Fuels REPORT

APPENDICES

CALIFORNIA ENERGY COMMISSION • DECEMBER 1989 • P300-89-018A

STATE OF CALIFORNIA
1975 1990
ENERGY COMMISSION

George Deukmejian, *Governor*

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APPENDIX A

CALIFORNIA ENERGY STATISTICS

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HISTORICAL
PRIMARY ENERGY RECEIPTS AND DELIVERIES
(TRILLIONS OF BTU)

ORIGIN/ENERGY TYPE	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
CALIFORNIA RECEIPTS													
NATURAL GAS	346	350	344	374	346	388	397	421	464	462	433	402	380
PETROLEUM	1834	1976	1964	1991	2021	2113	2198	2229	2308	2423	2329	2206	2118
NATURAL GAS PLANT LIQUIDS	59	57	60	62	64	59	54	48	51	50	34	33	47
HYDROPOWER	92	57	144	134	164	119	177	232	180	132	171	102	96
GEOTHERMAL & OTHER	74	74	60	80	101	113	91	130	134	170	210	193	197
SUBTOTAL CALIFORNIA	2405	2514	2572	2641	2696	2792	2917	3060	3137	3237	3177	2936	2838
OTHER STATES RECEIPTS													
NATURAL GAS	1144	1104	1046	1215	1253	1340	1148	1024	1059	1122	907	1212	1178
PETROLEUM	433	637	1377	1701	1708	1718	1363	1342	1476	1334	1690	1873	2051
LIQUIFIED PETROLEUM GAS	5	6	6	6	4	5	2	6	16	16	16	16	16
COAL	191	217	166	196	224	239	248	225	219	166	213	213	227
HYDROPOWER	118	52	93	57	100	134	207	216	271	217	251	166	171
NUCLEAR	51	87	81	96	51	36	37	43	138	176	297	350	376
SUBTOTAL OTHER STATES	1942	2103	2769	3271	3340	3472	3005	2856	3179	3031	3374	3830	4019
FOREIGN RECEIPTS													
NATURAL GAS	395	392	352	396	324	269	319	293	283	377	335	504	513
PETROLEUM	1758	2080	1150	949	719	376	254	327	345	267	266	278	283
HYDROPOWER													12
LIQUIFIED PETROLEUM GAS	3	1	2	3	3	2	4	2	11	12	12	12	12
SUBTOTAL FOREIGN	2156	2473	1504	1348	1046	647	577	622	639	656	613	794	820
TOTAL RECEIPTS													
NATURAL GAS	1885	1846	1742	1985	1923	1997	1864	1738	1806	1961	1675	2118	2071
PETROLEUM	4025	4693	4491	4641	4448	4207	3815	3898	4129	4024	4285	4357	4452
LIQUIFIED PETROLEUM GAS	67	64	68	71	71	66	60	56	78	78	62	61	75
COAL	191	217	166	196	224	239	248	225	219	166	213	213	227
HYDROPOWER	210	109	237	191	264	253	384	448	451	349	422	268	279
NUCLEAR	51	87	81	96	51	36	37	43	138	176	297	350	376
GEOTHERMAL & OTHER	74	74	60	80	101	113	91	130	134	170	210	193	197
GRAND TOTAL RECEIPTS	6503	7090	6845	7260	7082	6911	6499	6538	6955	6924	7164	7560	7677
EXPORT BY ENERGY TYPE													
PETROLEUM	687	715	704	611	602	666	673	629	653	515	570	671	681
LIQUIFIED PETROLEUM GAS	2	6	4	6	7	5	4	6	21	28	12	11	27
TOTAL EXPORT	689	721	708	617	609	671	677	635	674	543	582	682	708
STORAGE CHANGE/ENERGY TYPE													
NATURAL GAS	43	33	-2	-40	-61	-59	-62	51	-19	-20	-4	-25	15
PETROLEUM	-68	121	-195	4	113	-107	-35	-77	-34	-57	6	42	50
COAL	-1	10	-4	-2	3	2	-4	5	0	-2	1	2	1
LPG	-1	0	-1	1	2	0	-1	2	-1	0	0	0	0
TOTAL CHANGE	-27	164	-202	-37	57	-164	-102	-19	-54	-79	3	19	66
DELIVERIES BY ENERGY TYPE													
NATURAL GAS	1842	1813	1744	2025	1984	2056	1926	1687	1825	1981	1679	2143	2056
PETROLEUM													
MOTOR GASOLINE	1307	1397	1405	1447	1372	1321	1340	1415	1415	1473	1541	1577	1611
AVIATION FUELS	336	372	387	381	363	348	335	357	392	426	440	422	460
DISTILLATE FUELS	303	381	410	404	386	424	411	464	489	531	556	508	536
RESIDUAL FUELS	915	1144	1023	1081	929	798	519	467	523	547	527	547	461
MISC. FUELS	545	563	757	713	683	757	572	643	691	589	645	590	653
SUBTOTAL PETROLEUM	3406	3857	3982	4026	3733	3648	3177	3346	3510	3566	3709	3644	3721
LIQUIFIED PETROLEUM GAS	66	58	65	64	62	61	57	48	58	50	50	50	48
COAL	192	207	170	198	221	237	252	220	219	168	212	211	226
HYDROPOWER	210	109	237	191	264	253	384	448	451	349	422	268	279
NUCLEAR	51	87	81	96	51	36	37	43	138	176	297	350	376
GEOTHERMAL & OTHER	74	74	60	80	101	113	91	130	134	170	210	193	197
GRAND TOTAL DELIVERIES	5841	6205	6339	6680	6416	6404	5924	5922	6335	6460	6579	6859	6903

TABLE A-2
HISTORICAL
DELIVERIES BY SECTOR
(TRILLIONS OF BTU)

SECTOR/ENERGY DEMAND	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
ELECTRIC UTILITY													
NATURAL GAS	302	364	312	458	534	678	571	486	599	683	442	759	628
PETROLEUM													
DISTILLATE	0	0	0	0	0	0	2	2	2	2	2	2	5
RESIDUAL	596	774	619	640	391	284	99	65	22	28	38	20	78
SUBTOTAL PETROLEUM	596	774	619	640	391	284	101	67	24	30	40	22	83
COAL	135	141	110	138	152	165	187	188	182	128	171	169	183
HYDROPOWER	210	109	237	191	264	253	384	448	451	349	422	268	279
NUCLEAR	51	87	81	96	51	36	37	43	138	176	297	350	376
GEOTHERMAL & OTHER	74	74	60	80	101	113	91	130	134	170	210	193	197
TOTAL	1368	1549	1419	1603	1493	1529	1371	1362	1528	1536	1582	1761	1746
ELECTRICITY DELIVERED	520	527	545	567	566	591	578	584	611	641	659	682	717
CONVERSION LOSS	800	976	821	983	870	893	754	704	797	775	861	1020	967
TRANSMISSION LOSS	48	46	53	53	57	45	39	74	120	120	62	59	62
TOTAL LOSS	848	1022	874	1036	927	938	793	778	917	895	923	1079	1029
RESIDENTIAL END USER													
ELECTRICITY	154	162	174	182	176	183	179	187	200	199	200	211	215
NATURAL GAS	610	569	584	621	557	518	559	515	502	510	478	517	535
PETROLEUM													
DISTILLATE FUEL OIL	5	7	7	7	1	1	1	1	1	6	6	6	6
SUBTOTAL PETROLEUM	5	7	7	7	1	1	1	1	1	6	6	6	6
LPG	9	9	14	18	18	16	16	15	15	15	15	14	13
SUBTOTAL RESIDENTIAL	778	747	779	828	752	718	755	718	718	730	699	748	769
COMMERCIAL END USER													
ELECTRICITY	194	187	191	198	204	197	197	203	213	220	245	248	270
NATURAL GAS	183	187	174	177	165	178	187	173	172	197	193	180	193
PETROLEUM													
MOTOR GASOLINE	11	13	16	14	10	8	8	8	8	8	8	8	14
DISTILLATE FUEL OIL	9	13	13	10	21	30	29	27	27	13	13	12	13
RESIDUAL FUEL OIL	25	27	25	28	43	40	35	20	20	25	24	26	23
SUBTOTAL PETROLEUM	45	53	54	52	74	78	72	55	55	46	45	46	50
LPG	2	2	3	3	3	3	3	3	3	4	4	4	2
SUBTOTAL COMMERCIAL	424	429	422	430	446	456	459	434	443	467	487	478	515
INDUSTRIAL END USER													
ELECTRICITY	172	178	180	187	186	211	202	194	198	222	214	223	232
NATURAL GAS	747	693	674	769	728	682	609	513	552	591	566	687	701
PETROLEUM													
MOTOR GASOLINE	8	6	5	6	9	7	7	7	7	7	8	8	18
DISTILLATE FUEL OIL	78	104	110	138	105	112	127	103	103	103	108	104	110
RESIDUAL FUEL OIL	106	107	90	89	85	59	55	46	46	55	53	57	50
OTHER PETROLEUM	544	562	756	711	681	754	569	640	689	586	642	586	633
SUBTOTAL PETROLEUM	736	779	961	944	880	932	758	796	845	751	811	755	811
LPG	54	47	47	41	39	39	35	27	37	29	28	28	28
COAL	57	66	60	60	69	72	65	32	37	40	41	42	43
SUBTOTAL INDUSTRIAL	1766	1763	1922	2001	1902	1936	1669	1562	1669	1633	1660	1735	1815
TRANSPORTATION END USER													
PETROLEUM													
MOTOR GASOLINE	1288	1378	1384	1427	1353	1306	1325	1400	1400	1458	1525	1561	1579
AVIATION FUELS	336	372	387	381	363	348	335	357	392	426	440	422	460
DISTILLATE FUEL OIL	211	257	280	249	259	281	252	331	356	407	427	384	402
RESIDUAL FUEL OIL	188	236	289	324	410	415	330	336	435	439	412	444	310
LUBE OIL	1	1	1	2	2	3	3	3	2	3	3	4	20
SUBTOTAL PETROLEUM	2024	2244	2341	2383	2387	2353	2245	2427	2585	2733	2807	2815	2771
LPG	1	1	1	2	2	3	3	3	3	2	3	4	5
SUB TOTAL TRANSPORTATION	2025	2245	2342	2385	2389	2356	2248	2430	2588	2735	2810	2819	2776
TOTAL END USER	4993	5184	5465	5644	5489	5466	5131	5144	5418	5565	5656	5780	5875
TOTAL END USE DELIVERIES													
ELECTRICITY	520	527	545	567	566	591	578	584	611	641	659	682	717
NATURAL GAS	1540	1449	1432	1567	1450	1378	1355	1201	1226	1298	1237	1384	1428
PETROLEUM													
MOTOR GASOLINE	1307	1397	1405	1447	1372	1321	1340	1415	1415	1473	1541	1577	1611
AVIATION FUELS	336	372	387	381	363	348	335	357	392	426	440	422	460
DISTILLATE FUEL OIL	303	381	410	404	386	424	409	462	487	529	554	506	531
RESIDUAL FUEL OIL	319	370	404	441	538	514	420	402	501	519	489	527	383
MISC. FUELS	545	563	757	713	683	757	572	643	691	589	645	590	653
SUBTOTAL PETROLEUM	2810	3083	3363	3386	3342	3364	3076	3279	3486	3536	3669	3622	3638
LPG	66	58	65	64	62	61	57	48	58	50	50	50	48
COAL	57	66	60	60	69	72	65	32	37	40	41	42	43
TOTAL END USER	4993	5183	5465	5644	5489	5466	5131	5144	5418	5565	5656	5780	5874

TABLE A-3

PROJECTED PRIMARY ENERGY RECEIPTS AND DELIVERIES
(Trillion Btu)

Origin/Energy Type	1989	1994	2001	2009
California Receipts				
Natural Gas	352	269	175	136
Petroleum	1,917	2,257	2,078	2,148
Natural Gas Plant Liquids	49	52	54	59
Hydropower	140	146	148	150
Geothermal & Other	391	446	495	570
Subtotal California	2,849	3,170	2,950	3,063
Other States Receipts				
Natural Gas	1,120	1,183	1,394	1,628
Petroleum	2,228	2,147	1,368	742
Liquified Petroleum Gas	16	16	17	17
Coal	194	196	200	201
Hydropower	206	212	204	230
Nuclear	338	338	338	317
Subtotal Other States	4,102	4,092	3,521	3,135
Foreign Receipts				
Natural Gas	488	405	626	624
Petroleum	293	271	1,680	2,666
Liquified Petroleum Gas	12	12	12	13
Hydropower	12	12	12	12
Subtotal Foreign	805	700	2,330	3,315
Total Receipts				
Natural Gas	1,960	1,857	2,195	2,388
Petroleum	4,438	4,675	5,126	5,556
Liquified Petroleum Gas	77	80	83	89
Coal	194	196	200	201
Hydropower	358	370	364	392
Nuclear	338	338	338	317
Geothermal & Other	391	446	495	570
Grand Total Receipts	7,756	7,962	8,801	9,513
Export by Energy Type				
Petroleum	715	756	841	917
Liquified Petroleum Gas	24	24	24	24
Total Export	739	780	865	941
Deliveries by Energy Type				
Natural Gas	1,960	1,857	2,195	2,388
Petroleum				
Motor Gasoline	1,597	1,587	1,588	1,582
Aviation Fuels	466	491	540	588
Distillate Fuels	557	684	917	1,152
Residual Fuels	543	571	629	685
Misc. Fuels	560	586	611	632
Subtotal Petroleum	3,723	3,919	4,285	4,639
Liquified Petroleum Gas	53	56	59	65
Coal	194	196	200	201
Hydropower	358	370	364	392
Nuclear	338	338	338	317
Geothermal & Other	391	446	495	570
Grand Total Deliveries	7,017	7,182	7,936	8,572

TABLE A-4

PROJECTED DELIVERIES BY SECTOR
(Trillion Btu)

Sector/Energy Demand	1989	1994	2001	2009
Electric Utility				
Natural Gas	598	549	758	931
Petroleum				
Distillate	2	6	6	7
Residual	119	51	54	91
Subtotal Petroleum	121	57	60	98
Coal	152	152	154	152
Hydropower	358	370	364	392
Nuclear	338	338	338	317
Geothermal & Other	391	446	495	570
Total	1,958	1,912	2,169	2,460
Electricity Delivered	728	811	933	1,075
Conversion Loss	1,167	1,031	1,155	1,292
Transmission Loss	63	70	81	93
Total Loss	1,230	1,101	1,236	1,385
Residential End User				
Electricity	219	240	272	313
Natural Gas	532	538	548	571
Petroleum				
Distillate Fuel Oil	7	9	3	4
Subtotal Petroleum	7	9	3	4
LPG	15	15	16	18
Subtotal Residential	773	802	839	906
Commercial End User				
Electricity	276	312	371	444
Natural Gas	201	223	242	258
Petroleum				
Motor Gasoline	14	14	14	14
Distillate Fuel Oil	33	45	62	78
Residual Fuel Oil	4	4	4	8
Subtotal Petroleum	51	63	80	100
LPG	3	3	3	3
Subtotal Commercial	531	601	696	805
Industrial End User				
Electricity	233	259	290	318
Natural Gas	629	547	647	628
Petroleum				
Motor Gasoline	18	18	18	18
Distillate Fuel Oil	100	137	165	207
Residual Fuel Oil	56	117	101	174
Other Petroleum	539	564	587	605
Subtotal Petroleum	713	836	871	1,004
LPG	31	32	32	38
Coal	42	44	46	49
Subtotal Industrial	1,648	1,718	1,886	2,037
Transportation End User				
Petroleum				
Motor Gasoline	1,565	1,555	1,556	1,550
Aviation Fuels	466	491	540	588
Distillate Fuel Oil	415	487	681	856
Residual Fuel Oil	364	399	470	412
Lube Oil	21	22	24	27
Subtotal Petroleum	2,831	2,954	3,271	3,433
LPG	4	6	8	6
Subtotal Transportation	2,835	2,960	3,279	3,439
Total End User	5,787	6,081	6,700	7,187
Total End Use Deliveries				
Electricity	728	811	933	1,075
Natural Gas	1,362	1,308	1,437	1,457
Petroleum				
Motor Gasoline	1,597	1,587	1,588	1,582
Aviation Fuels	466	491	540	588
Distillate Fuel Oil	555	678	911	1,145
Residual Fuel Oil	424	520	575	594
Misc. Fuels	560	586	611	632
Subtotal Petroleum	3,602	3,862	4,225	4,541
LPG	53	56	59	65
Coal	42	44	46	49
Total End User	5,787	6,081	6,700	7,187

TABLE A-5

CALIFORNIA ANNUAL PETROLEUM SUMMARY
(Thousands of Barrels)

ACTIVITY	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Refinery Crude Oil Receipts													
Total Receipts	617,187	708,142	647,293	689,257	674,485	634,038	577,717	606,604	632,937	644,335	677,862	680,895	708,807
Domestic	349,147	394,513	494,258	565,100	576,100	573,783	544,164	558,613	579,675	608,927	640,985	647,494	671,590
Alaska	39,346	80,783	203,580	269,361	267,478	245,005	196,462	189,538	210,450	210,647	237,508	260,843	306,247
California and Other	309,801	313,730	290,678	295,739	303,672	328,778	347,702	369,075	369,225	398,280	403,477	386,651	365,343
Foreign	268,040	313,629	153,035	124,157	98,335	60,255	33,553	47,991	53,262	35,408	36,877	33,395	37,217
Refinery Product Output													
Motor Gasoline	276,714	303,554	300,581	306,955	294,808	286,957	272,219	289,680	300,667	306,097	324,187	339,023	345,574
Aviation Fuels	71,057	76,624	71,300	75,955	73,394	71,472	69,368	73,443	81,705	82,443	86,855	86,213	89,633
Distillate Fuels	72,801	84,705	81,437	89,745	80,236	89,084	88,130	94,720	104,844	105,397	110,743	102,212	111,120
Residual Fuels	134,713	171,144	141,534	159,525	166,935	132,819	94,403	86,052	92,929	92,580	93,304	90,850	88,828
Other	99,082	115,844	127,752	146,913	137,513	118,863	108,584	111,461	118,226	120,210	128,711	132,269	139,017
Total Output	654,367	752,871	722,604	779,093	752,886	699,195	632,677	655,356	698,371	706,727	743,800	750,567	774,172
Product Import/Export													
Import													
Motor Gasoline	9,423	5,411	6,980	6,586	6,232	8,904	22,937	17,937	10,742	17,166	18,736	24,616	25,776
Aviation Fuels	1,354	883	7,828	3,945	1,583	1,639	3,978	1,314	826	832	2,535	4,420	3,675
Distillate Fuels	1,650	2,056	4,769	3,195	1,379	1,729	2,463	2,073	1,594	1,888	1,847	7,212	2,254
Residual Fuels	28,474	48,152	22,958	33,832	18,035	14,332	10,944	5,886	6,687	4,003	5,356	4,368	10,905
Export													
Motor Gasoline	36,162	43,274	50,681	38,911	36,403	42,133	40,788	39,064	40,147	36,897	40,624	54,105	50,514
Aviation Fuels	12,429	12,159	11,015	13,305	10,525	11,899	14,507	12,314	12,402	9,680	10,539	16,335	11,401
Distillate Fuels	10,551	20,656	19,030	21,271	16,568	17,594	19,901	17,578	22,778	16,434	17,838	21,647	19,751
Residual Fuels	27,960	27,860	21,798	19,407	24,984	22,616	24,843	28,981	23,868	12,754	15,112	10,937	13,199
Stocks at End of Year													
Motor Gasoline	18,587	19,019	18,096	16,921	18,154	19,993	19,021	17,843	20,301	18,372	19,171	21,059	26,030
Aviation Fuels	5,463	5,142	5,081	4,504	4,884	4,604	4,388	3,850	4,901	3,474	4,663	4,661	5,359
Distillate Fuels	7,863	8,737	5,560	7,836	6,674	7,929	7,981	7,584	7,736	7,470	6,798	7,342	8,849
Residual Fuels	41,634	51,035	31,074	34,005	46,260	42,304	40,482	29,336	25,421	22,469	23,038	20,324	21,225
Product Supplied													
Motor Gasoline	248,962	266,259	267,803	275,805	261,413	251,988	255,343	269,641	268,674	288,295	301,500	300,418	306,897
Aviation Fuels	59,303	65,669	68,174	67,172	64,072	61,492	59,025	62,970	69,031	75,022	77,662	74,300	81,210
Distillate Fuels	51,958	65,362	70,353	69,393	66,209	73,537	70,560	79,612	83,455	91,117	95,424	87,233	92,115
Residual Fuels	145,501	182,035	162,655	172,019	147,731	131,133	82,566	74,306	79,616	86,781	82,979	86,942	85,587

Source: QFER submittals for 1976 to 1982 and PIIRA submittals for 1981 to 1988. PIIRA Forms: DOE/EIA-810 Monthly Refinery Report. CEC-M07/M12 California Major Petroleum Product Marketer and Storer Reports.

TABLE A-6

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	71.057	595	759	679	71,732	12,163	266	59,303
1977	76,624	773	110	-321	77,828	11,907	252	65,669
1978	71,300	2,897	4,931	-61	79,189	10,720	295	68,174
1979	75,955	2,551	1,394	-577	80,477	12,968	337	67,172
1980	73,394	1,426	157	380	74,597	10,254	271	64,072
1981	71,472	1,639	0	-280	73,391	11,596	303	61,492
1982	69,368	3,005	973	-186	73,532	13,594	913	59,025
1983	73,443	1,206	108	-527	75,284	11,262	1,052	62,970
1984	81,705	681	145	1,098	81,433	11,599	803	69,031
1985	82,443	696	135	-1,587	84,862	9,559	121	75,182
1986	86,855	1,299	1,236	1,189	88,201	10,436	103	77,662
1987	86,213	3,733	687	-2	90,635	16,345	-10	74,300
1988	89,633	3,134	541	697	92,611	11,292	109	81,240
Distillate Fuels								
1976	72,801	1,650	0	1,942	72,509	19,674	787	51,958
1977	84,705	2,056	0	743	86,018	19,717	939	65,362
1978	81,437	4,769	0	-3,177	89,383	18,159	871	70,353
1979	89,745	2,841	354	2,276	90,664	20,416	855	69,393
1980	80,236	1,379	0	-1,162	82,777	15,986	582	66,209
1981	89,084	1,729	0	-318	91,131	16,901	693	73,537
1982	88,103	2,463	0	105	90,461	18,657	1,244	70,560
1983	94,720	1,995	78	-397	97,190	16,930	648	79,612
1984	104,844	1,548	46	205	106,233	21,670	1,108	83,455
1985	105,397	1,776	112	-243	107,528	15,852	582	91,094
1986	110,743	1,764	83	-672	113,262	17,211	627	95,424
1987	102,210	6,942	270	542	108,880	20,348	1,299	87,233
1988	111,120	2,254	0	1,508	111,866	19,141	610	92,115
Motor Gasoline								
1976	276,714	9,423	0	1,013	285,124	36,160	2	248,962
1977	304,554	5,301	110	432	309,533	43,271	3	266,259
1978	300,581	6,692	288	-923	308,484	40,680	1	267,803
1979	306,955	6,586	0	-1,175	314,716	38,911	0	275,805
1980	294,808	6,081	151	1,224	299,816	38,398	5	261,413
1981	286,957	7,447	1,457	1,740	294,121	42,007	126	251,988
1982	280,973	8,395	5,389	-376	295,133	39,863	575	254,695
1983	292,633	6,705	4,805	-758	304,981	38,837	218	265,926
1984	304,347	4,682	3,279	2,256	310,052	39,513	564	269,975
1985	306,097	5,518	4,001	-1,947	317,563	36,790	106	280,667
1986	324,187	8,014	1,232	556	332,877	38,212	963	293,202
1987	339,023	13,698	1,810	2,367	353,164	52,238	508	300,418
1988	345,574	13,769	1,854	4,031	357,166	50,269	0	306,897
Residual Fuel Oils								
1976	134,713	20,821	7,653	-10,274	173,461	13,303	14,657	145,501
1977	171,144	30,144	17,310	9,401	209,895	12,654	15,206	182,035
1978	141,534	18,101	4,857	-19,961	184,453	10,522	11,276	162,655
1979	159,525	23,032	11,800	2,931	191,426	9,515	9,892	172,019
1980	166,935	13,118	4,917	12,255	172,715	11,908	13,076	147,731
1981	132,819	9,490	4,842	-6,598	153,749	6,885	15,731	131,133
1982	94,403	8,431	2,513	-2,062	107,409	12,966	11,877	82,566
1983	86,052	4,492	1,394	-11,349	103,287	9,914	19,067	74,306
1984	92,929	5,738	949	-3,868	103,484	11,761	12,107	79,616
1985	92,580	2,319	1,684	-2,952	99,535	5,531	7,223	86,781
1986	93,304	1,718	3,628	566	98,094	4,107	11,005	82,982
1987	90,850	1,811	2,557	-2,661	97,879	1,276	9,661	86,942
1988	88,828	2,296	8,609	947	98,786	3,684	9,515	85,587

Source: QFER submittals for 1976 to 1981 and PIIRA submittals for 1981 to 1986. PIIRA Forms: DOE/EIA-810 Monthly Refinery Report, CEC/M07-M12 California Major Petroleum Product Marketer and Storer Reports.

TABLE A-7

CRUDE OIL RECEIPTS AT CALIFORNIA REFINERIES BY SOURCE OF SUPPLY
(Percent of Total)

	1981	1982	1983	1984	1985	1986	1987	1988
SOURCE OF SUPPLY								
Domestic								
California	50.97	58.44	59.20	54.78	58.01	55.77	55.60	49.56
Alaska								
North Slope	36.23	32.97	29.96	32.26	33.54	35.68	36.94	42.77
Alaska Other	2.42	1.91	1.76	1.68	1.30	1.38	1.44	1.71
Federal Offshore	0.56	0.76	1.11	2.38	1.52	1.63	1.05	1.08
Other States	0.32	0.27	0.22	0.00	0.14	0.00	0.00	0.00
Total Domestic	90.50	94.35	92.25	91.10	94.51	94.46	95.03	94.62
FOREIGN								
OPEC								
Mideast	0.12	0.00	0.00	0.00	0.00	0.04	0.00	0.05
Indonesia	8.58	5.06	6.93	7.67	4.49	4.55	3.84	3.85
Other	0.37	0.13	0.25	0.37	0.28	0.54	0.00	0.00
Total OPEC	9.07	5.19	7.18	8.04	4.77	5.13	3.84	3.90
NonOPEC								
Mexico	0.00	0.02	0.00	0.00	0.00	0.00	0.04	0.00
Other	0.43	0.44	0.57	0.86	0.72	0.41	1.09	1.48
Total NonOPEC	0.43	0.46	0.57	0.86	0.72	0.41	1.13	1.48
Total Foreign	9.50	5.65	7.75	8.90	5.49	5.54	4.97	5.38

Source: PIIRA Form CEC-A04 California Refiners Report.

Percentages in Table A-7 are based on percentages rounded to the nearest whole percent reported on CEC-A04 and will not equal volumes reported on Tables A-5, A-8 and A-9.

TABLE A-8

CALIFORNIA REFINERY ACTIVITY BY TYPE AND AREA
1987

ACTIVITY	Refinery Type			State	Refinery Area		
	Topping	Hydro-Skimming	Complex	Total	Northern	Central	Southern
Product Output (mbbls)							
Motor Gasoline, Leaded	0	3,791	84,135	87,926	36,629	3,137	48,160
Motor Gasoline, Unleaded	0	8,594	242,503	251,097	104,958	6,589	139,550
Motor Gasoline, Blendstocks	441	109	0	0	0	0	0
Motor Gasoline, Totals	441	12,494	326,638	339,023	141,587	9,726	187,710
Aviation Fuels	706	2,503	83,004	86,213	35,392	459	50,362
Distillate Fuels	6,345	6,057	89,810	102,212	36,574	4,609	61,029
Residual Fuels	2,689	9,927	78,234	90,850	42,221	7,946	40,683
Lubricating Oils	1,629	0	5,131	6,760	5,149	1,629	-18
Asphalt and Road Oil	9,636	2,829	7,106	19,571	8,064	3,381	8,126
Wax	0	0	843	843	843	0	0
Petroleum Coke	0	0	40,116	40,116	12,991	0	27,125
Still Gas	25	1,418	39,330	40,773	16,611	1,082	23,080
Liquified Refinery Gases	0	511	14,782	15,293	6,393	454	8,446
Other Products	1,447	1,837	5,629	8,913	1,913	598	6,402
Unfinished Oils	1,752	2,421	0	0	0	2,989	0
Total Output	24,670	39,997	690,623	750,567	307,738	32,873	412,945
Feedstock Input (mbbls)							
Crude Oil	24,711	39,583	603,105	667,399	264,671	31,990	370,738
Natural gas Plant Liquids	0	459	7,337	7,796	1,143	459	6,194
Other Hydrocarbons and Hydrogen	0	11	4,059	4,070	3,070	11	989
Unfinished Oils	0	0	20,860	16,687	13,560	0	6,116
Motor Gasoline, Blendstocks	0	0	11,676	11,126	4,121	60	6,945
Total Input	24,711	40,053	647,037	707,078	286,565	32,520	390,982
Refinery Gain/Loss	-41	-56	43,586	43,489	21,173	353	21,963
Distillation Capacity (mb/d)							
Shutdown	32.8	10.5	105.5	148.8	80.0	43.3	25.5
Operating	112.1	156.7	1,989.0	2,257.8	834.1	124.0	1,299.7
Operable	144.9	167.2	2,094.5	2,406.6	914.1	167.3	1,325.2
Distillation Unit Input (mb/d)	59.3	108.8	1,672.3	1,840.4	757.9	79.8	1,002.7
Utilization (Percent)							
Operating	52.89	69.47	84.08	81.52	82.91	64.35	77.15
Operable	40.93	65.11	79.84	76.48	90.87	47.70	75.67
Crude Quality							
Average API Gravity (*)	16.77	27.92	23.67	23.57	22.75	22.86	24.25
Average Sulfur Content (%)	1.56	1.00	1.12	1.13	1.15	1.03	1.13
Fuel Use							
Crude Oil (mbbls)	0	0	0	0	0	0	0
Distillate (mbbls)	0	6	21	27	16	0	11
Residual (mbbls)	107	221	779	1,107	431	324	352
LPG (mbbls)	0	67	3,421	3,488	1,330	0	2,158
Natural Gas (mmcf)	3,520	3,488	67,178	74,186	46,581	3,917	23,688
Still Gas (mbbls)	25	1,573	38,238	39,836	16,129	1,122	22,585
Petroleum Coke/Catalyst (mbbls)	0	0	9,268	9,268	4,738	0	4,560
Petroleum Coke/Marketable (mbbls)	0	0	916	916	916	0	0
Electricity Purchased (Gwh)	73	246	5,144	5,463	2,577	212	2,674
Steam Purchased (mmbls)	253	0	2,527	2,780	2,527	253	0
Crude Receipts (mbbls)							
Domestic							
Alaska	0	2,909	257,934	260,843	135,401	0	125,442
California and other	24,967	36,696	318,351	380,014	122,706	32,173	225,135
Total Domestic	24,967	39,605	576,285	640,857	258,107	32,173	350,577
Foreign	0	35	33,360	33,395	6,453	0	26,942
Total Receipts	24,967	39,640	609,645	674,252	264,560	32,173	377,519

Source: PIIRA submittals, Form DOE/EIA-810 Monthly Refinery Report. CEC/M13 California Refinery Report.

