume of gas that may be delivered.

The state, through the California Public Utilities Commission (CPUC), regulates the price customers pay for gas service. First it must approve the costs the gas utility incurs through gas purchases and distribution. The CPUC may also determine transportation costs should a utility decide to "carry" gas owned by someone else.[7]

Secondly, the CPUC decides how to distribute gas utility costs among the various customer classes. At present, the CPUC follows a value of service policy in setting rates. Gas rates to industrial and utility customers are established equivalent to or slightly lower than the alternative fuel price. This policy was intended to ensure that gas was burned in lieu of fuel oil by as many interruptible customers (those having alternate fuel capability) as possible. The CPUC has announced that it is changing this policy and intends to implement cost of service based rates beginning January 1, 1987. Under a "cost of service" policy the cost of providing service to each customer class would be used to determine the gas rate for that class. The advantages of cost-of-service pricing are discussed in Chapter 4.

Generally, for interruptible customers cost of service rates would be lower than value of service rates. Firm customers such as residential and commercial customers, could receive a rate increase under a shift to cost of service rates because their true cost-of-service would not be offset (subsidized) by higher payments of interruptible customers.

The natural gas price forecast takes into account the various aforementioned pricing components and factors. The results of the forecast are displayed in Figure D-4. This figure displays statewide average utility gas purchase costs, the system average delivered cost, and the average residential cost for gas. (See Appendix F for methodology and assumptions supporting the gas price forecast.)

A fundamental assumption of the forecast is that deregulated gas wellhead prices will move in parallel with the oil product price forecast described in the previous section. It was also assumed that present CPUC policy of using value of service to set customer prices would continue. All prices are expressed in constant 1983 dollars.

C. Forecast of Gas Utility Purchase Costs (Wellhead Costs Plus Transport Costs)

Since 1976 gas utility purchase costs have increased dramatically from $1.72 per mmBtu in 1976 to $3.93 per mmBtu in 1983. In 1976 up to 90 percent of the gas used in California was regulated by the federal government. The wellhead

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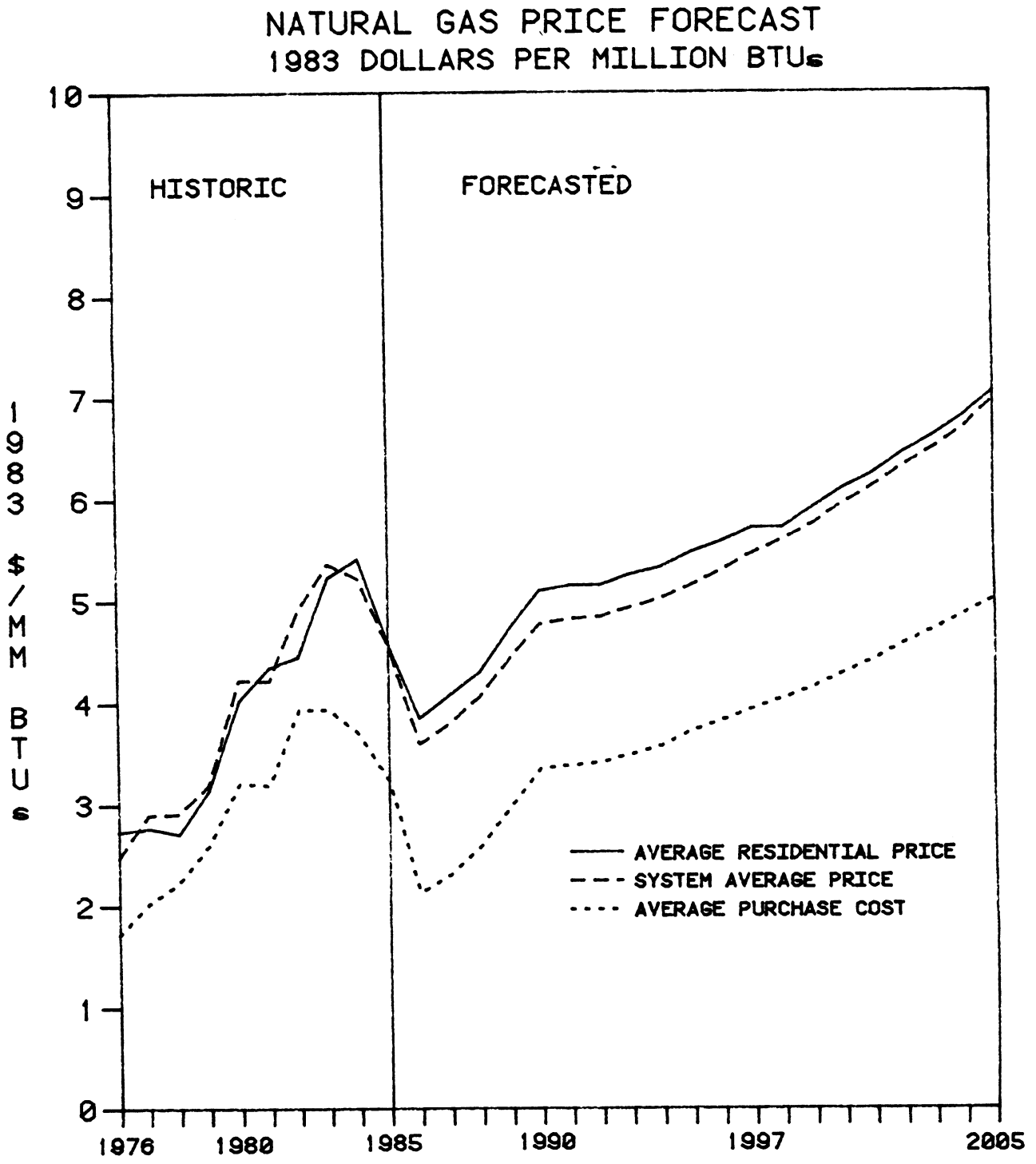
7. On October 17, the CPUC issued a proposed decision for public comment on contract carriage. The proposal would require California utilities to institute contract carriage tariffs following stipulated guidelines. See CPUC Proposed Decision in I. 84-04-079 et al. for details and Chapters 4 and 5.

FIGURE D-4



Historical: Based Upon Utility Reports
Projected: Developed By CEC Staff

costs were considered to be below the value of the gas as measured relative to other fuels, typically oil. The 1978 Natural Gas Policy Act (NGPA) allowed wellhead prices to increase to levels comparable to oil. In their enthusiasm to purchase new gas supplies, California's pipeline suppliers bought some gas at prices which were too high to sell. These high prices resulted in significantly reduced sales to consumers. Since then purchase costs have declined. Declining gas prices are the result of declining oil prices and gas supplies exceeding demand at the current level of prices.

Since purchase costs began to decline after 1983 there have been slight increases in utility gas sales. However, permanent changes have occurred in the character of gas need in California. To mention only a few, individual residential use has declined markedly, a few industries have permanently switched to other fuels such as coal, and electric utilities have four new nuclear power plants operating that are displacing gas use in conventional gas fired steam-electric plants.

The current CEC forecast indicates gas utility unit purchase costs will begin to gradually increase in 1987. Overall during the 20-year period gas purchase costs are estimated to increase at 2.2 percent per year above inflation for the 20-year period. While in the early years of the forecast, falling oil prices mean lower utility gas costs, increasing oil prices in the 1990s will mean that gas purchase costs will increase.

D. Forecasts of Average Customer Gas Prices

Between 1976 and 1983 the average customer's price for gas increased nearly 12 percent per year above inflation from $2.48 to $5.37 per mmBtu. The principal cause was increasing purchase costs. However, both the increasing overall costs to transport and distribute, and lower natural gas delivery volumes also contributed to the increase.

Since 1983 system average purchase costs have declined markedly. Although the average unit purchase cost component has been decreasing, the unit distribution cost continued to increase since 1983, due to both increasing unit distribution costs and lower gas delivery levels.[8]

The CEC's long-term outlook calls for average customer gas prices to decline substantially from the 1983 levels before beginning to increase in 1987. Over the 20-year forecast period, average customer prices are expected to increase annually at 2.1 percent per year above inflation. Unit distribution costs are expected to remain around 37 percent of the system average customers price.

Figure D-4 shows that since 1976 residential average gas rates have remained close to the system average rate. The forecast indicates that future residential rates will become higher than the system average. This reflects the impact of interruptible industrial customers and electric utilities

8. Distribution costs may be identified in Figure D-4 by the difference between system costs and purchase costs.

contributing less to fixed cost recovery. Because of the low oil price forecast, the difference between interruptible rates and gas utility purchase cost is reduced as compared to current conditions. Interruptible customer contribution to the gas utilities fixed distribution costs are thereby reduced. Uncollected costs must be shifted to the firm customers, notably residential and commercial sectors, if they are to be recovered.

The current average residential rates are closer to the actual residential cost-of-service than in the past. When the CPUC implements its cost-of-service rate-making policy, the rate impact on the residential customer would be less than the impact would have been several years ago when industrial interruptible customers were contributing more to fixed costs and subsidizing a portion of the costs of providing residential service.

IV. Coal Price Forecasts

The price of coal, unlike that of oil and gas, varies tremendously throughout the U.S. The primary factors which determine the price of coal are mining costs, transportation, heat content, and quality (ash, sulfur, and other contaminants). The average delivered price paid in the U.S. by utilities in 1984 was $34.66 per ton for coal, or about $1.64 per mmBtu delivered. The average delivered cost in 1984 for California industrial coal (primarily cement plants) was $54.50 per ton or $2.60 per mmBtu. The industrial coal price in California is about $16.00 per ton above the national average reflecting the much higher rail tariffs that California, with no significant coal reserves, must pay for transportation from distant coal states.

Forecast base prices and escalation rates for all existing and proposed coal-fired power plants in which California utilities have a share of ownership are presented in Table D-5. The coal price forecasts are based on a determination of current coal prices in the appropriate mining areas and the corresponding rail rates for moving the coal to the power plants. The differences among escalation rates between sites is due to differences in the relative proportion of commodity costs and transportation costs included in the base prices for each plant's coal sources as well as existing contract terms.

The escalation rates used for the commodity and transportation portions of the delivered coal price are shown in Table D-6.

V. Alternative Fuel Price Forecasts

A. Biomass

The largest category of biomass users is the forest products sector which uses an estimated 3.3 million tons (53 tBtus) of fuel annually. Fuel costs range from waste material having no value to $1.90 per mmBtus. The next largest user is the residential sector. About 2.8 million dry tons (45 tBtus) of firewood are burned in this sector. The fuel costs for this group range between $2.30/mmBtu in rural regions to $11.60/mmBtu in the urban areas. The non-forest products' cogeneration industry composed primarily of agricultural

TABLE D-5

COAL PRICE PROJECTIONS
(1983 dollars)

	New Plant	Mojave	Four Corners	Navajo	Coronado	IPP
1983 Delivered Base Price cents/mmBtu	217.0	96.3	66.1	87.4	216.1	154.7
Future Delivered Prices cents/mmBtu						
1990	240.8	99.7	68.4	91.5	244.8	168.8
1997	267.2	103.3	70.9	95.7	277.4	184.1
2005	301.1	107.5	73.8	100.8	320.0	203.3

Source. CEC staff forecast. See Appendix H.

TABLE D-6
COAL COST ESCALATION RATE PROJECTIONS
TRANSPORT AND COMMODITY
(1983 dollars)

Transportation Type	%/yr	Commodity Mine Type	%/yr
Rail	2.4	Underground	1.0
Truck	2.4	Surface	0.5
Slurry Pipeline	0.4		

Source: CEC Staff forecast. See Appendix H.

and industrial cogenerators is the next largest category using almost one-half million dry tons (7 tBtus) of fuel each year. The fuel used in this group is probably the most diverse, ranging from fruit pits and nut shells used by the agricultural industrial sector, to urban wood waste and orchard prunings used by a variety of industrial cogenerators. Fuel costs for this range between little or no value to $2.80 per mmBtu.

The last category of industrial user is the stand alone power plant, a relatively new entry in the biomass energy field. This group is currently estimated to use 220,000 dry tons (3.5 tBtus) of fuel priced at between $1.25 and $1.90 per mmBtus.

Although the biomass fuel cost is less expensive than natural gas, the capital cost and operation and maintenance cost of a biomass facility is higher than a facility fired by natural gas or fuel oil. For a 10 MW stand alone biomass-fired power plant, the most one can afford to pay for fuel is $1.43 per mmBtu if the avoided cost including capacity payment is $0.08 per kWh. With this avoided cost the use of straws and stalks is uneconomical. In addition, this level of avoided cost would hamper the use of in-forest and forest wood waste, orchard prunings, and urban wood waste if the transportation distance is more than a 25 mile radius from the end user and the transportation cost is greater than $0.15 per ton-mile ($0.01 per million Btu-mile).[9]

B. Municipal Solid Waste (MSW)

Fuel costs for MSW-to-energy plants cannot be easily predicted. At a conventional energy plant, the plant owner pays a price for the fuel delivered to the plant. At MSW-to-energy plants, the plant owner charges a price for each ton of MSW delivered to the plant (the tipping fee). The tipping fee is used, along with revenues generated from energy sales, to offset the capital and operating costs associated with disposing of MSW in a MSW-to-energy facility. The revenues from energy sales depend typically on electrical sales to a utility. The economics of the plant, and the required tipping fee, depend on the level of avoided cost payments from the utility.

Increasing MSW-to-energy plant tipping fees could potentially disrupt the supply of MSW to the plant. If the tipping fee increases to a level where it is less expensive for a community to transport the MSW to a landfill, the MSW-to-energy plant could lose a portion or all of its MSW supplies. However, in many cases, the MSW supply economics for a particular MSW-to-energy plant are significantly more complex due to factors such as long term contracts between plant owners and MSW collectors, and municipal laws which specify how tipping fees can be changed or adjusted.

C. Methanol

Natural gas is the primary feedstock for producing methanol today. For the currently operating CEC sponsored fleet demonstration program the cost is $.49 per gallon for methanol delivered in rail car lot sizes to California.

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9. See the Section on "Biomass" in Appendix J, Alternative Fuels.

Surplus capacity around the world for producing methanol from natural gas could potentially provide lower cost methanol to California with larger shipments. One source concludes 25 million barrels of methanol could be obtained annually, at a price to California of $0.35 to $0.45 per gallon.[10] This approach assumes the methanol would be purchased under five year contracts and delivered via large tankers. Although estimates of the cost of methanol from new plants at remote natural gas sites diverge widely, several analyses indicate methanol could be delivered for about $.60 per gallon to California.[11] In comparison, the cost at the refinery for gasoline is currently about $0.50 per gallon. A gallon of gasoline has about twice the energy content of a gallon of methanol. On an energy equivalent basis, the CEC methanol cost of $.49 per gallon in gasoline equivalents would cost about $.98 per gallon, about 110 percent more than gasoline at the refinery.

Depending on financing and other assumptions, estimates of the cost of methanol from coal vary widely. Several analyses have projected methanol could potentially be produced from large plants at a levelized cost of around $.80 per gallon.[12]

Table D-7 contrasts projected methanol costs with projected gasoline prices. The 1990 methanol price represents methanol from existing excess capacity; the 1997 value represents methanol made from remote natural gas resources and the 2005 value represents methanol derived from coal.

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10. Charles A. Stokes, Near-and Long-Term Fuel Methanol Supply, and Price Outlook and Suggested Supply-Inducing Strategies for California, for CEC, August 20, 1985.

11. Charles A. Stokes, Near- and Long-Term Fuel Methanol Supply, Jet Propulsion Laboratory, California Methanol Assessment, Vol. 1, (March 1982), p.12.

12. J. Frederick Weinhold, "Economics of the North Alabama Coal to Methanol Project," (Electric Power Research Institute Conference, April 14-19, 1985), p.13; Robert G. Jackson, An Analysis of the Potential for Coal-Based Plants to Produce Methanol for California, for CEC, September 23, 1985. JPL, California Methanol Assessment, p.15.

TABLE D-7

METHANOL VS. GASOLINE PRICE PROJECTIONS
Retail Excluding Taxes
(1983 dollars)

	Methanol			Gasoline	
Year	M100[a]	M85[b]	M85 Gasoline Equivalent[c]	Regular Unleaded	Premium Unleaded
1990	.47	.54	.86	.83	.95
1997	.66	.73	1.02	.95	1.10
2005	.84	.92	1.29	1.16	1.34

Notes: 1990 prices are for methanol produced from existing excess capacity.
1997 prices are for methanol produced from remote gas.
2005 prices are for methanol produced from coal.

a. Assumes $.10/gallon for distribution and margin.

b. 85 percent methanol, 15 percent premium unleaded gasoline.

c. Based on a 10 percent energy efficiency advantage with methanol engines for 1990 and a 20 percent advantage for 1997 and 2005.

Sources:

Methanol: Stokes, C.A., The Near- and Long-Term Methanol Supply and Price Outlook and Suggested Supply - Inducing Strategies for California, consultant report to CEC, August 20, 1985.

Gasoline: Staff forecast. See Table D-3.

APPENDIX E

NATURAL GAS DEMAND FORECAST

APPENDIX E

NATURAL GAS DEMAND FORECAST

INTRODUCTION

This appendix summarizes a range of alternative forecasts and possible levels of consumption for natural gas within California. This appendix is intended to document the examination of natural gas demand for the 1985 Biennial Fuels Report. Three principal sources of information are included: (1) CEC staff analyses prepared in July and August 1986 as part of the Common Forecasting Methodology 6 (CFM 6) process for electricity supply and demand; (2) gas utility views prepared for and documented in the 1985 California Gas Report; and (3) electric utility views prepared as part of CFM 6. Where possible these three views are compared and major differences noted.

This appendix incorporates the results of three aspects of staff effort to understand and compare these alternative sources. First, primary documents such as the 1985 CGR were reviewed and analyzed with some telephone contacts with sponsoring utilities. A draft of this appendix was prepared and mailed to utilities for review. Second, staff conducted a workshop to explore issues raised in preparing the draft of this appendix and to answer utility questions regarding staff analysis. Third, utilities prepared summaries of their 1985 CGR forecasts in the format of Tables E-2 to E-5 to facilitate comparison. These were substituted for draft versions which were prepared by staff using assumptions about how best to translate from the level of reporting in the 1985 CGR to that desired. This process resulted in a good understanding of the differences between gas and electric utility views and those of staff.

The natural gas forecasts presented here represent a mixture of requirement estimates and forecasts of sales. The CPUC priority of supply system was established to assure a supply of gas based upon a combination of the feasibility of alternative fuels and necessity for continuity of supply. Generally, residential usage has the highest priority and incentive rates to industrial customers and/or electric utility boiler fuel has the lowest. Utility views represented in the 1985 CGR do foresee some very minor curtailment of requirements. In addition, both CEC staff and utilities recognize that demand for natural gas is affected by policies of the state and federal governments. Table E-1 summarizes the basic thrust of conservation and fuel use policies by the CEC, CPUC, and federal government. Part of the differences between staff and utility estimates stem from alternative views about the ability of such policies to affect natural gas demand.

This appendix is organized to discuss demand forecasts by market segment. Four principal categories are identified--retail, cogeneration, electric generation, and thermally enhanced oil recovery only (TEOR-only). The retail segment consists of the residential, commercial, and industrial elements. TEOR-only consists of the steam flooding activity and excludes any ancillary cogeneration which may be involved with oil recovery. Such cogeneration is

Table E-1

Regulatory Policies Affecting Demand

Demand Segment	CEC	CPUC	Federal
Residential	reduce through conservation programs of utilities and state standards	reduce through conservation programs of utilities	NCPA tried to shield high priority customers from gas cost increases above inflation
Commercial	reduce through conservation programs of utilities and state standards	reduce through conservation programs of utilities	--
Industrial	--	a. maintain gas price competitiveness with oil b. reduce through conservation programs of utilities	a. FERC exploring need for wheeling requirements b. PIFUA imposes controls on MFBIs c. NCPA passed on gas cost increases above inflation to low priority customers
Cogeneration	facility siting policy of 1985 ER	avoided cost offer facilitate major expansion	PURPA expands opportunities for usage
Electric Generation	one-third of total generation from oil/gas is a goal of 1985 ER	maintain gas price competitiveness with oil	PIFUA imposes controls on gas use in power plants
TEOR only	--		FERC facilitating free market arrangements

included in the cogeneration market segment as incremental requirements. Each of the principal market segments is discussed in a separate section which follows a summary of requirements across all segments at both the statewide and gas utility level.

GAS UTILITY AND STAFF REQUIREMENTS FORECASTS

This section summarizes natural gas demand for the entire state for the three natural gas utility service areas. Six market segments are compared in each of Tables E-2 through E-5. Tables E-3 through E-5 have no CEC staff estimates for TEOR-only requirements since the statewide estimate presented in Table E-2 is not allocated to a specific gas utility service area. Industrial, commercial, residential, cogeneration, and electric generation have point estimates for three future years as both CEC staff and gas utilities make forecasts on this basis. The 1985 CGR also presents information on a point forecast basis for cogeneration, electric generation, and TEOR-only segments.

Statewide

Total statewide natural gas requirements presented in Table E-2 are in agreement. Although lack of agreement on consumption in the base year of 1983 for all segments somewhat confuses the comparison, clear differences among certain demand sectors in 1990, 1995, and 2000 are present.

The much larger industrial demand according to CEC staff is partially due to the difference in classification for the gas used in cogeneration facilities, even though an attempt has been made to put the 1985 CGR forecast on a comparable basis to the staff's analysis by splitting P3A gas into thermal process usage and incremental cogeneration usage. The sum of the staff industrial forecast and cogeneration range is comparable to the utility combined forecast. This classification problem is not fully resolved and may merit regulatory change in QFER reporting requirements to obtain accurate electricity generation and natural gas consumption by cogenerators.

The residential and commercial market segments are comparable.

Both 1985 CGR and electric utility CFM 6 submittals foresee higher usage of natural gas for cogeneration than the CEC staff forecast.

The TEOR-only range of CEC staff forecast is somewhat larger than the TEOR-only forecast of the gas utilities. This represents utility assessment that some portion of the TEOR market will not be served by utilities.

Generation of electricity by natural gas by electric utilities, as foreseen in the 1985 CGR and electric utility CFM 6 submittals, is substantially higher than staff estimates.

Pacific Gas and Electric Service Area

PGandE service area natural gas requirements differ substantially between CEC staff and utility estimates. Table E-3 summarizes total gas requirements from three general sources--CEC staff, 1985 CGR, and CFM 6 utility filings.

TABLE E-2

Statewide Natural Gas Demand

Demand Segment	Average Annual Requirements (mmcf/d) 1983	1990	1995	2000
Residential				
CEC Staff	1,340	1,491	1,518	1,537
California Gas Report	1,355	1,420	1,409	1,427
Commercial				
CEC Staff	480	569	601	621
California Gas Report	598	646	649	653
Industrial				
CEC Staff	742	1,037	1,137	1,277
California Gas Report	602	760	795	817
Cogeneration				
CEC Staff	35	297	346	403
California Gas Report	38	478	611	681
Utility CFM 6[a]	45	405	487	532
TEOR Only				
CEC Staff[b]	204[c]	736	772	816
California Gas Report	3	575	609	608
Electric Generation				
CEC Staff	1,396[a]	673	796	645
California Gas Report	1,238	875	970	1,064
Utility CFM 6[a]	1,606	759	1,080	1,187
Total Demand				
CEC Staff[a]	4,197	4,803	5,170	5,299
California Gas Report[d]	3,878	4,849	5,156	5,367

a. Staff interpretation of electric utility CFM 6 filings.

b. Estimate of total statewide gas requirement expressed in mmcf/d for TEOR steaming without cogeneration.

c. 1984 PIIRA statewide fuel use data reported for TEOR includes 35 percent gas and 65 percent crude oil usage.

d. Includes "Other" as delineated by PGandE in 1983 as 44; in 1990 as 95; in 1995 as 113; in 2000 as 117. This represents indepartmental sales and volumes sold for resale. These volumes are not included in sectoral summaries.

TABLE E-3

PGandE Service Area Natural Gas Demand

Demand Segment	Average Annual Requirements (mmcf/d) 1983	1990	1995	2000
Residential				
CEC Staff	546	559	563	576
California Gas Report	550	599	621	653
Commercial				
CEC Staff	222	258	270	275
California Gas Report	340	374	381	390
Industrial				
CEC Staff	367	475	527	603
California Gas Report	249	395	419	439
Cogeneration				
CEC Staff	16	113	135	157
California Gas Report	7	126	198	231
Utility CFM 6[a]	26	210	277	277
TEOR Only				
CEC Staff	N/A	N/A	N/A	N/A
California Gas Report	0	366	401	402
Electric Generation				
CEC Staff	495	178	199	189
California Gas Report	465	174	271	405
Utility CFM 6[a]	678	189	308	480
Other				
CEC Staff	0	0	0	0
California Gas Report	44	95	113	117
Total Demand				
CEC Staff	1,646	1,583	1,694	1,800
California Gas Report	1,655	2,129	2,404	2,637

a. Staff interpretation of electric utility CFM 6 filings.

PGandE has indicated that the gas requirements reported in the 1985 CGR and in its CFM 6 supply forms come from the same analysis. Differences in gas demand must therefore come from the particular methods and assumptions used by staff to translate CFM 6 electric energy production into the amount of gas used for generation. Ambiguities in PGandE resource plans allow multiple interpretations of gas demand. This problem was not fully resolved in this process.

The retail segment elements of residential and commercial have utility estimates higher than those of staff, while in the industrial element the utility is lower. Table E-7 indicates that CEC staff conservation program savings are higher which is consistent with the lower residential and commercial sector forecasts.

The cogeneration market segment presents an interesting case. These alternative estimates of gas demand do not come from PGandE itself, rather they are a result of inferring natural gas demand from CFM 6 resource plan submittals. Since alternative forms can be used to translate PGandE's electric generation by technology into gas demand, the appearance of disagreement reflects inadequate specificity in the CFM 6 supply forms to support BFR information needs.

The electric generation market segment also indicates that the two alternative reports of the same PGandE analysis can be interpreted to come to somewhat different conclusions.

Southern California Gas Service Area

SCG service area forecasts are presented from three sources in Table E-4. SCG has based its electric generation gas demand on the CFM 5 resource plans of the Southern California electric utilities. In some cases this work is nearly two years old.

Residential and commercial elements of the retail segment are higher in CEC staff views than those of SCG. This is contrary to the PGandE service area result. In addition, the CEC staff view of industrial requirements is higher than that of SCG just as it was for the PGandE service area. This gives a total retail market segment forecast for the CEC staff much larger than that presented by SCG.

The cogeneration market segment illustrates the divergence of views between 1985 CGR and electric utility CFM 6 results. The 1985 CGR result is nearly double that interpreted by staff from resource plan documentation presented to the CEC by Southern California electric utilities in recent CFM 6 filings.

Part of this difference is due to SCG's incomplete efforts to quantify the true incremental demand for cogeneration. Current billing practices and accounting systems do not allow a complete separation between the increment of gas used for cogeneration and that used for the underlying industrial/ commercial process.

TABLE E-4

SCG Service Area Natural Gas Demand

Demand Segment	Average Annual Requirements (mmcf/d) 1983	1990	1995	2000
Residential				
CEC Staff	717	836	856	860
California Gas Report	727	725	690	673
Commercial				
CEC Staff	229	271	288	299
California Gas Report	233	237	231	224
Industrial				
CEC Staff	366	548	595	657
California Gas Report	342	353	364	365
Cogeneration				
CEC Staff	9	167	184	216
California Gas Report	16	305	342	371
Utility CFM 6[a]	9	176	184	210
TEOR Only				
CEC Staff	N/A	N/A	N/A	N/A
California Gas Report	3	209	208	206
Electric Generation				
CEC Staff	726	432	514	400
California Gas Report	649	571	565	517
Utility CFM 6[a]	796	479	640	571
Total Demand				
CEC Staff	2,047	2,254	2,437	2,432
California Gas Report	1,970	2,400	2,400	2,356

a. Staff interpretation of electric utility CFM 6 filings.

San Diego Gas and Electric Service Area

For SDG&E service area there is much more unanimity of opinion regarding future natural gas requirements than for the PGandE and SCG service areas. SDG&E's contribution to the 1985 CGR was virtually unchanged from its CFM 5 filing to the CEC. Further, SDG&E's CFM 6 demand forecast filing to the CEC is only a minor update to its CFM 5 filing. Thus, SDG&E's official views have not changed in the retail area since late 1983.

Table E-5 indicates that the retail segment varies only a small amount between CEC staff and 1985 CGR forecasts.

The electric generation requirement foreseen by SDG&E is little changed between CFM 6 and 1985 CGR analyses. Compared to 1983 actual usage SDG&E expects to drop down and then resume higher levels of gas demand. Following the same pattern as for the larger utilities, this is substantially above the CEC staff value.

The cogeneration gas demand requirements presented by SDG&E in CFM 6 are similar to those incorporated into the 1985 CGR. The CFM 6 amount is the result of more recent SDG&E work since the 1985 CGR is based upon somewhat dated CFM 5 analyses. Both are much higher than CEC staff estimates. In part, SDG&E estimates very high penetration of cogeneration in the commercial sector. This once again touches upon the classification of the gas problem noted earlier. SDG&E follows the practice of classifying all gas used by a customer having a cogeneration facility as P3A, not just the true increment. Efforts to obtain a true incremental cogeneration demand and the appropriate increases to other sectors have been unsuccessful.

RETAIL SEGMENT FORECASTS

This section will review the principal categories of input assumptions and forecasting techniques that lead to the retail segment demand forecasts by CEC staff and utilities. Included are (1) economic and demographic assumptions (including fuel prices), (2) conservation program assumptions, and (3) forecasting techniques. Tables E-6 through E-8 tabulate principal known elements.

Of the three utility service areas, SCG had the greatest overall retail segment discrepancy while SDG&E had the least. In individual sectoral elements the SCG industrial results differed the greatest amount from the CEC staff analysis.

Economic/Demographic Input Assumptions

Table E-6 presents 1983 to 2005 growth rates for the principal variables used by CEC staff and each of the three gas utilities for each retail segment. Review of Table E-6 indicates that for each of the three gas service areas a very mixed picture of relative assumptions exists. No party is clearly higher

TABLE E-5

SDGandE Service Area Natural Gas Demand

Demand Segment	Average Annual Requirements (mmcf/d) 1983	1990	1995	2000
Residential				
CEC Staff	77	96	100	101
California Gas Report	78	96	98	101
SDG&E CFM 6	79	107	110	114
Commercial				
CEC Staff	29	39	43	46
California Gas Report	25	35	37	39
SDG&E CFM 6	30	37	44	50
Industrial				
CEC Staff	9	14	15	17
California Gas Report	11	12	12	13
SDG&E CFM 6	8	14	15	17
Cogeneration				
CEC Staff	10	17	27	30
California Gas Report	15	47	72	79
SDG&E CFM 6[a]	15	48	62	65
Electric Generation				
CEC Staff	175	63	83	56
California Gas Report	124	130	134	142
SDG&E CFM 6[a]	132	91	132	136
Total Demand				
CEC Staff	300	229	268	250
California Gas Report	253	320	352	374
SDG&E CFM 6	268	297	363	382

a. Staff interpretation of electric utility CFM 6 filings.

TABLE E-6

1983-2005 Economic/Demographic Growth Rates

	Pacific Gas and Electric		Southern California Gas		San Diego Gas and Electric	
	Utility	Staff	Utility	Staff	Utility	Staff
Residential						
Population	1.56	1.50	1.06	1.27	1.59	1.91
Households	N/A	1.86	1.54[a]	1.51	2.05	2.33
Gas Price	1.59	1.70	1.11[a]	1.22	1.62	0.81
Commercial						
Employment	N/A	2.35	2.04[b]	2.06	2.13	1.83
Floorspace	N/A	1.42	1.64[a]	1.85	2.04	3.19
NonFarm Private Income	3.64	3.27	2.87[b,c]	2.86	3.02[c,d]	3.67
Taxable Sales	N/A	4.16	Not Used	3.92	N/A	4.35
Gas Price	2.25	0.85	1.18[a]	0.58	1.62	0.40
Industrial						
Phys Production	2.96	1.15	N/A	1.08	N/A	N/A
Employment	N/A	1.94	1.19[a]	0.23	1.79	2.15
Value Shipment	N/A	4.83	N/A	3.71	N/A	4.78
Gas Price[e]	1.5 to 2.4	0.65	-1 to +1	0.73	1.7	0.31

a. Out year = 2000.
b. Base year = 1984.
c. Real personal income.
d. Per capita income added to population.
e. Industrial gas prices frequently calculated by SIC code industry, thus mixing differential price growth rates from various priority classes.

or lower than another. This table also shows that while CEC staff natural gas price escalation rates are consistently higher than those used by utilities, there is considerable diversity among the utilities. This illustrates an important point about the CGR process as mandated by the CPUC--the CGR is a compilation of the independent views of the major gas utilities and Southern California electric utilities. It is not an orchestrated, internally consistent process to produce statewide natural gas requirements forecasts. Thus, utilities can have widely differing views on fundamental assumptions that may be common to all in the real world.

Conservation Program Savings

Savings from conservation programs can be an important source of discrepancy between utility and CEC staff gas forecasts. Two components lead to these savings estimates--policy decisions about what programs should be counted and technical decisions about how to quantify savings from each program. Historically, CEC staff has been more inclusive in counting the impacts of various programs than utilities. In addition, rather different savings quantification techniques have led to alternative estimates for the same program. Such traditional differences continue to exist for these forecasts.

Table E-7 compares program savings by sector for the single year of 2000. For the PGandE and SDG&E service areas staff has consistently higher total savings. SCG has not documented savings by program, so no comparison is possible, but its general policy assumptions are known.

Mandated Programs

This category represents programs largely stemming from CEC policy action--standards for buildings and appliances. CEC staff assumes that the basic conservation policies of the 1985 ER persist, but are updated for an additional year's passage of time. This adds the full set of updated Title 24 Nonresidential Building Standards to the group of programs considered "reasonably expected to occur" (RETO). PGandE's policy assumptions are very similar to those of staff. For SDG&E and SCG the RETO decision is more conservative than that enunciated in the 1985 ER; thus it would lead to lower savings.

Utility Administered Programs

The results of savings estimates for utility administered programs--ZIP, commercial audits, schools and hospitals, etc.--are quite different between the PGandE and SDG&E service areas. The overall total across sectors is quite close for PGandE, but more than an order of magnitude different for SDG&E. Part of this difference is due to different assumptions about the level of funding for utility programs. PGandE assumes increasing real expenditures, thus getting increased savings over time. SDG&E assumes just the reverse, with both expenditures and savings falling over time. SCG also assumes that utility administered funding decreases over the forecast period. Staff assumes the continuation of the current rate of expenditure levels out to 1997 and then a major reduction.

Table E-7

Comparison of Conservation Program Savings

Demand Segment	Savings in 2000 (mmcf/d)					
	PG&E		SCG		SDG&E	
	Utility	Staff	Utility	Staff	Utility	Staff
Residential						
Mandated	26	213		250	30.0	46
Utility	95	103		71	.8	6
TOTAL	121	316		321	30.8	52
Commercial						
Mandated	9	7		11	.08	2
Utility	41	3		10	.10	1
TOTAL	50	10		21	.18	3
Industrial						
Mandated	4	6		10	.72	2
Utility	35	14		6	.04	1
TOTAL	39	20		16	.76	3
All Sectors						
Mandated	39	226		271	30.8	50
Utility	171	120		87	.9	8
TOTAL	210	346	NA	358	31.7	58

Note: "Utility" savings for CEC staff include public agency funded programs such as OEO Direct Weatherization, the Schools and Hospitals Program, and solar tax credits.

Forecasting Techniques

Table E-8 summarizes the basic approaches used by staff and the three gas utilities in preparing retail gas demand forecasts. While utilities have made some use of end-use forecasting techniques, these continue to be used mainly in quantifying conservation savings. The 1985 CGR working papers are quite unclear about the interaction and consistency between the two sets of models that PGandE and SDG&E use for base forecasts and conservation savings analyses.

California Energy Commission Staff

The CEC natural gas forecast is based on end use models for all major retail segments. The treatment of conservation program and market impacts depends on the retail segment and the type of program. In the case of utility administered programs not directed by CEC, mandate estimates of savings are derived from utility March 31 reports to the CPUC and staff assumptions of program funding.

Pacific Gas and Electric

The PGandE gas forecast is based on a combination of aggregate econometric techniques used for forecasting a nonconservation program demand scenarios and, for the residential and commercial segments, an end-use model to obtain conservation program impacts. The end-use model program savings are subtracted directly from the aggregate model's base results to obtain the final forecast.

Southern California Gas

The SCG forecast uses end-use models for each major segment. Each segment model incorporates the effects of conservation activities using some form of price response mechanism. Program induced measure penetrations are incorporated but SCG has not attributed savings to specific programs.

San Diego Gas and Electric

The SDG&E forecast models employ a mixture of end use and aggregate econometric techniques and a mixture of fuel price response mechanisms. The residential sector forecast and conservation program savings are prepared with an end use model. The commercial sector uses an end-use model to quantify building and appliance standard savings which are subtracted from an aggregate econometric result to obtain the final forecast.

ELECTRICITY GENERATION/COGENERATION SEGMENT POSSIBILITIES

The cogeneration and electricity generation market segments are highly regulated and difficult to forecast in the manner of the retail segment. Three sources of gas demand for these segments are reviewed here. First, the

Table E-8

Comparison of Demand Forecasting Methodologies

Source	Retail Demand Segment		
	Residential	Commercial	Industrial
PGandE	aggregate econometric supplemented by end-use model for mandated standard savings	aggregate econometric supplemented by end-use model for mandated standard savings	aggregate econometric
SCG	end-use model with behavior discrete choice structure	end-use model with aggregate fuel price elasticity response	end-use model with behavioral discrete choice structure
SDG&E	end-use model with microeconometric fuel price response	aggregate econometric supplemented by end-use model with aggregate fuel price elasticity structure for mandated standards savings	individual industry econometric
CEC Staff	end-use model with engineering characterization of mandated standards and judgemental penetration of retrofit measures	end-use model with aggregate fuel price elasticity response and judgemental penetration of retrofit measures	a. end-use model with equipment technology choice b. end-use model with aggregate fuel price elasticity response

1985 CGR presents gas utility views for these segments based upon gas and electric utility analyses of various vintages. Most of the analysis was conducted prior to the issuance of the 1985 California Electricity Report and lack of consistency between the fuel use and facility siting policies contained therein is not unexpected. Second, CFM 6 resource plans submitted by the major electric utilities have been analyzed and are presented for these two market segments. Third, simulations of staff CFM 6 resource plans using production cost models were used to develop the staff forecast. These differ from utility CFM 6 resource plans in several respects but most importantly in the level of electricity demand.

Gas Utility Forecasts

The 1985 CGR provides point forecasts of cogeneration and electric generation gas demand requirements. All of this work was prepared prior to issuance of the 1985 ER. SDG&E's analysis is the most dated while PGandE's is the most recent. SCG's cogeneration analysis is its own but its electric generation forecast is based upon CFM 5 electric utility resource plan filings with the CEC. These two market segments are interrelated in a complex fashion because electricity produced by cogenerators directly offsets some produced by utilities using gas fueled boilers, but the cogenerator is also using natural gas. Thus, the total gas usage is affected by the incremental heat rates of cogenerators, total heat rates of electric utility boilers, the degree of displacement of boiler fuel sourced electricity by cogeneration electricity, and many other electric resource planning issues. The dated analysis of SCG and SDG&E is probably not as reliable as the more recent PGandE work. Even PGandE analysis has not considered CEC 1985 ER policy decisions nor the continuing efforts of the CPUC to come to a rational implementation of PURPA requirements for cogeneration qualified facilities. Thus, the CGR point forecasts provided in Tables E-2 through E-5 mask a large amount of uncertainty.

Staff Forecast

The CEC staff forecast of gas demand for cogeneration and utility electric generation is based upon August 1986 computer simulations using production cost models of staff's version of CFM 6 resource plans to meet the adopted CFM 6 electricity demand forecast. The results of these simulations for each service area are presented in Tables E-9 through E-11.

CFM 6 Electric Utility Resource Plan Implications

Electric utilities file detailed demand forecast and resource plan documentation on a biennial cycle. The most recent of these filings occurred over the period June to August 1985. This currency appears to make such CFM 6 analysis the most accurate reflection of current electric utility planning. This currency is especially important because of the major potential for change in electric utility natural gas usage wrought by the CPUC's power

TABLE E-9

PG&E Service Area
Electric Generation Gas/Oil Requirements
(mmcf/d)

Year	Cogeneration	Combined Cycle (Coolwater)	Steam Electric
1986	45	32	293
1987	95	18	346
1988	131	11	208
1989	115	13	188
1990	113	11	167
1991		13	163
1992	127	16	165
1993	131	23	168
1994	136	29	170
1995	135	30	169
1996	134	29	170
1997	150	31	177
1998	153	22	181
1999	156	20	175
2000	157	10	179
2001	161	9	176
2002	167	11	181
2003	169	16	186
2004	178	17	174
2005	180	21	184

TABLE E-10

Southern California Gas Service Area
Electric Generation Gas/Oil Requirements
(mmcf/d)

	Cogeneration			Gas Turbine				Scatterwood III	Steam Electric			
Year	DWP	SCE	Total	DWP	SCE	BGP	Total	DWP	DWP	SCE	BGP	Total
1985	9	1	10	0	-	3	3	40	133	444	31	608
1986	10	40	50	0	-	3	3	39	113	396	29	538
1987	16	61	77	0	-	3	3	26	74	343	27	444
1988	18	114	132	0	-	3	3	20	68	290	25	383
1989	18	134	152	0	-	3	3	27	74	299	23	396
1990	18	149	167	0	-	3	3	32	86	290	21	397
1991	18	152	170	0	-	3	3	31	86	302	20	408
1992	18	152	170	0	-	3	3	32	83	321	19	423
1993	18	160	178	0	-	4	4	32	86	336	18	440
1994	18	160	178	0	-	4	4	25	73	361	17	451
1995	18	166	184	0	21	4	25	29	80	364	16	460
1996	18	173	191	0	41	5	46	27	75	363	15	453
1997	18	179	197	0	66	5	71	27	75	377	14	466
1998	18	186	206	0	56	5	61	25	71	329	12	412
1999	18	192	210	0	54	4	58	23	66	320	11	397
2000	18	198	216	0	41	4	45	15	57	274	9	340
2001	18	205	223	0	40	3	43	15	53	267	7	327
2002	18	211	229	0	41	3	44	15	55	276	5	336
2003	18	218	236	0	45	2	47	14	54	309	4	367
2004	18	224	242	0	46	1	47	14	54	319	2	375
2005	18	224	242	0	48	0	48	12	53	331	0	384

TABLE E-11

SDG&E Natural Gas Service Area
Electric Generation Gas/Oil Requirements
(mmcf/d)

Year	Cogeneration	Steam Electric
1985	5	79
1986	7	29
1987	12	29
1988	13	31
1989	15	50
1990	17	63
1991	20	65
1992	22	65
1993	24	69
1994	26	76
1995	27	83
1996	28	68
1997	29	81
1998	30	83
1999	30	69
2000	30	56
2001	30	57
2002	30	57
2003	30	62
2004	31	67
2005	31	71

purchase mandates for the three investor-owned utilities in California. Thousands of megawatts from nonutility facilities were signed up to long-run contracts during 1984 and the first one-half of 1985. Since this period was after the submittal of CFM 5 documentation for resource plans, it may crucially change utility planning. Given this situation, the CFM 6 resource plans were carefully analyzed for electric utility views on cogeneration and electric generation natural gas demand.

Electric utility implied projections of natural gas demand are summarized in Table E-12. These natural gas requirements are produced through conversion of electricity production by plant type to gas demand using unit heat rates. Unless otherwise noted below the gas projection numbers for the utility generation category in Table E-12 were derived from the utility CFM 6 projections for total energy generated from oil- or gas-fired steam boilers, combined cycle units, and peaking combustion turbines. The utility total includes, as well, energy from some future generic peaking facilities listed in SDG&E and PGandE supply plans. One-half of the energy from these generic facilities is assumed to come from gas-fired combustion turbines. The totals, therefore, represent a maximum utility gas demand scenario since some generation will probably occur using oil.

The projected cogeneration gas demand numbers are for the incremental amount of gas needed to generate electricity, i.e., the amount of gas needed beyond that required to satisfy the thermal demand. The cogeneration total also includes energy from generic alternative facilities listed in SCE and SDG&E CFM 6 supply forms. One-half of the energy from these generic facilities is assumed to come from gas-fired cogeneration facilities. Incremental heat rates of 6,000 Btu/kWh and 5,000 Btu/kWh were used for determining the amount of gas consumed for industrial/commercial and TEOR cogeneration, respectively.

Pacific Gas and Electric

The utility generation gas demand projections for PGandE are based on the capacity and energy number given in PGandE CFM 6 forms R-1 and R-2. The cogeneration numbers are taken from form R-4. PGandE owned cogeneration facilities totalling 179 MW are assumed to be retired in 1986. Cogeneration facilities operating in 1984, but not owned by PGandE, totalling 158 MW, are assumed to remain in operation through the rest of the 20-year forecast period producing 1,200 GWh annually.

The following heat rates were used in determining the amount of gas needed for generating the energy projected to come from PGandE plants.

Boilers	10,794 Btu/kWh
Combustion Turbines	15,025 Btu/kWh

TABLE E-12

CFM 6 Utility* Natural Gas Projections

(mmcf/d)

	Utility Generation					Industrial/Commercial Cogen					TEOR Cogeneration					Total				
Utility	1984	1990	1995	2000	2005	1984	1990	1995	2000	2005	1984	1990	1995	2000	2005	1984	1990	1995	2000	2005
PGandE	663	182	296	469	514	26	76	76	76	76	--	134	201	201	201	689	392	573	746	791
SMUD	0	0	0	0	0	0	0	0	0	0	--	--	--	--	--	0	0	0	0	0
SCE	649	303	507	489	612	8	86	90	116	139	--	74	78	78	78	657	463	675	683	829
LADWP	127	156	123	90	71	1	16	16	16	16	0	0	0	0	0	128	172	139	106	87
SDG&E	132	91	132	136	139	10	19	26	45	52	0	0	0	0	0	142	110	158	181	191
BGP	35	27	20	4	0	0	0	0	0	0	0	0	0	0	0	35	27	20	4	0
State	1,606	759	1,078	1,188	1,336	45	197	208	253	283	--	208	279	279	279	1,651	1,164	1,565	1,720	1,898

* Utility gas consumption based upon electric service basis.

Southern California Edison

The utility generation gas demand projection is based on SCE CFM 6 filing, forms R-1 and R-2. The energy total for TEOR cogeneration facilities was derived assuming a 70 percent capacity factor. SCE combined the total energy for cogeneration/biomass facilities given in form R-2. Twenty percent of this energy total was assumed to be from biomass facilities.

The following heat rates were used in projecting gas demand from SCE, LADWP, and BGP plants.

Boilers	11,400 Btu/kWh
Combustion Turbines	19,900 Btu/kWh
Combined Cycles	11,270 Btu/kWh

San Diego Gas and Electric

The cogeneration gas demand projection is based on numbers contained in SDG&E Executive Summary CFM 6 Demand Submittal (page 47) "Input Assumptions Cogeneration, Base Case." Because data was only given for the years 1990, 1997 and 2005 interpolated values were derived for the years 1995 and 2000.

The heat rates used in projecting gas demand for SDG&E plants are as follows.

Boilers	10,430 Btu/kWh
Combustion Turbines	15,386 Btu/kWh

LADWP and the Cities of Burbank, Glendale and Pasadena Utility generation gas demand projections for LADWP, and the cities of Glendale and Pasadena were based on their CFM 6 resource plan submittals. CFM 5 data was used for Burbank.

TEOR-ONLY SEGMENT POSSIBILITIES

California's thermally enhanced oil recovery operations (TEOR) could be the largest essentially untapped natural gas market in the United States. California's two largest gas utilities and three pipelines propose to serve the market. While it is acknowledged the potential for gas sales is large, no one knows for certain how large. Table E-13 summarizes the estimates prepared by a variety of sources.

California Gas Utilities

The California gas utilities in the 1985 CGR estimate combined sales in the 900 to 1,000 mmcf/d range during the 1990s. About 660 mmcf/d would be used for steaming and the rest for electric generation through cogeneration facilities.

Table E-13

TEOR-Only 1990 Gas Demand Estimates
(mmcf/d)

Source	Total Steaming Requirements	Amount Supplied
1985 CGR	--	660
Pipeline Sponsors		
El Dorado	--	520[a]
Mojave	988[a]	600[a]
Kern River	867[a]	700[a]
CPUC Staff	955[b]	--
CEC Staff	736[c]	--

a. Kern County Only
b. The following are covered--Kern County, Coalinga, San Ardo and Regions
c. Statewide

Pipeline Sponsors

The three pipeline sponsors propose to build pipelines of 520 mmcf/d (El Dorado), 600 mmcf/d (Mojave) and 700 mmcf/d (Kern River). Kern River estimates the 1990 Kern County market to be 1,059 mmcf/d with 867 mmcf/d for steaming production and the remainder electric generation. Mojave estimates the 1990 Kern County market to be 1,019 mmcf/d with 988 mmcf/d used for raising steam and 194 mmcf/d for generating electricity. Of its total demand forecast, Mojave estimates 140 mmcf/d would be supplied by local nonutility gas, 279 mmcf/d would be supplied by utilities or remain on crude oil and the remainder would be supplied by its project.

California Public Utilities Commission Staff

The California Public Utilities Commission Staff estimates by 1990 the potential for gas used for directed steaming could reach 955 mmcf/d with an additional 413 mmcf/d used to cogenerate electricity. Of the 1,365 mmcf/d, about 275 mmcf/d in equivalent fuel requirements could potentially be served by local nonutility gas or continue burning crude oil.

California Energy Commission Staff

Staff estimates the potential natural gas use in California's TEOR straight steaming operations in the 1990s range from 736 to 816 mmcf/d. These are presented on Table E-2 entitled "Statewide Utility Natural Gas Demand." No attempt has been made to determine to what extent these requirements might be shared by PGandE and SCG or nonutility suppliers.

In estimating potential gas use in TEOR operations, it was assumed that no more than 20 percent of total thermal demand could be supplied by crude. Thus, gas use represents 80 percent of total forecasted thermal demand. Incremental fuel requirements to generate electricity using cogeneration facilities would add to those steaming requirements.

APPENDIX F

NATURAL GAS SUPPLY AND PRICE FORECAST

APPENDIX F

NATURAL GAS SUPPLY AND PRICE FORECAST

INTRODUCTION

Staff uses several steps in forecasting natural gas supply and price. Each potential supply source is individually examined in terms of available resource, production capability, regulatory requirements and cost to purchase and transport. As new supplies are purchased to service lower priority interruptible industrial needs, the delivered price must be competitive with fuel oil. The following provide the basic criteria used:

- The resource could be identified, and amongst competitors, allocated to California.
- The wellhead cost could be estimated.
- A means of transportation could be identified and cost estimated.
- The estimated delivered cost to California is competitive with the projected residual fuel oil price.

Supply cases are developed to match the forecasted need if possible. This need generally includes all of the residential, commercial and industrial requirements and a portion of the fuel requirement to generate electricity.

Purchase and transport costs to bring the gas from each source to California are determined. California gas utility cost to distribute the gas to the customers are then estimated. Distribution costs include utilities' operational expenses, as well as the cost of various conservation and solar programs. All costs are then aggregated to determine total utility revenue requirements to purchase and distribute the gas. These costs are then allocated to the end users using current CPUC rate making policies and guidelines.

The following narrative discusses the assumptions used and the results of natural gas supply and price forecast. First, natural gas supply is discussed with a brief comment concerning each supply source. The total supply forecast is then compared with the natural gas demand forecast prepared in conjunction with the Electricity Report 6 electric demand forecast and the gas forecasts contained in the 1984, 1985 and 1986 California Gas Reports (Gas Report). Finally, pricing assumptions and results are discussed and contrasted with previous CEC forecasts and price forecasts from the California Gas Report.

The study period for this forecast extends from 1985 to 2005. While staff forecasts gas supply and price for all years in the study period, the tables in the text relate to only 1990, 1997, and 2005. These are key years used by the CEC for resource evaluation. To provide comparisons with the Gas Report's forecasts, 1995 and 2000 are also included. Attachment I contains staff summaries for all years.

SUMMARY

The purpose of the CEC supply/demand balance assessment is to identify potential periods where supply shortfalls may occur so that sufficient time and opportunity are provided to identify new supplementary supply sources or develop end-use efficiencies and techniques to make less gas go further.

The results of this assessment are that statewide natural gas supplies should be adequate through this decade and into the 1990s to meet all sectorial needs and some TEOR. However, supplementary gas supply for low priority interruptible industrial and electricity utility customers may be needed to meet future requirements beginning in the mid-1990s. Approximately 600 mmcf/d of additional supply above the forecasted supply of 3,664 mmcf/d will be necessary to meet all interruptible industrial customer needs with some gas left over for electric generations. To meet all needs, slightly over 1,090 mmcf/d in supplemental supply would be needed. More would be needed to meet expanded TEOR operations.

On an area basis, Northern California supplies are expected to be sufficient throughout the forecast period to meet substantially all PGandE's need with significant quantities available for either TEOR or sales to Southern California.

The need for significant supplemental supplies lies in Southern California. In the near term the staff forecast indicates adequate supplies for all sectors with gas available for TEOR. Beginning in the mid-1990s ever-increasing quantities of supplemental gas would be needed for industrial, electric generation and TEOR requirements. In 2005, about 560 mmcf/d in additional supply would be needed to meet industrial requirements with an additional 468 mmcf/d necessary to meet electric generation requirements.

Gas utility statewide supply forecasts presented in the 1986 California Gas Report are significantly higher than staff's, by 282 mmcf/d in 1990 and 1,804 mmcf/d in 2005. The differences are related to the approach in forecasting. Principally the utilities attempted to quantify the effects of recent state and federal regulatory actions to bring competition to the gas market. The staff elected to learn more about the evolving gas market and has only reported the additional supplies needed to meet anticipated demand. The utilities' interpretation of the new market concepts led to the higher supply forecasts.

The only gas demand included by staff for utility service of thermally enhanced oil recovery (TEOR) is represented by about 150 mmcf/d for cogeneration and reservoir stimulation. This is only a fraction of the supply needed to meet the potential demand for gas in this sector. For the long term the gas utilities would have to obtain additional natural gas supplies if they wish to serve a larger portion of this market and to participate in its potential growth.

There are substantial changes in this price forecast when compared with CFM 5. The main reason is that the overall cost for purchasing natural gas

supplies has been dropping since 1983. Secondly, staff has more thoroughly analyzed the utilities' distribution costs. The result is a forecast of utility system average delivered prices from 14 to 34 percent lower than previous forecasts.

In comparison with the 1985 California Gas Report, PGandE projections are consistently and increasingly higher than staff's, while SoCal Gas and SDG&E forecasts are lower. SoCal Gas forecasts have the best correlation with essentially the same price as staff in 1990 and slightly over 5 percent lower prices in the following years. San Diego's forecast, while not significantly different from staff's, is not consistent in percentage difference.

NATURAL GAS SUPPLY ASSUMPTIONS

Although substantial changes in supply estimates for several of California's supply sources have been made, there is relatively little difference between the total of this forecast and the CFM 5 forecast. This is because the changes balanced each other out. Comparisons between CFM 5 and the CFM 6 supply forecasts are presented in Tables F-1, F-2 and F-3. Following these are brief discussions of assumptions made for each supply source.

Table F-1 shows that there is a difference of 1,126 mmcf/d between staff's present forecast for 2000 and the gas utilities' latest forecast. This represents 27 percent of staff's total forecasted supply. The total difference between staff's previous forecast and the gas utilities' 1984 forecast was 459 mmcf/d or about 12 percent. In 1985 staff increased its CFM 6 estimates only slightly, but the 1985 Gas Report supply estimates were increased by 1,067 mmcf/d over the 1984 Gas Report. The 1986 Gas Report is only 833 mmcf/d higher for 2000 in comparison with the 1984 Gas Report.

Detailed summaries of staff forecasted supply by source and year for Northern California, Southern California, and the state total are provided in Attachment I.

Northern California Onshore

There were no substantial changes in staff supply assumptions for Northern California onshore production purchased by PGandE (Table F-4). The CEC staff continues to use 100 bcf per year in new reserve additions with purchases at 50 percent of maximum sustainable production levels. Staff's forecast is approximately 200 mmcf/d lower than the 1985 Gas Report by 2000.

Southern California Onshore

This forecast for the Southern California onshore supply (less exchanges) for the gas utilities is greatly reduced from CFM 5 (Table F-5). Staff has relied on SoCal Gas forecasts found in the Gas Report as the basis for its CFM 6 supply forecast. The 1986 Gas Report values include California produced exchange gas. This gas is producer owned and therefore does not add supply to meet utility demand. The other Gas Report numbers have been adjusted to not include exchange gas.

TABLE F-1

CALIFORNIA TOTAL GAS SUPPLY COMPARISONS
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6	4,379	4,406	4,243	4,085	3,664
Staff CFM 5	4,329	4,238	4,110	3,919	3,690
1984 Gas Report	4,290	4,303	--	4,378	--
1985 Gas Report	4,902	5,258	--	5,445	--
1986 Gas Report	4,661	5,171	--	5,211	5,468

TABLE F-2

NORTHERN CALIFORNIA GAS SUPPLY COMPARISONS
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6	1,836	1,982	2,037	2,000	1,849
Staff CFM 5	1,985	2,067	2,004	1,938	1,867
1984 Gas Report	1,774	1,849	--	1,906	--
1985 Gas Report	2,118	2,405	--	2,640	--
1986 Gas Report	2,074	2,223	--	2,324	2,469

TABLE F-3

SOUTHERN CALIFORNIA GAS SUPPLY COMPARISONS
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6	2,543	2,424	2,206	2,085	1,815
Staff CFM 5	2,344	2,171	2,106	1,981	1,823
1984 Gas Report	2,516	2,454	--	2,472	--
1985 Gas Report	2,784	2,853	--	2,805	--
1986 Gas Report	2,587	2,948	--	2,887	2,999

TABLE F-4

PGandE NORTHERN CALIFORNIA ONSHORE PRODUCTION PURCHASES
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6	259	227	219	198	173
Staff CFM 5	240	219	202	188	168
1984 Gas Report	301	276	--	268	--
1985 Gas Report	340	364	--	381	--
1986 Gas Report	354	356	--	354	354

TABLE F-5

SOCAL GAS ONSHORE PRODUCTION PURCHASES
mmcf/d

Source	1990	1997	2004/2005
Staff CFM 6	54	38	29
Staff CFM 5	130	130	130
1984 Gas Report	54	38	--
1985 Gas Report	57	42	--
1986 Gas Report	140	--	70

Offshore

In the 1984 Annual Petroleum Review (APR) staff evaluated the potential gross gas production from Southern California offshore resources. Because of timing of the completion of the APR, the results of this work were not used in the CFM 5 forecast.

For CFM 6 staff has made assumptions regarding the proportion of forecasted gross production reported in the 1984 APR which would be available for gas utility purchases. Principally it was assumed that all of the present gas production and 50 percent of new production (Hondo B, Sacate and Pescado) would be available for SoCal Gas purchases. The tabulation in Table F-6 summarizes the forecasted available supply. The staff forecast in the later years is about 200 mmcf/d less than the 1986 Gas Report forecast.

Southwestern Supply

The southwestern United States is California's largest source of natural gas, delivering about 67 percent of the state's supply. These deliveries are made through the pipelines of the El Paso Natural Gas Company (EPNG) and Transwestern Pipeline Company.

EPNG and Transwestern draw their gas from three areas, the San Juan Basin, Permian Basin, and the Anadarko Basin. The San Juan Basin located in the Four Corners Area of New Mexico can be expected to continue producing gas at the same levels for the next 8 to 10 years. Though new reserves are being found in the Permian Basin, supply from this area in western and eastern New Mexico is declining. The Anadarko in the Texas/Oklahoma Panhandle is the center of deep drilling. Production can be expected to remain level for the next few years.

Future supply for EPNG and Transwestern will be produced from existing proven reserves and new reserve additions. Interstate pipelines are required to provide the Federal Energy Regulatory Commission 20-year production estimates for proven reserves presently under contract. The estimates made by EPNG and Transwestern in 1984 were directly incorporated into the supply forecast for each pipeline.

In estimating new reserve additions, the staff considered. (1) estimate of potential natural gas reserves made by the Potential Gas Committee, (2) present reserve holdings of EPNG and Transwestern in basins which have been their traditional supply areas, (3) historic trends in reserve additions by the two pipeline companies, and (4) recent data submitted by EPNG concerning its anticipated reserve additions. The staff assumes that 75 percent of the Probable, 50 percent of the Possible, and 25 percent of the speculative gas reserves identified by the Potential Gas Committee for the San Juan, Anadarko, and Permian Basins will be proven over the next 20 years. Portions of these reserves were assigned to EPNG and Transwestern based on the proportions of their current reserve holdings in each basin. The resulting estimation of future reserve additions was then modified to reflect historic trends and current plans for reserve additions.

TABLE F-6

OFFSHORE GAS AVAILABLE TO UTILITIES
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6					
Existing Federal Offshore Production					
Hondo A	22	--	8	--	0
Pitas Point	49	--	23	--	10
Others	34	--	13	--	3
New Federal Offshore Production	35	--	42	--	12
State Lands	21	--	5	--	0
Total Staff CFM 6	161	128	91	56	25
Staff CFM 5	71	66	64	62	58
1984 Gas Report	193	152	--	104	--
1985 Gas Report	173	157	--	153	--
1986 Gas Report	355	364	--	252	219

Note: New federal offshore production would be from Platforms Hondo B, Pescado A, and Sacate A.

New reserve additions for EPNG were estimated to average 715 bcf per year during the 20-year study period. Total supply provided to California is summarized in Table F-7 and compared with CFM 6 and utility estimates in the 1984, 1985 and 1986 Gas Reports. The staff forecast starts slightly higher than the 1986 Gas Report in 1990 but declines with time. Contrarily, the 1986 Gas Report incorporates a slightly increasing supply from El Paso with over 500 mmcf/d higher supply than staff by 2005.

New annual reserve additions for Transwestern were estimated to average 182 bcf for the 20-year study period. Total supply to California by Transwestern is summarized on Table F-8. In the later years, the CFM 6 is about 100 mmcf/d lower than the 1986 Gas Report.

Canada

Canada is the second largest California supply source, with both PGandE and SoCal Gas having licenses or contracts to receive a total of 1,220 mmcf/d at the Canadian and U.S. Border.

The major long-term question concerning Canadian supplies is whether existing export licenses will be continued or if new licenses can be obtained. New gas is plentiful in western Canada. Current reserves exceed demand, but Canada restricts exports to a surplus above a long-term anticipated demand. For this forecast it was assumed that new licenses would be granted providing full reinstatement for both companies. For SoCal Gas this would assure delivery of 217 mmcf/d while the forecast for PGandE would provide 980 mmcf/d. These are consistent with gas utility estimates. Both staff and the utilities forecast Canadian supplies at or near the full license amounts.

Mexico

Mexico has extensive natural gas resources which could play a role in satisfying California's future gas needs. Under mutual agreement between Mexico and U.S. suppliers, no Mexican gas is presently entering the U.S. For this supply forecast, it was assumed Mexican deliveries would resume again in 1987 and continue through to 2005. With the exception of the new assumption that Mexican gas is supplied in 1987, there are no differences from previous supply forecasts.