TABLE A-9

CALIFORNIA REFINERY ACTIVITY BY TYPE AND AREA
1988

ACTIVITY	Refinery Type			State	Refinery Area		
	Topping	Hydro-Skimming	Complex	Total	Northern	Central	Southern
Product Output (mbbls)							
Motor Gasoline, Leaded	5	2,955	77,960	80,920	34,142	2,759	44,019
Motor Gasoline, Unleaded	15	8,608	256,031	264,654	111,161	6,745	146,748
Motor Gasoline, Blendstocks	851	0	0	0	0	0	0
Motor Gasoline, Totals	871	11,563	333,991	345,574	145,303	9,504	190,767
Aviation Fuels	940	1,356	87,337	89,633	36,949	213	52,471
Distillate Fuels	7,434	7,633	96,053	111,120	40,613	5,710	64,797
Residual Fuels	3,548	5,838	79,444	88,828	42,424	3,759	42,645
Lubricating Oils	1,861	0	4,886	6,747	5,014	1,861	-128
Asphalt and Road Oil	10,153	2,352	6,408	18,913	7,278	3,440	8,195
Wax	0	0	817	817	802	0	15
Petroleum Coke	0	1,122	41,677	42,799	13,680	1,039	28,080
Still Gas	42	2,227	40,672	42,941	17,299	1,538	24,104
Liquified Refinery Gases	0	468	17,241	17,709	7,569	463	9,677
Other Products	1,393	1,746	5,952	9,091	2,651	677	5,763
Unfinished Oils	2,314	4,398	0	0	0	5,372	0
Total Output	28,556	38,701	714,478	774,172	319,582	33,576	426,386
Feedstock Input (mbbls)							
Crude Oil	28,508	37,557	634,947	701,012	280,905	32,326	387,781
Natural gas Plant Liquids	0	516	7,723	8,239	1,645	516	6,078
Other Hydrocarbons and Hydrogen	107	62	4,148	4,317	3,173	62	1,082
Unfinished Oils	0	0	11,960	5,248	9,603	0	1,017
Motor Gasoline, Blendstocks	0	67	12,563	11,779	2,597	68	9,114
Total Input	28,615	38,202	671,341	730,595	297,923	32,972	405,072
Refinery Gain/Loss	-59	499	43,137	43,577	21,659	604	21,314
Distillation Capacity (mb/d)							
Shutdown	22.1	1.5	95.3	118.9	80.2	22.1	16.6
Operating	104.9	138.3	2,015.3	2,258.5	841.4	102.5	1,314.6
Operable	127.0	139.8	2,110.6	2,377.4	921.6	124.6	1,331.2
Distillation Unit Input (mb/d)	69.5	100.3	1,739.9	1,909.7	792.1	79.7	1,037.9
Utilization (Percent)							
Operating	66.42	72.77	86.57	84.55	94.40	77.99	79.16
Operable	54.84	71.94	82.66	80.32	86.18	64.13	78.17
Crude Quality							
Average API Gravity (*)	17.88	26.05	23.40	23.29	22.62	22.29	23.86
Average Sulfur Content (%)	1.75	1.16	1.16	1.18	1.19	1.02	1.19
Fuel Use							
Crude Oil (mbbls)	0	0	0	0	0	0	0
Distillate (mbbls)	0	1	93	94	83	0	11
Residual (mbbls)	173	134	465	772	385	301	86
LPG (mbbls)	15	88	4,149	4,252	1,980	56	2,216
Natural Gas (mmcf)	2,562	2,645	71,899	77,106	45,809	2,548	28,749
Still Gas (mbbls)	43	2,447	38,716	41,206	16,801	1,598	22,807
Petroleum Coke/Catalyst (mbbls)	0	0	9,750	9,750	4,780	0	4,970
Petroleum Coke/Marketable (mbbls)	0	0	1,063	1,063	1,062	0	1
Electricity Purchased (Gwh)	72	257	4,702	5,031	2,436	233	2,362
Steam Purchased (mmbls)	343	0	5,733	6,076	1,971	343	3,762
Crude Receipts (mbbls)							
Domestic							
Alaska	562	3,180	302,505	306,247	149,124	0	157,123
California and other	27,772	34,260	296,583	356,615	125,101	32,155	201,359
Total Domestic	28,334	37,440	599,088	664,862	274,225	32,155	358,482
Foreign	0	0	37,217	37,217	7,050	0	30,167
Total Receipts	28,334	37,440	636,305	702,079	281,275	32,155	388,649

Source: PIIRA submittals, Form DOE/EIA-810 Monthly Refinery Report. CEC/M13 California Refinery Report.

TABLE A-10

PROCESSING FACILITY CHANGE AT CALIFORNIA REFINERIES
FROM 1987 TO 1989
OPERABLE CAPACITY
(mbbls/stream day)

Type Refinery Facility	1987	Additions	Shut Down	Net Change	1989	% Change
Complex						
Crude Distillation	2,144.7	99.1	7.2	91.9	2,236.6	4.28
Vacuum Distillation	1,135.9	53.7	0.0	53.7	1,189.6	4.73
Thermal Cracking	422.8	49.8	37.7	12.1	434.9	2.86
Catalytic Cracking	604.3	52.0	15.8	36.2	640.5	5.99
Catalytic Reforming	486.9	21.8	36.0	-14.2	472.7	-2.92
Catalytic Hydro-cracking	360.4	204.1	3.0	201.1	561.5	55.80
Catalytic Hydro-treating	1,282.1	107.3	41.2	66.1	1,348.2	5.16
Hydroskimming						
Crude Distillation	209.0	0.0	72.0	-72.0	137.0	-34.45
Vacuum Distillation	80.0	0.0	42.0	-42.0	38.0	-52.50
Thermal Cracking	58.1	0.0	58.0	-58.1	0.0	-100.00
Catalytic Cracking	36.0	0.0	36.0	-36.0	0.0	-100.00
Catalytic Reforming	54.4	2.5	16.9	-14.0	40.0	-26.47
Catalytic Hydro-cracking	20.0	0.0	5.7	-5.7	14.3	-28.50
Catalytic Hydro-treating	71.3	9.0	7.8	1.2	72.5	1.68
Topping						
Crude Distillation	169.0	24.8	57.7	-32.9	136.1	-19.47
Vacuum Distillation	85.2	82.9	23.5	59.4	144.6	69.72
Thermal Cracking	16.8	0.0	11.8	-11.8	5.0	-70.23
Catalytic Hydro-treating	0.6	0.0	0.0	0.0	0.6	0.00
All Refineries						
Crude Distillation	2,522.8	123.9	137.0	-13.1	2,509.7	0.52
Vacuum Distillation	1,301.1	136.6	65.5	71.1	1,372.2	5.46
Thermal Cracking	497.7	49.8	107.6	-57.8	439.9	-11.61
Catalytic Cracking	640.3	52.0	51.8	0.2	640.5	0.03
Catalytic Reforming	541.3	24.3	52.9	-28.6	512.7	-5.28
Catalytic Hydro-cracking	380.4	204.1	8.7	195.4	575.8	51.37
Catalytic Hydro-treating	1,353.9	116.4	49.0	67.4	1,421.3	4.98

Source: PIIRA submittals. Form DOE/EIA-820 Annual Refinery Report.

TABLE A-11

CALIFORNIA PETROLEUM FUELS MARKET ACTIVITY
(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	MARKETER RECEIPTS	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS	STORAGE CHANGE
MOTOR GASOLINE, LEADED													
1986	JANUARY	8024	124	0	124	8148	1154	5	1159	6217	7376	6241	772
	FEBRUARY	6923	117	0	117	7040	1071	0	1071	6510	7581	5700	-541
	MARCH	7780	60	0	60	7840	950	0	950	8124	9074	4466	-1234
	APRIL	7474	33	0	33	7507	1002	47	1049	6362	7411	4562	96
	MAY	8549	95	0	95	8644	1084	0	1084	7043	8127	5079	517
	JUNE	8160	78	114	192	8352	1245	119	1364	6379	7743	5688	609
	JULY	8499	5	141	146	8645	1357	150	1507	7082	8589	5744	56
	AUGUST	8285	160	92	252	8537	1324	0	1324	8254	9578	4735	-1041
	SEPTEMBER	8728	154	0	154	8882	1335	0	1335	7076	8411	5206	471
	OCTOBER	8524	139	0	139	8663	1548	210	1758	6855	8613	5256	50
	NOVEMBER	8120	190	0	190	8310	1326	0	1326	7557	8883	4683	-573
	DECEMBER	8464	88	9	97	8561	1249	0	1249	7375	8624	4620	-63
1987	JANUARY	6902	210	167	377	7279	1076	38	1114	6888	8002	3897	-723
	FEBRUARY	6494	174	0	174	6668	955	0	955	4999	5954	4611	714
	MARCH	7361	249	53	302	7663	1451	0	1451	6504	7955	4319	-292
	APRIL	7449	234	0	234	7683	1184	108	1292	6578	7870	4132	-187
	MAY	8382	391	169	560	8942	1277	0	1277	6619	7896	5178	1046
	JUNE	7409	287	159	446	7855	1630	0	1630	6449	8079	4954	-224
	JULY	7914	389	0	389	8303	1872	0	1872	6807	8679	4578	-376
	AUGUST	7357	466	0	466	7823	1917	0	1917	6338	8255	4146	-432
	SEPTEMBER	7355	340	341	681	8036	1664	0	1664	6198	7862	4320	174
	OCTOBER	7073	33	375	408	7481	1630	0	1630	5740	7370	4431	111
	NOVEMBER	6609	52	266	318	6927	1259	0	1259	5350	6609	4749	318
	DECEMBER	7621	175	0	175	7796	965	297	1262	6643	7905	4640	-109
1988	JANUARY	6530	177	0	177	6707	1030	0	1030	5486	6516	4831	191
	FEBRUARY	6449	160	0	160	6609	1046	0	1046	5632	6678	4762	-69
	MARCH	6848	291	0	291	7139	1070	0	1070	6424	7494	4407	-355
	APRIL	6870	370	0	370	7240	1382	0	1382	5307	6689	4958	551
	MAY	6635	310	0	310	6945	1271	0	1271	6123	7394	4509	-449
	JUNE	5973	341	0	341	6314	1471	0	1471	5177	6648	4175	-334
	JULY	6664	629	0	629	7293	1198	0	1198	5563	6761	4707	532
	AUGUST	7518	312	0	312	7830	1142	0	1142	6642	7784	4753	46
	SEPTEMBER	6613	469	0	469	7082	1014	0	1014	5943	6957	4878	125
	OCTOBER	6860	93	0	93	6953	1177	0	1177	6081	7258	4573	-305
	NOVEMBER	6434	212	0	212	6646	876	0	876	5577	6453	4766	193
	DECEMBER	7526	14	0	14	7540	793	0	793	6047	6840	5466	700

TABLE A-12

CALIFORNIA PETROLEUM FUELS MARKET ACTIVITY
(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	MARKETER RECEIPTS	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS	STORAGE CHANGE
MOTOR GASOLINE, UNLEADED													
1986	JANUARY	19402	478	272	750	20152	1885	0	1885	15534	17419	10143	2733
	FEBRUARY	15591	377	0	377	15968	1642	0	1642	15492	17134	8977	-1166
	MARCH	17239	382	0	382	17621	1695	0	1695	18259	19954	6644	-2333
	APRIL	17697	1161	0	1161	18858	1620	0	1620	16252	17872	7630	986
	MAY	18025	534	0	534	18559	1569	0	1569	15804	17373	8816	1186
	JUNE	18999	290	174	464	19463	1427	179	1606	17242	18848	9431	615
	JULY	20206	407	355	762	20968	2104	183	2287	18490	20777	9622	191
	AUGUST	20526	562	-12	550	21076	2072	0	2072	20492	22564	8134	-1488
	SEPTEMBER	19986	580	0	580	20566	2366	0	2366	16797	19163	9537	1403
	OCTOBER	19393	714	87	801	20194	2529	70	2599	18163	20762	8969	-568
	NOVEMBER	19913	458	0	458	20371	2330	0	2330	17146	19476	9864	895
	DECEMBER	19680	828	0	828	20508	2328	0	2328	19197	21525	8847	-1017
1987	JANUARY	20054	1268	0	1268	21322	2401	65	2466	18595	21061	9108	261
	FEBRUARY	18561	851	0	851	19412	2016	0	2016	16961	18977	9543	435
	MARCH	20859	1092	99	1191	22050	2571	0	2571	19171	21742	9851	308
	APRIL	20654	1372	0	1372	22026	2327	0	2327	19199	21526	10351	500
	MAY	22476	1063	0	1063	23539	3141	0	3141	19501	22642	11248	897
	JUNE	21615	693	0	693	22308	2778	0	2778	19019	21797	11759	511
	JULY	22049	502	0	502	22551	3508	0	3508	19783	23291	11019	-740
	AUGUST	21889	391	0	391	22280	3800	0	3800	18491	22291	11008	-11
	SEPTEMBER	20498	911	0	911	21409	3584	0	3584	17885	21469	10948	-60
	OCTOBER	19583	1089	181	1270	20853	3358	0	3358	18636	21994	9807	-1141
	NOVEMBER	20671	620	0	620	21291	2682	0	2682	18016	20698	10400	593
	DECEMBER	22188	846	0	846	23034	3192	0	3192	20048	23240	10194	-206
1988	JANUARY	22181	1210	61	1271	23452	2920	0	2920	18627	21547	12099	1905
	FEBRUARY	19254	927	0	927	20181	3073	0	3073	18335	21408	10872	-1227
	MARCH	21152	1610	0	1610	22762	3258	0	3258	20362	23620	10014	-858
	APRIL	21606	917	710	1627	23233	3424	0	3424	19277	22701	10546	532
	MAY	21137	1531	994	2525	23662	3743	0	3743	19580	23323	10885	339
	JUNE	21470	1132	0	1132	22602	3509	0	3509	19510	23019	10468	-417
	JULY	23268	693	89	782	24050	3200	0	3200	20254	23454	11064	596
	AUGUST	22875	554	0	554	23429	3139	0	3139	19675	22814	11679	615
	SEPTEMBER	22640	694	0	694	23334	2745	0	2745	18362	21107	13906	2227
	OCTOBER	21938	397	0	397	22335	2467	0	2467	20504	22971	13270	-636
	NOVEMBER	22109	464	0	464	22573	2487	0	2487	21242	23729	12114	-1156
	DECEMBER	25024	262	0	262	25286	2834	0	2834	21167	24001	13399	1285

TABLE A-13

CALIFORNIA PETROLEUM FUELS MARKET ACTIVITY

FINISHED MOTOR GASOLINE

(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	MARKETER RECEIPTS	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS
1986	JANUARY	27426	602	272	874	28300	3039	5	3044	21751	24795	16384
	FEBRUARY	22514	494	0	494	23008	2713	0	2713	22002	24715	14677
	MARCH	25019	442	0	442	25461	2645	0	2645	26383	29028	11110
	APRIL	25171	1194	0	1194	26365	2622	47	2669	22614	25283	12192
	MAY	26574	629	0	629	27203	2653	0	2653	22847	25500	13895
	JUNE	27159	368	288	656	27815	2672	298	2970	23621	26591	15119
	JULY	28705	412	496	908	29613	3461	333	3794	25572	29366	15366
	AUGUST	28811	722	80	802	29613	3396	0	3396	28746	32142	12869
	SEPTEMBER	28714	734	0	734	29448	3701	0	3701	23873	27574	14743
	OCTOBER	27917	853	87	940	28857	4077	280	4357	25018	29375	14225
	NOVEMBER	28033	648	0	648	28681	3656	0	3656	24703	28359	14547
	DECEMBER	28144	916	9	925	29069	3577	0	3577	26572	30149	13467
1987	JANUARY	26956	1478	167	1645	28601	3477	103	3580	25483	29063	13005
	FEBRUARY	25055	1025	0	1025	26080	2971	0	2971	21960	24931	14154
	MARCH	28220	1341	152	1493	29713	4022	0	4022	25675	29697	14170
	APRIL	28103	1606	0	1606	29709	3511	108	3619	25777	29396	14483
	MAY	30858	1454	169	1623	32481	4418	0	4418	26120	30538	16426
	JUNE	29024	980	159	1139	30163	4408	0	4408	25468	29876	16713
	JULY	29963	891	0	891	30854	5380	0	5380	26590	31970	15597
	AUGUST	29246	857	0	857	30103	5717	0	5717	24829	30546	15154
	SEPTEMBER	27853	1251	341	1592	29445	5248	0	5248	24083	29331	15268
	OCTOBER	26656	1122	556	1678	28334	4988	0	4988	24376	29364	14238
	NOVEMBER	27280	672	266	938	28218	3941	0	3941	23366	27307	15149
	DECEMBER	29809	1021	0	1021	30830	4157	297	4454	26691	31145	14834
1988	JANUARY	28711	1387	61	1448	30159	3950	0	3950	24113	28063	16930
	FEBRUARY	25703	1087	0	1087	26790	4119	0	4119	23967	28086	15634
	MARCH	28000	1901	0	1901	29901	4328	0	4328	26786	31114	14421
	APRIL	28476	1287	710	1997	30473	4806	0	4806	24584	29390	15504
	MAY	27772	1841	994	2835	30607	5014	0	5014	25703	30717	15394
	JUNE	27443	1473	0	1473	28916	4980	0	4980	24687	29667	14643
	JULY	29932	1322	89	1411	31343	4398	0	4398	25817	30215	15771
	AUGUST	30393	866	0	866	31259	4281	0	4281	26317	30598	16432
	SEPTEMBER	29253	1163	0	1163	30416	3759	0	3759	24305	28064	18784
	OCTOBER	28798	490	0	490	29288	3644	0	3644	26585	30229	17843
	NOVEMBER	28543	676	0	676	29219	3363	0	3363	26819	30182	16880
	DECEMBER	32550	276	0	276	32826	3627	0	3627	27214	30841	18865

TABLE A-14

CALIFORNIA PETROLEUM FUELS MARKET ACTIVITY
(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	MARKETER RECEIPTS	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS	STORAGE CHANGE
AVIATION FUELS													
1986	JANUARY	7566	180	0	180	7746	659	0	659	6205	6864	4356	882
	FEBRUARY	6496	22	0	22	6518	1099	3	1102	5395	6497	4377	21
	MARCH	7044	98	80	178	7222	563	0	563	7095	7658	3941	-436
	APRIL	5822	178	0	178	6000	751	0	751	5443	6194	3747	-194
	MAY	6514	57	477	534	7048	613	0	613	6035	6648	4147	400
	JUNE	7752	164	194	358	8110	601	44	645	7389	8034	4223	76
	JULY	7919	29	106	135	8054	693	56	749	7095	7844	4433	210
	AUGUST	7905	132	229	361	8266	762	0	762	8116	8878	3821	-612
	SEPTEMBER	7264	75	0	75	7339	690	0	690	6212	6902	4258	437
	OCTOBER	7883	153	150	303	8186	1486	0	1486	6419	7905	4539	281
	NOVEMBER	7326	90	0	90	7416	995	0	995	6077	7072	4883	344
	DECEMBER	7364	121	0	121	7485	1524	0	1524	6181	7705	4663	-220
1987	JANUARY	7307	304	0	304	7611	1148	0	1148	6205	7353	4921	258
	FEBRUARY	6692	167	0	167	6859	1036	0	1036	5822	6858	4922	1
	MARCH	6980	161	130	291	7271	1296	0	1296	6233	7529	4664	-258
	APRIL	6713	150	0	150	6863	1300	0	1300	5073	6373	5154	490
	MAY	7490	324	144	468	7958	1352	0	1352	6543	7895	5217	63
	JUNE	6701	222	0	222	6923	1246	0	1246	6626	7872	4268	-949
	JULY	7830	206	69	275	8105	2023	0	2023	6367	8390	3983	-285
	AUGUST	7814	457	0	457	8271	1465	0	1465	6486	7951	4303	320
	SEPTEMBER	6764	354	0	354	7118	1413	-10	1403	5600	7003	4418	115
	OCTOBER	7120	537	344	881	8001	1250	0	1250	6475	7725	4694	276
	NOVEMBER	7198	497	0	497	7695	1380	0	1380	6152	7532	4857	163
	DECEMBER	7604	354	0	354	7958	1436	0	1436	6718	8154	4661	-196
1988	JANUARY	7514	356	0	356	7870	1442	0	1442	6594	8036	4495	-166
	FEBRUARY	6564	626	94	720	7284	1401	10	1411	6120	7531	4248	-247
	MARCH	7690	324	0	324	8014	1246	0	1246	6785	8031	4231	-17
	APRIL	6734	167	0	167	6901	960	0	960	5899	6859	4274	42
	MAY	7436	434	120	554	7990	1053	0	1053	6657	7710	4554	280
	JUNE	7559	196	0	196	7755	843	0	843	6201	7044	5265	711
	JULY	7497	263	226	489	7986	680	99	779	7461	8240	5011	-254
	AUGUST	7523	54	0	54	7577	673	0	673	7305	7978	4610	-401
	SEPTEMBER	7320	308	101	409	7729	536	0	536	6810	7346	4993	383
	OCTOBER	7292	122	0	122	7414	528	0	528	6384	6912	5495	502
	NOVEMBER	7273	155	0	155	7428	840	0	840	6306	7146	5777	282
	DECEMBER	9231	129	0	129	9360	1090	0	1090	8688	9778	5359	-418

TABLE A-15

CALIFORNIA PETROLEUM FUELS MARKET ACTIVITY
(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	MARKETER RECEIPTS	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS	STORAGE CHANGE
DISTILLATE FUELS													
1986	JANUARY	8953	122	0	122	9075	1387	117	1504	7108	8612	7933	463
	FEBRUARY	7580	86	0	86	7666	1103	31	1134	6651	7785	7814	-119
	MARCH	8557	91	0	91	8648	1205	36	1241	8579	9820	6642	-1172
	APRIL	10373	142	0	142	10515	1450	145	1595	8774	10369	6788	146
	MAY	11025	133	0	133	11158	1194	50	1244	9601	10845	7101	313
	JUNE	10186	103	52	155	10341	1602	46	1648	8205	9853	7589	488
	JULY	9705	149	45	194	9899	1377	73	1450	9531	10981	6507	-1082
	AUGUST	9453	288	0	288	9741	1108	29	1137	9044	10181	6067	-440
	SEPTEMBER	9339	56	0	56	9395	1566	15	1581	7768	9349	6113	46
	OCTOBER	9242	191	0	191	9433	1846	27	1873	7101	8974	6572	459
	NOVEMBER	7871	110	0	110	7981	1454	23	1477	6291	7768	6785	213
	DECEMBER	8459	293	-14	279	8738	1919	35	1954	6771	8725	6798	13
1987	JANUARY	8548	559	0	559	9107	1640	347	1987	7026	9013	6892	94
	FEBRUARY	7403	367	0	367	7770	1722	93	1815	6109	7924	6738	-154
	MARCH	8455	1532	0	1532	9987	1395	284	1679	8447	10126	6599	-139
	APRIL	8404	476	0	476	8880	1809	14	1823	7704	9527	5952	-647
	MAY	9325	595	0	595	9920	2017	120	2137	6037	8174	7698	1746
	JUNE	8612	443	0	443	9055	1498	26	1524	8252	9776	6977	-721
	JULY	8683	670	0	670	9353	1340	260	1600	8405	10005	6325	-652
	AUGUST	8443	622	0	622	9065	1873	32	1905	7472	9377	6013	-312
	SEPTEMBER	8532	401	270	671	9203	1451	19	1470	6365	7835	7381	1368
	OCTOBER	8191	433	0	433	8624	2369	54	2423	7613	10036	5969	-1412
	NOVEMBER	8400	237	0	237	8637	1439	17	1456	6280	7736	6870	901
	DECEMBER	9216	607	0	607	9823	1795	33	1828	7523	9351	7342	472
1988	JANUARY	8960	357	0	357	9317	2337	111	2448	7166	9614	7045	-297
	FEBRUARY	7545	343	0	343	7888	1738	31	1769	6140	7909	7024	-21
	MARCH	9186	349	0	349	9535	1563	24	1587	8371	9958	6601	-423
	APRIL	9444	115	0	115	9559	1985	122	2107	6254	8361	7799	1198
	MAY	10359	85	0	85	10444	2256	20	2276	8090	10366	7877	78
	JUNE	9496	120	0	120	9616	1415	11	1426	7851	9277	8216	339
	JULY	9320	14	0	14	9334	1229	176	1405	7841	9246	8304	88
	AUGUST	9183	258	0	258	9441	1549	22	1571	8788	10359	7385	-918
	SEPTEMBER	9743	255	0	255	9998	1133	16	1149	7657	8806	8577	1192
	OCTOBER	9330	139	0	139	9469	1457	26	1483	8210	9693	8353	-224
	NOVEMBER	9399	87	0	87	9486	1247	18	1265	8068	9333	8506	153
	DECEMBER	9155	132	0	132	9287	1232	33	1265	7679	8944	8849	343

TABLE A-16

CALIFORNIA PETROLEUM FUELS MARKETING ACTIVITY
(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLY	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS
>0.5% SULFUR RESIDUAL FUEL OIL												
1986	JANUARY	7509	48	0	48	7557	238	485	723	5721	6444	6791
	FEBRUARY	6255	389	0	389	6644	29	358	387	6496	6883	6552
	MARCH	6980	-143	0	-143	6837	649	567	1216	5214	6430	6959
	APRIL	7507	1	0	1	7508	354	1317	1671	8284	9955	4513
	MAY	7719	60	0	60	7779	196	349	545	5636	6181	6111
	JUNE	6118	49	0	49	6167	217	953	1170	5200	6370	5908
	JULY	6928	274	0	274	7202	202	486	688	6482	7170	5940
	AUGUST	6966	0	66	66	7032	235	940	1175	7433	8608	4364
	SEPTEMBER	5974	0	0	0	5974	66	402	468	4170	4638	5700
	OCTOBER	6294	-66	0	-66	6228	118	710	828	5901	6729	5199
	NOVEMBER	8127	0	0	0	8127	534	1023	1557	4530	6087	7239
	DECEMBER	6713	49	0	49	6762	22	853	875	7352	8227	5774
1987	JANUARY	6366	163	0	163	6529	53	747	800	5939	6739	5554
	FEBRUARY	5632	147	0	147	5779	485	707	1192	5406	6598	4735
	MARCH	7586	114	2	116	7702	124	472	596	6183	6779	5658
	APRIL	7902	25	0	25	7927	102	1041	1143	7721	8864	4721
	MAY	6782	0	0	0	6782	52	757	809	5758	6567	4936
	JUNE	6347	79	0	79	6426	143	534	677	5807	6484	4878
	JULY	6883	3	0	3	6886	109	321	430	6234	6664	5100
	AUGUST	7342	0	0	0	7342	186	578	764	6570	7334	5108
	SEPTEMBER	7449	606	0	606	8055	22	446	468	7392	7860	5303
	OCTOBER	7633	330	0	330	7963	0	527	527	7893	8420	4846
	NOVEMBER	7236	275	0	275	7511	0	434	434	6202	6636	5721
	DECEMBER	7825	69	0	69	7894	0	542	542	7879	8421	5159
1988	JANUARY	7559	63	0	63	7622	136	600	736	6763	7499	5264
	FEBRUARY	7078	248	0	248	7326	1	586	587	7390	7977	4613
	MARCH	7349	49	0	49	7398	80	482	562	6270	6832	5179
	APRIL	7038	430	0	430	7468	14	550	564	6877	7441	5206
	MAY	6502	0	0	0	6502	484	497	981	5837	6818	4890
	JUNE	5792	0	0	0	5792	1629	341	1970	4630	6600	4082
	JULY	6449	0	0	0	6449	288	375	663	5365	6028	4465
	AUGUST	6613	357	0	357	6970	436	378	814	6326	7140	4295
	SEPTEMBER	5637	151	0	151	5788	185	384	569	4809	5378	4705
	OCTOBER	5586	490	443	933	6519	63	1417	1480	6119	7599	3625
	NOVEMBER	6502	229	0	229	6731	150	824	974	4844	5818	4538
	DECEMBER	6991	279	0	279	7270	98	519	617	7585	8202	3606

TABLE A-17

CALIFORNIA PETROLEUM FUELS MARKETING ACTIVITY
(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLY	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS
<0.5% SULFUR RESIDUAL FUEL OIL												
1986	JANUARY	978	0	363	363	1341	0	120	120	684	804	17328
	FEBRUARY	610	0	293	293	903	0	293	293	631	924	17307
	MARCH	1117	203	484	687	1804	506	217	723	833	1556	17555
	APRIL	1329	0	210	210	1539	0	210	210	1516	1726	17370
	MAY	902	301	217	518	1420	153	217	370	819	1189	17601
	JUNE	650	0	210	210	860	0	210	210	951	1161	17300
	JULY	353	0	217	217	570	0	216	216	735	951	16919
	AUGUST	632	284	714	998	1630	94	219	313	1486	1799	16750
	SEPTEMBER	1042	0	60	60	1102	0	60	60	541	601	17251
	OCTOBER	811	153	367	520	1331	0	367	367	1012	1379	17203
	NOVEMBER	809	126	210	336	1145	241	216	457	461	918	17430
	DECEMBER	767	0	217	217	984	253	217	470	680	1150	17264
1987	JANUARY	604	0	217	217	821	0	217	217	1156	1373	16704
	FEBRUARY	270	0	196	196	466	0	196	196	1434	1630	15540
	MARCH	306	0	217	217	523	0	217	217	1445	1662	14401
	APRIL	261	0	210	210	471	0	210	210	505	715	14157
	MAY	644	0	217	217	861	0	217	217	730	947	14071
	JUNE	447	0	210	210	657	0	210	210	482	692	14036
	JULY	377	0	217	217	594	0	217	217	717	934	13696
	AUGUST	301	0	217	217	518	0	217	217	427	644	13570
	SEPTEMBER	716	0	210	210	926	0	210	210	527	737	13759
	OCTOBER	592	0	217	217	809	0	217	217	-1127	-910	15478
	NOVEMBER	737	0	75	75	812	0	75	75	487	562	15728
	DECEMBER	614	0	352	352	966	0	352	352	1177	1529	15165
1988	JANUARY	507	0	217	217	724	0	217	217	2896	3113	12795
	FEBRUARY	584	0	973	973	1557	0	197	197	-849	-652	15004
	MARCH	733	0	441	441	1174	0	223	223	862	1085	15093
	APRIL	726	0	427	427	1153	120	210	330	435	765	15481
	MAY	418	0	217	217	635	0	217	217	477	694	15422
	JUNE	479	0	517	517	996	0	210	210	762	972	15446
	JULY	435	0	682	682	1117	0	217	217	1495	1712	14889
	AUGUST	703	0	449	449	1152	0	217	217	1712	1929	14112
	SEPTEMBER	1263	0	2021	2021	3284	0	165	165	82	247	17149
	OCTOBER	1350	0	1795	1795	3145	0	262	262	-1005	-743	21037
	NOVEMBER	1449	0	210	210	1659	0	210	210	1923	2133	20563
	DECEMBER	1052	0	217	217	1269	0	217	217	3949	4166	17619

TABLE A-18

CALIFORNIA PETROLEUM FUELS MARKET ACTIVITY
(THOUSANDS OF BARRELS)

YEAR	MONTH	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	MARKETER RECEIPTS	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	CALIFORNIA SUPPLIED	TOTAL SUPPLIED	ENDING STOCKS	STORAGE CHANGE
RESIDUAL FUEL OILS													
1986	JANUARY	8701	48	363	411	9112	238	605	843	6619	7462	24119	1650
	FEBRUARY	6865	389	293	682	7547	29	651	680	7127	7807	23859	-260
	MARCH	8097	60	484	544	8641	1155	784	1939	6047	7986	24514	655
	APRIL	8836	1	210	211	9047	354	1527	1881	9800	11681	21883	-2634
	MAY	8621	361	217	578	9199	349	566	915	6455	7370	23712	1829
	JUNE	6768	49	210	259	7027	217	1163	1380	6151	7531	23208	-504
	JULY	7281	274	217	491	7772	202	702	904	7217	8121	22859	-349
	AUGUST	7598	284	780	1064	8662	329	1159	1488	8919	10407	21114	-1745
	SEPTEMBER	7016	0	60	60	7076	66	462	528	4711	5239	22951	1837
	OCTOBER	7105	87	367	454	7559	118	1077	1195	6913	8108	22402	-549
	NOVEMBER	8936	126	210	336	9272	775	1239	2014	4991	7005	24669	2267
	DECEMBER	7480	49	217	266	7746	275	1070	1345	8032	9377	23038	-1631
1987	JANUARY	6970	163	217	380	7350	53	964	1017	7095	8112	22258	-762
	FEBRUARY	5902	147	196	343	6245	485	903	1388	6840	8228	20275	-1983
	MARCH	7892	114	219	333	8225	124	689	813	7628	8441	20059	-216
	APRIL	8163	25	210	235	8398	102	1251	1353	8226	9579	18878	-1181
	MAY	7426	0	217	217	7643	52	974	1026	6488	7514	19007	129
	JUNE	6794	79	210	289	7083	143	744	887	6289	7176	18914	-93
	JULY	7260	3	217	220	7480	109	538	647	6951	7598	18796	-118
	AUGUST	7641	0	217	217	7858	186	795	981	6995	7976	18678	-118
	SEPTEMBER	8165	606	210	816	8981	22	656	678	7919	8597	19062	384
	OCTOBER	8225	330	217	547	8772	0	744	744	6766	7510	20324	1262
	NOVEMBER	7973	275	75	350	8323	0	509	509	6689	7198	21449	1125
	DECEMBER	8439	69	352	421	8860	0	894	894	9056	9950	20324	-1090
1988	JANUARY	8072	63	217	280	8352	136	817	953	9665	10618	18059	-2266
	FEBRUARY	7692	248	973	1221	8913	1	783	784	6571	7355	19617	1558
	MARCH	8082	49	441	490	8572	80	705	785	7132	7917	20272	655
	APRIL	7762	430	427	857	8619	134	760	894	7310	8204	20687	415
	MAY	6919	0	217	217	7136	484	714	1198	6313	7511	20312	-375
	JUNE	6270	0	517	517	6787	1629	551	2180	5391	7571	19528	-784
	JULY	6884	0	682	682	7566	288	592	880	6860	7740	19354	-174
	AUGUST	7315	357	449	806	8121	436	595	1031	8037	9068	18407	-947
	SEPTEMBER	6900	151	2021	2172	9072	185	549	734	4891	5625	21854	3447
	OCTOBER	6936	490	2238	2728	9664	63	1679	1742	5114	6856	24662	2808
	NOVEMBER	7951	229	210	439	8390	150	1034	1184	6767	7951	25101	439
	DECEMBER	8045	279	217	496	8541	98	736	834	11536	12370	21225	-3829

TABLE A-19

PETROLEUM PRODUCT STORAGE TANK CAPACITIES
AT MAJOR MARKETER AND MAJOR STORER FACILITIES
BY REGION AND BY TYPE FACILITY AT END OF YEAR

YR	PRODUCT	NORTHERN CALIFORNIA	CENTRAL CALIFORNIA	SOUTHERN CALIFORNIA	STATE TOTAL	REFINING FACILITY	BULK TERMINAL	OTHER FACILITY
86								
	MOTOR GASOLINES	10417	698	14009	25124	17899	6081	1144
	AVIATION FUELS	3153	58	3536	6747	5666	964	222
	DISTILLATE FUELS	4183	596	9968	14747	8485	2276	12385
	RESIDUALS, LOW SULFUR	4158	2604	29919	36681	1400	174	35110
	RESIDUALS, HIGH SULFUR	3566	807	8967	13340	11800	1227	313
	TOTAL STORAGE	42788	9868	64351	117007	72781	11212	33021
87								
	MOTOR GASOLINES	10272	733	14214	25219	17688	6567	964
	AVIATION FUELS	3112	50	4222	7384	6054	1222	108
	DISTILLATE FUELS	3682	1000	8678	13360	7690	2444	3298
	RESIDUALS, LOW SULFUR	3968	2050	27693	33711	1320	171	32027
	RESIDUALS, HIGH SULFUR	4358	492	8938	13788	11883	1597	308
	TOTAL STORAGE	42238	15165	78311	135714	72629	12589	50554
88								
	MOTOR GASOLINES	11157	663	17012	28832	21325	6645	842
	AVIATION FUELS	3125	25	5741	8891	5901	2896	94
	DISTILLATE FUELS	3930	859	8695	13484	7688	2872	2924
	RESIDUALS, LOW SULFUR	5013	2031	27230	34274	1008	210	33056
	RESIDUALS, HIGH SULFUR	3380	447	7355	11182	9032	1863	287
	TOTAL STORAGE	41607	10782	77713	130102	66450	14924	48910

Source: PIIRA submittals.

TABLE A-20

TEOR FUEL USE BY COUNTY BY FIELD

OIL IN BARRELS--GAS IN MCF

COUNTY	YEAR 1984		1985		1986		1987		1988	
	OIL BURNED	GAS BURNED	OIL BURNED	GAS BURNED	OIL BURNED	GAS BURNED	OIL BURNED	GAS BURNED	OIL BURNED	GAS BURNED
FRESNO										
COALINGA	2179807	1604444	1769968	5860148	1788352	4476743	996193	5368600	217520	6673851
*TOTAL FRESNO	2179807	1604444	1769968	5860148	1788352	4476743	996193	5368600	217520	6673851
KERN										
BELRIDGE, NORTH	6158	0	8919	0	7885	16477	0	28	0	0
BELRIDGE, SOUTH	1920657	38953935	2279943	45102074	1329429	51229541	287815	55346268	1980398	48459730
CYMRIC	24192	1915363	61326	2779076	108813	1537586	105127	2583748	81796	4048195
EDISON	134558	10359	323461	17031	178879	17272	258287	50759	0	54465
FRUITVALE	0	126294	0	0	0	60658	0	49694	0	0
KERN BLUFF	24154	0	42663	0	34693	0	1125	0	0	0
KERN FRONT	335405	340402	370318	293980	285542	167689	103735	83484	49607	19775
KERN RIVER	10661140	6576621	7880158	27308195	4596855	23084673	1961971	21611598	732976	47364814
LOST HILLS	0	1372222	0	1909024	0	2003691	0	3100528	0	970387
MCKITTRICK	374450	1623208	380475	3248494	222525	469635	217934	1023818	91944	169561
MIDWAY-SUNSET	4214451	6376740	4776271	8393743	4493326	8359963	4182421	10455375	3821177	21918004
MOUNT POSO	1512300	0	680739	4820200	752380	4885577	505076	6124094	810646	4183361
POSO CREEK	140276	0	19863	20082	27651	133711	43937	85128	39276	0
*TOTAL KERN	19355741	57303144	16824136	93891899	12037978	91966473	7667428	100514522	7607820	127188292
LOS ANGELES										
PLACERITA	0	11995	0	19425	0	0	0	377091	0	0
WILMINGTON	0	722296	0	560052	0	405108	655	467595	0	280416
*TOTAL LOS ANGELES	0	734291	0	579477	0	405108	655	844686	0	280416
MONTEREY										
SAN ARDO	2144347	2320985	2016402	2959345	1296737	1289829	1071772	1317926	1215404	1450757
*TOTAL MONTEREY	2144347	2320985	2016402	2959345	1296737	1289829	1071772	1317926	1215404	1450757
ORANGE										
HUNTINGTON BEACH	7429	505842	0	105461	0	366172	0	323072	0	186137
NEWPORT, WEST	0	0	0	0	0	0	0	0	0	0
YORBA LINDA	0	2235308	0	2496216	0	2373803	0	2053032	0	1688150
*TOTAL ORANGE	7429	2741150	0	2601677	0	2739975	0	2376104	0	1874287
SAN LUIS OBISPO										
ARROYO GRANDE	33936	10834	20419	138208	16427	201942	12527	1038168	8653	971731
GUADALUPE	0	1345835	0	1217612	0	518519	0	0	0	357458
*TOTAL SAN LUIS OBISPO	33936	1356669	20419	1355820	16427	720461	12527	1038168	8653	1329189
SANTA BARBARA										
CASMALIA	0	8884	0	0	0	11766	0	0	0	0
CAT CANYON	0	149602	0	980827	0	807609	2608	649984	0	493692
SANTA MARIA VALLEY	0	59500	0	50337	0	5024	0	0	0	1705
*TOTAL SANTA BARBARA	0	217986	0	1031164	0	824399	2608	649984	0	495397
UNDESIGNATED										
UNDESIGNATED FIELDS	3315	619071	0	5232289	0	4872688	7689	1126492	0	1144145
*TOTAL UNDESIGNATED	3315	619071	0	5232289	0	4872688	7689	1126492	0	1144145
VENTURA										
OXNARD	0	0	0	24889	0	81266	0	33786	0	18336
*TOTAL VENTURA	0	0	0	24889	0	81266	0	33786	0	18336
TOTAL	23724575	66897740	20630925	113536708	15139494	107370942	9758872	113270268	9049397	140454670

Source; PIIRA submittals.

TABLE A-21

CHANGE IN WORKING STORAGE CAPACITY
FROM JANUARY 1,1986 TO JANUARY 1,1987
AT CALIFORNIA REFINERIES

PRODUCT	1986 CAPACITY MBBLS	1987 CAPACITY MBBLS	CHANGE MBBLS	CHANGE PERCENT
CRUDE OIL	28883	26990	-1893	-6.55
MOTOR GASOLINE, LEADED	3573	2942	-631	-17.66
MOTOR GASOLINE, UNLEADED	7463	7431	-32	-.43
GASOLINE, BLENDING COMPONENTS	11933	12802	869	7.28
MIDDLE DISTILLATES	8014	7996	-18	-.22
RESIDUAL FUEL OILS	12009	10968	-1041	-8.67
ASPHALT AND ROAD OIL	2639	2432	-207	-7.84
LUBRICATING OILS	2249	1961	-288	-12.81
PROPANE/PROPYLENE	318	320	2	.63
BUTANE/BUTYLENE	1200	1209	9	.75
NAPHTHA-TYPE JET FUEL	1087	1014	-73	-6.72
KEROSENE-TYPE JET FUEL	3856	3719	-137	-3.55
OTHER STORAGE	18619	21996	3377	18.14

CHANGE IN WORKING STORAGE CAPACITY
FROM JANUARY 1,1987 TO JANUARY 1,1988
AT CALIFORNIA REFINERIES

PRODUCT	1987 CAPACITY MBBLS	1988 CAPACITY MBBLS	CHANGE MBBLS	CHANGE PERCENT
CRUDE OIL	26990	24743	-2247	-8.33
MOTOR GASOLINE, LEADED	2942	2365	-577	-19.61
MOTOR GASOLINE, UNLEADED	7431	7368	-63	-.85
GASOLINE, BLENDING COMPONENTS	12802	11778	-1024	-8.00
MIDDLE DISTILLATES	7996	6355	-1641	-20.52
RESIDUAL FUEL OILS	10968	9051	-1917	-17.48
ASPHALT AND ROAD OIL	2432	2729	297	12.21
LUBRICATING OILS	1961	1861	-100	-5.10
PROPANE/PROPYLENE	320	311	-9	-2.81
BUTANE/BUTYLENE	1209	1203	-6	-.50
NAPHTHA-TYPE JET FUEL	1014	872	-142	-14.00
KEROSENE-TYPE JET FUEL	3719	3096	-623	-16.75
OTHER STORAGE	21996	23978	1982	9.01

CHANGE IN WORKING STORAGE CAPACITY
FROM JANUARY 1,1988 TO JANUARY 1,1989
AT CALIFORNIA REFINERIES

PRODUCT	1988 CAPACITY MBBLS	1989 CAPACITY MBBLS	CHANGE MBBLS	CHANGE PERCENT
CRUDE OIL	24743	25235	492	1.99
MOTOR GASOLINE, LEADED	2365	2305	-60	-2.54
MOTOR GASOLINE, UNLEADED	7368	8014	646	8.77
GASOLINE, BLENDING COMPONENTS	11778	12259	481	4.08
MIDDLE DISTILLATES	6355	6791	436	6.86
RESIDUAL FUEL OILS	9051	7713	-1338	-14.78
ASPHALT AND ROAD OIL	2729	2738	9	.33
LUBRICATING OILS	1861	2499	638	34.28
PROPANE/PROPYLENE	311	314	3	.96
BUTANE/BUTYLENE	1203	1321	118	9.81
NAPHTHA-TYPE JET FUEL	872	787	-85	-9.75
KEROSENE-TYPE JET FUEL	3096	3123	27	.87
OTHER STORAGE	23978	31290	7312	30.49

Source: PIIRA submittals.

APPENDIX B

IMPACTS OF EFFICIENCY IMPROVEMENTS ON UTILITY POWER PLANTS

APPENDIX B

IMPACTS OF EFFICIENCY IMPROVEMENTS ON UTILITY POWER PLANTS

I. INTRODUCTION AND PURPOSE

A. Introduction

The efficiency with which a thermal power plant produces electricity is of great importance, especially when the primary fuel source is a non-renewable fossil fuel. Energy resources are depleted more quickly than necessary when power is generated at efficiency levels lower than the highest levels attainable with current technology. In addition, excessive environmental impacts result from inefficient electric generation. There are direct impacts such as air, water, and thermal pollution. Another result of inefficient energy generation is that more power plants need to be built in order to supply the needed electrical energy. This results in more extensive physical, sociological, and environmental impacts.

Over the past 10 years, industrial, commercial and residential sectors have realized productivity gains of 10 to 13 percent in end-use demand energy savings. During the same period, energy conversion efficiency[1] in the electric utility sector has remained nearly unchanged at 33 percent.[2] The market forces which have contributed to the relative stagnation of efficiency improvements in electric power generation are discussed in more detail in Section V. However, concerns relating to nonattainment of ambient air quality standards are in the forefront of public policy and regulatory activity, particularly in the Los Angeles vicinity, and therefore the need for cleaner-burning, more efficient power production is gaining in priority.

California utilities own and operate approximately 21,000 MW of fossil-fuel-fired generating capacity. About 7,000 MW of this capacity will reach the end of each generating unit's assumed nominal design and economic life (30-40 years) by 1999. A choice has to be made whether to retire, run, reserve, refurbish, repower, or replace these generating units.

B. Purpose

Staff believes that advanced combustion technologies will play a key role in addressing issues associated with the use of non-renewable fossil fuels, the continuing degradation of air quality, and the decisions that need to be made regarding California's aging power plants. The benefits that can be attained by replacing (in total or in part) aging power plants with advanced combustion technologies include the following:

- Increased system-wide energy conversion efficiency, resulting in reduced demand for non-renewable fossil fuels (e.g., natural gas);

- Improved air quality through reduced air emissions per unit of electric energy produced;

- Reduced production costs for electric generation, resulting in future utility rate reductions;

- Enhanced environmental quality due to minimizing the need for new, "green field" electric generating and transmission facilities;

- Retained generating capacity in the air basin to sustain high quality electric service (e.g. voltage support, frequency control, load response) and minimize transmission losses of imported power;

- Reduced public health and safety risks associated with the use of post-combustion emissions control systems.

Many of these benefits are applicable to the creation of new facilities as well as replacement of older facilities. Therefore, the Commission is interested in promoting these technologies to independent power producers (IPPs) as well as investor-owned utilities (IOUs).

C. Mandate

The California Energy Commission has the mandate "to reduce the wasteful, uneconomic, inefficient or unnecessary consumption of energy". This mandate addresses both the generation (supply) of energy and the utilization (demand) of energy in all forms. Through the development and implementation of market incentives and efficiency standards, the Commission has been successful in significantly reducing the utilization of energy (energy demand) in the building and appliance industry sectors. Until recently, little attention has been directed toward improvements on the generation or supply-side of the energy equation.

However, references to relevant sections of the Warren-Alquist Act establish that:

> Public Resources Code Section 25401(e)
>
> "The commission shall continuously carry out studies, research projects, data collection, and other activities required to assess the nature, extent, and distribution of energy resources to meet the needs of the state, including but not limited to fossil fuels and solar, nuclear, and geothermal

energy resources. It shall also carry out studies, technical assessments, research projects, and data collection directed to reducing wasteful, inefficient, unnecessary, or uneconomic uses of energy, including, but not limited to, ...

(e) Advances in power generation and transmission technology".

PRC Section 25403

"The commission shall submit to the Public Utilities Commission and to any publicly owned electric utility, recommendations designed to reduce wasteful, unnecessary, or uneconomic energy consumption resulting from practices including, but not limited to, differential rate structures, cost-of-service allocations,...which encourage the use of electrical power, peakload pricing, and other pricing measures."

Other relevant sections include PRC Sections 25310(a), 25402, and 25400.

D. California Environmental Quality Act (CEQA)

The Energy Commission, in its role as lead agency, is charged by CEQA to identify and evaluate project alternatives that will increase energy conversion efficiency, thereby reducing the rate of consumption of nonrenewable resources.

Energy Commission staff is required to conduct efficiency analyses in order to identify opportunities for realizing significant additional fuel savings, concurrent with reducing and mitigating environmental impacts. Staff must consider several alternative project configurations and make comparisons with the "no project" alternative in order to satisfy the statutory requirement of Sections 21100 - Environmental Impact Reports; 15040.1 - Authority; 15126(d) -Environmental Impact, Alternatives; 15130 and 15355 - Cumulative Impacts; 15382 - Significant Effect on the Environment; and in particular Appendix F - Energy Conservation.

E. Summary of Contents

Section II below discusses the current status and trends in the areas of end-use electricity demand, energy conversion efficiency, air quality, natural gas use, and alternative fuels. Section III focuses on the benefits to be gained by improving energy conversion efficiency. Section IV discusses the impact of gas-fired QF and self-generation facilities on the overall utility gas-fired generation efficiency. It also looks at the results of the Energy Commission's Resource Case Analysis Report, which considers the

impact of replacing 2,000 MW of Southern California Edison's electric generating capacity with advanced combustion turbines. Section V analyzes the market forces that hamper progress in improving efficiency. Section VI focuses on the status and benefits of advanced combustion technologies. Section VII discusses the application of advanced combustion turbines in new facilities as well as in replacing or repowering existing aging plants. It also looks at the air quality benefits in the transportation sector that can be achieved through the use of more efficient, cleaner-burning combustion turbine technologies. Section VIII outlines suggested actions that could be taken in order to speed the introduction of more efficient, cleaner-burning electric generation technologies in California. Section IX provides a summary of this appendix.

II. CURRENT STATUS AND TRENDS

A. End-Use Demand

U.S. energy efficiency gains over the last 12 years have increased by 35 percent, saving approximately $150 billion in 1986. Half of this increase came from more efficient use of energy, while the other half came from structural changes in the economy away from energy-intensive industries[3].

California reacted to Organization of Petroleum Exporting Countries (OPEC) price increases and uncertain availability by taking several actions. These actions include the development of energy management programs, investment in more productive, less energy-intensive technologies, and further diversification of its resource base. These steps have netted a savings of $23 billion, which comprises more than 15 percent of the total U.S. savings.

B. Energy Conversion Efficiency

Energy conversion efficiency in the electric utility sector remained essentially unchanged at 33 percent (excluding the impact of QF additions in the later years). Utilities' use of natural gas in their electric generation facilities has not decreased in response to rising fuel prices. Due to the Energy Cost Adjustment Clause (ECAC) proceedings, utilities are allowed to pass through fuel costs to their ratepayers. Hence, there is no incentive to save fuel since the utilities' profits will not be decreased by rising fuel costs.

C. Air Quality

Air quality continues to deteriorate in the South Coast (Los Angeles vicinity) and other California air basins, which are in

nonattainment for one or more "criteria" pollutants. Currently, existing utility generating plants contribute only four percent of total nitrogen oxides (NO_x) emissions (a precursor to ozone). However, the recently adopted SCAQMD emission control rules effectively prescribe post-combustion emission controls as the solution. This "after-the-fact" approach allows for emissions from the combustion process to exceed acceptable levels as long as there are post-combustion control systems in place which will reduce the emissions to an acceptable level. In contrast, the Commission advocates the use of advanced combustion technologies which have combustion processes that will inherently produce low levels of emissions, thereby eliminating the expense of post-combustion emissions control.

D. Fuel Use

Natural gas demand is expected to increase an average of 1.7 percent per year from a present 25 percent of total energy use to 29 percent.[4] This forecast was based on the Electricity Report 6 (ER 6) electric utility system fuel diversity policy, which limits any one prime energy resource to one third of the total.[5] Electricity Report Seven (ER 7) relaxed this policy.[6]

Less restrictive use of oil and natural gas in the California electric utility resource mix will result in a greater growth in demand and may adversely impact fuel availability and price. In addition, attainment of national and California air quality standards by means of post-combustion controls and the phasing-out of oil consumption will contribute to increased growth in natural gas demand and may also contribute to diminished availability and upward pressure on pricing.

Focusing fuels policy on efficiency improvement and upgrades of existing electric utility generating facilities may realize significant increases in electric utility system-wide efficiency, improved air quality and reduced electric power production costs, which together may overcome the adverse impacts on natural gas availability and price cited here.

E. Alternative Fuels

Short-term displacement of California natural gas-fired electric generation by out-of-state hydroelectric power or alternative fuel-fired generation may become increasingly unavailable as the western states' electric energy demand increases. Inter-system exchanges will continue only as long as mutual benefit is realized.

Many substitute fuels and generation technologies will become more competitive at higher natural gas price levels. These include biomass, ethanol, methanol, geothermal, hydroelectric, hydrogen, and solar. However, these alternatives may be much less attractive in terms of cost than improvements in energy conversion efficiency.

III. BENEFITS TO BE GAINED BY IMPROVING ENERGY CONVERSION EFFICIENCY

Natural gas supply disruptions at a time of increasing gas demand would present a risk to continued power supply. Efficiency improvements and upgrades to existing electric utility power plants, combined with improvements in the natural gas transmission and storage infrastructure, will allow greater electric utility system flexibility to respond to temporary fuel supply disruptions.

Significant improvements in air quality can be achieved by choosing cleaner-burning, more efficient, advanced combustion technologies rather than technologies performing at California's current overall energy conversion efficiency. This is best shown when emissions are expressed in pounds of emissions per unit of electrical energy produced rather than the more traditional units of pounds of emissions per unit of fuel energy input. Consider the following equation which expresses the relationship between NO_x emissions in pounds of NO_x per MWhr of electrical energy produced and in pounds of NO_x per MMBtu (10^6 Btu) of fuel consumed.

$$(\text{lbs } NO_x/\text{MWhr}) = \frac{341.4 * (\text{lbs } NO_x/\text{MMBtu})}{\text{Efficiency in } \%}$$

A reduction in NO_x emissions per MWhr of electrical energy produced can be achieved in one of two ways: either the amount of NO_x produced per MMBtu of fuel consumed can be reduced, or the efficiency can be increased. Any advanced combustion technology that has a higher efficiency will therefore decrease the emissions when expressed as lbs NO_x/MWhr, even if the emissions in lbs NO_x/MMBtu remains constant. Note, however, that advanced combustion technologies that inherently emit less NO_x (i.e. have lower emissions per MMBtu of fuel consumed) will also decrease the emissions when expressed in lbs NO_x/MWhr.

Fortunately, many of the advanced combustion technologies are not only highly efficient but also are inherently cleaner-burning than their less advanced counterparts. These two improvements combined demonstrate the great potential for dramatic decreases in emissions that can be achieved with advanced technologies.

There are other benefits that can be attained by replacing older, less efficient power plants with higher efficiency, cleaner-burning plants. By increasing a plant's energy conversion efficiency, greater economic efficiency will result from the more

productive utilization of both capital and fuel. Efficiency improvements can reduce costs and risks to both ratepayers and stockholders. In- creasing the output and productivity of existing power plants offers substantial opportunities to cut cost. Deferring new plants by improving the productivity of existing plants reduces utility risks and cash flow problems, in particular those associated with new "green field" plant additions.

There are also many positive environmental impacts associated with replacing older power plants. These are discussed in detail in Section VII.

A. Economics of End-Use Applications

Improvements in the efficiency with which electricity is generated can also have far-reaching effects on end uses. For example, the economic attractiveness of end uses such as electric heat pumps and electric cars increases as the energy conversion efficiency increases. This can be seen by considering the logistics of the electric energy delivery system and how it affects the applications in the space heating and transportation sectors.

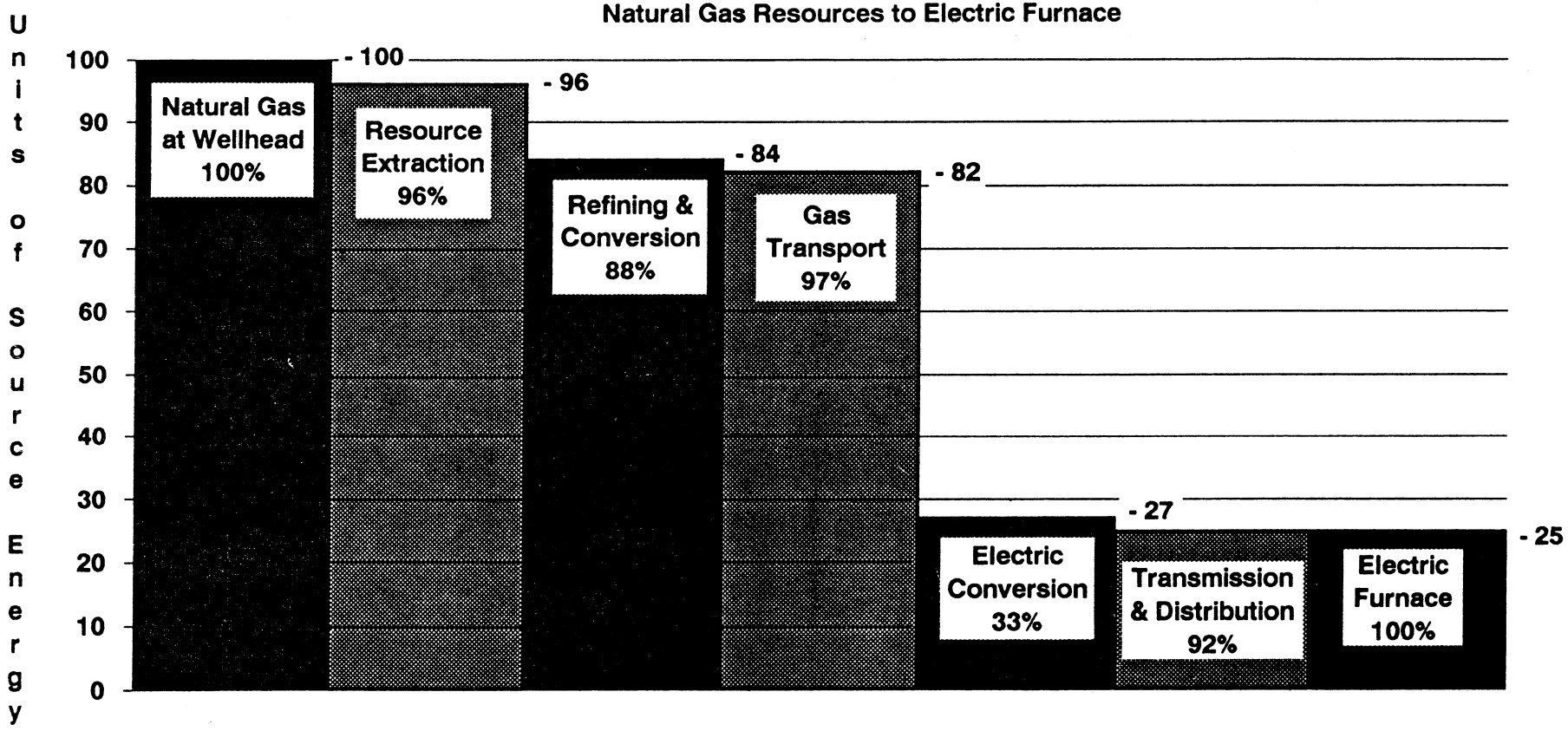
B. Electric Energy Delivery System

The logistics of electric energy production and end-use, fueled by natural gas, follows a seven-step process (listed below and shown in the accompanying "efficiency staircase" graphic, Figure B-1):

		Efficiency (%)	Units 100
1.	Resource Extraction - (exploration, field development and gas gathering)	96%	96
2.	Refining and Conversion - (purification and compression)	88%	84
3.	Transport - (interstate gas pipelines)	97%	82
4.	Conversion to electricity -	33%	27
5.	Transmission and Distribution -	92%	25
6.	Utilization - (electric furnace)	100%	25
7.	End-use (space heating) demand.		