Rocky Mountain

There were no changes made in supply estimates from the Rocky Mountains since CFM 5 (Table F-9). Staff has anticipated that both PGandE and EPNG would move ahead in developing their Rocky Mountain lease holdings. EPNG has announced plans to start exploration and development of their holdings.

PGandE, on the other hand, has indicated a lessened interest in developing their holdings. The apparent reason for PGandE's decreasing interest in the region is CPUC staff reluctance to support the continued use of ratepayer revenues collected through the Gas Exploration and Development Adjustment program to explore and develop the resource.

TABLE F-7
SUPPLY FROM EL PASO PIPELINE COMPANY
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6	2,101	1,946	1,844	1,751	1,400
Staff CFM 5	2,100	1,834	1,738	1,567	1,423
1984 Gas Report	2,380	1,833	--	1,380	--
1985 Gas Report	2,216	2,033	--	1,792	--
1986 Gas Report	1,890	1,988	--	2,024	1,939

TABLE F-8

SUPPLY FROM TRANSWESTERN PIPELINE COMPANY
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6	466	409	395	378	357
Staff CFM 5	415	347	327	303	227
1984 Gas Report	493	329	--	323	--
1985 Gas Report	495	315	--	192	--
1986 Gas Report	435	446	--	455	465

TABLE F-9

ROCKY MOUNTAIN SUPPLIES
mmcf/d

Source	1990	1995	1997	2000	2004/2005
Staff CFM 6	81	334	335	357	369
Staff CFM 5	81	334	335	357	369
1984 Gas Report	11	8	--	3	--
1985 Gas Report	30	16	--	8	--
1986 Gas Report	38	27	--	15	9

Staff continues to believe the Rocky Mountains could substantially contribute to California's gas supplies in the 1990s. The ability of the area to do so is evidenced by recent filings with the FERC that indicate there are proven undedicated reserves which could produce at a rate of 350 mmcf/d for 11 years before declining in production. Staff estimates conservatively that Rocky Mountain production at levels up to 400 mmcf/d could be developed and sustained for California gas utility use from PGandE and EPNG lease holdings. These volumes have been assumed in the CFM 6 forecast.

To move such large volumes to California would require the construction of a Rocky Mountain pipeline as proposed by PGandE several years ago. Because of the company's reduced interest in developing Rocky Mountain leases, PGandE has expressed little current interest in the pipeline. Nevertheless, staff has assumed the existence of such a pipeline for the supply forecast, starting in 1995. Staff believes that a Rocky Mountain pipeline is likely to be developed because it is a cost effective approach to providing additional gas supplies to California.

COMMENTS ON SUPPLY FORECAST DIFFERENCES

It is evident after reviewing the preceding discussions that there are significant differences between staff and gas utility supply forecasts. These are the result of using different forecasting approaches. Tables F-10 and F-11 bring together and compare the CEC and Gas Report supply forecasts.

Staff's forecast takes a traditional approach; to identify resources, transportation and associated costs. As a result of this approach, there are significant potential gas resources in the United States and Canada that are not included in the CEC forecast of supplies available to California. The exclusion is based on the staff analysis that either transportation is unavailable, resources have not been identified, or the delivered price of the gas would not be competitive with alternative fuels available to marginal fuel users.

TABLE F-10

PGandE GAS SUPPLY

Comparison of CEC CFM 6 Forecast
With the 1986 California Gas Report
mmcf/d

	1990			1995			2000			2005		
Source	CEC	86 GR	Diff.	CEC	86 GR	Diff.	CEC	86 GR	Diff.	CEC	86 GR	Diff.
California	259	354	+ 94	227	356	+129	198	354	+156	173	354	+181
Canada	939	842	- 97	980	914	- 66	980	956	- 24	980	993	+13
EPNG	567	840	+273	506	911	+405	578	954	+376	462	999	+537
Rocky Mtn.	48	38	- 10	231	27	-204	208	15	-193	198	9	-189
Supplement	23*	0	-23	38*	15	- 23	36*	45	+ 9	36*	114	+ 78
TOTAL	1,836	2,074	+238	1,982	2,223	+241	2,000	2,324	+324	1,849	2,469	+620

*Mexico + Sanitary Landfill

TABLE F-11

SOCAL GAS SUPPLY

Comparison of CEC CFM 6 Forecast
With the 1986 California Gas Report
mmcf/d

Source	1990			1995			2000			2005		
	CEC	85 GR	Diff.	CEC	85 GR	Diff.	CEC	85 GR	Diff.	CEC	85 GR	Diff.
CA Onshore	54	140	+86	41	105	+64	34	83	+49	29	70	+41
CA Offshore	161	355	+194	128	364	+236	56	252	+196	25	219	+194
El Paso	1,534	1,050	-484	1,440	1,077	-363	1,173	1,070	-103	938	940	+2
Transwestern	466	435	-31	409	446	+37	378	455	+77	357	465	+108
Canada	217	216	-1	217	216	-1	217	216	-1	217	216	-1
Rocky Mtn.	33	--	-33	103	--	-103	149	--	-149	171	--	-171
Supplement	78*	0	-78	86*	0	-86	78*	71	-7	78*	449	+371
SUBTOTAL	2,543	2,196	-347	2,424	2,208	-216	2,085	2,147	+62	1,815	2,359	+544
Out-of-State Exchange	--	100	+100		100	+100		100	+100	--	0	0
EOR Supply	--	241	+241	--	590	+590	--	590	+590	--	590	+590
Transport	--	50	+50	--	50	50	--	50	+50	--	50	+50
TOTAL	2,543	2,587	+44	2,424	2,948	+524	2,085	2,887	+802	1,815	2,999	+1,184

*Mexico + Sanitary Landfill

Competitive market forces have been facilitated by recent state and federal regulatory actions. These could make some of these resources available to California. As the regulatory developments have only recently occurred and the gas market is only beginning to feel the effects, staff elected not to automatically assume the new market could meet all needs. Instead the levels of additional supply needed to supplement traditional supplies have been quantified. These are identified as gas/oil requirements in Appendix A.

The gas utilities have forecasted gas supplies in a traditional manner, but also have attempted to quantify the effects of the evolving market. The results of incorporating new gas market concepts are reflected in supplies identified as transport gas, out-of-state exchange, EOR, and supplemental. These, in general, represent new nontraditional supply with unidentified sources of gas.

Additionally, some of the utility forecasted supplies from traditional sources also have been affected by new market concepts. As an example, PGandE indicates in the 1986 California Gas Report that El Paso will be able to supply and transport a major portion of 1140 mmcf/d well into the future. This is because of the evolving regulatory environment.

The staff cannot at this time resolve the differences in forecasted supply. Significant work must first be done in assessing the impacts of the various forces affecting the natural gas market. This is not a simple matter as regional supply and demand, pipeline capacity and availability, costs, and regulatory environment must all be incorporated in the evaluation. Steps have been taken to start the necessary evaluations.

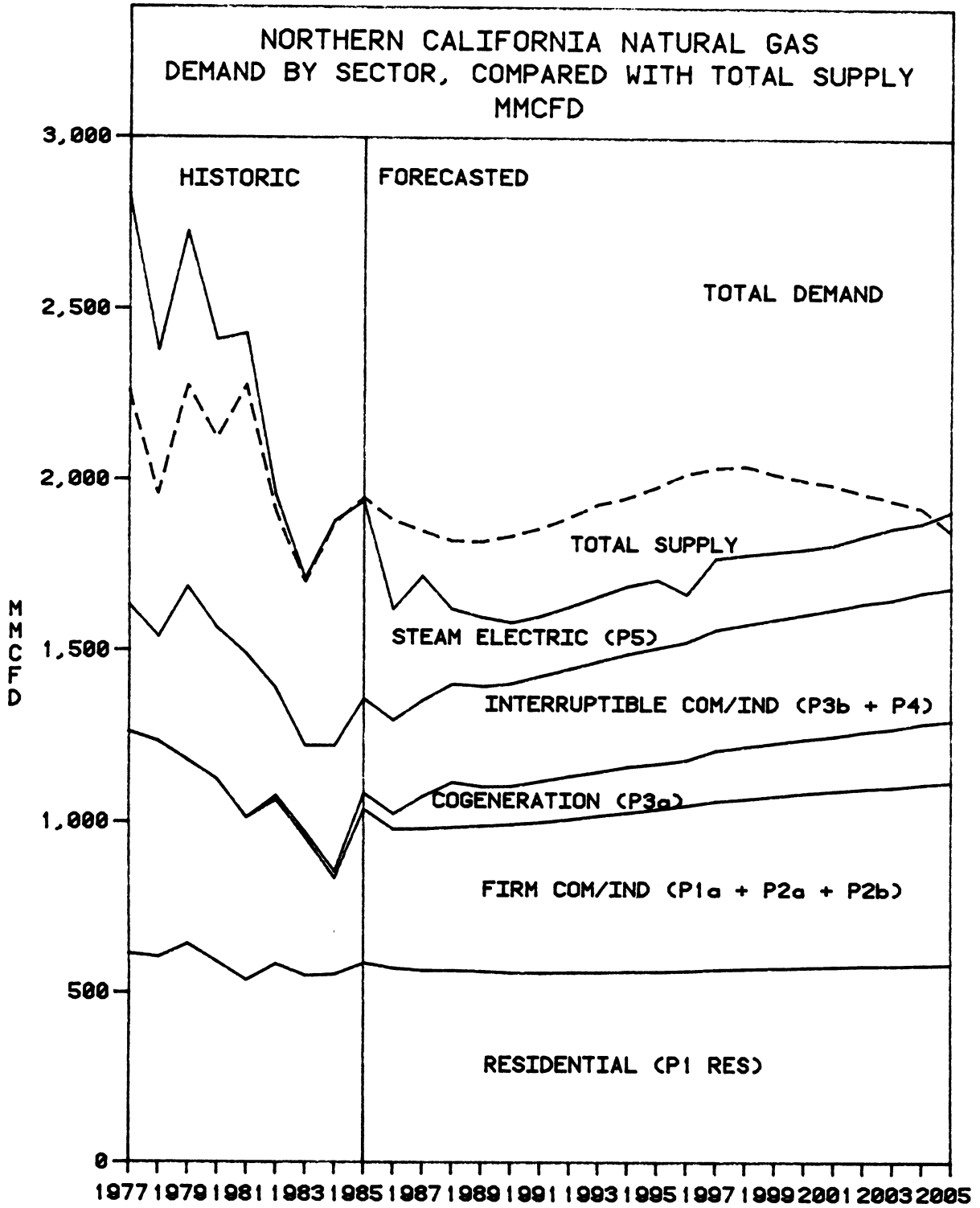
SUPPLY/DEMAND BALANCE

In preparing the supply and demand balance, the CFM 6 supply forecast was compared with the July 1986 demand forecast developed in conjunction with the adopted ER 6 electricity demand forecast. Figures F-1 and F-2 provide total forecasted supply contrasted with demand by end-use sector for Northern and Southern California. The demand forecast includes only 150 mmcf/d TEOR gas requirements to meet cogeneration and some steaming requirements. Supply, as reflected in the figures, do not include potential movement of Northern California surplus gas to Southern California as discussed below.

The supply and demand balance shows that for California utilities to fully meet projected demand for gas, in excess of 1,000 mmcf/d in new supplemental supply above that expected from traditional sources would be needed in 2005. This does not include supply needed to allow the utilities to serve a larger portion of the EOR market.

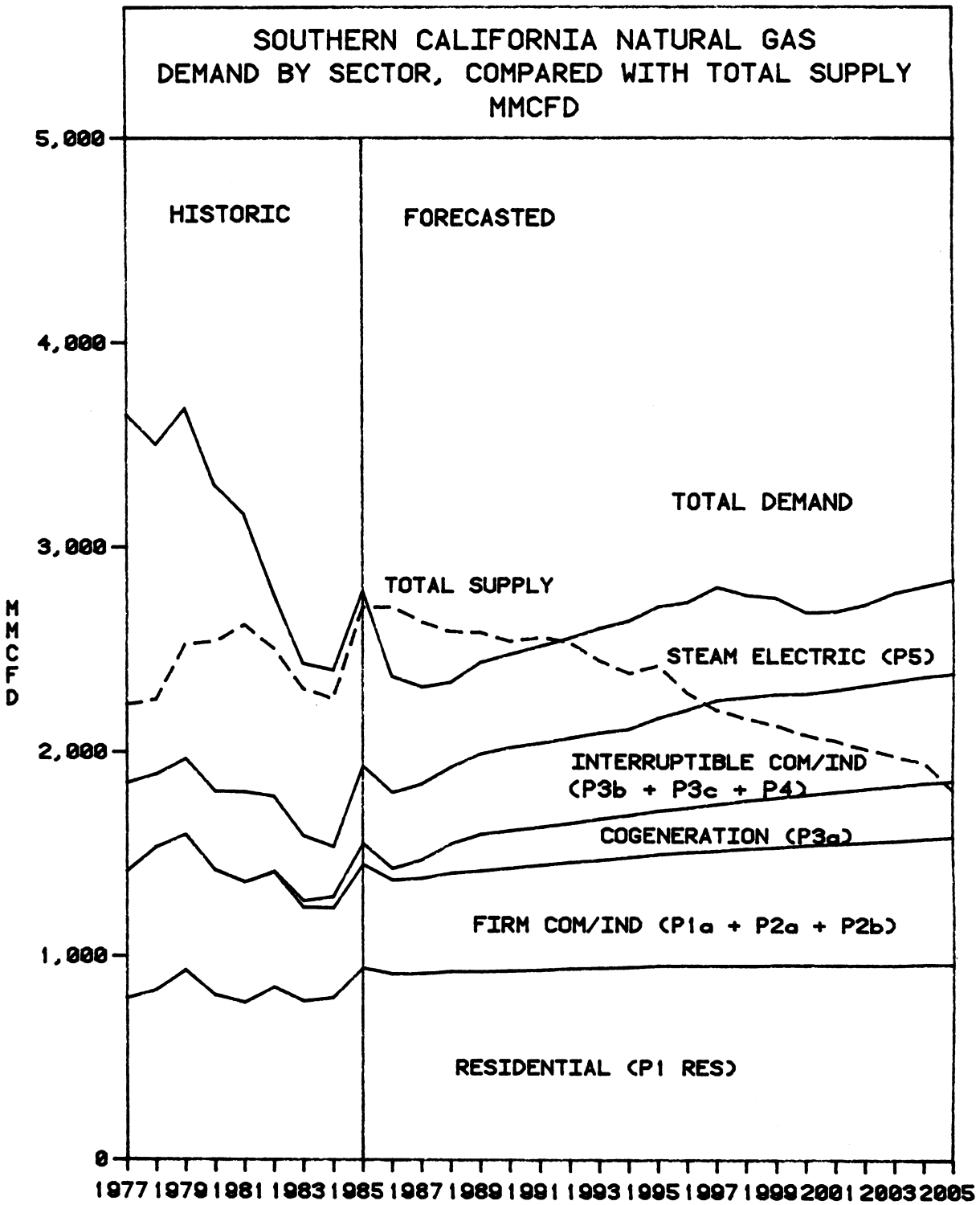
For Northern California, supply is forecasted to be more than sufficient on an annual average basis to meet substantially all PGandE's residential, commercial, industrial, cogeneration, and electric generation needs throughout the study period. Surplus gas was forecasted to be sufficient to provide

FIGURE F-1



Historic: California Gas Report
Forecasted: CFM VI Forecast

FIGURE F-2



Historic: California Gas Report
Forecasted: CFM VI Forecast

significant quantities of gas to other markets as TEOR through most of the study period. For price forecasting purposes, surplus gas beyond 5 to 6 years out was assumed to be sold to the Southern California utilities for their use in meeting their traditional customer needs.

In the near term, Southern California gas supplies should be sufficient to meet substantially all customer gas needs. Significant quantities of additional gas would be available for five or so years for other customers as TEOR. Beginning in the mid-1990s growing quantities of supplemental supplies would be required to meet electric generation, industrial and TEOR needs. Oil would have to be used to satisfy any of the gas requirements not satisfied by supplemental supplies. By 2005, about 560 mmcf/d of additional supply would be necessary to meet the interruptible industrial and commercial sector's demand, and about 530 mmcf/d would be needed for electric generation requirements. For price forecasting purposes, a portion of these requirements were assumed to be met by surplus gas from PG&E.

NATURAL GAS PRICES

The modified BFR gas price forecasts generally were from 14 to 34 percent below forecasts used in BR V. Table F-12 illustrates the differences for key planning years by gas utility service area.

TABLE F-12

Staff Forecasted Utility System Average Delivered Prices
1983 Dollars per mmBtu

	1990			1995			2000-2005		
Utility	CFM 5	MODBFR	Diff.	CFM 5	MODBFR	Diff.	CFM 5	MODBFR	Diff.
PGandE	5.56	4.76	-14.4%	6.93	5.10	-26.4%	8.72	6.47	-25.8%
SoCal Gas	5.76	4.73	-17.9%	7.30	5.13	-29.7%	9.33	7.30	-21.8%
SDG&E	5.83	4.86	-16.6%	7.69	5.07	-34.1%	9.75	7.11	-27.1%

Specific reasons for the differences are briefly listed below.

- Modified BFR oil price estimates forecast 22 percent lower oil prices than previous forecasts.

- Supplies from the Southwest in the CFM 6 forecast were assumed to be lower in price. This forecast included lower Canadian gas prices due to renegotiated contracts with suppliers. Transportation cost forecasts were also lower.

- California gas utility distribution costs were determined to be lower after an extensive staff study concluded that non-commodity (margin) costs would experience relatively little real growth over the forecast period.

Wellhead Price Assumptions

Natural gas prices were determined on the basis of categories of gas as designated by the Natural Gas Policy Act. Generally, decontrolled wellhead prices were equated to 70 percent of the forecasted price for crude oil. High cost gas was initially set equal to the present weighted average price paid by El Paso and Transwestern and then allowed to escalate over time with oil. Wellhead prices for categories which remain under federal control were escalated following NGPA provisions.

The Canadian Border price for natural gas was set to provide a delivered price that was competitive with Southwest source gas. The International Border price for Mexican gas was set equal to the decontrolled domestic wellhead price.

Distribution Cost Assumptions

Distribution costs add about 40 percent to the system average delivered price of natural gas. A complete assessment of California gas utilities isolated each of the many components that contribute to distribution costs. Primarily as a result of CEC CFM 6 forecasted decreases in the cost of capital (debt and stocks), real growth in distribution costs over the forecast horizon is projected at about one-half percent per year.

Distribution costs are highly sensitive to the rate of growth in gas plants. The assumptions used in this forecast were that plant growth would equal utility forecasted levels for the first 4-5 years of the forecast and that the remaining forecast period would equal the highest historical experience over the previous 5, 10 and 15 year periods for each utility. For the forecast period this provided an annual 9.3 percent plant growth increase. Should the gas utilities develop/maintain strong cash positions, the CPUC will likely see plant addition requests well above this level. The CPUC response to these requests and their ability to judiciously grant plant increases will have a direct impact upon future distribution costs.

To underscore the significance in the rate of plant growth, the difference between a 6 percent and 11 percent annual plant growth scenario would cost over an additional $1 billion (1983 dollars) per year by the year 2005 and the cumulative costs over the forecast period would exceed $10 billion (1983 dollars). These growth rates are used for comparison purposes since 6 percent represents the average historical plant growth rates and 11 percent represents the levels being planned by utilities.

End-Use Price Assumptions

End-use prices were calculated assuming continuation of "value of service" rate setting practices, consistent with previous price forecasts. Average interruptible industrial and commercial customer rates were assumed to be at full parity with the price of 0.5 percent sulfur content residual fuel oil (LSFO). Special incentive rates were not specifically forecasted. Gas rates for electric generation were set at 95 percent parity with 0.5 percent LSFO in

the PGandE and SDG&E service areas. For electric utilities served by SoCal Gas, the gas rate was set at 95 percent parity with 0.25 percent LSFO. Cogeneration rates were equated to the electric generation gas rate.

Commercial and residential rates were initially set at 100 percent and 90 percent, respectively, of the system average delivered price. Revenue balances were performed which generally required upward adjustments to cover gas utility expenses. These were uniformly applied to the commercial and residential rates.

PRICE COMPARISONS WITH THE CALIFORNIA GAS REPORT

The gas utilities have provided forecasts of their anticipated average cost of gas to their customers in the California Gas Reports. A comparison between the utilities' forecast and the modified BFR price forecast is provided in Table F-13. The 1986 California Gas Report does not contain a complete set of projected gas prices so the 1985 California Gas Report was used.

TABLE F-13

FORECASTED SYSTEM AVERAGE DELIVERED COST

Comparison of CEC Modified BFR Price Forecast
With the 1985 California Gas Report
1983 Dollars per mmBtu

	1990			1995			2000		
Utility	CEC	85 GR	Diff.	CEC	85 GR	Diff.	CEC	85 GR	Diff.
PGandE	4.76	5.01	-5.0%	5.10	5.69	-10.4%	5.67	6.62	-14.4%
So Cal Gas	4.73	4.78	-0.1%	5.13	4.86	+5.6%	6.01	5.70	+5.4%
SDG&E	4.86	4.56	+6.6%	5.07	4.95	+2.4%	6.12	5.62	+8.9%

PGandE projections are consistently and increasingly higher than staff's while SoCal Gas and SDG&E forecasts are lower. SoCal Gas forecasts have the best correlation with essentially the same price as staff in 1990 and slightly over 5 percent lower prices in the following years. San Diego's forecast, while not significantly different from staff's, are not consistent in percentage difference.

APPENDIX F

ATTACHMENT A

TABLE F-A-1

DATE: 05/05/86

NATURAL GAS WELL_HEAD PRICES
MODIFIED BFR PRICE FORECAST-RUN 3
1983 DOLLARS PER MMBTU

YEAR	S102	S103	S104 POST 1974	S104 1973-74	S104 & S106 PRE 1973	S107	S108	S109	CANADA BORDER
1986	1.31	1.31	2.31	1.50	0.58	2.32	4.00	2.31	1.31
1987	1.61	1.61	2.31	1.50	0.58	2.66	3.90	2.31	1.61
1988	1.98	1.98	2.31	1.50	0.58	3.05	3.80	2.31	1.98
1989	2.44	2.44	2.31	1.50	0.58	3.49	3.70	2.31	2.44
1990	3.00	3.00	2.31	1.50	0.58	4.00	3.61	2.31	3.00
1991	3.03	3.03	2.31	1.50	0.58	4.00	3.74	2.31	3.03
1992	3.07	3.07	2.31	1.50	0.58	4.00	3.87	2.31	3.07
1993	3.10	3.10	2.31	1.50	0.58	4.00	4.01	2.31	3.10
1994	3.14	3.14	2.31	1.50	0.58	4.00	4.15	2.31	3.14
1995	3.22	3.22	2.31	1.50	0.58	4.00	4.23	2.31	3.14
1996	3.31	3.31	2.31	1.50	0.58	4.00	4.32	2.31	3.14
1997	3.40	3.40	2.31	1.50	0.58	4.10	4.41	2.31	3.24
1998	3.49	3.49	2.31	1.50	0.58	4.20	4.49	2.31	3.35
1999	3.59	3.59	2.31	1.50	0.58	4.30	4.58	2.31	3.46
2000	3.68	3.68	2.31	1.50	0.58	4.41	4.67	2.31	3.58
2001	3.78	3.78	2.31	1.50	0.58	4.51	4.77	2.31	3.70
2002	3.89	3.89	2.31	1.50	0.58	4.62	4.86	2.31	3.82
2003	3.99	3.99	2.31	1.50	0.58	4.74	4.96	2.31	3.94
2004	4.10	4.10	2.31	1.50	0.58	4.85	5.06	2.31	4.08
2005	4.21	4.21	2.31	1.50	0.58	4.97	5.16	2.31	4.21

Source: California Energy Commission staff.

TABLE F-A-2

DATE: 08/2

CALIFORNIA UNIT BORDER COST
MED. SUPPLY AND MED. PRICE CASE
MODIFIED BFR PRICE FORECAST
1983 DOLLARS PER MMBTU

SOURCE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
ONSHORE - NORTH	1.79	1.97	2.22	2.56	3.00	3.03	3.07	3.10	3.14	3.22	3.31	3.40	3.49
ONSHORE - SOUTH	2.23	2.30	2.44	2.67	3.00	3.03	3.07	3.10	3.14	3.22	3.31	3.40	3.49
OFFSHORE	2.25	2.34	2.74	3.15	3.44	3.26	3.14	3.17	3.20	3.26	3.31	3.34	3.40
EL PASO	2.15	2.27	2.48	2.84	3.25	3.32	3.32	3.43	3.50	3.63	3.72	3.87	3.91
TRANSWESTERN	2.03	2.30	2.61	3.04	3.55	3.59	3.67	3.72	3.88	3.94	4.09	4.12	4.27
PAC INTERSTATE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTHWEST	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CANADA (PGT)	1.92	2.23	2.62	3.08	3.32	3.40	3.47	3.55	3.63	3.76	3.88	4.01	4.19
CANADA (SCG)	3.34	3.46	3.68	4.02	3.72	3.70	3.69	3.74	3.73	3.84	3.97	4.09	4.22
CANADA (NEW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROCKY MTN (PGT)	3.09	3.10	3.19	3.25	3.35	3.12	3.49	3.57	3.65	4.33	4.38	4.38	4.39
ROCKY MTN (EPNG)	2.35	2.67	3.07	3.53	4.10	4.13	4.17	4.21	4.26	4.54	4.59	4.61	4.65
MEXICO	0.00	2.69	3.06	3.52	4.08	4.11	4.15	4.18	4.22	4.22	4.22	4.32	4.43
INDONESIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH SLOPE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SNG COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOUTH AMERICA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AUSTRALIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIGESTER-MANURE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAN LAND FILL	2.16	2.34	2.54	2.76	3.00	3.03	3.07	3.10	3.14	3.22	3.31	3.40	3.49

SOURCE	1999	2000	2001	2002	2003	2004	2005
ONSHORE - NORTH	3.59	3.68	3.78	3.89	3.99	4.10	4.21
ONSHORE - SOUTH	3.59	3.68	3.78	3.89	5.14	5.30	5.44
OFFSHORE	3.74	3.98	4.18	4.40	4.61	4.86	5.07
EL PASO	4.01	4.19	4.32	4.52	4.63	4.82	4.97
TRANSWESTERN	4.42	4.56	4.66	4.86	5.00	5.18	5.34
PAC INTERSTATE	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTHWEST	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CANADA (PGT)	4.30	4.44	4.60	4.73	4.85	4.98	5.11
CANADA (SCG)	4.35	4.48	4.63	4.78	4.94	5.09	5.26
CANADA (NEW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROCKY MTN (PGT)	4.40	4.40	4.41	4.45	4.46	4.48	4.54
ROCKY MTN (EPNG)	4.69	4.71	4.74	4.81	4.89	4.97	5.05
MEXICO	4.54	4.66	4.78	4.90	5.02	5.16	5.29
INDONESIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH SLOPE	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SNG COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOUTH AMERICA	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AUSTRALIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIGESTER-MANURE	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAN LAND FILL	3.59	3.68	3.78	3.89	3.99	4.10	4.21

Source: California Energy Commission staff.

TABLE F-A-3

DATE: 08/22/86

NORTHERN CALIFORNIA SUPPLY
MED. SUPPLY CASE
MMCFD

SOURCE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
ONSHORE - NORTH	352	328	294	277	259	247	240	234	229	227	224	219	210
ONSHORE - SOUTH	0	0	0	0	0	0	0	0	0	0	0	0	0
OFFSHORE	0	0	0	0	0	0	0	0	0	0	0	0	0
EL PASO	596	678	672	606	567	548	571	596	601	506	564	590	604
TRANSWESTERN	0	0	0	0	0	0	0	0	0	0	0	0	0
PAC INTERSTATE	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (PGT)	915	805	808	879	939	980	980	980	980	980	980	980	980
CANADA (SCG)	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (NEW)	0	0	0	0	0	0	0	0	0	0	0	0	0
ROCKY MTN (PGT)	17	20	23	27	32	38	45	53	62	180	157	149	144
ROCKY MTN (EPNG)	2	3	7	12	16	21	30	38	45	51	56	61	66
MEXICO	0	15	15	15	18	18	18	18	18	20	20	20	20
INDONESIA	0	0	0	0	0	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0	0	0	0	0	0
SAN LAND FILL	0	1	2	3	5	7	9	12	15	18	18	18	18
TOTAL	1882	1850	1821	1819	1836	1859	1893	1931	1950	1982	2019	2037	2042

SOURCE	1999	2000	2001	2002	2003	2004	2005
ONSHORE - NORTH	202	198	193	188	183	178	173
ONSHORE - SOUTH	0	0	0	0	0	0	0
OFFSHORE	0	0	0	0	0	0	0
EL PASO	590	578	565	551	538	525	462
TRANSWESTERN	0	0	0	0	0	0	0
PAC INTERSTATE	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0
CANADA (PGT)	980	980	980	980	980	980	980
CANADA (SCG)	0	0	0	0	0	0	0
CANADA (NEW)	0	0	0	0	0	0	0
ROCKY MTN (PGT)	138	134	133	128	124	118	114
ROCKY MTN (EPNG)	70	74	79	80	82	83	84
MEXICO	20	18	18	18	18	18	18
INDONESIA	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0
SAN LAND FILL	18	18	18	18	18	18	18
TOTAL	2018	2000	1986	1963	1943	1920	1849

Source: California Energy Commission staff.

TABLE F-A-4

DATE: 08/22/86

SOUTHERN CALIFORNIA SUPPLY
MED. SUPPLY CASE
MMCFD

SOURCE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
ONSHORE - NORTH	0	0	0	0	0	0	0	0	0	0	0	0	0
ONSHORE - SOUTH	70	66	62	57	54	51	48	46	43	41	40	38	37
OFFSHORE	162	171	180	167	161	161	154	149	143	128	113	91	83
EL PASO	1610	1508	1496	1560	1534	1559	1542	1459	1402	1440	1316	1254	1226
TRANSWESTERN	640	600	553	493	466	453	436	423	413	409	402	395	383
PAC INTERSTATE	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (PGT)	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (SCG)	217	217	217	217	217	217	217	217	217	217	217	217	217
CANADA (NEW)	0	0	0	0	0	0	0	0	0	0	0	0	0
ROCKY MTN (PGT)	0	0	0	0	0	0	0	0	0	0	0	0	0
ROCKY MTN (EPNG)	3	7	13	24	33	43	61	76	90	103	115	125	134
MEXICO	0	60	60	60	72	72	72	72	72	80	80	80	80
INDONESIA	0	0	0	0	0	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0	0	0	0	0	0
SAN LAND FILL	5	6	6	6	6	6	6	6	6	6	6	6	6
TOTAL	2707	2635	2587	2584	2543	2562	2536	2448	2386	2424	2289	2206	2166

SOURCE	1999	2000	2001	2002	2003	2004	2005
ONSHORE - NORTH	0	0	0	0	0	0	0
ONSHORE - SOUTH	35	34	33	32	31	30	29
OFFSHORE	67	56	48	41	35	29	25
EL PASO	1199	1173	1147	1120	1092	1067	938
TRANSWESTERN	385	378	374	367	363	360	357
PAC INTERSTATE	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0
CANADA (PGT)	0	0	0	0	0	0	0
CANADA (SCG)	217	217	217	217	217	217	217
CANADA (NEW)	0	0	0	0	0	0	0
ROCKY MTN (PGT)	0	0	0	0	0	0	0
ROCKY MTN (EPNG)	142	149	159	163	165	168	171
MEXICO	80	72	72	72	72	72	72
INDONESIA	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0
SAN LAND FILL	6	6	6	6	6	6	6
TOTAL	2131	2085	2056	2018	1981	1949	1815

Source: California Energy Commission staff.

TABLE F-A-5

DATE: 08/22/86

TOTAL CALIFORNIA SUPPLY
MED. SUPPLY CASE
MMCFD

SOURCE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
ONSHORE - NORTH	352	328	294	277	259	247	240	234	229	227	224	219	210
ONSHORE - SOUTH	70	66	62	57	54	51	48	46	43	41	40	38	37
OFFSHORE	162	171	180	167	161	161	154	149	143	128	113	91	83
EL PASO	2206	2186	2168	2166	2101	2107	2113	2055	2003	1946	1880	1844	1830
TRANSWESTERN	640	600	553	493	466	453	436	423	413	409	402	395	383
PAC INTERSTATE	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (PGT)	915	805	808	879	939	980	980	980	980	980	980	980	980
CANADA (SCG)	217	217	217	217	217	217	217	217	217	217	217	217	217
CANADA (NEW)	0	0	0	0	0	0	0	0	0	0	0	0	0
ROCKY MTN (PGT)	17	20	23	27	32	38	45	53	62	180	157	149	144
ROCKY MTN (EPNG)	5	10	20	36	49	64	91	114	135	154	171	186	200
MEXICO	0	75	75	75	90	90	90	90	90	100	100	100	100
INDONESIA	0	0	0	0	0	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0	0	0	0	0	0
SAN LAND FILL	5	7	8	9	11	13	15	18	21	24	24	24	24
TOTAL	4589	4485	4408	4403	4379	4421	4429	4379	4336	4406	4308	4243	4208

SOURCE	1999	2000	2001	2002	2003	2004	2005
ONSHORE - NORTH	202	198	193	188	183	178	173
ONSHORE - SOUTH	35	34	33	32	31	30	29
OFFSHORE	67	56	48	41	35	29	25
EL PASO	1789	1751	1712	1671	1630	1592	1400
TRANSWESTERN	385	378	374	367	363	360	357
PAC INTERSTATE	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0
CANADA (PGT)	980	980	980	980	980	980	980
CANADA (SCG)	217	217	217	217	217	217	217
CANADA (NEW)	0	0	0	0	0	0	0
ROCKY MTN (PGT)	138	134	133	128	124	118	114
ROCKY MTN (EPNG)	212	223	238	243	247	251	255
MEXICO	100	90	90	90	90	90	90
INDONESIA	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0
SAN LAND FILL	24	24	24	24	24	24	24
TOTAL	4149	4085	4042	3981	3924	3869	3664

Source: California Energy Commission staff.

TABLE F-A-6

DATE: 08/13/86

PACIFIC GAS & ELECTRIC COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
1983 DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1986	4.21	3.86	3.34	2.24	3.05	3.49
1987	4.56	4.26	3.75	2.55	2.55	3.71
1988	4.71	4.52	4.07	2.97	2.97	4.02
1989	5.09	4.95	4.51	3.39	3.39	4.44
1990	5.33	5.27	4.86	3.80	3.80	4.76
1991	5.35	5.30	4.91	3.87	3.87	4.80
1992	5.33	5.31	4.93	3.92	3.92	4.81
1993	5.41	5.39	5.01	3.99	3.99	4.88
1994	5.43	5.43	5.06	4.06	4.06	4.94
1995	5.62	5.61	5.22	4.17	4.17	5.10
1996	5.66	5.67	5.29	4.27	4.27	5.17
1997	5.78	5.80	5.42	4.37	4.37	5.29
1998	5.87	5.90	5.52	4.47	4.47	5.40
1999	5.95	6.00	5.63	4.59	4.59	5.51
2000	6.10	6.16	5.77	4.70	4.70	5.67
2001	6.22	6.29	5.90	4.83	4.83	5.81
2002	6.39	6.45	6.05	4.94	4.94	5.97
2003	6.49	6.57	6.17	5.06	5.06	6.10
2004	6.64	6.73	6.33	5.20	5.20	6.27
2005	6.82	6.91	6.49	5.32	5.32	6.47

Source: California Energy Commission staff.

TABLE F-A-7

DATE: 08/13/86

SOUTHERN CALIFORNIA GAS COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
1983 DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1986	3.52	3.48	3.12	2.32	2.32	3.47
1987	3.61	3.69	3.44	2.68	2.68	3.68
1988	3.92	4.08	3.87	3.13	3.13	3.97
1989	4.40	4.60	4.38	3.56	3.56	4.33
1990	4.88	5.11	4.88	3.99	3.99	4.73
1991	4.97	5.20	4.97	4.06	4.06	4.80
1992	5.00	5.25	5.02	4.12	4.12	4.82
1993	5.13	5.36	5.12	4.19	4.19	4.92
1994	5.23	5.47	5.22	4.25	4.25	5.02
1995	5.34	5.58	5.34	4.36	4.36	5.12
1996	5.50	5.75	5.49	4.47	4.47	5.30
1997	5.63	5.89	5.62	4.58	4.58	5.49
1998	5.54	5.88	5.66	4.69	4.69	5.61
1999	5.87	6.16	5.88	4.82	4.82	5.79
2000	6.08	6.36	6.06	4.93	4.93	6.01
2001	6.24	6.53	6.23	5.05	5.05	6.19
2002	6.49	6.76	6.42	5.19	5.19	6.45
2003	6.70	6.97	6.61	5.31	5.31	6.67
2004	6.94	7.21	6.81	5.44	5.44	6.92
2005	7.22	7.48	7.04	5.58	5.58	7.30

Source: California Energy Commission staff.

TABLE F-A-8

DATE: 08/13/86

SAN DIEGO GAS & ELECTRIC COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
1983 DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1986	4.09	3.95	3.74	2.70	3.05	3.82
1987	4.50	4.41	4.21	2.55	2.55	4.03
1988	4.68	4.71	4.55	2.97	2.97	4.28
1989	5.05	5.15	5.00	3.39	3.39	4.56
1990	5.38	5.54	5.41	3.80	3.80	4.86
1991	5.35	5.55	5.43	3.87	3.87	4.86
1992	5.30	5.53	5.43	3.92	3.92	4.85
1993	5.45	5.67	5.55	3.99	3.99	4.94
1994	5.49	5.73	5.62	4.06	4.06	4.98
1995	5.59	5.85	5.74	4.17	4.17	5.07
1996	5.80	6.05	5.93	4.27	4.27	5.33
1997	5.90	6.17	6.05	4.37	4.37	5.55
1998	6.02	6.32	6.20	4.47	4.47	5.87
1999	6.09	6.41	6.30	4.59	4.59	5.88
2000	6.26	6.58	6.47	4.70	4.70	6.12
2001	6.42	6.76	6.64	4.83	4.83	6.28
2002	6.64	6.97	6.84	4.94	4.94	6.49
2003	6.79	7.14	7.00	5.06	5.06	6.66
2004	6.98	7.33	7.20	5.20	5.20	6.84
2005	7.19	7.54	7.40	5.36	5.36	7.11

Source: California Energy Commission staff.

TABLE F-A-9

DATE: 08/22/86

PACIFIC GAS & ELECTRIC
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P4	P5	TOTAL
1986	570	242	165	45	169	107	325	1623
1987	565	245	169	95	173	109	364	1720
1988	565	247	173	131	176	111	219	1622
1989	562	250	177	115	180	114	201	1599
1990	559	252	181	113	184	116	178	1583
1991	559	255	186	120	188	119	176	1603
1992	560	259	190	127	193	121	181	1631
1993	561	262	195	131	197	124	191	1661
1994	562	266	200	136	202	127	199	1692
1995	563	270	205	135	207	129	199	1708
1996	565	273	211	134	212	132	139	1666
1997	568	277	216	150	217	135	208	1771
1998	570	279	220	153	220	137	203	1782
1999	573	281	223	156	223	139	195	1790
2000	576	283	227	157	226	141	189	1799
2001	577	285	230	161	229	143	187	1812
2002	579	287	233	167	231	145	197	1839
2003	580	288	236	169	234	146	209	1862
2004	581	290	240	178	237	148	204	1878
2005	583	292	243	180	240	150	223	1911

Source: California Energy Commission staff.

TABLE F-A-10

DATE: 08/22/86

SOUTHERN CALIFORNIA GAS
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P3C	P4	P5	TOTAL
1986	823	291	130	50	231	39	90	538	2192
1987	829	297	134	77	237	26	93	444	2137
1988	832	304	139	132	243	20	96	383	2149
1989	834	310	143	152	249	27	98	396	2209
1990	836	317	148	167	256	32	101	392	2249
1991	839	322	151	170	260	31	102	408	2283
1992	843	327	154	170	264	32	104	423	2317
1993	847	332	157	178	268	32	105	440	2359
1994	851	337	160	178	272	25	107	451	2381
1995	856	342	163	184	298	29	108	460	2440
1996	856	348	166	191	323	27	110	453	2474
1997	856	353	169	197	352	27	111	466	2531
1998	857	557	172	206	347	25	113	412	2689
1999	858	361	174	210	349	23	115	397	2487
2000	860	365	178	216	340	15	117	340	2431
2001	859	369	181	223	342	15	119	327	2435
2002	859	372	184	229	348	15	121	336	2464
2003	860	376	187	236	355	14	122	367	2517
2004	861	379	190	242	357	14	124	375	2542
2005	862	383	193	242	365	12	126	384	2567

Source: California Energy Commission staff.

TABLE F-A-11

DATE: 08/22/86

SAN DIEGO GAS & ELECTRIC
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P4	P5	TOTAL
1986	93	31	4	7	11	4	29	179
1987	94	31	4	12	11	5	29	186
1988	95	32	5	13	12	5	31	193
1989	95	32	5	15	12	6	50	215
1990	96	33	5	17	12	6	63	232
1991	97	33	5	20	12	6	65	238
1992	98	34	5	22	12	6	65	242
1993	98	34	5	24	12	6	69	248
1994	99	35	6	26	13	6	76	261
1995	100	36	6	27	13	7	83	272
1996	100	36	6	28	13	7	68	258
1997	100	37	6	29	13	7	81	273
1998	100	38	6	30	13	7	83	277
1999	101	38	6	30	14	7	69	265
2000	101	39	6	30	14	7	56	253
2001	102	39	6	30	14	7	57	255
2002	102	40	6	30	14	7	57	256
2003	102	40	7	30	14	8	62	263
2004	102	41	7	31	15	8	67	271
2005	103	41	7	31	15	8	71	276

Source: California Energy Commission staff.

TABLE F-A-12

DATE: 08/22/86

CALIFORNIA SUMMARY
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P3C	P4	P5	TOTAL
1986	1486	564	299	102	411	39	201	892	3994
1987	1488	573	307	184	421	26	207	837	4043
1988	1492	583	317	276	431	20	212	633	3964
1989	1491	592	325	282	441	27	218	647	4023
1990	1491	602	334	297	452	32	223	633	4064
1991	1495	610	342	310	460	31	227	649	4124
1992	1501	620	349	319	469	32	231	669	4190
1993	1506	628	357	333	477	32	235	700	4268
1994	1512	638	366	340	487	25	240	726	4334
1995	1519	648	374	346	518	29	244	742	4420
1996	1521	657	383	353	548	27	249	660	4398
1997	1524	667	391	376	582	27	253	755	4575
1998	1527	874	398	389	580	25	257	698	4748
1999	1532	680	403	396	586	23	261	661	4542
2000	1537	687	411	403	580	15	265	585	4483
2001	1538	693	417	414	585	15	269	571	4502
2002	1540	699	423	426	593	15	273	590	4559
2003	1542	704	430	435	603	14	276	638	4642
2004	1544	710	437	451	609	14	280	646	4691
2005	1548	716	443	453	620	12	284	678	4754

Source: California Energy Commission staff.

TABLE F-A-13

DATE: 08/22/86

PACIFIC GAS & ELECTRIC
MODIFIED BFR PRICE FORECAST
SELECTED INPUT DATA
1983 DOLLARS

YEAR	PURCHASE COSTS K$/DAY	PURCHASE COSTS $/MMBTU*	DISTRIBUTION COSTS K$/DAY	DISTRIBUTION COSTS $/MMBTU*	TOTAL COSTS K$/DAY	TOTAL COSTS $/MMBTU*	SUPPLY MMCFD	POWER PLANT GAS PRICE $/MMBTU	INDUSTRIAL GAS PRICE $/MMBTU
1986	4095	2.06	2821	1.43	6916	3.49	1881	3.05	2.24
1987	4261	2.19	2952	1.52	7213	3.71	1850	2.55	2.68
1988	4772	2.48	2920	1.53	7692	4.02	1821	2.97	3.13
1989	5554	2.91	2924	1.54	8478	4.44	1819	3.39	3.57
1990	6261	3.23	2940	1.53	9201	4.76	1837	3.80	4.00
1991	6471	3.31	2900	1.49	9371	4.80	1859	3.87	4.07
1992	6693	3.36	2883	1.45	9576	4.81	1893	3.92	4.13
1993	7002	3.45	2897	1.43	9899	4.88	1931	3.99	4.20
1994	7216	3.52	2899	1.42	10115	4.94	1949	4.06	4.27
1995	7723	3.70	2898	1.40	10621	5.10	1982	4.17	4.39
1996	8064	3.80	2902	1.37	10966	5.17	2019	4.27	4.49
1997	8387	3.92	2913	1.37	11300	5.29	2037	4.37	4.60
1998	8657	4.03	2926	1.37	11583	5.40	2042	4.47	4.71
1999	8761	4.13	2931	1.39	11692	5.51	2018	4.59	4.83
2000	8963	4.27	2946	1.41	11909	5.67	1999	4.70	4.95
2001	9181	4.39	2952	1.42	12133	5.81	1986	4.83	5.08
2002	9374	4.53	2965	1.44	12339	5.97	1964	4.94	5.20
2003	9485	4.64	2974	1.46	12459	6.10	1942	5.06	5.33
2004	9659	4.78	2990	1.49	12649	6.27	1920	5.20	5.47
2005	9554	4.92	3000	1.55	12554	6.47	1849	5.32	5.60

* ASSUMES 1050 BTU PER CUBIC FOOT.

Source: California Energy Commission staff.

TABLE F-A-14

DATE: 08/22/86

SOUTHERN CALIFORNIA GAS
MODIFIED BFR PRICE FORECAST
SELECTED INPUT DATA
1983 DOLLARS

YEAR	PURCHASE COSTS K$/DAY	PURCHASE COSTS $/MMBTU*	DISTRIBUTION COSTS K$/DAY	DISTRIBUTION COSTS $/MMBTU*	TOTAL COSTS K$/DAY	TOTAL COSTS $/MMBTU*	SUPPLY MMCFD	POWER PLANT GAS PRICE $/MMBTU	INDUSTRIAL GAS PRICE $/MMBTU
1986	5809	2.19	3403	1.29	9212	3.47	2529	2.32	2.24
1987	6147	2.39	3306	1.29	9453	3.68	2449	2.68	2.68
1988	6638	2.64	3328	1.33	9966	3.97	2394	3.13	3.13
1989	7501	3.02	3269	1.32	10770	4.33	2369	3.56	3.57
1990	8228	3.39	3245	1.34	11473	4.73	2311	3.99	4.00
1991	8388	3.44	3311	1.36	11699	4.80	2324	4.06	4.07
1992	8401	3.45	3323	1.37	11724	4.82	2317	4.12	4.13
1993	8824	3.56	3362	1.36	12186	4.92	2359	4.19	4.20
1994	9141	3.66	3391	1.36	12532	5.02	2381	4.25	4.27
1995	9640	3.78	3420	1.34	13060	5.13	2428	4.36	4.38
1996	9863	3.92	3452	1.38	13315	5.30	2395	4.47	4.49
1997	9478	4.02	3479	1.48	12957	5.49	2248	4.58	4.60
1998	9639	4.11	3517	1.50	13156	5.61	2234	4.69	4.71
1999	9533	4.22	3546	1.57	13079	5.79	2152	4.82	4.83
2000	9596	4.38	3585	1.64	13181	6.01	2089	4.93	4.95
2001	9625	4.50	3608	1.69	13233	6.19	2037	5.05	5.08
2002	9571	4.67	3633	1.78	13204	6.45	1951	5.19	5.20
2003	9439	4.80	3679	1.88	13118	6.67	1874	5.31	5.33
2004	9382	4.95	3723	1.97	13105	6.92	1804	5.44	5.47
2005	8788	5.11	3756	2.19	12544	7.30	1638	5.58	5.60

* ASSUMES 1050 BTU PER CUBIC FOOT.

Source: California Energy Commission staff.

TABLE F-A-15

DATE: 08/22/86

SAN DIEGO GAS & ELECTRIC
MODIFIED BFR PRICE FORECAST
SELECTED INPUT DATA
1983 DOLLARS

YEAR	PURCHASE COSTS		DISTRIBUTION COSTS		TOTAL COSTS		SUPPLY	POWER PLANT GAS PRICE	INDUSTRIAL GAS PRICE
	K$/DAY	$/MMBTU*	K$/DAY	$/MMBTU*	K$/DAY	$/MMBTU*	MMCFD	$/MMBTU	$/MMBTU
1986	431	2.29	286	1.53	717	3.82	179	3.05	2.24
1987	490	2.51	296	1.52	786	4.03	186	2.55	2.68
1988	561	2.77	306	1.51	867	4.28	193	2.97	3.13
1989	714	3.16	314	1.39	1028	4.56	215	3.39	3.57
1990	866	3.56	317	1.30	1183	4.86	232	3.80	4.00
1991	901	3.61	312	1.25	1213	4.86	238	3.87	4.07
1992	920	3.62	311	1.23	1231	4.85	242	3.92	4.13
1993	973	3.74	313	1.21	1286	4.94	248	3.99	4.20
1994	1051	3.84	312	1.14	1363	4.98	261	4.06	4.27
1995	1125	3.97	313	1.11	1438	5.07	270	4.17	4.39
1996	1067	4.11	314	1.21	1381	5.33	247	4.27	4.49
1997	991	4.21	313	1.33	1304	5.55	224	4.37	4.60
1998	869	4.31	314	1.56	1183	5.87	192	4.47	4.71
1999	962	4.43	315	1.45	1277	5.88	207	4.59	4.83
2000	949	4.59	316	1.53	1265	6.12	197	4.70	4.95
2001	962	4.72	317	1.56	1279	6.28	194	4.83	5.08
2002	983	4.90	319	1.59	1302	6.49	191	4.94	5.20
2003	993	5.03	320	1.63	1313	6.66	188	5.06	5.33
2004	1020	5.20	323	1.65	1343	6.84	187	5.20	5.47
2005	996	5.36	324	1.75	1320	7.11	177	5.36	5.60

* ASSUMES 1050 BTU PER CUBIC FOOT.

Source: California Energy Commission staff.

APPENDIX G

RESULTS OF 1985 CEC STAFF DELPHI SURVEY ON FUTURE OIL PRICES

APPENDIX G

RESULTS OF 1985 CEC STAFF DELPHI SURVEY ON FUTURE OIL PRICES

PURPOSE

The purpose of this paper is to present the results of the CEC staff's 1985 Delphi survey on future oil prices. The preliminary oil price forecasts developed from the survey are presented for consideration in the proceedings of the 1985 Biennial Fuels Report. The following narrative discusses the staff's Delphi survey method, the issues that this year's survey focused on and a summary of the Delphi survey results. This is followed by a discussion of survey results and a comparison of the results with the CEC's BR V oil price projections and other comparable long-term forecasts.

INTRODUCTION

In 1983, the staff began using a Delphi survey of oil price forecasts as the primary basis for developing its oil price projections. Prior to 1983, the CEC staff compiled and analyzed various crude oil price forecasts in the literature and selected a representative forecast to use as the official CEC forecast. In the Delphi survey process currently used by the CEC staff, a panel of experts is selected and each panelist's opinions regarding future changes in oil prices and related economic variables are systematically polled through a series of questionnaires. The results of the initial survey round are compiled, averaged, summarized and fed back to survey panelists who are then given an opportunity to modify their previous responses. The results of the second round are used as the basis for the staff oil price forecast.

The Delphi survey method was chosen because it incorporates a number of features which make it particularly attractive to the Commission compared to earlier methods. Specifically:

- The forecast survey responses can be precisely tailored to the CEC's 20-year planning period. Forecasts developed by other institutions generally address shorter or disparate periods.

- The flexibility of the survey method allows it to be shaped to address oil price issues important to the CEC.

- The survey methodology imposes a common response format on panelists. This permits consistent, systematic statistical treatment of survey responses to arrive at a representative result.

- The survey makes it possible to consult with and incorporate the views of a relatively large number of geographically dispersed experts.

- The expertise possessed by panelists tends to ensure that each viewpoint is based on a knowledgeable assessment of market fundamentals.

- The broad institutional representation among panelists provides a wide range of viewpoints.

- The anonymity guaranteed to survey panelists' responses encourages candor.

ISSUES FOR THE 1985 DELPHI OIL FORECAST SURVEY

Three major issues were highlighted in the 1985 Delphi Oil Forecast Survey: the shape of the forecast curve, the desire to develop an alternative perspective on oil prices and the need to reflect new legislative mandates.

The 1983 Delphi Oil Forecast Survey developed average annual rates of oil price change for the 5-, 12-, and 20-year CEC planning periods by asking panelists to restrict their answers to these periods. The resulting "curve" implied that oil price trend changes would coincide with CEC's planning years, an obviously unrealistic perspective. In order to avoid this bias, this year's survey was designed to allow forecaster panelists the freedom to choose both their own intermediate trend change points and the number of separate trends they expected within the forecast period.

The desire to develop an alternative oil price perspective was sparked by the 1984 joint Cambridge Energy Research Associates/Arthur Anderson & Company study The Future of Oil Prices: The Perils of Prophecy (CERA/AAC). The authors of the study pointed out that the uncertainties involved in forecasting combined with the potentially significant impact of fundamentally unpredictable events on future oil prices made planning on the basis of single line forecasts a highly risky endeavor. In place of this traditional approach, the authors suggested developing alternative scenarios of plausible futures that would incorporate different oil price paths and which could be used to test the robustness of long-term plans in the face of uncertainty. The CEC is familiar with this approach, having used it most recently in the 1981 Biennial, Report Energy Tomorrow. This year's survey has incorporated questions designed to elicit panelists' views of what an alternative forecast would be if their most likely forecast were incorrect.

Finally, the need to reflect new legislative mandates was raised by the passage of AB 1549 wherein the CEC was directed to assess the risk of fuel supply disruptions and price shocks. This year's survey contained questions directed at developing base line information on the probability of a supply disruption.

SURVEY METHODOLOGY

The survey methodology incorporated three phases: panel selection, instrument development, and survey administration.

Panel Selection

Panel selection involved a two-part process. First, a list of prominent national and international oil companies, educational institutions, financial institutions, professional firms, governmental bodies, and industry

associations was prepared. Second, individuals responsible for preparing and evaluating oil prices forecasts in these institutions were invited to participate in the survey panel. The final panel of 33 members was more than twice as large as the 14 member panel that participated in the 1983 Delphi Forecast Survey. The 1985 panel includes 3 members from major oil companies, 4 members from universities, 3 members from financial institutions, members from government bodies, and 11 members from professional firms including both consulting firms and "think tanks," and 4 members from industry associations. Eight of the survey participants are from outside the United States. Eight of the 1985 panelists also participated in the 1983 survey.

In order to encourage candor, the panelists participation was solicited with the understanding that their identities and responses would not be disclosed. The same practice was followed in the 1983 survey.

Instrument Development

The survey instrument was designed to address the three major issues mentioned earlier as well as some related topics. The survey consisted of four sections:

- Part I asked panelists to estimate the most likely path that oil prices would follow over the forecast period. Panelists were free to estimate both the magnitude of annual rates of price change and length of the periods over which the changes would be expected to occur. In addition, panelists were asked to estimate a rate of real U.S. GNP growth that would be consistent with their oil price forecast. Finally, panelists were asked to indicate whether their oil price forecast included oil supply disruptions.

- Part II asked panelists to estimate the most probable alternative oil price paths. That is, if their most likely estimate were significantly wrong, what alternative price path would they select? Panelists were also asked to indicate the situation(s) that would cause the alternative forecast. GNP and supply interruption questions identical to those in Part I were also asked.

- Part III asked panelists to estimate the probabilities that their forecasts were generally correct as well as the probability that a major oil supply interruption would occur during the forecast period.

- Part IV solicited panelist opinions on the likely future relationship between oil prices and U.S. natural gas wellhead prices.

A copy of the survey is presented as Attachment A.

Survey Administration

The first round of the survey was administered in June, 1985. The results of the first round were compiled and sent to the panelists in July, 1985 along with an opportunity to change their responses. Identical surveys were used for the first and second rounds.

SURVEY RESULTS

Responses to each of the survey questions are discussed below.

Most Likely Forecast

The annual rate estimates for each year of the forecast period were compiled to obtain an average rate of change for each year. These yearly averages were then used to develop a price series based on the 1984 annual average price of internationally traded crude oil. This price series is illustrated in Figure G-1. The resulting series was examined to establish the precise year of trend changes. The starting and ending prices were then used to characterize the trend period on the basis of annual average compounded rate of change. The results of this exercise, presented below in Table G-1, show that the survey indicates that prices will fall until 1990, after which they will rise first modestly for another five years and then more rapidly for the remainder of the forecast period.

TABLE G-1

Most Likely Forecast
(%/yr)

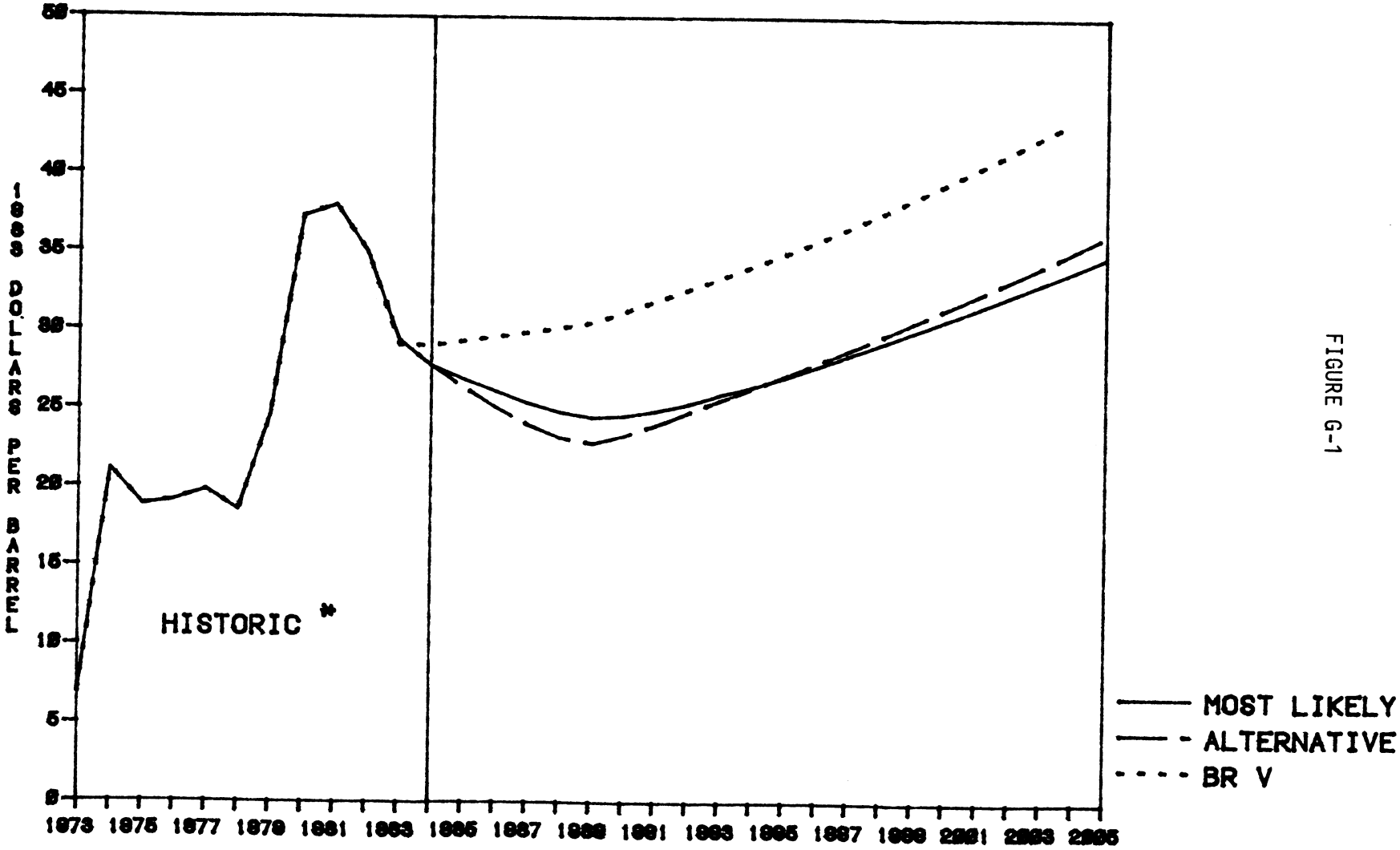
Period	Annual Average Rate of Change	Standard Deviation	Range
1985-1989	-2.4	2.6	-10 to 2.2
1990-1994	1.6	2.5	-3.4 to 11
1995-2005	2.5	2.0	0 to 10

Alternative Forecast

The compilation procedure used for the most likely forecast was repeated for the alternative forecast. The results, presented in Table G-2, show prices falling more rapidly for the first five years followed by a stronger reversal that remains relatively constant through the end of the forecast period. The curve for the alternative forecast is also presented in Figure G-1.

FIGURE G-1

HISTORIC AND FORECASTED CRUDE OIL PRICES



* DOE, AVERAGE PRICE OF INTERNATIONALLY TRADED OIL

TABLE G-2

Alternative Forecast
(%/yr)

Period	Annual Average Rate of Change	Standard Deviation	Range
1985-1989	-3.8	6.0	-22.6 to 6.9
1990-1994	2.9	4.2	-5 to 6.6
1995-2005	2.9	2.8	-0.2 to 10

Reasons Why the Alternative Case Might be True

The reasons that panelists gave for their alternative forecasts focused primarily on three factors.

- Ten panelists indicated that the collapse of OPEC could cause prices to reach lower levels.
- Eight panelists indicated that slower economic growth than anticipated could throttle oil demand recovery, extending the time before price recovery would begin to occur.
- Five panelists indicated that a stronger resurgence in oil demand would cause prices to increase more rapidly after they ended their decline.

Confidence Estimates

Panelists were asked to estimate the probability that their most likely forecast and most probable alternative forecast would be correct. The results, presented in Table G-3, show that panelists believed their most likely forecast had an even (50 percent) chance of being correct. They were twice as confident about their most likely forecast compared to their alternative.

TABLE G-3
Estimated Probability of Being Correct*
(Percent)

Error	Mean	Range	Standard Deviation
Most likely forecast	52.7	25 to 80	2.3
Alternative forecast	26.5	10 to 50	1.7

*100 percent is certainty.

Probability of a Major Oil Supply Disruption Resulting in a Price Shock

Panelists were asked to use CEC forecast periods in estimating the probability of occurrence of a major supply disruption with accompanying price shock. The results presented in Table G-4, show that the near term probability is low but that there is a 50 percent chance that an interruption would occur at some point during the forecast period.

TABLE G-4

	Probability that a Supply Interruption Will Occur (%)	Range
1985-1989	10.9	0 to 40
1985-1997	28.6	0 to 75
1985-2005	51.4	0 to 100

GNP Changes

There is a range of GNP rates of change that can be associated with any particular oil price path. Thus, panelist opinions in this subject area are indicative but not predictive. Results are presented in Table G-5.

Table G-5

Annual Average Rates of Change for Real GNP

	Most Likely Forecast	Alternative Forecast
1985-1989	2.9	2.8
1989-1994	2.7	2.2
1994-2005	2.6	2.4

Correspondence Between Oil and U.S. Natural Gas Wellhead Prices

Twenty-five of 33 panelists said that future natural gas wellhead prices would increase and decrease at the same rate of change as future oil prices.

DISCUSSION

There is strong general agreement among panelists on the general shape of the forecast i.e., prices will continue to fall and then eventually rise. The major areas of disagreement center around how steeply and for how long prices will fall and when and in what manner price recovery will take place.