Each of the above steps in the logistics of the energy delivery system has an efficiency of at least 88 percent, except the energy conversion of natural gas to electricity. Electric utility oil/gas system efficiency is currently 33 percent. The cumulative efficiency for electric resistance space heating is 25 percent.

FIGURE B-1
EFFICIENCY STAIRCASE:
Natural Gas Resources to Electric Furnace



The two major end-use demands of space heating and transportation together comprise approximately half of California's overall energy demand. Each can be met by alternative energy system logistics paths. Each of these paths lead to different overall energy efficiencies. The staircase efficiency profiles show the energy efficiency implications of the alternative paths of direct gas utilization and the indirect utilization of gas-fired electric generation to satisfy the end-use demand:

Space Heating - direct natural gas-fired
- indirect electric furnace/heat pump

Transportation - direct natural gas-fired automobile
- indirect electric car

Space heating. An alternative energy logistics flow path utilizing a gas furnace for space heating is shown by the efficiency staircase in Figure B-2. Of the 100 units of source energy at the natural gas wellhead, 82 units remain at the residence gas meter. A gas furnace with a seasonal efficiency (SE) of 72 percent[7] would provide 59 units of the original source energy as heat delivered to the conditioned space. This compares with only 25 units for the electric furnace described above.

The use of a residential heat pump dramatically improves the overall system efficiency from that of an electric furnace. The efficiency staircase of Figure B-3 shows that for every 100 units of available source energy, a typical heat pump[8] is capable of delivering 58 units to the conditioned space, compared to the 25 units of the electric furnace. This is possible because a heat pump is "pumping" the lesser "quality" outdoor ambient heat "uphill" to the higher level quality necessary to heat the conditioned space to a comfortable temperature. Note, however, that the heat pump efficiency level of 58 units still falls short of the gas furnace logistics efficiency of 59 units.

But what if the utility system energy conversion efficiency was increased 10 percentage points, from 33 percent to 43 percent? This would be possible by repowering and replacing older, less efficient generating units with advanced combustion technologies (described in Section VI). The revised heat pump efficiency staircase, shown in Figure B-4, indicates that 28 percent more energy would be available at the customer's meter. The same heat pump, with a coefficient of performance of 2.35, would then be able to deliver 76 units of energy to the conditioned space, surpassing the gas furnace logistics flow of 59 units by 29 percent.

Transportation. Personal transportation requirements can be met by two alternative energy logistics paths - a standard internal combustion engine-powered automobile fueled by compressed natural

FIGURE B-2
EFFICIENCY STAIRCASE:
Natural Gas Resources to Gas Furnace

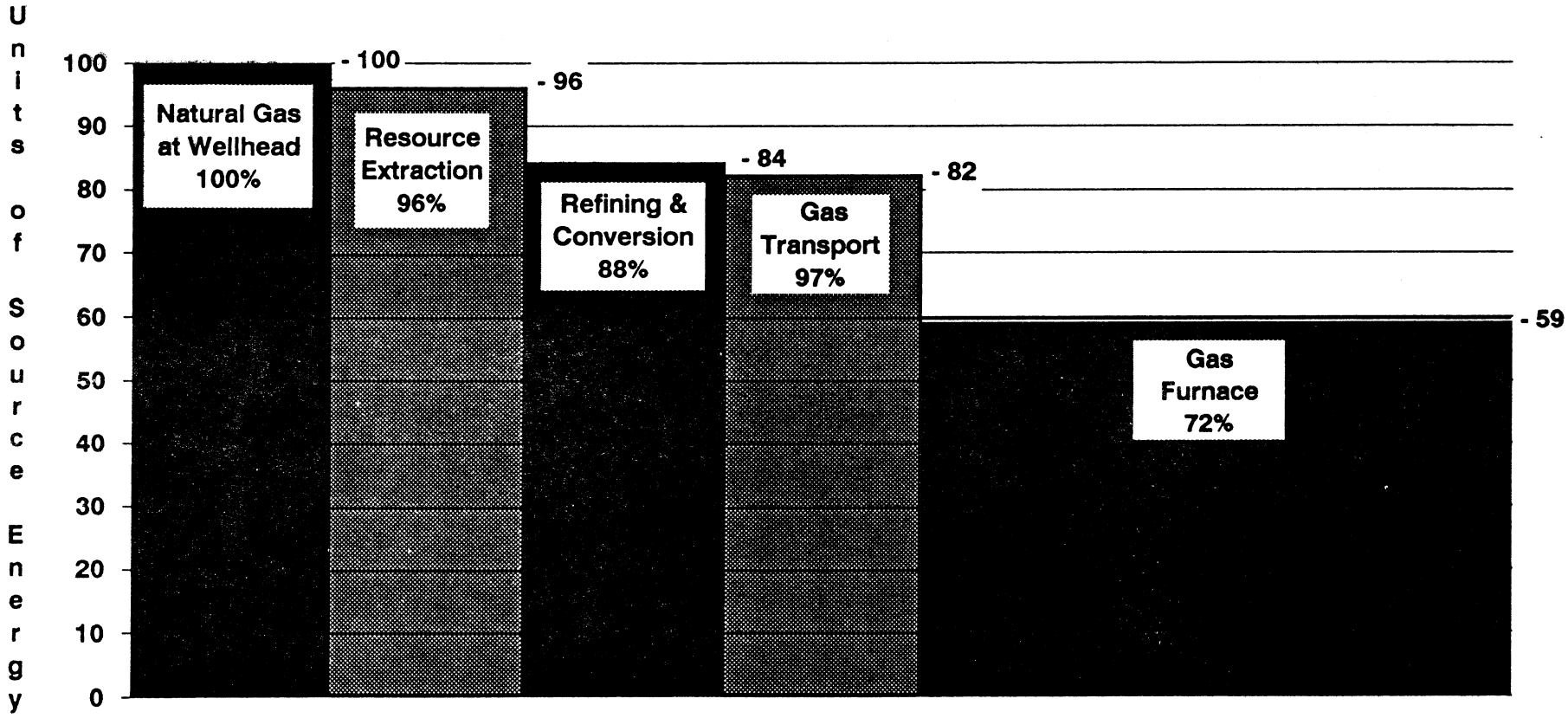


FIGURE B-3
EFFICIENCY STAIRCASE:
Natural Gas Resources to Heat Pump

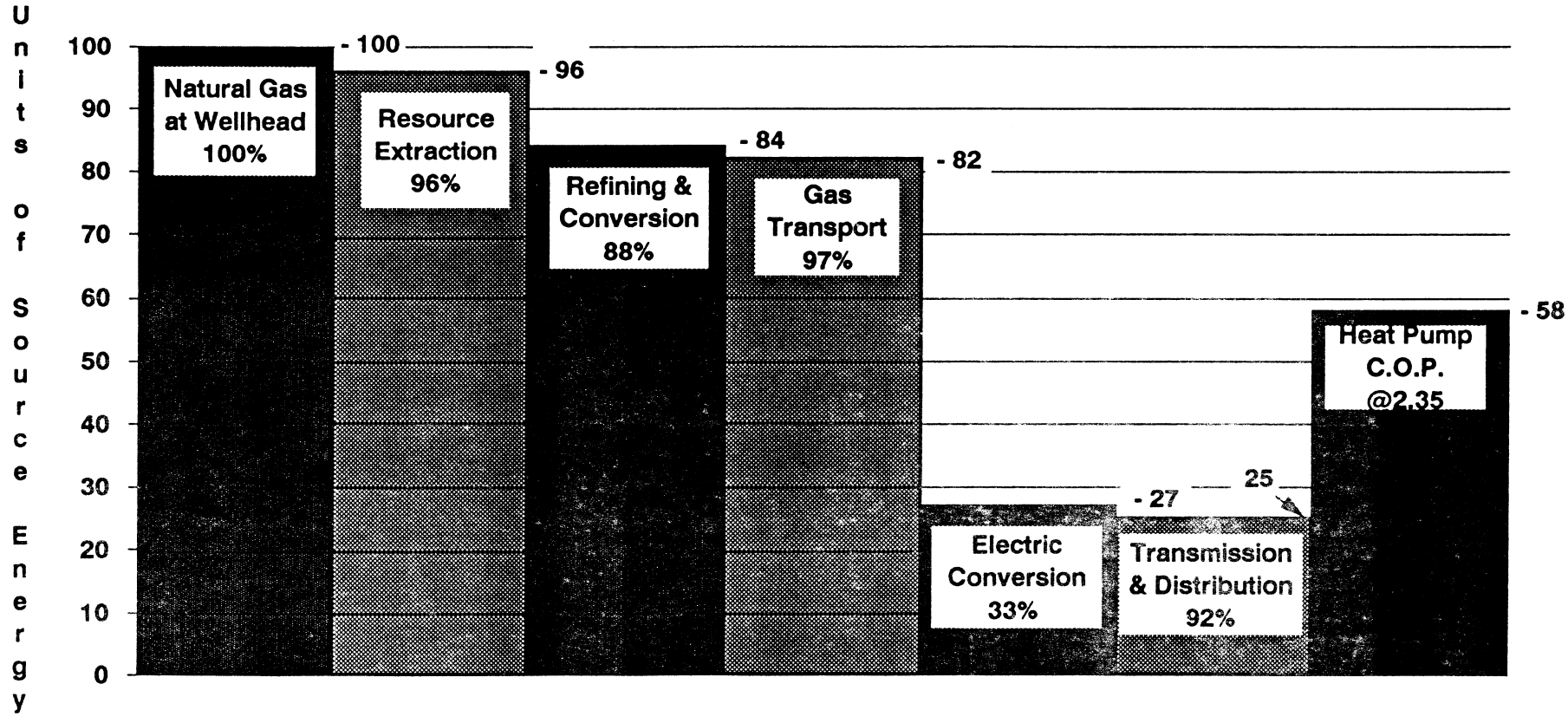
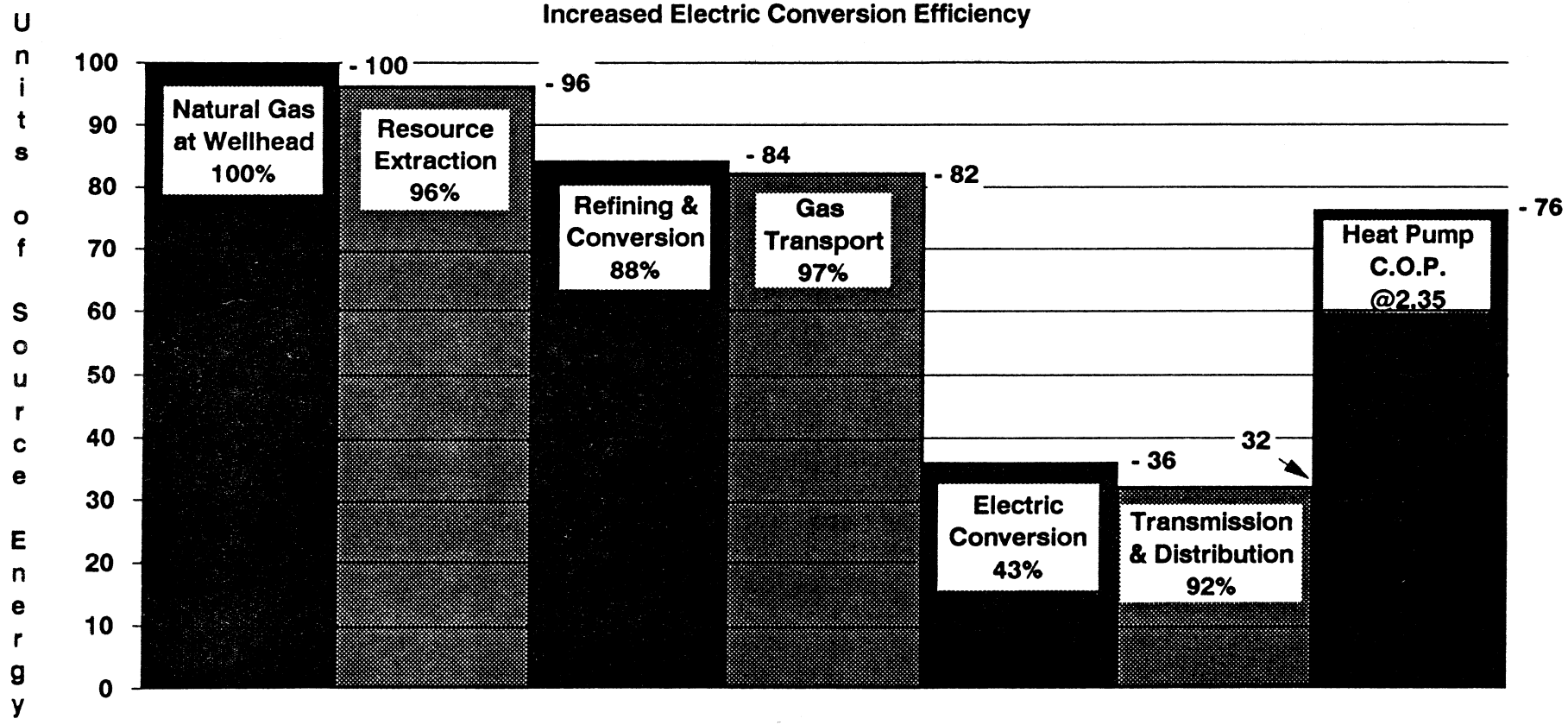


FIGURE B-4
EFFICIENCY STAIRCASE:
Natural Gas Resources to Heat Pump -
Increased Electric Conversion Efficiency



gas (CNG) and an electric car designed to meet the driving range and performance requirements of the urban driving cycle.

The CNG-fueled automobile efficiency staircase, shown in Figure B-5, indicates that of the 100 units of natural gas source energy available at the wellhead, only approximately 11 units of energy are realized in useful work in transporting its occupants from point A to point B. This is based on an engine efficiency of 30 percent[9], followed by mechanical transmission losses and rolling resistance, each with 70 percent efficiency.[10]

The electric car efficiency staircase, shown in Figure B-6, indicates that it is capable of delivering 13 units of source energy equivalent work, which is an 18 percent improvement over the CNG-fueled automobile. The electric car suffers the unique loss of battery recharging, which is 68 percent efficient, and similar mechanical transmission losses and rolling resistance which have a combined 81 percent efficiency.

But what if, as before, the utility system energy conversion efficiency was increased 10 percentage points, from 33 percent to 43 percent? The electric car efficiency staircase, shown in Figure B-7, indicates that the electric car system efficiency increases 31 percent, from 13 source energy units to 17 source energy units. At this level of efficiency, the electric car is approximately 50 percent more efficient than the CNG-fueled automobile.

IV. EFFICIENCY IMPROVEMENTS/UPGRADES REALIZED TO DATE

The rapid market penetration of higher efficiency, natural gas-fired QF cogeneration and customer self-generation capacity additions in California have and will continue to contribute to significant improvements in utility systemwide heat rates. In 1992, cogeneration and self-generation installed capacity is expected to total 4,488 MW, or 15.6 percent of total gas-fired generating capacity.[11] Since most QF cogenerators are "must-run"[12] facilities, they would displace significant amounts of energy production from less efficient existing utility-owned power plants. In 1992, it is expected that approximately 26.3 percent of total gas-fired electric generation will come from QF cogenerators and self-generators.

However, the electric generation energy conversion efficiency of each QF cogenerator and customer self-generator varies considerably. This is due primarily to the considerably higher market value placed on electricity over that of thermal service (an electric Btu is four times more valuable than a thermal Btu). This higher valuation drives the performance objectives of the individual facility.

FIGURE B-5

EFFICIENCY STAIRCASE:

Natural Gas Resources to CNG-Powered Automobiles

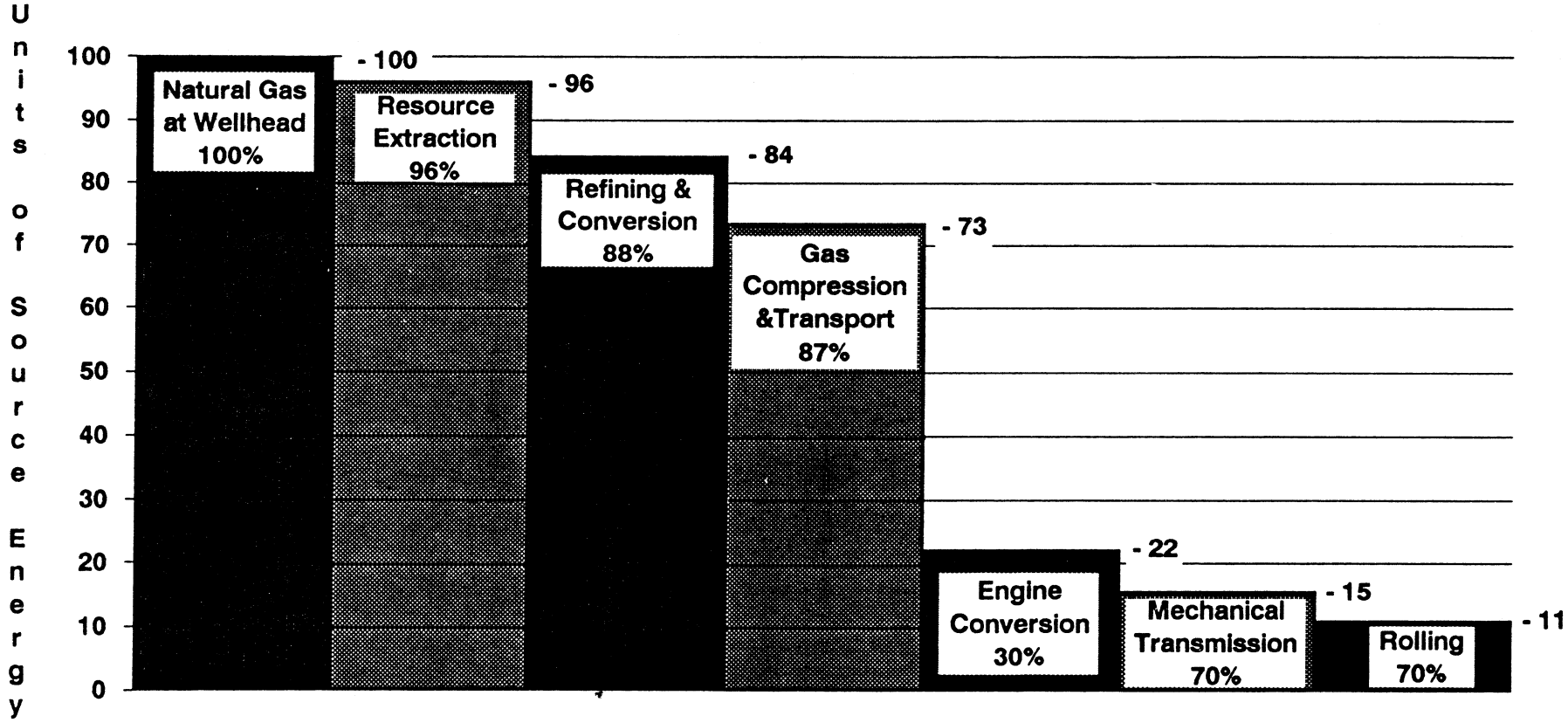


FIGURE B-6
EFFICIENCY STAIRCASE:
Natural Gas Resources to Electric-Powered Automobiles

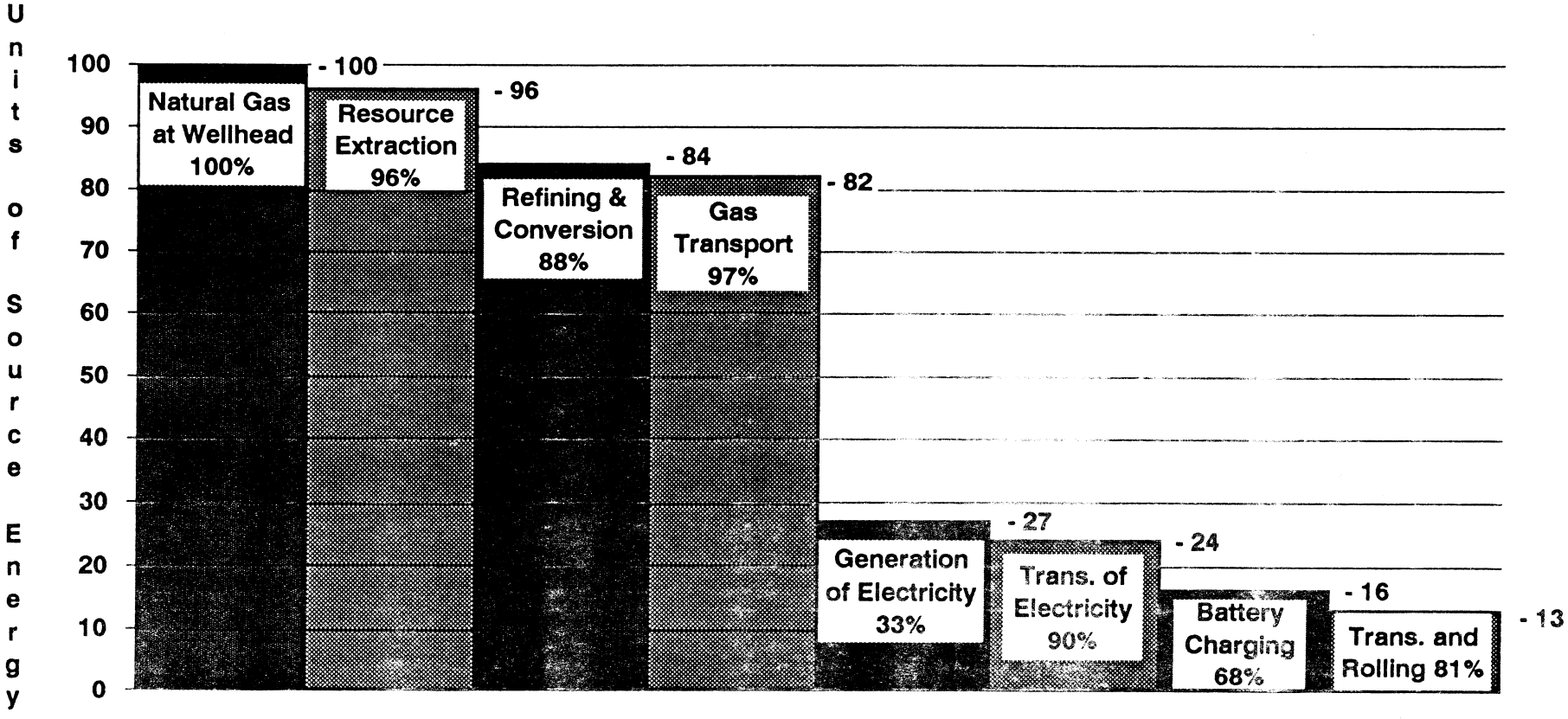
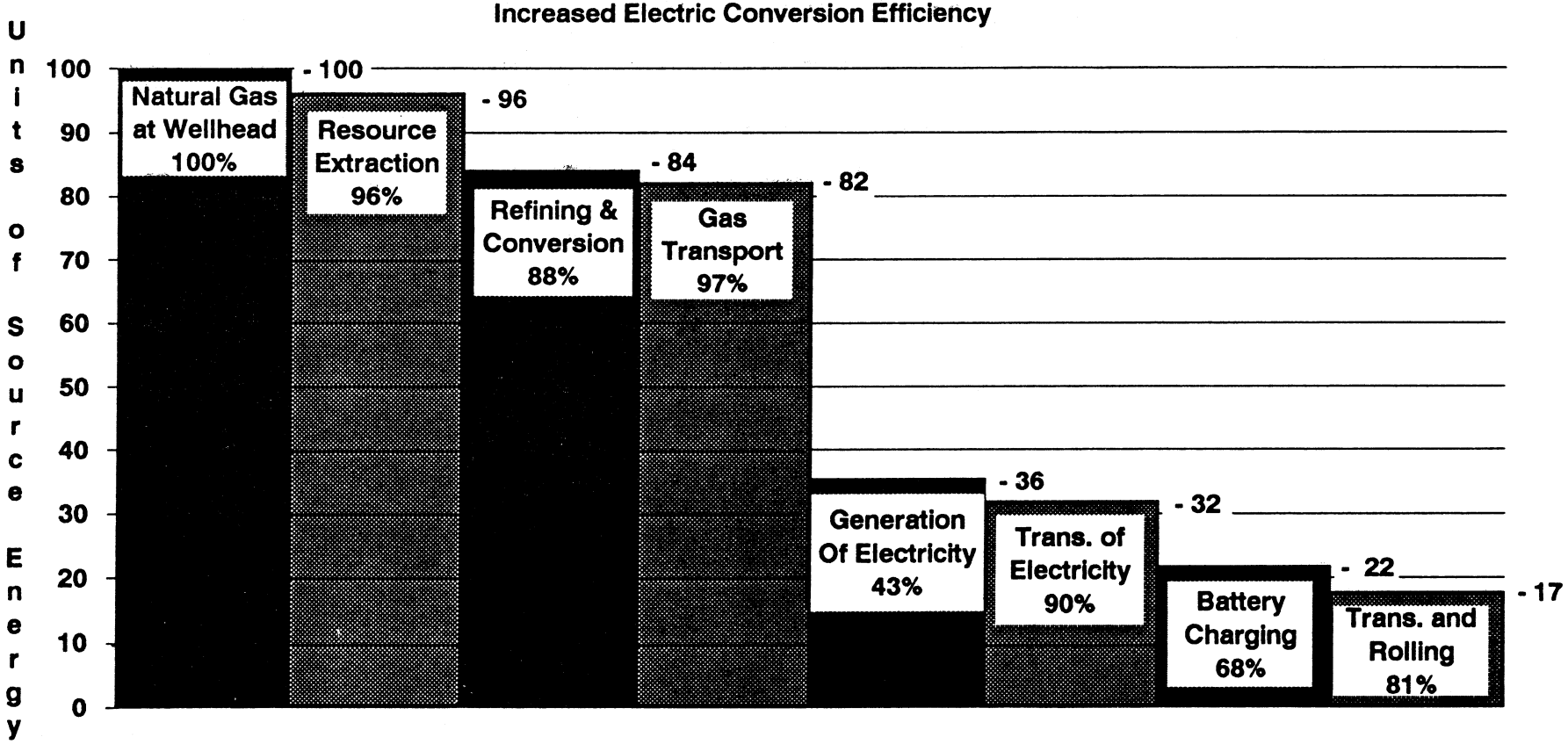


FIGURE B-7
EFFICIENCY STAIRCASE:
Natural Gas Resources to Electric-Powered Automobiles-
Increased Electric Conversion Efficiency



The national Public Utility Regulatory Policies Act (PURPA) efficiency standards set only minimal thresholds for energy conversion efficiency from cogeneration facilities. This allows for project designs which optimize electric power generation at the expense of reduced thermodynamic efficiency.

Energy commission staff experience in evaluating the Applications for Certification for 15 jurisdictional QF cogeneration projects with respect to energy efficiency, discovered a range of electric energy conversion efficiency (expressed as heat rates) from 4400 Btu/kWhr to 7700 Btu/kWhr[13,14]. The weighted average heat rate is 5410 Btu/kWhr. Assuming a constant utility gas-fired generation average heat rate of 10,500 Btu/kWhr, and an average cogeneration heat rate of 5410 Btu/kWhr, the overall system-wide heat rate, based on an energy production weighted average, would be 9,161 Btu/kWhr.[15] As a result, the utility system-wide heat rate has decreased, or the overall efficiency has increased, by 12.8 percent.

A. Results of Resource Case Analysis Report Study

In response to the pressing need to improve the air quality of the South Coast Air Quality Management District (SCAQMD), Energy Commission staff included in its Resource Case Analysis Report (RCAR) several different strategies for complying with the new proposed emission limitation rules. The baseline "Business as Usual" case adhered to the strict prescriptive requirements laid out in the rule, which was to rely on plant retirements and Selective Catalytic Reduction (SCR) retrofits.[16]

Energy Commission staff viewed the proposed SCAQMD regulations as a "band-aid" approach. Staff concluded that a more optimum strategy would incorporate innovative technologies such as advanced combustion turbines, which are more efficient than conventional technology and display clean-burning characteristics. These technologies should be considered by the utilities as a means of achieving SCAQMD's air quality goals.

Strategies were developed in order to simultaneously meet the following objectives:

- Increase system-wide energy conversion efficiency, resulting in reduced demand for non-renewable fossil fuels (i.e., natural gas);
- Improve air quality through reduced air emissions per unit of electric energy produced by fossil-fuel-fired, advanced combustion electric generation technologies; and
- Reduce production costs for electric generation resulting in future utility rate reductions.

In addition, other objectives can be met simultaneously by upgrading electric generation efficiency and optimizing system operations:

- Enhance environmental quality by minimizing need for new, "green field" electric generating and transmission facilities,
- Reduce uncertainty in predicting available electric generating capacity,
- Retain generating capacity in the air basin to sustain high quality electric service (e.g. voltage support, frequency control, load response) and minimize transmission losses of imported power,
- Maintain/enhance electric utility system flexibility to respond to system contingencies (e.g. equipment failures/ outages, adverse hydro-electric generation), and
- Reduce public health and safety risks associated with post-combustion emissions controls such as SCR.

The first strategic alternative, called the "Innovative Technology" compliance strategy, relied on SCR retrofit only when it was cost-effective. Refueling with methanol was assumed as a transitional solution until existing boilers could be permanently replaced with advanced combustion turbines called intercooled steam-injected gas turbines (assumed to be commercially available in 1994).

The second strategic alternative, called the "Environmentally Responsive Resource Case", built upon the foundation established by the Innovative Technology strategy. It further reduced demand through additional conservation and load management, and then met capacity expansion needs with preferred resources that are not fossil fuel-based.

These strategies were applied to the Southern California Edison (SCE) system which has approximately 2,000 MW, of a total 6,000 MW, potential economic replacement of existing steam electric generation.

The results were impressive:

- SCAQMD air quality emissions standards were attained for electric power generation;
- Electric energy production from natural gas-fired electric power plants native to the South Coast Air Basin and SCE's service area increased, although overall consumption of natural gas for electric power generation was reduced. The actual decrease in SCE's gas-fired generation heat rate was equal to 13.22 percent in 1994 (the year in which 1808 MW of

existing steam generating units were assumed to be replaced with advanced combustion turbines);

- Electric power generation production costs decreased with resultant cost reduction to the SCE ratepayer;

- Native, in-basin, electric power generation was retained. This is essential to:

  - maintain quality of service;

  - retain/enhance system operating flexibility at least cost; and

  - to respond to increased growth in electricity demand resulting from, for example, the displacement of fossil fuel combustion by advanced, highly efficient, electric-fired industrial processes, and the electrification of the transportation sector; and

- Public health and safety risks of post-combustion emissions controls were reduced.

V. MARKET IMPEDIMENTS TO REALIZING EFFICIENCY IMPROVEMENTS

Under the current regulatory conditions, the significant economic and environmental benefits identified above are not likely to be realized. Competitive market forces need to be used to reduce the impediments to efficiency improvements. Some of the current impediments to realizing efficiency improvements include:

- The need for efficiency improvements is not a prominent issue in present-day regulatory proceedings. The current regulatory process does not give incentives to be more efficient. For example, the current practice of compensating utilities for fuel expense increases, subject to automatic adjustment clauses, tends to discourage efficient use of fuel.

- At present, the external costs associated with environmental impacts caused by electric power generation have not been quantified. Placing a value on environmental costs when considering which resources and technologies to develop is an important step in achieving a least-cost energy future.

- There are no rewards for taking the technological risks associated with new generating technologies.

Section VIII discusses specific actions which could bring about competitive pressures to achieve the energy efficiency goals explored here.

VI. STATUS OF ADVANCED COMBUSTION TURBINE TECHNOLOGY

A. Background

Existing utility steam turbine (Rankine power cycle) generating units are capable of electric generating conversion efficiencies up to an optimal level of 34 percent (a heat rate of about 10,000 Btu/kWh). A promising advanced steam turbine design is the Kalina cycle, which is near commercial operation and is predicted to have an energy conversion efficiency of 49 percent. The Kalina cycle is a Rankine cycle that uses ammonia and water. Its shortcomings include potential high capital costs, as well as environmental concerns related to the ammonia storage requirements. In addition, attaining higher efficiencies through higher peak steam temperatures (than the current 1000 degrees F) results in design trade-offs which lead to reduced availability and reliability.

The gas (combustion) turbine has historically been viewed as a capacity resource which contributes to a utility's reserve margin. In this mode it is placed in service only when major system contingencies arise, such as another generating unit outage or loss of transmission capacity. The gas turbine is an attractive technology because of its low capital cost per kilowatt (kW) of power produced. This low cost reflects the simplicity of the simple cycle gas turbine (see Figure B-8A), which exhibits a low efficiency (approximately 32 percent).

The low unit capital cost makes the gas turbine very attractive for cogeneration applications. Gas turbine power plants are also relatively insensitive to economies of scale, making them the preferred power source for all but the largest cogeneration installations. Their high temperature exhaust (800 to 1000 degrees F), when recovered in a heat recovery steam generator (HRSG) for steam service to the host thermal load, dramatically increases the overall cogeneration system efficiency to levels approaching 80 percent.

Utilities increased their interest in short lead-time, relatively inexpensive gas turbine power plants in the 1960s, in response to rapid increases in electricity demand. This trend came to an abrupt end after the oil shocks of the 1970s. Utility interest then turned to alternative fuel technologies. Commercial airlines, also reeling from the same fuel price increases, had limited options. They pressed the gas turbine manufacturers to substantially improve turbine efficiency. With the benefit of Department of Defense research and development funding, and both commercial and government orders for new engines, manufacturers made major improvements in materials, design and manufacturing techniques. As a result, advancements in gas turbines for aircraft applications

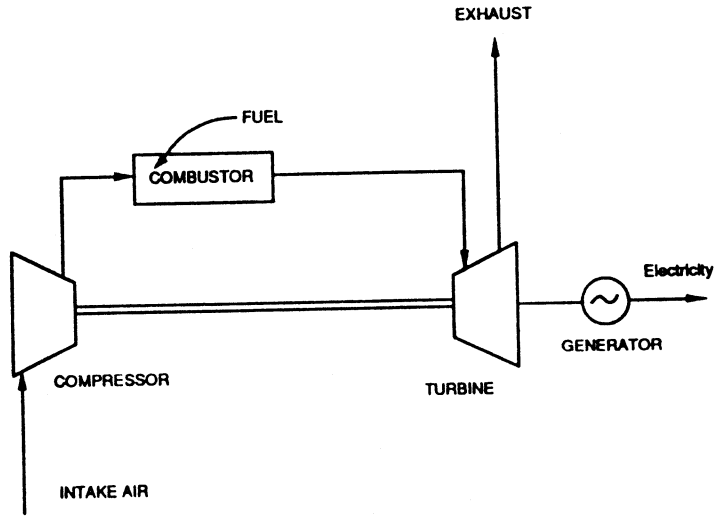


Figure B-8a: **SIMPLE POWER CYCLE**

Intake air is compressed, mixed with fuel and ignited in the combustor. The hot combustion gases expand in the power turbine which drives both the compressor and generator by a common shaft. The cooler exhaust gases exit to the atmosphere.

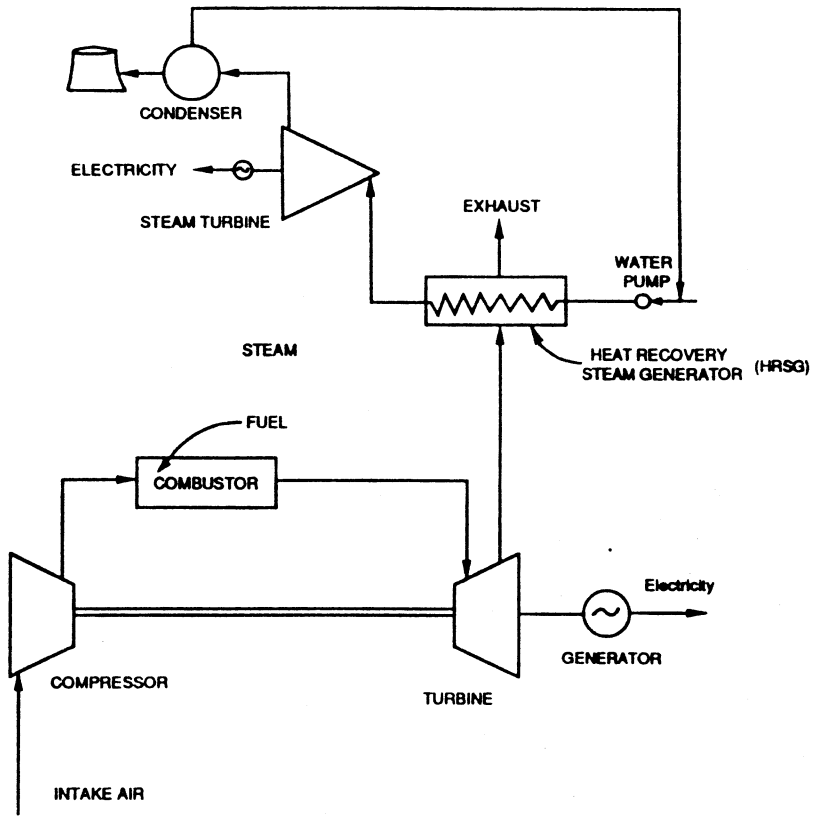


Figure B-8b: **COMBINED CYCLE**

Compression, combustion, and expansion of air occurs as in the simple power cycle. The remaining energy in the hot exhaust gases is recuperated in the HRSG to raise steam. This steam is expanded in the steam turbine to produce additional shaft power to a second electric generator.

accelerated while advancements in heavy-duty, industrial gas turbines for electric utility applications progressed at a slower pace.

It is important to distinguish the heavy-duty, industrial gas turbine (electric utility) characteristics from those of the aeroderivative turbines. There is a considerable difference in size and weight, as the latter has not only to propel but also fly along with the airplane. The aeroderivative units range in size up to 35 MW (in simple cycle configuration), compared to the industrial turbine sizes up to 135 MW. Differing compression ratios and exhaust temperatures favor the industrial turbine for combined cycle operations.

There have been advances in industrial gas turbine technologies in recent years. For example, the GE Frame 7F advanced combined cycle combustion turbine has a stated efficiency of 51.2 percent.[17] However, this combined cycle (see Figure B-8B) is not an inherently cleaner technology, and thus its impact on emissions reduction is evident only when emissions are expressed in pounds of emissions per unit of electrical energy produced. Without the promise of being inherently cleaner-burning, there will still be the need for post-combustion emissions control systems.

Application of aircraft engine-based technology to electric utility gas turbine use was a logical progression. These gas turbines have demonstrated high availability and reliability in cogeneration applications which typically require continuous baseload operation. This availability is enhanced by the aeroderivative's modular construction, which allows for easy parts removal and replacement. Because of their smaller size relative to industrial gas turbines, multiple units can be located at one plant site, which further increases the plant's overall reliability.

B. Status of Aeroderivative Turbine Technology

Despite all the "high tech" improvements in aeroderivative turbine performance made in the last 15 years for in-flight service, there remain significant opportunities for further technology advancement for stationary power plant applications. The sources for these improvements are many: aircraft engine technology improvements, existing thermodynamic cycle efficiency improvements, and application of existing technology in related disciplines to gas turbine advancement.

The concept of injecting steam directly into the gas turbine (along with the air and fuel necessary to produce combustion) to increase efficiency and power is a product of aircraft engine evolution that has also been successfully demonstrated in electricity generation applications. The steam-injected gas turbine (STIG) has a typical efficiency of about 44 percent, compared with an efficiency of 32

percent for simple-cycle gas turbines (see Figure B-9A). In addition, the STIG has the additional benefit of substantially reducing nitrogen oxide (NO_x) emissions which contribute to the formation of ozone.

A typical simple cycle gas turbine has a NO_x emissions level of 0.39 lbs of NO_x created per million Btus of fuel consumed (0.39 lbs NO_x/MMBtu), which corresponds to emissions of about 120 ppm. The use of steam injection lowers the NO_x emissions by 70 percent or more. One gas turbine manufacturer has guaranteed that its STIG can achieve a NO_x emissions level below 25 ppm, which corresponds to about 0.08 lbs NO_x/MMBtu, when operated within their warranty conditions.

This represents a significant improvement over the simple cycle gas turbine, although the NO_x emissions level from a STIG is not low enough by itself to attain the level required by the South Coast Air Quality Management District (SCAQMD) and some other California air districts. Selective catalytic reduction (SCR), a post-combustion NO_x emissions control, is considered by SCAQMD and some other districts as the best available control technology (BACT). Currently, this BACT level is set at 9 ppm (0.03 lbs NO_x/MMBtu). SCAQMD thus requires that gas turbines at new sites be able to meet a NO_x emissions level of 9 ppm. Since the STIG is only guaranteed to meet 25 ppm, SCR will be needed for STIGs in new applications. The transportation, storage, and use of the ammonia required by SCR, however, raise safety questions, especially in populated areas.

For gas turbine retrofit applications, the SCAQMD NO_x emissions Compliance Limit is not a single limit, but is a function of the gas turbine thermal efficiency and a Reference Limit which allows for slightly higher emissions if SCR is not needed to meet the Compliance Limit. The SCAQMD Rule 1134 Compliance Limit for stationary gas turbine units is expressed as:

Compliance Limit = Reference Limit * (EFF/25 percent)

where:

Compliance Limit = allowable NO_x emissions (ppm by volume)

Reference Limit = the NO_x emission limit (ppm by volume), calculated at ISO conditions, corrected to 15 percent oxygen on a dry basis. For plants 10.0 MW and over, the Reference Limit is 9 ppm. For plants 10.0 MW and over without SCR, the Reference Limit is 12 ppm.

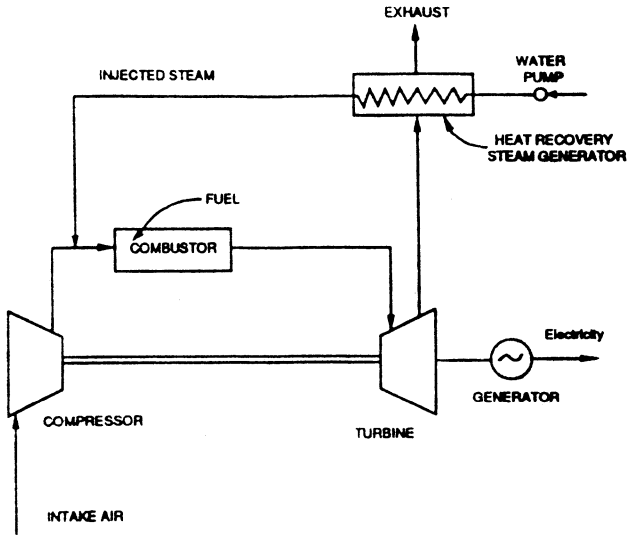


Figure B-9a **STEAM -INJECTED GAS TURBINE** (STIG)

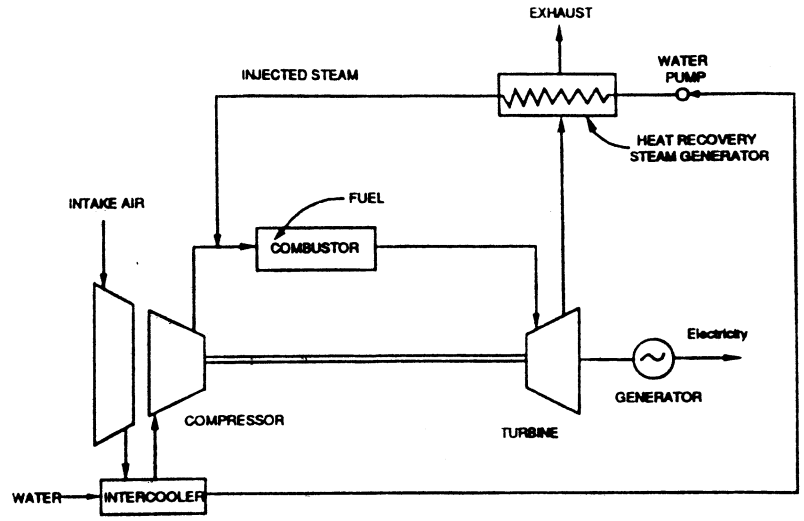


Figure B-9b **INTERCOOLED STEAM -INJECTED GAS TURBINE** (ISTIG)

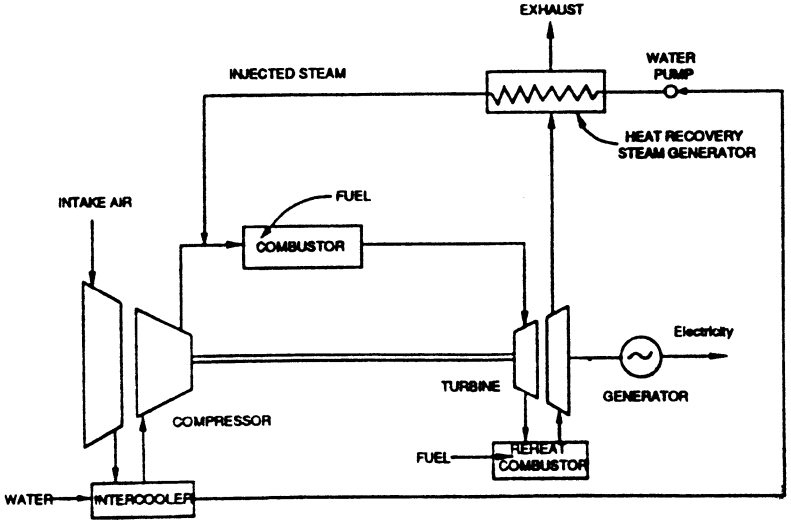


Figure B-9c **INTERCOOLED STEAM -INJECTED GAS TURBINE WITH REHEAT** (IR-STIG)

Notes

STIG: Like simple power cycle, except that the remaining energy in the hot turbine exhaust gases is recuperated in the HRSG to raise steam, part of which is then injected into the combustor for increased power output and higher efficiency.

ISTIG: Like STIG, except the that intercooler between compressor stages reduces compressor power requirements and allows for increased mass flow and higher combustion firing temperatures, which realize further increases in power output and efficiency.

IR-STIG: Like ISTIG, except that the reheat combustor before the power turbine allows for increased power output and higher efficiency.

EFF = the manufacturer's rated efficiency of the gas turbine after correction from lower heating value to higher heating value of the fuel.

The higher heating value efficiency for the STIG is 39.6 percent, based on the lower heating value efficiency of 44 percent. Without the benefit of SCR, the Compliance Limit which the STIG must meet is:

$$\text{Compliance Limit} = (12\ \text{ppm}) * (39.6\ \text{percent}/25\ \text{percent}) = 19.0\ \text{ppm}$$

It should be noted that steam injection has been used in operating STIGs to achieve NO_x emissions in the 12-14 ppm range. However, there is not sufficient operating data available for the manufacturer to lower its guarantee at this time. Thus, the power producer who chooses to build and operate a STIG without SCR bears the responsibility for retrofitting with SCR if the facility cannot maintain NO_x emissions at or below the Compliance Limit.

Another area in which significant efficiency improvements can be made is in applying existing thermodynamic cycle efficiency enhancements to advanced gas turbines. The benefits of cycle modifications such as reheat, intercooling, and regeneration to the simple gas turbine (Brayton) cycle are well-documented. The combination of these cycle modifications and advanced combustion turbines such as the STIG has not been commercially demonstrated to date. However, it is predicted that an intercooled STIG (ISTIG) could achieve an efficiency of 52.5 percent, while an intercooled STIG with reheat (IR-STIG) could achieve an efficiency of 55 percent (see Figures B-9B and B-9C).

The same gas turbine manufacturer who has guaranteed a NO_x emissions level no higher than 25 ppm for the STIG will most likely be able to apply a comparable or better guarantee to its ISTIG (see Table B-1). While the emissions level for the ISTIG are not low enough to compare to the BACT level of 9 ppm that can be achieved with SCR, it is expected that the ISTIG will not need SCR in retrofit applications.

The higher heating value efficiency for the ISTIG is 47.3 percent based on the lower heating value efficiency of 52.5 percent. Without the benefit of SCR, the Compliance Limit which the ISTIG must meet is:

$$\text{Compliance Limit} = (12\ \text{ppm}) * (47.3\ \text{percent}/25\ \text{percent}) = 22.7\ \text{ppm}$$

TABLE B-1

COMPARISON OF NO_x EMISSIONS FOR GAS TURBINE TECHNOLOGIES

Technology	NO_x Emissions ppm	NO_x Emissions lb NO_x/MMBtu	Efficiency[1] (Percent)	Heat Rate (Btu/kWhr)[2]	lb NO_x/MWhr[3]
Simple Cycle	120	0.39[4]	32	10,700	4.2
STIG	25[5,6]	0.08	44	7,800	0.62
ISTIG	≤25[7,8]	≤0.08	52.5	6,500	≤0.52
IR-CRGT	<3[9]	<0.01	≥55	≤6,200	<0.06

[1]Appendix B, Section VI.

[2]Lower heating value heat rate in Btu/kWhr
= 100 x (3,414 Btu/kWhr)/percent.

[3]NO_x emissions in lb NO_x/MWhr
$$= \frac{NO_x \text{ emissions in lb } NO_x/\text{MMBtu})*(\text{Heat rate in Btu/kWH})}{1,000}$$

[4]California Energy Commission. Staff Recommendations for Generic Power Plant Emission Factors (Final Version), August 1989.

[5]This value represents a guarantee by one gas turbine manufacturer. Re: Memo, S. Baker (CEC) to R. Strand (CEC), "Seminar on Controlling Gas Turbine Emissions", March 27, 1989.

[6]Actual operating data show that NO_x emissions in the 12 to 14 ppm range can be achieved. Re: 1) Memo, S. Baker (CEC) to R. Strand (CEC), "Seminar on Controlling Gas Turbine Emissions", March 27, 1989; 2) D.A. Kolp, and D.J. Moeller, "World's First STIG LM5000 Installed at Simpson Paper Company", ASME paper 88-GT-198.

[7]Given the improvements in design from the STIG to the ISTIG, it is likely that the gas turbine manufacturer's guarantee on NO_x emissions for the ISTIG will be equal to or better than that for the STIG.

[8]The ISTIG is expected to meet the stringent SCAQMD NO_x emissions requirement for retrofit applications without the use of SCR. See text, Section IV.B.

[9]Mr. Jack Janes, P.E. (CEC staff).

Again it is noted that steam injection has been used in operating STIGs to achieve NO_x emissions in the 12-14 ppm range. It is therefore considered probable that the ISTIG could achieve similar NO_x emissions, and even more likely that the ISTIG could meet the Compliance Limit of 22.7 ppm.

This elimination of the need for SCR represents a significant economic and safety improvement. However, it should be noted that although NO_x emissions decrease with increasing steam injection, the carbon monoxide (CO) emissions increase. Hence, there may be the need for CO post-combustion emissions control. CO control is, however, much safer and less expensive than SCR.

The California Energy Commission Research and Development staff is examining an aeroderivative turbine cycle configuration which holds substantial promise of very high efficiency as well as extremely low pollutant emissions. The concept of a chemically recuperated gas turbine (CRGT) applies existing technology from the chemical industry to gas turbine applications. Analysts believe that an intercooled CRGT with reheat (IR-CRGT) will achieve an efficiency greater than 55 percent, while producing NO_x and carbon monoxide (CO) substantially below currently mandated levels (see Figure B-10). It is estimated that a NOx emissions level between 1/9 and 1/3 of the BACT level (i.e., 0.003 to 0.01 lbs NO_x/MMBtu) can be achieved with the CRGT.

This technology blends steam with desulfurized natural gas, and the mixture is passed through the superheater tubes of the gas turbine's heat recovery steam reformer (HRSR). With the aid of a special nickel-based catalyst, the steam-natural gas mixture reacts chemically, producing a hydrogen-rich, low Btu gas. The superheater effluent (reformate) then fuels the gas turbine generator. The turbine exhaust heat, thermochemically recouped and recycled, yields a significant thermodynamic advantage over conventional steam-only exhaust heat recuperation. The recuperation process gives nearly a one-for-one conversion of energy from exhaust gas heat into increased fuel energy. Additionally, it is known that the low Btu fuel produces combustion products that are inherently very low in NO_x and CO concentration. Hence, there would be no need for either NO_x or CO post-combustion emissions control. A comprehensive report on the analysis of this staff concept is in progress to confirm these expectations.[18]

A comparison of the NO_x emissions for the simple cycle gas turbine, STIG, ISTIG, and IR-CRGT is shown in Table B-1. The inherent NO_x reduction that can be attained with the advanced technologies is easily seen by comparing the values of lbs of NO_x formed per million Btus of fuel consumed. For example, for an identical fuel input, the IR-CRGT will produce 39 times less the amount of NO_x that a simple cycle gas turbine produces. This inherent reduction becomes even more dramatic, however, in light of efficiency improvements. By reducing the quantity of fuel burned to produce a

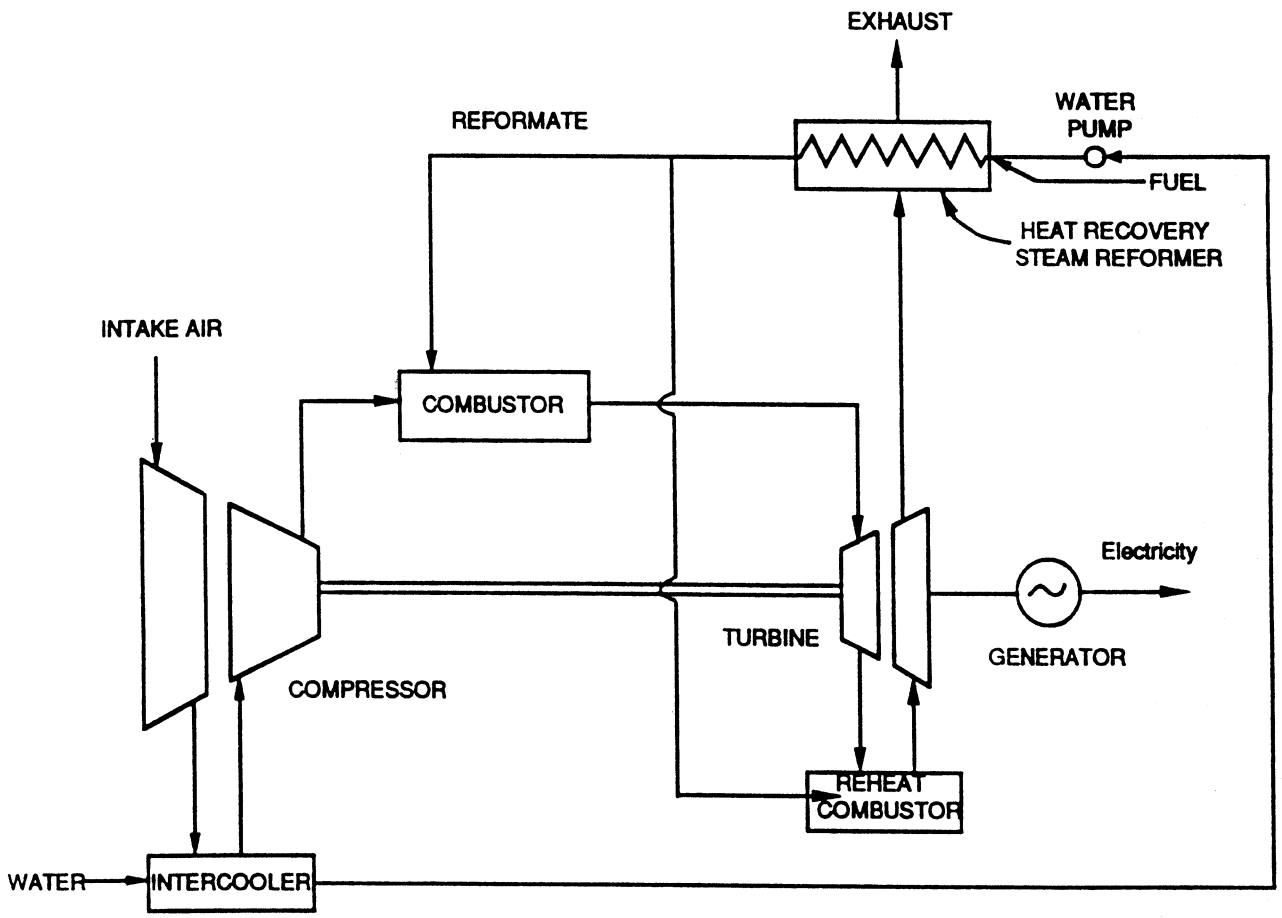


Figure B-10: **INTERCOOLED CHEMICALLY RECUPERATED GAS TURBINE WITH REHEAT**

Like IR-STIG Cycle except the remaining energy in the hot turbine exhaust gas is recuperated in a chemical reformer. Desulfurized natural gas and steam pass over a nickel-based catalyst bed, which promotes a chemical reaction to produce a hydrogen-rich gas. The reformer effluent in turn fuels both combustors. Dramatic reductions in air emissions result, as well as an increase in efficiency.

unit of electrical energy, the more efficient machines effectively leverage their cleaner emissions to further reduce total emissions.

Expressing NO_x emissions in term of lbs of NO_x produced per MWhr of electric energy produced provides a better overall measure of NO_x emissions which takes into account both combustion and efficiency improvements; comparing NO_x emissions based on energy production for the simple cycle gas turbine and the IR-CRGT, it can be seen from Table B-1 that for equal amounts of energy produced, the IR-CRGT will produce 70 times less the amount of NO_x emissions of a simple cycle gas turbine.

A summary of the status of these advanced combustion power cycles is as follows:

Existing advanced combustion power cycles

1. Advanced Combustion Turbines:

   a. STIG (44 percent efficiency)
   b. Advanced Combined Cycle[19] (51 percent efficiency)

2. Repowering existing steam boilers (40-44 percent efficiency)

Near commercial advanced combustion power cycles

1. Advanced Combustion Turbines:

   a. ISTIG (52.5 percent efficiency)
   b. IR-STIG (Reheat: 55 percent efficiency)
   c. IR-CRGT (Reheat: 55 percent plus efficiency)

2. Advanced Steam Turbine (Kalina Cycle) (49 percent efficiency)

C. Cost and Performance Characteristics of Advanced Combustion Turbine Power Cycles

The family of advanced combustion turbines based on the engines used on modern aircraft is capable of achieving not only significantly higher energy conversion efficiency with accompanying cost savings, but also promises capital cost economies approaching 40 percent for the CRGT. This level has not been seen since the early 1970s; at that time, economies of scale were realized from the field fabrication of ever larger central station power plants. The advanced combustion turbine's capital cost economies derive from the substantial knowledge gained in long factory production runs, minimizing field erection costs. In addition, the relatively small

output of these machines (100 to 200 megawatts) allows the addition of generating capacity in small steps, rather than in 750 to 1000 megawatt blocks.

The potential of these high efficiency, advanced combustion technologies can best be described by the graphic shown in Figure B-11.[20] The competitive position of each of the advanced combustion turbine alternatives is depicted on a graph relating operating efficiency, fuel price, and installed capital cost. Each advanced gas turbine is positioned on the graph according to its cost and performance characteristics.

The units holding the upper left positions (higher installed capital cost and lower efficiency) on the graph are a diverse offering of utility size combined-cycle configurations which are indicative of currently available turbine technology.[21] Not shown, but in a similar competitive position, is the STIG. The STIG is targeted principally to cogeneration projects designed for electric generating output of 30 to 50 MW, and which require significant thermal load-following capability.

Although combined-cycle configurations have been applied to cogeneration applications with more or less constant thermal loads, their principal competitive advantage would be in utility intermediate and baseload power plant applications in a size range from 250 to 500 MW. The graph indicates that these plants would be able to recover their cost at a fixed charge rate of 18 percent, if operated in a baseload service with a capacity factor of 80 percent based on incremental fuel savings over that of a nominal 10,500 Btu/Kwh utility steam generating unit, in the range of fuel price from $4.00 to $7.00 per MMBtu ($4.20 to $7.35 per thousand cubic feet).

The more competitive ISTIG and IR-CRGT advanced combustion turbine power cycle configurations hold positions in the lower right portion of the graph. These technologies are capable of recovering their capital costs at a fixed charge rate of 18 percent, even at fuel costs lower than $3.25 per MMBtu ($3.41 per thousand cubic feet).

A summary of relative competitive positions at varying capacity factors, from 75 to 95 percent, is shown in Figure B-12.