The shape of the most likely forecast is consistent with the fundamentals of most current analyses of the international oil market. In particular, the forecast supports the notion that the current world crude oil over-supply will last for a number of years, causing prices to erode. Toward the end of the decade some combination of increasing demand and decreasing production both spurred by falling prices is expected to cut heavily into surplus production capacity. This would at first result in only modest price increases but these increases would get larger toward the latter half of the nineties.

The major feature of the alternative forecast is a steeper price decline followed by a steeper, more rapid price escalation. This scenario is also plausible. However, comparison of the price curves of the two forecasts show that the steeper decline provides only a short-term advantage. From 1992 through the end of the forecast period the real price of the alternative forecast is higher than the most likely forecast price. This pattern leads to the inference that deep price declines may cost more in the long run through their disruptive effects then more moderate, controlled price declines. It is interesting to note that both forecasts suggest that oil prices will not reach their current level again for another 10 years.

The differences between the most likely and the alternative forecast appear relatively small. This may be an indication of the significance of small changes in spawning different futures. Analysts tend to focus on large scale market displacements, such as world supply interruptions, when discussing different future scenarios. Historically, this can be justified by the events of 1973 and 1978. However, different futures may be based upon the results of the interaction of subtle changes throughout the market. Scenarios that are developed to test planning assumptions will need to reflect this subtlety.

The Delphi energy panelists appear to be relatively free of the conformity behavior ascribed to them in the CERA/AAC report. In both rounds, variation around the average forecast was relatively high and the range of forecasts submitted was quite broad. Even more compelling is the finding that only 4 of 33 panelists changed their forecasts between rounds 1 and 2. This is consistent with the performance of the 1983 Delphi panel which also demonstrated little change between rounds.

A graphical comparison of the BR V forecast with the 1985 Delphi mostly likely forecast, shown in Figure G-1, reveals that the new forecast is substantially lower. The BR V forecast featured an annual average rate of change of 1.9 percent for the 20-year period while the 1985 Delphi most likely forecast's annual average rate of change is 1.1 percent. The primary reason for the difference is that the BR V forecast had either flat or increasing prices throughout its forecast period while the 1985 Delphi forecast begins with five year period of price declines.

The differences between the forecasts may be attributable to differences in information about market dynamics. The BR V forecast was developed in mid-1983, only two years after oil prices reached their 1981 peak.

Although there had been a steady price decline since 1981, there was still limited understanding in the energy community about the role that increased

non-OPEC production and reduced world oil consumption would continue to play in forcing down oil prices. With the benefit of two additional years to assess the evidence, the current forecast envisions a continuation of the 1981 downward trend through 1989.

Another comparison of interest is between the 1985 Delphi most likely and alternative forecasts and recent comparable long-term institutional forecasts. All of the comparable forecasts are from institutions that were unaffiliated with survey panelists. Figure G-2 presents this comparison graphically and shows that in spite of the widely recognized strong continuing downward pressure on oil prices the CEC forecast is one of the only long-term forecasts which incorporates a price decline, the exception being the 1985 Gas Report forecast of SoCal Gas.

CONCLUSION

The oil price forecasts developed by staff using a Delphi survey provide a reasonable set of forecasts that can be used by the CEC as a basis for planning in CFM VI:

- The results of the forecast are consistent with current market fundamentals and provide insights into the plausible alternative futures that energy planning needs to encompass.
- The Delphi panelists are well qualified to provide informed opinions on future oil prices by virtue of responsibility, experience and affiliation.
- The Delphi methodology permitted systematic analysis of the opinions of the panelists within a common framework so that a representative forecast could be prepared.

SUMMARY

A Delphi survey of future oil prices was used to develop representative forecasts for consideration in the proceedings of the 1985 Biennial Fuels Report. Two forecasts were developed: a most likely forecast and an alternative forecast.

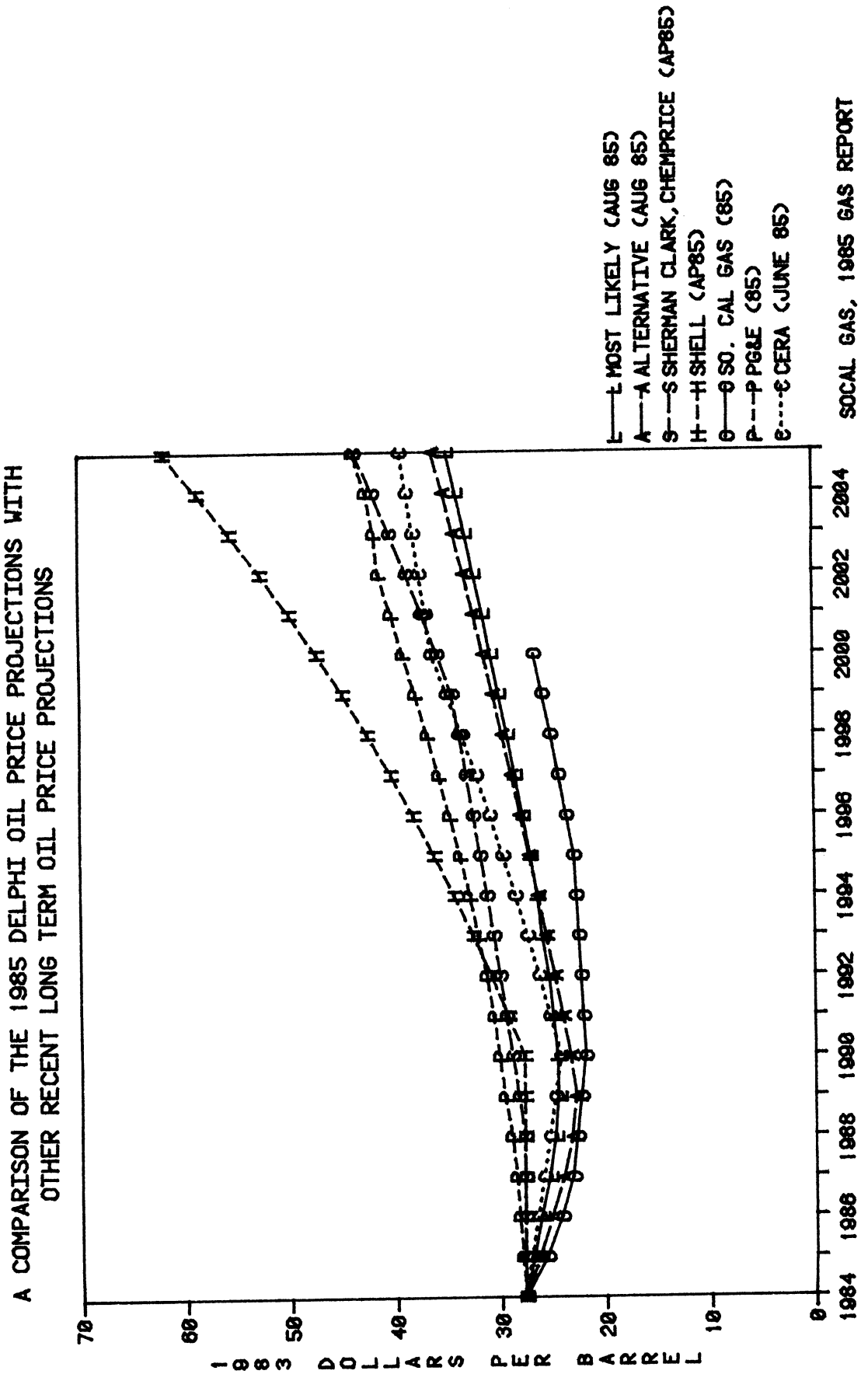
The most likely forecast calls for the following average annual rates of real oil price change.

1985-1989	-2.4%/yr
1990-1994	1.6%/yr
1995-2005	2.5%/yr

The alternative forecast calls for the following average annual rates of real oil price change.

1985-1989	-3.8 %/yr
1990-1994	2.9 %/yr
1995-2005	2.9 %/yr

FIGURE G-2


A COMPARISON OF THE 1985 DELPHI OIL PRICE PROJECTIONS WITH
OTHER RECENT LONG TERM OIL PRICE PROJECTIONS
1983 DOLLARS PER BARREL
70
60
50
40
30
20
10
0
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
L MOST LIKELY (AUG 85)
A ALTERNATIVE (AUG 85)
S SHERMAN CLARK, CHEMPRICE (AP85)
H SHELL (AP85)
O SO. CAL GAS (85)
P PG&E (85)
C CERA (JUNE 85)
SOCAL GAS, 1985 GAS REPORT

An assessment by the panel of the probability of occurrence of a significant oil supply interruption finds that while the near term probability is low, there is approximately 50 percent chance that there will be a significant interruption within the forecast period.

ATTACHMENT A

CALIFORNIA ENERGY COMMISSION
DELPHI PANEL SURVEY: Round 2
July 1985

This survey consists of 12 questions divided into four sections.

- The first section asks you to estimate the most likely price path that oil will follow over the next 20 years;
- The second section asks you to estimate the most probable alternative oil price path. That is, if your first estimate was <u>significantly</u> wrong, what alternative price path would you select as most likely,
- The third section asks you to estimate the probabilities that your forecasts are generally correct; and
- The fourth section asks your opinion on the likely future relationship between oil prices and U.S. natural gas prices.

Part I MOST LIKELY CASE

Question 1

Enter your estimates of the most likely average annual rates of international real oil price change for the period 1985-2005.

Note: This and similar following questions ask you to estimate both the magnitude of annual rates of price changes and the periods over which they are expected to occur. For example, suppose you believe that oil prices will be falling in real terms at 1.0 percent/year until 1992 after which time they will begin to increase, first slowly at 0.5 percent/year until 1995 and then at a faster rate, 1.5 percent/year, for the remainder of the 20-year period. You would then answer as follows:

1985 - 1992	-1.0	Percent/per year
1992 - 1995	0.5	Percent/per year
1995 - 2005	1.5	Percent/per year

You may use more or less than three intervals if you wish.

International Real Crude Oil Prices
Average Annual Rates of Change
Most Likely Case

1985 - 19__	_____	Percent/per year
19__ - 19__	_____	Percent/per year
19__ - 2005	_____	Percent/per year

Question 2

For each of the same time intervals, enter your estimate of a sustainable average annual rate of change in U.S. real GNP that would correspond to your Question 1 answer.

U.S. Real GNP
Average Annual Rates of Change
Most Likely Case

1985 - 19__	_____	Percent/per year
19__ - 19__	_____	Percent/per year
19__ - 2005	_____	Percent/per year

Question 3

Does your most likely oil price case assume a major international oil supply disruption resulting in a price shock?

Yes

No

Part II MOST PROBABLE ALTERNATIVE CASE

Questions 4-7 concern the most probable "alternative" to your "most likely" estimate. That is, if your "most likely" estimate was significantly wrong, what would be your estimate for the most probable alternative.

Question 4

Enter your estimate of the most probable alternative rate of international real oil price change for the period 1985-2005.

International Real Crude Oil Prices
Average Annual Rates of Change
Most Probable Alternative Case

1985 - 19__	_____	Percent/per year
19__ - 19__	_____	Percent/per year
19__ - 2005	_____	Percent/per year

Question 5

For each of the same time intervals, enter your estimate of a sustainable average annual rate of change in U.S. real GNP that would correspond to your Question 4 answer.

U.S. Real GNP
Average Annual Rates of Change
Next Most Probable Alternative Case

1985 - 19__	_____	Percent/per year
19__ - 19__	_____	Percent/per year
19__ - 2005	_____	Percent/per year

Question 6

Does your most probable alternative case for future oil prices assume a major international oil supply disruption resulting in a price shock?

Yes

No

Question 7

What, in your opinion, would be the most likely reason for the "alternative case rather than the "most likely" case to be true? _____

_____

Part III PROBABILITY ESTIMATES

Questions 8-10 ask your opinions about the probability you ascribe to your forecasts.

Question 8

Estimate the probability (0-100 percent) that your "most likely" case will be generally correct. _____ Percent

Question 9

Estimate the probability (0-100 percent) that your most probable "alternative" case will be generally correct. _____ Percent

Note: By definition the answer to Question 8 will be greater than the answer to Question 9 unless you can t choose between cases.

Question 10

Estimate the probability (0 to 100 percent) that a major oil supply disruption will occur resulting in a price shock similar to or greater than those experienced in 1973-74 and 1979;

within the next 5 years _____ percent,

within the next 12 years _____ percent,

within the next 20 years _____ percent.

Part IV NATURAL GAS PRICES

Questions 11 and 12 ask for your opinions regarding the likely future relationship between natural gas and oil prices.

Question 11

Do you believe that the deregulated wellhead price of natural gas in the U.S. will be linked to and move with changes in the price of oil during the forecast period 1985-2005?

Yes

No

Question 12

If your answer to question 11 was "No", please enter your estimate of the most likely average annual rate of change for the wellhead price of uncontrolled natural gas for the period 1985-2005.

Real Price of U.S. Uncontrolled Natural Gas At the Wellhead
Average Annual Rates of Change

1985 - 19__	_____	percent/per year
19__ - 19__	_____	percent/per year
19__ - 2005	_____	percent/per year

The information below is for record keeping purposes only. The individual responses of participants will not be disclosed

Name _____ Organization _____
Date _____

APPENDIX H

CEC STAFF COAL PRICE FORECASTS

APPENDIX H

CEC STAFF COAL PRICE FORECASTS

Introduction

This appendix contains coal price forecasts for all existing and proposed coal-fired power plants in which California utilities have a share of ownership. The forecasts were prepared for use in the CFM V electricity price forecasts. The forecasts were prepared in graphical and tabular formats.

The tabular format appears on Table H-1 and is the CEC staff price forecast for each out-of-state coal plant. In addition to the existing and planned coal-fired plants which are all located outside of California a "new plant" forecast is presented. The "new plant" forecast assumes that the plant is in Northern California with coal delivered to Sacramento. These forecasts have been updated from the 1984 CFM V forecasts by using 1983 constant dollars instead of 1982 and by extending the forecast period by one year to 2005.

The forecast is also presented as a set of graphs of utility and staff forecasts for each power plant prepared for the purpose of comparing the 1983 and 1984 staff forecasts with the utility forecasts. PGandE and SCE submitted a price forecast for a generic (new plant) located in California. The remainder of the forecasts labelled as utility forecasts were not submitted by the utilities directly, but were instead, prepared by CEC staff from various utility submittals. Each of the graphical forecast comparisons is followed by a page detailing the staff assumption made in preparing the forecasts.

Methodology

The forecasts were prepared by obtaining the base period coal prices in the appropriate mining areas and the corresponding rail rates for moving the coal to the power plants. An escalation rate of 2.4 percent (real) was developed from the Association of American Railroads Quarterly Price Index which was then applied to all rail transportation base rates. Real escalation rates for surface mined coal (0.5 percent) and underground mined coal (1.0 percent) were developed from Department of Energy surface and underground mine models. These escalation rates were used to prepare all the forecasts except the Mohave plant forecast. A separate transportation escalation rate was developed for the Mohave plant which receives its coal by slurry pipeline. The real escalation rate (0.39 percent) was developed from the "Coal Price and Transportation Agreement" for the Mohave plant. Finally, because the current coal prices for the Navajo, Mohave, and Four Corners plants are so far below the current prices in their respective mining districts, a one-time 5 or 10 percent price increase was added to each forecast at various times prior to 1995.

Because the transportation element of the delivered price escalates at 2.4 percent above inflation and the mine-mouth coal prices escalate at no more than 1.0 percent, a price breakdown of the delivered price into transportation and coal price elements was essential in preparing the forecasts. Although

base period delivered prices were submitted for each plant by the utilities, only the Mohave price was submitted as separate transportation and coal price elements; therefore, for all other plants staff estimated the proportion of the delivered price attributable to the transportation and coal price elements. The rail price was estimated from published tariffs in the western states for unit train shipments (10,000 tons per shipment) for 1 million tons per year and over. The resulting transportation rate was then subtracted from the utility submitted base delivered price to obtain the rail/coal price proportions.

Accordingly, the graphs of the utility coal price forecasts must be used with caution and in consideration of the assumptions made.

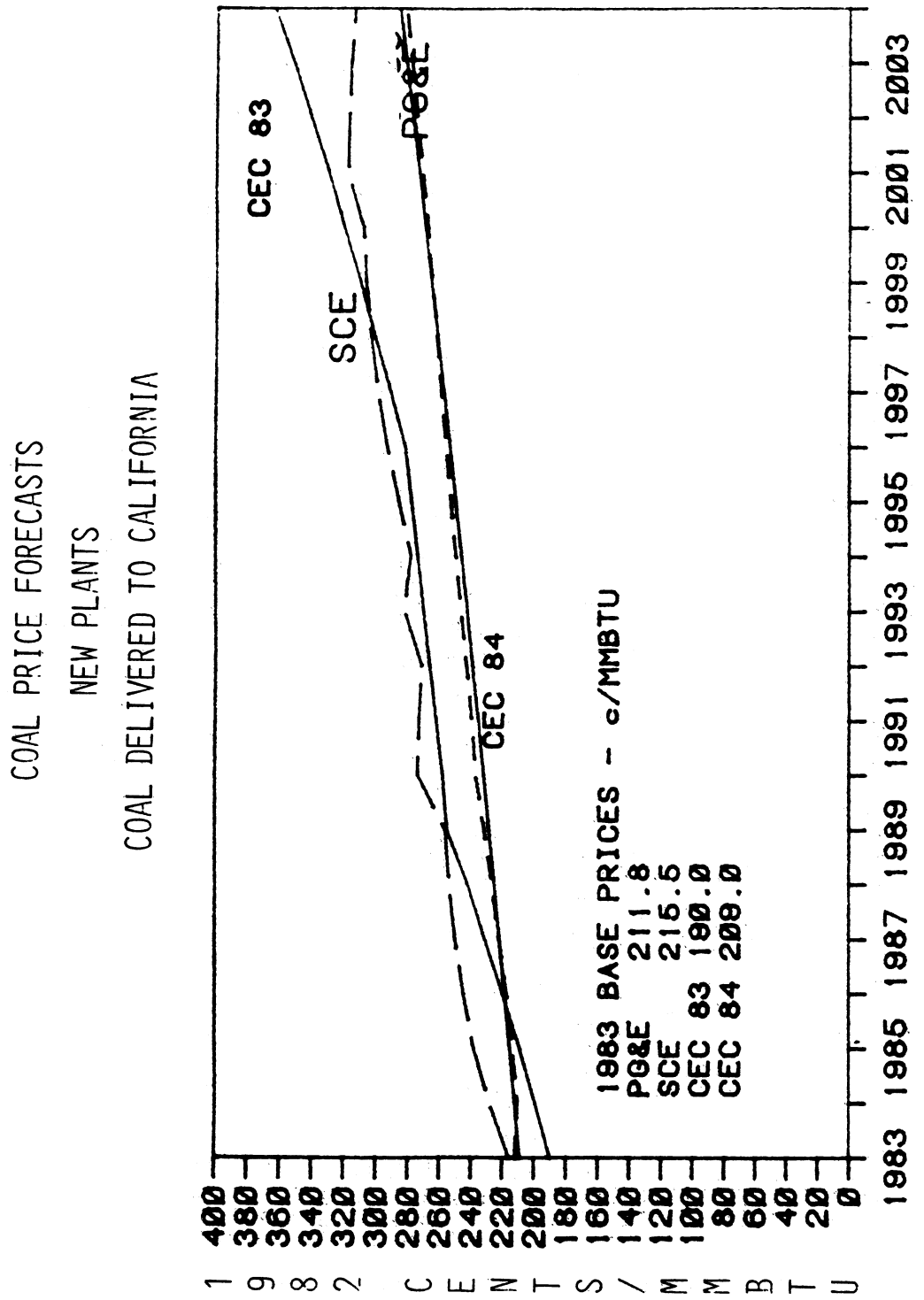
TABLE H-1

COAL PRICE FORECASTS
1983 Dollars

	New Plant	Mohave	Four Corners	Navajo	Coronado	IPP
1983 Base Price cents/mmBtu	217.0	96.3	66.1	87.4	216.1	154.7
Future Prices cents/mmBtu						
1990	240.8	99.7	68.4	91.5	244.8	168.8
1997	267.2	103.3	70.9	95.7	277.4	184.1
2005	301.1	107.5	73.8	100.8	320.0	203.3

Source: CEC Staff

FIGURE H-1



Source: CEC staff and various utility submittals.

FORECAST ASSUMPTIONS
NEW PLANTS

1983 CEC FORECAST

This forecast assumes high rail escalation (5% real), and coal sources in Colorado, Wyoming, and Montana after 1990. It averages coal prices from those states and also averages the rail distances from those states to Sacramento and Barstow.

1984 CEC FORECAST

This forecast was prepared specifically for a future coal plant built in Northern California with coal delivered by rail to Sacramento from Price, Utah and Star Lake, New Mexico. Transportation is 45% and coal is 55% of the delivered cost.

PG&E FORECAST

This forecast was prepared specifically for a future coal plant built in Oakland and utilizing coal from mines in central Utah. The forecast was submitted separately from the CFM V required filings.

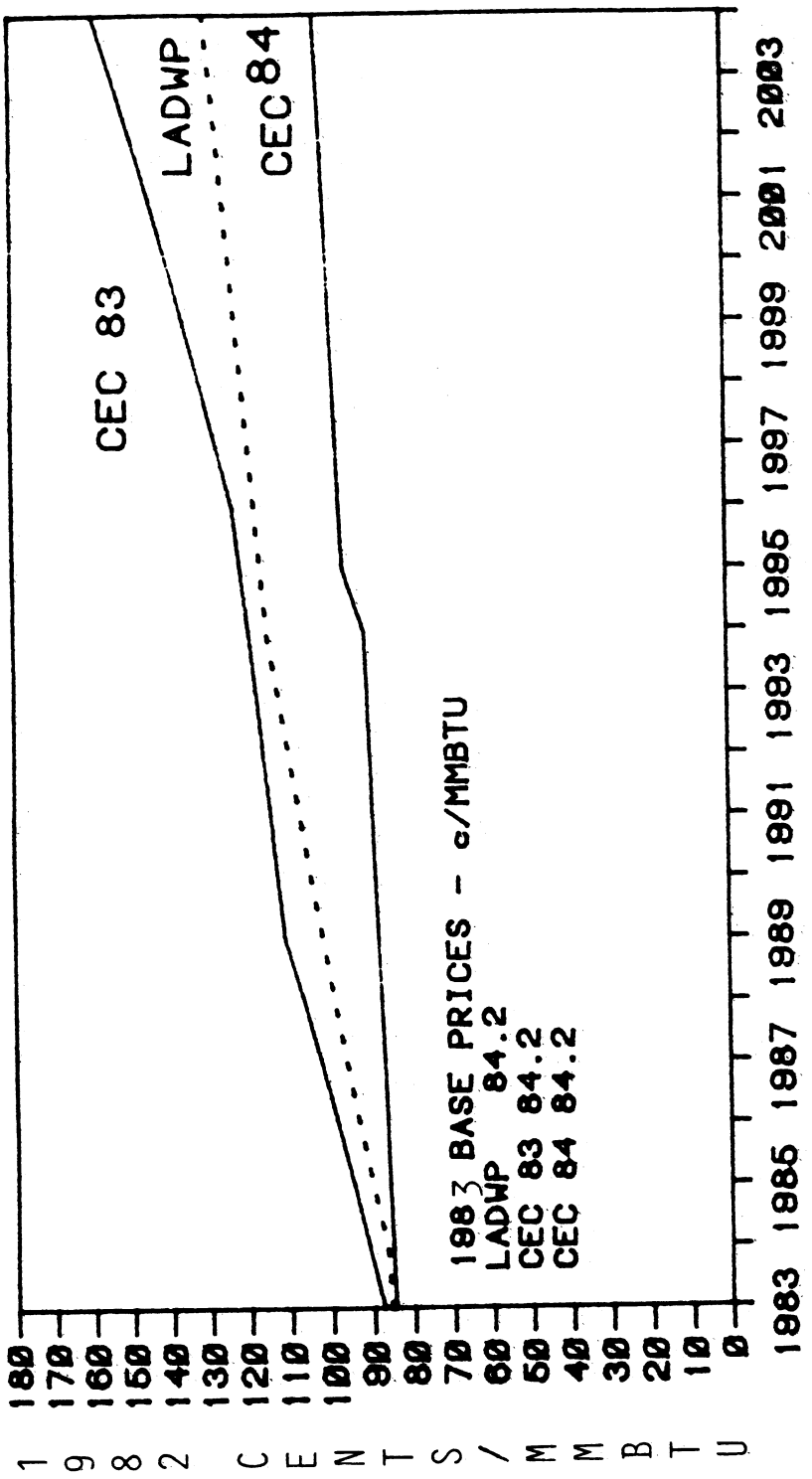
SCE FORECAST

This forecast was prepared specifically for a future coal plant built in Southern California and utilizing coal from western states. CEC staff modified the SCE forecast only by changing the prices from nominal to real 1982 dollars. The SCE inflation rates presented in CFM V were used to change from nominal to real prices.

LADWP FORECAST

LADWP does not prepare a generic forecast.

FIGURE H-2



Source: CEC staff and CFM V utility submittals.

FORECAST ASSUMPTIONS
NAVAJO POWER PLANT

1983 CEC FORECAST

No 1983 forecast was prepared for Navajo.

1984 CEC FORECAST

This forecast uses CFM V base price data, a 0.5% escalation rate for surface mined coal and 2.4% rail escalation rate. The rail transportation portion of the delivered price was estimated to be 8% and the coal price 92%. A one-time 5% coal price increase was added in 1995 to bring the coal price more into line with current Arizona coal prices.

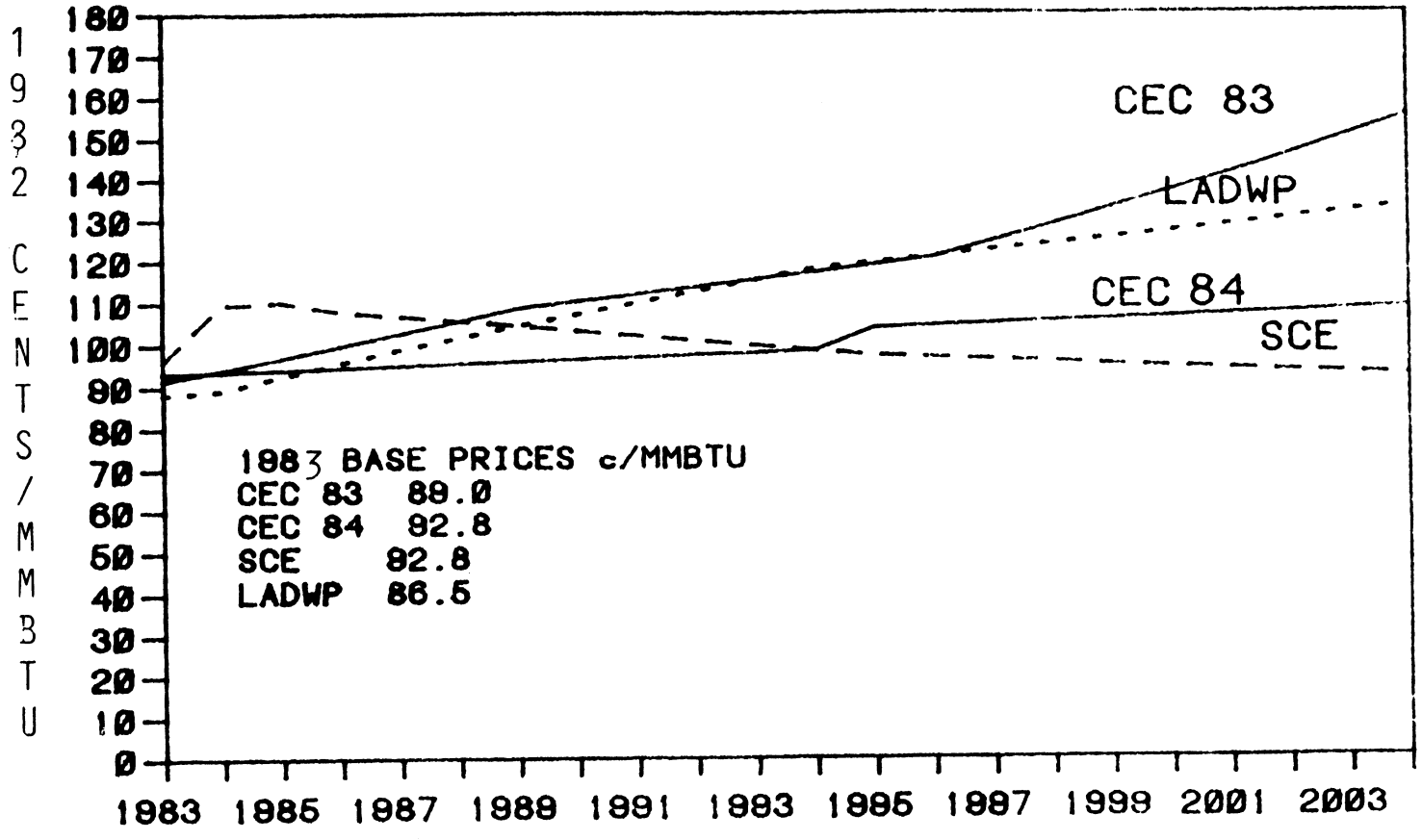
LADWP FORECAST

Staff used the CFM V coal price escalation rate and base price submitted by LADWP to prepare this forecast. LADWP considers this plant to be a mine-mouth plant because the project owns and operates the 93 mile rail transportation system. Staff believes that the coal price escalation rate was developed for the Intermountain Power Plant and may not be applicable here.

FIGURE H-3

COAL PRICE FORECASTS

MOHAVE POWER PLANT



Source: CEC staff and CFM V utility submittals.

FORECAST ASSUMPTIONS
MOHAVE POWER PLANT

1983 CEC FORECAST

This forecast used CFM IV data, high rail rate escalation (5.0%), and assumed an additional 50 cents per ton for increased reclamation costs. Pipeline coal delivery was assumed to have the same escalation rate as rail delivery.

1984 CEC FORECAST

This forecast assumed a pipeline coal transportation escalation of 0.39% and used CFM V data. Any additional reclamation costs were assumed to be incorporated in the CFM V base delivered prices. Transportation is 16% and the mine-mouth coal price is 84% of the delivered price. A one-time 5% coal price increase is added in 1995 to bring coal prices more into line with current Arizona coal prices.

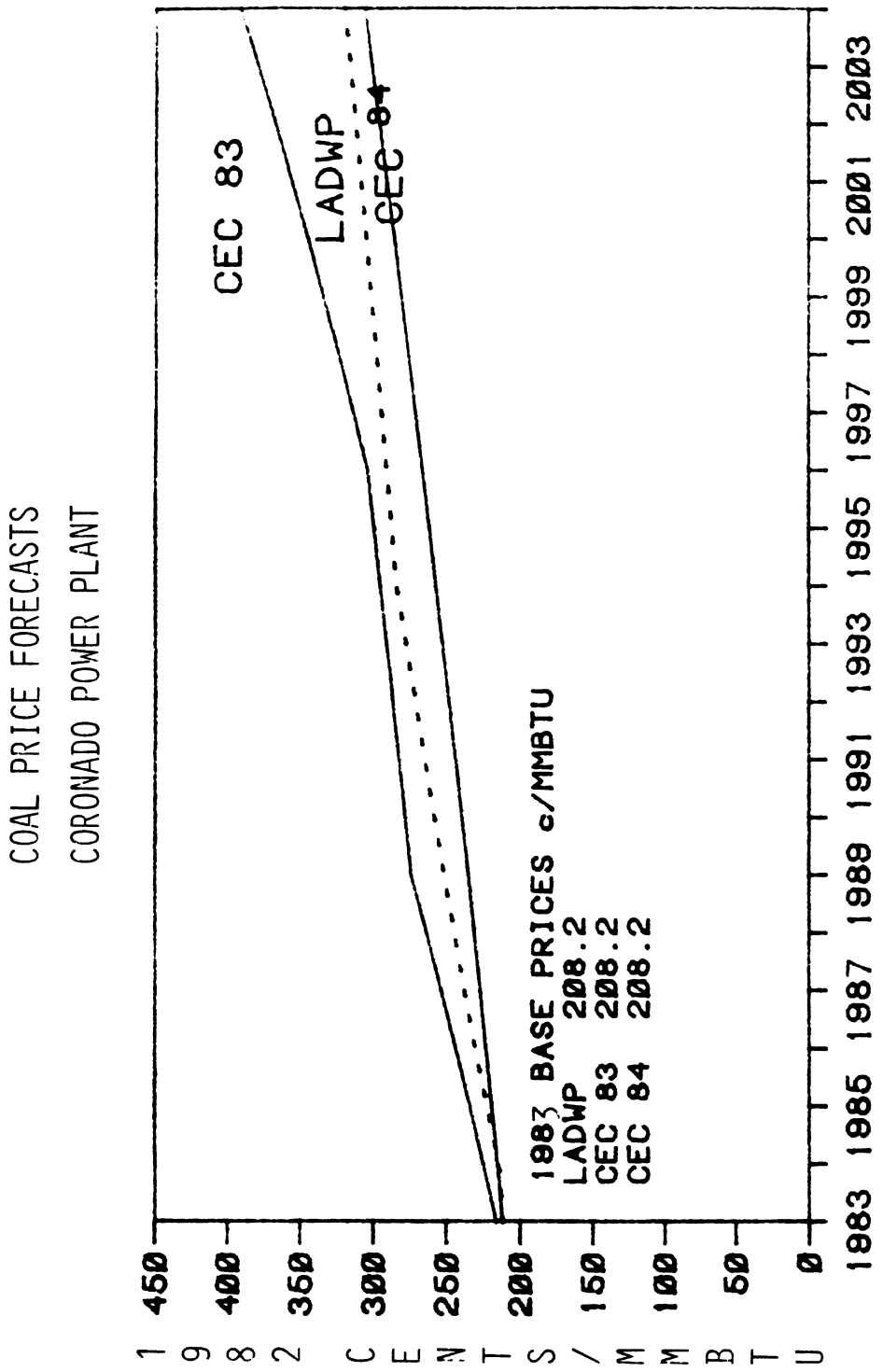
SCE FORECAST

Staff used the CFM V coal price escalation rate and the delivered price submitted by SCE to prepare this forecast. Staff changed the SCE nominal prices presented in CFM V to real prices using the inflation rate submitted by SCE in order to be able to compare the forecasts.

LADWP FORECAST

Staff used the CFM V coal price escalation rate and the delivered price submitted by LADWP to prepare this forecast. Because LADWP submitted a real price escalation rate, no conversion was necessary in order to make comparisons. Staff believes that the LADWP price escalation rate was developed for the Intermountain Power Plant and may not be applicable here.

FIGURE H-4



Source: CEC staff and CFM V utility submittals.

FORECAST ASSUMPTIONS
CORONADO POWER PLANT

1983 CEC FORECAST

No 1983 forecast was prepared for Coronado.

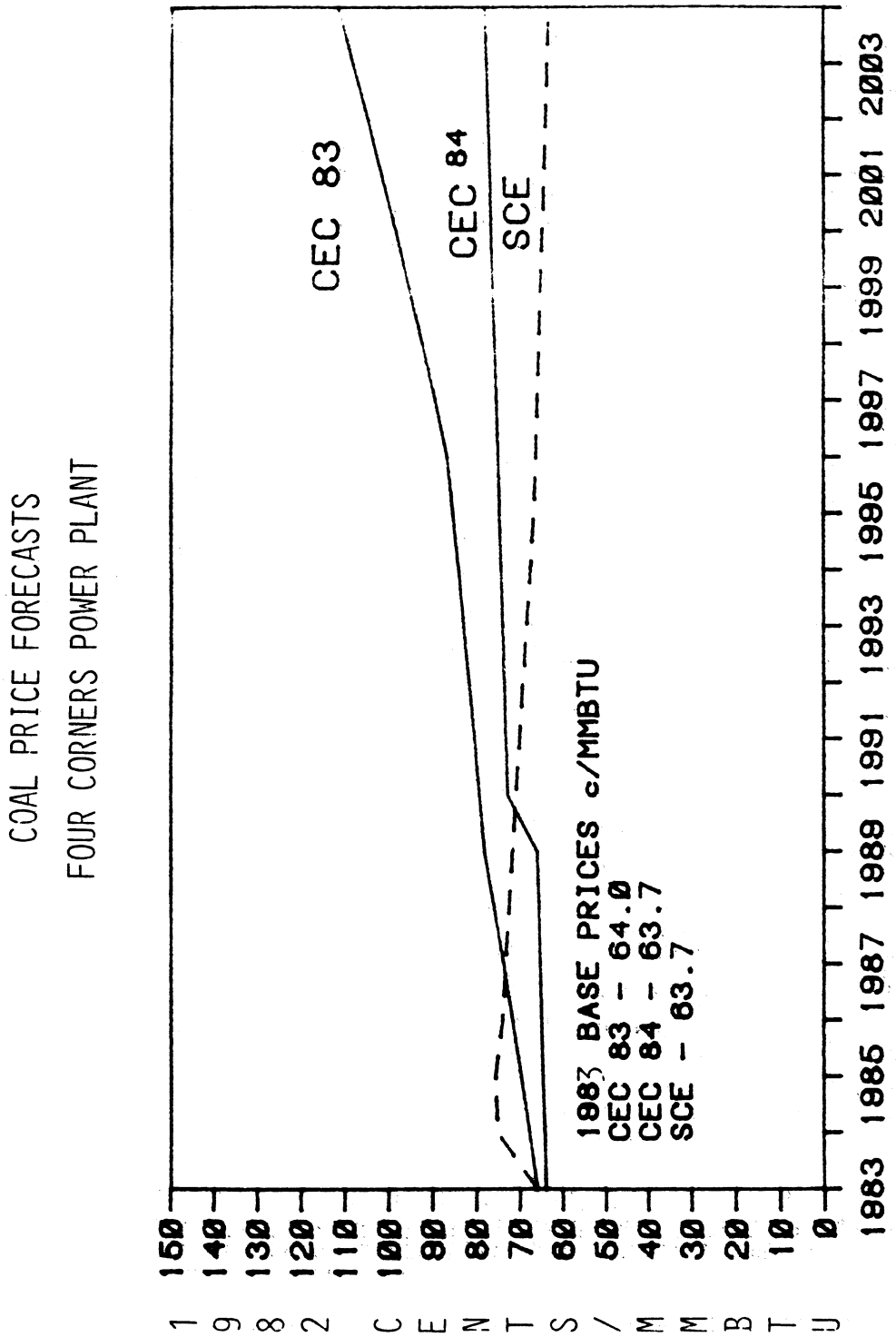
1984 CEC FORECAST

This forecast uses CFM V base prices, a 1.0% escalation rate for underground mined coal, and a 2.4% escalation rate for transportation. Staff estimated that the rail and truck transportation comprises 55% of the delivered cost and mine mouth coal is 45% of the delivered cost. Because the mine mouth coal prices are already comparable with New Mexico and Utah coal prices, no one-time price increase was used.

LADWP FORECAST

Staff used the CFM V coal price escalation rate and base price submitted by LADWP to prepare this forecast. Staff believes that the coal price escalation rate was developed for the Intermountain Power Plant and may not be applicable here.

FIGURE H-5



Source: CEC staff and CFM V utility submittals.

FORECAST ASSUMPTIONS
FOUR CORNERS POWER PLANT

1983 CEC FORECAST

This forecast used CFM IV data, assumed an additional 50 cents per ton for increased reclamation costs, and used the same escalation rate as for new plants. This is a mine-mouth plant and has no transportation element.

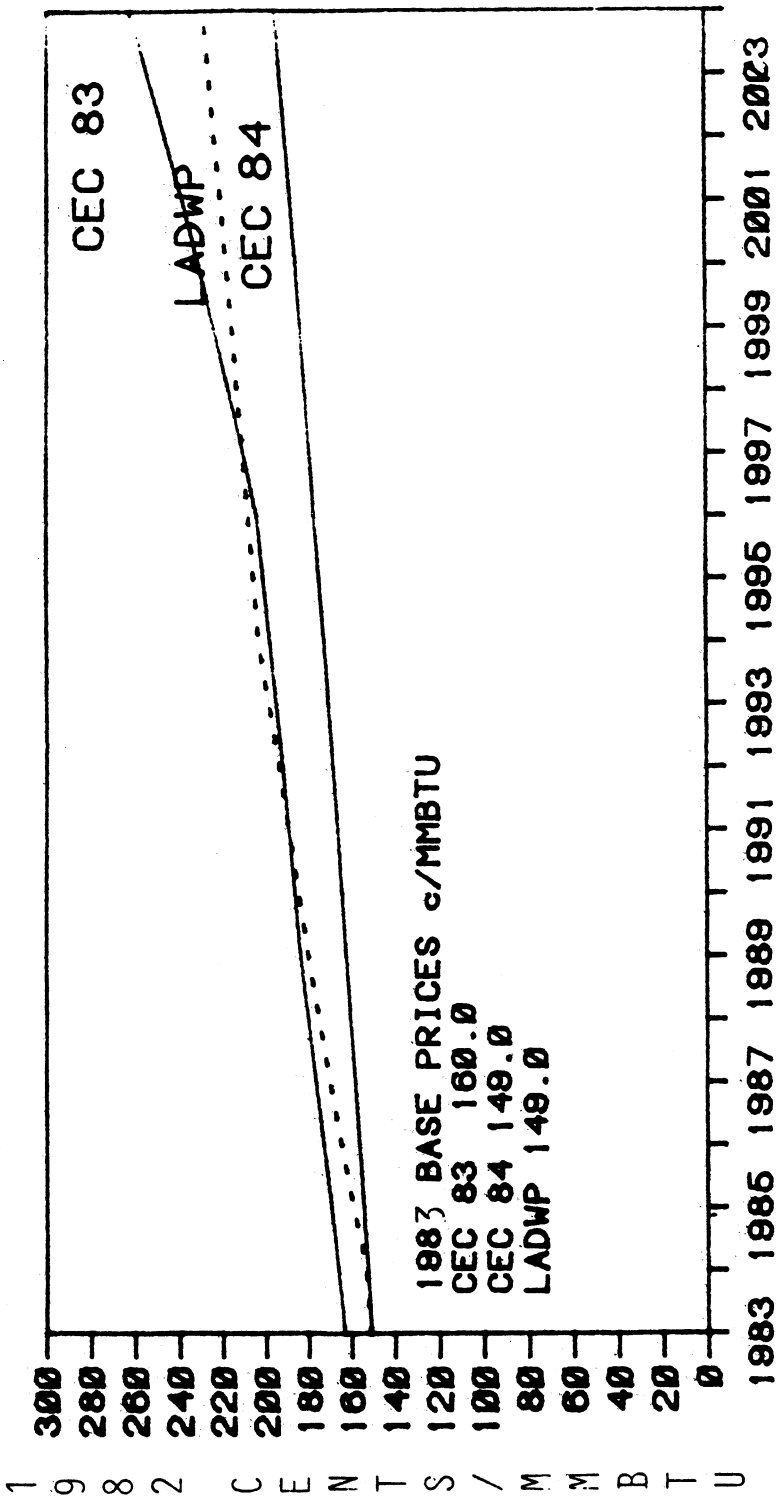
1984 CEC FORECAST

This forecast used CFM V data, a 0.5% escalation rate for surface mined coal and assumed that the CFM V base price accounted for all reclamation costs. This is a mine-mouth plant and has no transportation element. A one-time 10% coal price increase was added in 1990 to bring coal prices more into line with current New Mexico coal prices.

SCE FORECAST

Staff used the CFM V coal price escalation rate and base price submitted by SCE to prepare this forecast. The SCE nominal prices were changed to real prices using the inflation rate submitted by SCE in order to compare the forecasts.

FIGURE H-6



Source: CEC staff and CFM V utility submittals.

FORECAST ASSUMPTIONS
INTERMOUNTAIN POWER PLANT

1983 CEC FORECAST

This forecast used CFM IV data and assumed a smaller escalation rate (2.0% vs. 2.9%) for the first 5 years of the forecast because the coal price and transportation agreements were new. After the initial 5 year forecast the coal price escalation rate was the same as for all other plants. The forecast uses a 5% rail price escalation, and a 50 cent per ton increase to account for added reclamation costs.

1984 CEC FORECAST

This forecast uses the CFM V base price, a 1.0% mine mouth escalation rate for underground mines, and a 2.4% escalation rate for both rail (90%) and truck (10%) delivery. Staff estimated the rail and truck component of the delivered price to be 18% and the mine mouth price to be 82%. No one-time coal price escalation was added because the contracts are new and comparable to current Utah coal prices.

LADWP FORECAST

Staff used the base price and coal price escalation rate submitted by LADWP in CFM V to prepare this forecast. No modifications were needed and the coal price escalation rate is believed to be specific for this plant.

APPENDIX I

FORECAST OF CALIFORNIA TEOR PRODUCTION 1986-2006

APPENDIX I

FORECAST OF CALIFORNIA TEOR PRODUCTION 1986-2006

Introduction

This appendix describes the California Energy Commission's (CEC) 1986 forecast of Thermally Enhanced Oil Recovery (TEOR) production over the period 1986-2006. This forecast interacts with California energy policy in several ways. First, TEOR production represents a large fraction of California's total onshore production, and this share will increase over time as primary production declines. Second, TEOR activity can be influenced by state regulatory policy regarding fuels used to generate the steam used in TEOR operations, i.e. oil and gas. Finally, TEOR operations constitute a very large potential new market for natural gas in California. The sheer size of this potential market--on the order of 20 percent of current total gas use in California--raises questions about the optimal physical and institutional arrangements for providing gas to TEOR operators. Thus the forecast of fuel requirements for TEOR forms an important element of this forecast.

This appendix presents a base case forecast and four sensitivity cases. The differences among the five cases reflect alternative schedules for developing the new acreage available for TEOR projects. The base case corresponds to operator plans as of the beginning of 1986, and the sensitivity cases explore possible reactions to the recent declines in oil prices. The resource base and the ultimate total production are the same in all cases. Incremental production (1986 and after) is projected to be 4.9 billion barrels total. The five cases all have peak production levels of around 530,000 barrels per day, but differ widely on when this level is reached.

Similarly, the demand for fuel for TEOR, excluding cogeneration, peaks at close to 1 bcf/day of gas equivalent, with differences regarding when this value is reached.

The remainder of this paper describes the results of these five scenarios in greater detail. We then examine the implications of oil price changes on TEOR project economics. Two attachments describe the basic oil production and fuel demand forecast methodology, and the TEOR economics model.

Base Case Forecast

The base case forecast represents a development scenario consistent with operator plans as of early 1986, before the substantial decline in world oil prices. Although at first glance it would appear that the price decline implies a substantial downward revision in this forecast, several observations temper this first impression. First, TEOR investment decisions will be made not on the basis of current prices alone, but on expectations of prices over the 10-to-15-year life of the steam injection project. Second, the long-run price which makes TEOR investments uneconomic is low relative to many other oil investments. For fields which have steam generators in place, this price is often below $10/bbl. A more detailed description of the impact of oil prices on TEOR economics appears below.

Figure I-1 presents the base case oil production forecast. This forecast, along with the four other cases, is presented in tabular form in Table I-1. This case can be interpreted as an upper bound on the rate of development. In this case TEOR production continues its current upward trend until 1990 before leveling off somewhat. Production continues to increase gradually until the year 2000, when it reaches a peak of 530 mbd. The forecast shows constant production at this level until 2006. At this point, all known candidate fields for TEOR operations have been put into production.

Figure I-2 shows the demand for steam which corresponds to the base case TEOR oil production scenario. Steam demand has been expressed in terms of millions of cubic feet per day (mmcfd) of gas equivalent primary fuel requirements, to facilitate comparison with other current assessments of TEOR as a potential gas market. This demand grows from 800 mmcfd of gas equivalent in 1985 to a peak level of 1,020 mmcfd equivalent in the year 2000. This level is maintained until 2006. Currently, about 66 percent of the energy demand for TEOR is supplied by oil.[1] Steam demand for the base-case and the sensitivity cases is shown in tabular form in Table I-2.

Low Price Cases

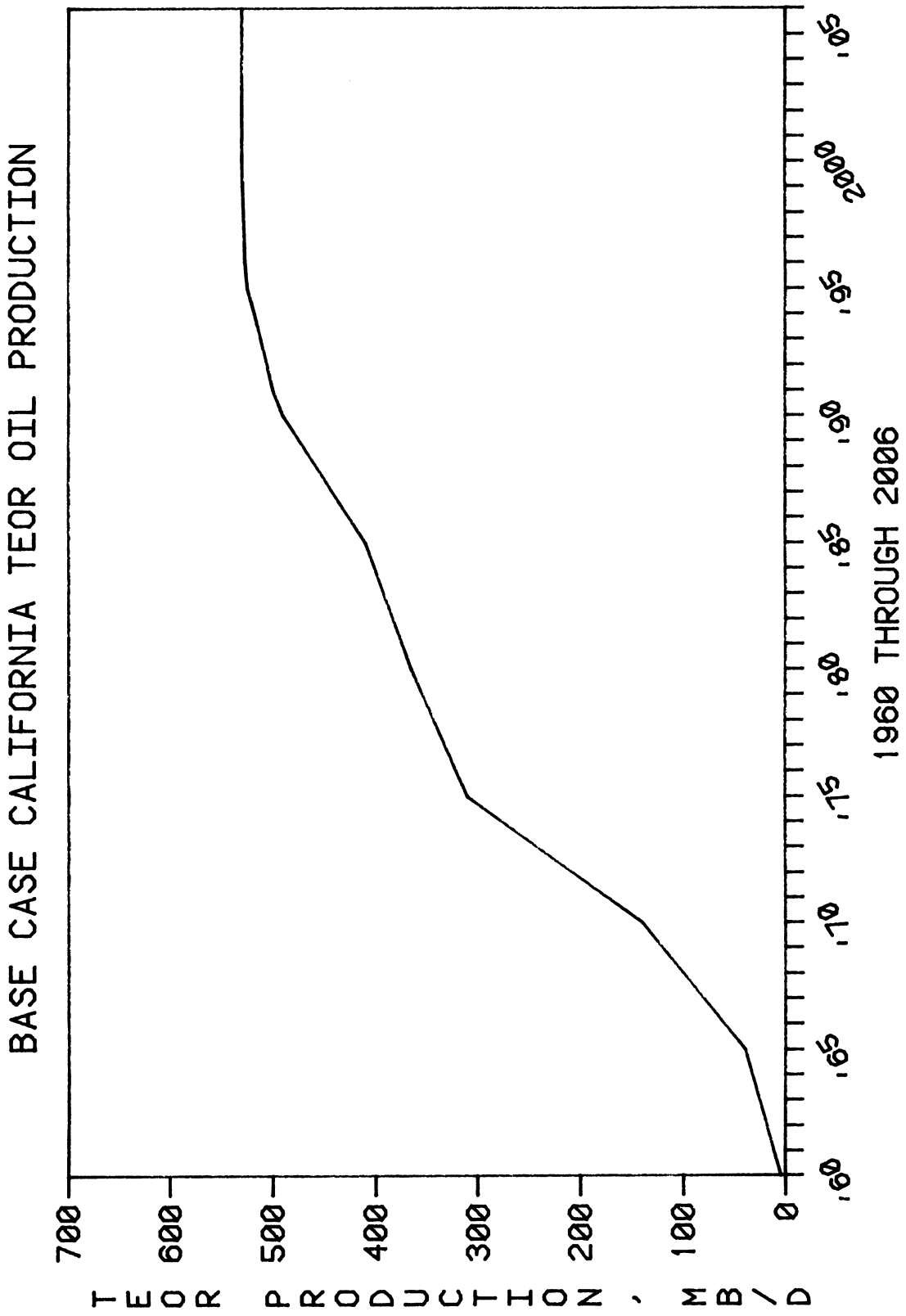
The low price cases attempt to bound the potential impacts of recent price declines on TEOR operations in California. Because the precise impact of changing price expectations on TEOR investment plans is a subtle matter, we have developed sensitivity cases which assume different investment-level reactions in lieu of a model which would express these reactions as a function of recent price data.

It is clear from information available so far that there will be some delays in TEOR development in response to the recent oil price declines. However, as pointed out by Chevron, one of the major TEOR operators, it is really only a question of timing. The heavy oil resources in California will eventually be developed.[2] Trade press accounts indicate that producers are undecided in adjusting their plans in response to recent events.[3]

Considering this uncertainty in the impact of lower prices on producer behavior, we have developed several sensitivity cases to assess the range of possible responses. In each of these cases, a portion of the base-case projects in the initial years is postponed. After a specified time, acreage additions return to base-case levels. The projects postponed from the beginning of the forecast period are effectively delayed until the very end of the planning horizon. This assumed schedule corresponds to a situation where enough capital is available to resume base-case investment levels, but not to "make up" the postponed projects.

Oil production results for five cases are presented in Figure I-3 and Table I-1. Case b is the base-case. Case 1 shows the result of delaying 30 percent of the projects scheduled for 1986 and 1987 in the base case. Case 2 represents postponement of 50 percent of all base-case projects during this same period. Case 3 illustrates the effects of postponing 30 percent of the projects scheduled for 1986-90. Case 4 assumes postponement of 50 percent of the base-case projects over this 5-year period.

FIGURE I-1



Source: California Energy Commission Staff, 1986.

TABLE I-1

TEOR OIL PRODUCTION
(THOUSAND BARRELS DAILY)

Year/Case	Base Case	Case 1	Case 2	Case 3	Case 4
1965	40	40	40	40	40
1986	425	422	413	413	403
1990	490	470	425	410	375
1995	525	520	475	400	360
2000	530	530	530	515	510
2006	530	530	530	530	530

Case Descriptions:

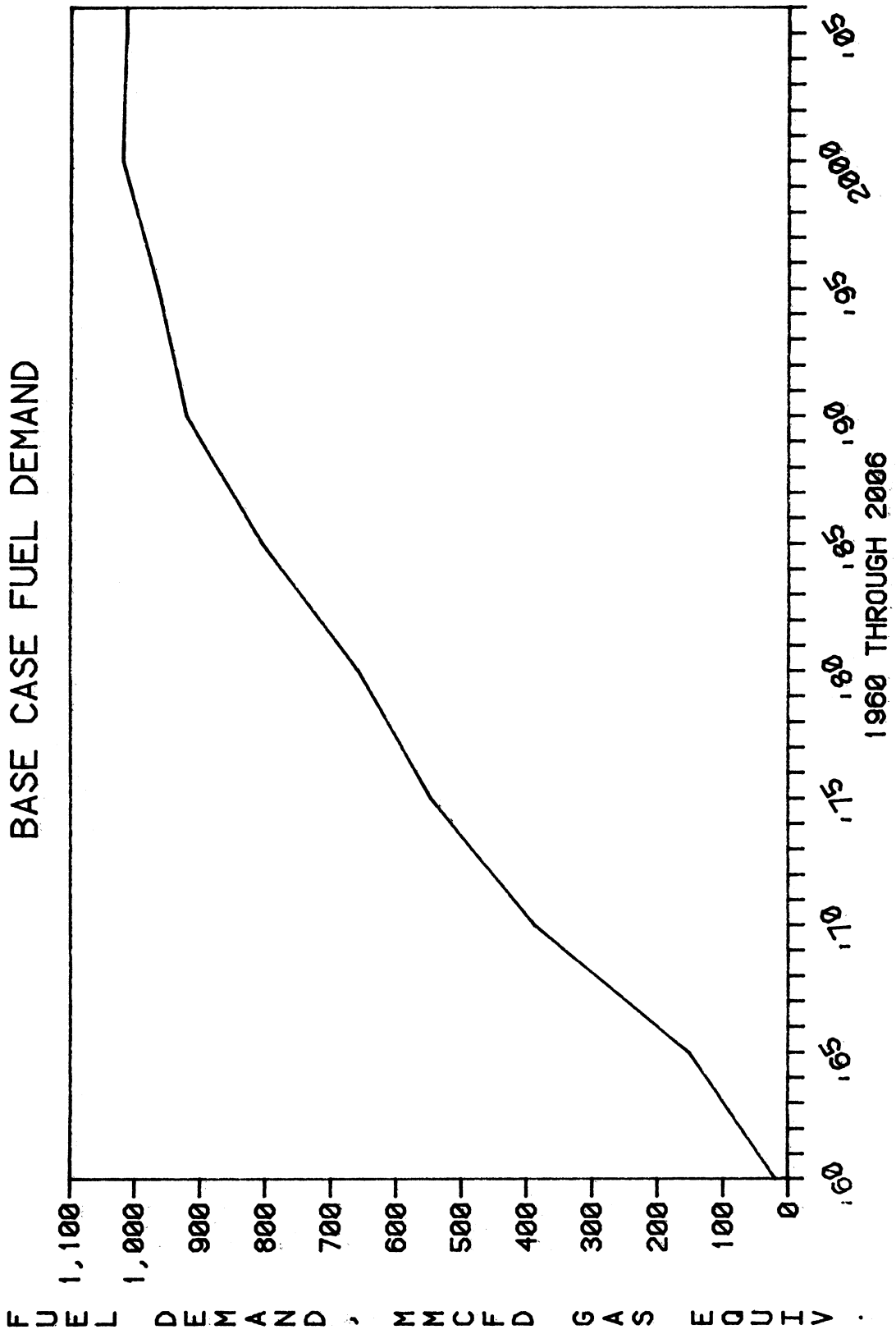
Case 1: 30 percent of the base case projects scheduled for 1986 and 1987 are postponed and not rescheduled during the forecast period.

Case 2: 50 percent of the base-case projects scheduled for 1986 and 1987 are postponed.

Case 3: 30 percent of the base-case projects scheduled for 1986 through 1990 are postponed.

Case 4: 50 percent of the base-case projects scheduled for 1986 through 1990 are postponed.

FIGURE I-2



Source: California Energy Commission Staff, 1986.

TABLE I-2

TEOR FUEL REQUIREMENTS
(MMCFD OF GAS EQUIVALENT)*

Year/Case	Base Case	Case 1	Case 2	Case 3	Case 4
1965	152	152	152	152	152
1985	805	805	805	805	805
1990	920	901	845	770	706
1995	965	930	905	850	775
2000	1020	1015	1015	1000	963
2005	1015	1020	1020	1020	1020

Case Descriptions:

Case 1: 30 percent of the base case projects scheduled for 1986 and 1987 are postponed and not rescheduled during the forecast period.

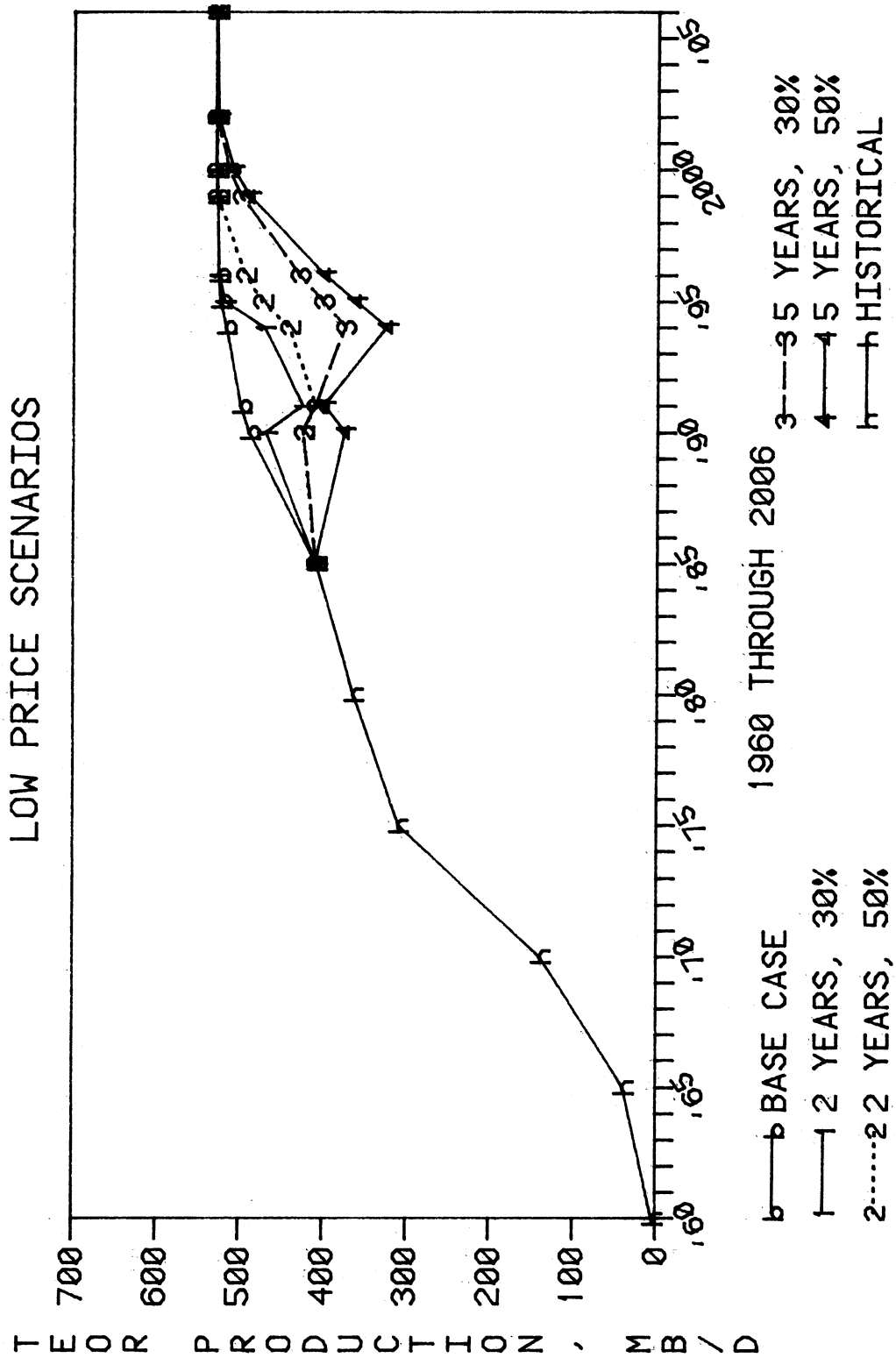
Case 2: 50 percent of the base-case projects scheduled for 1986 and 1987 are postponed.

Case 3: 30 percent of the base-case projects scheduled for 1986 through 1990 are postponed.

Case 4: 50 percent of the base-case projects scheduled for 1986 through 1990 are postponed.

*These fuel requirements represent the total demand for fuel corresponding to the respective scenarios, expressed in MMCFD of gas equivalent and exclusive of any incremental steam demand for TEOR cogeneration applications.

FIGURE I-3



Source: California Energy Commission Staff, 1986.

Even the mildest cutbacks and quickest recovery assumed in Case 1 have a significant impact on California oil production during the late 1980s and early 1990s. By 1991, oil production in this scenario is about 75 mbd less than in the base case. Oil production does not return to base case levels until 1997. The difference in production between 1986 and 1997 are made up only after the end of the forecast horizon, because we assumed that capital availability would prevent investment from exceeding base-case levels. The other three low-price scenarios result in progressively more severe impacts on California heavy oil production. In the most extreme case, TEOR production drops to a low of 325 mbd in 1994, and does not recover to base-case levels until after 2000.

Figure I-4 and Table I-2 show the steam demands which correspond to the base-case and the four low-price cases. In all of the low-price scenarios, the peak demand level of around 1,020 mmcfd is reached near the end of the century. However, the assumed development schedule has a significant impact on the demand for fuel between now and 1995. In the most severe cutback case, demand in 1995 is reduced to 775 mmcfd compared to 965 mmcfd in the base case.