Figure B-11

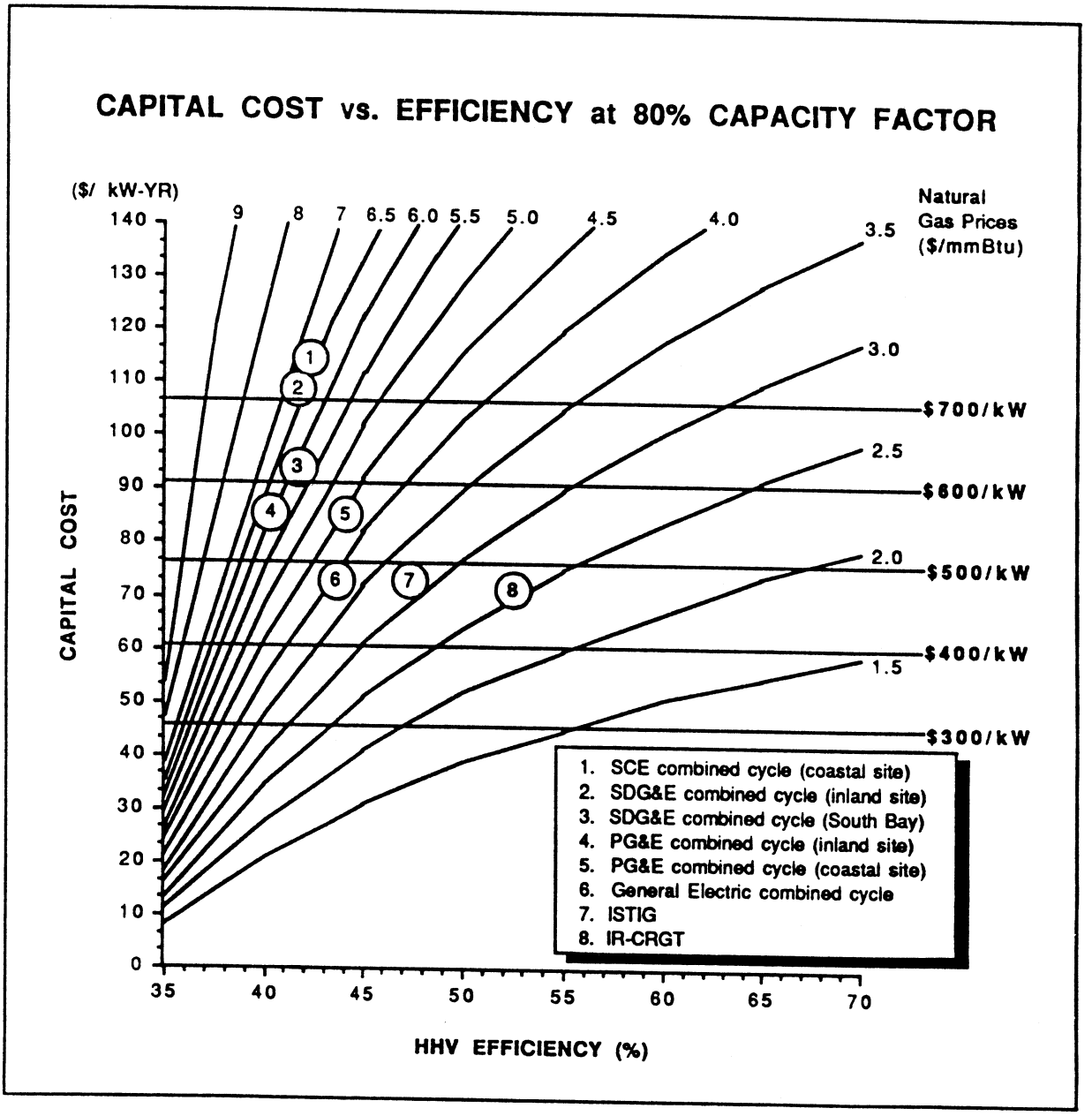
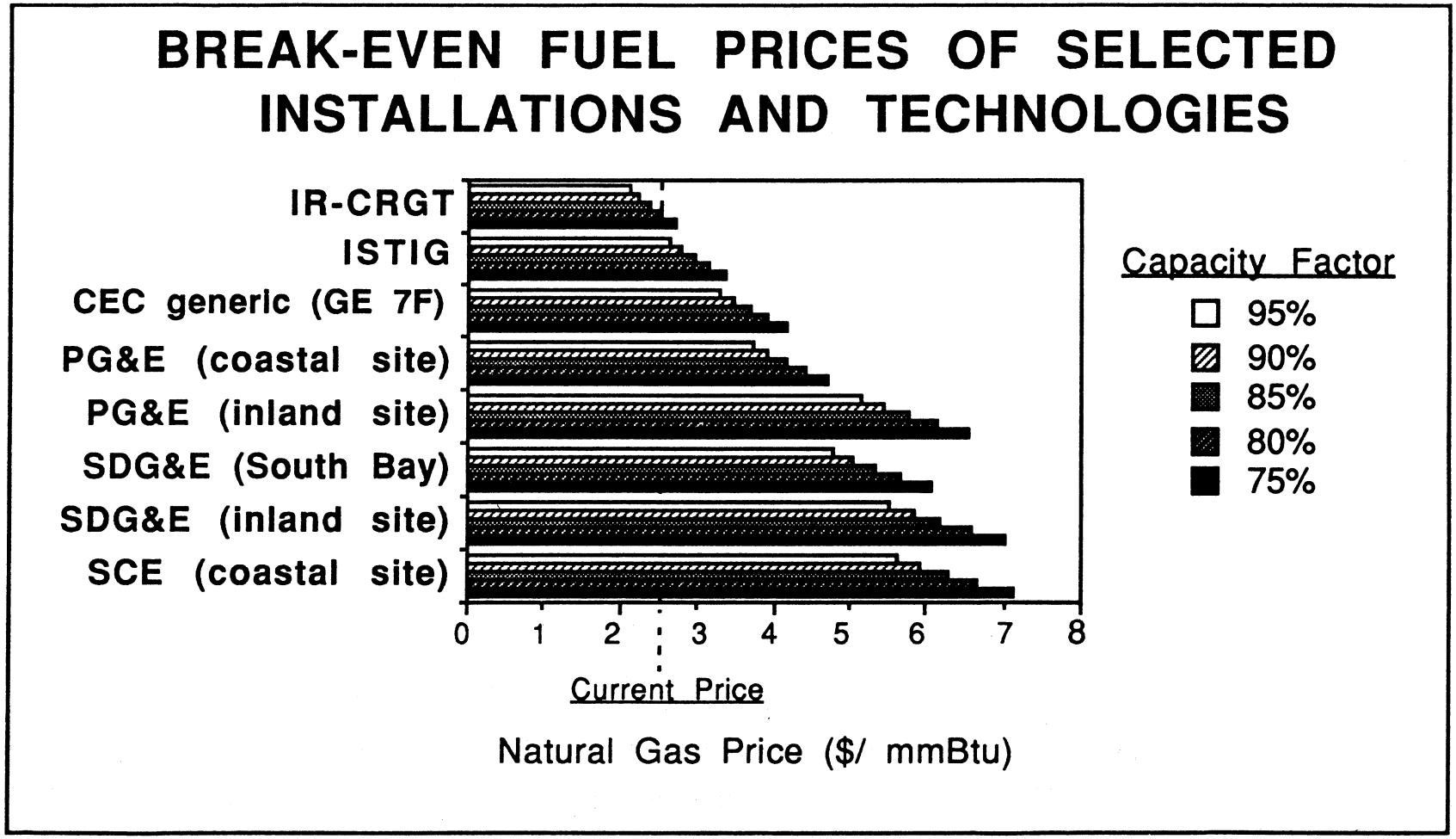

CAPITAL COST vs. EFFICIENCY at 80% CAPACITY FACTOR
($/ kW-YR)
CAPITAL COST
HHV EFFICIENCY (%)
Natural Gas Prices ($/mmBtu)
9
8
7
6.5
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
$700/kW
$600/kW
$500/kW
$400/kW
$300/kW
1. SCE combined cycle (coastal site)
2. SDG&E combined cycle (inland site)
3. SDG&E combined cycle (South Bay)
4. PG&E combined cycle (inland site)
5. PG&E combined cycle (coastal site)
6. General Electric combined cycle
7. ISTIG
8. IR-CRGT

Figure B-12


BREAK-EVEN FUEL PRICES OF SELECTED INSTALLATIONS AND TECHNOLOGIES
IR-CRGT
ISTIG
CEC generic (GE 7F)
PG&E (coastal site)
PG&E (inland site)
SDG&E (South Bay)
SDG&E (inland site)
SCE (coastal site)
0
1
2
3
4
5
6
7
8
Current Price
Natural Gas Price ($/ mmBtu)
Capacity Factor
95%
90%
85%
80%
75%

VII. APPLICATIONS OF ADVANCED COMBUSTION TURBINES

A. New Facilities

These advanced combustion turbine designs, which are highly efficient, clean-burning, and relatively low in capital costs, are well-suited for use in new installations. They are inexpensive enough to be run in continuous baseload operation, and yet are flexible enough to be used for load following and peaking applications.

Machines such as the ISTIG can be used in cogeneration and combined cycle configurations. The CRGT, on the other hand, makes less steam available for cogeneration use, since more of the waste energy is used in the machine. It is therefore better suited for direct power generation applications. However, it should be noted that under the Public Utilities Commission's upcoming bid process, the market for building CRGTs will be open to QFs.

B. Impact of CPUC Bid Process

The California Public Utilities Commission (CPUC) is currently changing the process by which new electrical generation capacity is approved. Its revised procurement process involves the introduction of competitive bidding by QFs to meet identified utility needs. Thus, the market for QFs would be greatly expanded since they could be involved in proposals for new capacity as well as retrofitting or replacing existing capacity. Although the Energy Commission supports the use of competitive bidding in the CPUC's QF procurement process, it urges the CPUC to improve on the current bid process by "...open[ing] the bidding to all resource options, including QFs, IPPs, and utilities outside of the recipient's service area."[22] In this manner, the potential to introduce advanced combustion technologies is expanded to a wider market.

C. Plant Life Management Options: Replacement and Repowering

Significant opportunities exist for incremental efficiency improvements and upgrades among the population of older, less efficient, existing utility power plants which have reached or will be reaching the end of their nominal or economic design lives.

California utilities own and operate approximately 21,000 MW of fossil-fuel-fired generating capacity. More than 7,000 MW of this capacity will reach the end of each generating unit's assumed nominal design and economic life (30-40 years) during the current planning horizon (1988-2007). A choice has to be made whether to retire, run, reserve, refurbish, repower, or replace these generating units. These are the Plant Life Management Options (PLMO) to consider.[23] The emphasis in this report on significant efficiency improvements/upgrades and reduced power plant air emissions, warrants focused attention to the implementation strategies of repowering and replacement. The repowering or replacement of less efficient plants provides an excellent opportunity to employ advanced combustion technologies without needing to wait for new demand to be created.

Units designated for repowering will require extensive repair and modifications, including major component replacement. Repowering will improve availability, efficiency, emissions and operating flexibility. Due to the intensive capital investment required, the life of the repowered unit may be extended by 20 or 30 years. An example of unit repowering is the mating of an oil- or gas-fired combustion turbine to an existing boiler. The resultant combined cycle would realize incremental capacity and efficiency gains, plus significant improvements in availability and forced outage rates.

The option with the most promise of dramatic increases in energy conversion efficiency is the replacement option. Old power plant units may be replaced completely with the latest in power generation equipment at the existing site. An example would be to replace an existing, marginally performing, inefficient non-reheat steam generation unit with an advanced gas turbine system capable of efficient and reliable operation for both intermediate and baseload duty cycles. The existing power plant site would be redeveloped, capitalizing on existing infra-structure (such as transmission and substation facilities). Reuse of an existing site would avoid the environmental impacts of developing a "green field" power plant site.

Relocating existing generation to new "green field" locations would result in relocating many, if not all, of the land use, socioeconomic and environmental impacts associated with the existing generating facility. Additionally, significant new environmental impacts are likely to be associated with a new site. Redevelopment of existing generating facilities can avoid incurring new impacts and the associated environmental costs.

The environmental benefits to be gained by redeveloping existing sites are summarized below:[24]

Land Use:

Redeveloping existing power plant sites would have negligible land use impacts. Potential new land use conflicts could occur depending on the magnitude of change in air pollutant emissions and air pollution control strategies (e.g. Selective Catalytic Reduction of NO_x requiring the storage and use of ammonia).

Redeveloping existing sites also results in little or no change in appurtenant facilities being required. An exception would be if a change in fuel requiring new supply lines.

Redeveloping existing sites will avoid the potential loss of prime agricultural lands due to constructing new "green-field" power plants and the appurtenant facilities such as electric transmission lines, fuel supply lines, water lines, waste lines, and roads.

Socioeconomics:

Socioeconomic impacts associated with power plant construction or reconstruction include employment, population, housing and public services and facilities. Most of the power plants being considered for redevelopment were built in the 1950s and are located near the load center they serve. Redeveloping a power plant at an existing site would have positive employment impacts and insignificant impacts on population, housing, and public services and facilities.

Construction of new "green field" power plants near or distant from the load center can result in significant socioeconomic impacts depending on the location. Power plants built at rural locations can provide some limited employment opportunities for local workers in the building trades and service industries. However, these projects can negatively impact housing, schools, public services like fire and law enforcement, and public facilities like roads. While most power plant projects contribute significant property taxes, the revenues are not usually available to a local jurisdiction until after the first year of construction, by which time substantial impacts have already occurred.

Water quality and supply:

Water quality and supply impacts should not change significantly by redeveloping existing power plant sites. Replacement power plants built at a new location would result in new impacts to water quality and supply. These impacts range from insignificant to significant, depending on the location selected.

Quality of discharge water from redeveloped plant sites should be improved. Redeveloped plants, even if larger in generating capacity, tend to require less water and producing lower volumes of waste water.

New waste discharge requirements are not typically required for existing power plants that are repowered or replaced, and do not increase the volume, constituents, or temperature of waste water.

Biological Resources:

Redevelopment of existing power plant sites will have the least impact on plant and animal biological resources. Redeveloped power plants using once-through cooling that are more efficient will require less cooling water per kWh produced and will thus have less of an impact on aquatic biological resources. New "green field" power plant sites have the potential of having significant impacts on rare and endangered species, areas of critical biological concern, species of special concern, and commercial and recreational resources.

Construction of new power plants remote from the load center can result in significant biological resource impacts associated with the construction of electric transmission lines, fuel supply lines, water supply and waste discharge lines in addition to the necessary access roads.

Other Environmental Impacts:

Redevelopment of existing power plant sites will have the least impact on other environmental resources. New "green field" power

plant sites have other potential significant impacts on environmental resources.

Impacts to cultural and paleontological resources may result either directly or indirectly from the construction and operation of a new power plant. Indirect impacts to resources can occur due to inadvertent damage or outright vandalism due to improved access to the project area.

Construction and operation of a new power plant and related facilities, like electric transmission lines, can adversely affect the scenic resources of the viewshed surrounding a facility by introducing man-made features into a generally natural setting or by creating discordant visual contrasts with existing man-made features.

Construction and operation of a new power plant and related facilities can have adverse affects on the transportation system serving the project area due to increases in car and truck traffic during construction and operation.

D. Air Quality Benefits in the Transportation Sector

As discussed in Section III, the electric car is 18 percent more efficient than a CNG-fueled when the electricity generated for use in the electric car is obtained from an electric generating facility that has an efficiency of 33 percent. If the efficiency of the power plant is increased to 43 percent (by using advanced combustion technologies, for example), the electric car is about 50 percent more efficient than the CNG-fueled car.

In addition to fuel costs savings, air quality would also benefit from electric car use. Consider a comparison between the NO_x emissions for a CNG-fueled car and for an electric car.

Today's automobile, meeting the new California Air Resources Board (CARB) emissions standard, is allowed to emit NO_x at a rate up to 0.4 grams NO_x/mile. This is equivalent to the rate of 0.000881 lbs NO_x/mile.

An electric car consumes energy at a rate of 0.7 kWhr/mile.[25] If the electric car was charged overnight by the energy produced from a utility advanced combustion turbine power plant (e.g. an intercooled steam-injected gas turbine) its emissions rate would be considerably less.

The ISTIG power plant, capable of meeting the stringent emissions controls promulgated by the South Coast Air Quality Management District, would have a design heat rate of 7,150 Btu/kWhr. The resultant power plant emission rate would be 0.03 lbs/MMBtu times the heat rate of 7150 Btu/kWhr equal to 0.0002145 lbs/kWhr (or .2145 lbs/MWhr).[26]

The electric car NO_x emissions rate can be calculated by multiplying the ISTIG power plant emissions rate times the energy consumption rate of an electric car, which results in an electric car emissions rate of 0.0001502 lbs NO_x/mile. This emissions rate is 5.9 times less than the current CARB emissions standard.

It is expected that reactive organic gases (ROG) and carbon monoxide (CO) emissions would be reduced by even larger amounts. This is because automobile emissions controls for ROG and CO are not as effective as those on utility power plants.

VIII. SUGGESTED ACTIONS TO SPEED THE INTRODUCTION OF MORE EFFICIENT, CLEANER-BURNING ELECTRIC GENERATION TECHNOLOGIES IN CALIFORNIA

There are several reasons why it is important to begin implementing more efficient and cleaner-burning technologies in California's electric generation system. These include:

- California utilities' dependency on natural gas for electric generation;
- Non-compliance with national and California clean air standards;
- Recent and imminent technology developments promising dramatic improvements in electrical energy generating efficiency;
- A large proportion of California's existing power plants will soon reach the end of their nominal design life, providing an opportunity to extend their life or replace them; and
- Vulnerability due to the uncertainty of future energy price volatility.

A. Prospective Actions for Consideration

In order to realize the significant benefits of increased energy conversion efficiency, cleaner air, and reduced energy costs from improvements and upgrades of existing utility electric generating units, there are a variety of actions that can be undertaken. The options or actions discussed below encompass a wide range of possible alternatives. The Energy Commission could decide to pursue various combinations to ensure success.

Energy Planning. The Commission, in carrying out its electric/energy systems planning mandate under the Warren/Alquist Act, should endeavor to create more balance between resource planning and the conservation of existing resources. The need for energy system performance upgrades (redevelopment opportunities) should be balanced with the integrated assessment of need for additional future generating capacity to meet the increasing energy demands of the expanding California economy.

The Integrated Assessment of Need for the Electricity Report should address the need for higher efficiency energy production. Explicit mixed (or paired) strategies should be identified (e.g. ER 7 Environmentally Responsive Case) to reveal the synergistic effects of generation efficiency improvements/upgrades and demand side management (DSM) programs targeted at peak shaving and daily load shifting. The resultant flattening of the utilities' daily load profile will improve the economics of power plant replacement with advanced, high efficiency, low emissions combustion technologies, as the duty cycle of candidate generating units will improve in the direction of higher energy production and capacity factors.

The Electricity Report system planning efforts should also analyze whether the lower marginal electric generation costs of generating

unit replacements have the potential to establish a lower decremental cost basis for the pricing of North West energy purchases, thereby further reducing overall energy production costs.

In determining the integrated assessment of need, the replacement of existing utility generating units should be considered a "nondeferrable" resource. This would effectively exempt utility replacements from the CPUC bid process.

To further the realization of efficiency objectives, the Energy Commission should establish electric utility system efficiency goals, for example: an annual oil and gas system heat rate reduction target of 1 percent/yr (similar in concept to the recent SCAQMD boiler rule change requiring annual reductions in NO_x emissions).

The CPUC should revise its Iterative Cost-Effective Methodology (ICEM) to replace the first-year cost decision criteria with life-cycle societal benefit/cost criteria for choosing among resource alternatives. The first-year test discriminates against the highly efficient, low emissions, but more capital intensive resource, thus denying ratepayers the life-cycle benefits of a cleaner environment and reduced cost of service.

Environmental Protection. It is imperative that the link between energy development, production, distribution, conversion and utilization, and the environment be recognized. Environmental impacts result at each stage of the energy efficiency logistics path. The Energy Commission needs to document both the efficiency and environmental cumulative impacts occurring at each stage of the energy logistics flow paths identified in Section III.

Accounting for environmental costs is important to resource development and conservation in electricity planning for three key reasons: 1) if external costs are not included in the cost estimates for resources, then the full impact on society to build a resource has not been fully considered, 2) including environmental costs could significantly alter the order in which resources are developed to achieve a least-cost energy future, and 3) key resources, such as gas-fired combined cycle or coal plants (the resource choice at the margin), often significantly determine how much conservation will be cost-effective.

Most environmental costs are extraordinarily difficult to quantify. The valuation of emission reduction credits is a necessary first step in placing a value on environmental costs, but the ultimate valuation should take place in the marketplace.[27] Suggested valuation options:

- Update descriptive information on environmental impacts.

- Create spreadsheet comparisons of environmental impacts and resource options:
  - Note primary effect, significant consequence and means to mitigate,
  - Evaluate cumulative environmental impacts for entire energy logistics path.
- Evaluate costs among alternative resource choices:
  - Identify order-of-magnitude present value costs,
  - Conduct sensitivity tests.
- Subjectively assess the relative merits of:
  - Credit for conservation, and
  - Penalty for resource emissions.
- Rank resource options by environmental impacts.
- Discourage exportation of California air pollution to other locales in the Western Systems Coordinating Council (WSCC) region:
  - Determine the relative impacts of different combustion technologies on the greenhouse effect and global warming,
  - Account for external costs of increased carbon dioxide emissions,
  - Quantify external costs of other greenhouse-gas emissions by out-of-state resources.
- Integrate and balance all related state agency environmental policies as they affect energy supply and conservation. Collaborate with air quality management districts to address uncertainty regarding air permit status of existing plants when implementing refurbishment, repowering, and replacement strategies.
- Review Commission siting cases for other environmental controls imposed on a case-by-case basis during the licensing process. Examples: socioeconomic impact mitigation such as reimbursing local jurisdictions for "boom-town" effects would be added to generating plant capital cost estimates.
- Measure, evaluate, and as appropriate, regulate air emissions on a lb/MWhr basis rather than a lb/MMBtu basis. Dealing with polluting emissions as a function of end gain (i.e. electrical energy produced) rather than as a function of an intermediate

step (i.e. fuel burned) allows for more realistic cost-benefit analysis in the valuing of emissions control alternatives.

- Develop emissions reduction supply curves to ensure that least cost measures are implemented first.

- Supply curves must necessarily be based on a well developed data base, such as the California Energy and Pollution Data Base proposed by Lawrence Berkeley Lab.[28] This data base should address the cumulative emissions of each energy logistics path to the point of end use, being careful not to double account for individual point source emissions along the way.

Facilities Siting. Possible actions include:

- Reexamine and amend Commission siting regulations to encourage siting of clean, high efficiency resources and make allowance for expedited review. Revise power plant siting regulations regarding the refurbishment, repowering and replacement of existing generating units.

- Remove the 50 MW threshold from the Commission siting regulations Modifications clause. Concurrently, establish a simpler, faster licensing procedure for refurbishment, repowering and replacement of existing generating units, not to exceed nine months.

- Establish "demonstration status" for utility replacement strategies incorporating preferred high efficiency, low emissions advanced combustion technologies. This would effectively exempt utility replacements from the Energy Commission's Need determination.

Market Forces. Detailed discussions of market forces can be found in Chapter 6 and Appendix C.

Performance Standards. Possible actions include:

- Redefine the statutory definition of cogeneration to require higher efficiency levels to achieve California QF status.

- Create an electric generation efficiency standard to establish a minimum efficiency performance level.

Technology Development. The Energy Commission should demonstrate the R-CRGT or IR-CRGT advanced gas turbine. The Commission should follow the lead of the U.S. computer industry and create an Advanced Gas Turbine Development Consortium to advance the interests of U.S. turbine vendors, California and U.S. utility and independent power producers, air quality management districts, and public utility commissions to join in the development and demonstration

of the IR-CRGT power cycle configuration. The potential customer participants would represent sufficient "Launch Orders" to make the IR-CRGT a commercial reality.

Further IR-CRGT market penetration in California would also result if, on an interim basis, the government could create a market. This could be done by buying up the emission reductions credits for CRGT replacements, and selling them for a future profit once the market values exceeded the cost of the first CRGT credits.

IX. SUMMARY

Advanced combustion technologies can play a key role in addressing issues associated with the use of non-renewable fossil fuels, the continuing degradation of air quality, and the decisions that need to be made regarding California's aging power plants. Advanced technologies such as the STIG are commercially available today. Other advanced gas turbines such as the ISTIG are undergoing active design and engineering. The equipment options necessary to exploit the promising CRGT technology already exist and are in separate use; the remaining challenge is to combine these options to demonstrate that the actual performance of the CRGT meets the theoretical expectations. The Commission is encouraged by these emerging technologies, and will continue to investigate ways to incorporate these promising technologies into California's electric power generation system.

ENDNOTES

1. Energy conversion efficiency is defined as the ratio of electrical energy output to the supplied energy input, expressed in percent. The supplied energy input is calculated based on the fuel's lower heating value (LHV), or net heating value. The LHV excludes the energy content of the heat of vaporization of water to steam, whereas the higher heating value (HHV) includes it. All efficiencies in this appendix are based on lower heating values, except for Figure B-11.

2. Recent additions of Qualifying Facility (QF) cogeneration have been excluded. Southern California Edison (SCE) heat rate improvement programs, underway since 1979, have realized an approximate three percent reduction in the heat rate of their oil and gas steam units. Further improvements at SCE and other investor-owned utilities have been prevented to some extent by must-run QFs, which displace utility energy production.

3. Conservation Report, California Energy Commission, 1988.

4. Fuels Report, California Energy Commission, December, 1987.

5. Electricity Report Six, California Energy Commission, January, 1987.

6. Electricity Report Seven, California Energy Commission, June 1989, Section 8.5.2.

7. Heat Pump and Furnace Comparison Study, authors: Berkeley Solar Group and Charles Eley Associates, sponsors: California Energy Commission, Pacific Gas and Electric, Southern California Edison, Southern California Gas, Air Conditioning and Refrigeration Institute, Gas Appliance Manufacturers Association, and Sacramento Municipal Utility District, March 25, 1988.

8. The coefficient of performance for a heat pump with mid-range performance capability is 2.35. This means that for every unit of energy delivered to the customer meter, 2.35 units of energy are delivered to the conditioned space.

9. An engine efficiency of 30 percent can be realized only under full-load driving conditions. Part-load efficiency may be reduced by as much as half.

10. Energy and the Environment, John M. Fowler, Ph.D., 1984, and CEC Transportation Technology Fuels Office.

11. Electricity Report Seven, California Energy Commission, Basic System, p 4-37, June, 1989.

12. CPUC-approved Standard Offer contract terms provide incentives which maximize energy production from cogeneration facilities. Very few contracts limit QF power production or subject the control over energy production to utility dispatch requirements.

13. A. Rodney Gottschalk, Associate Mechanical Engineer, Engineering Office, Energy Facility Siting and Environmental Protection Division, 1986.

14. Each heat rate is determined by calculating the "fuel chargeable to electric power generation", which is the proportion of the total fuel input to a cogeneration facility that is directly attributed to electric power generation.

15. (26.3% * 5410 Btu/kWhr for cogen.) + (73.7%*10,500 Btu/kWhr for utility) = 9,161 Btu/kWhr.

16. Selective Catalytic Reduction (SCR) is a post-combustion, NO_x emissions control, considered by the South Coast Air Quality District and other California air districts as the Best Available Control Technology.

17. Gas Turbine World Performance Specs, June 1989.

18. Jack Janes, P.E., "Chemically Recuperated Gas Turbines", California Energy Commission, Development Division, Research and Development Office, October, 1989. (DRAFT)

19. For example, the General Electric Company's most recent offering, the Frame 7F.

20. Data points 1 through 5 obtained from Common Forecasting Methodology Form R10-C for Electricity Report '90. Data points 6 through 8 obtained from "Technology Characterizations" for Electricity Report '90, Staff Issue Paper #7R, October 11, 1989.

21. Recent utility filings in the Electricity Report '90 and CPUC biennial update proceedings.

22. Electricity Report Seven, California Energy Commission, June 1989, p. 2-14.

23. "Retirement Options (Plant Life Management) for Existing Utility Power Plants", Testimony for ER 7 Retirements Hearing on November 18, 1988 (paper dated November 4, 1988).

24. This section was prepared by Roger E. Johnson, Senior Socioeconomics/Land Use, California Energy Commission, July, 1989.

25. Personal discussion with Mike Gardner of Southern California Edison company, July, 1989.

26. The value of 0.03 lbs NO_x/MMBtu corresponds to 9 ppm at 15 percent oxygen, which is the current BACT level. While it is not known at this time whether the ISTIG will be able to achieve this level without relying on SCR, this level can certainly be attained with SCR if necessary.

27. Current CEC Staff evaluation of NO_x emissions is reported in ER-90 Staff Issue Paper #3, entitled "Valuing Emission Reductions for Electricity Report 90", November 8, 1989 (Draft).

28. H. Akbari, B. Andersson, R. Mowris, and A.H. Rosenfeld, Testimony before the California Legislature Joint Committee on Energy Regulation and the Environment on Energy Efficiency and the Environment, 2 June, 1989.

APPENDIX C

ECONOMIC INCENTIVES AS ENVIRONMENTAL POLICY TOOLS

APPENDIX C

ECONOMIC INCENTIVES AS ENVIRONMENTAL POLICY TOOLS

I. INTRODUCTION

Chapter 6 of the 1989 Fuels Report discusses several incentive-based environmental policies and briefly reviews their advantages relative to mandates as environmental policy tools. This appendix provides a more detailed assessment of economic incentives for environmental policy-making. The appendix discusses the following topics:

1. quantity-based versus price-based incentive mechanisms
2. cost-effective pollution control
3. empirical evidence on cost-effectiveness
4. potential criticisms of incentive-based approaches.

Three broad conclusions emerge from this appendix. First, there are important technical and institutional differences in quantity-based and price-based incentives that policy-makers should consider in choosing and designing policy instruments. Second, there is a strong theoretical case suggesting that cost-effectiveness is a property of well-designed incentives but not of command and control policies. This theoretical case is supported by a large body of empirical evidence showing that substantial reductions in pollution control costs can result from implementation of incentive-based policies. Third, the potential criticisms of economic incentives appear much less important upon closer examination.

II. QUANTITY-BASED VERSUS PRICE-BASED INCENTIVE MECHANISMS

Two broad classes of incentive-based mechanisms are available to policy-makers. Quantity-based incentives regulate the amount of emissions (or the ambient environmental quality resulting from emissions) from all sources and allow sources to trade emission reduction credits. Price-based strategies set a fee for uncontrolled emissions. As noted in Chapter 6, each incentive mechanism will cause cost-minimizing sources to select an abatement level for which marginal abatement costs are equal to the credit price or emissions fee. In spite of this similarity, regulators should be aware of important differences between the two types of incentive policies.

A. Technical Considerations

Since a quantity-based strategy regulates the number of credits available to all sources, changes in economic conditions will not affect the aggregate amount of emissions but will increase or

decrease credit prices. Under the same circumstances, a price-based incentive mechanism will increase or decrease the aggregate amount of emissions. Two examples will illustrate this point. In a growing urban area, the entry of new sources of air pollution (either stationary sources or mobile sources) will increase the demand for credits, and if the supply of credits is fixed, the price of credits will rise to accommodate the growth in the number of sources. Since the number of credits is fixed, total emissions and ambient environmental quality will be the same. With a fee-based incentive, when new sources enter the region, they add abatement equipment to control emissions up to the point where marginal abatement costs equal the fee. However, the remaining uncontrolled emissions from new sources increases total emissions and degrades ambient environmental quality. Another example leads to a different result. An improvement in abatement technology that reduces abatement costs will reduce credit prices since the new technology reduces the demand for credits. However, the new technology has no effect on total emissions or ambient environmental quality. A fee-based incentive will cause individual sources to increase abatement because of the decrease in abatement costs. In this case, the new technology reduces total emissions and improves environmental quality.

These examples suggest two important points. First, for different changes in economic conditions, one incentive mechanism automatically adjusts to new conditions but the other type of incentive requires conscious action by regulators for the same effect on total emissions and the price of discharges to the environment.[1] Thus, in the first example, if regulators increase fees by an amount equal to the rise in the price of a credit, the two incentive mechanisms result in an identical level of total emissions and an identical price for uncontrolled discharges after the entry of new sources. Similarly, in the second example, a decrease in the number of credits available can result in an identical improvement in ambient environmental quality from the new technology as under a price-based incentive. However, one policy does not dominate the other for all conceivable alterations in the initial regulatory conditions.

Second, regulatory lag may be an important consideration in selecting a quantity-based or price-based incentive mechanism. Regulators may be slow in recognizing new circumstances or in taking action. For example, lengthy regulatory proceedings may be necessary to change the quantity of credits or change fees. If regulators expect rapid technological change, they may prefer a price-based incentive policy. However, if regulatory lag is short, the two types of policies may look equally attractive.

The number of sources of pollution and their size may be an important consideration. Tietenberg (1989) argues that quantity-based strategies, since they rely on trading of credits, may be inappropriate for environmental problems involving a large number

of relatively small sources, or where differences in abatement costs for sources are modest in relation to the transactions costs of a trade. If sources are relatively small, they will need to purchase, or can provide for sale, a small quantity of credits. The costs of locating a willing trading partner, negotiating a price, setting up a contract, and satisfying regulatory requirements for trading, are more likely to exceed the gains from trading, or will constitute a larger proportion of the gains from trading credits, when numerous small sources are being regulated. Relatively large transactions costs will reduce the number of trades and will thus reduce the efficiency of a quantity-based strategy relative to a comparable price-based policy. The transactions costs of a price-based strategy will be relatively lower because the fee, and fee collection, is centrally administered.[2]

A final technical consideration involves uncertainty about marginal abatement costs and marginal benefits of environmental improvements. Once uncertainty about costs and benefits is acknowledged, the choice of a quantity-based or price-based instrument depends on the percentage change in abatement for a given percentage change in abatement costs.[3] This consideration is treated more thoroughly in a later section of the appendix.

B. Institutional Considerations

Since quantity-based strategies control emissions directly, assuming adequate monitoring of credit holders, emissions cannot be higher than allowed by the total number of credits permitted by regulators. Regulators may miss some opportunities to increase environmental protection but will avoid unexpected degradation of the environment. Price-based strategies control emission levels indirectly--the response of sources to a given fee is determined by marginal abatement costs. For a given emissions reduction target, regulators may set an emissions fee that is too high or too low, which respectively leads to more abatement than desired or too little abatement. Regulators can, of course, adjust the emissions fee once the response of polluters is known. The indirect nature of price-based policies means that regulators cannot be certain that the emissions reduction target will be met. Since the primary mission of environmental regulators is environmental protection, if regulators are risk-averse, the certainty of credits in terms of an emissions reduction target will make quantity-based policies more attractive than price-based incentives. If price-based policies are dictated by other technical or institutional considerations, risk-averse regulators are likely to select an emissions fee that errs on the side of too much abatement. This practice would increase the social costs of pollution control, suggesting that a quantity-based strategy would be the preferred policy instrument from society's viewpoint as well.

Regulators and legislators may prefer quantity-based incentives for several other reasons. In comparison to a price-based policy, a quantity-based policy would require a modest revision of the existing permitting system that is used for most air and water pollutants. Since quantity-based policies create a link between command and control policies and incentives, regulators may prefer such strategies. Politically, price-based incentives may be untenable policy instruments because of their tax-like appearance. Incentive-based policies have been rejected by some regulators, legislators and environmental groups as sanctioning "unethical" or "immoral" behavior, for example, trading in rights to pollute when the right to a clean environment is viewed as belonging to the public.[4] Quantity-based incentive policies may be more acceptable than price-based policies since polluters can earn credits for "good behavior", that is, abatement levels greater than legally required. Finally, polluters are likely to find quantity-based incentive policies more acceptable than price-based incentive policies because of the potential to earn credits that can be sold to offset abatement costs.[5]

III. COST-EFFECTIVE POLLUTION CONTROL

The economic criteria for cost-effective pollution control is not dependent on the selection of an incentives or mandates policy approach. This section of Appendix C therefore discusses the principle of cost-effectiveness, independent of the means used to achieve this goal. The discussion then shifts to the application of this principle to incentive-based policies and mandates, respectively.

A. The Principle of Cost-Effectiveness

Policy-makers are faced with meeting a regional emission reduction goal from abatement by several different sources of pollution. Obviously, many different abatement combinations from each polluter will meet the regional goal. However, there is a unique combination of individual source emission reductions that satisfy the regional target and that minimize regional abatement expenditures. Minimizing total abatement costs requires that each source's abatement level result in equal marginal abatement costs for all sources.[6] Sources with different marginal cost functions will therefore have different emission reduction levels.

The intuitive logic behind this principle is relatively easy to grasp. Consider an allocation of emission reductions that does not equalize marginal abatement costs. For example, suppose there are two sources, each of which has cut back pollution by 10 tons per day. For source one, the cost of the tenth ton of emission reduction is $1,000 and for source two, it is $2,000. If source one

controlled an additional ton of pollution, and source two controlled one ton less, the total emission reduction of both firms is still 20 tons. However, regional abatement costs would fall by $1,000 since source two would avoid abatement costs of $2,000 while source one would incur further abatement costs of $1,000. As long as the marginal costs of abatement are not equal among all sources, redistribution of emission reductions among sources can reduce total abatement expenditures while meeting the emission reduction target.

B. Cost-Effective Incentives

Quantity-based or price-based incentive policies can be cost-effective. For example, with emission reduction credits, an active market for credits will establish a uniform price at which credits are purchased and sold. Suppose that NO_x credits are priced at $500 per ton. Sources will compare their abatement costs with the credit price of $500 to determine if they should buy or sell credits. The incentive--a credit price or emissions fee--will motivate sources to examine emission reduction options such as end-of-process treatment or recycling (for example, stack gas scrubbers, waste-water treatment or recycling) or process changes (for example, different operating temperatures or pressures).[7]

Since all sources can buy or sell a credit, all sources will voluntarily select an abatement level at which marginal abatement costs are $500--precisely the condition required for cost-effectiveness. Other abatement levels imply that the source is not minimizing costs. For example, if the marginal abatement cost is $250, the source is holding a pollution credit that could be sold for $500 when the cost of pollution cleanup is $250. Regulators do not need to set each source's abatement levels to achieve a cost-effective set of source controls. The incentive policy puts polluters, who have the best information on abatement costs, in a position where utilizing this information effectively will help the polluter save money. At the same time, the resulting reduction in emissions reduces the amount of environmental damage borne by society. Thus, incentive-based policies can be cost-effective, reduce the information needed by regulators to control environmental damage, and encourage socially desirable behavior by polluters.

C. Cost-Effective Mandates

For mandates, regulators must prescribe an emission reduction or a specific emission control technology for all individual sources that meets the regional environmental quality goal and that equalizes marginal abatement costs. Regulators can achieve both goals when each source's marginal abatement cost function is known--that

is, regulators are as well-informed about the menu of abatement options and their costs, for each source, as plant managers and environmental control officers.[8 9] With this information, regulators can administratively assign abatement levels to each source that equalize marginal abatement costs.

It is doubtful that regulators can effectively satisfy this substantial information demand. Although regulators can attempt to induce sources to provide abatement cost information or may rely on estimated abatement cost functions, neither alternative is entirely satisfactory. Sources are unlikely to volunteer information on abatement costs since revealing low-cost emission reduction options may result in a larger emission reduction assignment.[10] Given the experience of many firms with environmental regulation in last 15 years, this concern is not unfounded. Estimated cost functions present a different set of problems since they are often (though not always) developed from engineering cost studies. When applied to relatively new abatement methods for which there is little commercial experience, costs are likely to be underestimated. Site-specific considerations can increase or decrease actual abatement costs relative to engineering cost estimates. One example is instructive. EPA's estimates of the capital costs for controlling air pollutants released from petroleum refineries were approximately $1.4 billion, whereas actual capital costs were roughly $600 million (Wall Street Journal (1980).

The problem of inadequate information is not static in nature--even if regulators currently have accurate information for a cost-effective mandate, changes in abatement technology, the availability of process changes (perhaps stimulated by changing input prices) and alterations in a firm's product mix, or a change in demand for a firm's products, will make this information rapidly outdated. Regulators cannot simply collect this information once, implement a cost-effective mandate and then rest on their laurels. Information on abatement costs must be revised periodically, along with adjustments in individual source abatement levels as indicated by new data.

It thus appears that cost-effective mandates are unlikely to be observed in practice since regulators may not have the required information. However, advocates of command and control policies are concerned with cost-effectiveness but approach this issue from a different angle. Recognizing that existing capital will eventually be replaced, regulators and legislators typically require more stringent emission limitations from new sources. If retrofitting existing sources is more expensive than incorporating emission control processes into new products and plants, this approach would be cost-effective. Progress towards environmental standards can be promoted by replacement of existing equipment with new equipment that reduces emissions. A moment's reflection reveals two flaws in this logic. First, this new source bias actually retards

environmental improvements because it extends the life of existing capital. Maloney and Brady's (1988) empirical analysis of utility power plants shows that in states where the new source bias is likely to be prominent (including California), the average age of utility power plants is four years older and that emissions are (on average) 27 percent higher. According to Gruenspecht's (1982) analysis of the stricter tailpipe emission standards enacted in 1981, if the new standards had not been required, emissions of HC and CO from the automobile fleet would have been lower in 1981-1984 by 1-2 percent each year.[11] Lower emissions occur because consumers replace their old cars with a new one more rapidly since new cars are less costly without the more stringent 1981 emission controls.

Second, an incentive-based policy accomplishes exactly what regulators intend since it increases the relative cost of existing capital that pollutes more compared to new capital that is less polluting. Sources will replace older equipment with newer equipment that pollutes less when the additional control cost of the newer equipment is less than the incentive payments from existing equipment's higher emissions.[12] Hence, regulators can control this aspect of the capital replacement decision through the number of emission credits allowed or the magnitude of an emission fee. If fewer emission credits are allowed, the price of a credit will be higher, resulting in a higher rate of capital turnover and an increase in the abatement capability of replacement capital that is put into service.

IV. EMPIRICAL EVIDENCE ON COST-EFFECTIVENESS

The observed response of firms to incentive-based policies demonstrates that pricing emissions does cause firms to reduce environmental wastes. This section discusses three different types of empirical evidence that suggest that incentive-based policies are cost-effective. The evidence from sewer surcharges and the Emissions Trading Program is based on experience with incentive policies that have been implemented. A third body of evidence is based on simulation studies of incentive-based policies.

A. Sewer Surcharges

Several municipalities in the U. S. and Canada use sewer surcharges. The surcharge is a payment for discharge of water-borne wastes exceeding a specified concentration. Statistical studies of sewer surcharges conducted by Ethridge (1972) and Sims (1979) demonstrate that the response to emission charges can be substantial. For example, Ethridge estimates that a 1 percent increase in the sewer surcharge decreases poultry processors' discharges by .5 percent (1/2 percent).

B. The Emissions Trading Program

EPA's Emissions Trading Program has been extensively analyzed by several scholars (Tietenberg (1985); Hahn (1989); Hahn and Hester (1989a); Dudek and Palmisano (1988); and Liroff (1980) and (1986)). The trading program allows stationary air pollution sources, under specific circumstances, to buy and sell emission reduction credits. A credit is created when a source permanently reduces its emissions below the amount assigned to it by the State Implementation Plan. Transactions are conducted under one of four concepts that define the program--bubbles, netting, offsets and banking. Trades can be internal--within a firm--or external--between firms. The bubble concept treats a site as a single discharge point and allows sources to control some discharge points within the bubble less heavily than legally required in exchange for more stringent controls at other points within the bubble, so long as bubble emissions are the same (or lower). Sources that are modifying or expanding their plant can net out of the new source review requirement by an emission reduction elsewhere in the plant that is equal to or larger than emissions from the plant expansion or modification. New sources locating in a nonattainment area must control emissions more stringently than existing sources and must purchase an amount of offsets from existing sources (either from its own plants in the region or other firms) that exceeds the remaining uncontrolled emissions.[13] Banking allows sources to "store" a credit for later internal use or external sale.

Although this program has not resulted in a market as envisioned by economists, it has provided considerable flexibility and cost-savings to polluters in meeting emission reduction targets specified by state or local regulators. Hahn's (1989, p. 100) estimates indicate that netting has resulted in cost-savings in the range of $500 million to $12 billion.[14] Federal and state-approved bubbles have resulted in cost-savings of $435 million. Estimates of the cost-savings from offsets are not available, though approximately 2,000 such transactions have taken place, suggesting cost-savings in the hundreds of millions of dollars. In addition, the netting program has saved sources $25 to $300 million in permitting costs.

C. Simulation Studies

Simulation studies of command and control policies versus incentive policies, such as emission fees or tradeable emission credits, suggests that incentives are cost-effective. Studies have been conducted for air pollutants such as NO_2, SO_2 (both within an airshed and for long-range transport), particulates, chloroflurcarbons (CFC's), and for water pollutants that affect biological oxygen demand and also for heavy metals as water pollutants. Tietenberg (1985, p. 42-43 and p. 46) compares the regional abatement cost of a command and control strategy with an incentive-based

policy for ten studies of air pollution control and three studies of water pollution control. For the air pollution control studies, the command and control strategy costs two to twenty-two times more than an incentive approach.[15] For the water pollution studies, the command and control strategies are one and one-quarter to three times more costly than incentive-based strategies. More recent studies by Atkinson and Tietenberg (1987) and Opaluch and Kashmanian (1985) also indicate that command and control approaches are more costly. Several studies of long-range transport of SO_2 emissions, including a national study by the Congressional Budget Office (1986), two studies of the state of Illinois (Raufer and Feldman (1987); Diemer and Eheart (1988) and a study pertaining to Cleveland (Atkinson (1983)), contribute additional evidence that command and control policies are more costly than incentive policies.

Taken as a whole, the data from the Emission Trading Program and the simulation studies is convincing evidence that incentive-based policies can be designed to substantially reduce emission control costs. Although this data is insufficient to provide an estimate of the national cost-savings if incentive-based policies formed the mainstay of U.S. environmental policy, Ackerman and Stewart (1988) suggest that if incentive-based policies only reduce control costs by one-third, the annual reduction in control costs would be over $15 billion.

V. POTENTIAL CRITICISMS OF ECONOMIC INCENTIVES

Incentive-based policies have been criticized on both technical and institutional grounds. This section discusses some of these potential criticisms of incentives, including:

1. market power
2. uncertainty
3. transactions costs
4. ethical issues.

As this discussion shows, these criticisms are much less damaging to the case for implementing incentive-based policies than a first impression might indicate.

A. Market Power

If the market for pollution has one or two large polluters, emission fees or tradeable credits may be inefficient in allocating emission control among sources since the price for disposing of pollution will not be a competitive price (Rose (1973); Hahn (1984)). For example, with a tradeable emission reduction credits policy, a large emitter with credits to sell may act like a

monopolist and too few credits would be sold, raising regional abatement costs. There have been three empirical studies of market power in environmental policy problems (de Lucia (1974); Hahn (1984); Maloney and Yandle (1984)). Collectively, this research suggests that the increase in abatement costs due to market power, compared to the cost-minimizing abatement levels, is relatively small. For example, Hahn's (1984) analysis of SO_2 emissions in Southern California indicates that at most, regional abatement costs would be approximately 15 percent higher if the largest polluter could exercise market power.

Though the results of these empirical studies are encouraging, they constitute a small sample of the potential applications of incentives. On the basis of this limited evidence, market power does not appear to be a large stumbling block to the implementation of incentive-based policies, however, market power may be important for applications of incentives which have not yet been proposed or studied.

B. Uncertainty

Uncertain benefits and costs are inherent in environmental policy-making but uncertainty need not paralyze policy-makers since several methods exist to account for uncertainty in making policy decisions. One interesting question that has been investigated is the choice between quantity-based and price-based incentive mechanisms (Weitzman (1984); Adar and Griffin (1976); Fishelson (1976); Watson and Ridker (1984)). Briefly, the conclusions of this research suggest a modest modification of the traditional benefit-cost criteria. If the range of estimates for pollution control costs and benefits can be treated in terms of probabilities, then policy-makers should select the level of emission reduction credits or emission fees to maximize expected net benefits.[16] The two types of policies may yield different levels of expected net benefits, depending on the likelihood of different estimates of marginal benefits and marginal costs and on the elasticity of the marginal benefit and marginal cost functions.[17] For example, given estimates of marginal abatement costs, emission fees would (on average) yield greater net benefits than tradeable credits if the marginal benefit function is relatively elastic (that is, a given percentage change in marginal benefit is accompanied by a relative large percentage change in emission reductions).

The empirical study of Watson and Ridker (1984) evaluates tradeable emission reduction credits and emission fees at the national level with a simulation model that maximizes expected net benefits of the two policy instruments. Two important conclusions emerge from this study. First, accounting for uncertainty by choosing tradeable credits or emission fees would reduce the social costs of meeting

environmental goals by no more than three percent. Second, the the results indicate that emission fees are the best policy instrument under a wide range of assumptions.

This study is highly aggregated in terms of industrial sectors and pollutants examined. These two conclusions may or may not be applicable for more specific problems in specific regions, for example, controlling NO_x in California's urban areas. However, uncertainty clearly does not imply regulatory paralysis with respect to the design and implementation of incentive-based environmental policies.

C. Transaction Costs

Any incentive-based policy must have relatively low implementation and administration costs, otherwise the efficiency gains available from incentive-based policies relative to command and control policies will be eroded by the costs of collecting emission fees or the costs that buyers and sellers of credits may incur in conducting a credit trade. The discussion below focuses on two issues with respect to transactions costs. First, regulators are likely to discover that incentive-based policies do not increase transactions costs, and could greatly reduce such costs, relative to mandates. Second, the regulatory climate can result in unnecessarily high transactions costs.

The transactions costs of incentive-based policies may be lower than those of mandates because incentives substantially reduce or eliminate the necessity for writing standards and negotiating compliance dates for individual sources or industries. Incentive-based policies let sources decide for themselves how much abatement is economically sensible, given a credit price or emission fee. In addition, sources are motivated to reduce emissions as quickly as possible but the speed with which adjustments to the incentive policy occur are determined by market processes rather than regulatory decree.[18]

Incentive policies will leave other regulatory tasks largely intact but will also require new functions that environmental regulators do not currently perform. For example, any incentive-based policy will still require that regulators determine the magnitude of the regional emission reductions, the effect of emission reductions on ambient environmental quality and the design of monitoring and compliance procedures. Incentives may improve regulatory performance with respect to these functions because regulators will no longer have to devote the largest proportion of their time and resources to regulating individual sources. For example, improved information on the transport and effects of pollutants (better air quality models and more knowledge about the health effects of NO_x, for example) could be socially valuable because it can help allocate

resources towards those pollutants that are most damaging and away from those which are less damaging. In addition, Ackerman and Stewart (1988) argue that incentive-based environmental policy will lead to a more focused and intelligent debate in Congress and by the public on the desired amount of environmental quality. In their view, incentive-based policies foster the democratic process of determining the level of environmental quality by opening the debate to the general public, instead of concentrating on arcane technical issues.[19] Finally, monitoring and compliance procedures are important under incentives or mandates because regulators cannot achieve the regional emissions reduction target if sources are discharging more than their credit holdings allow. However, if a portion of the regulatory budget originates from the incentive policy (for example, from credit brokerage fees, emission fee collection or compliance penalties), regulators are motivated to design an incentive policy that encourages participation in the market and that discourages noncompliance, otherwise, the regulatory budget will be reduced (Ackerman and Stewart (1988, p. 180-183)).

Regulators will face a new set of tasks. A tradeable emission reduction credits policy will require regulators to design regulations for the certification of credits, procedures for distributing permits (e.g., grandfathering or an auction), and the rules governing trading of credits. An emission fee policy will require that regulators estimate a regional marginal abatement cost function in order to select an emissions fee that will achieve the emission reduction target and will also require the design of regulations for collecting the fee from sources.[20]

Although these tasks are new and unfamiliar to environmental regulators, regulators may discover that eliminating the responsibility for determining each source's abatement level and technology in exchange for designing and regulating environmental markets is a favorable trade. Empirical evidence on the relative implementation costs of incentives versus command and control policies is skimpy. Seskin, et al. (1983) estimate administration, monitoring and enforcement costs for their study of NO_2 emission reductions in the Chicago urban area. They conclude that the implementation costs of an emission fee and a command and control strategy "...are of the same order of magnitude..." (1983, p. 121). Their data shows that this is a conservative conclusion since the implementation costs of the emission fee are less (by as much as 50 percent) than the command and control policy. The lower costs result primarily from a reduction in agency costs associated with negotiating (or litigating) compliance deadlines for sources.

The regulatory environment may itself contribute to relatively high transaction costs. For example, some critics have argued that quantity-based incentives will not work because sources will not trade credits. Though there is some basis for this criticism, it

is flawed in two respects. If there are too few sources for an active market to develop, regulators have the alternative of price-based incentives. Regulators should address this issue in choosing between quantity-based or price-based incentives. Another reason for lack of trading may be due to uncertainty about future regulatory actions or because the rules governing trading are cumbersome. Raufer and Feldman's (1987) interviews with midwestern utility personnel indicate that utilities may be reluctant to sell SO_2 reduction credits because of uncertainty with respect to regulatory revision of emission reduction goals. Raufer and Feldman argue that allowing leasing of emission reduction credits would facilitate trading since the lessor ultimately retains the rights to the credits created by excess emission reductions.

The Emissions Trading Program has several features that increase the transactions costs of external trades. The program includes restrictions on which sources can purchase emission reduction credits, regulations on trading ratios between sources, uncertainty regarding the creation and certification of an emission reduction credit and lengthy procedural requirements for conducting a trade. However, the large transactions costs of the Emissions Trading Program are not an inherent characteristic of incentive-based policies. Hahn and Hester's (1989b) comparison of four emission trading programs shows that differences in program performance is partially attributable to different regulations governing trading. One explanation for restrictive regulations is that regulators are unfamiliar and uncomfortable with emission reduction credits (and other incentive policies). In the long-run, regulators are likely to loosen existing controls on the credit market as they gain confidence in the new policies. Another explanation, offered by Hahn (1989), is that the restrictions present in the Emission Trading Program represent regulatory attempts to balance industry's demand for more flexibility with the demands of environmental groups for tough air pollution controls.

To summarize this discussion of transactions costs, it appears that the new tasks imposed on regulators by incentive-based policies are not likely to increase the transactions costs of environmental regulation. The available empirical evidence indicates that incentives could substantially <u>reduce</u> transactions costs. Regulatory restrictions can be one source of an inactive market in credits. However, the relatively high transaction costs observed in existing quantity-based policies, such as the Emissions Trading Program, are partially explainable by the preferences of regulators themselves.

D. Ethical Considerations

Some participants in the debate over environmental policy instruments have argued that they find incentives ethically untenable (see, for example, Kelman (1981)). Different views about the

ethical implications of different policy tools are an important and legitimate part of the environmental policy debate. The purpose of this section is to highlight two contributions from economic theory to this debate.

Some policy-makers have been critical of incentives because they believe that it is unethical to give polluters the right to pollute through tradeable credits or emission fees because the public has the right to a clean environment. This argument is technically incorrect--both types of incentives can be structured so that the public has the right to a clean environment but polluters pay for the privilege of using the environment for waste disposal (Griffin and Bromley (1982); Stevens and Vaux (1990)).[21] If the public does not wish to sell this right, polluters must clean up all of their emissions.[22] The present permitting system incorporated in the mandates approach <u>does</u> <u>not</u> give the public the right to a clean environment. Instead, polluters have a limited right (determined by their permit) to use the environment as a waste sink.

The concern about ethics stems partly from intergenerational equity issues. Bromley's (1989) research suggests that economic analysis can contribute more to the policy-making process when economists are more conscious of alternative entitlement arrangements than at present. In particular, Bromley argues that the assignment of environmental property rights to the present generation or to future generations can affect perceptions of the economically efficient action.

VI. CONCLUSIONS

Well-designed incentives offer policy-makers an alternative set of environmental policy tools that can substantially reduce the cost of pollution control. In addition, incentive policies can reduce the need for regulation of individual sources. Though much remains to be learned about specific applications of economic incentives, policies such as the Emissions Trading Program and sewer surcharges have provided useful information on the design and working with incentive programs. This information should prove useful to policy-makers implementing new applications of economic incentives for environmental regulation.

ENDNOTES

1. Other factors that could alter the regulatory equilibrium would include changes in demand for output produced by sources, changes in input prices, or new production processes.

2. It is implicitly assumed that the regulatory apparatus underlying a price-based incentive is efficient in its use of resources. A specific example of a situation with a large number of small sources would be automobile emissions. In this case, an annual emissions fee may be the best policy choice.

3. In technical terms, the selection of a quantity-based or price-based policy depends on the elasticity of abatement costs and marginal benefits.

4. A later section of the appendix suggests that both types of incentives allows regulators to assign the property right to the public, polluters or partially to both parties.

5. Our observation suggests that the initial reaction to such polices is positive because most polluters anticipate being sellers of credits, not buyers.

6. For simplicity, it is assumed that a unit of emissions from any individual source has the same effect on ambient environmental quality, regardless of location. In practice, this is not true for some types of air and water pollution, such as particulates or biological oxygen demanding water pollutants. Cost-effectiveness, in this case, is based on a similar decision-rule that also equalizes marginal costs across different sources.

   The timing of emission releases is another important factor for the cost-effectiveness of pollution control efforts. The Clean Air Act does not give regulators any opportunity to account for the timing of emissions, and our discussion therefore ignores this factor. Tietenberg (1985, p. 149-167 and p. 204-206) argues that reforming the Clean Air Act to allow for temporal variations in emissions control could provide further gains in air quality and reductions in control costs.

7. Mandates present sources with a completely different motivation. Any increase in pollution control raises abatement costs (but does not offer the potential to reduce, for example, permit costs). Thus, sources are better off attempting to reduce their own control requirements by seeking a variance, litigation, lengthy delays in compliance and debating the agency's choice of the control technology.

8. Note that this implies regulators are informed about the cost function, not merely one or two points on the function.

9. If all sources have the same marginal abatement cost function, information about one source is sufficient and all sources can be assigned the same emission reduction. However, empirical evidence indicates that sources have different marginal abatement cost functions. For example, sources in different industrial categories, such as refineries and nitric acid plants, have different abatement options for NO_x control. Several empirical studies (for example, Atkinson (1983); O'Neil, et al. (1983)) suggest that even in the same industry, differences in control costs may be substantial. South Coast Air Quality Management District staff estimates of the cost of three proposed rules in the 1989 Air Quality Management Plan are consistent with this finding (National Economic Research Associates (1988, p. 57)).

10. As regulators well recognize, the command and control policy approach gives industry motivation to overstate their abatement costs in order to avoid stringent emission limitations. Sonstelie and Portney (1983) offer several incentive-based mechanisms to induce truthful revelation of pollution control costs by sources.

11. However, NO_x emissions would have been higher.

12. Since capital typically has a life of more than one year, the comparison between marginal abatement cost and avoided incentive payments will be in terms of present discounted value. For the sake of simplicity, the text ignores this complication. Note that as in the other examples employed in Chapter 6 and this appendix, the capital replacement decision is determined by marginal abatement costs and the magnitude of the incentive (other factors the same). This leads to cost-effective capital replacement but also allows sources to determine if retrofitting is economically sensible, given an emission reduction credit price.

13. A nonattainment area has air quality worse than specified by the National Ambient Air Quality Standards.

14. Hahn notes that there is substantial uncertainty in this estimate because little data on netting transactions is available.

15. The two policy approaches are compared in relative terms rather than dollars because the estimates of potential cost-savings from the various studies are not directly comparable. The cost estimates differ because of factors such as differing base years, regions and pollutants, and stringency of the regional environmental goal. Nonetheless, some dollar estimates may put the relative costs in perspective. Seskin, Anderson and Reid (1983) estimate that the annual cost savings for NO_2 emissions control in Chicago from an emission fee policy is equal to $121 million. Krupnick (1986), using the same model and the same standard, applied instead to Baltimore, estimates annual cost savings from an emission fee policy is equal to $8.2 million.

16. Specifically, estimated costs and benefits would be described in terms of probability density functions. Some estimates of control costs (and benefits) are more likely than others and would thus be assigned a higher frequency of outcome.

17. As noted earlier, "elasticity" is a technical term used to characterize the percentage change in abatement for a given percentage change in abatement costs (or abatement benefits).

18. Other factors that influence the installation date of abatement devices or processes include interest rates, capital costs and construction costs.

19. In addition, incentive policies, relative to inefficient command and control strategies, yield a clearer picture of the true social costs of a given level of environmental quality.

20. As noted earlier, regulators may prefer quantity-based incentives because the emission fee may be too high or too low if the estimated regional abatement cost function is incorrect. The emission fee policy itself will improve estimates

of abatement costs, relative to command and control policies, because sources have a stronger incentive to truthfully reveal abatement costs instead of overstating abatement costs. In addition, regulators can adjust the fee based on observed emission reductions after implementing the fee.