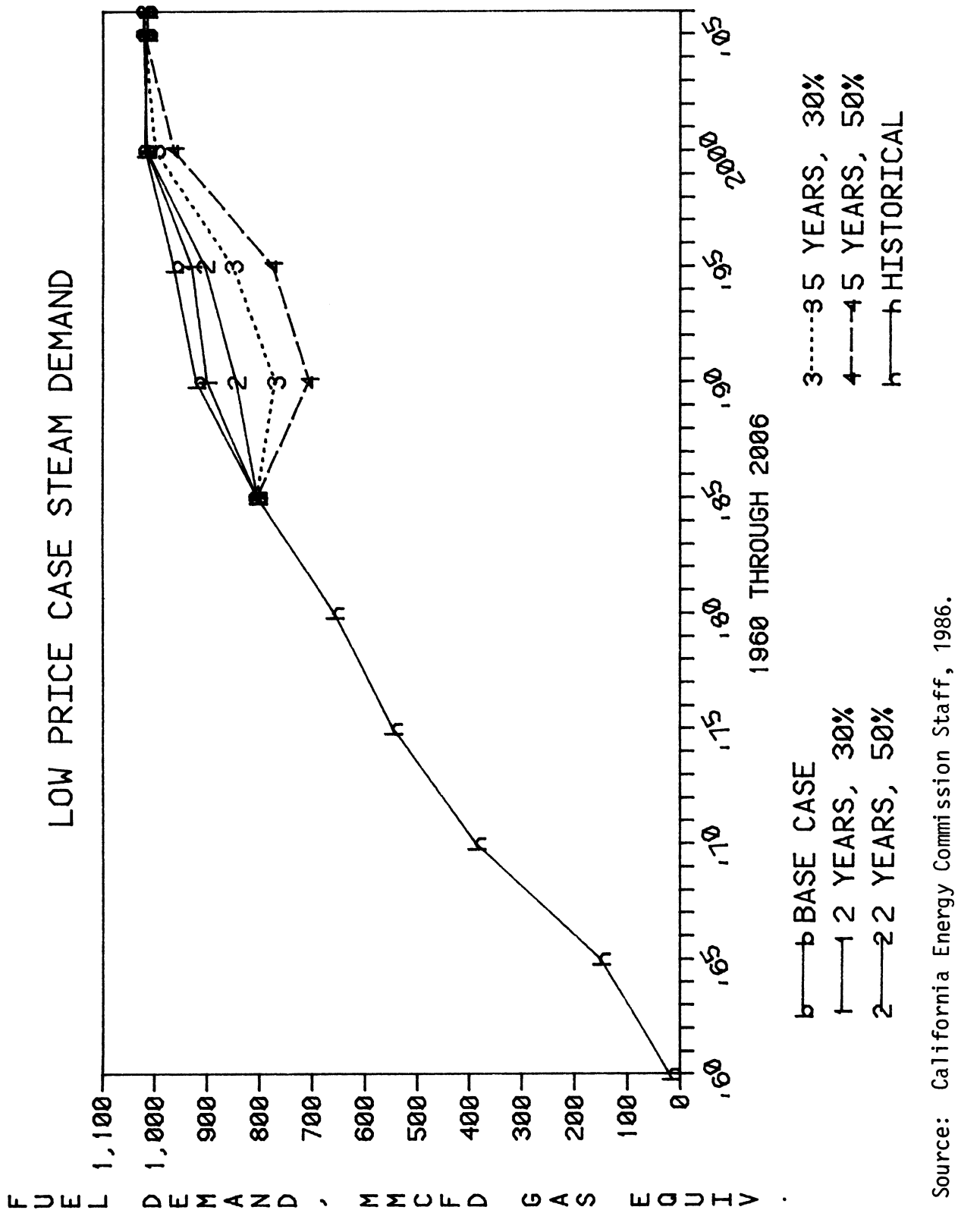
Key Assumptions Which Influence The Forecast

This forecast depends on two distinct kinds of parameters. The first type of data describes the characteristics of California's heavy oil resource base. This resource base consists of a number of pools, each of which is described by parameters such as acreage, pay zone thickness, and residual oil saturation. A second major determinant of the future of TEOR oil production is the way that this resource base is developed. This development is described in terms of the number of acres added to TEOR projects each year. The following discussion focuses on the sensitivity of the forecast to the values of these parameters.

The physical description of the resource base used for this projection has been assembled from diverse sources.[4] The resulting data base describes California heavy oil steam recovery projects on a pool-by-pool basis. Some of the data needed were inevitably not available for some of the pools. In some cases, estimates were used. Typically, the average value over all the other pools was used to fill in missing values for less sensitive parameters such as steam quality and porosity.[5]

One parameter which was particularly problematical was residual oil saturation. This parameter describes the amount of oil which will remain in the formation at the end of the recovery process. The value of this parameter always represents an estimate, since it cannot be known until the end of the project. Laboratory procedures can be used to develop estimates of residual oil saturation, but these estimates are only available for some of the pools. For pools where an estimate was not available we used the average over all the pools for which data was available. The amount of oil ultimately recovered from any given pool depends critically on the value assumed for residual oil saturation. The time profile of production also depends strongly on the value of this parameter.

FIGURE I-4



Source: California Energy Commission Staff, 1986.

Even though the CEC's data base is disaggregated down to the pool level, it still masks some variations in characteristics which may occur within a given pool. We have had to assume that some parameters like porosity were homogeneous within each pool. Variations in these values might affect the projected outcome, but we do not have a good way to assess the impact of such variations.

Forecasting the development behavior of the operators of California heavy oil fields poses additional problems. The first problem is deciding at what point each project will be abandoned as its production declines. We have developed rules of thumb for this decision which attempt to capture some of the gross features of the financial and technical realities which govern this decision in practice. However, the aggregate production profile is not particularly sensitive to the criterion used.

Another aspect of the operators' development strategy, however, poses a more difficult problem. The forecast production profile is relatively sensitive to the rate at which new projects are brought into production. The amount of capital committed to new projects depends on many unknowns, such as the financial condition of the operating companies and the availability of alternative petroleum investments which might be more attractive. The irresolvable uncertainty in this aspect of TEOR development provides additional motivation for the five scenarios representing different strategies, to illustrate a range of possible outcomes.

We also lack data on the rate of steam injection for each project. Our forecast assumes an injection rate of 0.8 bbls/acre-ft/day throughout the life of the project. This value is an estimate of the current average injection rate for TEOR projects. In practice, injection rates are higher in the beginning of a TEOR project and lower in the later years. Although this simplifying assumption will affect the production profile for a given field, the aggregate production profile is not as sensitive to this input, because there is a relatively even distribution of vintages of projects at any given time.

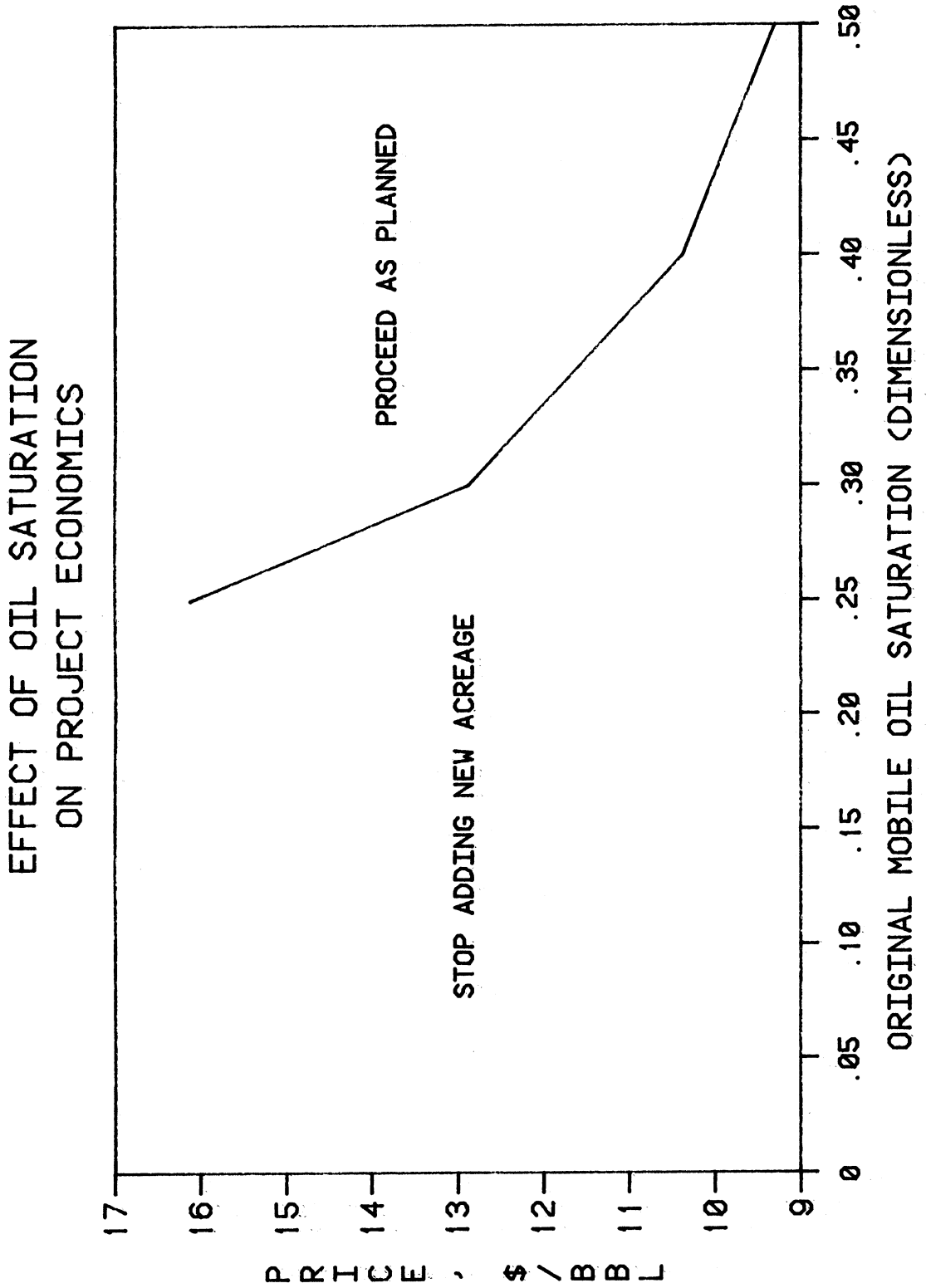
Impact of Oil Prices on TEOR Economics

Although it is difficult to forecast producer behavior precisely, for the reasons discussed above, CEC has used a simple model of the economics of TEOR operations to provide some information about what oil price scenarios make TEOR unattractive from a simple project-economics viewpoint.

The economic model uses a simplified version of the production forecast methodology described in Attachment A, together with economic data and price assumptions to calculate the net present value (NPV) of a TEOR project. The NPV is calculated on the basis of after-tax cash flow. As a starting point, we assume that only projects with positive NPV will be undertaken, and that negative-NPV projects will be postponed or cancelled.

Figure I-5 illustrates the range of prices at which TEOR projects become uneconomic by this criterion if the price of oil is assumed to remain constant in real terms throughout the 10-15 year life of the project. If oil prices increase during the life of the project, the initial price can be lower than that shown in Figure I-5. The cutoff point is plotted as a function of the initial mobile oil saturation, with other reservoir parameters held at nominal values. The cutoff point is defined as the price below which no new project acreage will be added, even where existing steam generator capacity is available.[6] Figure I-5 shows that for a project whose initial mobile oil saturation is 0.25, the cutoff oil price is around $16/bbl. A project with an initial saturation of 0.5, however, is economic at any oil price greater than $9.30/bbl.

FIGURE I-5



Source: California Energy Commission Staff, 1986.

Attachment I-A
Oil Production Methodology

Algorithm Description

This TEOR oil production forecast is produced by taking data describing individual pools of oil, forecasting the production for each pool, and summing over all pools. Its contribution lies in applying known methods to a newly-developed California heavy oil data base, disaggregated to the pool level.

Figure I-A-1 shows the three basic steps in the calculations for developing a forecast. The first step is to set up the scenario which describes how new TEOR projects are added over time. For each pool, the total acreage is divided into projects, which are started at different times. Within a pool, all projects are assumed to have the same basic reservoir characteristics, including porosity, net pay, initial and residual oil saturation. Projects are also assumed to be developed in the same way (e.g., using the same steam injection rate). Consequently, all projects in a given field will have identical production profiles, shifted progressively back in time.[7]

The total number of acres of projects added in each year is the key parameter distinguishing the five development scenarios described above. In the base case, projects are scheduled so that the number of acres added per year is roughly consistent with plans of some of the large operators as of early 1986. The sensitivity cases represent downward deviations from this trend.

The second phase of the calculations computes the production profile for each project. The analysis of a given project is detailed below. The third step simply sums the production from all projects to get total annual production, the model's basic output. Fuel use from all projects is also summed.

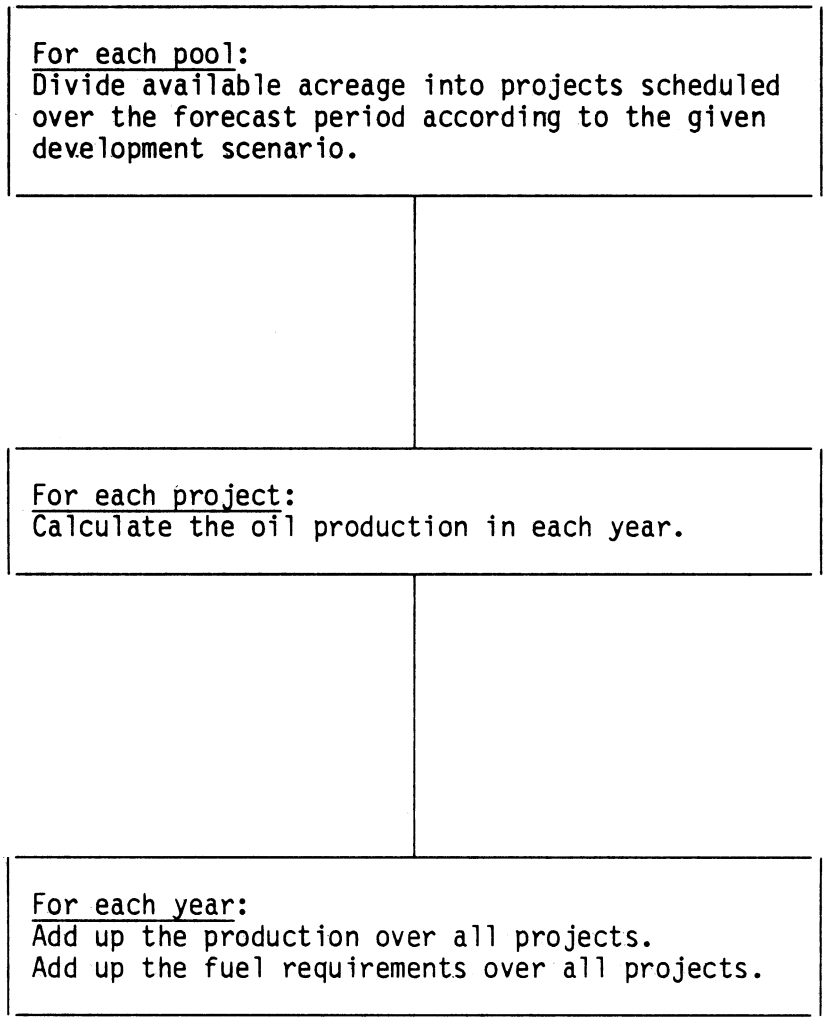
Projection for a Given Project

The projection for each pool is based on the correlations provided by Gomaa.[8] This paper gives a set of equations which can be used to predict oil recovery as a function of reservoir parameters, steam injected, and other factors.

Gomaa's paper represents the state of the art in the simplified modeling of steam flooding projects. In a steam flood operation, steam is injected continuously into one well, while nearby wells are used to recover the oil displaced by the steam.

In actual practice, another approach called steam cyclic, or "huff and puff" is also used. In this method, the same well is used alternately for steam injection and then for production. Although we are not aware of a model applicable to steam cyclic operation, this does not seem to be a serious problem. The most common practice is to begin a project with steam cyclic operation for an initial period, and then to convert to a steamflood mode. In the long run, then, projects tend to converge to the steamflood model. Using

FIGURE I-A-1: OUTLINE OF THE TEOR FORECASTING METHOD



Gomaa's basic steamflood model to describe the history of a project like that described above will only distort the time profile at the very beginning of the project, when production rates are quite low. Total recovery will be the same for steamflood and steam cyclic operations.

A production profile for a given project is calculated as follows:

1. A "heat utilization factor" is calculated as a function of the input steam quality. This factor gives the effective heat input as a fraction of the total heat input into the reservoir. This factor is computed from a graph supplied in the Gomaa paper. (Reference 8, Figure 12.)

2. The heat loss to the overlying and underlying rock is computed using a table derived from Gomaa. (Reference 8, Figure 13.)

3. The cumulative effective heat injected through the current year is calculated as follows:

$$Q_e = y \times 0.128 \times \sum_{t=1}^{T} [I_g \; h \; (1-VHL)]_t$$

Where

Q_e is the effective heat input, in MMBTU/gross acre-foot,
y is the heat utilization factor,
I_g is the injection rate in bbl/day per gross acre-foot,
h is the enthalpy of the input steam in BTU/lb, and
VHL is the heat loss to the underlying and overlying rock (See Reference 8 equations 2 and 3).
T is the index of the current year, and
t is the running time index.

4. The cumulative recovery percentage is obtained from a table derived from Gomaa, (Figure 14), as a function of initial mobile oil saturation and cumulative heat input.

5. The mobile oil is calculated using

$$M = 7758 \; S_{om} \; P \; N \; A$$

Where

M is the mobile oil in barrels,
S_{om} is the mobile oil saturation,
P is the average porosity of the pool,
N is the net pay in feet, and
A is the acreage,
The constant 7758 converts from volume units of acre-feet to barrels.

6. Cumulative oil recovered in barrels is found as the product of cumulative recovery percentage and original mobile oil.

7. The difference between cumulative oil recovered this year and last year becomes the production figure for this year.

8. Fuel use is computed by dividing the input Btus by an assumed average boiler efficiency of 0.8 and converting to mmcfd of gas equivalent.

9. A check is made to see if the economic limit has been reached for this project. We have used a minimum ratio of oil produced to fuel required as a proxy for a more detailed economic decision process. If the (proxy) economic limit has been reached, the project is abandoned. Otherwise, the calculations are repeated until the economic limit is reached or until the end of the projection horizon.

Attachment I-B
Economic Simulation Methodology

The Economics Model is implemented using 20/20 spreadsheet software, laid out as in Figure I-B-1.

The top half of the model is a simplified version of the production methodology described in Attachment I-A. The physical characteristics of the reservoir are located in the upper left: injection rate, project size (acres), thickness, mobile oil saturation, and porosity. The next few lines go through the calculations described in Attachment I-A resulting in a production forecast for this particular reservoir in thousands of barrels per year. (Except as noted all figures in this spreadsheet are in thousands.)

The production forecast feeds into the economics section, which appears on the bottom half of the spreadsheet. Its inputs are the discount rate, initial price, price growth rate, inflation rate, and action of initial investment which is allocated to intangible drilling costs. There is also an input for evaluating the project with and without the capital charge for steam generation equipment.

The economic simulation is all done in real terms. Accordingly, the initial price is adjusted by the nominal growth rate and inflation rate to compute the real dollar price in each year. Gross revenue is computed as the product of annual production and oil price.

If a project requiring a new steam generator is to be evaluated, as in the example, the capital investment is computed as a function of the required heat input rate. A 5 mmBtu/hr steam generator is assumed to cost $850,000 and the fraction of this capacity needed for this project is charged as investment in the first year. (That is, steam generators are assumed to be kept operating at 100 percent capacity utilization.) Operating cost and G&A are charged at a rate of $6.50 per barrel of oil recovered. Steam cost is simply the barrels of fuel required multiplied by the real price of oil. (For economic purposes it is assumed that leasehold crude is used as fuel. If natural gas costs the same as oil per million Btu, using natural gas would improve the project economics because a scrubber would not be required on the steam generator, reducing both capital and operating costs.) Before tax cash flow (BTCF) is gross revenue minus investment minus operating cost minus steam cost.

It is assumed that the property in question is leased and that 12.5 percent royalties are payable on all oil which leaves the leasehold (i.e. fuel barrels incur no royalty obligation). Thus the economics of a TEOR property which is owned fee-simple are more favorable than these shown here.

The investment cost is split into intangible drilling costs and capitalized investment. For the cases run here, it is assumed that 60 percent of the required investment becomes intangible drilling costs, and is expensed in the first year. The remainder is depreciated over five years using cross-over depreciation. Percentage depletion has been ignored here, as it only applies

TEOR ECONOMICS MODEL
21 FEB 1986
D. KLINE

PRODUCTION MODEL -- INPUTS

INJECTION RATE	0.7880	BBL/ACRE-FT/DAY	DECREASE RATE	0.75
PROJECT SIZE	5	ACRES		
THICKNESS	150	FEET		
MOBIL OIL SAT.	0.40	AVG POROSITY	0.30	
ORIG. MOBILE OIL	698	THOUSAND BARRELS		

BBLS STEAM	216	216	216	216	216	216	216	162	121	91	68	51	38	29	22
BBLS FUEL	14.4	14.4	14.4	14.4	14.4	14.4	14.4	10.8	8.1	6.1	4.6	3.4	2.6	1.9	1.4
MMBTU/AF/D	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.21	0.16	0.12	0.09	0.07	0.05	0.04	0.03
1-VHL	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.75	0.74	0.73	0.72	0.71	0.71	0.70	0.70
EFFECTIVE CUM HEAT INPUT	64	128	192	256	320	384	449	511	572	632	691	750	808	866	923
CUM PCT RECVRD	0.004	0.036	0.115	0.226	0.342	0.457	0.548	0.624	0.676	0.717	0.750	0.774	0.795	0.804	0.813
BBLS/YEAR	3	22	55	78	81	81	64	53	36	29	23	17	14	6	6
BPD	0.01	0.06	0.15	0.21	0.22	0.22	0.17	0.15	0.10	0.08	0.06	0.05	0.04	0.02	0.02
OIL/FUEL RATIO	0.20	1.55	3.84	5.39	5.60	5.60	4.42	4.93	4.47	4.77	5.00	4.91	5.61	3.33	4.43

ECONOMICS MODEL -- INPUTS

PRESENT VALUE
299

DISCOUNT RATE	0.15	INVESTMENT	YES
PRICE	15.00		
NOMINAL PRICE GR	0.000		
INFLATION RATE	0.000		
IDC =	0.600	* INVESTMENT	

YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PRODUCTION, B/D	8	61	151	212	221	221	174	146	99	79	62	46	39	18	17
PRODUCTION, MB/Y	3	22	55	78	81	81	64	53	36	29	23	17	14	6	6
REAL PRICE	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00
GROSS REVENUE	44	334	829	1,163	1,208	1,208	954	797	543	434	341	251	215	96	96
INVESTMENT	(126)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OP COST + G&A	(19)	(145)	(359)	(504)	(523)	(523)	(413)	(345)	(235)	(188)	(148)	(109)	(93)	(42)	(41)
STEAM COST	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(162)	(121)	(91)	(68)	(51)	(38)	(29)	(22)
BTCF	(316)	(26)	254	443	469	469	325	290	186	155	125	91	84	26	33
ROYALTIES	(21)	15	77	118	124	124	92	79	53	43	34	25	22	8	9
DEPR	(20)	(12)	(7)	(5)	(5)	0	0	0	0	0	0	0	0	0	0
INT DRILL COST	(75)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PCT DEPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAXABLE INCOME	(265)	(53)	170	320	339	345	233	211	134	112	91	66	62	17	23
ITC	(8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCOME TAX	(143)	(27)	87	163	173	176	119	107	68	57	46	34	31	9	12
ATCF	(152)	(14)	91	162	172	169	114	103	65	55	45	32	30	8	11
PRESENT VALUE	299														

FIGURE I-B-1

to small independent operators. Finally taxable income, investment tax credit, and income tax are calculated. After tax cash flow (ATCF) is before tax cash flow minus royalties minus income tax. The present value of the project is the present value of the after tax cash flow.

Appendix I - Footnotes

1. See Table N-14.

2. Quait, A.B., (Chevron U.S.A., Inc.), letter to Commissioner Arturo Gandara, Docketed in California Energy Commission Docket 85-BFR-1, (Received May 22, 1986).

3. Hagar, R., and B. Williams, "Transmission Systems Set Sights on Rising Gas Markets in the U.S.," Oil and Gas Journal (June 16, 1986).

4. We have used California Department of Conservation, Division of Oil and Gas, 70th Annual Report of the State Oil and Gas Supervisor, (1984), as well as Oil and Gas Journal, "Annual Production Report," April 1986, and Conservation Committee of California Oil Producers, 1983 Annual Review of California Oil and Gas Production (1984).

5. Porosity is a measure of the space between rock particles which is potentially filled with oil, expressed as a fraction of the volume of the oil-bearing formation.

6. When spare steam generator capacity is available, the capital in place is regarded as "sunk," and the economics of the project does not incur a charge for building the generator. The project must still clear a hurdle, however, because TEOR oil production does not begin until two to three years after steaming is initiated. The cost of the steam injected in the first few years must be recovered (at the assumed discount rate) in order for the project to have a positive NPV.

7. The production profiles within a pool will be identical if expressed in units of production rate per acre. Projects may be different sizes (acres) in different years.

8. Gomaa, E., "Correlations for Predicting Oil Recovery by Steam Flood," Journal of Petroleum Technology, (February, 1980).

APPENDIX J

ALTERNATIVE FUELS

METHANOL FUEL FOR TRANSPORTATION
INTRODUCTION

If an alternative to petroleum fuels is to be introduced on a significant basis in California within the next 20 years, the chances are high that the fuel will be methanol. Since 1979, the California Energy Commission (CEC), with heavy cooperative involvement of the automobile and fuel industries, has conducted extensive studies and demonstrations of methanol--the simplest and least expensive alcohol--as a motor fuel replacement for gasoline and distillate fuels. The results of these efforts, and other complementary work with methanol elsewhere in the U.S. and the world, confirms the readiness of this fuel for use in transportation and provides the necessary confidence to explore strategies for its introduction.

The CEC has declared its preference for methanol and its desire to see this fuel become commercially viable as a petroleum substitute. CEC's selection of methanol for continued development is based on methanol's extensive supply potential from U.S. coal resources and excess world natural gas supplies, together with its air quality benefits and its adaptability to existing motor fuel applications. Many other public and private organizations at the state and federal levels are likewise pursuing methanol as the most effective and readily-available alternative fuel. Air quality agencies, in particular, are actively investigating methanol implementation as an air quality improvement strategy, since major air quality benefits have been demonstrated for this fuel.

Despite the growing recognition and acceptance of methanol as the best new source of fuel for the U.S., many uncertainties remain about how-- and when-- this fuel might actually achieve widespread application. Much of this uncertainty stems from economic considerations, since today's petroleum Prices do not provide sufficient advantage for new investment in methanol supply and use. However, a number of potential developments can be envisioned which could stimulate methanol's introduction as a transportation fuel. These include developments affecting the price and supply of both methanol and petroleum fuels and various initiatives by government and industry to advance methanol use in the name of energy security and environmental quality.

PROGRESS IN THE TRANSPORTATION USE OF METHANOL

California's cooperative program within industry, complemented by activities elsewhere in the U.S. and in foreign countries, has shown the effectiveness of methanol as a fuel and resolved technical obstacles to its application.

Following successful fleet tests of different methanol-fueled makes and models of automobiles, CEC undertook an ongoing extensive fleet test of over 500 methanol Ford Escorts operated by state and local government agencies in fleets throughout the state. The fleet is served by a growing network of methanol fueling stations, currently numbering eighteen sites. After two years in operation, this fleet is providing highly reliable service, comparable in virtually all respects to gasoline vehicle service except for

limitations of refueling range and station sites. In combination with the test fleets, the total mileage acquired with methanol vehicles in the state's program now exceeds ten million miles. Other private sector fleets--including a large program being conducted by Bank of America--have also contributed to the extensive body of experience with methanol as an automotive fuel. The results have established sufficient confidence on the part of the U.S. auto industry to allow marketing of methanol vehicles in large numbers as soon as the demand exists. Conversion of existing automobiles--the method applied by Bank of America--is also considered an available means of providing methanol-fueled vehicles.

Testing and demonstration is also continuing with heavy-duty (diesel engine) vehicles. Two methanol-fueled buses built by General Motors and by a West German company, M.A.N., are in routine daily transit service in the Golden Gate Transit District in a CEC-sponsored demonstration. Over 50,000 miles of closely-monitored operation to date shows these vehicles to be acceptable replacements for conventional diesel buses. Another heavy-duty vehicle demonstration is underway at the University of California, Chico, where a methanol-fueled farm tractor built by Komatsu of Japan has been successfully operated for over a year.

CONTINUING METHANOL DEVELOPMENT ACTIVITIES

The 1985 Biennial Report directs that CEC's methanol fuel demonstration programs be carried forward to completion, indicating that the state's active involvement in vehicle testing will conclude when the current 500 vehicle automobile fleet and the transit bus demonstration end in 1988. Two additional projects have been under consideration, but are not presently authorized. They include a test of high-performance methanol police vehicles in the California Highway Patrol fleet and a methanol heavy-duty truck test in conjunction with the California trucking industry.

Even though falling petroleum prices have had a definite effect on the general priority and sense of urgency attached to alternative fuels development in the U.S., there are indications that interest in methanol introduction is sustaining. At the federal level, both Congress and the Administration have, during the last two years, initiated steps to encourage the use of methanol. The main results have been an equalization of the federal highway fuel tax to place methanol on an equal energy basis with gasoline and a methanol vehicle fleet program currently being implemented by federal agencies. Also, emission standards for methanol vehicles are under development by EPA. Legislation currently before Congress would grant auto companies a credit for methanol vehicles under federal fuel economy regulations.[1]

Other countries, including Japan and West Germany, are also pursuing alternative fuel strategies involving methanol. Japan has followed California's experience closely and has announced a national plan to undertake a large-scale conversion of fleets to methanol. West Germany has investigated

1. S. 1097 (Danforth), 1985.

methanol for many years and is currently pursuing a program of widespread methanol blending with gasoline.

In the U.S., methanol/gasoline blending is also the subject of much current interest, partly due to the ongoing federal regulatory phase-out of leaded gasoline. Methanol and ethanol are both recognized as effective replacements for lead as an octane enhancer. However, methanol's acceptance as a blending component under federal and state air quality regulations has been slower than that of ethanol.

Interest in heavy-duty vehicle applications of methanol is also growing. Transit districts in Seattle and in Florida have undertaken projects to demonstrate methanol buses. Other districts, including the Southern California Rapid Transit District are also studying possibilities for acquiring methanol buses with funding assistance from the federal Urban Mass Transportation Administration.

COST OF METHANOL VS. PETROLEUM FUELS

Methanol--historically a chemical market commodity--is barely beginning its entry into the world fuels market. A large surplus of methanol production capacity has resulted from lower than expected demands for chemical uses and the anticipation of fuel demands which have been slow to materialize. With recent expansions, world methanol capacity has grown to seven billion gallons per year, representing more than a one billion gallon per year surplus over current demand levels. The price of methanol, reflecting this surplus, has remained at or near $0.45 per gallon (f.o.b. the U.S. Gulf Coast) for the past several years.

During the next five years, additional planned capacity could further increase the methanol surplus. This prospect, coupled with low petroleum prices, creates an outlook for continued availability of methanol at the prevailing price through 1990. A billion gallons per year or more of surplus methanol is estimated to be available to the California fuel market at a cost of $0.40 (± $0.05), delivered via tanker to California ports. Possible sources of this supply include Canada, Mexico, South America, Malaysia, and New Zealand, all of which have existing or under construction methanol production using nonconventional natural gas resources--i.e., gas that is not economically marketable via pipeline.

Beyond 1990, continued growth of a California and U.S. market for methanol fuel will require further expansion of world methanol production capability and prices adequate to justify investment in new capacity. Excess natural gas in various parts of the world is expected to continue to be the most economical feedstock for methanol production for most of the remainder of the century. Therefore, methanol price projections for this period center around the cost of new supply from such sources. Fortunately, the well-established production technology allows for accurate estimation of production costs, although financing provisions, taxation, return on investment, and other assumptions contribute to some variation among individual estimates. A recent assessment places the price of new methanol at $0.55-0.65 (1985 $), f.o.b. California, based on available low-cost ($0.50-2.00 per million Btu) gas

sources.[2] The same study also estimates that as much as 80 billion gallons of methanol per year could be made available from such sources.

In the longer term, the most advantageous source of methanol to sustain a large-volume fuel supply has, for some time, been recognized to be U.S. coal resources. While continued natural gas discoveries and lower-than-expected petroleum prices may have pushed back the timetable for this option, methanol from coal remains an available strategy for domestic fuel supply. Only one existing plant produces methanol from coal in the U.S.--a small facility operated by Tennessee Eastman Company which began operation in 1983. However, the combination of coal gasification and methanol synthesis processes comprising coal-to-methanol plant designs represents established technology and permits reasonably confident projections of process effectiveness and production cost. An estimate of $0.80-0.95 per gallon (1985 $) appears to adequately account for the variables affecting the delivered price of fuel to California from a coal-to-methanol project in the Western U.S.[3] The quantity of methanol available from the nation's vast coal resources is estimated to represent 250 to 500 years of equivalent gasoline supply.

Based on the cost estimates discussed above, Table J-1 shows the projected price of methanol fuel compared with forecasted gasoline prices (in 1983 dollars). These methanol prices assume that a large enough fuel market develops to permit large-volume shipment to California by 1990. The 1997 estimate is the midpoint of the cost range reported above for methanol from natural gas. The 2005 estimate is the midpoint of the cost range for methanol from coal.

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2. Stokes, C. A., The Near- and Long-Term Methanol Supply and Price Outlook and Suggested Supply-Inducing Strategies for California, consultant report to CEC, August 20, 1985.

3. Jackson, R. J., An Analysis of the Potential for Coal-Based Plants to Produce Methanol for California, consultant report to CEC, September 23, 1985.

TABLE J-1

METHANOL VS. GASOLINE PRICE PROJECTIONS
Retail Excluding Taxes
(1983 dollars)

	Methanol			Gasoline	
Year	M100	M85[1]	M85 Gasoline Equivalent[2]	Regular Unleaded	Premium Unleaded
1990	0.47	0.54	0.86	0.83	0.95
1997	0.66	0.73	1.02	0.95	1.10
2005	0.84	0.92	1.29	1.16	1.34

[1]85% methanol, 15% premium unleaded gasoline

[2]Based on a 10% energy efficiency advantage with methanol engines for 1990 and a 20% advantage for 1997 and 2005.

The price comparison in Table J-1 indicates that the price of methanol is likely to remain slightly higher than that of gasoline on an equivalent basis given the prevailing petroleum price forecast. Methanol is expected to gain a distinct price advantage over premium unleaded gasoline. With higher than forecasted petroleum prices, methanol could become significantly less expensive than either regular or premium unleaded gasoline, although competition in the marketplace might be expected to result in pricing closer to equivalent value. One factor not accounted for in this comparison is the potential cost effect of new distribution facilities for methanol. However, pricing margins should include enough latitude to account for the required investment.

The assumed efficiency of methanol use in automobile engines has a significant effect on comparisons of methanol versus gasoline cost. Although it has only about half the energy content of most gasoline, methanol has demonstrated an efficiency advantage that allows it to make up part of this difference. Efficiency levels for methanol engines representing a 10 percent energy advantage over gasoline engines in 1990 and a 20 percent advantage thereafter are reflected in the comparative cost projections presented in Table J-1.

These efficiency levels are based on auto industry estimates of anticipated results of continued methanol engine development.[4,5]

SOURCES OF METHANOL SUPPLY

An important factor in the choice of methanol is the extent of supply options available. The original inception for CEC's focus on methanol involved a determination of the best use of the nation's extensive coal resources.[6] Methanol continues to be both the cleanest and most economical liquid fuel producible from coal. And coal continues to be seen as the ultimate long-term source of methanol, providing assurance that the country could--if the need arises--become virtually self-reliant for its fuel supply. One plant is currently in operation producing methanol from coal, an Eastman Kodak Company plant in Tennessee. A large-scale coal-to-methanol project has reached the advanced planning and permitting stages, the Dunn-Nokota Methanol Project in North Dakota. This project is awaiting a positive sign of a developing fuel methanol market before beginning construction. Other major companies with large coal holdings, including Conoco and Koppers, have also studied the possibility of producing fuel methanol if a market develops.

The most likely sources of coal-based methanol for California would be the Western United States--particularly Montana, Wyoming, Colorado, Utah, North

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4. Bruce Simpson, Ford Motor Company, testimony at BR V Hearing, April 10, 1985.

5. GM's viewpoint on Alternative Fuels, A.J. Sobey, presentation at Joint U.S./Canadian Meeting on Alternative Fuels, June 25-26, 1985.

6. Clean Coal Fuels, Alternate Fuel Strategies for Stationary and Mobile Engines, Acurex Corporation, report to CEC, July 1981.

Dakota and New Mexico--and Alaska. Strippable reserves of western subbituminous coal (a low grade coal) are considered sufficient for virtually centuries of methanol supply, even if high demand prevails. Replacing all U.S. gasoline demand with coal-based methanol would roughly double the current use of coal in the country.

Technology for producing methanol from coal is commercially available as a combination of coal gasification units, available from several companies, including Texaco and Lurgi, and methanol synthesis units, also available from several suppliers. The Texaco coal gasification process is currency in use at the Coolwater Project in California, while the Lurgi gasifier is used in the Great Plains project in North Dakota, the SASOL Project in South Africa and other projects.

A major transition to methanol would not abruptly result in a large-scale coal-to-methanol industry. Low cost natural gas in areas not served by collection pipelines are seen as the near-term sources of methanol production, with coal-based methanol development following as the cheapest natural gas sources are utilized. Many areas of the world are considered to be likely sources of methanol production from natural gas. Currently, methanol is produced in the U.S., Canada, South American and European Countries, Asian and Middle East countries and the Soviet Union. With an expanded market, new production would also be expected in Alaska, Mexico, Australia and other countries. An advantage of methanol production from remote gas resources is the availability of modular technology that is efficient to transport and assemble, reducing both costs and lead times.

Other sources of methanol including sources within California, are also under investigation, with a real possibility that an in-state methanol industry could be developed to partially supply future demands for this fuel in the state. Of particular current interest is natural gas liquids produced in association with offshore coastal oil recovery. The possibility of modular package plants producing low-cost methanol from these sources in areas such as Santa Barbara County is being actively examined by several companies.

Other miscellaneous feedstocks, including residual products from petroleum refining and various biomass resources, could also some day contribute to the state's methanol supply. For example, the City of San Diego has completed a feasibility study showing that a portion of its sewage treatment process waste gas could provide a source of methanol sufficient to fuel the city's entire municipal fleet of gasoline vehicles.

AVAILABILITY OF METHANOL VEHICLES

No domestic or foreign automobile maker currently markets a vehicle designed to operate on a high percentage of methanol. However, two companies--Ford and Volkswagen--have built limited numbers of methanol models on production lines in the U.S. primarily for use in CEC's demonstration programs. Additionally, Ford, General Motors, and several foreign automobile makers operating in Brazil have, within the last five years, changed over virtually their entire production of vehicles in that country to ethanol models, responding to a national ethanol movement enacted there. These examples, along with

consistent statements by the automobile industry that methanol models will be produced when the demand develops, provide evidence to support a reasonable timetable for methanol vehicle introduction.

An important new development is the emergence of technology for vehicles capable of running on either methanol or gasoline (or any combination of the two). Ford is close to releasing a limited number of such vehicles for initial demonstration. Such technology represents a major breakthrough for a transition to methanol, since it offers a solution to the problem of limited availability of methanol fueling sites in the early years of methanol introduction. In addition, it now becomes possible to think of a standardized automotive technology capable of accepting both fuels, eliminating the need for the vehicle purchaser to choose between a gasoline model or a methanol model. Thus, the automotive fleet could gradually become methanol-compatible through the phase-in of "flexible fuel vehicles."

The development of methanol-fueled heavy-duty vehicles is also taking place, although on a slower timetable than gasoline automobiles. One manufacturer, M.A.N. Truck and Bus Corporation of West Germany, now offers a methanol-fueled transit bus after several years of commercial development. General Motors also has put forth considerable effort in developing a methanol/diesel engine currently being used in a CEC-sponsored transit bus demonstration along with a M.A.N. bus. This test, and other demonstrations being conducted elsewhere, are advancing the commercial availability of methanol-fueled buses and trucks.

BLENDING OF METHANOL WITH GASOLINE

A unique advantage of alcohol fuels is their ability to be directly mixed into the existing gasoline supply. This has been done at a significant level with ethanol for a number of years and more recently with methanol on a smaller scale, both in the U.S. and abroad.

Most applications of methanol for fuel are expected to use some fraction of a petroleum fuel for a variety of technical and safety reasons. Fuel formulations consisting of a high methanol fraction (i.e., more than 5 to 15 percent) require vehicles equipped specifically to handle such fuels. However, up to about the 10 percent level, methanol can be used directly as a gasoline supplement in existing automobiles. Many methanol industry analysts view this practice as the simplest and most cost-effective means of beginning the introduction of methanol fuel into the U.S. transportation system. Several major companies--most notably ARCO--are already involved in methanol/gasoline blend marketing, and industry exploration of this use of methanol for octane enhancement has intensified with EPA's announced schedule for removing lead from gasoline. However, the future prospects for expanding this practice remain uncertain due to federal and state restrictions on fuel vapor pressure.

AIR QUALITY IMPLICATIONS OF METHANOL FUEL USE

Methanol exhaust and vapor emissions have been shown to be less photochemically reactive in the atmosphere than hydrocarbon emissions from petroleum fuels. Ozone modeling studies by five independent organizations

provide support for this conclusion.[7-11] These studies are the basis for the interest in methanol on the part of the air quality agencies.

Even with the highly effective emission control systems required on new vehicles, and the further improvement resulting from inspection and maintenance (I & M) programs. motor vehicles will continue to provide a major fraction of the emissions of nitrogen oxides (NO_x) and hydrocarbons (HC) which, in the presence of sunlight, combine to form ozone, the main cause of smog conditions in urban air basins such as the Los Angeles area.[12] Gasoline-fueled, light-duty vehicles (passenger cars and pick-up trucks) are the major source of mobile emissions responsible for ozone formation, as shown in Figure J-1. These vehicles produce over 80 percent of the hydrocarbons from mobile sources, which in turn account for about 40 percent of the total emission inventory. Reactive hydrocarbons are viewed as the critical target for achieving reduced ozone levels. Therefore, use of a cleaner burning fuel such as methanol--i.e., a fuel whose combustion products are inherently less reactive--is regarded by CARB and SCAQMD as possibly the most significant means of achieving any further reduction in the motor vehicle sector's contribution to ozone.[13,14]

Figure J-2 gives an illustration of the magnitude of the ozone reduction potential of methanol substitution in motor vehicles, as estimated by Systems Applications Inc. (SAI). The estimated reduction is based on results of modeling simulations for the South Coast Air Basin (SCAB) which assess the atmospheric photochemistry conditions likely to occur with a major transition to methanol. A complete changeover to methanol vehicles in the air basin is

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7. California Institute of Technology, Mathematical Modeling of Photochemical Air Pollution, report to CARB, 1982.

8. Systems Applications, Inc., Impacts of Methanol on Smog, 1983.

9. Radian Corporation, Analysis of Chemistry Mechanisms and Photochemical Dispersion Models for Use in Simulating Methanol Photochemistry, report for EPA, January 1985.

10. U. C. Riverside, Preliminary Results of Ongoing Study for CARB of Ozone Effects From Methanol Substitution, 1985.

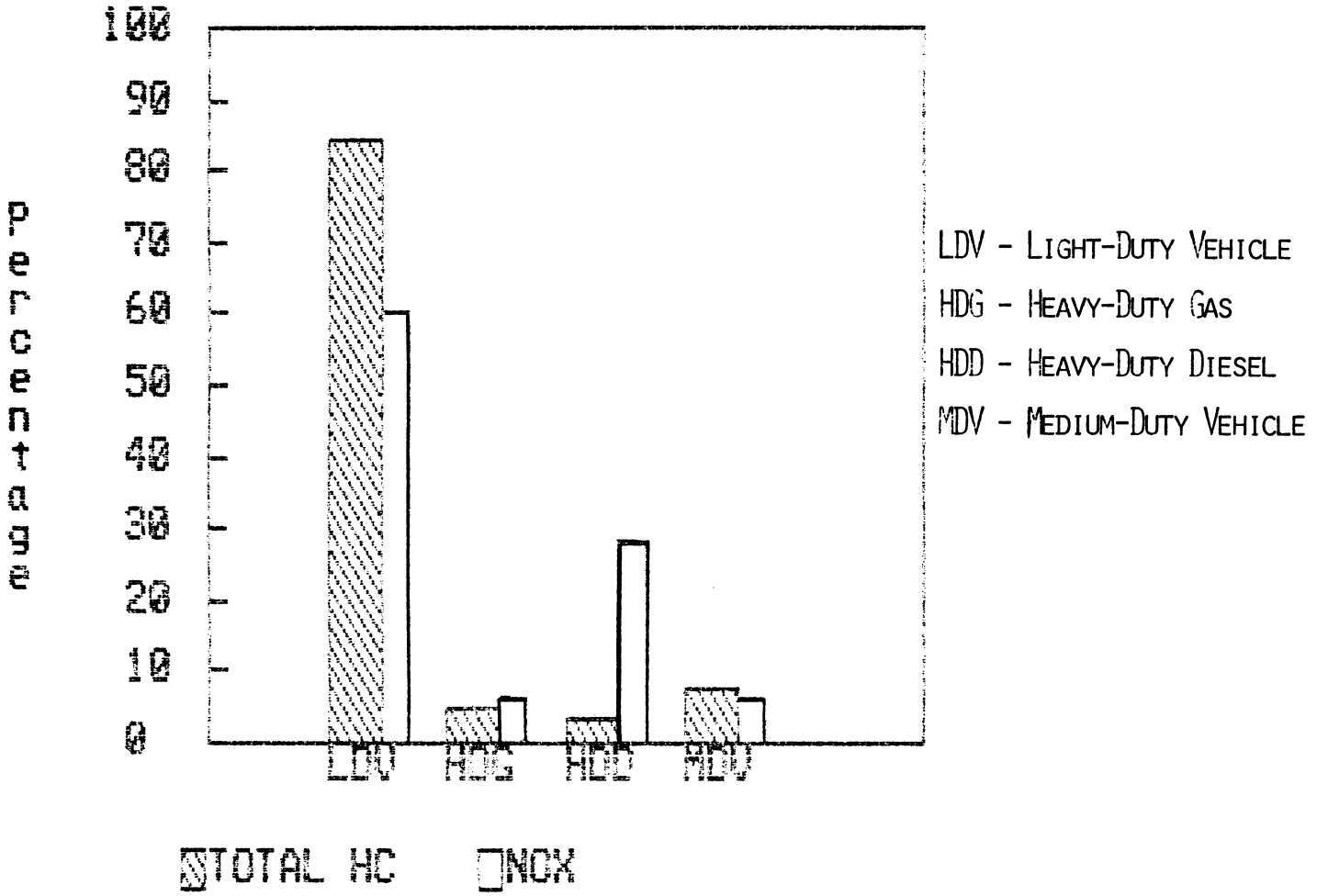
11. Assessment of Emissions from Methanol-Fueled Vehicles and Implications for Ozone Air Quality, R. J. Nichols et al., Ford Motor Company, 1985.

12. Steve Albu, California Air Resources Board, testimony at BFR Hearing, September 24, 1985.

13. Dr. Larry Berg, South Coast Air Quality Management District, testimony at BR V Hearing, April 10, 1985.

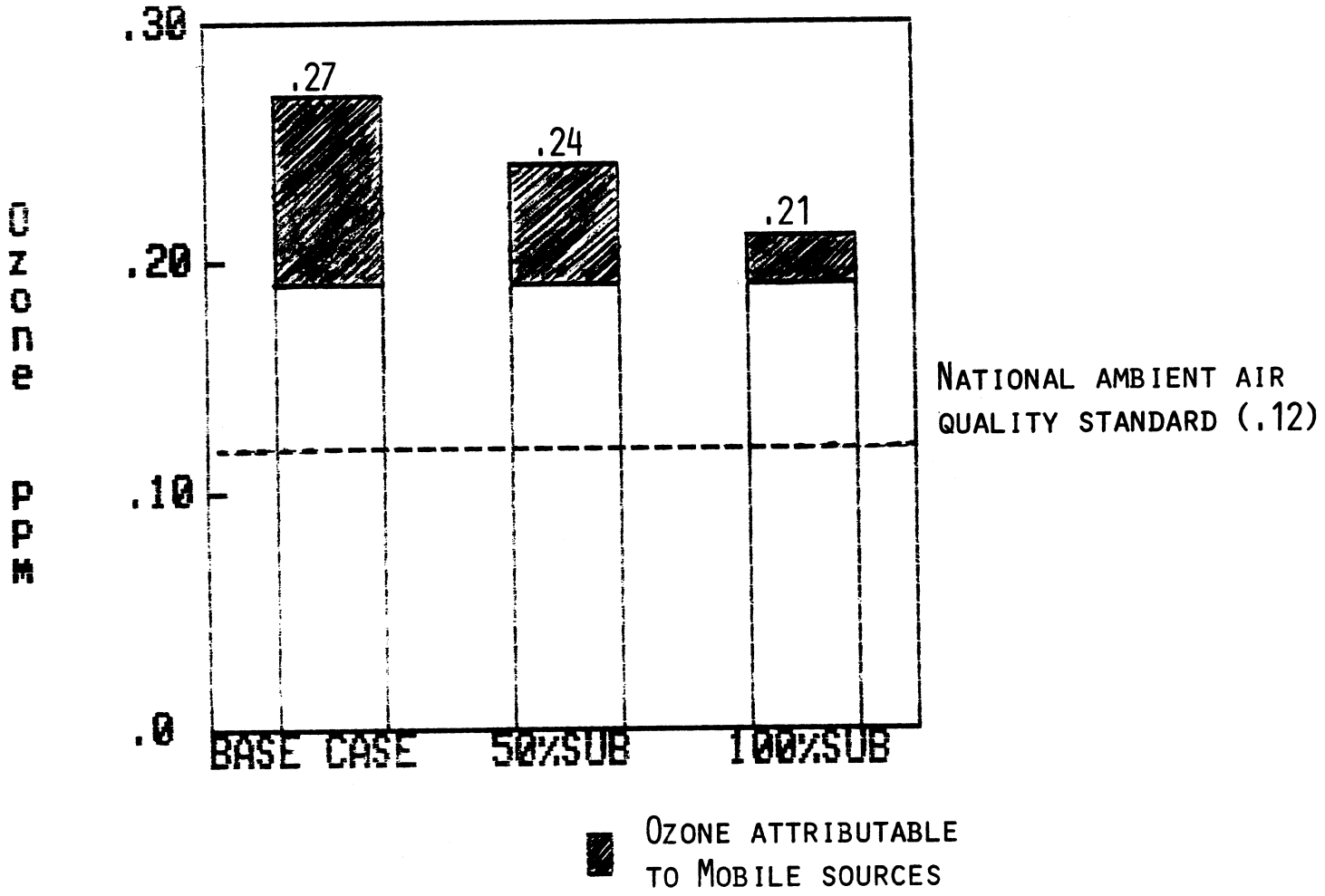
14. South Coast Air Quality Management District Hearing on Motor Vehicle Emissions, June 12, 1981.

FIGURE J-1



VEHICULAR SOURCES OF HYDROCARBON AND NO_X (OZONE PRECURSOR EMISSIONS) FOR THE SCAB IN 1984. (SOURCE: ARB, TECHNICAL SUPPORT DIVISION, EMISSION INVENTORY BRANCH, 1984)

FIGURE J-2



Effect of large scale substitution of methanol vehicles on peak ozone in the SCAB. (Source: SAI, 1983)

estimated by the SAI study to result in a 22 percent reduction in peak ozone levels. Replacing half the gasoline cars with methanol cars would yield an ozone reduction of 11 percent. The significance of these levels of improvement should be considered in light of the following points:

- For comparative purposes, all control measures currently included in the South Coast Air Quality Management District's State Implementation Plan (1982 Revision) for the SCAB in the year 2000 result in an improvement in ozone of 26 percent.

- The estimated levels of reduction are greater than those that can be shown for most other individual ozone control strategies that have been proposed or studied. The state's recently implemented vehicle I & M program is an example of an important control measure that is expected to result in no more than a two percent ozone reduction in the SCAB.

- The high case reduction represents a 75 percent improvement in the contribution to photochemical smog from on-road vehicles--i.e., methanol vehicle emissions react to produce only about one-quarter as much ozone compared with the same mass (grams/mile) of hydrocarbon and NO_x emissions from gasoline vehicles.

- The modeling work examines only the mobile source sector. Further ozone reductions would be expected from methanol substitution in the stationary sector.

Another important consideration in the photochemical modeling work is the assumptions employed for methanol vehicle emissions. Quantitatively, methanol automobiles were assumed to meet the same emission standards as comparable gasoline models. Thus, the ozone benefits indicated by the modeling results reflect only the difference in chemical makeup of methanol vehicle emissions--specifically, the lower reactivity of unburned methanol versus the highly reactive hydrocarbons in gasoline vehicle exhaust.

EPA has acknowledged that the ability of methanol vehicles to improve upon emission levels of new gasoline vehicles is limited by the already highly effective emission control systems being used.[15] In fact, EPA is in the process of promulgating emission standards for methanol vehicles that are expected to be substantially the same as for new gasoline vehicles. However, methanol's simple molecular structure and combustion efficiency are recognized as capable of yielding lower levels of emissions in engines and emission control systems designed to take advantage of these characteristics. Thus, the air quality benefits of first-generation methanol vehicles--developed through adaptation of gasoline vehicles--are expected to become even more pronounced with future vehicle technology optimized for methanol use.

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15. The Environmental Protection Agency View of Methanol as an Alternative Fuel, Richard Olson, testimony at BR V Hearing, April 10, 1985.

One component of methanol vehicle exhaust--formaldehyde--presents a potentially negative impact that is the subject of continuing studies. Formaldehyde levels from current methanol vehicles are somewhat higher than from comparable gasoline vehicles, although still considerably lower than pre-catalyst-equipped gasoline vehicles. However, EPA's assessment of this subject indicates that the levels measured to date are, for the most part, within design targets based on avoiding potential adverse health effects.[16] Development of catalysts with greater effectiveness at removing formaldehydes from methanol exhaust also shows promise for minimizing the significance of this problem.

A final topic of current interest regarding air quality impacts of methanol involves the growing practice of blending methanol in gasoline. Air quality agencies are much less enthusiastic about low percentage methanol blends (e.g., about 10 percent) than high percentage blends (85-90 percent), due to the potentially higher evaporative emissions from the lower blends. Nevertheless, the fuels industry continues to pursue this option as an economically attractive means of establishing an initial market for fuel methanol. ARCO has conducted the most aggressive effort, marketing its EPA-approved "Oxinol" blend at some 2,000 stations in the Eastern United States. Another blend waiver granted to DuPont has been the subject of recent controversy due to restrictive vapor-control conditions attached by EPA. A Canadian company, Ocelot, is conducting a legislatively-authorized methanol blend fleet trial program here in California. A major objective is to apply improved vapor control techniques to mitigate the evaporative emissions concerns in a manner acceptable to CARB. Success of this effort could represent a major step toward environmental acceptance of methanol/gasoline blend fuels in California. The emergence of fuel-flexible vehicle technology provides further impetus for resolving the problems associated with blending, since such vehicles will be designed to operate on all combinations of methanol and gasoline.

METHANOL USE IN THE HEAVY-DUTY VEHICLE SECTOR

Significant additional air quality benefits have been demonstrated for diesel engine applications of methanol. The primary focus of interest is on two major components of diesel exhaust--particulate matter (PM) and NO_x. Both represent subjects of increasing concern and are targets for much more stringent emission standards. As illustrated in Figure J-3, both pollutants are substantially reduced with methanol fueling.

Air quality and public health impacts of diesel bus and truck emissions in urban areas are known to be severe. Diesel-fueled vehicles cause a visibility reduction of 27 percent in the South Coast Air Basin, and diesel-caused soilage costs (repainting houses, cleaning drapes, etc.) amount to $400.

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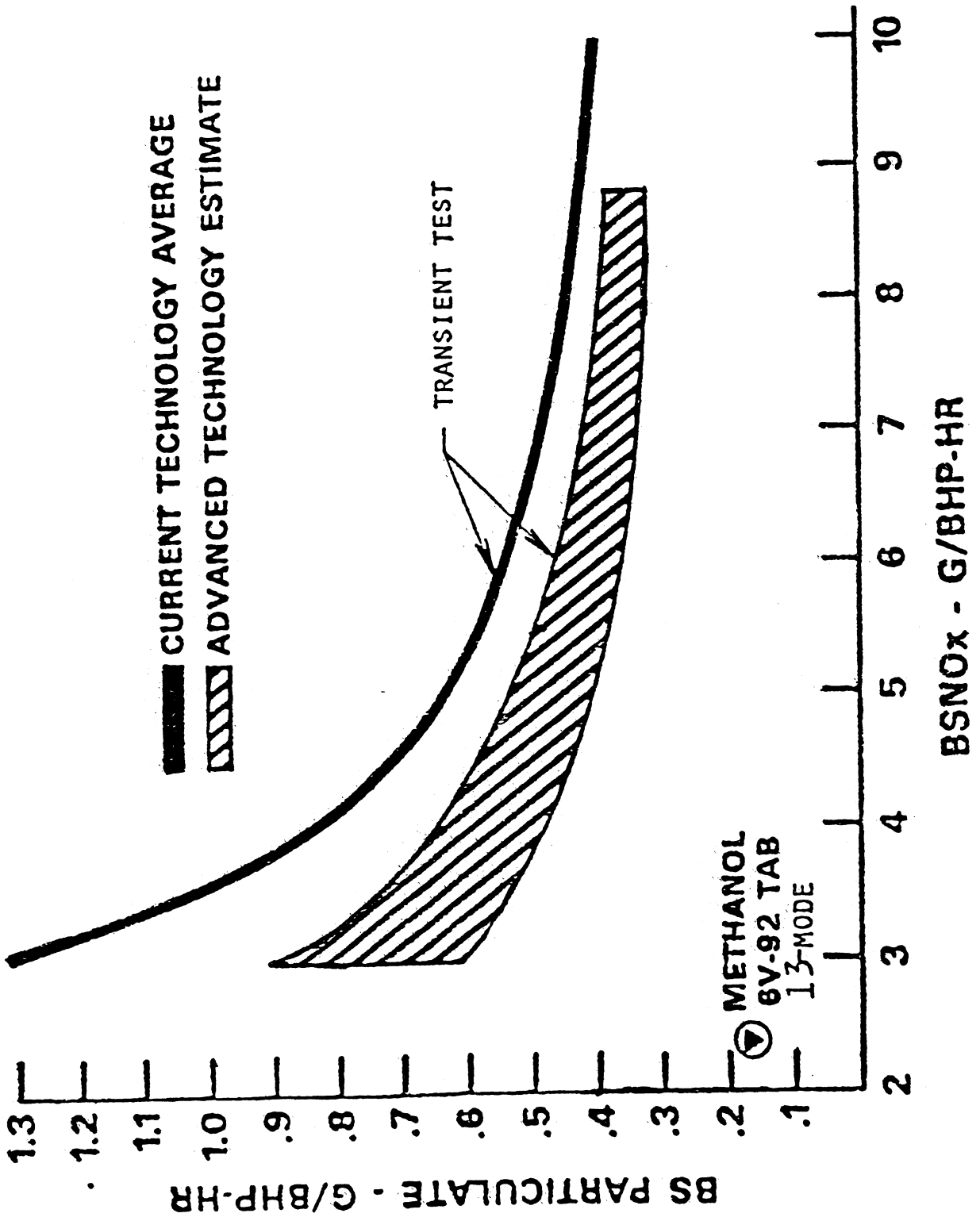
16. Toxicologically Acceptable Levels of Methanol and Formaldehyde Emissions From Methanol-Fueled Vehicles, C. Harvey et al, EPA, 1984.

FIGURE J-3



SOURCE: DEVELOPMENT OF DETROIT DIESEL ALLISON 6V-92TA METHANOL FUELED COACH ENGINE, R. TOEPEL ET AL, GENERAL MOTORS CORP., NOVEMBER 1983.

million annually in that area.[17] These amounts are steadily increasing because of the trend to dieselize all trucks.

The diesel emissions problem results from a combination of the relatively low quality of number 2 diesel fuel and the limited effectiveness of state-of-the-art emission control systems for diesel engines. Air quality regulations are under consideration which would require improvements in both diesel fuel quality and diesel engine emission controls. The use of methanol could actually reduce emissions beyond what these measures would achieve, perhaps more cost effectively. Therefore, air quality agencies, transit districts, engine manufacturers, trucking associations and others are actively investigating the methanol alternative as a possible solution to the diesel emissions problem.

As a general class of vehicles, heavy-duty trucks have not been required to meet the stringent emission standards imposed on light-duty, passenger car type vehicles. However, under Clean Air Act regulations, the Environmental Protection Agency (EPA) has adopted more stringent tailpipe emission standards for trucks. The new standards, promulgated in March 1985, are compared with the existing heavy-duty diesel and methanol engine/vehicle emissions in Table J-2. In addition, the California Air Resources Board is considering adopting standards more stringent than the EPA standards for 1991 and 1994.

Price comparisons of diesel and methanol for the years 1990, 1997, and 2005 are examined in Table J-3. These comparisons were made based on the 1985 Delphi Petroleum Price Forecast, based on 1983 dollars.

In any cost comparison, the difference in volumetric energy content of diesel and methanol must be considered. The energy equivalence ratio (EER) shown in the tables shows the number of gallons of fuel methanol (M85--85 percent methanol, 15 percent unleaded gasoline) required to equal the energy content of one gallon of diesel fuel. If engine efficiencies are the same, the EER value of 1.97 means that it would take 1.97 gallons of M85 to go the same distance as one gallon of diesel. Table J-3, for example, shows fuel methanol to be $0.54 per gallon in 1990. In order to travel the same distance using one gallon of diesel, 1.97 gallons of M85 must be consumed at a total fuel cost of $1.06 ($0.54 x 1.97); therefore, $1.06 becomes the energy equivalent cost when comparing M85 to diesel in 1990. The EER value is also used as a cost multiplier to determine the equivalent fuel methanol operating cost. This EER value is used throughout the discussion.

Based upon fuel cost alone, both the base and high forecast cases show that fuel methanol would be 30 to 43 percent more costly than diesel over the period 1990 to 2005. However, neither case assumes any impact due to emission regulations or changes to diesel fuel specifications; these regulations and fuel requirements will have an effect on the cost of vehicle operation.

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17. Presentation by Tom Cackette, ARB, at Methanol Fuel in Transit Coach Applications Workshop, August 6-7, 1985.

TABLE J-2

CURRENT METHANOL TECHNOLOGY VERSUS
EPA STANDARD FOR HEAVY-DUTY ENGINES
(gr/bhp-hr.)

	NO_x	Particulate	Aldehyde
EPA Standard			
1988	6.0	0.6	---
1991	5.0	0.25	---
		(Buses) 0.1	---
1994	5.0	0.1	---
Current Diesel Technology 1/			
(Transient test)			
Buses In Use	24.4	6.24	0.60
Zero-Mile	6.25	0.57	0.10
Current Methanol Technology 2/			
GM/DDA (13-mode)	2.2	0.17	0.15
M.A.N (7-mode)	5.75	0.02	0.045

TABLE J-3

DIESEL VS. METHANOL PRICE PROJECTIONS
RETAIL EXCLUDING TAXES
(1983 dollars)

Year	Diesel #2 $/Gal. Retail	Fuel Methanol (M85) $/Gal. Retail	Volumetric Energy Equivalence Ratio (EER) Gal. M85/Gal. Diesel	Energy Equivalent Cost M85 $/Gal.
1990	$0.74	$0.54	1.97	$1.06
1997	$0.85	$0.73	1.97	$1.44
2005	$1.04	$0.92	1.97	$1.81

The new EPA heavy-duty vehicle emission regulations will require diesel vehicles to use emission control devices, called particulate traps. Thesetraps might reduce particulates up to 80 percent (with no affect on NO_x), but could reduce fuel economy 5 percent or more. Initial cost, replacement frequency and maintenance costs of emission control devices all affect the per mile cost of vehicle operation. Reliable costs are unknown for particulate traps, although estimates place trap life at 100,000 miles and cost at about $4,200. In fact, particulate trap technology has yet to be developed to meet the EPA standards.

The South Coast Air Quality Management District (SCAQMD) is proposing the adoption by CARB of a rule requiring the use of a cleaner diesel fuel in the SCAB to reduce particulate emissions. This fuel will be low sulfur, with aromatics ranging from 10 to 5 percent, adding $0.25 to $0.45 a gallon to the cost of diesel fuel.[18] Use of this fuel will generate lower particulate emissions, but will not negate the need for particulate traps. However, fuel economy may be improved slightly compared to that achieved with the use of #2 diesel.

The impact on fuel price of these diesel fuel specifications is shown in Tables J-4 and J-5. The energy equivalent cost of fuel methanol continues to be higher than that of diesel.

The full impact of measures designed to lower diesel exhaust emissions is shown in Tables J-6 and J-7. Here, the operating penalties associated with particulate traps and the cost of higher quality diesel fuel are incorporated into a cost-per-mile comparison with M85. From the perspective of operating fuel costs, M85 is competitive with higher quality diesel fuel. This information can also be displayed as a methanol-diesel indifference price,Figure J-4. The methanol indifference price represents the upper methanol price limit that a consumer might be willing to pay given a certain diesel price. This is calculated by incorporating the cost of traps and fuel economy penalty into the cost of the diesel fuel, and then comparing that price with the price of an equivalent amount of methanol fuel. The points shown in the figure correspond to 1) a 1997 Delphi Case, and 2) a 1997 "clean" diesel case (+$0.25/gal), and 3) a 1997 "clean" diesel case (+$0.45/gal). Clearly, the second and third points shown would indicate that the forecasted price range for M85 in 1997, $0.73 per gallon, is below the methanol indifference price range of $0.75 to $0.82 per gallon, respectively. Of course, the actual cost competitiveness of methanol to diesel will depend on the extent of the promulgated and proposed air quality regulations. But it certainly appears that methanol is an economic fuel choice for the future.

Although heavy-duty methanol engine technology is in its infancy, regulatory agencies and transit districts, particularly in the South Coast Air Basin, have been very encouraged by demonstration results to date. The SCAB has

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18. Presentations by Paul Wuebben, SCAQMD, and Steve Albu, ARB, at BFR Hearings, September 24, 1985.

TABLE J-4

"CLEAN" DIESEL AND METHANOL PRICE COMPARISON
(Cost of "Clean" Diesel = +$0.25/Gal)

Year	"Clean" Diesel $/Gal.	Fuel Methanol $/Gal.	Equivalent Energy Cost $/Gal.
1990	$0.99	$0.54	$1.06
1997	$1.10	$0.73	$1.44
2005	$1.29	$0.92	$1.81

TABLE J-5

"CLEAN" DIESEL AND METHANOL PRICE COMPARISON
(Cost of "Clean" Diesel = +$0.45/Gal)

Year	"Clean" Diesel $/Gal.	Fuel Methanol $/Gal.	Equivalent Energy Cost $/Gal.
1990	$1.19	$0.54	$1.06
1997	$1.30	$0.73	$1.44
2005	$1.49	$0.92	$1.81

TABLE J-6

HEAVY-DUTY ENGINE PER MILE COST
FUEL AND EMISSION CONTROL

Year	Fuel Type[1]	Fuel $/Mi.	Emission Control Costs-$/Mi.	Total $/Mi.
1990	Diesel	$0.14 [2]	$0.05[3]	$0.19
	Methanol	0.15	Ø	0.15
1997	Diesel	$0.16	$0.05	$0.21
	Methanol	0.16	Ø	0.16
2005	Diesel	$0.18	$0.07	$0.25
	Methanol	0.26	Ø	0.26

[1] Methanol = M85

[2] Cost of diesel - $0.74 + 0.25/gal = $0.99; fuel economy of 7 mpg (California Transportation Energy Demand: 1984-2004), P300-85-002, April 1985.

[3] Trap-associated fuel economy penalty of 5%; trap life-cycle cost of $0.04/mile (trap cost - $4,200 ÷ by life expectancy of 100,000 miles).

TABLE J-7

HEAVY-DUTY ENGINE PER MILE COST
FUEL AND EMISSION CONTROL

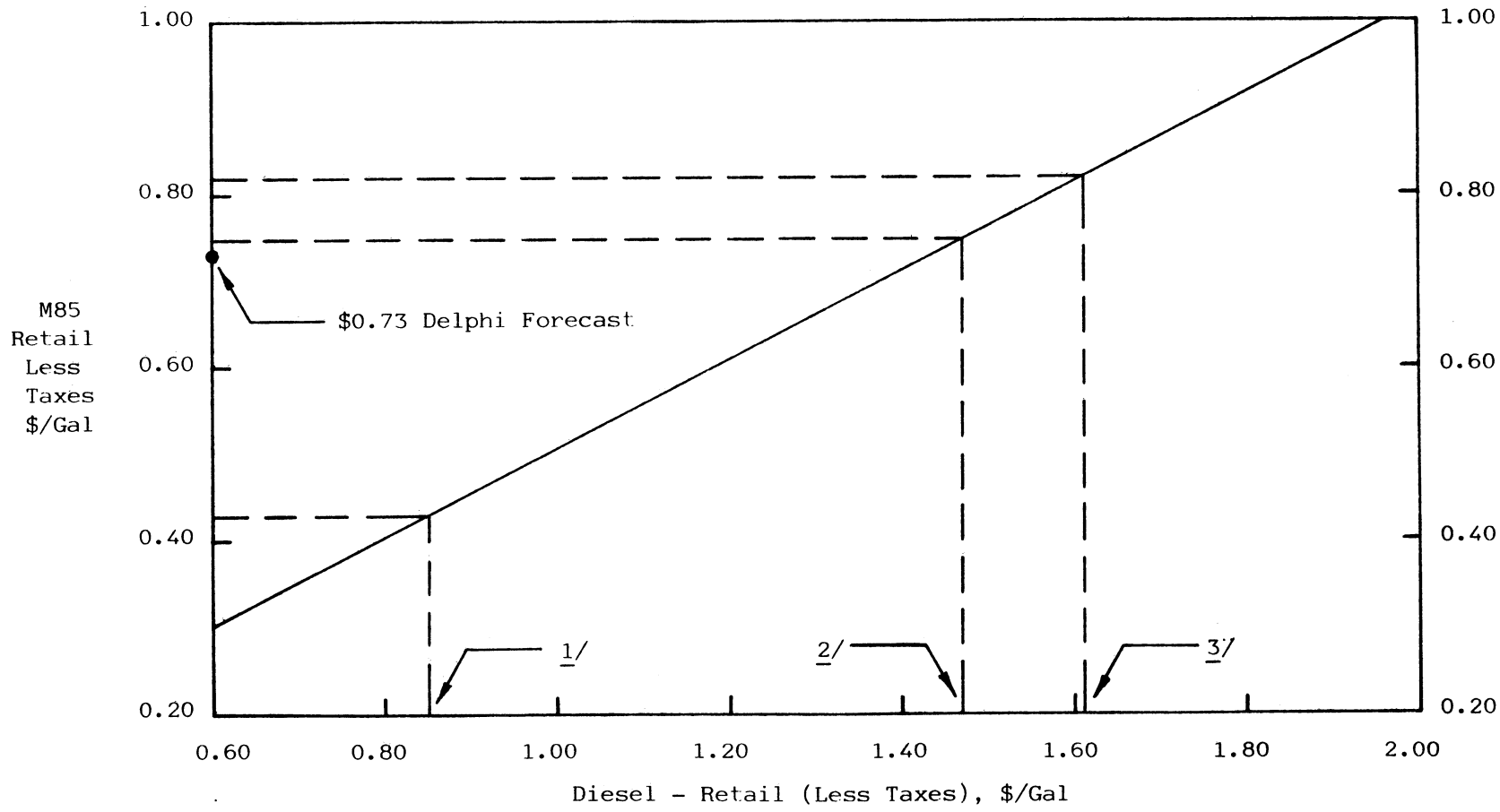
Year	Fuel Type[1/]	Fuel $/Mi.	Emission Control Costs-$/Mi.	Total $/Mi.
1990	Diesel	$0.17[2/]	$0.06[3/]	$0.23
	Methanol	0.15	Ø	0.15
1997	Diesel	$0.19	$0.04	$0.23
	Methanol	0.16	Ø	0.16
2005	Diesel	$0.21	$0.06	$0.26
	Methanol	0.26	Ø	0.26

[1/] Methanol = M85

[2/] Cost of diesel - $0.74 + 0.45/gal = $1.19; fuel economy of 7 mpg (California Transportation Energy Demand: 1984-2004), P300-85-002, April 1985.

[3/] Trap-associated fuel economy penalty of 5%; trap life-cycle cost of $0.04/mile (trap cost - $4,200 ÷ by life expectancy of 100,000 miles).

METHANOL-DIESEL INDIFFERENCE PRICE, 1997



1/ 1997 Delphi Case, $0.85 per gallon
2/ 1997 "Clean" Diesel (+$0.25/gal and emission control costs)
3/ 1997 "Clean" Diesel (+$0.45/gal and emission control costs)

FIGURE J-4

approximately one-half the state's truck and bus population, and these agencies see methanol-fueled trucks and buses as a way to significantly improve air quality.

As an air quality strategy, methanol is an economically attractive option to diesel fuel. At this time, methanol-fueled vehicles cost more than their diesel counterparts; however, increased technology development and higher vehicle production volumes should eliminate this cost differential. Further demonstrations and hardware improvements are necessary to ensure operators of equipment reliability.

Successful major introduction of methanol into truck and bus fleets will partially depend on the cost and effectiveness of particulate traps. At this time, major diesel engine manufacturers agree that development of a reliable and effective trap technology is far from being achieved. Particulate traps are limited in the emissions they control. They will have no effect on NO_x and SO_x emissions. Both the SCAQMD and the ARB feel that these emissions, in addition to particulates, must be controlled, and methanol represents a viable emission control strategy.

If the estimated cost penalties due to pollution control take effect, transit vehicle and truck operators in areas like the South Coast Air Basin may turn to methanol as an emission control strategy rather than retrofitting their vehicles with particulate traps. Based on the preceding analysis, the per mile cost of methanol could become competitive with diesel fuel when environmental costs are considered. Previous discussion has emphasized efforts to make diesel fuel emissions meet EPA standards. Methanol-fueled, heavy-duty vehicle emissions are currently lower than EPA 1994 standards. There is really no way to estimate the savings in diesel-related air pollution damages by the use of methanol.

Heavy-duty trucks and transit buses have a 12-20 year lifetime. Engines are rebuilt one or more times during the useful life of the vehicle, typically every 150,000-200,000 miles. Conversion of these older vehicles to methanol would accelerate introduction of methanol-fueled vehicles into the fleet. Methanol-fueled trucks could regain the performance capabilities lost due to the use of particulate traps while lessening vehicle pollutants. At least one manufacturer is developing a methanol retrofit kit for buses with a conversion cost estimated to be under $10,000, which amortized over the life of the engine, would be a cost-effective emission control strategy.[19]

Projections for the methanol-fueled heavy-duty truck market are difficult to make at this time. Although there have been several demonstrations of methanol-fueled transit vehicles, there have been no demonstrations of methanol-fueled, heavy-duty trucks. Although conversion of these vehicles to

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19. Booz-Allen Hamilton presentation at Methanol Fuel in Transit Coach Applications Workshop, August 6-7, 1985.

methanol could have significant impact on air quality, conversion or purchase of new vehicles will not occur until the technology has been successfully demonstrated in medium- to heavy-duty trucks.

USE OF METHANOL IN STATIONARY SOURCES

SUMMARY

Methanol is an extremely low-polluting fuel which can be made from a variety of feedstocks including natural gas, coal and biomass. It can be used in gas turbines, reciprocating engines, boilers and fuel cells for a wide variety of applications including automobiles, busses, tractors, airplanes, and industrial and utility uses.

Methanol currently is twice as expensive as natural gas on an energy basis. The higher cost of methanol precludes use in the stationary energy production sector at the present time. The use of methanol must offset significant other costs before it will be chosen as a fuel for stationary sources. Some of these other costs are discussed below, but they are not expected to be large enough to overcome the Btu price differential.

There are no known technical barriers to the use of methanol as a fuel for gas turbines. Although further testing is needed to confirm preliminary results, methanol also appears to be a technically viable fuel for large electric utility boilers and fuel cells.

Testing of methanol as a replacement fuel in utility boilers using the overfiring process has been successfully completed at the bench scale. Field testing is required before methanol overfiring can be employed on a commercial basis.

However, the incentive for commercial application of overfiring is dependent on the need for further reduction of air pollution emissions from electric utility boilers. This need is unlikely at this time.

The most likely stationary source use of methanol is in peaking turbines located in the SCAB.

A modest cost savings is associated with bulk delivery of methanol. Up to 14 cents/gallon can be saved, as long as the rate of delivery is scaled to the rate of use. This would probably require development of one -- or a few -- stationary sources using methanol because the volume of fuel used in stationary sources is much greater than transportation. For example, the CEC's UC Davis cogeneration test used 400,000 gallons per month for 3.0 megawatts while the CEC 500 car Ford Escort fleet used only 30,000 gallons per month. However, due to the significant fuel cost differential identified and the uncertainty associated with other events which must occur before methanol use will be cost-effective, methanol is not expected to be used in the near future to fuel stationary sources located in California.

INTRODUCTION

At the direction of the Legislature, the California Energy Commission (CEC) initiated the Clean Coal program in 1979 as a two phase program to determine the most viable coal-based fuels for use in California. The purpose of Phase

I was to identify fuel and engine combinations which merited field testing to determine their near-term cost effectiveness compared to conventional fuels and engines. The purpose of Phase II was to perform the field testing.

Methanol is the major synthetic fuel being considered at the CEC due to its potential use in a wide variety of applications and because it can be made from a wide variety of feedstocks. At the present time, most of the market for methanol is in the chemical industry. Due to a reduced methanol demand currently being experienced worldwide, methanol producers are actively attempting to develop fuel markets, especially transportation fuels where a transportable, liquid fuel is best suited to the needs of that market.

TYPES OF STATIONARY SOURCE EQUIPMENT BEST SUITED FOR METHANOL USE

Methanol is a pure alcohol with a chemical composition of CH3OH. It differs from petroleum and coal fuels which have complex and variable chemical compositions. It is possible to take advantage of methanol's chemical simplicity by designing processes to optimize combustion efficiency while reducing air pollution emissions. The most promising applications of methanol as a fuel for stationary sources include gas turbines, steam boilers and fuel cells.

Gas Turbine

Gas turbines work by using hot expanding air to drive a turbine. The turbine is coupled to an electric generator to produce electricity. In a gas turbine, the combustion products pass directly through the turbine section. As a result, the fuel must be fairly clean to avoid fouling the turbine. Methanol is an ideal fuel for gas turbines. It has no sulfur, ash or fuel-bound nitrogen. The only pollutant of concern is oxides of nitrogen (NO_x) with the nitrogen originating in the combustion air. Since methanol burns at a relatively low temperature and since the rate of NO_x formation due to combustion air decreases with decreasing temperature, NO_x emissions from methanol fueled turbines are extremely low.

SCE tested methanol in a gas turbine in 1979 by converting a 25 megawatt (MW) turbine and operating it for a total of 500 hours. They found emissions ranging from 20-50 parts per million (ppm) NO_x at 15 percent oxygen (O_2), depending upon the water injection rate. This is much lower than distillate oil (Jet A) which ranges from 55-210 ppm, depending upon water injection rate. SCE made no attempt to determine how much water they could use with methanol. In an effort to optimize the process by minimizing NO_x emissions, the CEC extended the SCE work by performing a 1000 hour test at the University of California, Davis (UC Davis). Water, which mixes readily with methanol, was blended with the fuel immediately prior to combustion. Emission rates of 10-20 ppm NO_x at 15 percent O_2 were obtained, again depending upon rate of water addition. General Electric has also conducted turbine testing and they are reportedly willing to guarantee their large turbines (Frames 5 and 7) at a 9 ppm NO_x level when operated on methanol.

Gas turbines are typically used in one of two modes of operation: peaking and base load. The peaking turbine is a stand-alone unit which can be turned off

or on very quickly and operated for relatively few hours to meet peak power demands. This flexibility comes at the expense of low thermal efficiency, leading to high hourly fuel costs. Conversely, baseloaded turbines are designed to operate for extended periods of time. They have additional equipment to capture heat from the combustion gases after it passes through the turbine. This "waste heat" is transferred into steam in a waste heat boiler. The resulting steam can be used to generate electricity or can be used in any other process requiring steam. The baseload configuration is much more efficient than the peaking mode of operation, but its electrical output cannot be turned up and down as readily as the peaking turbine. In some applications, the turbine can be uncoupled from the heat recovery equipment, allowing a facility to operate in either mode. Most cogeneration applications which use a gas turbine are baseload facilities.

The annual fuel requirements for a peaking turbine are small compared to those for a baseload turbine. Fuel cost is important but it is not an overriding concern for peaking turbines; operating flexibility is of paramount importance. Methanol is an ideal fuel for peaking turbines where air pollution emissions must be kept low.

Some locations such as the South Coast Air Quality Management District (SCAQMD) in the Los Angeles area require very low emission rates for new cogeneration facilities. Depending upon the amount of fuel required per year, it may be more cost-effective to use methanol than to use conventional fuels and emissions control hardware such as selective catalytic reduction (SCR) to achieve these very low emission rates. Based upon maximum expected costs for SCR, and assuming methanol costs 40 cents per gallon, a cogeneration facility operating for less than 1800 hours per year would cost less to operate than a natural gas cogeneration facility using SCR. However, it is not likely that it would be economical to operate a cogeneration facility for less than 1800 hours per year. Base load gas turbines require large amounts of fuel each year. A differential cost of only $0.20/mmBtu can mean the difference between a successful project and a failure. Since methanol is expected to remain a much more costly fuel, it is probably more cost effective to use conventional fossil fuels, especially natural gas, and to install SCR where needed. In locations where SCR is not required, methanol would have to cost less than 24 cents per gallon for such a facility to have lower annual fuel costs than a natural gas facility with gas priced at $4.25/mmBtu. Use of methanol should be given serious consideration by anyone wishing to locate a peaking turbine in the South Coast Air Basin (SCAB) or other areas with similar emissions requirements.

Steam Boilers

Steam boilers are used to generate steam for use in electric power plants and industrial processes. Electric utility boilers tend to be very large steam producers and use very large amounts of fuel. Methanol has been tested as a complete replacement fuel for an electric utility boiler. In 1981, SCE conducted tests on the use of methanol in a 44 MW boiler. They found methanol to have only one half the NO_x emissions of natural gas or residual oil (90-100 ppm NO_x at 3 percent 02 on methanol compared to 200-240 ppm on natural gas or fuel oil). Once again NO_x is the only pollutant of concern when burning

methanol. SCE also determined that increased boiler steam output could be obtained with methanol. However, the increased price of methanol cannot be overcome by the extra steam volume.

Investigators have recently developed an advanced form of staged combustion utilizing partial displacement of a dirty fuel with a clean one and variously identified as "reburning," "dual-fueling," or "overfiring." In large boilers with burners located at several different heights (called burner elevations), it is possible to burn one fuel in the lower burner elevations and another fuel in the upper ones. This creates two distinct combustion zones in the boiler with different rates of air pollution generated in each zone. If a clean fuel such as natural gas or methanol is used in the upper zone, the process can be used to control air pollution generated in the lower zone. SCE has successfully tested the overfiring process using natural gas as the clean fuel to reduce NO_x emissions from residual oil combustion.

They found that it is possible to use 67 percent (Btu basis) residual oil and 33 percent natural gas and to have lower NO_x emissions than when burning 100 percent natural gas! This result was obtained in a full scale test at SCE's Alamitos Power Plant.

Methanol overfiring has several potential benefits compared to natural gas overfiring. The CEC has sponsored bench scale methanol overfiring tests and feasibility studies. Based upon these preliminary studies, lower NO_x emissions are possible with methanol than with natural gas. Overall NO_x emissions can be reduced by about 50-80 percent depending upon the degree of NO_x control already implemented on a given boiler. Oxides of sulfur (SO_x) and particulate emissions are reduced only by the percent that methanol displaces the conventional fuel. In addition, boiler efficiency improvements are theoretically possible. However, these effects must be verified with full-scale tests.

Although the overfiring process appears a promising pollution control technology for residual oil fired boilers, it has not been tested at full scale. This is not a high priority test at the present time because most electric utility boilers are currently fueled by natural gas rather than residual oil.

Before it becomes commercially viable, methanol overfiring will have to be tested at full scale and it must prove to be more cost effective than natural gas overfiring. Only full scale testing can verify the use of lower percentages of methanol. This is because the bench testing was limited to a minimum of 33 percent methanol. However, levels as low as 10 percent methanol are likely to be optimum given the price differential of the fuels.

Based upon the preliminary results of bench-scale testing conducted by a CEC contractor, the methanol overfiring process is cost-effective at a methanol price of 45 cents per gallon assuming 10 percent methanol and 90 percent residual oil. This price is based upon assuming that the NO_x reductions have no value. Only efficiency improvements are included. If the NO_x reductions have a value of $10,000 per ton, up to 65 cents per gallon could be paid for the methanol.

SCE and Los Angeles Department of Water and Power (LADWP) must both reduce their 1990 boiler NO_x emissions by about 60 percent in the SCAB, compared to 1982 levels. They intend to accomplish this goal by utilizing natural gas as a boiler fuel and by importing large amounts of electricity from outside the air basin. As a contingency measure they are also looking at various options to reduce NO_x emissions from their electric utility boilers. Natural gas overfiring, or methanol overfiring, may become necessary for in-basin electric utility boilers if either imported power (including hydroelectric) or natural gas supplies are lower than currently anticipated. Before large quantities of residual oil are used for electric utility boilers, full-scale testing of methanol overfiring should be completed.

Fuel Cells

Fuel cells were developed as a part of the United States' effort to explore outer space. They electrochemically convert a source of hydrogen to electricity and water. Since hydrogen is the product converted to electricity, air pollution emissions are relatively insensitive to the fuel (feedstock) used in the fuel cell fuel processor to generate the hydrogen. Fuel cells have historically been very expensive and are just now being field tested by the Gas Research Institute (GRI) for use in stationary source applications. Local utility participation includes SCE and Pacific Gas and Electric Company (PG&E). Fuel cells can be used in small installations such as apartment complexes, cogenerating both heat and electricity very efficiently.

Fuel cells powered by either methanol or natural gas are a very clean source of electricity which should be capable of being sited easily, even in the SCAB. Typically, natural gas is used as the source of hydrogen. However, methanol is much easier to convert to hydrogen than is natural gas. In addition, conversion efficiency of methanol to hydrogen is about eight percent better than with natural gas. If methanol economics and distribution problems can be overcome, it may be the fuel of choice for fuel cells.

CURRENT LEVEL OF DEVELOPMENT AND FACTORS INFLUENCING DEVELOPMENT TRENDS

Although both SCE and the CEC have completed successful field testing of methanol as a fuel for electric utility equipment, no one is using methanol in a commercial stationary source operation at the present time. This is due to the fact that on a Btu basis, methanol is about twice as expensive as the conventional fuels it would replace. Therefore, the major factors impeding the use of methanol are economic uncertainties. To understand the extent of the economic issues, it is necessary to examine factors beyond the direct fuel costs in terms of dollars per million Btu of the fuels. Among the factors to consider are costs of delivering the fuel to the site and other factors including the cost of complying with environmental requirements and efficiency or capacity improvements achieved using methanol.

Direct Fuel Cost Comparison

During the UC Davis methanol field study, methanol had a burner tip price of 60 cents/gallon ($9.28/mmBtu). At the same time natural gas was $5.30/mmBtu. Given the uncertainties of switching to a new fuel, the costs would have to favor methanol by a significant but unknown amount before a fuel purchaser would choose to use methanol as a fuel.

Methanol Delivery

Methanol can be transported in existing petroleum pipelines and stored in existing petroleum storage tanks with relatively minor costs required for converting from the use originally intended for the equipment. This infrastructure may be available for conversion to methanol use as the demand for these facilities has diminished.

Several methods of bulk delivery have been proposed as options to reduce the cost of delivery to California. Among these are rail tank trains of 10-100 cars, pipelines, contract ships at 3,500 dry weight tons (DWT) and ocean-going tankers at 20,000 DWT. These options could be used to supply a large volume of methanol to California, but the implementation of any of these methods must be in concert with the level of methanol demand so that fuel storage costs do not erode the cost savings of the bulk delivery. Savings of 4-14 cents/gallon methanol are possible as long as storage costs are not involved. If the methanol is delivered in bulk and then stored for use, storage costs can cost as much as 14 cents/gallon and more, depending upon how long the fuel must be stored.

The following table illustrates the minimum level of demand that is expected to be needed by each delivery mode and the cost savings attributed to each delivery mode, based upon preliminary staff studies:

SAVINGS ATTRIBUTABLE TO BULK METHANOL DELIVERY

Mode of Transport		Threshold Demand (10^3 gal)	Delivery Savings (¢/gal)
Railroad		300	4-6
Pipeline		1,000/day	4-10
Contract	Ship	6,000	11-13
Ocean	Tanker	13,000	12-14

The minimum delivery level (at which modest savings occur) is provided by railroad and is estimated at 300,000 gallons. This corresponds to the annual consumption of a fleet of about 5,000 Ford Escorts or a 2+ megawatt base load cogeneration plant, or a 24 megawatt peaking plant operating 100 hours per year. However, all of these options will involve major storage costs as mentioned previously. Thus, bulk delivery of methanol requires commitment to a significant volume of methanol use, and it is unlikely, as explained elsewhere in this paper, that stationary sources will be able to provide this demand.

Other Factors

Before anyone would choose to use methanol instead of natural gas, there must clearly be significant additional economic factors which overcome the cost differential. Among these factors are the costs of complying with environmental requirements--including procurement and maintenance of control hardware such as SCR--and procurement of emission offsets. In general, when relatively small annual quantities of fuel are required, such as for peaking turbines, methanol may be less costly than utilizing natural gas and SCR, if SCR use is required by the local air quality district.

Methanol currently costs nearly twice as much as natural gas. At the present time, the methanol price is fairly stable. At the same time, the price of natural gas is going down. Thus, current price trends would tend to increase this ratio, not decrease it.

Both emission control requirements and operating benefits attributed to use of methanol were also considered. For example, expensive pollution control technology is required in some geographical areas for most new equipment and may even be required for some existing equipment, including electric utility boilers, refinery process heaters and thermally enhanced oil recovery (TEOR boilers. The cost of complying with these regulations must be compared on a case-by-case basis to the cost of switching to a cleaner, more expensive fuel such as methanol.

One of the benefits of using methanol is that the process can sometimes be made more efficient. For example, the capacity of the unit can often be increased. This occurs in a gas turbine because a larger physical volume of air and fuel must pass through the turbine, providing more useful work per mmBtu of fuel. Another benefit that occurs in an overfired boiler is an increase in thermal efficiency caused by a lower smoking point (allowing for operation at a lower level of excess oxygen and a reduced volume of exit gases per mmBtu of fuel input) and reduced needs for spray attemperation (reducing parasitic steam requirements).

Even though these external factors erode the price differential, they do not overcome it at the present time. Either the price of methanol must decrease substantially or the price of conventional fuels must increase. Neither of these trends is apparent at this time.

As discussed earlier, several factors would have to change before the use of methanol would be cost effective in stationary sources. These factors should be monitored and, if they change substantially, the following actions are recommended.

- Use of methanol should be evaluated for economic feasibility if limited-duration peaking turbines are needed in the South Coast Air Basin.

- Methanol overfiring should be tested if residual oil is used in the electric utility boiler located in the South Coast Air Basin.

- Methanol should be considered as a fuel for fuel cells if developmental problems preclude use of natural gas.

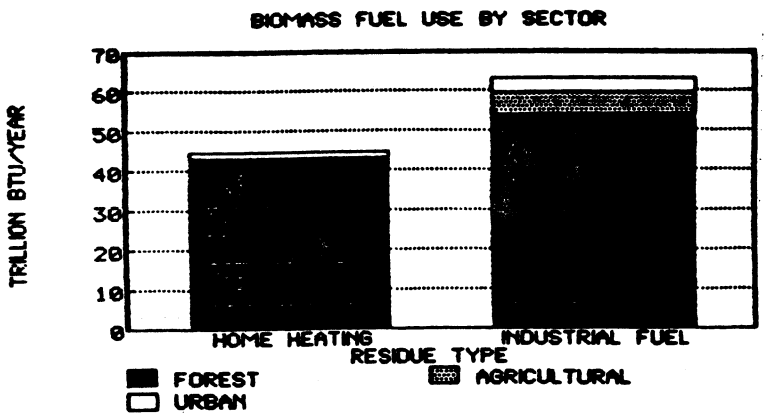
BIENNIAL FUELS REPORT

BIOMASS

I. SUMMARY OF SUPPLY AND DEMAND PROJECTIONS

The majority of biomass fuel converted to energy in California is wood used for industrial purposes to produce process steam and electrical power. Currently this totals 4 million tons (63 trillion BTU) of wood each year. In addition, a large quantity of wood is also used for domestic home heating in woodstoves and fireplaces. The current usage for domestic purposes is about 2.8 million tons (45 trillion BTU) Per year. The future domestic usage is estimated to increase to about 3.7 million tons (59 trillion BTU) with the sharpest increase in rural regions where low cost natural gas is not available. Figure J-5 shows the quantity and derivation of biomass fuel currently used in California.

Figure J-5

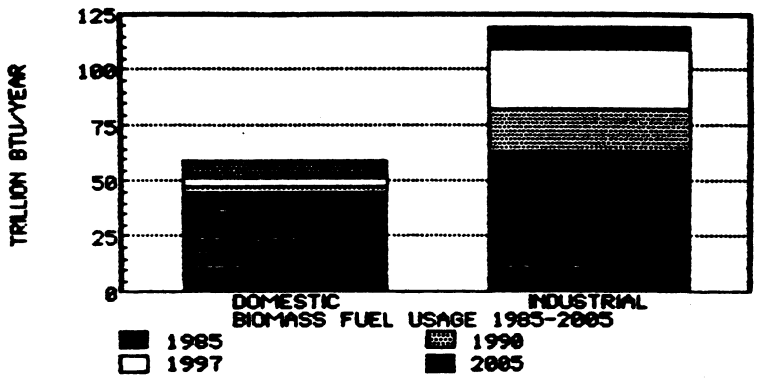


Nearly all of the biomass fuel is derived from California forest resources. Fuel for domestic home heating use is extracted directly from the forests in the form of cord wood while industrial fuels are, for the most part, waste products of the forest products industry.

Biomass fuel in the industrial sector is used to produce both process steam and electricity. Figure J-6 summarizes the current and projected use of biomass fuels. In 1983, California used about 3.6 million dry tons (58 trillion BTU) to generate process steam and electricity (with 220 MW installed capacity). Most of the fuel was used by cogenerators in the forest products industry that burned wood processing waste, predominantly generated on site. A relatively small amount of biomass fuel, derived from agricultural and urban woodwaste, was used by a few newer facilities. Since that time, another 5 trillion BTU or 30 MW of generation capacity have come on line and 99 MW are currently under construction that will use an additional 16 trillion BTU of biomass. Most new facilities continue to be associated with the forest products industry, however, stand-alone power plants have become significant in the use of biomass fuel for electrical generation purposes. CEC staff estimates that by 1990, 83 trillion BTU of biomass fuel will be used by industry with 372 MW of installed generation capacity. By 1997, 110 trillion BTU of biomass fuel will be used with installed capacity of 540 MW. Growth in industrial fuel use beyond 110 trillion BTU will be hampered by fuel availability issues. CEC staff estimates that the use of biomass fuel for

industrial purposes could approach 7.5 million tons (120 trillion BTU with 600 MW of installed capacity) by the year 2005.

Figure J-6



Because of the short lead times (2-4 years) required to plan, obtain permits and construct most biomass facilities, (less than 30 MW) it is difficult to make long range projections of biomass fuel use.

Future growth of the industrial biomass sector will trend toward smaller facilities that can take advantage of small captive fuel supplies. These facilities will be sized to displace retail energy costs of (both the thermal and electrical) host or nearby industries and little electricity will be sold to the grid. This trend to smaller facilities will be accompanied and motivated by increasing retail rates for electricity and relatively modest increases in the avoided cost of electrical power.

Similarly, use of biomass fuel for home heating purposes will continue to increase because of higher retail energy prices.

II. DESCRIPTION OF THE BIOMASS RESOURCE AND ITS USE FOR FUEL

In the context of this report biomass is the most organic material that can be combusted, gasified or digested anaerobically. Today biomass is being used in California to meet both domestic and industrial fuel needs. Biomass that is used for fuel is derived from a number of sources and consists primarily of forest and industry wood waste, agricultural industry and field crop wastes, manures, and urban woodwaste. Biomass does not include fossilized organics nor for the purposes of this discussion does it include municipal solid waste (MSW).

One third of the land in California is devoted to farming and about half is forest lands. It is not surprising, then, that California has substantial quantities of biomass residues which are generated as a by-product of food and fiber production. In 1984, California produced an estimated 48 million dry tons of biomass residues equivalent to 690 trillion BTU.

A. Sources and quantities of biomass residues

Table J-8 lists the primary sources of biomass residues in California. It shows that although there is 48 million tons (690 trillion BTU) of residue generated, only 13 million tons (210 trillion BTU) of this material is technically available for energy purposes. About 6.8 million tons (108 trillion BTU) of this material is now being used. Of the biomass fuel now being used in California, about 4 million tons (63 trillion BTU) is used for industrial purposes to produce process steam and electricity with 2.8 million tons (45 trillion BTU) used in wood stoves and fireplaces for domestic home heating.

As can be seen in Table J-8 the four largest categories of biomass residues remaining to be used for fuel are in-forest wastes, forest product manufacturing residues, orchard prunings and urban woodwaste. The technology to convert these residues to energy exists, however the economics of collecting, transporting and storing the material severely impacts the quantities being used for energy. The economics of using forest products woodwaste will be dictated by values of competing products made from these wastes. Harvesting in-forest residues and orchard and vineyard prunings can only be economically justified if a removal fee is paid to the fuel processor. A disposal fee for urban woodwaste is commonly paid in most urban areas. This "subsidy" makes urban wood waste especially attractive as a fuel resource because it can offset the additional processing and transportation costs required to put urban wood waste into a power plant fuel yard. Central collection points prove to be an additional advantage to reduce labor and transport costs incurred in fuel preparation.

B. Cost of biomass fuel used in California

Table J-9 summarizes the quantities and cost of biomass residues available in California. The largest category of users is the forest products sector which uses an estimated 3.3 million tons (53 trillion BTU) of fuel annually with a fuel cost ranging from 0 to $1.90 per million BTU. The next largest user is the residential sector. About 2.8 million dry tons (45 trillion BTU) of firewood are burned in this sector. The fuel costs for this group range between $2.30 and $11.60 per million BTU, with the high cost being in the urban areas, and the low being in the rural regions. The non-forest products' cogeneration industry composed primarily of agricultural and industrial cogenerators is the next largest category using almost one-half million dry tons (7 trillion BTU) of fuel each year. The fuel used in this group is probably the most diverse ranging from fruit pits and nut shells used by the agricultural industrial sector to urban wood waste and orchard prunings used by a variety of industrial cogenerators. Fuel costs for this group range between $0 and $2.80 per million Btu. The last category of industrial user is the stand alone power plant, a relatively new entry in the biomass energy field. This group is currently estimated to use 220,000 dry tons (3.5 trillion BTU) of fuel priced at between $1.25 and $1.90 per million Btu. This sector of the market is expected to increase substantially as several stand-alone power plants are under construction or in the advanced planning stage.

TABLE J-8

SOURCES AND AMOUNT OF BIOMASS RESIDUES IN CALIFORNIA

(TRILLION BTUS/YEAR)

RESIDUE TYPE	TOTAL RESIDUES GENERATED	AVAILABLE FOR FUEL	CURRENTLY USED FOR FUEL	CURRENTLY USED FOR RESIDENTIAL HEATING	CURRENTLY USED USED FOR INDUSTRIAL PURPOSES	TOTAL AMOUNT UNUSED
FOREST RESIDUES						
1. In-Forest	152	106	44	43	1	62
2. Forest Products Mfg	85	70	53	0	53	17
3. Chaparral	122	0.2	0.1	0.1	0	0.1
AGRICULTURAL RESIDUES						
1. Orchard & Grape Prunings	29	14	3	0.6	2	11
2. Field Crop	93	2	0	0	0	2
3. Food & Fiber Processing	15	5	3.0	0	3	2
4. Manures	130	1	0.1	0	0.1	1
URBAN WOOD WASTE	67	13	5	1.6	3.6	8
TOTALS	693	211	108	45	63	103

TABLE J-9

BIOMASS FUEL USE AND COST BY SECTOR

RESIDUE TYPE	FUEL USE AND COST BY SECTOR Billion BTU/year ($/million BTU)			
	DOMESTIC HEATING	INDUSTRIAL USAGE		
		Ag/Indust Cogen	Forest Products	Stand Alone Power
Forest Residues				
A. In-Forest	42,500 (2.31-11.56)	8 (1.25-1.88)	496 (1.25-1.88)	880 (1.25-1.88)
B. Forest Products Manufacture	--- ---	80 (1.25-1.88)	50,256 (0-1.88)	2,640 (1.25-1.88)
C. Chaparral	80 (3.75-11.6)	--- ---	--- ---	--- ---
Agricultural Residues				
A. Orchard and Grape Prunings	640 (3.13-6.25)	1,232 (1.25-1.88)	1,024 (1.25-1.88)	--- ---
B. Field Crop Residue	--- ---	--- ---	--- ---	--- ---
C. Food and Fiber Processing Residue	--- ---	2,976 (0-2.81)	--- ---	--- ---
D. Manures	--- ---	60 (0-2.50)	--- ---	--- ---
Misc Woodwaste				
A. Urban Woodwaste	1,600 (2.50-6.25)	170,000 (0.94-1.63)	896 (1.25-1.88)	--- ---
TOTAL	44,820 (2.31-11.6)	6,952 (0-2.81)	52,672 (0-1.88)	3,520 (1.25-1.88)

--- indicates fuel not presently used in this sector.

Figure J-7 shows the sources and costs of domestic heating for Californians. The average statewide costs for electric heating, the most expensive heating fuel, is $0.074 per kWh or the equivalent of $21.70 per million BTU. The statewide average cost for natural gas is $5.60 per million BTU, and is within the range of firewood costs of $2.30 to $11.56 per million BTU. Heating with wood is competitive in areas using electric heating, and may not be competitive in areas where wood cost is higher than natural gas. The CEC staff anticipates that the use of biomass as a domestic heating fuel will continue to grow not only for economic reasons but for aesthetic reasons that are difficult to quantify.

Figure J-8 shows the fuel costs for industrial users of biomass residues collected and transported within a 25 mile radius of the end user. Although the biomass fuel cost is less expensive than natural gas, the capital cost and operation and maintenance cost of a biomass facility is higher than a facility fired by natural gas or fuel oil. For a 10 MW stand alone biomass-fired power plant, the most one can afford to pay for fuel is $1.43 per million BTU if the avoided cost including capacity payment is $0.08 per kWh. With this avoided cost, the use of straws and stalks is uneconomical. In addition, this $0.08 per kWh avoided cost will hamper the use of in-forest and forest wood waste, orchard prunings, and urban wood waste if the transportation distance is more than a 25 mile radius from the end user and the transportation cost is greater than $0.15 per ton-mile ($0.01 per million BTU-mile).

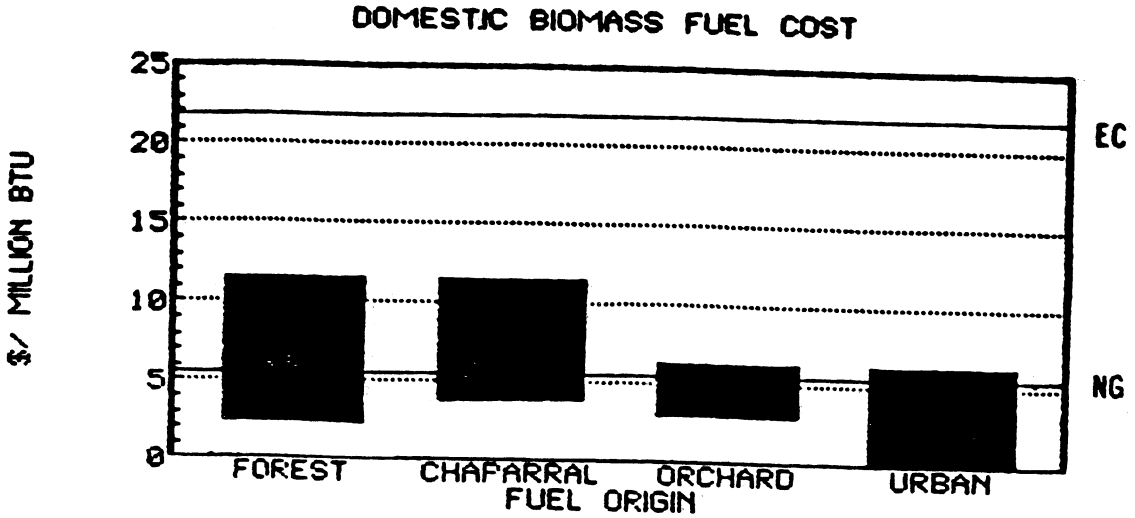
III. CURRENT USE AND FUTURE TRENDS IN BIOMASS FUEL USE

A. Current Use

Biomass is used as a fuel to heat homes and to produce electric power and process steam. Currently there are over 9 million households in California, and the U.S. Forest Service estimates that 2.5 million of these households are burning wood in fireplaces and woodstoves for total or supplemental heating. This usage accounts for about 40 percent of the amount of biomass currently used for fuel. The main factor which caused many Californians to convert to wood as a heating fuel is the relative low cost of wood fuel when compared to some conventional heating fuels (e.g., propane, electricity, and oil). According to a U.S. Forest Service report, over 70 percent of all households that burn wood for home heating, cut and collect their own wood rather than purchase it through a wood yard. About 57 percent of these wood burners live in the rural areas as compared to 17 percent in urban areas. Since the majority of the wood burners are in the rural mountain areas, many are able to get wood fuel at relatively low cost. The U. S. Forest Service believes that the wood collected for domestic heating purposes does not compete with wood harvested for lumber' pulp chips, or fuel chips, and it is a matter of national policy to assure adequate firewood for domestic heating purposes.

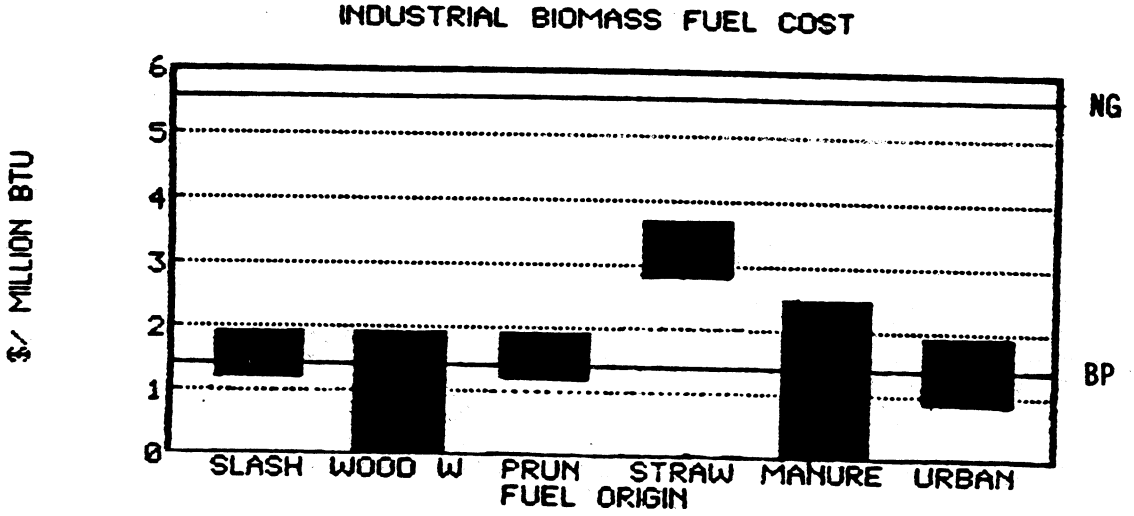
Numerous industries also use biomass fuel to supply process heat, steam and electrical power. Currently, 27 industrial facilities and two stand-alone power plants are selling electricity to the utilities, and 54 facilities are generating process heat and steam for their own use. industrial use of biomass fuel has been steadily increasing since the 1970s. In 1983, there was

FIGURE J-7



EC: Electricity cost @ 7.4¢/kWh
NG: Natural gas cost @ $5.6/mmBtu

FIGURE J-8



NG: Natural gas @ $5.6/mmBtu
BP: Breakeven point for a 10 MW stand alone powerplant is $1.43/million Btu @ 8¢/kWh

220 MW of installed generating capacity fired by biomass fuel in California. Table J-10 indicates that biomass fueled facilities now in operation use 3.95 million tons (63 trillion BTU) of biomass and account for nearly 250 MW of installed electrical generating capacity in California.

TABLE J-10
STATUS OF INDUSTRIAL FULL USE
(July 31, 1985)

Number of Operational Projects	Number of Tons (million)	Energy (Trillion Btu/year)	Operational (MW)
83*	3.95	63.4	250

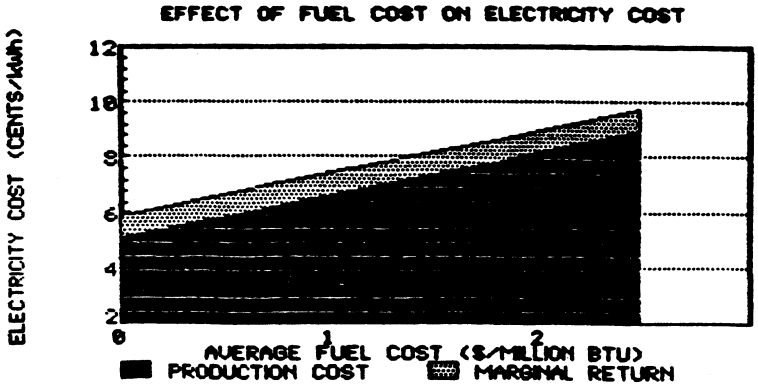
*Does not include methane fermentation projects.

B. Limitations to biomass industrial development

1. Fuel Supply - Lack of a primary source of low cost fuel will be a major barrier to further development of biomass energy facilities. There are currently about 6.5 million dry tons (103 trillion BTU) per year of biomass fuel remaining to be used for energy in California. Most of this fuel tends to be more expensive and less attractive to industrial users.

2. Economics of biomass power production - The economics of power production from biomass fuel is becoming less attractive due to decreases in the avoided cost of electricity and elimination of the energy tax credit. These factors are expected to weaken the biomass industry and to curb the relatively rapid growth that has occurred in the past few years. The suspension of interim Standard Offer 4 also has had a chilling effect on the biomass industry. Biomass power plants and cogeneration facilities require a larger capital investment and have higher operation and maintenance costs than conventional gas and oil burning facilities. In order to compete with these fuels, it is necessary that the cost of biomass be much lower than natural gas and fuel oil. Figure J-9 illustrates how small changes in the avoided cost of electricity will affect the average fuel cost any power production facility can afford to pay for fuel.

FIGURE J-9



3. Environmental limitations

Current air pollution regulations require offsets for pollutants (including precursors) that are in excess of ambient air quality standards. As with many new combustion sources, industrial biomass facilities have difficulty in identifying and obtaining the required offsets. In the past these facilities were granted favorable treatment and were required by state law to make only a good faith effort to comply with the offset requirement. Current conflicts between state law and Federal Clean Air Act requirements have, in reality, eliminated this exemption and sharply curtailed the number of projects seeking permits in non attainment areas.

There has been much concern over air pollution caused by increased numbers of residential woodstoves and fireplaces in both the rural and urban areas of California. Residential woodburning systems have been known to release particulates and hydrocarbons into the atmosphere; some of which are considered carcinogenic. Because of increases of these pollutants caused by increases in residential woodburning installations, local agencies are considering instituting regulations affecting the number and type of woodburning units to be installed, the days when woodburning will be allowed, and the types of control equipment for existing units. Regulations of this type will increase the cost of woodheating and may limit the number of future woodstove installations to the rural areas where wood is much cheaper than available conventional heating fuels.

4. Competing uses for biomass fuel - As mentioned earlier, domestic home heating is the second largest user of biomass fuel. There will be continued pressure by this sector of the market to convert or use more wood fuel. This is especially true in rural areas where biomass fuel is plentiful and available heating fuels (e.g., propane and electricity) are expensive. These areas are among the fastest growing areas in the state and therefore the CEC staff estimates that there will continue to be a demand for biomass fuel for home heating use.

C. Future trends in the use of biomass fuel

Over 600 MW (or 96 trillion BTU equivalent) of installed electrical generating capacity are currently in the permitting or planning stage of development. Most of these facilities were first proposed when the economics of power production appeared more favorable and before the environmental and fuel limitations were as apparent as they are today. Actual growth of the biomass industry will be limited to about 250 additional MW (40 trillion BTU) of electrical power.

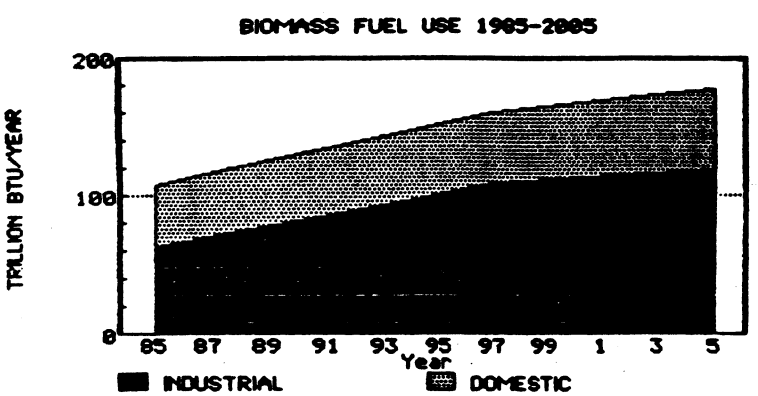
Major growth areas will consist of new and more efficient use of captive fuel supplies by the forest products industry. Older facilities will be replaced with new more efficient larger facilities. A few stand-alone power plants will be constructed at strategic locations to take advantage of local fuel conditions.

Domestic fuel usage is estimated to increase substantially in the rural mountain and coastal areas where existing heating fuels are more expensive than wood. Since most of these areas are located near public forests, wood fuel is readily available and at a relatively lower cost ($2.30 to 6.80 per million BTU) than propane or electricity ($12 or 21.70 per million BTU, respectively).

The CEC staff estimates that the biomass usage will be about 83 trillion BTU by 1990 and 110 trillion BTU by 1997. Because of the short lead times (2-4 years) required to plan, obtain permits and construct most biomass facilities, it is difficult to make long range projections of biomass-fueled electrical generation. The staff believes that based on an inventory of fuel believed to be technically and economically available for energy that 13 million tons (210 trillion BTU) of biomass is the upper limit of development.

Figure J-10 indicates the CEC staff projections of biomass fuel use in both the industrial and domestic sectors.

FIGURE J-10



IV. STABILITY OF THE BIOMASS FUEL MARKET

The use of biomass fuels increased during the last decade in part due to price shocks in the petroleum and natural gas markets and uncertainties in the future price projections for these fuels. Residential users and some industries saw biomass as a means to lower energy costs and to insulate themselves from petroleum price increases such as occurred in the early 1970's. Although the price of biomass fuel is generally much lower than fuel oil and natural gas on a heating basis, there has been a general realization among those who use biomass to generate electricity that protection from price shocks and fuel supply interruptions is not assured with the conversion to biomass fuel. This is especially true for those dependent on fuels they don't generate themselves.

Industries that rely on biomass fuels produced or collected by others are vulnerable to a number of factors that threaten a stable, low cost energy source.

A. Health of the Economy

For some industries, higher prices for conventional fuels and high avoided cost payments for electricity were a driving force behind the conversion to biomass fuels. However, these same conditions can adversely affect the health of the economy and actually create problems for biomass energy development because of the dampening effects they cause on the economy as a whole. For example, most biomass currently used for production of electrical energy in California is derived from the forest products industry. Major economic changes resulting in a reduced demand for housing and manufactured products will severely impact this industry. Residues from the forest products industries supply much of the biomass fuel for stand alone power plants.

B. Underdeveloped fuel supply infrastructure

The threat of a biomass fuel supply disruption exists because of an underdeveloped fuel supply infrastructure. Fuel suppliers have been reluctant to enter the market because of uncertainties in the future demand for the fuel product and high capital and operating costs. These uncertainties are a result of several changes that have occurred that dramatically affect the economics of power production. The economics of power production with biomass fuel is being reassessed due to decreases in the avoided cost, lack of a long term utility contract (e.g., Standard Offer 4) for electricity and changes in tax laws such as the proposed elimination of the investment tax credit and the accelerated cost recovery system (ACRS). These factors are expected to weaken the biomass industry and to curb the relatively rapid growth that has occurred in the past few years. These conditions suppress the price that biomass facilities can pay for fuel and have acted to weaken the biomass fuel supply infrastructure by driving fuel suppliers out of the market and discouraging the entry of new suppliers. These uncertainties are likely to be reduced by 1986 because the bulk of the viable projects not now under construction will either break ground or be shelved by then.

C. Dependence on annual crop yields

California's experience has shown that yearly fluctuations in fuel supply can occur due to crop failures. This fact can strongly affect power plants or cogenerators relying on agriculturally derived fuels. For example, the fuel supply of facilities which rely on peach pits, walnut shells or almond shells is affected dramatically by the yield of these crops. Government programs used to manage commodity surpluses can also affect fuel supply. Facilities which may require a fuel such as cotton stalks could be affected by programs such as the Payment in Kind (PIK) program which dramatically reduced the acreage of cotton grown in 1983.

In conclusion, industries that rely on biomass fuel and especially the open biomass fuel market are highly subject to fuel supply interruption. Although the price of most biomass fuel currently used is generally much lower than fuel oil and natural gas on a heating basis, this fuel, supplied largely by the forest products industry, is pretty well allocated. Hence, future growth in the electricity generating sector will have to rely more on other sources of biomass fuel. These sources will be more expensive and have not been thoroughly developed. This fact will increase the risk associated with fuel supply interruption and will hamper development of the industry.

Sectors of the market that do not have an in-house supply of fuel are the most vulnerable to fuel supply interruption. They are the least able to control fuel prices and are most subject to biomass fuel market instability. This market sector primarily consists of stand alone wood fired power plants or cogenerators that depend almost exclusively on the fragile and still developing biomass fuel market.

Domestic users of biomass fuels, either produced or collected by others, are less vulnerable to wood supply disruptions than industrial users. As stated previously, most domestic users generally cut their own wood in public forests. Since the U.S. Forest Service believes that there are adequate supplies of firewood for domestic heating in the future, those that cut firewood in public forests for home heating can be ensured an adequate, stable, and low cost source of firewood in the future.

USE OF MUNICIPAL SOLID WASTE AS A FUEL

I. SUMMARY AND CONCLUSIONS

1. USE OF MSW AS A FUEL

Municipal solid waste (MSW) refers to non-hazardous solid waste materials produced primarily by residential and commercial sources. MSW can be used as a fuel by direct burning of the solid waste materials, or by collecting and burning the combustible gas formed in a landfill.

Use of MSW as a fuel in California is dependent on the approaches adopted for solving MSW disposal problems in the state. Currently in California, an estimated 36 million tons of MSW per year are collected and transported to landfills for permanent disposal. Approximately 80 percent of this MSW is generated in the major urban areas of the state. The majority of communities in these areas will fill their existing landfills by 1995. Consequently, to meet future MSW disposal requirements, communities must site new landfills or develop alternative MSW disposal methods. However, because of new stringent regulations and other barriers affecting the opening of new landfills, some of these communities will have no choice but to find an alternative solution to their MSW disposal problems. In addition to the problems of determining methods for disposal of future waste, past and existing landfill disposal practices have created public safety and environmental problems. Uncontrolled landfill gas that migrates to the surface of existing landfills is emitted to the atmosphere creating air pollution, safety, and odor problems. Landfill gas can also migrate through the soil and contaminate groundwater supplies.

To help solve the MSW disposal problems, many communities in California are proposing to build MSW-to-energy plants, and are currently installing landfill gas recovery facilities. Due to landfill capacity problems occurring throughout California, about one-fourth of all MSW disposed in California could be burned in MSW-to-energy plants by the year 1990 if all of the plants currently proposed by project proponents are built. Similarly, during the next five years, demand for landfill gas is expected to more than triple in California due to regulatory requirements and favorable economics.

In general, MSW is a poor quality fuel for direct burning because it is difficult and expensive to use compared to other types of fuels. Also, several environmental issues associated with direct burning of MSW have not been completely resolved. Therefore, the primary reason for direct burning of MSW in a MSW-to-energy plant is to dispose of the refuse. Steam and electricity are produced and sold to energy users to provide a revenue source which can be used to help pay for MSW disposal costs. In contrast, landfill gas is relatively high quality fuel. Collection and use of landfill gas is simple, and the gas can be used in conventional combustion devices. Also, use of landfill gas collection systems are being installed not only to prevent gas migration, but also to recover the gas for use as a fuel.

2. MSW SUPPLY AND DEMAND PROJECTIONS

Projections of the MSW supply available for direct burning, and the demand for MSW to be used as fuel by MSW-to-energy plants, are presented in Figure J-11. Conclusions that can be made about the use of MSW as a fuel by direct burning are:

- Refuse materials from residential and commercial sources are waste materials that presently are not used as a fuel in California. MSW is not a preferred fuel source for direct burning because it has a highly variable composition, has poor fuel properties, is difficult and expensive to use compared to other fuels, and has unresolved environmental issues.

- The theoretical potential supply of MSW available to burn in MSW-to-energy plants is essentially the quantity of MSW collected and transported to landfills in California that accept 100 tons per day or more of refuse. The current supply is estimated to be 35 million tons per year or 315 trillion Btu per year. Assuming current MSW disposal practices do not change, the future supply of MSW in California is projected to increase as a result of increasing population in the state.

- The demand for MSW to be used as fuel in California is expected to increase rapidly during the next 20 years based on current proposals to build new MSW-to-energy plants. Currently, the only operational MSW-to-energy plant in California burns less than 0.3 million tons per year. However, if all of the plants currently proposed by projects proponents are built and if no other MSW disposal alternatives are pursued, the amount of MSW burned in MSW-to-energy plants is projected to increase to eight million tons per year or 72 trillion Btu per year by 1990. Similarly, the year 2005, it is projected that about 47 percent of all MSW collected in California for disposal might be burned in MSW-to-energy plants, if no other alternative disposal methods are used.

- Future supply of MSW available to burn in MSW-to-energy plants may be reduced by expanded community resource recycling programs or by changes in packaging practices.

- Future demand for MSW as fuel may be reduced by barriers to new plant development resulting form citizen opposition, environmental concerns, regulatory requirements, and changes in plant financing procedures and tax incentives.

The supply and demand projections for landfill gas are presented in Figure J-12. Conclusions that can be made about use of landfill gas as a fuel are:

FIGURE J-11

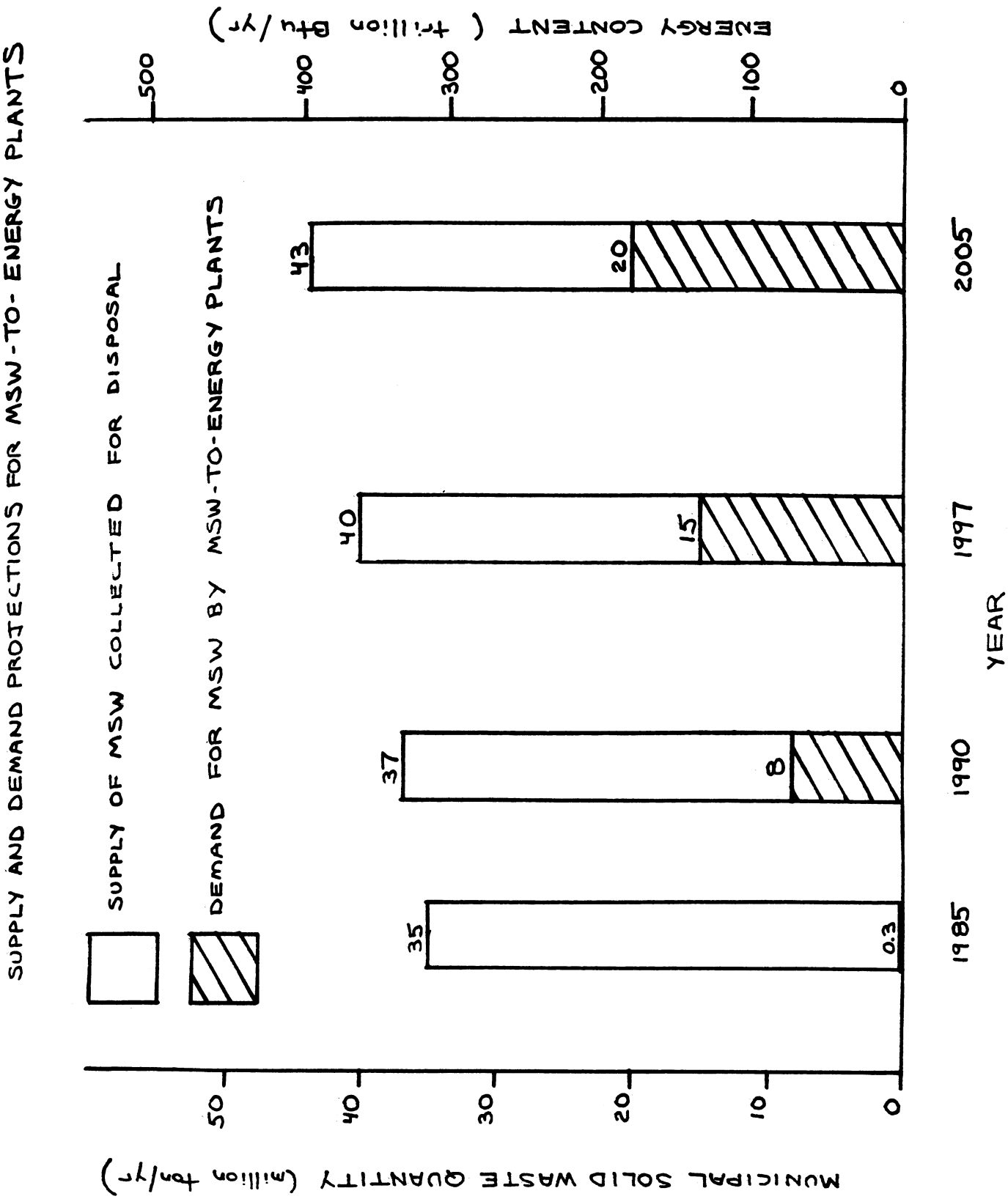
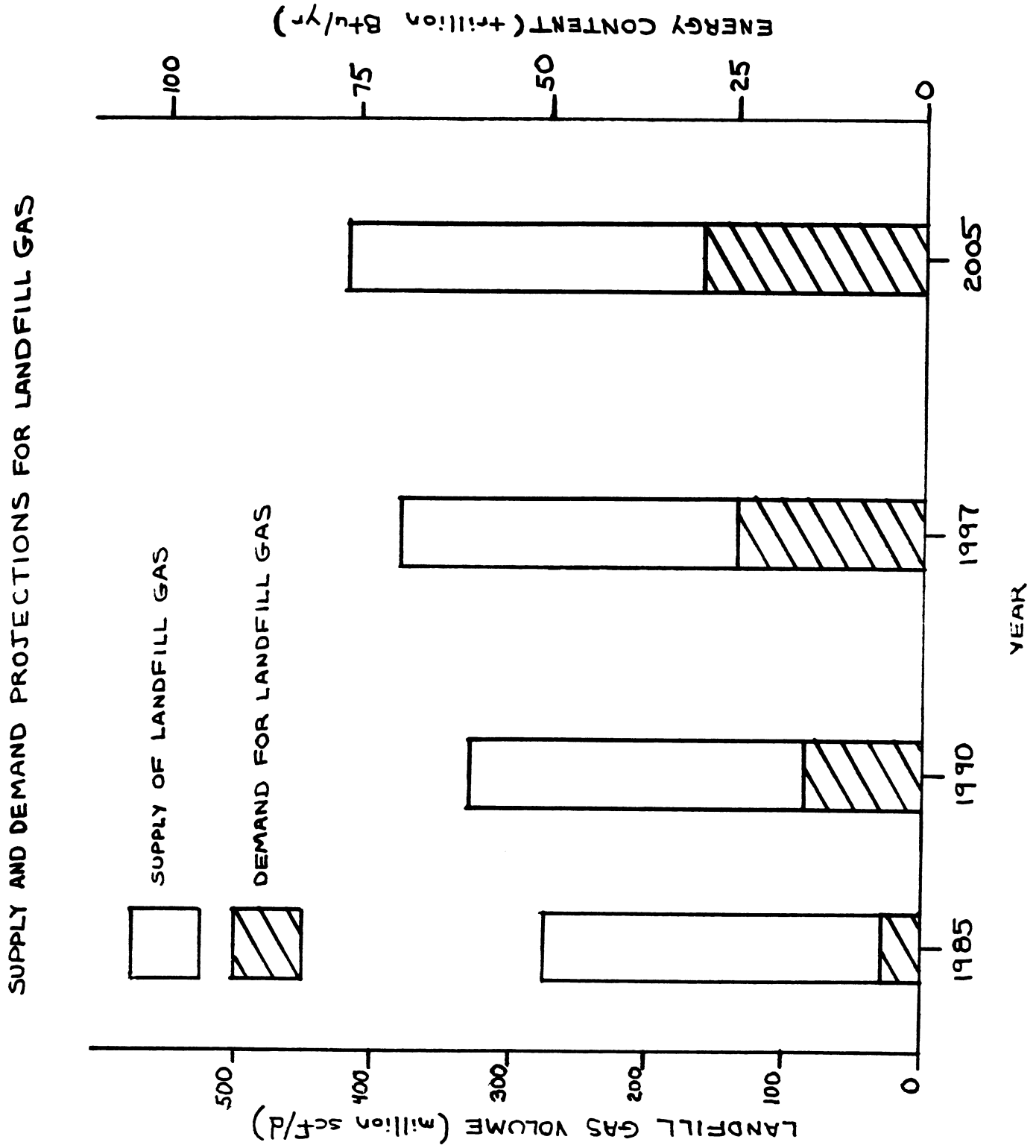

SUPPLY AND DEMAND PROJECTIONS FOR MSW-TO-ENERGY PLANTS
SUPPLY OF MSW COLLECTED FOR DISPOSAL
DEMAND FOR MSW BY MSW-TO-ENERGY PLANTS
ENERGY CONTENT (trillion Btu/yr)
500
400
300
200
100
0
43
20
40
15
37
8
35
0.3
2005
1997
1990
1985
YEAR
50
40
30
20
10
0
MUNICIPAL SOLID WASTE QUANTITY (million ton/yr)

FIGURE J-12


SUPPLY AND DEMAND PROJECTIONS FOR LANDFILL GAS
SUPPLY OF LANDFILL GAS
DEMAND FOR LANDFILL GAS
LANDFILL GAS VOLUME (million scf/d)
500
400
300
200
100
0
ENERGY CONTENT (trillion Btu/yr)
100
75
50
25
0
1985
1990
1997
2005
YEAR

- Landfill gas is a preferred fuel source because it is a high quality fuel, is easy to use, has relatively low air pollutant emission rates, alleviates the environmental problems due to gas migration in existing landfills, and is already commercially available and competitive with natural gas.

- The supply of landfill gas will increase over the next 20 years as a result of (1) continued gas collection from MSW already in place in existing landfills, (2) new gas collection systems installed at existing landfills, and (3) additional gas generated from MSW projected to be disposed of at new landfills.

- The theoretical potential supply of landfill gas currently available in California is 275 million standard cubic feet per day (scf/d). This is equivalent to approximately 50 trillion Btu per year. However, there are only 25 landfill gas recovery facilities operating in California producing only 35 million scf/d (6 trillion Btu per year). The demand for landfill gas is expected to increase by more than 300 percent during the next five years in the major urban areas in the state. Due to regulatory requirements to install gas collection systems at landfills and economic use factors that favor the use of gas, demand is projected to increase, but at a slower rate than before. From 1997 to 2005, demand for landfill gas is projected to increase at an even slower rate. By the year 2005, the demand is expected to be approximately 38 percent of the total landfill gas supply.

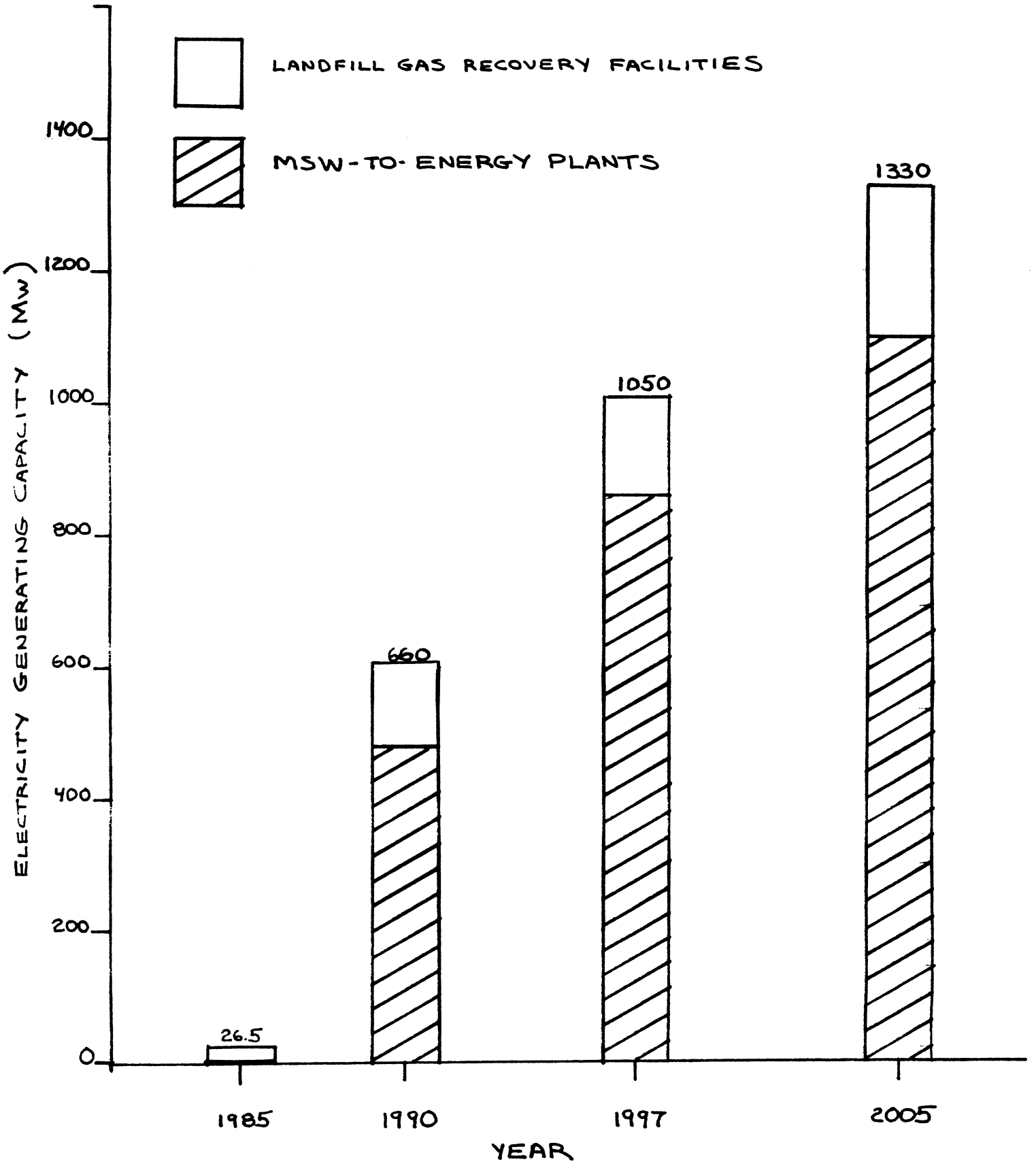
- Future supply of landfill gas will depend on amounts and organic matter content of MSW disposal of in landfills. Direct use of MSW at MSW-to-energy facilities will reduce the amount of MSW going to landfills, and thereby reduce potential landfill gas supplies. Similarly, reductions in the organic matter content of MSW due to expanded resource recycling programs may decrease the future supply of landfill gas.

- Future demand for the use of landfill gas as fuel will increase, if regulations requiring landfill gas collection systems are adopted statewide. Future demand to use landfill gas as a fuel may be reduced by a decrease in natural gas prices or electric utility avoided costs.

Energy obtained by burning MSW directly or burning collected landfill gas can be used for heating applications, process steam production, or electricity generation. Most large MSW-to-energy projects proposed for construction in urban areas of California will maximize electricity production, and sell the electricity to local utilities. Smaller size MSW-to-energy plants are more likely to be constructed in less densely populated urban communities or rural areas in the state, and will probably operate as cogeneration facilities. The major use of landfill gas in California is expected to be as a primary fuel source for either an internal combustion engine or gas turbine unit driving an electrical generator. Figure J-13 summarizes the future statewide electricity generating capacity projected to be available from MSW-to-energy plants and landfill gas recovery facilities.

FIGURE J-13

ELECTRICITY GENERATING CAPACITY PROJECTIONS



II. MSW-TO-ENERGY PLANTS

1. DESCRIPTION OF FUEL GROUP AND END-USE INDUSTRIES

a. Fuel Group

In general, MSW is a very diverse mixture of paper, yard wastes, food wastes, glass, metals, plastics and any other materials which are discarded as wasted items. Consequently, unlike most conventional fossil fuels, MSW does not have a consistent composition. MSW varies from community to community, and from one season to the next. This high degree of variation in composition is an important factor in determining how MSW is used as a fuel. For example, energy producing facilities that use direct burning of MSW must be designed to handle potentially large variations in heating value or moisture content throughout the year.

In addition to its highly variable composition, MSW differs from conventional fossil fuels in four other important ways. First, MSW has a significantly lower energy content than coal or oil. For example, the heating value of MSW is approximately 4,500 Btu per pound compared to 12,000 Btu per pound for bituminous coal. Consequently, up to three pounds of MSW must be burned to produce the same amount of energy released from one pound of coal.

Therefore, to achieve the same energy production rate, an MSW-fired furnace is significantly larger than an oil or coal-fired furnace. Second, MSW has a high total ash content. Whereas the ash content of coal is generally less than ten percent, the ash content of MSW is typically more than twenty percent. Consequently, a facility designed for burning MSW requires more extensive ash handling equipment than an oil- or coal-fired furnace. Third, MSW has a very high moisture content which is typically in the range of 25 to 30 percent. High moisture content creates a need for special fuel handling and storage equipment. Finally, MSW contains significant quantities of chlorine. High chlorine content causes equipment corrosion and results in additional air pollutant emission problems. To mitigate corrosion problems, MSW-to-energy plants must use expensive corrosion-resistant materials. Chlorine-related air pollution problems are mitigated by using control equipment generally not required on oil or coal combustion units. Because of these differences between MSW and fossil fuels, the cost of constructing an MSW-fired combustion unit typically is two to three times higher than an oil- or coal-fired combustion designed to produce the same heat output.

b. End-Use Industries

The main purpose of an MSW-to-energy plant is to safely dispose of refuse by incineration. However, recovery and sale of energy produced from the incineration process provides a major revenue source that can help pay for MSW disposal costs. Consequently,

there is an increasing emphasis to build MSW incinerators that optimize energy recovery, and to locate these MSW-to-energy plants near to energy users. Energy users can be local utilities that will purchase electricity for distribution to the grid, or thermal energy users such as manufacturing plants. Due to the nature of the incineration process, MSW-to-energy plants tend to be operated at a relatively constant set of conditions, much like base load power plants. As a result, end-use industries associated with MSW-to-energy facilities are greatly influenced by the type and size of the facility.

There are two basic types of MSW-to-energy plants: mass burn plants and refuse-derived fuel (RDF) plants. For a mass burn plant, little or no processing of MSW is performed prior to feeding the refuse to the furnace. Major advantages cited for mass burn technology include relatively simple fuel feeding systems, good reliability, long periods of continuous operation between maintenance shutdowns, lower capital cost than RDF plants, and a high degree of commercial availability. For an RDF plant, the refuse is first shredded to a uniform size and then processed to remove selected types of non-combustible materials (e.g., ferrous metals, aluminum, and glass). The resulting RDF is fed directly to the furnace or stored for future use. Major advantages cited for RDF plants include a potentially better thermal performance by firing a more uniform fuel, additional revenues from the sale of recovered materials, and the capability to burn coal in the furnace if the MSW supply is disrupted.

Mass burn is the technology most commonly used in Europe and Japan, and is currently the MSW-to-energy technology generally preferred in the United States. Enthusiasm for RDF technology has waned since the 1970's when several large RDF plants constructed in the eastern United States experienced severe operating and safety problems. However, recent extensive and expensive modifications to RDF plants have significantly improved their performance levels. Consequently, application of simplified RDF processing and handling systems, improved fuel feeding methods, and corrosion protection of components may increase the competitiveness of RDF technology in the MSW-to-energy plant market in the United States.

The size of an MSW-to-energy plant is expressed in terms of the total amount of MSW the plant is capable of burning in one day. Today, most large MSW-to-energy plants are built having two or three integrated furnace/boiler units. A unit design consisting of a refractory-lined or rotary incinerator in conjunction with a waste heat boiler is also used for some smaller plants. In general, the burn capacity of a modern MSW-to-energy unit ranges from 250 to 750 tons per day (tpd). From an energy production viewpoint, one ton of MSW contains approximately nine million Btu and, when burned in a MSW-to-energy plant, can produce approximately 5,000 pounds of high quality process steam or about 500 kilowatts of electricity.

In California, the size of proposed MSW-to-energy plants varies according to the amount of MSW available and, consequently, is related directly to the population density in the location of the plant. Therefore, in major urban areas such as San Francisco, San Diego and Los Angeles, many MSW-to-energy plants are being proposed which will have the capability to burn more than 1,000 tpd of MSW and produce significant quantities of steam or electricity. For example, energy production levels from a 1,100 tpd size plant would be 230,000 pounds per hour of process steam or 23 megawatts of electricity. There are few steam users in California that would use this quantity of steam year-round. As a result, most large MSW-to-energy plants in California are proposing to maximize electricity production for sale to the local utility.

For rural communities and less densely populated urban communities, such as Fresno and Sacramento, the proposed size of MSW-to-energy plants generally range from 300 to 700 tpd. Energy production levels from these size plants will range from 62,000 to 150,000 pound per hour of process steam, or 6 to 15 megawatts of electricity. In general, these steam production levels correspond to the energy demands of medium-sized manufacturing facilities or district heating plants. Consequently, MSW-to-energy plants in rural or smaller urban communities may operate as cogenerators, supplying baseload electricity to local utilities and process steam to nearby heat users.

2. CURRENT USE AND FUTURE TRENDS

a. Current Fuel Supply and Demand Estimates

The supply of MSW potentially available as fuel is theoretically the quantity of MSW collected and transported to landfills for permanent disposal. The estimated amount of MSW currently landfilled in California is 36 million tons per year. Approximately 80 percent of this MSW is generated in the greater Los Angeles, San Francisco and San Diego urban areas. In addition, more than 95 percent of the MSW landfilled in California is disposed of in landfills that accept 100 tpd or more of refuse. Assuming that it is practical to burn only the MSW from 100 tpd or larger landfills, there are approximately 35 million tons per year of MSW currently available in California for use as fuel. This is equivalent to approximately 315 trillion Btu per year of energy.

The actual current demand for MSW as a fuel in California is very low because MSW-to-energy plants are just beginning to emerge in the state. At present, the only operational MSW-to-energy plant in California is located in Susanville. This small cogeneration plant uses approximately 96 tpd of MSW as fuel, and is capable of generating about 1.5 megawatts of electricity. Consequently, the current amount of MSW actually used in California as fuel is less than 30,000 tons per year or 270 billion Btu per year.

b. Future Supply and Demand Projections

The future supply of MSW in California is projected to increase as a result of increasing population in the State. It is estimated that the annual supply of MSW in California will be 37 million tons (333 trillion Btu) in 1990, 40 million tons (360 trillion Btu) in 1987, and 43 million tons (387 trillion Btu) in 2005. These supply projections assume there are no changes in per capita MSW generation rates, no changes in consumer packaging practices, and continuance of current recycling practices. Because changes will probably occur in these three areas, the projected future MSW supply values should be considered as the maximum amounts of MSW that could potentially be available for MSW-to-energy plants.

Future demand for MSW as a fuel source is projected to increase significantly in California as many of the MSW-to-energy plant projects currently under discussion begin operation. Projection of demand for MSW in the year 1990 is made assuming that all MSW-to-energy plant projects currently planned for California will be built and begin operation on schedule. The individual plant burn capacity and gross electricity generating capacity as reported by the project proponents are listed by electric utility service area in Table J-11. By the year 1990, 23 MSW-to-energy plants are projected to be operating in California. These plants will burn a total of 8 million tons of MSW (72 trillion Btu) per year and have an installed gross electricity generating capacity of 537 megawatts.

The years 1997 and 2005 are well beyond the lead times normally associated with planning specific MSW-to-energy plant projects. Consequently, demand for MSW as a fuel is projected assuming that only the refuse from communities facing landfill closure during these time periods will be available for use as fuel, and that 70 percent of this available MSW will actually go to MSW-to-energy plants for use as fuel. Estimates of the energy demands associated with these MSW-to-energy plants are projected assuming most of the plants will be located in densely populated urban areas. The justification for this assumption is that existing trends show nearly all of the major urban communities in California will have used their existing landfill capacity by 1995. Consequently, pressure to resolve MSW disposal problems will be greater in these areas than in less densely populated areas that may have residual landfill capacity. Future energy demand estimates also assume that most of the facilities will be large MSW-to-energy plants operated as baseload power plants. In particular, 80 percent of the energy available from the MSW-to-energy plant is assumed to be used for electricity generation. The remaining energy is assumed to be used to produce process heat or steam.

Based on the above assumptions, MSW-to-energy plants in California could burn up to approximately 15 million tons of MSW (135 trillion Btu) per year and have an installed gross electricity generating capacity of about 830 megawatts by 1997. By the year 2005, MSW-to-

energy plants could burn up to approximately 20 million tons (180 trillion Btu per year) of MSW and have an installed gross electricity generating capacity of 1,100 megawatts.

c. Potential Impacts on Supply and Demand Projections

The estimated use and demand of MSW as fuel projected to occur in the future can be impacted by a number of factors. Rapid decreases in landfill capacity and increased ground water contamination problems at existing landfills, could all accelerate the development of MSW-to-energy projects.

Factors that could delay or prevent use of MSW as a fuel include citizen opposition to MSW-to-energy facilities, environmental concerns, costs of meeting regulatory requirements, increased availability of inexpensive landfills, and an abundance of inexpensive fossil fuels. If a large number of these factors are present, estimates of future use of MSW as a fuel can be expected to dwindle significantly or be shifted dramatically away from the present.

3. FUEL SUPPLY AVAILABILITY AND PRICE IMPACTS

a. Fuel Supply Disruptions

Supply disruptions of MSW can be expected to occur in two ways: disruptions in the collection and transfer of MSW (e.g., a garbage collectors strike), and decreased generation of MSW.

Due to the putrescible nature of MSW, no more than a 3 day supply is maintained at mass burn type MSW-to-energy plants. RDF type plants operating today frequently have limited storage capacity. Consequently, any disruption in the collection and transfer of MSW would force many MSW-to-energy plants to shut down and cease energy production. However, because long term accumulation of MSW at the sources must be prevented to protect public health, problems affecting the collection and transit of MSW are expected to be quickly resolved. As a result, disruptions in the collection and transfer of MSW most likely will be short term and not have a significant overall impact.

More significant overall impacts on MSW supplies may occur due to changes in consumer packaging practices or initiation of extensive resources recycling programs. Legislative actions or economic forces which lead to reduced use of disposable packaging could decrease the total amount of MSW available to MSW-to-energy plants. Similarly, extensive resource recycling programs could also reduce MSW supplies.

b. Fuel Price Impacts

Fuel price impacts for MSW-to-energy plants cannot be easily predicted. At a conventional energy plant, the plant owner pays a price for the fuel delivered to the plant. At MSW-to-energy plants, the plant owner charges a price for each ton of MSW delivered to the plant (the tipping fee). The tipping fee is used, along with revenues generated from energy sales, to offset the capital and operating costs associated with disposing of MSW in a MSW-to-energy facility.

In many agreements, the tipping fee is adjusted on a monthly basis using a formula which accounts for plant operating and maintenance costs, finance payments, and credits for energy sales and recovered material sales (if any). Thus, during the operating life of a MSW-to-energy plant, the tipping fee may increase significantly if operating and maintenance costs escalate faster than energy prices due to inflation or if energy revenues decline due to falling electricity and steam prices.

Increasing MSW-to-energy plant tipping fees could potentially disrupt the supply of MSW to the plant. If the tipping fee increases to a level where it is less expensive for a community to transport the MSW to a landfill, the MSW-to-energy plant could lose a portion or all of its MSW supplies. However, in many cases, the MSW supply economics for a particular MSW-to-energy plant are significantly more complex due to factors such as long term contracts between plant owners and MSW collectors, and municipal laws which specify how tipping fees can be changed or adjusted.

c. Impact on State Economy

MSW supply disruptions and price fluctuations are expected to have a minor impact on the State's overall economy. The development of MSW-to-energy plants in California will create temporary field construction jobs and a small number of permanent plant operator jobs. The major plant equipment components are manufactured by companies primarily located outside of California. If the initial MSW-to-energy plants built in California fail to operate profitably due to MSW supply disruptions and price fluctuations, the willingness of the financial community to invest in additional MSW-to-energy plants in California may be affected. This could significantly increase the costs of financing plants. It may also place a severe burden on the budgets of some city or county governments faced with no other MSW disposal alternative but to build a MSW-to-energy plant.

III. LANDFILL GAS

1. DESCRIPTION OF FUEL GROUP AND ENERGY END-USE INDUSTRIES

a. Fuel Group

Landfill gas differs from natural gas in several important ways including its source, methods of collection and composition. Natural gas is formed as the result of a geological process spanning millions of years. In comparison, landfill gas is formed in a matter of months by the anaerobic decomposition of the organic fraction of municipal solid waste (MSW) in a landfill. Because of this rapid rate of gas formation, the generation of landfill gas poses potential environmental problems. Landfill gas migrates to the surrounding environment outside of the landfill by following the path of least resistance. Uncontrolled landfill gas that is emitted to the atmosphere creates a public nuisance and is a possible detriment to public health. Landfill gas can also migrate through the soil and enter groundwater supplies.

Collection of landfill gas can alleviate the environmental problems of off-site migration. Commercial demonstrations have also shown that the collected gas can be a viable alternative to natural gas. While natural gas is collected under great pressure from reservoirs located hundreds of feet below the earth's surface, landfill gas is collected in a much different manner.

A collection system consists of a series of wells connected by a gathering system. A slight vacuum is pulled at each well. It is important that air not be drawn into the landfill because the landfill gas forming process is anaerobic.

The rate of production and composition of the gas generated in a landfill is dependent on the composition of the waste, age of the landfill, moisture content and temperature. Gas production rates from landfills in California generally average .075 cubic feet of gas per year for every pound of garbage. When collected from the landfill, the gas is composed of approximately 50 percent methane (CH_4) and 50 percent carbon dioxide (CO_2) with trace amounts of other gases. This gas has a heating value of approximately 500 Btu per standard cubic foot (Btu/scf).

Landfill gas normally is treated prior to burning in a combustion device. The extent of gas treatment is dependent on the intended application of the gas. As more contaminants are removed from the gas, the heating value of the gas increases but costs also increase. Gas treatment includes removal of water, carbon dioxide, nitrogen particulates and trace contaminants. To produce a medium-Btu gas (500 to 550 Btu/scf), only water, trace contaminants and particulates are removed. For a high-Btu gas (1000 Btu/scf), with a heating value approaching that of natural gas, the carbon dioxide

must also be removed. With minor modifications, landfill gas can be burned in conventional combustion devices designed to burn natural gas. Consequently, the technology to use landfill gas as a fuel is commercially available. Because most contaminants are removed, air pollutant emission rates from burning landfill gas are comparable to the rates associated with burning natural gas.

b. Energy End-Use Industries

Energy end-use industries associated with the use of landfill gas can be broadly classified according to the three ways in which the gas is marketed: medium Btu gas for use as a boiler fuel substitute; high Btu gas for use as pipeline quality gas; and medium Btu gas for use at small-scale electricity production plants.

Typically, buyers of medium Btu gas use it as a boiler fuel substitute to produce process steam. For financial reasons, medium Btu gas cannot be transported more than a few miles from its generation source. As a result, users of medium Btu gas must be located near the landfill providing the gas. Consequently, industries using medium Btu landfill gas as a fuel will most likely be small to medium sized manufacturing plants located in the urban areas of California.

High Btu gas is predominantly sold to gas companies to be mixed with their natural gas in pipeline transmission systems. High Btu landfill gas can be compressed and piped much like natural gas. Long distance transport is economic, reducing the need for nearby users. However, due to the costs involved in upgrading landfill gas to a high Btu level, major buyers of this fuel are expected to be large utilities located in urban areas.

The last market for landfill gas is for use in producing electricity for sale to a local utility. Essentially, pretreated medium Btu gas is used as the primary fuel source for either an internal combustion engine or a gas turbine driving an electrical generator. Of the three market uses, generation of electricity is the least efficient way to use landfill gas. However, the high avoided costs or displacement of high retail rates makes this energy option viable in many areas of California.

2. CURRENT USE AND FUTURE TRENDS

a. Current Use

The supply of landfill gas in California is difficult to determine because data on the amount of MSW in place at existing landfills is incomplete, gas formation rates vary significantly due to local conditions, and the period of time the MSW has been in place at some landfills is uncertain. Consequently, until more information becomes available, a simplified approach must be used to estimate the theoretical potential supply of landfill gas currently available

in California. The total MSW tonnage in place was estimated for each landfill in California receiving 200 tpd or more of MSW, and multiplied by a statewide average gas formation rate (0.075 standard cubic feet of gas per pound of MSW per year). Using this approach, the estimated current supply of landfill gas in California is 275 million standard cubic feet per day (scf/d). This is equivalent to 150 trillion Btu per year.

There are 25 landfill gas recovery facilities presently operating in California producing a total of 35 million standard cubic feet per day (scf/d) of landfill gas. This is equivalent to approximately 6.4 trillion Btu per year. Table J-12 is a listing of these facilities along with gas and/or electrical production by utility service area.

Direct use of medium Btu gas from landfills occurs at 11 facilities in California. Approximately 25 million scf/d is currently being collected and used for various applications. An additional 10 million scf/d of landfill gas is processed at the Operating industries and Palo Verdes landfill sites to remove carbon dioxide and produce a fuel with a heating value equal to natural gas. This results in approximately 5 million scf/d of high Btu gas which is added to the existing natural gas pipelines.

Currently in California, electrical generation using landfill gas occurs at 12 facilities and accounts for approximately 25 megawatts; 17 MW generated in the Southern California Edison service area and 8 MW generated in the Pacific Gas and Electric service area. With the exception of one facility, all recovery operations in California that produce electricity utilize internal combustion engines for electrical production. Puente Hills uses landfill gas as fuel in a gas turbine to drive an electrical generator. This facility is unique in that it also supplies medium Btu gas to a local college as fuel for boilers.

b. Future Trends

The use of landfill gas as a fuel source has grown rapidly over the last several years and by most indications, will continue to increase. Based on estimates provided by project proponents, it is projected that the supply of available landfill gas will be 330 million scf/d (60 trillion Btu per year) by 1990. Of this amount, it is projected that approximately 86 million scf/d (16 trillion Btu per year) will be recovered and used as medium or high Btu fuel for either direct application or electrical generation. This projection takes into account all landfill gas recovery projects under construction or in the planning phase as of 1985. This projection also includes gas recovery at all active landfills in the Bay Area Air Quality Management District (BAAQMD) that have one million tons or more in place as required by BAAQMD regulations.

Gas production is calculated by using the tonnage in place at landfills receiving 200 tons per day or more, and the average gas production rate per pound of refuse. It is difficult to project the end use of this fuel. However, it is expected that the majority of the fuel will be used to generate electricity, as the conditions for direct application exist in a limited number of locations. By 1990, 122 megawatts of electricity may be generated from landfill gas recovery.

By 1997, it is projected that a possible 380 million scf/d of gas (69 trillion Btu per year) will be available from landfills in California. Of this supply, it is estimated that approximately 133 million scf/d (24 trillion Btu per year) will be recovered and utilized as a fuel. The possible electrical equivalency of this fuel is 190 MW.

For 2005, the total amount of gas generated in California landfills is projected to be 420 millions scf/d (77 trillion Btu per year). Of this amount, it is estimated that 160 million scf/d (29 trillion Btu per year) will be collected and recovered as a fuel source. If this fuel were used only to generate electricity, the result would be approximately 230 MW.

In projecting the fuel supply from landfills for the years 1997 and 2005, only those landfills with 2 million tons in place were considered. The total tons in place by these dates were summed and the average gas formation rate (.075 scf/lb/year) was applied to this value to calculate the total gas production. With the exception of those landfills in the BAAQMD, the demand for this fuel was projected to be 50 percent of the total supply. This was determined to be the average recovery rate at facilities presently operating. For landfills in the Bay Area, the assumption was made that 100 percent of the gas generated will be collected and recovered for energy. This assumption is based on BAAQMD regulations requiring collection systems for most landfills in the Bay Area.

c. Factors Influencing Projections

There are several factors that influence the projected trends in landfill gas recovery and utilization. Recent actions that serve as an incentive to the development of landfill gas recovery include required air pollution control measures for gaseous emissions from landfills. By 1987, the Bay Area Air Quality Management District (BAAQMD) will require gas collection and monitoring for all landfills with over one million tons of refuse in place. The South Coast Air Quality Management District (SCAQMD) recently adopted a regulation that will require the majority of landfills in the South Coast area to install gas collection systems by 1989. It is anticipated that the South Coast and Bay Area requirements will serve as incentives for other APCD's to require landfill gas recovery systems.

Additional factors exist which may influence the development of landfill gas utilization as a fuel source. If natural gas prices or retail electrical rates escalate rapidly, use of landfill gas recovery systems can be expected to rapidly grow. However, this scenario appears unlikely at this time.

3. FUEL SUPPLY AVAILABILITY AND PRICE IMPACTS

a. Fuel Supply Disruptions

There are no direct fuel supply disruptions associated with landfill gas recovery. Landfill gas will continue to form by the process of anaerobic decomposition of MSW in a landfill. Once a system is in place, generated gas will continue to be collected on a continuous basis.

b. Fuel Price Impacts

Fuel prices can either accelerate or slow the development of landfill gas utilization. If natural gas prices or retail electrical rates escalate rapidly, the demand for landfill gas may increase. However, the demand for landfill gas may be reduced if conventional fuel costs decrease.

c. Impact on State Economy

Fuel supply availability and pricing for landfill gas are expected to have a very minor impact on the state's economy. The major impact that could result from an increase in landfill gas development in California would be a temporary increase in new jobs.

APPENDIX K

COMPARISON OF TWO TIER VALUE-OF-SERVICE AND SINGLE TIER COST-OF-SERVICE UEG GAS RATES IN THE PGandE SYSTEM

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COMPARISON OF TWO TIER VALUE-OF-SERVICE AND SINGLE TIER COST-OF-SERVICE UEG GAS RATES IN THE PGandE SYSTEM

This appendix provides the calculations and basic assumptions used to compare the relative benefits of two alternative gas rate structures for utility electric generation (UEG).

The reference for the comparison is a single tier value-of-service UEG gas rate structure (VSI) where UEG gas costs are estimated to equal UEG fuel oil costs. The first alternative is a two-tier value-of-service UEG gas rate (VS2) with the weighted average gas price equal to UEG fuel oil costs. In this alternative the second tier price is set near the gas utility's (UG's) incremental cost-of-service while the first tier price is set at a level sufficient to cover all other UG revenue requirements associated with serving the UEG. Total revenue collected by the UG will be the same in VS2 as in VSI if gas sales to UEG are the same. The second alternative is a single tier cost-of-service gas rate (CSI) based on the UG's cost to serve the UEG customer.[1]

Potential gas rate benefits would be applicable to both the electric ratepayer and the gas ratepayer. For the electric ratepayer these would be from the areas of fuel costs, economy energy purchases, operation and maintenance expenses, and purchases from QFs and from geothermal steam producers. Gas utility ratepayers may also receive benefits from contributions to the UG's margin from sales to UEGs, QFs and TEOR steam generators. Overall benefits would be the total of electric and gas ratepayer benefits.

The results of the analysis are provided in Table K-1 showing differences between each of the alternative rate structures compared to VS1 reference gas rate. Without elaboration, the cost-of-service based UEG rate provides more overall benefits to the state's ratepayers. These benefits would potentially be higher if economy energy purchased had been based on the UEG gas rate. Additionally, no attempt was made to determine the effect on QF purchased energy produced from energy inputs other than utility gas (solar, wind, MSW, nonutility gas).

BACKGROUND

POWRSYM analysis[2] was performed on the PGandE system for the year 1990 using PG&E CFM 6 data. This analysis was performed for the VSI gas rates and for VS2 gas rates.

The principal resource difference between the VS1 and VS2 runs concern the use of dispatchable cogeneration and UEG generation. The second tier gas rate in VS2 is lower than the average UEG gas price that is used to set the price for cogeneration energy. As a result, less dispatchable cogeneration is purchased under VS2 than in VS1 because UEG steam electric units are run more.

TABLE K-1

COMPARISON OF TWO-TIER VALUE-OF-SERVICE AND
SINGLE TIER COST-OF-SERVICE UEG GAS RATE STRUCTURES
IN THE PGandE SYSTEM
(Millions of 1990 Dollars)

	Annual Ratepayer Benefits[a]	
	Two-Tier Rate[b] (VS2)	Cost-of-Service Rate (CS1)
Electric Ratepayer Benefits		
UEG Gas Fuel Purchase Cost	-144.3	144.2
Operation and Maintenance Expenses	-18.1	0
Economy Energy Purchase Costs	0[c]	0[c]
QF-Cogeneration Purchase Costs	205.2	135.9
Geothermal Purchase Costs	-22.1	39.6
Total	20.7	319.7
Gas Ratepayer Benefits		
UEG Fuel Purchases	5.1	-144.2
QF Cogeneration Fuel Purchases	-76.4	-105.5
TEOR Fuel Purchases	9.6	0
Total	-61.7	-249.7
Overall Ratepayer Benefits	-41.0	70.0

a. Savings are with reference to expenditures under a single tier value-of-service rate structure.

b. POWRSYM simulations based on PGandE CFM VI Resource Plan.

c. There are no economy energy savings because PGandE does not purchase economy energy from the Southwest.

Note: Negative values are increased expenditures.

The gas rates assumed under CS1 provide the same gas price to both the cogenerator and the UEG steam electric units. It was therefore assumed that under CS1 the UEG would run its system in the same manner as in VSI, but with cost-of-service based rates. Table K-2 provides a summary of the values used for VS1, VS2 and CSI.

ELECTRIC RATEPAYER BENEFITS

Potential electric ratepayer benefits would be derived from UEG fuel costs, economy energy purchases, operation and maintenance expenses, purchases from QF's, and from geothermal steam purchases. This may be expressed in equation form as

$$ERB = BFC + BEE + BOM + BQF + BGEO \quad (1)$$

where:

ERB = Electric ratepayer benefits
BFC = UEG fuel cost benefits
BEE = UEG economy energy purchases benefits
BOM = UEG operation and maintenance costs benefits
BQF = UEG cogeneration energy costs benefits
BGEO = UEG geothermal generation costs benefits.

The following provides the assumption and basic calculations used to derive ERB.

UEG Fuel Cost Benefits

The UEG fuel costs are determined by multiplying the unit cost times the quantity of fuel purchased. In this analysis the fuel is natural gas. For each of the alternative rates the resultant fuel cost is subtracted from the base cost (VS1) to obtain fuel costs benefits. In equation form this is expressed as follows:

Fuel cost = Unit Price * Quantity of Fuel (2)

BFC = Fuel Cost (VS1) - Alternate gas rate fuel cost (3)

VS1 Fuel Cost

FC (VS1) = \$7.40 per mmBtu * 75.1 TBtu (see 2)
= \$555.7 million

VS2 Fuel Cost

FC (VS2) = \$6.89 per mmBtu * 101.6 TBtu (see 2)
= \$700.0 million

TABLE K-2

SUMMARY OF INPUT FACTORS
FOR COMPARISON OF TWO-TIER AND COST-OF-SERVICE UEG
RATE STRUCTURES IN PGandE SYSTEM
(1990 Dollars)

	Input Factors		
	Value-of-Service		Cost-of-Service
	Single Tier (VS1)	Two Tier (VS2)	Single Tier (CS1)
Electric Utility			
Gas Price ($/mmBtu)	7.40	6.89	5.48
Gas Use (TBtu)	75.1	101.6	75.1
Gas Generation (GWH)	6,599	9,535	6,599
Nuclear Fuel Price (Mil/KWH)	4.04	4.04	4.04
Nuclear Generation (GWH)	12,345	12,345	12,345
Generation from Cogen (GWH)	8,287	5,413	8,287
Geothermal Generation (GWH)	9,887	9,887	9,887
Operation & Maintenance (10^6 $)	122.2	140.3	122.2
Cogeneration			
Gas Price ($/mmBtu)	7.40	6.89	5.91
Gas Use (TBtu)	70.8	46.2	70.8
Gas Utility			
Average Gas Cost ($/mmBtu)	5.25	5.25	5.25

Source: SERA, Electric Utility Purchase/Generation Tradeoffs: Gas Pricing Implications, October, 1985 prepared under contract to the CEC.

BFC (VS2) = FC (VS1) - FC (VS2) (see 3)
= $555.7 million - $700.0 million
= -$144.3 million

CSI Fuel Cost

FC (CSI = $5.48 per mmBtu * 75.1 TBtu (see 2)
= $411.5 million

BFC (CSI) = FC (VSI) - FC (CS1) (see 3)
= $555.7 million - $411.5 million
= $144.2 million

Economy Energy Purchase Benefits

Economy energy purchases from Southwest utilities are priced by splitting the difference between the seller's cost and the buyer's avoided cost. Gas rates, therefore, can affect the economy energy costs.

PGandE purchases no economy energy from Southwest utilities. For this analysis it is therefore assumed there are no economy energy purchase benefits.

BEE (VS2) = 0

BEE (CSI) = 0

O&M Cost Benefits

The UEG operation and maintenance expenses will vary somewhat according to the use of the generation facilities. The differences in O&M costs between the several alternatives and the base rate case provide the benefits. This may be expressed as follows:

OM = OM (VSI) - OM costs for each of the alternatives (4)

VS2 Operation and Maintenance Benefits

OM (VS2) = OM (VS1) - OM (VS2) (see 4)
= $122.2 million - $140.3 million
= - $18.1 million

CS1 Operational and Maintenance Benefits

OM (CS1) = OM (VS1) - OM (CSI) (see 4)
= $122.2 million - $122.2 million
= 0

QF Cost Benefits

The UEGs purchase energy from various QFs including cogenerators. (In this analysis only cogenerators using UG gas are considered.) Differences in

cogeneration energy purchase costs can be estimated using the costs of natural gas to the cogenerator produced at a contractually specified 8,540 Btu per KWH heat rate. The differences in the overall purchase cost establish benefits. This is expressed in the following equations.

QF energy costs = 8,540 Btu per kWh * QF gas rate * QF energy (5)

BQF = QF (VS1) - Alternate QF energy costs (6)

VS1 QF Energy Costs

QF (VS1) = 8,540 Btu per kWh * $7.40 per mmBtu * 8,287 GWH (see 5)
= $523.7 million

VS2 QF Energy Cost

QF (VS2) = 8,540 Btu per kWh * $6.89 per mmBtu * 5,413 GWH (see 5)
= $318.5 million

BQF (VS2) = QF (VS1) - QF (VS2) (see 6)
= $523.7 million - $318.5 million
= $205.2 million

CS1 QF Energy Cost

QF (CS1) = 8,540 Btu per kWh * $5.48 per mmBtu * 8,287 GWH (see 5)
= $387.8 million

BQF (CSI) = QF (VS1) - QF (CS1) (see 6)
= $523.7 million - $387.8 million
= $135.9 million

Geothermal Generation Cost Benefits

There is a specific formula used to determine the price PGandE pays for geothermal steam. The formula is based on fuel costs and quantities of energy generated and is as follows:

PS = [(C1 * ACg * Gg + ACn * Gn)/(Gg + Gn)] + .5 (7)

where:

Ps = The price paid for steam in mills per kWh

C1 = A coefficient which takes into account change in gas/oil heat rates, unit costs and inflation.

ACg = The average cost of natural gas in $ per mmBtu

Gg = Electric generation in GWH

ACn = The average cost of nuclear fuel in mills per kWh

Gn = Electric generation using nuclear fuel in GWH

The formula uses last year's results to determine this year's steam cost. For this analysis using 1990 data would provide 1991 steam costs. By assuming a discount factor of 15 percent the 1991 cost was adjusted to represent a 1990 steam cost.

Benefits for each of the alternatives are determined by first obtaining the difference between the unit steam purchase costs between the alternatives and the base rate case. The difference multiplied by the geothermal generation (9,887 Gwh) provides the geothermal generation cost benefits which are then adjusted to 1990 dollars. This may be expressed as

BGEO = [(PS (VS1) - PS for alternatives) * 9,887 GWH]/1.15 (8)

Coefficient Determination

Heat Rate Ratio Initial Gas Rate Inflation Adjustment

$$C1 = \frac{8{,}523 \text{ Btu per kWh}}{8{,}272 \text{ Btu per kWh}} * \frac{1}{\$.31611 \text{ per mmBtu}} * \frac{2.11 \text{ mill per kWh}}{1}$$

$$C1 = 6.8774 \frac{\text{mill per kWh}}{\$ \text{ per mmBtu}}$$

VS1 Geothermal General on Cost

$$PS\ (VS1) = [[6.8774 \frac{\text{mill per kWh}}{\$/\text{mmBtu}} * \$7.40/\text{mmBtu} * 6{,}599 \text{ GWH}$$

$$+ 4.04 \text{ mill/kWh} * 12{,}345 \text{ GWH}]\ /(6{,}599 \text{ GWH} + 12{,}345 \text{ GWH})]$$

$$+ .5 \qquad \text{(see 7)}$$

$$= 20.86 \text{ mill/kWh}$$

VS2 Geothermal Generation Costs

$$PS\ (VS2) = [[6.8774 \frac{\text{mill per kWh}}{\$/\text{mmBtu}} * \$6.89 \text{ per mmBtu} * 9{,}535 \text{ GWH}$$

$$+ 4.04 \text{ mill/kWh} * 12{,}345 \text{ GWH}]/\ (9{,}535 \text{ GWH} + 12{,}345 \text{ GWH})]$$

$$+ .5 \qquad \text{(see 7)}$$

$$= 23.43 \text{ mill per kWh}$$

BGEO (VS2) = 9,887 GWH [PS (VS1) - PS (VS2)]/ 1.15 (see 8)
= 9,887 GWH (20.86 mill per kWh - 23.43 mill per kWh)/ 1.15
= -$22.1 million

CS1 Geothermal Generation Cost

$$PS\ (CS1) = [[6.8774 \frac{\text{mill per kWh}}{\$/\text{mmBtu}} * \$5.48 \text{ per mmBtu} * 6{,}599 \text{ GWH} + 4.04 \text{ mill/kWh} * 12{,}345 \text{ GWH}]/ (6{,}599 \text{ GWH} + 12{,}345 \text{ GWH})] + .5 \quad \text{(see 7)}$$

$$= 16.26 \text{ mill per kWh}$$

$$BGEO\ (CS1) = 9{,}887 \text{ GWH } [PS\ (VS1) - PS\ (CSI)]/ 1.15 \quad \text{(see 8)}$$
$$= 9{,}887 \text{ GWH } (20.86 \text{ mill per kWh} - 16.26 \text{ mill per kWh})/ 1.15$$
$$= \$39.6 \text{ million}$$

Summary of Electric Ratepayer Benefits

$$ERB = BFC + BEE + BOM + BQF + BGEO \quad (1)$$

Two Tier Value of Service Rates (VS2)

$$ERB(VS2) = - \$144.3 \text{ million} + 0 - \$18.1 \text{ million} + \$205.2 \text{ million} - \$22.1 \text{ million} \quad \text{(see 1)}$$

$$ERB(VS2) = 20.7 \text{ million}$$

Single Tier Cost-of-Service Rates (CSI)

$$ERB(CS1) = \$144.2 \text{ million} + 0 + 0 + \$135.9 \text{ million} + \$39.6 \text{ million} \quad \text{(see 1)}$$

$$ERB(CS1) = \$319.7 \text{ million}$$

GAS RATEPAYER BENEFITS

Gas ratepayers may also benefit from changing UEG gas rates. This would result from contribution to the gas utilities' margin or distribution costs from sales to UEGs, cogenerators and TEOR steam generators. This may be expressed as follows.

$$GRB = UEG + QF + TEOR \quad (9)$$

where:

GRB = Gas ratepayer benefit
UEG = UEG distribution cost contributions benefit
QF = QF distribution cost contribution benefits
TEOR = TEOR distribution cost contribution benefits.

Distribution costs are the gas utilities' cost to operate its system, that is, the cost or margin above gas acquisition costs. For this analysis, an average gas acquisition cost is used and assumed to be $5.25 per mmBtu. This is consistent with SERA assumptions that the incremental cost of service for the second tier in VS2 is 15 cents per mmBtu.[3] This acquisition cost is applicable to all sectors.

In general the distribution cost contribution may be estimated by multiplying the difference between the gas rate and the gas acquisition cost by the quantity of sales. This may be expressed in equation form as follows:

DC = [GR - $5.25 per mmBtu] * GS (10)

where:

DC = Distribution cost contribution
GR = Gas rate
GS = Gas sales for the appropriate gas rate.

Gas ratepayer benefits for each sector can be determined by comparing the contributions to distribution costs:

Sector = DC (alternate gas rate) - DC (VS1) (11)

where:

Sector = Sector benefit for UEG, QF or TEOR
DC (alter) = distribution cost contribution for one of the alternate rates
DC (VS1) = distribution cost contribution for rate case VS1.

UEG Distribution Cost Contribution Benefits

VS1 UEG Distribution Cost Contribution

DC UEG (VS1) = ($7.40 per mmBtu - $5.25 per mmBtu) * 75.1 TBtu (see 10)
= $161.5 million

VS2 UEG Distribution Cost Contribution

DC UEG (VS2) = ($6.89 per mmBtu - $5.25 per mmBtu) * 101.6 TBtu (see 10)
= $166.6 million

UEG (VS2) = DC UEG (VS2) - DC UEG (VS1) (see 11)
= $166.6 million - $161.5 million
= $5.1 million

CS1 UEG Distribution Cost Contribution

DC UEG (CS1) = ($5.48 per mmBtu - $5.25 per mmBtu) * 75.1 TBtu (see 10)
= 17.3 million

UEG (CS1) = DC UEG (CS1) - PC UEG (VSI) (see 11)
= $17.3 million - $161.5 million
= - $144.2 million

QF Distribution Cost Contribution Benefits

VS1 Cogeneration Distribution Costs Contribution

DC QF (VS1) = ($7.40 per mmBtu - $5.25 per mmBtu) * 70.8 TBtu (see 10)
= $152.2 million

VS2 Cogeneration Distribution Cost Contribution

DC QF (VS2) = ($6.89 per mmBtu - $5.25 per mmBtu) * 46.2 TBtu (see 10)
= $75.8 million

QF (VS2) = DC QF (VS2) - DC QF (VS1) (see 11)
= $75.8 million - $152.2 million
= -$76.4 million

CS1 Cogeneration Distribution Cost Contribution

DC QF (C51) = ($5.91 per mmBtu - $5.25 per mmBtu) * 70.8 TBtu (see 10)
= $46.7 million

QF (CS1) = DC QF (CSI) - DC QF (VS1) (see 11)
= $46.7 million - $152.2 million
= -$105.5 million

QF TEOR Steaming Distribution Cost Contributions

In VS2 TEOR dispatchable cogeneration is cut back, but TEOR steaming requirements continue. In Appendix F it was indicated that current TEOR cogeneration machines are using 46 percent of the fuel for steam, 28 percent for electricity and 26 percent is waste heat.

For the purposes of this analysis it is assumed that fuel component for steaming will continue at the same level and that waste heat is equally shared between steaming and electric generation. This then requires that 59 percent of the TEOR cogeneration fuel would be applied to steaming operations.

Reduced cogeneration fuel requirements (RCG) is the difference between QF fuel requirements in VS1 and VS2. This equals

RCG = 70.8 TBtu - 46.2 TBtu
= 24.6 TBtu

Increased TEOR steaming fuel requirements (SFR) would then be 59 percent of the reduced cogen fuel requirements.

SFR = .59 * RCG
= .59 x 24.6 TBtu
= 14.5 TBtu

TEOR gas rates currently approach cost-of-service. It is therefore presumed that the TEOR gas rate equals the cogeneration gas rate in CS1 or $5.91 per mmBtu.

DC TEOR (VS2) = ($5.91 per mmBtu - $5.25 per mmBtu) * 14.5 TBtu (see 10)

= $9.6 million

TEOR (VS2) = DC TEOR (VS2) - DC TEOR (VS1) (see 11)
= $9.6 million - 0
= $9.6 million

There is no TEOR benefit for VS1 and CS1 as there are no increased sales for straight TEOR steaming resultant from decreased TEOR cogeneration.

Summary of Gas Ratepayer Benefits

GRB = UEG + QF + TEOR (9)

Two Tier Value of Service Rates (VS2)

GRB (VS2) = $5.1 million - $76.4 million + 9.6 million (see 9)
= -$61.7 million

Single Tier Cost-of-Service Rate (CS1)

GRB (CS1) = -$144.2 million - $105.5 million + 0 (see 9)
= -$249.7 million

OVERALL RATEPAYER BENEFITS

Overall ratepayer benefits (ORB) for the alternative rate cases would be a summation of the corresponding electric and gas ratepayer benefits.

ORB = ERB + GRB (12)

Two-Tier Value-of-Service Rate (VS2)

ORB (VS2) = $20.7 million - $61.7 million (see 12)
= -$41.0 million

Single Tier Cost-of-Service (CS1)

ORB (CS1) = $319.7 million - $249.7 million (see 12)
= $70.0 million

Footnotes - Appendix K

1. Cost of service gas rates for cogeneration and UEG steam electric facilities were developed based on work recently published by the Southern California Gas Company.* The cost-to-serve used in the CEC analysis was the SoCal Gas total cost less cost of gas and the CAM balancing account. Cogeneration values were taken from values of GN 3, 4, 7 and UEG values were taken from GN 5. The calculation could be expressed as follows:

   Cost-to-serve = total Cost - Cost of gas - CAM Balancing Account

   The cost-to-serve values were then inflated to 1990 dollars from November 1985 dollars using CEC inflation factors.** To approximate cost-to-serve factors which would not escalate, only half of the cost-to-serve values for 1985 were inflated to 1990 dollars. This may be expressed as follows.

   1990 $ Cost-to-Serve = Cost-to-Service (1 + Inflation factor)/2

   The applicable rate under cost-of-service (CS1) is obtained by adding the unit cost-to-serve in 1990 dollars to the gas utility average acquisition cost. Consistent with data used in the SERA analyses the acquisition cost was estimated to be $5.25 per mmBtu.

   Cost-of-Service Rate = $5.25 per mmBtu + 1990$ Cost-to-Serve

   <u>Cogeneration Cost-of-Service</u> ($ per mmBtu)

   Cost-of-Service = 3.95 - 3.26 - .10
   = .59

   1990 $ Cost-of-Service = $\frac{.59}{2}$ (1 + 142.65)
   = .66

   Cost-of-Service Rate = 5.25 + .66
   = $5.91 per mmBtu

   <u>UEG Cost-of-Service ($ per mmBtu</u>

   Cost-of-Service = 3.52 - 3.23 - .09
   = .20

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*So Cal Gas, <u>Base Supply and Load Equation Cost Allocation Study, November 1985 CAM</u>, Tab Summary

**CEC CFM 6 Inflation Factors as of May 20, 1985 based on 1983 equals 100.0
1986 = 113.85
1990 = 142.65

$$1990\ \$\ \text{Cost-of-Service} = \frac{.20}{2}\left(1 + \frac{142.65}{113.85}\right)$$
$$= .23$$

$$\text{Cost-of-Service Rate} = 5.25 + .23$$
$$= \$5.48 \text{ per mmBtu}$$

2. Sierra Energy Risk and Assessment, Inc. (SERA) participated in the BFR 85 proceedings as an expert witness for the CEC. Its testimony was contained in the report Electric Utility Purchase/Generation Tradeoffs Gas Pricing Implications. Principal information used by CEC in Appendix K analysis was drawn from pages V-15 to V-22 and Table C-1 and C-2 in the SERA Report.

3. Ibid, p. V-22.

APPENDIX L

IMPACTS OF ECONOMIC AND FINANCIAL DEVELOPMENTS IN THE OIL INDUSTRY

APPENDIX L
IMPACTS OF ECONOMIC AND FINANCIAL DEVELOPMENTS IN THE OIL INDUSTRY

I. Introduction

This chapter examines the implications for California petroleum markets of recent and projected future economic and financial developments in the oil industry. This analysis focuses primarily on three areas. The implications of deteriorating oil company performance on investment decisions, the effects of changes in the structure of the oil industry heralded by the recent wave of mergers and acquisitions, and the potential effects of increased competition in product markets from foreign refineries soon to become operational. A discussion of the impacts of federal and state regulations is also provided.

The oil industry assessment uses the financial performance statistics of the largest oil producers and refiners in California as its primary data source. Table L-1 lists the 16 companies which are considered. These companies consist of those which have more than 1 percent of crude oil production or 2.5 percent of the refinery capacity in California. The oil industry assessment is based upon a recent contract analysis performed by Price Waterhouse under the direction of the CEC staff.[1]

This chapter first describes economic and financial trends in the oil industry. The second section pursues the implications of these trends on California product markets. The third section examines the potential impacts of federal and state regulations on California petroleum product prices, and is followed by a summary of the chapter.

II. Financial Trends in the Oil Industry

A. Financial Performance

The key measures of financial performance of the oil industry are: short-term liquidity, capital structure and long-term solvency, return on investment, and results of operations.

Short-term Liquidity. Short-term liquidity measures a company's ability to meet its short-term (usually one year) obligations. Without it, a company may be limited in its ability to take advantage of profitable opportunities as they arise and to pay current debt which could lead to forced sale of assets and possibly insolvency.

Short-term liquidity for the group of companies has followed a downward trend. A decline in this measure can reflect either declining current assets and/or increasing current liabilities. As shown below, current assets fell 18 percent from 1980 to 1984 while current liabilities remained basically unchanged.

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1. Price Waterhouse, "Draft Financial Analysis of Major Oil Companies Operating in California," October 1985.

TABLE L-1

THE GROUP OF 16 COMPANIES[a]

5 International Majors	6 National Majors
Exxon Corporation	Arco Oil and Gas, a subsidiary of Atlantic Richfield Company
Mobil Oil Corporation	Phillips Petroleum Company
Shell Oil Corporation	Unocal Corporation
Texaco, Inc. (Acquired Getty Oil Company)	Champlin Petroleum Corp., a subsidiary of Union Pacific Corporation
Chevron Corporation (Acquired Gulf Oil Company)	Conoco, Inc., a subsidiary of Du Pont and Company
	Sun Company, Inc.
3 Independents	**2 Recent Acquisitions**
Petro-Lewis Corporation	Getty Oil Company (acquired by Texaco, Inc.
Tosco Corporation	Gulf Oil Company (acquired by Chevron Corporation)
Tenneco, Inc.	

[a]Although Santa Fe Energy Company accounts for over 1 percent of California production, it is not included in this analysis because it is a subsidiary of Kuwait Petroleum Corporation and does not provide standardized financial and operational data.

Source: Price Waterhouse, "Draft Financial Analysis of Major Oil Companies Operating in California," October 1985.

Current Assets and Liabilities: Company Summary
(millions of dollars)

	1980	1984	% Change
Current Assets	$94,131	$77,214	-18
Current Liabilities	$69,701	$69,687	0

Mergers and industry restructuring activities are clearly behind the decline in short-term liquidity. Texaco, Chevron, Du Pont, and Phillips acquired Getty (1984), Gulf (1984), Conoco (1981), and Aminoil/Geysers/GAO (1983 and 1984), respectively. In addition, Exxon, recording the next largest decline after Gulf, has taken major restructuring actions in the form of the large stock repurchase programs since 1982.

Capital Structure and Long-Term Solvency. Capital structure, the sources of funds which are invested in the assets of a company, is a key factor affecting a company's long-term financial condition. The major sources of funds are owner equity and liabilities (debt).

Companies usually prefer to use internal funds from retained earnings to finance investment. However, current weak market conditions have strained company finances. Given reduced cash flow, they have been forced to rely more heavily on the debt markets. The share of debt to total capital has increased dramatically in 1984, primarily reflecting this increasing reliance on the debt markets to finance investment.

Because the industry is aggressively attempting to reduce its debt, the increase in debt, higher interest charges and repayment commitments do not appear to seriously threaten the overall long-term solvency of the group of companies operating in California. Texaco and Chevron, two of the four companies mostly responsible for the large increase in 1984 debt, have sold or have plans to sell significant assets to streamline operations and alleviate heavy debt burdens. Texaco has recently announced that completed and anticipated sales of assets arising from the Getty acquisition would soon total $2.5 billion. Chevron has announced its plans to sell over $5 billion in assets over the next 3 to 4 years.

While Texaco and Chevron will be reducing their debt in the near term, several of the national majors face likely increases in debt. In early 1985, two national majors embarked upon major stock repurchase programs which will likely weaken their capital structure by increasing debt. First, Atlantic Richfield announced plans to repurchase about $4 billion of its shares, as a part of an effort to increase the profitability of continuing operations. Second, Unocal has bought back about $3.6 billion of its shares, preventing an attempted hostile takeover. Further, some of the smaller independents could face a more serious debt situation and corresponding solvency concerns as sales of assets have not always been successful in preventing income losses.

Return on Investment. Return on investment (ROI) is a key measure used to assess financial performance, relating income to the size of capital necessary

to generate it. The basic formula for computing the ROI is net income/total assets.

Figure L-1 shows that the ROI for the group of companies has followed a downward trend, falling by almost half, from 9 percent in 1980 to 5 percent in 1984. With the exception of 1982, the five international majors have maintained a return 1 to 2 percent higher than the six national majors.

The deterioration in the ROI reflects the negative effect of declining petroleum prices on profit margins. In addition, recent merger/ acquisition activity has reduced the ROI. The reduction occurs because mergers result in investments in assets whose return is not immediately realized because of the time necessary to integrate the new assets into existing operations. The corresponding increase in company debt and interest charges also reduces profit margins.

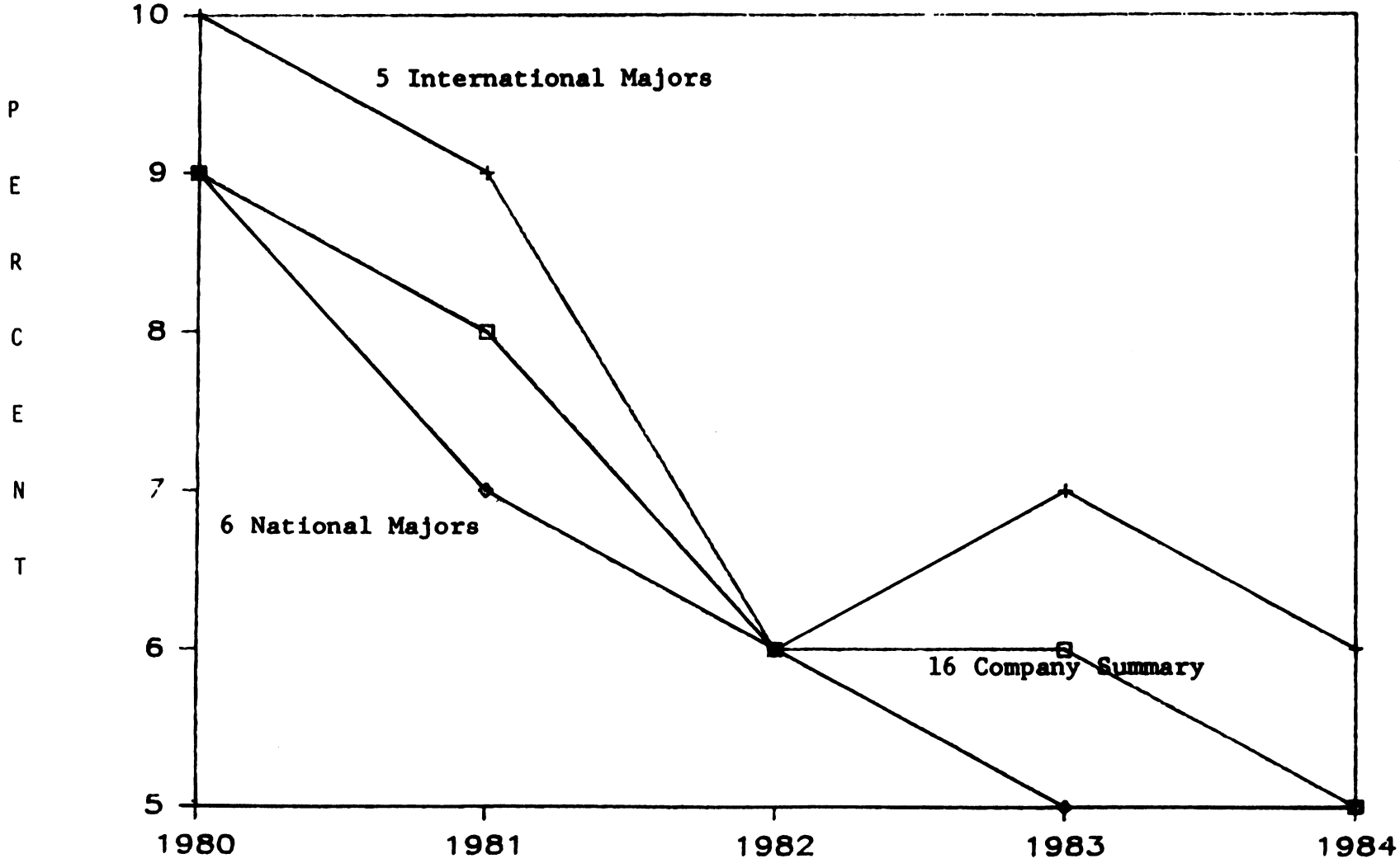
Results of Operations

The results of operations, namely income, is the single most important determinant is assessing a company's financial condition. As shown in Figure L-2 net income has fallen from $23.7 billion in 1980 to $15.9 billion in 1984. The results for individual companies are mixed. In 1984, for example, 7 of the 15 companies recorded increases and 6 reported declines in net income.

In all four areas of analysis, the group of companies' aggregate financial condition has deteriorated over the 1980 to 1984 period. Deteriorating performance, however, has not been uniform across companies or across years. Regardless, several general trends have emerged. These are:

- o Short-term liquidity has been reduced.
  - Current assets fell 18 percent from 1980 to 1984.
- o Debt was increased significantly taking a much larger share of the overall capital structure.
  - The debt to total capital ratio, after falling from 1980 to 1983, rose dramatically from 0.52 in 1983 to 0.56 in 1984, an increase of 7 percent.
  - Between 1980 and 1984, the share of current to total debt declined from 51 to 38 percent while the long-term share, correspondingly, increased from 49 to 62 percent.
- o Return on investment has deteriorated.
  - ROI (net income/total assets) declined from 9 percent in 1980 to 5 percent in 1984.
- o Net income has declined.

Return on Assets Ratio 1/

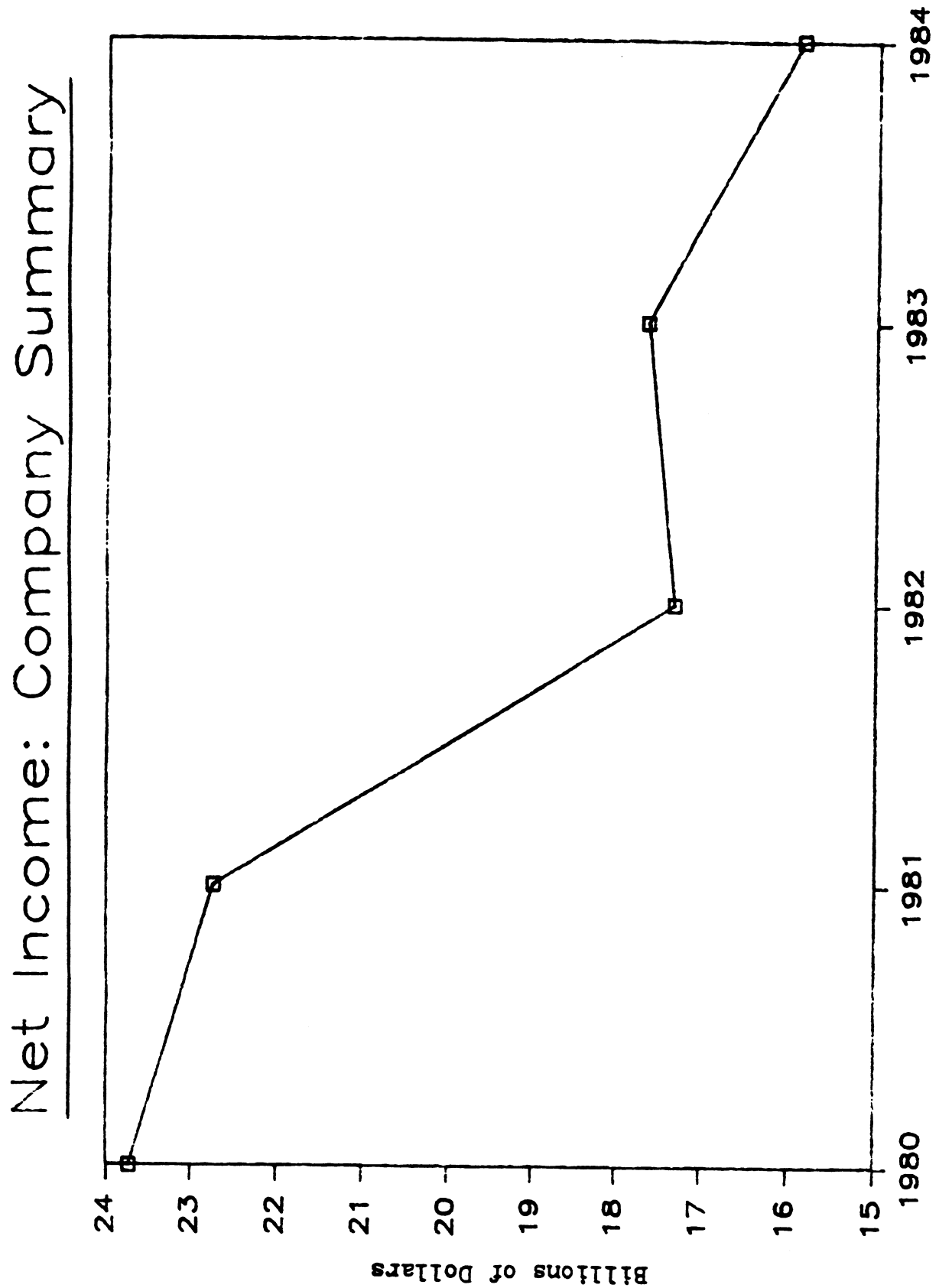


1/ Net income/total assets.

Source: Price Waterhouse, "Draft Financial Analysis of Major Oil Companies Operating in California," October 1985.

FIGURE L-1

FIGURE L-2



Source: Individual company 10Ks.

- Net income declined 33 percent, from $23.7 billion in 1980 to $15.9 billion in 1984.

These trends are the result of falling oil prices and the widespread surge in oil industry restructuring. Despite internal efforts to improve future income and return on investment, oil companies will continue to face an uncertain petroleum market, over which they have little control. While the industry is taking aggressive steps to improve short-term liquidity, reduce debt and increase return on investment, continued weak market conditions may seriously hamper efforts to improve company financial performance in the short-term.

B. Mergers, Acquisitions and Restructuring in the Oil Industry

A firm becomes a merger candidate when there exists a partner with whom better utilization of assets, greater market share, and ultimately greater profits are obtainable. In most oil company mergers, the weaker partner had significant, but underperforming assets, primarily reserves of oil and gas. Both Gulf and Getty, for example, made reserves available to Chevron and Texaco, respectively, for considerably less than it would have cost to acquire such reserves through exploration.

Internal restructurings are undertaken in response to the same phenomena as mergers and acquisitions. Thus, the restructuring of Atlantic Richfield was essentially the same as the takeover-induced restructurings of Phillips and Unocal. In all three cases, common stock was replaced by long-term debt. With fewer shares outstanding, the value of each share rose since, other things being equal, earnings per share would rise.

As shown in Table L-2, from 1979 to 1985, 15 mergers occurred within the group of companies studied. These mergers involved a total transactions value of about $50 billion, of which $31 billion was associated with 1984.

As a result of these mergers, the oil industry operating in California has become more concentrated. In particular, operations have become more concentrated in the group of international major companies. Acquisition activity, i.e., one firm's purchase of part of another company, has followed a similar path. Internal restructurings within the companies have also become prevalent with divestitures or sales of assets representing the most widespread activity.

In the short run, the mergers, acquisitions, and stock repurchase restructurings over the past several years have adversely affected the four key financial indicators for the group of companies. Continued or worsening market conditions will make the industry's efforts to reduce debt and increase income less effective and further deteriorate industry financial performance. In the long-run, the current restructuring activities being undertaken in today's weak product market could improve the oil industry's financial health.

TABLE L-2

MERGER ACTIVITY: 1979-84

Year	Company	Description
1979	Mobil	Acquired General Crude for $.763 billion
1979	Exxon	Acquired Reliance Electric for $1.17 billion
1979	Shell	Acquired Belridge Oil Co. for $3.65 billion
1979	Sun	Acquired Elk River Resources for $.3 billion
1980	Tenneco	Acquired Houston Oil and Minerals for $1.6 billion
	Sun	Acquired Texas Pacific Oil Co. for $2.3 billion
1981	Du Pont	Acquired Conoco, Inc. for $7.8 billion
1983	Phillips	Acquires General American Oil Co. of Texas for $1.14 billion
1984	Chevron	Acquired Gulf Oil for $13.3 billion
	Texaco	Acquired Getty Oil for $10.1 billion
	Mobil	Acquired Superior Oil for $5.7 billion
	Tenneco	Acquired Ekco Products, Inc., Car-4, and Creole Gas Pipeline Corp. for about $249 million
	Phillips	Acquired Aminoil, Inc. and Geysers Geothermal Co. for about $1.6 billion
	Sun	Acquired Exeter Oil Co.
1985	Shell	Acquired by Royal Dutch/Shell Group of Companies

Source: Price Waterhouse, "Draft Financial Analysis of Major Oil Companies Operating in California," October 1985.

III. Impacts of Oil Industry Financial Trends on California Products Market

A. Supply Impacts

The changes in the structure of both individual firms and of the industry itself have not yet dramatically altered the patterns of crude oil supply in the state. However, such changes may occur in the future if a significant portion of the firms in the group of national majors continue to weaken financially in the next few years.

Supplies of crude oil to California from known Alaska reserves are expected to decline by the late 1980s. The only firms likely to continue the search for new discoveries in the Beaufort Sea will be the international majors. These firms have remained relatively strong, however, those with high debt service requirements will be consolidating their finances until at least 1987. Therefore, further exploration endeavors will be delayed in the near term.

The national majors have fewer assets and less cash flow than the international majors. Therefore, in order to pursue high cost exploration, they must invest a higher fraction of their total revenues in exploration, and development than will the internationals. With lowered profits and large debt, they will not likely increase financial risk with new exploration activities.

Financial performance also affects the petroleum product supply market. As indicated in company financial reports, for many of the large firms operating in California, the refining and marketing segments contribute less to profits than does crude oil production. Nonetheless, the refining industry here and abroad requires continued large investments to remain viable.

Poor financial results restrict the ability of companies to upgrade their refineries. As a result, old, inefficient refineries are among the first to be shutdown or sold. In particular, when a refinery handles other companies' crudes and is in need of upgrading investments, a financially pressed firm is likely to close the refinery or sell it to another firm. Such asset sales offer companies a way to reduce total debt. Refinery sales have been initiated by Chevron, Texaco, Mobil and ARCO, however, no major firm has announced plans to leave the California market. Instead, sales of out-of-state refineries increase a company's reliance on the performance of its California refineries.

The most important change in California refinery operations may occur with respect to increased fuel oil competition from Asia and the Arabian Gulf. New refinery construction in OPEC nations will add an exportable volume of petroleum products up to 1 million b/d to the Asia-Pacific region. With as much as 350,000 b/d of this supply in the form of fuel oil entering the Asia-Pacific market, the current surplus of fuel oil will continue into the indefinite future. West Coast refiners will have little choice but to export their residual oil at even more competitive prices.

B. Price Impacts

Regardless of merger activity, worldwide crude oil prices are expected to remain weak over the next five years. California consumers will benefit in the short-term, but weak prices may result in lower investment in Alaska North Slope explorations.

Without significant investments by 1990 in exploration and production, costs of crude oil and products in California may rise as Alaska supplies decline and more expensive imports capture relatively larger shares of the market. Due to the continuing weakness of many of the national majors and the inability of independent producers or refiners to invest in large scale or high risk projects, such investment will likely be carried out by the international majors. Competition will fall and prices may rise to reflect the internally generated capital needed by the major oil companies to reduce debt and explore for new resources.

IV. Regulatory Impacts on Petroleum Product Prices

Petroleum product refining and distribution in California is subject to increasingly stringent air quality regulations at the federal, state, and local levels. Proposed changes in these regulations at all three governmental levels could have a significant adverse impact on the economic and financial structure of the California refining industry. The exact nature of eventual regulations cannot be known precisely, and even if it could, the impacts on refining costs would be difficult to quantify precisely. Despite this difficulty the potential impacts of some of the new and proposed rules can be discussed.

A. Federal and State Regulations

Lead Phasedown. Current EPA regulations call for the elimination of all lead from gasoline by January 1, 1988. Refiners will have to use one of several possible means to replace the octane boost currently provided by lead. All of the alternatives increase the cost of producing gasoline. However, at least one oil company estimates that consumers are not likely to experience impacts greater than one and a half cents per gallon.[2]

Heavy Duty Vehicle Emission Standards. EPA standards will require buses and trucks to install more pollution control devices, such as particulate traps. This equipment will increase the operating costs of these heavy duty vehicles. In addition, particulate traps require the use of low-sulfur diesel fuel. Low sulfur diesel will cost more to produce than current diesel, and require refinery adjustment.

Gasoline Volatility Restrictions. EPA is considering volatility restrictions which could affect both refinery and service station operations. In California, this could require the installation of stage-II at-the-pump vapor

2. Testimony of John Rak, ARCO Petroleum Products Company, August 27, 1985.

recovery systems in these areas of the state which do not already require them. Additional requirements could affect refinery operations.

Reid Vapor Pressure Restrictions. The Air Resources Board (ARB) also controls gasoline volatility via Reid vapor pressure limitations during the summer months, and is considering tightening these restrictions. This measure would affect gasoline refiners' costs. A study commissioned by the South Coast Air Quality Management District estimated additional costs at between $0.18 and $0.37 cents per barrel of crude oil refined.[3]

Airborne Toxics. The Air Resources Board established a program to control airborne toxics in 1982. Several chemicals associated with gasoline refining and consumption, such as the class 1A toxics benzene and diethylbromide, are on the list of substances to be controlled. Although it is unclear at this time what forms of control will be taken, controls may raise the cost of refining gasoline.

Low Sulfur Diesel Fuel. As of January 1, 1985 the Air Resources Board requires reduced levels of sulfur in diesel fuel produced in Southern California refineries. However, the differential effect of this regulation on Northern and Southern California diesel prices is unclear; 1985 Southern California wholesale diesel prices have been sometimes higher and sometimes lower than Northern California diesel prices.

Local Regulations

The Air Resources Board is considering an option to require low sulfur/low aromatic diesel fuel for use in the South Coast Air Basin. If such a requirement were adopted, the ARB estimates that it could raise the price of diesel fuel in Southern California by $0.15 per gallon.[4]

B. Impacts of Federal and State Regulations

The regulations described above could increase the costs of producing refined petroleum products. Such cost increases could have one of several results. Most straightforwardly, they could be passed straight through to consumers in the form of higher product prices across the board. However, competition among California refiners to maintain market share will tend to force some of the cost increases back onto refiners, reducing their profit margins and perhaps inducing further refinery closures. Cost passthrough could also be suppressed by the new competition provided by overseas refiners. To the extent that overseas refiners have access to higher quality crude than California refiners, they may have a cost edge in meeting some of the updated standards, such as for reduced sulfur content. It is conceivable that some

3. Testimony of Paul Wuebben, South Coast Air Quality Management District, September 24, 1985.

4. Testimony of Steve Albu, California Air Resources Board, September 24, 1985.

market niches may be made more accessible to foreign competition as a by-product of these regulations.

This discussion of the potential costs of complying with air quality regulations does not constitute an argument against implementing them. As better estimates of the impacts of the regulations become available, they can be used to get a better fix on the regulations' associated costs and benefits.

V. Summary

The reduced demand for crude oil and the fall in crude oil prices has had far reaching effects on oil industry operations. From 1980 through 1984, the aggregate financial performance of 16 major oil companies operating in California deteriorated. Short-term liquidity, a measure of a company's ability to pay its short-term obligations, was reduced and debt increased significantly. Return on investment dropped and net income for the group declined by one-third. With some companies financially weakened and others needing to replace high cost production with lower cost reserves, the stage was set for major changes in the oil industry.

Amid the mergers, acquisitions and internal restructurings, the international firms have retained stronger financial positions than the national and independent companies. They will therefore, be more likely to conduct most of the near-term high risk exploration activity. Even so, mergers will slow exploration programs in the short term as companies work to reduce their debt.

In the long-term, the cost cutting measures being undertaken today could improve the industry's financial health. However, continuing or worsening market conditions could reduce the effectiveness of these measures and further deteriorate financial performance.

Structural changes in the oil industry have not yet dramatically altered the supply of crude oil and petroleum products in California. Poor financial results from refining and marketing operations have caused refinery sales to be initiated by four firms, however, none have announced plans to leave the California market.

Increasing fuel oil supplies from foreign export refineries will prolong the current surplus of this fuel. As a result, West Coast refiners may be forced to reduce the price of the residual oil they currently export.

There are a number of potential federal and state regulatory initiatives directed toward improving the environmental characteristics of certain fuels that could increase fuel production costs for California refiners. It is not yet clear, however, how large these potential increased costs might be or to what extent they would be reflected in consumer fuel prices.

APPENDIX M

GOVERNMENT REVENUE IMPACT STUDY

APPENDIX M

GOVERNMENT REVENUE IMPACT STUDY

SUMMARY

The 1983 federal allocation system test (AST-4) developed a scenario under the administration's proposed market response policy in which oil prices were assumed to increase from $34/barrel to $98/barrel in less than six months. Such a large change could be expected to depress nonoil economic activity and increase unemployment, reducing tax revenues while increasing demands on the state's hardship program. On the other hand, California's revenue from oil royalties and state tideland sales could be expected to increase as would income taxes from larger oil company profits. In order to help resolve uncertainty as to the balance of these potential changes, this study investigates the potential effects of a sudden oil price increase on two years of California government revenues and the consequent capability of the state to adequately fund increased low-income assistance program (hardship programs) needs over that period. The study also examines the extent to which federal programs for sharing increased Windfall Profits Tax revenues with the state would help mitigate any hardship program revenue shortfalls.

The study examined three shortage response cases: a base disruption case which assumed no federal response, a 50 percent federal disruption case which assumed that half of excess Windfall Profits taxes were transferred to the states, and a 100 percent federal response case which assumed all excess Windfall Profits taxes were transferred to the states.

Predictions about how the economy will respond to a sudden oil price increase are subject to large uncertainties. To bound the scope of this uncertainty and assess the reliability of results, three economic responses (median, best and worst) were developed using the Stanford Energy Modeling Forum's (SEMF) 1982 comparison of the responses of ten oil market models to hypothetical oil disruption scenarios.[1] The median, best and worst scenarios represent the median, least, and largest impact on GNP and associated economic variables (CPI and unemployment rate) among the SEMF model runs.

The results of the analyses are expressed below in terms of millions of dollars net revenue surpluses (+) or deficits (-) for each shortage response-economic response combination:

1. Hickman, Bert G. 1983. EMF 7 Model Comparisons. Key Relationships and Parameters and Huntington, Hillard G. A Summary of the Energy Modeling Forum Results of Macroeconomic Effects of Energy Shock. December 1983. Stanford, California.

TABLE M-1

Net Impact on State Revenues
of a 188 Percent Oil Price Increase
Millions of Current $

Economic Response	Shortage Response		
	Base Disruption	50 Percent Federal Response	100 Percent Federal Response
Worst Case	-6,415	-4,318	-2,570
Median Case	-1,548	+835	+2,672
Best Case	+3,168	+5,525	+7,570

The results support the following conclusions:

- The most likely net impact on state government revenues from a sudden oil price increase of the magnitude used in AST-4 would be a deficit of $1.5 billion over a two year period.
- Estimates of the effects on government revenues are highly sensitive to differences in assumptions about economic responses to the price increase.
- A federal response program which distributed as little as 50 percent of excess Windfall Profits Tax revenues might be sufficient to rectify hardship program deficits.
- States without oil related income increases to partially offset increased hardship program and other revenue needs might experience greater impacts than California and might require more federal assistance.
- The state would need to act in a timely fashion to redistribute any increased oil related revenues to prevent specific hardship and nonhardship program needs from increasing disproportionately over their base budget funding.
- The key to an effective federal response is the early allocation of excess Windfall Profits Tax revenue for mitigating state impacts.

INTRODUCTION

The Federal Administration's proposed market response to future oil shortages has generated considerable debate over the potentially acute impacts of a sudden oil price increase on low and fixed income groups and on the economy in general. The California Energy Commission (CEC) began investigating these

issues prior to 1980 by contracting with the UCLA Business Forecasting Project[2] to determine the potential impact of petroleum shortfalls on the United States and California economies in a decontrolled oil price environment. Subsequently, in preparing its 1983 Biennial Report,[3] CEC described the relationship between the oil price shocks of the 1970's and the recessionary periods which followed.

Presently academicians, government planners, and public policy experts are continuing to argue the merits of the federal market response policy in light of expected economic impacts from oil shocks. This discussion has gained momentum in the wake of the EIA's Allocation Systems Test 4 (AST-4). The U.S. Department of Energy (DOE) 1983 test scenario projected a 188 percent increase in crude oil prices to $98/bbl in less than six months in response to an oil supply cutoff.

While the generally adverse social and economic impacts of a price shock of this magnitude are readily apparent, the exact magnitude as well as the specific impacts on government, particularly at the state and local level, are uncertain. Immediately after a price shock, government tax revenues tied to petroleum products would decrease while demands for government services would increase. In the longer term, income and sales tax revenues could drop significantly as recessionary impacts resulting from the rapid increase in oil prices take hold. These revenue declines could affect the viability of state and local government programs. To what degree these programs can be maintained during and after an oil crisis is unknown. Although state and local governments were able to conduct business during previous oil shortages, energy expenditures took a relatively smaller part of average income and price increases were muted by controls. On a real basis, the cost of oil is still four times higher today than it was in 1973. A further 188 percent increase could have relatively more severe effects then any previous shortage.

Another unknown is the likely response of the federal government to avert the social and economic hardships associated with the market response. Clearly, a major source of increased federal revenue which could be used to offset these hardships is the Windfall Profits Tax (WPT). Two options exist for rapidly distributing these federal funds. via a decrease in federal income tax withholding, or an increase in block grants made directly available to states.

The purpose of this study is to assess the impacts of an oil price shock, as large as that foreseen in AST 4, on the revenue needs of the state for hardship assistance programs and to determine the extent to which federal responses can help to mitigate these impacts.

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2. Harrison, Glenn W. and Kimball, Larry J. (UCLA). The Impact of Petroleum Shortfalls on the United States and California. June 1981. Los Angeles.

3. California Energy Commission 1983 Biennial Report. Sacramento, California.

STUDY DESIGN

The impacts of a price shock on state revenues were evaluated under three shortage response scenarios:

- o A base disruption case in which the effects of the price shock would not be mitigated by any federal government response;
- o A 50 percent federal response case in which the federal government would recycle half of its excess Windfall Profits Tax (WPT) receipts to mitigate price shock impacts; and
- o A 100 percent federal response case in which the federal government would recycle all of its excess WPT receipts for maximum price shock mitigation.

In order to develop a range of plausibility for assessing the study findings, each of the three shortage response scenarios was evaluated under three sets of economic response assumptions:

- o A median economic response;
- o A best economic response; and
- o A worst economic response.

These three sets of economic responses were developed from the Stanford Energy Modeling Forum's 1982 comparison of ten selected forecasting models responses to an oil price disruption. The Stanford comparisons showed that there were substantial differences among the different models as to the likely economic responses to an oil disruption. The range of values was plus and minus 50 percent from the median GNP value. To bound the uncertainty attributable to using the median case among these forecasts as the basis for this study, best and worst economic response cases were developed by using the best and worst GNP responses from the Stanford study data.

The final study design is shown in Figure M-1.

FIGURE M-1
FINAL STUDY DESIGN

Economic Response	Shortage Response		
	Base Disruption	50 Percent Federal Response	100 Percent Federal Response
Best Case			
Median Case			
Worst Case			

METHODOLOGY

The study was divided into four tasks. A simplified flow diagram, Figure M-2, shows the key elements of each task and each task's relationship to the final study results.

The first task identified the size of the oil price increase used as a basis for the economic and government revenue impact analysis. Rather than creating a specific supply disruption scenario, with its attendant oil production or inventory management behavior assumptions, the level of the price shock was chosen to be the same as used in AST-4.[4] Under the hypothetical base disruption case, the oil price increase would begin in August 1984 and last through June 1986. The price of crude oil was assumed to rise from $34, the oil price at the time of AST-4, to $98 per barrel.

The second task determined the impacts of the price shock on California's economy by developing the base disruption case for each set of economic response assumptions. This task used oil price shock impacts from the Stanford Energy Modeling Forum studies as a basis. The key economic indicators developed from the SEMF studies are shown in Table M-2. Since the SEMF studies modeled U.S. economic response the SEMF forecasted economic variables were transformed to (i.e., Gross National Product to Gross State Product) on the basis of the relationships contained in the UCLA study done for the CEC in 1981.[5] Baseline economic conditions for the nondisruption case as shown in Table M-3 were derived from forecasts by the California Commission on State Finances (COSF).[6]

Economic impacts were measured via changes in economic indicators considered most important for projections of state and local government revenues and potential program needs. Revenue projection indicators were personal income, corporate profits, taxable sales, sales of petroleum products and state-owned oil production.[7] Program needs indicators were the California Consumer Price

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4. Department of Energy. AST-4 Test Messages. May 1983. Washington, D.C.

5. Harrison. The Impact of Petroleum Shortfalls on the United States and California (COSF).

6. Commission on State Finance. Quarterly General Fund Forecast. December 1983. Backup data provided by Brad Williams of COSF.

7. Lerner, Lionel J., "Disruption Base Case Economic Impacts," Memo to B. B. Blevins, February 1 and February 24, 1984 revisions.

   Lerner, Lionel J., "Federal Response Case Economic Impacts," Memo to B. B. Blevins, March 1, 1984.

FIGURE M-2

GOVERNMENT REVENUE IMPACT STUDY
METHODOLOGY

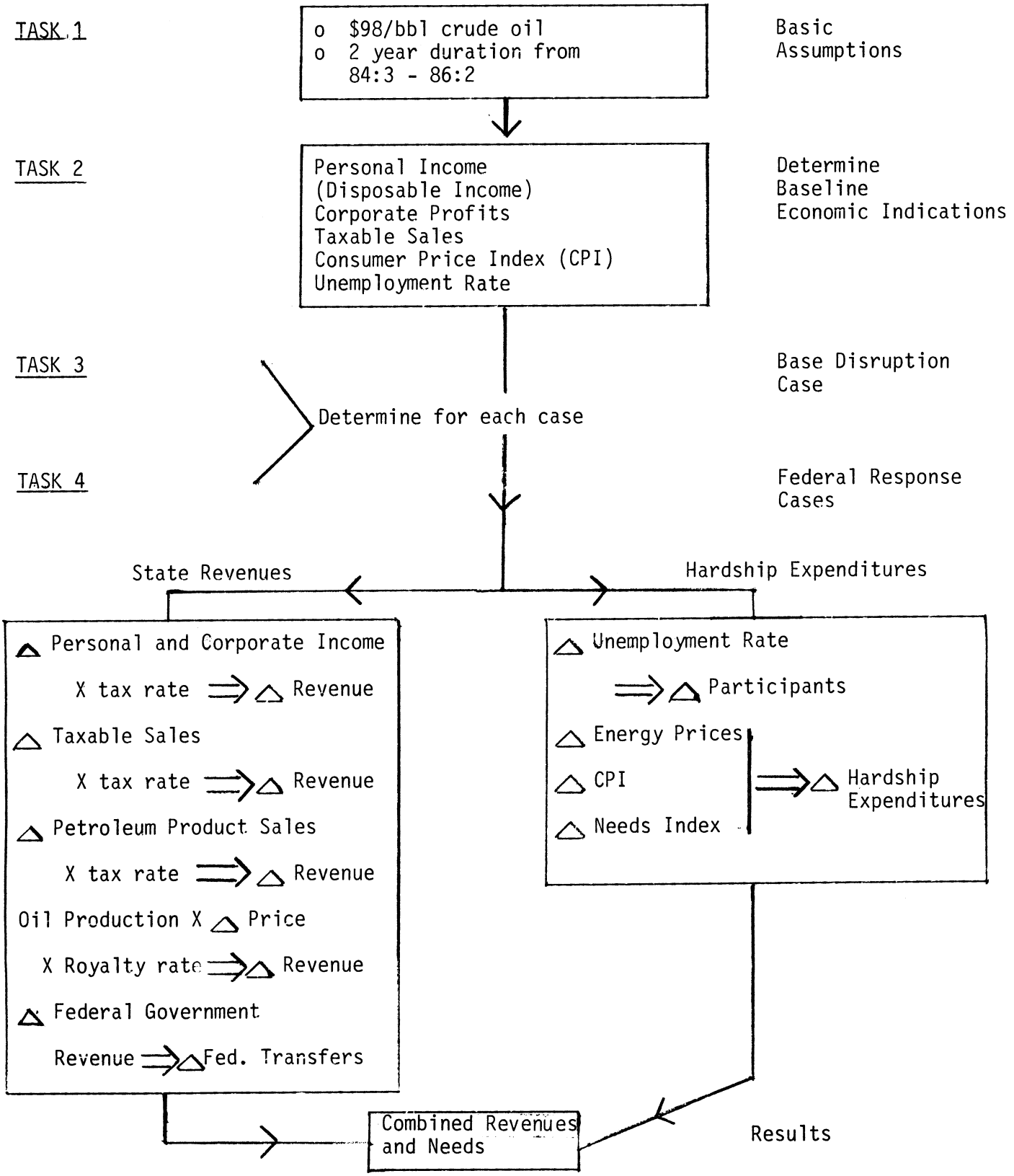

TABLE M-2

Projected Impacts of Oil Price Shock
on Key Economic Indicators
(Percentage Change)

	1984 Qtr. 3	1984 Qtr. 4	1985 Qtr. 1	1985 Qtr. 2	1985 Qtr. 3	1985 Qtr. 4	1986 Qtr. 1	1986 Qtr. 2
U.S. GNP								
Median	- 1.5	- 4.1	- 8.3	-10.2	-10.9	-10.2	-10.4	-10.0
Worst	-15.9	-23.7	-23.7	-23.7	-19.6	-19.6	-18.6	-18.6
Best	- 1.3	- 1.9	- 1.9	- 1.9	- 1.9	- 1.9	- 1.8	- 1.8
U.S. Unemployment								
Median	0.3	1.4	1.8	3.1	4.5	4.5	4.0	4.3
Worst	8.8	13.2	13.2	13.2	6.8	6.8	6.4	6.4
Best	0.8	1.1	1.1	1.1	1.5	1.5	1.4	1.4
U.S. CPI								
Median	4.3	8.6	9.8	10.9	11.7	12.0	11.8	12.1
Worst	8.3	12.4	12.4	12.4	8.3	8.3	7.9	7.9
Best	3.5	5.3	5.3	5.3	5.3	5.3	5.0	5.0

Source: Computed by CEC staff based on SEMF data.

TABLE M-3

Baseline Projections of Relevant Economic Variables for California
(Billions of Current $)

	1984 Qtr. 3	1984 Qtr. 4	1985 Qtr. 1	1985 Qtr. 2	1985 Qtr. 3	1985 Qtr. 4	1986 Qtr. 1	1986 Qtr. 2
Personal Income	371.1	379.1	388.5	379.1	406.9	415.2	423.8	432.0
Oil Corporate Profits	2.7	2.8	2.8	2.9	2.9	3.2	3.2	3.3
Other Corporate Profits	26.0	26.0	28.7	28.6	28.6	28.6	31.9	31.8
Taxable Sales	194.8	198.8	203.2	207.6	211.6	212.0	222.0	224.0

Source: Commission on State Finances.

Index, California Necessities Index and the California unemployment rate.[8] The third task determined changes in state revenues and in funding requirements for state assisted and/or financed hardship programs. These change estimates were derived using the economic indicator values generated by the disruption case analyses.

A major oil supply disruption causes energy prices to rise, thereby increasing hardships for consumers. Past studies have shown that low income households spend approximately 20 percent of their disposable income on energy compared to an average of 9 percent for all households. Low income families, therefore, are likely to be harder hit than other groups of consumers as a result of a major oil price increase.

This study defined hardship as a significant decrease in real income resulting from an energy price shock. Hardship program needs were defined as the funding needed to maintain the real value of hardship program benefits at a given level of real income. Hardship programs employed were low-income assistance programs. The specific low-income assistance programs included for analysis were energy assistance (LIEAP), Aid to Families with Dependent Children (AFDC), Supplementary Security Income (SSI), and food stamps.[9] Appendix A describes these programs in more detail and the derivation of hardship program impacts.

To analyze the effects of the disruption on state revenues, CEC examined major state revenue sources that would be affected by an oil supply disruption. These revenue sources are personal and corporate income tax revenues, fuel tax revenues, and oil royalty payments and sales taxes.[10]

The fourth task developed two scenarios to estimate the range of mitigation that different federal responses would provide. A 50 percent and a 100 percent scenario were assumed to reflect the range of increased federal windfall profits taxes that would be recycled into the economy in ways designed to mitigate specific shortage related impacts. The recycling would take two forms: a decrease in federal income tax withholding and an increase in block grants made directly to the states.

The following assumptions were used in the federal response cases.

- The $98 per barrel oil price shock would generate an additional $92.5 billion in excess Windfall Profits Tax (WPT) revenues per year.

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8. Lerner, Lionel J., "Hardship Program Needs - Concepts and Preliminary Method," Memo to B. B. Blevins, February 23, 1984. Lerner, Lionel J., "Hardship Program Needs Analysis," Memos to B. B. Blevins, April 26 and May 17, 1984.

9. Ibid.

10. Lerner, Lionel J. "Disruption Base Case Economic Impacts".

- The federal economic response package (revenue recycling) would be in place and operating by January 1, 1985 six months after the onset of the price increases. The funds would be disbursed beginning in the first quarter of 1985 and ending in the second quarter of 1986.

- In the first year (first quarter of 1985 through the fourth quarter of 1985), the federal government would allocate two-thirds of excess WPT funds for reducing federal taxes and the remaining one-third for block grants to states. California's percentage share was assumed to be 10 percent of the total, reflecting its relative population size.[11]

It should be noted that any federal response program allocating increased windfall profits tax revenues to states would only be active for, at maximum, one year. This is because the current federal funding formula would consider increased WPT revenues to be "basic" by the second year of the price shock and automatically allocate them to the states through income tax reductions and low income assistance as is currently the practice.[12] Thus, the key to an effective federal response program would be early action to distribute increased WPT revenues.

RESULTS

Effects of Disruption on Hardship Program Needs

Table M-4 summarizes net hardship program needs for the base disruption and federal response cases under the three different economic response cases. For the median base disruption case the hardship program deficit is slightly over $2 billion, assuming normal, nondisruption funding for state hardship programs. The 50 percent and 100 percent federal response cases both reduce the deficit. In the 50 percent case the hardship program deficit is reduced by 70 percent to just over $600 million. The 100 percent federal response creates a surplus of over $500 million.

Under the worst base disruption case, hardship programs have a deficit of just over $3.3 billion. The 50 percent federal response case reduces that deficit to just under $2 billion and the 100 percent response case further reduces the deficit to $900 million.

Under the best base disruption case, the hardship deficit is $700 million, about one-third the median base disruption effect. The effect of both federal response cases is to create surpluses for hardship programs.

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11. Blevins, B. B., "Assumptions Relating to the Federal Response Case," Memo to Lionel Lerner, February 3, 1984.

12. Blevins, B. B., "Resolution of Issues Raised at our February 7 Meeting," Memo to Revenue Impacts Study Group, et al. March 16, 1984.

TABLE M-4

FUNDING STATUS OF HARDSHIP NEED PROGRAMS

Surplus (+) or Deficit (-)

Million $

	1984-85	1985-86	Total
Base Disruption			
Worst	-753	-2,600	-3,353
Median	-612	-1,452	-2,064
Best	-470	-303	-773
50% Federal Response			
Worst	58	-2,032	-1,974
Median	214	-827	-613
Best	371	378	749
100% Federal Response			
Worst	618	-1,559	-941
Median	832	-317	515
Best	1,046	925	1,971

The difference between base disruption case and federal response case is due primarily to federal funds being available six months earlier in the federal response case.

The range established by the difference between the best and worst economic response cases is partly determined by the participation rates in hardship programs. Under the best economic response case the participation rates do not change from the nondisruption case. Thus, even though unemployment increases, the same proportion of eligible recipients are assumed to continue to need assistance. In the worst economic response case, the participation rate increases to 100 percent so that all eligible unemployed are deemed to require and receive assistance.

Effects of Disruption on State Revenues

Total state revenues are projected to be approximately $33 billion in fiscal year 1985-86. The State General Fund accounts for approximately 85 percent of this amount. Increases in hardship expenditures due to an oil price shock would be funded from the General Fund if additional federal funds were not available. Figure M-3 shows the source of revenues and expenditures for the General Fund. Following is a discussion of the potential impacts of an oil price shock on major state revenue sources.

Personal and Corporate Income Tax Revenues - Price shocks reduce personal income in two ways. First, increased energy prices reduces money available for nonenergy purchases and, therefore, reduces consumer demand for products. Second, increased energy costs causes some industrial production to be unprofitable. Both of these factors cause output to decline thereby lowering the demand for labor. The result is an increase in unemployment and a decrease in income which decreases the revenue from personal income taxes collected by the state. Personal income tax revenues decrease in the median case by $75 million in FY 1984-85 and by $403 million in FY 1985-86 for a total decrease of $478 million[13] (Table M-5).

On the other hand, corporate income tax revenues increase in the median case by $930 million in FY 1984-85 and by $913 million in FY 1985-86 for a total of $1,843 million.[14] These corporate income tax revenue increases are attributable to a large increase in oil corporate profits which offset revenue reductions caused by nonoil corporate revenue losses.

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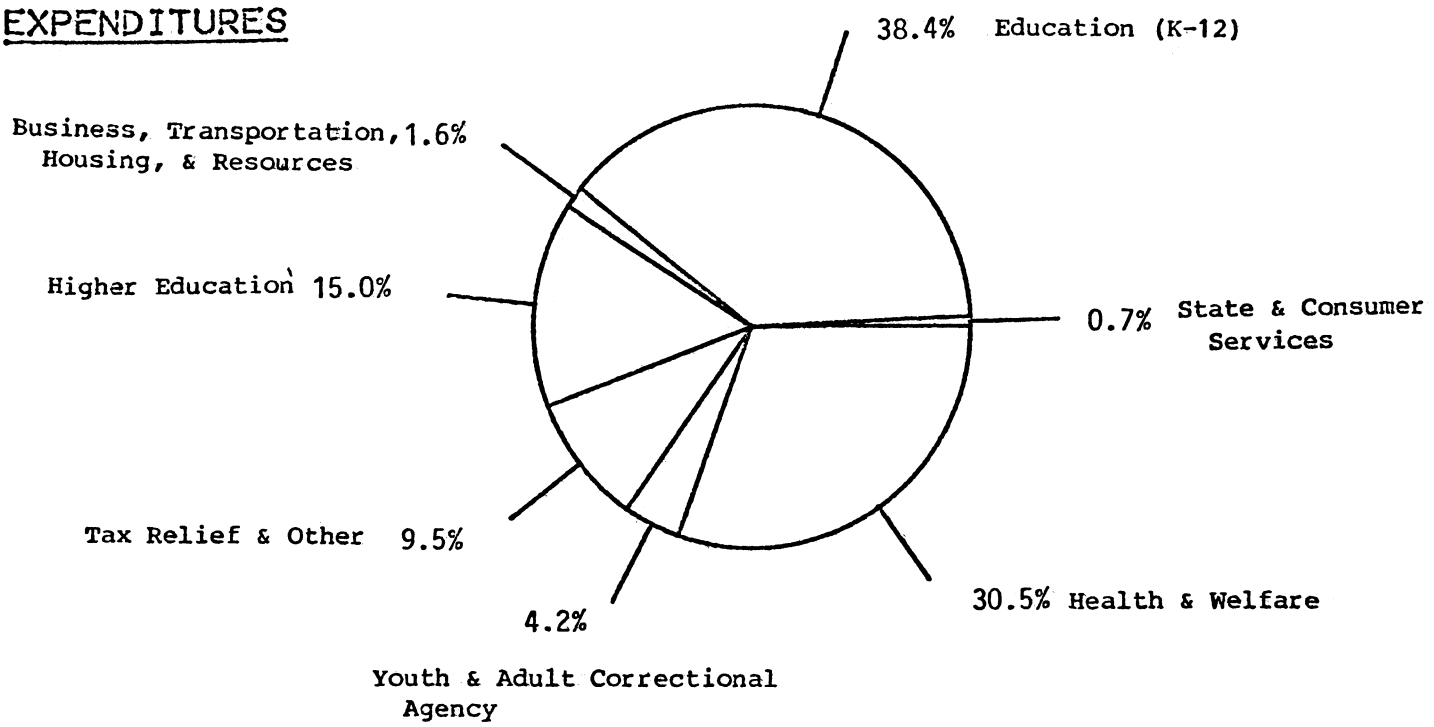
13. Personal income tax revenues were derived from Department of Finance, "Requested Income Tax Estimates," Memo to B. B. Blevins.

14. Corporate income tax revenues were derived from Department of Finance, "Requested Corporation Franchise Tax Estimates," Memo to B. B. Blevins.

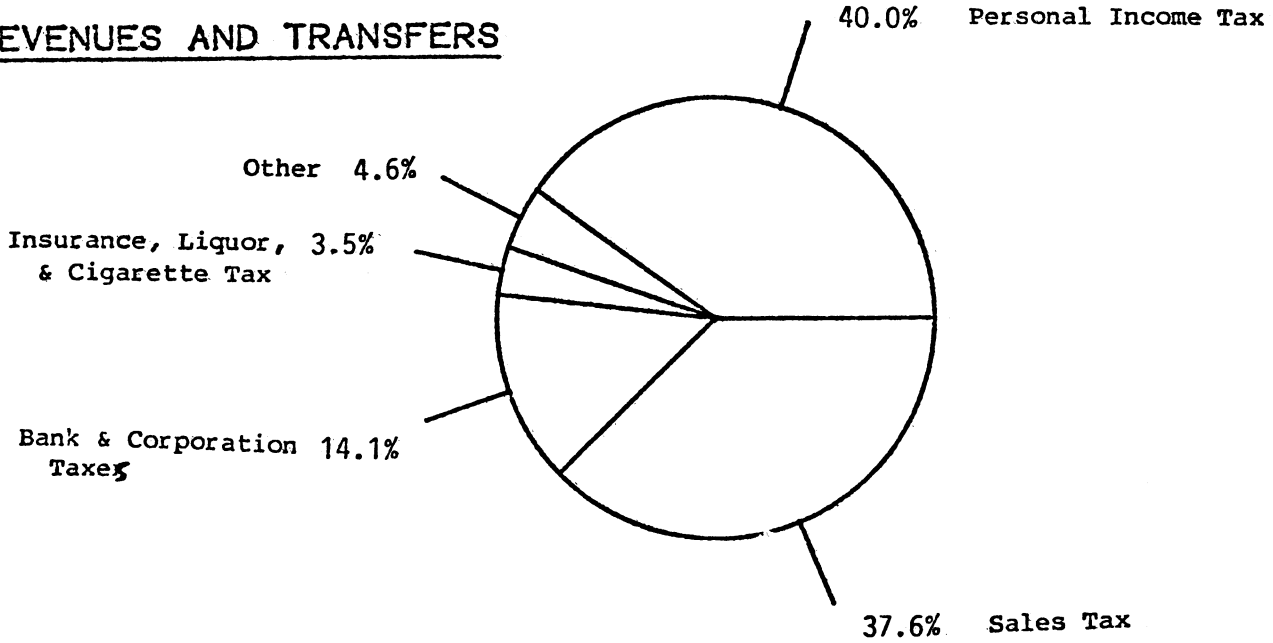
FIGURE M-3

GENERAL FUND REVENUES AND EXPENDITURES FOR CALIFORNIA*

EXPENDITURES



REVENUES AND TRANSFERS



*Excludes Special Fund Revenues and Expenditures
Source: Governor's Budget 1985-86

TABLE M-5

BASE DISRUPTION CASE REVENUE CHANGES

($ millions)

Revenue Year	General Fund Taxes: Personal Income Tax	General Fund Taxes: Corporate Income Tax	General Fund Taxes: Sales Tax	General Fund Taxes: Total	Fuel Tax	Oil Revenues	Total Change
Worst							
1984-85	-111	838	-175	552	-252	828	1,128
1985-86	-1,722	718	-575	-1,579	-273	779	-1,073
Total 1984-86	-1,833	1,556	-750	-1,027	-525	1,607	55
Median							
1984-85	-75	930	58	913	-252	828	1,489
1985-86	-403	913	-154	356	-273	779	862
Total 1984-86	-478	1,843	-96	1,269	-525	1,607	2,351
Best							
1984-85	199	1,015	235	1,449	-252	828	2,025
1985-86	862	1,051	267	2,180	-273	779	2,686
Total 1984-86	1,061	2,066	502	3,629	-525	1,607	4,711

Sales Tax Revenues - Sales tax revenues are reduced because of the decrease in income and consumption caused by the price shock. Net decreases for the two year period total $96 million.[15]

Fuel Tax Revenues - Annual fuel tax revenue would normally equal approximately $900 million in both FY 1984-85 and FY 1985-86. The oil price shock reduces fuel sales and, therefore, reduces fuel tax revenues by $252 million in FY 1984-85 and by $273 million in FY 1985-86.[16]

Changes in Royalty Payments - Under the base disruption case, income from oil royalties and Long Beach tidelands oil sales would increase by $828 million in FY 1984-85 and by $779 million in FY 1985-86 for a two year total of $1,607.[17]

Federal Response Effects on State Revenues - The federal response cases increase state revenues by increasing overall economic activity through increased income of disadvantaged groups. These funds are used to purchase goods and services which, in turn increases employment and income. The revenue effects of federal response cases are presented in Tables M-6 and M-7.

A summary of net changes in state revenues for median, best and worst base disruption and federal response cases is presented in Table M-8.

Net Impacts on Government Capabilities

Table M-9 shows net surpluses or deficits that result from combining hardship need program funding balances with state revenue increases. In six out of nine cases, the state appears to have revenue surpluses because additional income overbalances increased hardship needs. However, this finding is misleading for a number of reasons.

- It assumes that all net revenue increases would be diverted only to handling hardship needs.
- It does not take into account the effects of inflation on the total state budget.

Since hardship needs account for only 12.75 percent of the 84/85 and 85/86 budgets, it is not clear that hardship programs would necessarily have a claim on 100 percent of additional state revenues. Moreover, some of the increased revenues would automatically go to non-General Fund accounts. For example,

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15. Sales tax revenues were estimated by CEC staff based on COSF data.

16. Podva, Montana, "Estimates of Fuel Tax Revenues," Memo to John Rozsa, November 28, 1985.

17. Derived from data submitted to CEC by David Brown of the State Lands Commission, August 20, 1984.

TABLE M-6

50 PERCENT FEDERAL RESPONSE CASE REVENUE CHANGES

($ millions)

Revenue Year	General Fund Taxes: Personal Income Tax	General Fund Taxes: Corporate Income Revenues	General Fund Taxes: Sales Tax	General Fund Taxes: Total	Fuel Tax	Oil Revenues	Total Change
Worst							
1984-85	-78	853	-131	644	-252	828	1,220
1985-86	-1,261	758	-450	-953	-273	779	-447
Total 1984-86	-1,339	1,611	-581	-309	-525	1,607	773
Median							
1984-85	110	948	163	1,221	-252	828	1,797
1985-86	76	955	-51	980	-273	779	1,486
Total 1984-86	186	1,903	112	2,201	-525	1,607	3,283
Best							
1984-85	234	1,033	281	1,548	-252	828	2,124
1985-86	1,417	1,145	354	2,916	-273	779	3,422
Total 1984-86	1,651	2,178	635	4,464	-525	1,607	5,546

TABLE M-7

100 PERCENT FEDERAL RESPONSE CASE REVENUE CHANGES

($ millions)

Revenue Year	General Fund Taxes: Personal Income Tax	General Fund Taxes: Corporate Income Revenues	Sales Tax	Total	Fuel Tax	Oil Revenues	Total Change
Worst							
1984-85	-45	868	-88	735	-252	828	1,311
1985-86	-797	795	-327	-329	-273	779	177
Total 1984-86	-842	1,663	-415	406	-525	1,607	1,488
Median							
1984-85	144	963	150	1,257	-252	828	1,833
1985-86	553	998	106	1,657	-273	779	2,163
Total 1984-86	697	1,961	256	2,914	-525	1,607	3,996
Best							
1984-85	270	1,050	330	1,650	-252	828	2,226
1985-86	1,912	1,188	537	3,637	-273	779	4,143
Total 1984-86	2,182	2,238	867	5,287	-525	1,607	6,369

TABLE M-8

CHANGES IN STATE REVENUES

(Millions of Current Dollars)

	1984-85	1985-86	Total 1984-86
Base Disruption			
Worst	1,128	-1,073	55
Median	1,489	862	2,351
Best	2,025	2,686	4,711
50% Federal Response			
Worst	1,220	-447	773
Median	1,797	1,486	3,283
Best	2,124	3,422	5,546
100% Federal Response			
Worst	1,311	177	1,488
Median	1,833	2,163	3,996
Best	2,226	4,143	6,369

TABLE M-9

NET STATE FUNDING STATUS
Surplus (+) or Deficit (-)

Economic Response	Shortage Response		
	Base Disruption	50 Percent Federal Response	100 Percent Federal Response
Worst	-3,298	-1,201	-547
Median	+287	+2,670	+4,511
Best	+3,938	+6,295	+8,340

royalty oil income goes directly into an account that is primarily used to fund state college and university building expenditures. Legislative action would probably be necessary to divert these monies.

A more serious problem is the effect of oil price stimulated inflation on the general state budget. Higher inflation due to the oil price increases could be expected to increase state expenditures across the board. These increases would cause deficits in nonhardship areas which could compete with hardship areas for the increased revenues.

Table M-10 shows the inflationary impacts of oil price increases in the nonhardship portions of the California state budget. In the median case, almost $2 billion in additional funding would be needed.

TABLE M-10

IMPACTS OF OIL PRICE INCREASE INDUCED
INFLATION ON NONHARDSHIP AREAS OF CALIFORNIA STATE BUDGET
(Million Current $)

Case	1984/85	1985/86	Total
Worst	-871	-2,246	-3,117
Median	-486	-1,349	-1,835
Best	-270	-500	-770

Assuming that the state would initially use additional revenues to maintain all parts of its budget expenditures' purchasing power, inflation deficits need to be subtracted from revenues to determine the likely surpluses that would be available for hardship expenditures. Table M-11 shows the effect of this operation on available revenues under all cases.

TABLE M-11

FUNDS AVAILABLE FOR HARDSHIP PROGRAM NEEDS*

(Million Current $)

	1984/85	1985/86	Total
Base Disruption			
Worst	257	-3,319	-3,062
Median	1,003	-487	516
Best	1,755	2,186	3,941
50% Federal Response			
Worst	349	-2,693	-2,344
Median	1,311	137	1,448
Best	1,854	2,922	4,776
100% Federal Response			
Worst	440	-2,069	-1,629
Median	1,347	814	2,161
Best	1,956	3,643	5,599

*Changes in State Revenues (Table M-5) Less Impact of Oil Price Increase Induced Inflation (Table M-7).

Net impacts on state revenues when hardship needs and inflation adjusted available revenues are combined are shown in Table M-I2. The median base disruption case shows a deficit of over $2 billion for hardship programs if no additional federal assistance is forthcoming. However, federal assistance at only the 50 percent level is sufficient under the median case to develop a surplus for hardship programs.

The worst base disruption case scenario deficit balloons to over $6 billion without federal intervention and remains at almost $3.4 billion even under the 100 percent federal response case. The best case disruption case shows a revenue surplus.

The range between the best and worst case effects is indicative of the extent to which differences in predictions about the economic impacts of a price shock among similar forecasting techniques affect the outcome of this study. In this case these differences are large enough to reverse the findings of the study from a deficit in the median case to a surplus in the best case.

CONCLUSIONS

- The most likely net impact on state government revenues from a sudden oil price increase of the magnitude used in AST-4 would be a deficit of $1.5 billion over a two-year period.

- Estimates of the size of the impacts on government revenues are highly sensitive to differences in assumptions about economic responses to the price increase.

- A federal response program which distributed as little as 50 percent of excess Windfall Profits Tax revenues might be sufficient to rectify hardship program deficits.

- States without oil related income increases to partially offset increased hardship program and other revenue needs might experience greater impacts than California and might require more federal assistance.

- The state would need to act in a timely fashion to redistribute any increased oil related revenues to prevent specific hardship and non-hardship program needs from increasing disproportionately over their base budget funding.

- The key to an effective federal response is the early allocation of excess Windfall Profits Tax revenue for mitigating state impacts.

TABLE M-12

FUNDING STATUS OF HARDSHIP PROGRAMS

AFTER APPLYING FUNDS AVAILABLE FROM ADDITIONAL STATE REVENUES

Surplus (+) Deficit (-)

	1984/85	1985/86	Total
Base Disruption			
Worst	-496	-5,919	-6,415
Median	391	-1,939	-1,548
Best	1,285	1,883	3,168
50% Federal Response			
Worst	407	-4,725	-4,318
Median	1,525	-690	835
Best	2,225	3,300	5,525
100% Federal Response			
Worst	1,058	-3,628	-2,570
Median	2,179	497	2,676
Best	3,002	4,568	7,570

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GOVERNMENT REVENUE IMPACT STUDY

ATTACHMENTS

ATTACHMENT 1

"HARDSHIP PROGRAM NEEDS" - CONCEPTS AND PRELIMINARY METHOD

Summary

This memo defines "hardship" as a significant decrease in real income resulting from an energy price shock. "Hardship program needs" are defined as the amount needed to maintain the real value of "hardship program" benefits at a given level of real income from other sources. "Hardship programs" are defined as unemployment insurance and low-income assistance programs. The low-income assistance programs are energy assistance, Aid to Families with Dependent Children (AFDC), Supplemental Security Income (SSI), and food stamps.

This memo outlines a method of estimating "hardship program needs." "Hardship program needs" will be estimated as the product of the number of qualified households, the proportion of qualified households receiving the grants, the average real grant, and the appropriate price or wage index.

The margin of error in the projected "hardship program needs" will be greater than in projections of unemployment rates because hardship program needs are affected not only by unemployment rates but also by social factors, such as divorce, which are more difficult to project.

Hardship

For purposes of analysis, "hardship" is defined as any significant decrease in real income with respect to the nondisruption case resulting from an oil price shock. It is not possible for state or federal funds to prevent hardship for all groups since there will be an overall significant decrease in real income. (The preliminary base disruption case analysis shows a decrease in Gross National Product of about seven percent the first year and about 15 percent the second year.) (Lerner, 1984.) It is theoretically possible for state or federal funds to prevent all hardship for some groups (for example, low income groups) at the expense of others. It does not appear possible in practice to prevent all hardship to low income groups because it is impossible to tell to what extent any family's loss of income would be due to the oil price shock.

Hardship Programs

For purposes of this analysis, "hardship programs' include:

- Unemployment insurance payments.
- Low-income energy assistance programs such as the Energy Crisis Intervention Program (ECIP) and the Home Energy Assistance Program (HEAP). (These programs cover only increases in gas and electricity bills. The federal response case analyses would include a program covering transportation fuel costs.)
- Low-income assistance programs not related to energy, such as Aid to Families with Dependent Children (AFDC), Supplemental Security Income (SSI), and food stamps.

Most of these programs are directed to low-income groups. It should be noted that unemployment insurance benefits can aid people not in low-income groups. Also, the Federal tax rebates in the Federal response case are directed to groups other than low-income.

For purposes of this analysis, "low-income" is defined as an income below 130 percent of the official poverty level established by the Federal Department of Health and Human Services. (The 130 percent is the eligibility criterion for low-income energy assistance.)

Hardship Program Needs

"Hardship Program Needs" are defined as the amount needed to maintain real benefit payments in the disruption cases at the level in the nondisruption case for a family with the same real income from sources other than "hardship programs." The California Necessities Index (CNI) would convert money income for low-income groups to real income. The money income for low-income groups would be that estimated in determining eligibility -- i.e., assuming no undetected unreported income. The Consumer Price Index (CPI) would be used to convert unemployment insurance in current dollars to real income.

The following example illustrates the proposed definition of "hardship program needs." Suppose that in the nondisruption case a family gets $200 per month in "hardship program" benefits and receives $300 per month in non-hardship program income. (Non-hardship program income includes earnings, child support, and all other income considered in determining eligibility for the programs.) Suppose that in the base disruption case, the CNI increases by 10 percent and the family's non-hardship program income falls to zero. Suppose further then for every three dollars decrease in non-hardship program income, hardship program benefits increase by two dollars. Then, the "hardship program needs" for that family will increase by $20 + $220 or $240 per month. The $20 maintains the real value of the original $200 in benefits, while the $220 ($200 in nondisruption case dollars) compensates for two-thirds of the reduction in nonhardship program income. In this example, although its "hardship program needs" are met, the family's real income falls from $500 per month to $400 ($440/1.1) or by one-fifth which is a definite increase in hardship. However, this increase in hardship would occur if the nonhardship program income reduction occurred in the nondisruption case.

This definition assumes that the Legislature maintains the nondisruption status quo in eligibility and real benefit levels for the low-income assistance programs. (Some legislators might press for reduction of "hardship" by increasing real benefit levels, while others might attempt to freeze benefits in current dollars, thereby permitting a drastic reduction in real benefit levels over the two year period of the assumed price shock.)

For purposes of this analysis, the "status quo" for low income assistance programs would be two alternative levels. The first level, for both fiscal year 1984-5 and fiscal year 1985-6, is the fiscal year 1983-4 benefits level, indexed to the CNI. The second level, in 1984-5, is 96 percent of the 1983-4 benefits; the second level, in 1985-6, is 92 percent of the 1983-4 benefits. The second level is indexed to the CNI in both fiscal years.

The first level reflects current legislation. The second level appears to reflect the intent of the 1984-5 Governor's budget since in the Governor's budget the proposed capping of the CNI adjustment to 2 percent rather than the anticipated 6 percent increase means that real "welfare" benefits would decline by 4 percent in 1984-5. This "status quo" at least in the first level may require an increase

in the maximum allowable monthly payments in the HEAP and ECIP programs. This increase could be needed to maintain the real value of payments for the total of all low-income assistance programs. The increase would be proportionate to the increase in fuel prices.

Unemployment benefits, while not a low-income assistance program, may also require an adjustment. To the extent that unemployment benefits are based on wages earned in the last job, their real value would decline in the disruption cases. Two possible adjustments will be considered:

- Adjustment in proportion to the CPI. This adjustment would maintain the real value of unemployment benefits, but would increase benefits relative to wage levels. (Wages would increase less than proportionally to the CPI increase in the disruption cases.)

- Adjustment in proportion to the average wage level. This adjustment would not maintain the real value of unemployment benefits, but would maintain benefits relative to wage levels.

These adjustments in ECIP, HEAP, and unemployment payments would not apply to the nondisruption case since the CPI and fuel prices in that case increase by only about five percent in the first year. In the disruption cases the CPI increases about 20 percent and fuel prices more than double in the first year. (This estimate assumes that gasoline accounts for most of consumers' spending on fuel.)

It appears possible, in principle, to meet "hardship program needs" as defined here. They can be estimated, at least approximately, once the actual fuel prices and quantities are known. Also the programs' beneficiaries are only a part of the population. (Allowing for overlap between unemployment insurance and low-income assistance programs, a rough estimate is about 15 percent of the population in the non-disruption case and 25 percent of the population in the disruption cases. As there is some income elasticity, the percent of oil products used by the beneficiaries would be less.)

Hence, a third of the "windfall tax" revenues combined with other state revenues could suffice to meet these needs. (In the federal response case, the other two-thirds would be used as an income tax rebate, which is not considered a hardship program.)

Preliminary Method of Estimating "Hardship Program Needs"

The following discussion is intended only to illustrate the concepts described above. Staff will determine the exact method to be used after discussion with state agencies involved in budgeting for unemployment benefits, low-income energy assistance (HEAP and ECIP), and other low-income assistance programs. These discussions will take place later this month and early in March.

Cases Considered

"Hardship program needs" would be estimated for the non-disruption, base disruption, and federal response cases.

Basis of Calculation

Multiplicative. All "hardship program needs" would be estimated as the product of number of qualified households (or qualified unemployed individuals), the proportion of qualified households receiving the grant, the average real grant in 1982 dollars, and the appropriate price or wage index.

Number of qualified households. In the nondisruption case the number of qualified households for low-income programs in January 1984 is the 1.2 million households which "fall under poverty guidelines" (Blevins, 1984) - i.e., have incomes excluding low-income assistance of less than 130 percent of the poverty line established by the Federal Department of Health and Human Services. This number would increase at 2 percent per year, proportionate to the population (COSF, 1983). In the disruption cases, the numbers would increase as a function of unemployment. (The exact function would be determined on the basis of discussions with agencies budgeting for the low-income assistance programs.)

Proportion of qualified households receiving the grant. Some households which are qualified to receive low-income assistance do not apply for it. This situation occurs because some households do not want to accept "welfare" because of the stigma attached to it (Moffit, 1983). Others may find the time needed to apply for the grant excessive in relation to the likely benefits. Others may resent the invasion of privacy needed to determine eligibility.

Unless there are data to the contrary, staff will assume that the proportion of qualified households receiving the grant will remain at its present level in the nondisruption case. Staff will assume that in the disruption cases the proportion receiving the grant may gradually increase as the potential recipients exhaust other sources of income and as unemployment increases. The proportion receiving the grant will not reach or even approach 100 percent. For example, if the current percent of qualified households receiving AFDC is 50 percent, that proportion would be 75 percent or less at the end of the two year period.

For unemployment insurance, staff will assume that all eligible individuals receive the grant. Because the program is "insurance," the "stigma" problem is absent. A person accepting unemployment insurance is not labelled as "poor." However, as the extent of unemployment increases, many unemployed will continue to be unemployed after their benefits expire. Staff will assume that the proportion of unemployed with unexpired benefits will remain at its present level in the nondisruption case. The proportion of unemployed with unexpired benefits will decrease in the disruption cases. (Again, the probable extent of such decrease would be discussed with agencies budgeting for unemployment insurance payments.)

Average real grant. In the nondisruption case, the average real grant for low-income programs would be assumed either to remain at its present level or to fall to 96 percent of its present level in 1984-5 and to 92 percent of its present level in 1985-6. (This corresponds to the alternative "status quo" concepts discussed earlier.) The average real grant for unemployment insurance would be assumed to remain at its present level.

In the disruption cases, the average real grant for low-income programs except for energy assistance would increase gradually, reflecting the exhaustion of other income sources affecting the amount of grants.

The average real grant for unemployment insurance would either remain constant in the disruption cases or decrease at the same rate as real wages. Consistent with the base disruption and federal response case analyses, staff would assume real wages decrease by the adjusted median results of the Stanford Energy Modelling Forum (SEMF) models. (This assumption is consistent with the two alternative policies of adjusting unemployment insurance benefits discussed earlier.)

Price of Wage Index. As real grants will be estimated in 1982 dollars, all applicable price or wage indexes will be percentages of the 1982 level. In the nondisruption case, the CPI will be used for all programs. (This assumption is consistent with the COSF view that the CNI will increase at the same rate as the CPI in 1984 and 1985. The indices behave similarly because both indices now use residential rents for the shelter component.) In the disruption cases, staff would calculate the CNI and apply it to the low-income assistance programs except for energy assistance. The CNI likely would differ from the CPI because the CNI includes fuel and transportation components which may account for a higher percentage of low-income groups' spending than other groups' spending. The calculation of the CNI may use the RAND Corp. estimates of the impact of an oil price shock on prices of various industires (RAND 1981). Staff would adjust these estimates so that for the average consumer, the adjusted RAND estimates' weighted average would be equal to the CPI impact estimated in the staff disruption case analyses. The CNI estimate would be the weighted average of the RAND Corp. estimates, with weights consistent with those in the CNI, and adjusted by the factor used to yield the CPI impact for the average consumer.

The index used for the low-income energy assistance programs would be an index of fuel prices, based on prices and quantities for gasoline, natural gas, and electricity. The price of gasoline in 1982 dollars will be assumed to increase as indicated in the disruption case analyses. The price of natural gas in 1982 dollars will be assumed to increase by fifty percent of the residual fuel oil price increase. This assumption reflects the current gas glut and is based on discussions with Fuels Office staff. (The nondisruption case price of natural gas will be the residential natural gas price projections of the Fuels Office.)

The price of electricity will be assumed to increase as compared to the non-disruption case in proportion to the percent of the current price of electricity accounted for by oil and gas, and staff also assumes a complete switchover from oil to natural gas. (The nondisruption case price of electricity will be the residential electricity price projections of the Systems Assessment Office.)

The prices for the PGandE , SCE, SCG (gas), and service areas would be used if time permits. If not, the PGandE prices would be used since PGandE's service area has the largest number of customers, and include both gas and electricity customers.

Overlap and Undercount. The analysis described above would be done for each program individually and the results added to obtain total "hardship program needs." This procedure could either exaggerate or underestimate the actual needs for several reasons.

For example, the CNI used for AFDC and SSI programs includes fuels and transport components which may overlap the indexing for fuels prices used for the low-income energy assistance programs. Another source of exaggeration could be neglect of price and nonprice conservation. Including such conservation in the analysis would require detailed cost-effectiveness analyses of gas, electricity, and transportation energy conservation programs. These analyses would include the cost of the conservation measures as well as the energy savings. The analyses would be made from the viewpoint of the low-income consumers and also from that of the financing agency. Data would be required on the extent to which the "energy and transportation programs" in the Federal response case include energy conservation programs targeted to low-income groups. There would be insufficient time to do the cost-effectiveness analyses.

On the other hand, the procedure could underestimate "hardship program needs" because the CNI is computed using data for Los Angeles, San Diego, and San Francisco. The proper weights for natural gas and electricity for a CNI for more extreme climate zones would be larger than for these three regions. Also many rural regions would have higher weights for transportation in their CNI.

However, correction for overlap and undercount would use data for utility service areas subdivided into climate zones and also for regional use of transportation fuel. While such data may exist, there would be insufficient time to do the calculations.

Margin of Error

The margin of error in projections of "hardship program needs" will be larger than in the disruption case projections of the unemployment rate and the consumer price index. This is because the impact of increases in unemployment on "hardship program needs" is not direct. Rather, the change in "hardship program needs" results from many individual decisions concerning life-styles which are affected mainly by noneconomic factors. For example, the number of households eligible for AFDC is affected by divorces, marital separations, the extent to which courts award and enforce child support payments, attitudes concerning various methods of "planned parenthood," and the degree of success of "workfare" programs. These noneconomic factors also affect the proportion of eligible households which apply for grants and the average real grant.

Staff will not attempt to quantify the margin of error, as was done for impacts on Gross National Product, because of the effect of non quantifiable social factors, such as those mentioned above for AFDC.

APPENDIX N

PETROLEUM INDUSTRY INFORMATION REPORTING ACT DATA

APPENDIX N
PETROLEUM INDUSTRY INFORMATION REPORTING ACT DATA

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TABLE N-1

CALIFORNIA ANNUAL PETROLEUM SUMMARY
(Thousands of Barrels)

Activity	1976	1977	1978	1979	1980	1981	1982	1983	1984
Refinery Crude Oil Receipts									
Total Receipts	617,187	708,142	647,293	689,257	674,485	634,038	577,717	606,604	632,937
Domestic	349,147	394,513	494,258	565,100	576,100	573,783	544,164	558,613	579,675
Alaskan	39,346	80,783	203,580	269,361	267,478	245,005	196,462	189,538	210,450
California and Other	309,801	313,730	290,678	295,739	308,672	328,778	347,702	369,075	369,225
Foreign	268,040	313,629	153,035	124,157	98,335	60,255	33,553	47,991	53,262
Refinery Product Output									
Motor Gasoline	276,714	304,554	300,581	306,955	294,808	286,957	272,219	289,680	300,667
Aviation Fuels	71,057	76,624	71,300	75,955	73,394	71,472	69,368	73,443	81,705
Distillate Fuels	72,801	84,705	81,437	89,745	80,236	89,084	88,103	94,720	104,844
Residual Fuels	134,713	171,144	141,534	159,525	166,935	132,819	94,403	86,052	92,929
Other	99,082	115,844	127,752	146,913	137,513	118,863	108,584	111,461	118,226
Total Output	654,367	752,871	722,604	779,093	752,886	699,195	632,677	655,356	698,371
Product Import/Export									
Import									
Motor Gasoline	9,423	5,411	6,980	6,586	6,232	8,904	22,937	17,937	10,742
Aviation Fuels	1,354	883	7,828	3,945	1,583	1,639	3,978	1,314	826
Distillate Fuels	1,650	2,056	4,769	3,195	1,379	1,729	2,463	2,073	1,594
Residual Fuels	28,474	48,152	22,958	33,832	18,035	14,332	10,944	5,886	6,687
Export									
Motor Gasoline	36,162	43,274	40,681	38,911	38,403	42,133	40,788	39,064	40,147
Aviation Fuels	12,429	12,159	11,015	13,305	10,525	11,899	14,507	12,314	12,402
Distillate Fuels	20,551	20,656	19,030	21,271	16,568	17,594	19,901	17,578	22,778
Residual Fuels	27,960	27,860	21,798	19,407	24,984	22,616	24,843	28,981	23,868
Stocks at End of Year									
Motor Gasoline	18,587	19,019	18,096	16,921	18,145	19,993	19,021	17,843	20,301
Aviation Fuels	5,463	5,142	5,081	4,504	4,884	4,604	4,388	3,850	4,901
Distillate Fuels	7,863	8,737	5,560	7,836	6,674	7,929	7,981	7,584	7,736
Residual Fuels	41,634	51,035	31,074	34,005	46,260	42,304	40,482	29,336	25,421
Product Supplied									
Motor Gasoline	248,962	266,259	267,803	275,805	261,413	251,988	255,343	269,641	268,674
Aviation Fuels	59,303	65,669	68,174	67,172	64,072	61,492	59,025	62,970	69,031
Distillate Fuels	51,958	65,362	70,353	69,393	66,209	73,537	70,560	79,612	83,455
Residual Fuels	145,501	182,035	162,655	172,019	147,731	131,133	82,566	74,306	79,616

Source: QFER submittals for 1976 to 1981 and PIIRA submittals for 1981 to 1984.
PIIRA Forms: DOE/EIA-810 Monthly Refinery Report. CEC-M07/M12 California Major Petroleum Product Marketer and Storer Report.

TABLE N-2

ANNUAL PETROLEUM PRODUCT FUEL MARKET SUMMARY

(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORT	FOREIGN IMPORT	STORAGE CHANGE	TOTAL SUPPLY	DOMESTIC EXPORT	FOREIGN EXPORT	CALIF. SUPPLIED
AVIATION FUELS								
1976	71057	595	759	679	71732	12163	266	59303
1977	76624	773	110	-321	77828	11907	252	65669
1978	71300	2897	4931	-61	79189	10720	295	68174
1979	75955	2551	1394	-577	80477	12968	337	67172
1980	73394	1426	157	380	74597	10254	271	64072
1981	71472	1639	0	-280	73391	11596	303	61492
1982	69368	3005	973	-186	73532	13594	913	59025
1983	73443	1206	108	-527	75284	11262	1052	62970
1984	81705	681	145	1098	81433	11599	803	69031
DISTILLATE FUELS								
1976	72801	1650	0	1942	72509	19764	787	51958
1977	84705	2056	0	743	86018	19717	939	65362
1978	81437	4769	0	-3177	89383	18159	871	70353
1979	89745	2841	354	2276	90664	20416	855	69393
1980	80236	1379	0	-1162	82777	15986	582	66209
1981	89084	1729	0	-318	91131	16901	693	73537
1982	88103	2463	0	105	90461	18657	1244	70560
1983	94720	1995	78	-397	97190	16930	648	79612
1984	104844	1548	46	205	106233	21670	1108	83455
MOTOR GASOLINES								
1976	276714	9423	0	1013	285124	36160	2	248962
1977	304554	5301	110	432	309533	43271	3	266259
1978	300581	6692	288	-923	308484	40680	1	267803
1979	306955	6586	0	-1175	314716	38911	0	275805
1980	294808	6081	151	1224	299816	38398	5	261413
1981	286957	7447	1457	1740	294121	42007	126	251988
1982	272219	13315	9622	-975	296131	40167	621	255343
1983	289680	10264	7673	-1088	308705	38846	218	269641
1984	300667	5249	5493	2588	308821	39559	588	268674
RESIDUAL FUEL OILS								
1976	134713	20821	7653	-10274	173461	13303	14657	145501
1977	171144	30842	17310	9401	209895	12654	15206	182035
1978	141534	18101	4857	-19961	184453	10522	11276	162655
1979	159525	23032	11800	2931	191426	9515	9892	172019
1980	166935	13118	4917	12255	172715	11908	13076	147731
1981	132819	9490	4842	-6598	153749	6885	15731	131133
1982	94403	8431	2513	-2062	107409	12966	11877	82566
1983	86052	4492	1394	-11349	103287	9914	19067	74306
1984	92929	5738	949	-3868	103484	11761	12107	79616

SOURCE: QFER submittals for 1976 to 1981 and PIIRA submittals for 1981 to 1984.
PIIRA Forms: DOE/EIA-810 Monthly Refinery Report, CEC-M07/M12 California Major Petroleum Product Marketer and Storer Reports.

TABLE N-3

CRUDE OIL RECEIPTS AT CALIFORNIA REFINERIES
BY SOURCE OF SUPPLY
(Percent of Total)

Source of Supply	Year 1981	1982	1983	1984
Domestic				
California	50.97	58.44	59.20	54.78
Alaska North slope	36.23	32.97	29.96	32.26
Alaska Other	2.42	1.91	1.76	1.68
Federal Offshore	0.56	0.76	1.11	2.38
Other States	0.32	0.27	0.20	0.00
Total Domestic	90.50	94.35	92.23	91.10
Foreign				
OPEC				
Mideast	0.12	0.00	0.00	0.00
Indonesia	8.58	5.06	6.93	7.67
Other	0.37	0.13	0.25	0.37
Total OPEC	9.07	5.19	7.18	8.04
Non-OPEC				
Mexico	0.00	0.02	0.00	0.00
Other	0.43	0.44	0.57	0.86
Total Non-OPEC	0.43	0.46	0.57	0.86
Total Foreign	9.50	5.65	7.75	8.90

Source: PIIRA submittals.
PIIRA Form: CEC-A04 California Refiners Annual Report.

Percentages in Table N-3 does not equal the fractions of refinery crude oil receipts in Table N-1 due to rounding of figures reported from PIIRA form CEC-A04, California Refiners Annual Report. Figures from CEC-A-4 are based on total crude oil receipts at California refineries, excluding refinery exchanges. Figures from Table N-1 represent net totals, thereby accounting for part of the differences between tables.

TABLE N-4

CALIFORNIA RECEIPTS AT CALIFORNIA REFINERIES
BY TRANSPORTATION METHOD
Year 1984
(Thousands of Barrels)

Source	Refinery Type			State	Refinery Location		
Method	Topping	Hydro-Skimming	Complex	Total	North	Central	South
Domestic							
Pipeline	35,193	47,081	252,710	334,984	116,452	53,776	164,756
Tanker	1,112	1,417	221,723	224,252	100,573	97	123,582
Barge	1,217	398	4,959	6,574	2,434	398	3,742
Railroad	0	0	7,491	7,491	0	0	7,491
Truck	2,240	3,240	894	6,374	0	3,916	2,458
Total Domestic	39,762	52,136	487,777	579,675	219,459	58,187	302,029
Foreign							
Pipeline	0	0	0	0	0	0	0
Tanker	125	638	52,369	53,132	16,723	0	36,409
Barge	0	0	130	130	130	0	0
Railroad	0	0	0	0	0	0	0
Truck	0	0	0	0	0	0	0
Total Foreign	125	638	52,499	53,262	16,853	0	36,409
Total							
Pipeline	35,193	47,081	252,710	334,984	116,452	53,776	164,756
Tanker	1,237	2,055	274,092	277,384	117,296	97	159,991
Barge	1,217	398	5,089	6,704	2,564	398	3,742
Railroad	0	0	7,491	7,491	0	0	7,491
Truck	2,240	3,240	894	6,374	0	3,916	2,458
Total Receipts	39,887	52,774	540,276	632,937	236,312	58,187	338,438

Source: PIIRA submittals.

PIIRA Form: DOE/EIA-820 Annual Refinery Report.

TABLE N-5

CALIFORNIA REFINERY ACTIVITY
Year 1984

Activity	Refinery Type: Topping	Refinery Type: Hydro-Skimming	Refinery Type: Complex	State Total	Refinery Location: North	Refinery Location: Central	Refinery Location: South
Crude Receipts (mbbls)							
Domestic							
Alaska	0	1,312	209,138	210,450	101,598	0	108,852
California and Other	39,762	50,824	278,639	369,225	117,861	58,187	193,177
Total Domestic	39,762	52,136	487,777	579,675	219,459	58,187	302,029
Foreign	125	638	52,499	53,262	16,853	0	36,409
Total Receipts	39,8877	52,774	540,276	632,937	236,312	58,187	338,438
Feedstock Input (mbbls)							
Crude Oil	36,187	52,706	539,080	627,973	234,082	55,407	338,484
Natural Gas Plant Liquids	0	761	6,981	7,742	885	761	6,096
Other Hydrocarbons	0	1	3,843	3,844	2,568	1	1,275
Unfinished Oils	0	0	27,956	19,525*	9,885	0	17,582
Total Input	36,187	53,468	577,860	659,084*	247,420	56,169	363,437
Product Output (mbbls)							
Motor Gasoline	669	12,382	287,616	300,667	116,980	10,373	173,314
Aviation Fuels	2,561	3,225	75,919	81,705	33,263	1,620	46,822
Distillate Fuels	7,033	12,874	84,937	104,844	35,764	10,417	58,663
Residual Fuels	10,435	14,857	67,637	92,929	35,798	17,934	39,197
Lubricating Oil	1,720	5	2,123	3,848	2,157	1,725	-34
Asphalt and Road Oil	8,481	1,996	6,805	17,282	7,216	3,488	6,578
Wax	0	0	846	846	846	0	0
Petroleum Coke	383	0	36,445	36,828	11,831	383	24,614
Still Gas	398	1,175	36,917	38,490	14,494	932	23,064
Liquified Petroleum Gases	59	-13	13,109	13,155	6,044	47	7,064
Unfinished Oils	2,754	5,677	0	0*	0	7,942	0
Other Products	999	285	6,493	7,777	1,650	274	5,853
Total Output	35,492	52,463	618,847	698,371*	266,043	55,135	385,135
Refinery Gain	-695	-1,005	40,987	39,287	18,623	-1,034	21,698
Crude Quality							
API Gravity (°)	18.91	29.45	24.20	24.28	23.15	24.46	25.05
Sulfur Content (%)	1.39	0.73	1.10	1.09	1.11	0.96	1.09
Fuel Use							
Crude Oil (mbbls)	0	4	0	4	0	4	0
Fuel Oil (mbbls)	196	230	2,233	2,659	1,767	385	507
Liquified Petroleum Gases (mbbls)	1	114	3,096	3,207	1,272	76	1,859
Natural gas (mmcf)	2,014	2,451	77,308	81,773	47,712	2,539	31,523
Still Gas (mbbls)	386	1,055	32,832	32,273	13,401	814	20,060
Petroleum Gas (mbbls)	0	0	9,202	9,202	5,398	0	3,804
Electricity (GWh)	89	179	4,940	5,208	2,467	175	2,566
Steam (mmbls)	0	0	8,113	8,113	8,113	0	0
Capacity (mb/sd)							
Operating (average)	151.9	184.1	1,899.8	2,235.8	795.8	204.2	1,236.3
Idle (average)	22.7	33.0	165.2	220.9	7.2	57.7	91.9
Operable (average)	174.6	217.1	2,065.0	2,456.7	866.5	261.9	1,328.2
Utilization (percent)							
Operating	60.11	78.66	78.27	77.07	82.58	70.59	74.59
Operable	52.28	66.73	72.01	70.14	75.80	55.02	69.43

*Statewide total does not equal sum of disaggregated data by refinery type and location. The differences between the disaggregated data and statewide totals are due to the exchange of unfinished oils from topping and hydroskimming refineries to complex refineries for use as a feedstock input.

Source: PIIRA submittals.

PIIRA Form: DOE/EIA-810 Monthly Refinery Report.

TABLE N-6

PROCESSING FACILITY CHANGES AT CALIFORNIA REFINERIES
From January 1, 1982 to January 1, 1985

Type Refinery/Facility	Operable Capacity (Mbbls/stream day) 1982	Additions	Shut-Down	Net Change	1985	Percent Change
Complex						
Crude Distillation	2,241.5	93.7	165.2	-71.5	2,170.5	-3.19
Vacuum Distillation	1,114.3	119.0	50.0	69.0	1,183.3	6.19
Thermal Cracking	420.9	65.3	30.4	34.9	455.8	8.29
Catalytic Cracking	587.7	65.1	36.8	28.3	616.0	4.82
Catalytic Reforming	512.7	31.0	33.3	-2.3	510.4	-0.45
Catalytic Hydrocracking	331.7	54.5	19.0	35.5	367.2	10.70
Hydrotreating	1,090.2	213.0	41.5	171.5	1,261.7	15.73
Hydroskimming						
Crude Distillation	254.8	101.0	114.3	-13.3	241.5	-5.22
Vacuum Distillation	73.0	51.0	50.0	1.0	74.0	1.37
Thermal Cracking	19.9	0.0	0.0	0.0	19.9	0.00
Catalytic Reforming	43.9	21.2	20.7	0.5	44.4	1.14
Catalytic Hydrotreating	97.3	61.2	55.7	5.5	102.8	5.65
Topping						
Crude Distillation	222.8	40.1	136.5	-96.4	130.4	-43.27
Vacuum Distillation	78.1	30.5	46.1	-15.6	62.5	-19.97
Thermal Cracking	0.0	16.8	0.0	16.8	16.8	0.0
Catalytic Hydrotreating	0.6	0.0	0.0	0.0	0.6	0.0
All Refineries						
Crude Distillation	2,719.1	234.8	416.0	-181.2	2,541.9	-6.67
Vacuum Distillation	1,265.4	200.5	146.1	54.4	1,319.8	4.30
Thermal Cracking	440.8	82.1	30.4	51.7	492.5	11.73
Catalytic Cracking	587.7	65.1	36.8	28.3	616.0	4.82
Catalytic Reforming	556.6	52.2	54.0	-1.8	554.8	-0.32
Catalytic Hydrocracking	331.7	54.5	19.0	35.5	367.2	10.70
Hydrotreating	1,188.1	274.2	97.2	177.0	1,365.1	14.90

Source: PIIRA submittals.
PIIRA Forms: DOE/EIA-820 Annual Refinery Report.

TABLE N-7

PROCESSING FACILITY CHANGES AT CALIFORNIA REFINERIES
From January 1, 1982 to January 1, 1985

Refinery Type / Facility	Operating Capacity (mbbls/Stream Day) 1982	Additions	Shut-down	Net Change	1985	Percent Change
Complex						
Crude Distillation	2,015.1	122.7	198.8	-76.1	1,939.0	-3.78
Vacuum Distillation	1,026.3	134.0	70.5	63.5	1,089.8	6.19
Thermal Cracking	420.9	65.3	37.4	27.9	448.8	6.63
Catalytic Cracking	587.7	65.1	48.8	16.3	604.0	2.77
Catalytic Reforming	486.0	46.0	46.8	- 0.8	485.2	-0.16
Catalytic Hydrocracking	328.7	57.5	33.0	24.5	353.2	7.45
Hydrotreating	1,072.2	229.5	73.0	156.5	1,228.7	14.60
Hydroskimming						
Crude Distillation	208.1	75.0	102.6	-27.6	180.5	-13.26
Vacuum Distillation	60.5	38.5	52.5	-14.0	46.5	-23.14
Thermal Cracking	10.1	0.0	0.0	0.0	10.1	0.00
Catalytic Reforming	43.4	18.7	27.7	- 9.1	34.4	-20.97
Catalytic Hydrotreating	96.8	55.7	81.2	-25.6	71.2	-26.45
Topping						
Crude Distillation	175.8	54.9	128.0	-73.1	102.7	-41.58
Vacuum Distillation	64.6	20.9	33.1	-12.2	52.4	-18.89
Thermal Cracking	0.0	8.4	0.0	0.0	8.4	--
Catalytic Hydrotreating	0.5	0.0	0.0	0.0	0.5	0.00
All Refineries						
Crude Distillation	2,399.0	252.6	429.4	-176.8	2,222.2	-7.37
Vacuum Distillation	1,151.4	193.4	156.1	37.3	1,188.7	3.24
Thermal Cracking	431.0	73.7	37.4	36.3	467.3	8.42
Catalytic Cracking	587.7	65.1	48.8	16.3	604.0	2.77
Catalytic Reforming	529.4	64.7	74.5	- 9.8	519.6	-1.85
Catalytic Hydrocracking	328.7	57.5	33.0	24.5	353.2	7.45
Hydrotreating	1,169.5	285.2	154.2	131.0	1,230.4	11.20

Source: PIIRA submittals.
PIIRA Form: DOE/EIA-820 Annual Refinery Report.

TABLE N-8

CHANGE IN WORKING STORAGE TANK CAPACITY
FROM JANUARY 1, 1984 TO JANUARY 1, 1985
AT CALIFORNIA REFINERIES
(THOUSANDS OF BARRELS)

PRODUCT	CAPACITY 1984	CAPACITY 1985	CHANGE MBBLS	CHANGE PERCENT
CRUDE OIL	33452	30690	-2762	-8.26
MOTOR GASOLINE, LEADED	4135	4209	74	1.79
MOTOR GASOLINE, UNLEADED	7378	7040	-338	-4.58
GASOLINE, BLENDING COMPONENTS	12756	12113	-643	-5.04
MIDDLE DISTILLATES	7894	7488	-406	-5.14
RESIDUAL FUEL OILS	12479	11296	-1183	-9.48
ASPHALT AND ROAD OIL	3198	2975	-223	-6.97
LUBRICATING OILS	977	2189	1212	124.05
PROPANE/PROPYLENE	381	324	-57	-14.96
BUTANE/BUTYLENE	1142	1160	18	1.58
NAPHTHA-TYPE JET FUEL	1259	1195	-64	-5.08
KEROSENE-TYPE JET FUEL	4116	3791	-325	-7.90
OTHER STORAGE	20136	19352	-784	-3.89

SOURCE: PIIRA submittals.
PIIRA Form: DOE/EIA-820 Annual Refinery Report.

TABLE N-9

CALIFORNIA REFINERY PRODUCT SHIPMENTS
BY METHOD OF TRANSPORTATION FOR YEAR 1984
(percent)

Product	Pipeline	Tanker	Barge	Truck	Railroad
Refinery Type					
Motor Gasoline					
Complex	84.62	4.20	2.82	8.36	0.00
Hydroskimming	26.42	0.00	0.00	73.58	0.00
Topping	0.00	0.00	0.00	100.00	0.00
Aviation Fuels					
Complex	87.22	7.44	1.24	4.10	0.00
Hydroskimming	34.45	0.00	0.00	65.55	0.00
Topping	55.07	0.00	0.00	44.93	0.00
Distillate Fuels					
Complex	71.89	16.78	1.51	9.14	0.69
Hydroskimming	23.86	0.00	0.00	74.76	1.38
Topping	47.18	0.00	13.02	39.48	0.32
Residual Fuels					
Complex	31.69	46.24	20.69	1.39	0.00
Hydroskimming	8.00	19.52	1.29	71.18	0.00
Topping	35.87	0.00	44.72	19.42	0.00
Refinery Location					
Motor Gasoline					
North	72.93	8.44	6.90	11.73	0.00
Central	31.04	0.00	0.00	68.96	0.00
South	90.59	1.24	0.00	8.17	0.00
Aviation Fuels					
North	83.22	13.40	2.65	0.73	0.00
Central	40.02	0.00	0.00	59.83	0.00
South	86.26	2.49	0.11	11.12	0.00
Distillate Fuels					
North	57.58	30.12	5.33	6.60	0.37
Central	29.21	0.00	0.00	68.84	1.95
South	74.55	5.10	0.52	19.07	0.77
Residual Fuels					
North	3.64	65.20	31.16	0.00	0.00
Central	8.70	18.01	0.00	73.29	0.00
South	57.86	19.94	18.54	3.66	0.00
All Refineries					
Motor Gasoline	81.35	3.94	2.67	12.00	0.00
Aviation Fuels	84.12	6.91	1.15	7.82	0.00
Distillate Fuels	63.91	13.39	2.16	19.78	0.75
Residual Fuels	27.97	36.71	19.79	15.53	0.00

Source: PIIRA submittals.
PIIRA Form: CEC-A04 California Refiners Annual Report.

TABLE N-10A

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
MOTOR GASOLINES
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982											
JANUARY	22937	935	719	1654	23283	3419	227	3646	19637	21301	1308
FEBRUARY	19526	670	614	1284	22722	2744	0	2744	19978	19397	-1912
MARCH	22704	1569	497	2066	26275	2938	248	3186	23089	17887	-1505
APRIL	20792	2106	772	2878	25173	3024	109	3133	22040	16384	-1503
MAY	21443	1688	1358	3046	25295	3545	18	3563	21732	15578	-806
JUNE	24828	1605	555	2160	24661	3393	18	3411	21250	17905	2327
JULY	24462	1463	839	2302	24298	3462	0	3462	20836	20371	2466
AUGUST	22541	969	1037	2006	24674	3756	0	3756	20918	20244	-127
SEPTEMBER	22246	603	896	1499	24194	3434	0	3434	20760	19795	-449
OCTOBER	23405	663	701	1364	24786	3469	0	3469	21317	19778	-17
NOVEMBER	22959	675	1062	1737	25037	3828	0	3828	21209	19437	-341
DECEMBER	24376	369	572	941	25733	3155	1	3156	22577	19021	-416
1983											
JANUARY	22852	1046	318	1364	24808	3343	0	3343	21465	18314	-592
FEBRUARY	21510	1244	702	1946	22110	2258	0	2258	19852	19660	1346
MARCH	21126	1970	907	2877	26138	2940	218	3158	22980	17525	-2135
APRIL	22237	1340	678	2018	25662	3214	0	3214	22448	16118	-1407
MAY	23978	668	913	1581	25590	3030	0	3030	22560	16117	-31
JUNE	25730	1227	1094	2321	25878	3114	0	3114	22764	18274	2173
JULY	27212	759	960	1719	27312	3294	0	3294	24018	19903	1619
AUGUST	27059	297	476	773	26330	3979	0	3979	22351	21405	1502
SEPTEMBER	24652	391	352	743	27697	4015	0	4015	23682	19103	-2302
OCTOBER	25024	271	286	557	27081	3645	0	3645	23436	17603	-1500
NOVEMBER	23699	436	337	773	24722	2886	0	2886	21836	17353	-250
DECEMBER	24601	615	650	1265	25377	3128	0	3128	22249	17843	489
1984											
JANUARY	25324	647	675	1322	24105	2987	0	2987	21118	20366	2541
FEBRUARY	21739	575	204	779	24137	2839	0	2839	21298	18747	-1619
MARCH	24489	725	817	1542	25957	3036	23	3059	22898	18821	74
APRIL	25894	579	244	823	26427	3505	0	3505	22922	19111	290
MAY	27223	593	866	1459	25739	3467	1	3468	22271	22054	2943
JUNE	25644	243	782	1025	26062	3071	271	3342	22720	22661	607
JULY	24621	197	0	197	26906	3267	258	3525	23381	20461	-2088
AUGUST	25530	431	331	762	27550	3731	0	3731	23819	19203	-1258
SEPTEMBER	24342	118	425	543	25615	3971	4	3975	21640	18473	-730
OCTOBER	25823	509	308	817	26361	3447	0	3447	22914	18752	279
NOVEMBER	25428	252	468	720	24812	3121	0	3121	21691	20088	1336
DECEMBER	24610	380	373	753	25150	3117	31	3148	22002	20301	213

SOURCE: PIIRA submittals.
PIIRA Forms: DOE/EIA-810 Monthly Refinery Report, CEC-MO7/M12 California Major Petroleum Product Marketer and Storer Reports.

TABLE N-10B

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
MOTOR GASOLINE, LEADED
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982											
JANUARY	11017	214	373	587	10884	1706	227	1933	8951	6814	720
FEBRUARY	8923	39	353	392	10039	1420	0	1420	8619	6090	-724
MARCH	9987	646	339	985	11954	1453	248	1701	10253	5108	-982
APRIL	10326	621	408	1029	11110	1446	99	1545	9565	5353	245
MAY	9809	569	845	1414	11558	1865	0	1865	9693	5018	-335
JUNE	10577	256	357	613	10959	1840	0	1840	9119	5249	231
JULY	11558	332	353	685	10713	1810	0	1810	8903	6779	1530
AUGUST	10034	210	355	565	10611	1764	0	1764	8847	6767	-12
SEPTEMBER	10106	82	397	479	10656	1693	0	1693	8963	6696	-71
OCTOBER	9761	80	512	592	10846	1775	0	1775	9071	6203	-493
NOVEMBER	10044	282	501	783	11326	1960	0	1960	9366	5704	-499
DECEMBER	10328	48	381	429	10470	1314	0	1314	9156	5991	287
1983											
JANUARY	9198	169	132	301	9958	1618	0	1618	8340	5418	-459
FEBRUARY	9205	427	702	1129	10044	1157	0	1157	8887	5708	290
MARCH	8807	1134	659	1793	11663	1392	218	1610	10053	4645	-1063
APRIL	9506	544	485	1029	10605	1721	0	1721	8884	4575	-70
MAY	9949	203	590	793	10340	1401	0	1401	8939	4980	402
JUNE	10808	301	757	1058	10774	1590	0	1590	9184	6072	1092
JULY	10831	145	330	475	11650	1629	0	1629	10021	5728	-344
AUGUST	10811	117	152	269	10915	2040	0	2040	8875	5893	165
SEPTEMBER	10503	101	352	453	11297	2097	0	2097	9200	5552	-341
OCTOBER	10378	116	173	289	11465	1868	0	1868	9597	4754	-798
NOVEMBER	9933	94	168	262	9899	1426	0	1426	8473	5050	296
DECEMBER	9543	290	305	595	9860	1555	0	1555	8305	5328	278
1984											
JANUARY	9862	359	502	861	10196	1363	0	1363	8833	5841	527
FEBRUARY	8754	210	0	210	9495	1347	0	1347	8148	5310	-531
MARCH	9711	291	477	768	10459	1411	0	1411	9048	5330	20
APRIL	10074	169	114	283	10234	1791	0	1791	8443	5453	123
MAY	9776	397	336	733	10074	1522	0	1522	8552	5888	435
JUNE	9583	103	517	620	9586	1375	271	1646	7940	6505	617
JULY	9306	92	0	92	9963	1520	258	1778	8185	5873	-565
AUGUST	9131	96	160	256	9938	1924	0	1924	8014	5322	-551
SEPTEMBER	8657	83	425	508	9467	1716	2	1718	7749	5020	-302
OCTOBER	9633	279	0	279	10118	1509	0	1509	8609	4814	-206
NOVEMBER	8819	66	346	412	9062	1347	0	1347	7715	4983	169
DECEMBER	8965	138	182	320	8725	1274	31	1305	7420	5543	560

TABLE N-10C

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
MOTOR GASOLINE, UNLEADED
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982											
JANUARY	13129	651	98	749	13747	1713	0	1713	12034	7517	131
FEBRUARY	10566	484	0	484	12564	1324	0	1324	11240	6003	-1514
MARCH	13120	209	0	209	13974	1392	0	1392	12582	5358	-645
APRIL	12578	1064	0	1064	13658	1576	0	1576	12082	5342	-16
MAY	13044	741	0	741	13934	1680	0	1680	12254	5193	-149
JUNE	14100	485	0	485	13318	1553	0	1553	11765	6460	1267
JULY	13317	690	117	807	13616	1638	0	1638	11978	6968	508
AUGUST	13984	202	0	202	13995	1797	0	1797	12198	7159	191
SEPTEMBER	13122	168	0	168	13270	1741	0	1741	11529	7179	20
OCTOBER	13188	89	0	89	13366	1694	0	1694	11672	7090	-89
NOVEMBER	13436	177	0	177	13646	1868	0	1868	11778	7057	-33
DECEMBER	14919	56	0	56	14919	1841	1	1842	13077	7113	56
1983											
JANUARY	13738	249	0	249	14698	1725	0	1725	12973	6386	-711
FEBRUARY	12310	569	0	569	12192	1101	0	1101	11091	7073	687
MARCH	13535	336	0	336	13974	1548	0	1548	12426	6970	-103
APRIL	13647	390	0	390	14657	1492	0	1492	13165	6350	-620
MAY	14371	209	0	209	15145	1626	0	1626	13519	5785	-565
JUNE	14448	439	0	439	14722	1524	0	1524	13198	5950	165
JULY	16279	438	0	438	15166	1665	0	1665	13501	7501	1551
AUGUST	15675	113	0	113	15053	1935	0	1935	13118	8236	735
SEPTEMBER	14948	223	0	223	15860	1917	0	1917	13943	7547	-689
OCTOBER	14143	40	0	40	15012	1776	0	1776	13236	6718	-829
NOVEMBER	14663	52	0	52	14650	1461	0	1461	13189	6783	65
DECEMBER	15404	86	0	86	15382	1573	0	1573	13809	6891	108
1984											
JANUARY	15490	214	0	214	14146	1623	0	1623	12523	8449	1558
FEBRUARY	12833	337	0	337	14530	1449	0	1449	13081	7089	-1360
MARCH	15869	251	0	251	15515	1625	0	1625	13890	7694	605
APRIL	15869	369	0	369	16106	1713	0	1713	14393	7826	132
MAY	16874	162	109	271	15839	1945	0	1945	13894	9132	1306
JUNE	16368	101	111	212	16386	1695	0	1695	14691	9326	194
JULY	16116	87	0	87	16599	1747	0	1747	14852	8886	-396
AUGUST	16197	282	0	282	17429	1807	0	1807	15622	7936	-950
SEPTEMBER	16476	34	0	34	16210	2255	2	2257	13953	8236	300
OCTOBER	16085	229	0	229	16679	1938	0	1938	14741	7871	-365
NOVEMBER	16621	180	0	180	16457	1774	0	1774	14683	8215	344
DECEMBER	17278	153	0	153	16839	1843	0	1843	14996	8807	592

TABLE N-10D

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
MOTOR GASOLINE, UNSPECIFIED
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982											
JANUARY	-1209	70	248	318	-1348	0	0	0	-1348	6970	457
FEBRUARY	37	147	261	408	119	0	0	0	119	7304	326
MARCH	-403	714	158	872	347	93	0	93	254	7421	122
APRIL	-2112	421	364	785	405	2	10	12	393	5689	-1732
MAY	-1410	378	513	891	-197	0	18	18	-215	5367	-322
JUNE	151	864	198	1062	384	0	18	18	366	6196	829
JULY	-413	441	369	810	-31	14	0	14	-45	6624	428
AUGUST	-1477	557	682	1239	68	195	0	195	-127	6318	-306
SEPTEMBER	-982	353	499	852	268	0	0	0	268	5920	-398
OCTOBER	456	494	189	683	574	0	0	0	574	6485	565
NOVEMBER	-521	216	561	777	65	0	0	0	65	6676	191
DECEMBER	-871	265	191	456	344	0	0	0	344	5917	-759
1983											
JANUARY	-84	628	186	814	152	0	0	0	152	6510	578
FEBRUARY	-5	248	0	248	-126	0	0	0	-126	6879	369
MARCH	-1216	500	248	748	501	0	0	0	501	5910	-969
APRIL	-916	406	193	599	400	1	0	1	399	5193	-717
MAY	-342	256	323	579	105	3	0	3	102	5352	132
JUNE	474	487	337	824	382	0	0	0	382	6252	916
JULY	102	176	630	806	496	0	0	0	496	6674	412
AUGUST	573	67	324	391	362	4	0	4	358	7276	602
SEPTEMBER	-799	67	0	67	540	1	0	1	539	6004	-1272
OCTOBER	503	115	113	228	604	1	0	1	603	6131	127
NOVEMBER	-897	290	169	459	173	-1	0	-1	174	5520	-611
DECEMBER	-346	239	345	584	135	0	0	0	135	5624	103
1984											
JANUARY	-28	74	173	247	-237	1	0	1	-238	6076	456
FEBRUARY	152	28	204	232	112	43	0	43	69	6348	272
MARCH	-1091	183	340	523	-17	0	23	23	-40	5797	-551
APRIL	-49	41	130	171	87	1	0	1	86	5832	35
MAY	573	34	421	455	-174	0	1	1	-175	7034	1202
JUNE	-307	39	154	193	90	1	0	1	89	6830	-204
JULY	-801	18	0	18	344	0	0	0	344	5702	-1127
AUGUST	202	53	171	224	183	0	0	0	183	5945	243
SEPTEMBER	-791	1	0	1	-62	0	0	0	-62	5217	-728
OCTOBER	105	1	308	309	-436	0	0	0	-436	6067	850
NOVEMBER	-12	6	122	128	-707	0	0	0	-707	6890	823
DECEMBER	-1633	89	191	280	-414	0	0	0	-414	5951	-939

TABLE N-10E

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
AVIATION FUELS
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982											
JANUARY	5325	69	0	69	5368	1018	31	1049	4319	4630	26
FEBRUARY	5642	58	0	58	5023	1138	65	1203	3820	5277	677
MARCH	6316	203	0	203	6765	1675	74	1749	5016	5031	-246
APRIL	5081	701	0	701	5897	1312	82	1394	4503	4916	-115
MAY	5423	50	0	50	5902	858	94	952	4950	4487	-429
JUNE	5539	578	0	578	6383	904	84	988	5395	4221	-266
JULY	6275	242	711	953	6577	766	93	859	5718	4872	651
AUGUST	5981	389	262	651	7274	1579	63	1642	5632	4230	-642
SEPTEMBER	6218	95	0	95	5978	1076	85	1161	4817	4565	335
OCTOBER	5668	246	0	246	6435	1536	58	1594	4841	4044	-521
NOVEMBER	6001	89	0	89	5542	832	78	910	4632	4592	548
DECEMBER	5899	285	0	285	6388	900	106	1006	5382	4388	-204
1983											
JANUARY	5832	250	0	250	5684	1454	48	1502	4182	4772	398
FEBRUARY	5571	230	0	230	5356	798	75	873	4483	5217	445
MARCH	5668	215	0	215	6415	476	77	553	5862	4685	-532
APRIL	5317	252	45	297	6501	702	64	766	5735	3798	-887
MAY	6115	141	63	204	6535	578	72	650	5885	3582	-216
JUNE	6287	41	0	41	5761	721	46	767	4994	4153	567
JULY	6863	48	0	48	6744	735	115	850	5894	4319	167
AUGUST	6634	1	0	1	6893	1170	138	1308	5585	4061	-258
SEPTEMBER	7082	0	0	0	5914	1161	103	1264	4650	5229	1168
OCTOBER	6053	0	0	0	6388	1232	108	1340	5048	4894	-335
NOVEMBER	5872	5	0	5	6179	1358	101	1459	4720	4592	-302
DECEMBER	6149	23	0	23	6914	877	105	982	5932	3850	-742
1984											
JANUARY	6328	2	0	2	6245	728	108	836	5409	3942	85
FEBRUARY	6298	0	0	0	5915	1069	95	1164	4751	4325	383
MARCH	6268	311	70	381	5956	646	104	750	5206	5018	693
APRIL	6794	0	0	0	6410	940	80	1020	5390	5402	384
MAY	6544	99	0	99	7070	989	61	1050	6020	4975	-427
JUNE	7094	0	0	0	7513	1369	56	1425	6088	4556	-419
JULY	7625	0	0	0	7517	1007	46	1053	6464	4610	108
AUGUST	7362	25	0	25	8045	1232	49	1281	6764	3952	-658
SEPTEMBER	7103	0	0	0	7004	1014	47	1061	5943	4051	99
OCTOBER	7091	0	0	0	6891	789	45	834	6057	4251	200
NOVEMBER	6788	0	75	75	6484	889	77	966	5518	4630	379
DECEMBER	6410	244	0	244	6383	927	35	962	5421	4901	271

TABLE N-10F

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
DISTILLATE FUELS
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982											
JANUARY	7769	7	0	7	7009	2078	277	2355	4654	8902	767
FEBRUARY	6422	407	0	407	7703	996	32	1028	6675	8028	-874
MARCH	6444	446	0	446	7250	2038	335	2373	4877	7668	-360
APRIL	6698	279	0	279	7011	1314	264	1578	5433	7628	-34
MAY	7241	106	0	106	8142	2007	33	2040	6102	6833	-795
JUNE	7666	33	0	33	7708	2045	95	2140	5568	6824	-9
JULY	7293	164	0	164	7687	961	96	1057	6630	6594	-230
AUGUST	7321	22	0	22	7355	1037	18	1055	6300	6582	-12
SEPTEMBER	7672	251	0	251	8318	1706	18	1724	6594	5934	-395
OCTOBER	7526	257	0	257	8091	1309	32	1341	6750	5626	-308
NOVEMBER	8230	52	0	52	6263	1647	29	1676	4587	7645	2019
DECEMBER	7821	439	0	439	7924	1519	15	1534	6390	7981	336
1983											
JANUARY	7725	164	0	164	7809	1472	39	1511	6298	8059	80
FEBRUARY	7427	544	0	544	7630	1183	45	1228	6402	8400	341
MARCH	5985	384	0	384	7575	1007	44	1051	6524	7194	-1206
APRIL	6169	158	0	158	7808	934	41	975	6833	5683	-1481
MAY	8211	139	0	139	7404	1177	168	1345	6059	6648	946
JUNE	8185	101	0	101	8075	1395	50	1445	6630	6858	211
JULY	8611	73	78	151	8398	1451	40	1491	6907	7222	364
AUGUST	8518	84	0	84	9026	1291	43	1334	7692	6798	-424
SEPTEMBER	9420	56	0	56	9465	1983	42	2025	7440	6803	11
OCTOBER	8560	38	0	38	8925	1941	48	1989	6936	6496	-327
NOVEMBER	7605	86	0	86	7384	1658	38	1696	5688	6803	307
DECEMBER	8304	168	0	168	7691	1438	50	1488	6203	7584	781
1984											
JANUARY	7698	39	0	39	8876	1750	38	1788	7088	6453	-1139
FEBRUARY	8367	369	0	369	8455	1828	22	1850	6605	6732	281
MARCH	9028	37	0	37	8530	1660	96	1756	6774	7267	535
APRIL	9194	69	44	113	9000	1943	120	2063	6937	7574	307
MAY	9775	17	0	17	9477	2042	348	2390	7087	7889	315
JUNE	9372	37	0	37	9809	1773	45	1818	7991	7489	-400
JULY	9188	125	0	125	9597	1712	36	1748	7849	7146	-284
AUGUST	9086	139	0	139	8946	1746	256	2002	6944	7425	279
SEPTEMBER	8640	381	0	381	9052	1714	41	1755	7297	7394	-31
OCTOBER	8603	103	0	103	8348	1744	52	1796	6552	7752	358
NOVEMBER	8079	42	0	42	8134	1805	23	1828	6306	7739	-13
DECEMBER	7814	190	2	192	8009	1953	31	1984	6025	7736	-3

TABLE N-10G

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
RESIDUAL FUEL OILS
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982											
JANUARY	9047	448	0	448	10185	1275	500	1775	8410	41869	-690
FEBRUARY	9390	1063	467	1530	9443	1606	1611	3217	6226	43331	1477
MARCH	9698	894	415	1309	8614	1495	949	2444	6170	45724	2393
APRIL	8705	1167	0	1167	10460	1964	1299	3263	7197	45136	-588
MAY	8579	626	923	1549	11328	1273	710	1983	9345	43936	-1200
JUNE	7416	616	381	997	8603	439	626	1065	7538	43746	-190
JULY	6461	596	0	596	8230	331	928	1259	6971	42573	-1173
AUGUST	7227	875	0	875	8523	771	1318	2089	6434	42152	-421
SEPTEMBER	6642	943	327	1270	7498	1070	913	1983	5515	42566	414
OCTOBER	6894	590	0	590	9532	1538	1130	2668	6864	40518	-2048
NOVEMBER	6714	414	0	414	7599	342	1192	1534	6065	40047	-471
DECEMBER	7630	199	0	199	7394	862	701	1563	5831	40482	435
1983											
JANUARY	6920	12	735	747	9377	925	1828	2753	6624	38926	-1710
FEBRUARY	6371	56	0	56	9829	548	2483	3031	6798	35524	-3402
MARCH	8153	1049	659	1708	10712	560	1556	2116	8596	34674	-851
APRIL	8371	656	0	656	10496	1019	2031	3050	7446	33205	-1469
MAY	9000	432	0	432	11065	1450	2059	3509	7556	31572	-1633
JUNE	7197	73	0	73	7544	842	1934	2776	4768	31284	-274
JULY	6494	450	0	450	8008	502	1282	1784	6224	30278	-1064
AUGUST	6264	0	0	0	7620	480	1514	1994	5626	28922	-1356
SEPTEMBER	6742	253	0	253	6376	1208	1018	2226	4150	29545	619
OCTOBER	6726	849	0	849	7095	915	1411	2326	4769	30025	480
NOVEMBER	6848	194	0	194	6725	644	1180	1824	4901	30342	317
DECEMBER	6966	468	0	468	8440	821	771	1592	6848	29336	-1006
1984											
JANUARY	7832	908	0	908	8674	1452	1402	2854	5820	29370	66
FEBRUARY	7305	850	0	850	7366	1661	1051	2712	4654	30159	789
MARCH	7609	763	0	763	8603	892	1061	1953	6650	29928	-231
APRIL	7459	1347	0	1347	8827	1129	516	1645	7182	29907	-21
MAY	7236	380	0	380	9323	1285	1301	2586	6737	28245	-1707
JUNE	7838	225	267	492	7782	1077	992	2069	5713	28793	548
JULY	7994	214	318	532	7344	659	760	1419	5925	29915	1182
AUGUST	7483	231	0	231	8529	872	631	1503	7026	29100	-815
SEPTEMBER	7101	327	0	327	9039	809	670	1479	7560	27489	-1611
OCTOBER	8093	24	37	61	7360	69	1138	1207	6153	28283	794
NOVEMBER	7639	370	0	370	9866	1104	1691	2795	7071	26426	-1857
DECEMBER	9340	99	327	426	10771	752	894	1646	9125	25421	-1005

TABLE N-10-H

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
RESIDUALS, HIGH SULFUR
(THOUSANDS OF BARRELS)

		REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982												
	JANUARY	6902	248	0	248	7613	1247	500	1747	5866	6103	5603
	FEBRUARY	6488	736	0	736	6784	1195	1508	2703	4081	6543	5035
	MARCH	7299	427	0	427	7329	1360	949	2309	5020	6940	5991
	APRIL	7898	642	0	642	8372	1456	1299	2755	5617	7108	5809
	MAY	7561	530	0	530	8938	1273	710	1983	6955	6261	5551
	JUNE	6727	616	0	616	6757	439	626	1065	5692	6847	6221
	JULY	5408	198	0	198	6550	331	928	1259	5291	5903	4975
	AUGUST	6443	421	0	421	6898	653	1318	1971	4927	5869	4551
	SEPTEMBER	5964	408	327	735	5631	786	913	1699	3932	6937	6024
	OCTOBER	6119	363	0	363	7772	1370	800	2170	5602	5647	4847
	NOVEMBER	6279	363	0	363	6309	342	1135	1477	4832	5980	4845
	DECEMBER	6897	199	0	199	5760	713	701	1414	4346	7316	6615
1983												
	JANUARY	6040	12	735	747	7386	750	1828	2578	4808	6868	5040
	FEBRUARY	5446	56	0	56	5704	547	2483	3030	2674	6666	4183
	MARCH	7285	1049	659	1708	8604	560	1556	2116	6488	7055	5499
	APRIL	6658	656	0	656	8368	807	1830	2637	5731	6001	4171
	MAY	7755	195	0	195	8361	839	1701	2540	5821	5590	3889
	JUNE	6138	73	0	73	6107	743	1576	2319	3788	5680	4104
	JULY	5492	168	0	168	6401	412	1282	1694	4707	4997	3715
	AUGUST	5403	0	0	0	6094	28	1154	1182	4912	4306	3152
	SEPTEMBER	5204	2	0	2	4703	590	1018	1608	3095	4813	3795
	OCTOBER	5569	202	0	202	5393	338	1411	1749	3644	5191	3780
	NOVEMBER	5851	194	0	194	5019	122	1180	1302	3717	6217	5037
	DECEMBER	5855	64	0	64	7077	342	771	1113	5964	5063	4292
1984												
	JANUARY	6852	258	0	258	7010	619	1402	2021	4989	5131	3729
	FEBRUARY	6242	486	0	486	5461	628	1051	1679	3782	6398	5347
	MARCH	6343	666	0	666	6942	67	1061	1128	5814	6465	5404
	APRIL	6384	718	0	718	6860	112	516	628	6232	6707	6191
	MAY	6237	162	0	162	7912	34	1301	1335	6577	5239	3938
	JUNE	6904	14	267	281	6295	28	992	1020	5275	6129	5137
	JULY	6896	1	318	319	5760	33	760	793	4967	7524	6764
	AUGUST	6363	12	0	12	6975	443	631	1074	5901	6924	6293
	SEPTEMBER	6096	113	0	113	7506	66	670	736	6770	5627	4957
	OCTOBER	6942	11	37	48	6501	69	1138	1207	5294	6116	4978
	NOVEMBER	6611	232	0	232	8286	80	1691	1771	6515	4673	2982
	DECEMBER	8451	3	0	3	8781	238	894	1132	7649	4346	3452

TABLE N-10I

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
RESIDUALS, LOW SULFUR
(THOUSANDS OF BARRELS)

		REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1982												
	JANUARY	2145	200	0	200	2572	28	0	28	2544	35766	35766
	FEBRUARY	2902	327	467	794	2659	411	103	514	2145	36788	36685
	MARCH	2399	467	415	882	1285	135	0	135	1150	38784	38784
	APRIL	807	525	0	525	2088	508	0	508	1580	38028	38028
	MAY	1018	96	923	1019	2390	0	0	0	2390	37675	37675
	JUNE	689	0	381	381	1846	0	0	0	1846	36899	36899
	JULY	1053	398	0	398	1680	0	0	0	1680	36670	36670
	AUGUST	784	454	0	454	1625	118	0	118	1507	36283	36283
	SEPTEMBER	678	535	0	535	1867	284	0	284	1583	35629	35629
	OCTOBER	775	227	0	227	1760	168	330	498	1262	34871	34541
	NOVEMBER	435	51	0	51	1290	0	57	57	1233	34067	34010
	DECEMBER	733	0	0	0	1634	149	0	149	1485	33166	33166
1983												
	JANUARY	880	0	0	0	1991	175	0	175	1816	32058	32058
	FEBRUARY	925	0	0	0	4125	1	0	1	4124	28858	28858
	MARCH	868	0	0	0	2108	0	0	0	2108	27619	27619
	APRIL	1713	0	0	0	2128	212	201	413	1715	27204	27003
	MAY	1245	237	0	237	2704	611	358	969	1735	25982	25624
	JUNE	1059	0	0	0	1437	99	358	457	980	25604	25246
	JULY	1002	282	0	282	1607	90	0	90	1517	25281	25281
	AUGUST	861	0	0	0	1526	452	360	812	714	24616	24256
	SEPTEMBER	1538	251	0	251	1673	618	0	618	1055	24732	24732
	OCTOBER	1157	647	0	647	1702	577	0	577	1125	24834	24834
	NOVEMBER	997	0	0	0	1706	522	0	522	1184	24125	24125
	DECEMBER	1111	404	0	404	1363	479	0	479	884	24273	24273
1984												
	JANUARY	980	650	0	650	1664	833	0	833	831	24239	24239
	FEBRUARY	1063	364	0	364	1905	1033	0	1033	872	23761	23761
	MARCH	1266	97	0	97	1661	825	0	825	836	23463	23463
	APRIL	1115	629	0	629	2007	1017	0	1017	990	23200	23200
	MAY	999	218	0	218	1411	1251	0	1251	160	23006	23006
	JUNE	934	211	0	211	1487	1049	0	1049	438	22664	22664
	JULY	1098	213	0	213	1584	626	0	626	958	22391	22391
	AUGUST	1120	219	0	219	1554	429	0	429	1125	22176	22176
	SEPTEMBER	1005	214	0	214	1533	743	0	743	790	21862	21862
	OCTOBER	1151	13	0	13	859	0	0	0	859	22167	22167
	NOVEMBER	1027	138	0	138	1579	1024	0	1024	555	21753	21753
	DECEMBER	939	96	327	423	2040	514	0	514	1526	21075	21075

TABLE N-11

CALIFORNIA PETROLEUM PRODUCT SHIPMENTS OF MAJOR MARKETERS
BY TRANSPORTATION METHOD FOR YEAR 1984
(percent)

Marketer Type	Transportation Method				
Product	Pipeline	Tanker	Barge	Truck	Railroad
Nonrefiner					
Motor Gasoline	3.52	15.92	0.05	80.51	0.00
Aviation Fuels	56.19	15.62	0.00	28.19	0.00
Distillate Fuels	2.24	67.42	1.03	29.28	0.00
Residual Fuels	1.66	22.59	59.92	15.83	0.00
Refiner[1)]					
Motor Gasoline	56.54	0.80	7.55	34.88	0.00
Aviation Fuels	72.78	4.87	14.61	7.74	0.00
Distillate Fuels	55.88	4.50	11.32	29.09	0.22
Residual Fuels	27.59	17.79	29.21	25.41	0.00
All Marketers[2)]					
Motor Gasoline	38.35	5.94	4.98	50.58	0.00
Aviation Fuels	72.29	4.86	14.05	8.80	0.00
Distillate Fuels	14.21	53.08	3.37	29.27	0.05
Residual Fuels	25.10	18.21	32.23	24.26	0.00

1) Refiner shipments include both shipments from refiners and from bulk terminals resulting in double counting.

2) All marketer shipments include double counted shipments by refiners and shipments between reporting companies.

Source: PIIRA submittals.
PIIRA Form: CEC-A10 California Major Petroleum Product Marketer Annual Transportation Report.

TABLE N-12

CHANGE IN PETROLEUM PRODUCT STORAGE TANK CAPACITIES
FROM 1981 TO 1984

Product	1981	1984	Change Mbbls	Change Percent
Motor Gasoline	26,938	29,635	2,697	10.01
Aviation Fuels	7,259	6,858	- 401	- 5.52
Distillate Fuels	13,932	12,862	- 1,070	- 7.68
Residual Fuels				
Low Sulfur	50,228	40,669	- 9,559	- 19.03
High Sulfur	12,993	12,785	- 208	- 1.60
Total	63,221	53,484	- 9,737	- 15.40
Other Products	25,679	37,753	12,074	47.02
Total Storage	137,029	140,592	3,563	2.60

Source: PIIRA submittals.

PIIRA Forms: CEC-A09 California Major Petroleum Product Marketer and Major Petroleum Product Storer Annual Storage Report.

TABLE N-13

PETROLEUM PRODUCT STORAGE TANK CAPACITIES
AT MAJOR MARKETER AND MAJOR STORER FACILITIES
BY REGION AND BY FACILITY TYPE AT END OF YEAR 1984
(Thousand of Barrels)

Product	North	Central	South	State Total	Refining Facility	Bulk Terminal	Other Facility
Motor Gasoline	12,762	1,284	15,589	29,635	21,627	7,370	638
Aviation Fuels	2,936	77	3,845	6,858	5,524	1,143	191
Distillate Fuels	3,958	649	8,255	12,862	7,510	2,224	3,128
Residual Fuels							
Low Sulfur	5,107	3,359	32,233	40,699	1,616	305	38,778
High Sulfur	3,929	1,079	7,777	12,785	11,324	1,042	419
Total	9,036	4,438	40,010	53,484	12,940	1,347	39,197
Other Products	18,014	6,101	13,638	37,753	23,792	2,968	10,993
Total Storage	46,706	12,549	81,337	140,592	71,393	15,052	54,147

Source: PIIRA submittals.

PIIRA Forms: CEC-A09 California Major Petroleum Product Marketer and Major Petroleum Product Storer Annual Storage Report.

TABLE N-14

MAJOR CRUDE OIL PRODUCERS' T.E.O.R. FUEL USE AND
PRODUCTION FROM DESIGNATED FIELDS BY PRODUCING AREA FOR YEAR 1984

Producing Area	Production			T.E.O.R. Fuel		
	20° API and less (Barrels)	Total (Barrels)	Net (Barrels)	Crude Oil (Barrels)	Natural Gas (MCF)	Crude Equivalent (Barrels)
San Joaquin Valley						
East	61,465,872	61,733,582	49,038,612	12,694,970	7,061,676	13,973,351
West	105,265,972	119,922,520	111,208,277	8,714,243	51,808,918	18,093,340
Total	166,731,844	181,656,102	160,246,889	21,409,213	58,870,594	32,066,691
Los Angeles Basin	38,702,034	49,549,608	49,542,179	7,429	3,351,219	614,077
Central Coast	16,745,939	16,894,916	14,716,633	2,178,283	3,895,640	2,883,489
Unspecified	11,623,689	52,109,884	52,109,884	0	2,955,617	535,039
Total	233,803,506	300,210,510	276,615,585	23,594,925	69,073,070	36,099,296

[1] Major crude oil producer: Atlantic-Richfield Company; Berry Ewing; Berry Holding; Berry Oil; Champlin Petroleum Company; Chevron, U.S.A. Inc.; Conoco Inc.; Exxon Company U.S.A; Getty Oil Company; Grace Pet.; Gulf Exploration and Production; Long Beach Development; M.H. Whittier; Marathon Oil Company; Mobil Oil Corporation; Occidental Petroleum; Petro-Lewis Corporation; Phillips Petroleum; Santa Fe Energy; Shell Oil Company; Sun Exploration; Tenneco; Texaco Inc.; Thums Long Beach Company; Union Oil Company of California.

[2] Designated Oil Fields by Producing Area:

San Joaquin, East: Edison; Fruitvale; Kern Bluff; Kern Front; Kern River; Mount Paso; Paso Creek.
San Joaquin, West: Belridge, No.; Belridge, So.; Coalinga; Cymric; Lost Hills; McKittrick; Midway-Sunset.
Los Angeles Basin: Huntington Beach; Newport, West; Placerita; Wilmington; Yorba Linda.
Central Coast: Arroyo Grande, Casmalia; Cat Canyon; Guadalupe; Oxnard; San Ardo; Santa Maria Valley.

Source: Production Data--California Division of Oil and Gas Well Statistics Data.
T.E.O.R. Fuel Use--California Energy Commission, PIIRA Data.
PIIRA Form: CEC-A14 California Major Crude Oil Producers Annual TEOR Fuel Use Report.

TABLE N-15

CRUDE OIL PRODUCTION FROM DESIGNATED T.E.O.R. FIELDS
BY PRODUCING AREA FOR YEAR 1984

Producing Area Designated TEOR Field	20°API Gravity and Less	Total Crude Oil Production	Incremental Crude Oil Production [1]
	Thousands of Barrels		
San Joaquin, East			
Edison	1,022	1,245	462
Fruitvale	871	1,039	0
Kern Bluff	260	260	203
Kern Front	2,824	2,824	1,408
Kern River	49,306	49,359	47,200
Mount Poso	6,980	6,987	6,956
Poso Creek	2,060	2,060	837
Total	63,323	63,774	57,066
San Joaquin, West			
Belridge, North	209	1,077	474
Belridge, South	36,034	46,728	30,173
Coalinga	9,427	10,075	8,100
Cymric	5,568	5,659	4,696
Lost Hills	2,430	5,238	1,773
McKittrick	3,927	4,179	1,910
Midway-Sunset	50,757	50,842	40,296
Total	108,352	123,798	87,422
Los Angeles Basin			
Huntington Beach	3,637	8,673	575
Newport, West	1,112	1,112	203
Placerita	515	515	178
Wilmington	34,422	40,635	230
Yorba Linda	2,008	2,015	1,708
Total	41,694	52,950	2,894
Central Coast			
Arroyo Grande	290	294	103
Cusmalia	469	513	4
Cat Canyon	4,985	4,995	2,666
Guadalupe	1,310	1,310	796
Oxnard	297	399	292
San Ardo	7,705	7,705	5,941
Santa Maria Valley	2,623	2,623	51
Total	17,679	17,839	9,853
Designated Oil Fields Total	231,048	258,361	157,235
Undesignated Oil Fields	16,526	123,583	565
State Total	247,574	381,944	157,800

Source: California Division of Oil and Gas Well Statistics Data

[1] Increased production due to TEOR projects.

TABLE N-16

CALIFORNIA CRUDE OIL PRODUCTION FROM TEN LARGEST FIELDS AND STATEWIDE TOTAL
(Thousands of Barrels)

Field	Annual 1983	Annual 1984	Daily Average 1883	Daily Average 1984	Percent Change
1. Midway-Sunset	47,499	50,842	130.1	138.9	6.76
2. Elk Hills	55,529	49,592	152.1	135.5	-10.91
3. Kern River	48,257	49,359	132.2	134.9	2.04
4. Belridge, South	41,304	46,728	113.2	127.7	12.81
5. Wilmington	38,496	40,635	105.5	111.0	5.21
6. Coalinga	9,584	10,075	26.3	27.5	4.56
7. Huntington Beach	9,076	8,673	24.9	23.7	-4.82
8. San Ardo	8,054	7,705	22.1	21.1	-4.52
9. Ventura	7,306	7,390	20.0	20.2	1.00
10. Mount Poso	7,552	6,987	20.7	19.1	-7.73
Top Ten Total	272,657	277,985	747.0	759.5	1.67
All Other Fields	101,873	103,959	279.1	284.1	1.79
State Total	394,530	381,944	1,026.1	1,043.6	1.71

Source: 69th Annual Report of the State Oil and Gas Supervisor, California Department of Conservation, Division of Oil and Gas, 1983.