21. The principal lesson of the Coase theorem (Coase (1960)) is that if the nuisance market is competitive and transaction costs are inconsequential, the assignment of the property right to polluters or to the public will have no effect on the efficient amount of emission control but will affect who pays for pollution control. As noted earlier in this section, one or both of these assumptions can be violated in practice, and the assignment of the property right to the environment can affect the efficient amount of emission control as well as who pays for it.

22. This outcome implies that the public places a value on the right to a clean environment which is greater than the cost of eliminating emissions. The concern over ethics may reflect different preferences for a clean environment. Some members of the public may value a clean environment less than others and would therefore willingly part with this right for less compensation from polluters than other members of the public.

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APPENDIX D

NATURAL GAS DEMAND FORECAST

APPENDIX D

NATURAL GAS DEMAND FORECAST

This appendix provides CEC staff assumptions and methodologies used to generate the sectorial demand forecasts. Part I presents aggregated forecasts by utility and nonutility service and compares the forecasts with the 1989 California Gas Report. Part II discusses residential, commercial, industrial and agricultural gas demand, assumptions and methodologies. In Part III the demand for gas in electricity generation is summarized and compared with previous CEC forecasts. Methodologies and assumptions concerning the Utility Electric Generation (UEG) supply plans are presented in Part IV.

Unless otherwise stated the natural gas demand forecasts represent total gas and oil requirements. These forecasts are for average year conditions, meaning average temperature, rainfall and UEG outages. Natural gas demand would be affected if the temperature or rainfall varies substantially from normal. Additionally, abnormal UEG plant outages or alternative electric energy source additions or deletions could also substantially alter natural gas demand forecasts.

I. NATURAL GAS DEMAND SUMMARY

This section summarizes the natural gas demand by utility and nonutility service areas. Utility natural gas demand is also compared with the 1989 California Gas Report.

Figure D-1 provides an overview of the aggregated forecasted natural gas and oil demand. Natural gas demand growth in the core market[1] is relatively flat and stable while the noncore market exhibits increasing gas demand. Oil use represents about 12 percent of the noncore demand. Noncore customers switch from gas to oil because of price, not because of a lack of gas supply. There are not sufficient cheaper natural gas resources available to California that can compete with the low oil prices as provided in the Delphi V oil price forecast (see Appendix F). In the SoCalGas service area it is assumed that air quality restrictions inhibit the use of oil. Total natural gas demand by sector (prior to any fuel switching) is presented on Figure D-2 and Table D-1. Figure D-2 displays historic and forecasted gas consumption by sector.

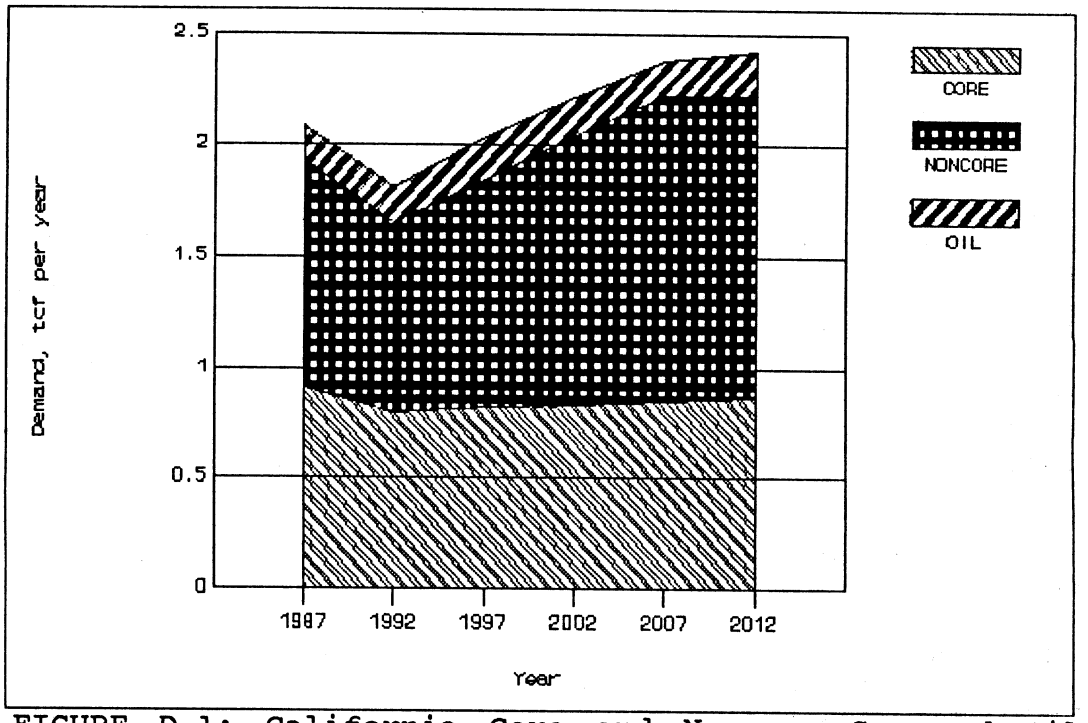


FIGURE D-1: California Core and Noncore Gas and Oil Demand

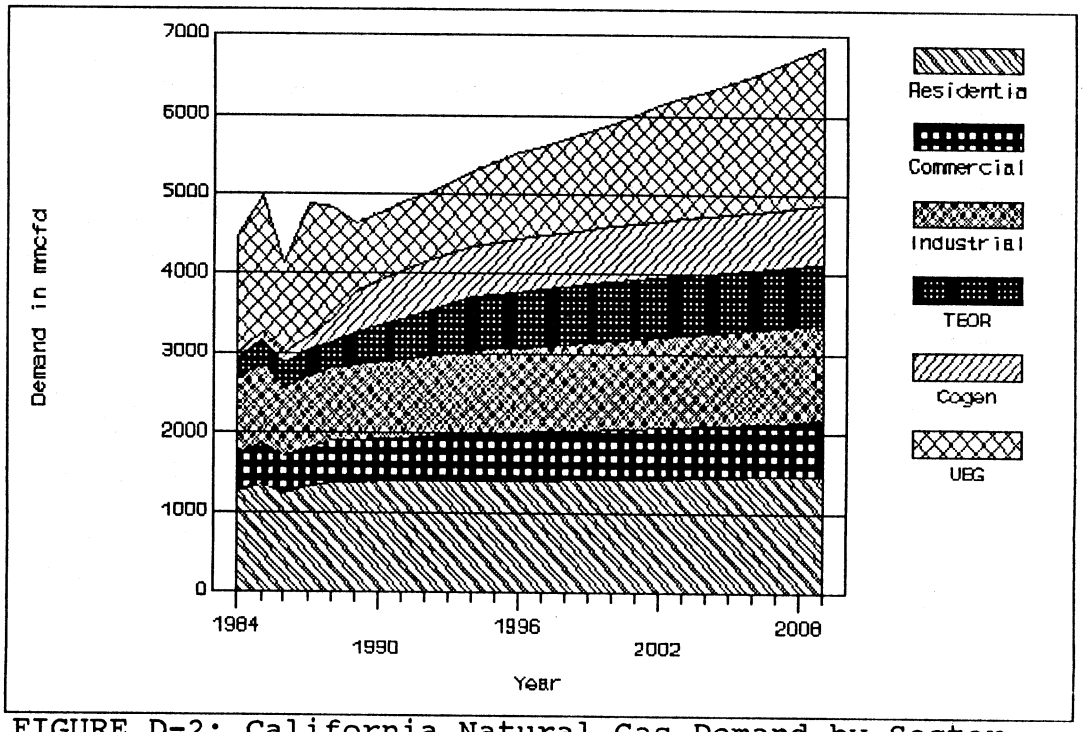


FIGURE D-2: California Natural Gas Demand by Sector

TABLE D-1

CALIFORNIA SUMMARY[1]
FORECASTED POTENTIAL NATURAL GAS DEMAND BY SECTOR
(mmcfd)

Year	Residential	Commercial	Industrial[2]	Cogeneration[3]	UEG [4]	Total
1987	1,332	483	1,435	170	1,663	5,083
1990	1,392	535	1,519	557	849	4,852
1995	1,408	588	1,715	651	1,021	5,383
2000	1,423	623	1,857	694	1,291	5,888
2009	1,489	674	1,964	734	1,972	6,833

[1]Includes utility and nonutility served gas requirements except for C.P. National and Southwest Gas Corporation service areas.

[2]Includes TEOR oil burn.

[3]Incremental fuel requirement.

[4]Includes conventional oil and gas fired utility boilers and gas turbines.

The principal growth in demand occurs in the electric generation, including cogeneration, and enhanced oil recovery (EOR) sectors. Gas demand in the industrial sector increases modestly. Residential and commercial sectors are either stable or experience small growths which have little impact on total demand.

A. Nonutility Natural Gas Demand

Nonutility gas demand represents that portion of natural gas service that is satisfied by nonutility supply sources. These consist of either direct sales of California gas production to end users or natural gas deliveries to EOR from new pipeline projects. It was assumed there would be no direct deliveries between the new pipeline projects and other classes of customers. Table D-2 provides an estimate of the nonutility demand for the various sectors.

TABLE D-2

NONUTILITY NATURAL GAS DEMAND
mmcfd

	1987	1990	1995	2000	2005	2009
PG&E Service Area						
Process	34	75	75	76	76	76
Assembly	10	10	10	10	10	10
Total	44	85	85	86	86	86
SCG Service Area						
Process	95	115	115	115	115	115
Assembly	2	4	4	4	4	4
Total	97	119	119	119	119	119
EOR Steaming						
California Production	123	173	187	144	97	68
Pipeline Supply	0	0	135	329	466	510
Total	123	173	322	473	563	578

California natural gas marketer reports filed with the Commission were used to determine the proportion of nonutility supply that would serve the commercial sector and assembly, process and mining (excluding EOR demand) industries.

B. Utility Natural Gas Demand

Natural gas demand satisfied by the utility service area includes natural gas sales and third party owned gas transported on the utility system.[2] To arrive at the utility served gas demand, the nonutility served portion of gas demand was subtracted from the total gas demand forecasted for the entire state. Table D-3 presents a summary of the utility natural gas demand forecast. The total statewide gas demand is presented at the end of this appendix (refer to Tables D-27 to D-29).

C. Comparison of Energy Commission and California Gas Report Natural Gas Demand Forecasts

Except for the initial and final years of the study period the 1989 California Gas Report total utility gas demand is consistently higher than the Commission forecast. Figures D-3 through D-8 provide a sectorial comparison of the two demand forecasts on a statewide basis for selected years.

In general the Gas Report demand forecast is consistently higher than the Commission forecast in the residential, EOR and cogeneration sectors for all years and the UEG sector in the early years. The Commission forecast is consistently higher than the Gas Report forecast in the commercial and industrial sectors for all years and the UEG sector in the later years.

For the most part the differences are small and can probably be attributed to definitional differences. For the commercial and industrial sectors, the Commission uses Standard Industrial Classification definitions while the utilities are more directed toward rate classifications. Fuel used for cogeneration may also be treated differently. The Commission determines all process heat requirements as if conventional fuel burning equipment is being used. Cogeneration natural gas use is the incremental additional gas burned if conventional fuel burning equipment is swapped for cogeneration equipment. Gas utilities may use a definition similar to the Commission's or include total cogeneration fuel use under cogeneration, or use a mixture of the two.

TABLE D-3

STATEWIDE NATURAL GAS UTILITY DEMAND SUMMARY
mmcfd

	Core			Noncore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	TOTAL
1987	1332	323	222	160	530	260	169	1666	4663
1990	1391	358	225	177	534	226	557	849	4317
1995	1409	393	253	195	603	183	651	1022	4709
2000	1423	417	270	206	643	144	694	1291	5087
2005	1454	436	287	215	685	103	718	1645	5543
2009	1489	451	301	223	717	79	734	1972	5966

Source: DAO Natural Gas Forecast for the 1989 Fuels Report, June 1, 1989.
Revised ER 8 UEG Forecaast, July 13, 1989.
NARG model run, November 6, 1989.

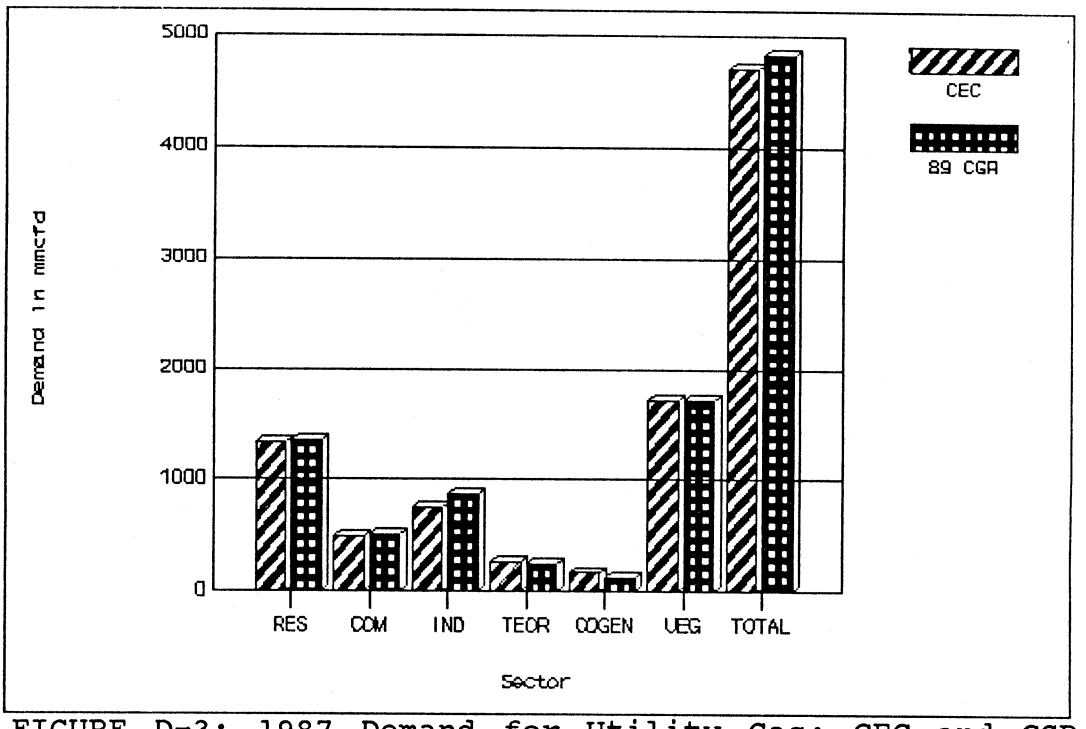


FIGURE D-3: 1987 Demand for Utility Gas; CEC and CGR Comparisons

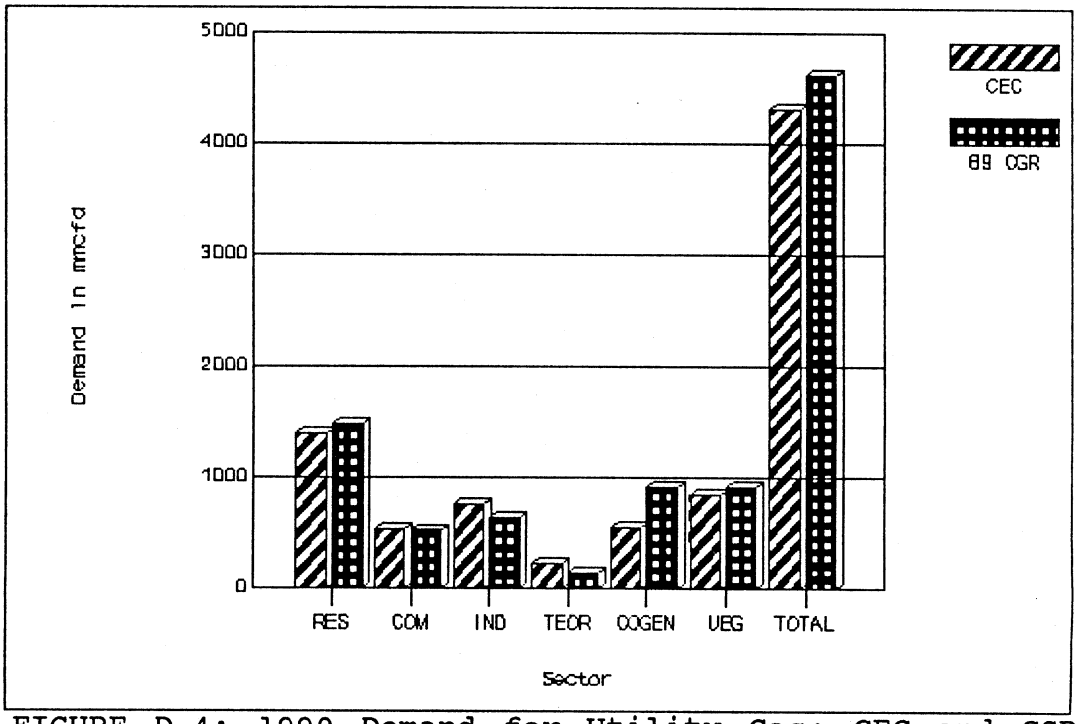


FIGURE D-4: 1990 Demand for Utility Gas; CEC and CGR Comparisons

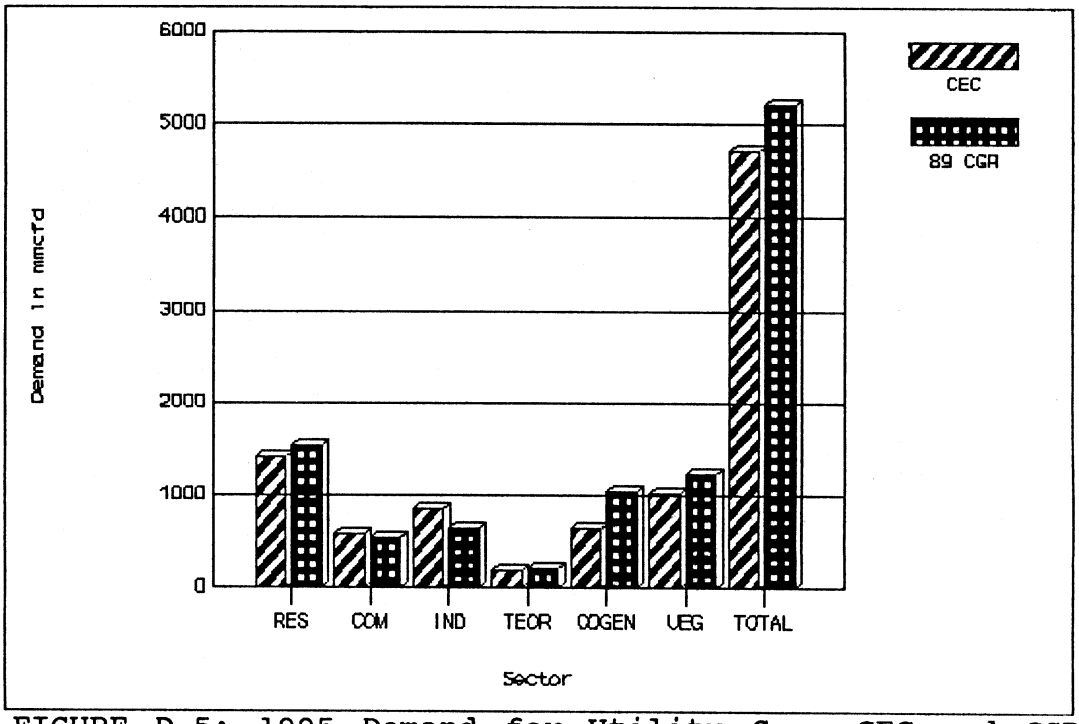


FIGURE D-5: 1995 Demand for Utility Gas; CEC and CGR Comparisons

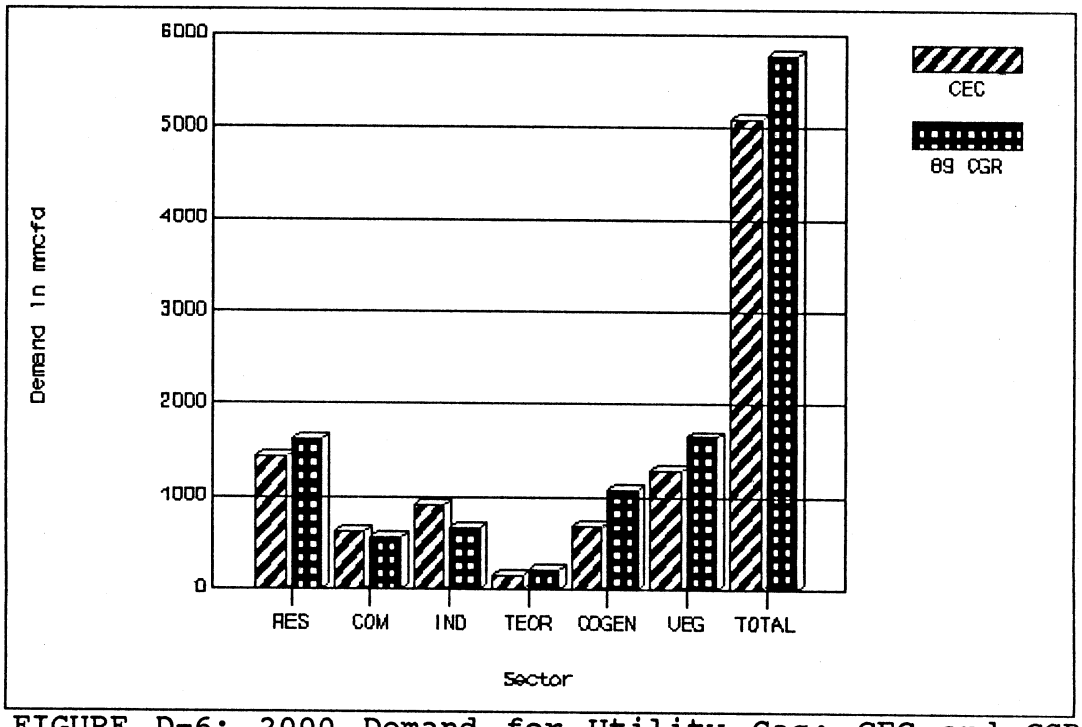


FIGURE D-6: 2000 Demand for Utility Gas; CEC and CGR Comparisons

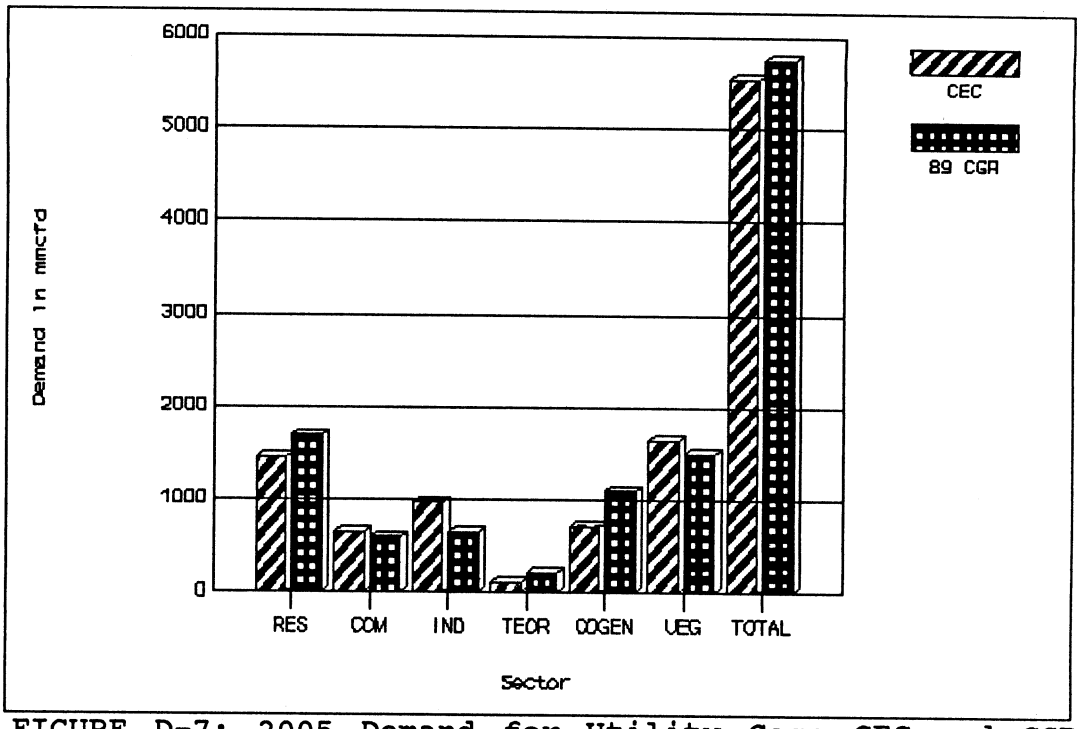


FIGURE D-7: 2005 Demand for Utility Gas; CEC and CGR Comparisons

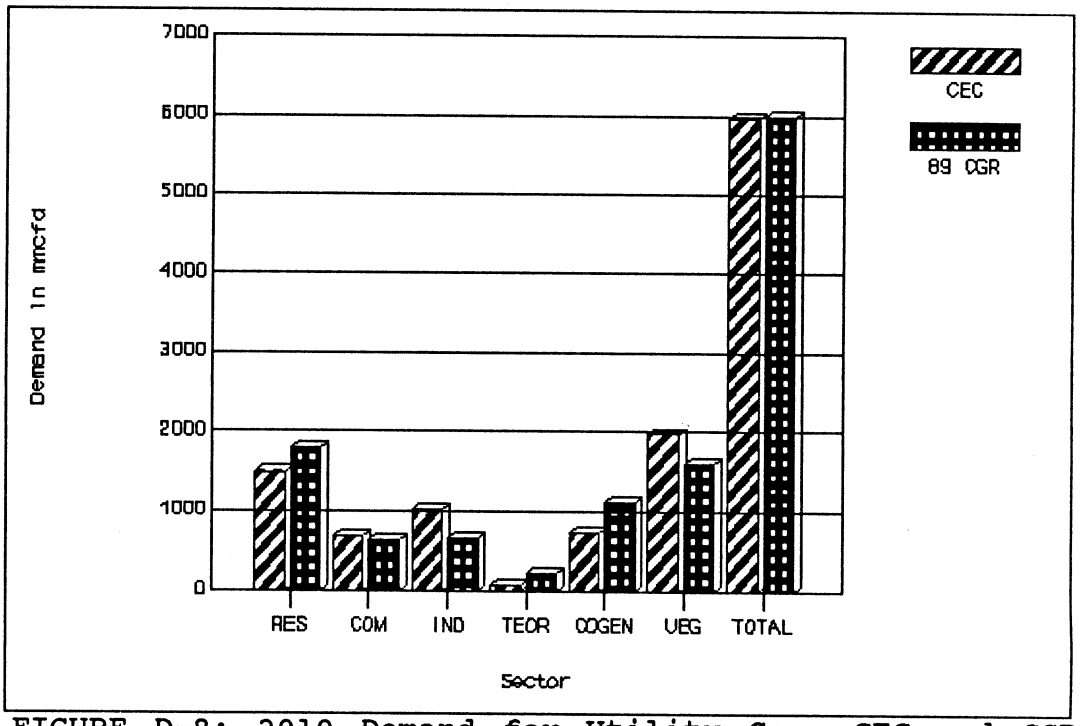


FIGURE D-8: 2010 Demand for Utility Gas; CEC and CGR Comparisons

II. RESIDENTIAL, INDUSTRIAL, COMMERCIAL AND AGRICULTURAL DEMAND FOR NATURAL GAS

A. Introduction

This section of the appendix presents the Commission forecast of natural gas consumption (utility sales plus gas from other sources) for end uses other than electrical generation. The demand for natural gas by utilities and cogenerators for electrical generation is provided separately in Part III of this appendix.

The Commission prepared the demand forecast for electricity and natural gas in the residential, commercial, industrial and agricultural sectors using models which simultaneously forecast demand for each energy type. The staff prepared the natural gas forecasts using the models and data used to develop the Common Forecasting Methodology (CFM) 8 electrical demand forecast.

The historical data base of consumption for the forecast relies on the deliveries reported by the gas utilities as well as deliveries and use reported by California gas producers (see Section C, Historic Gas Consumption). These data include gas used to support electrical generation in cogeneration. As the forecasts presented here address end use demand such as process heat and space conditioning for the various sectors excluding electrical generation, the historical data were appropriately reduced by estimates of incremental gas use in cogeneration (see Section D).

B. Forecast Results

Tables (D-17 through D-26) at the end of this appendix provide the results of the forecast for utility planning areas and statewide. The 1977 through 1987 values are historical data. The historical and forecast values reflect California gas utility deliveries and producer deliveries and use less incremental gas use in support of electrical generation in cogeneration. "TCU" includes consumption for transportation, communication, utilities, and some portion related to national defense. Commercial, TCU, process, and assembly values include a portion of consumption reported as unclassified by the utilities. For each forecast by geographical area the first table provides the forecast in energy units and the second table provides the forecast in volume units.

C. Historic Gas Consumption

The staff derived information on the consumption of natural gas in California for the years 1977 to 1987 from the Quarterly Fuels and

Energy Report (QFER).[3] This information was used to calibrate forecasts of consumption of natural gas by customer sector within California gas utility areas.

Gas customers obtain natural gas in one of four ways. Most of California's customers purchase gas from the nearest gas utility company. Another source of natural gas for some large industrial customers is direct purchase from a California gas marketer or producer delivered via nonutility pipelines. Recently, gas producers and marketers located outside California have been able to transport gas to customers through the pipeline systems of California gas utilities. Finally, some gas users other than gas marketers are fortunate enough to have their own gas fields. Through QFER reporting requirements, the Commission receives the volumes and disposition of these gas transactions.

D. Natural Gas End Use Consumption by Planning Area

Tables D-4, D-5 and D-6 show the historical consumption of natural gas by customer sectors for three gas planning areas in California: Pacific Gas and Electric (PGandE), Southern California Gas (SoCal Gas), and San Diego Gas and Electric (SDG&E). The consumption comprises utility sales, utility deliveries of customer owned gas, and direct deliveries by gas marketers or producers. Gas deliveries to electric utilities for electrical generation are discussed in Parts III and IV. Quarterly Fuel and Energy Report (QFER) submittals by the utilities and marketers/producers are the primary data sources.

Gas consumption by utility service area is allocated to each planning area as follows:

Gas Planning Areas		
PGandE	SoCal Gas	SDG&E
PGandE	SoCal Gas	SDG&E
Coalinga	Long Beach	
Palo Alto		

Gas sales by CP National and Southwest Gas are located in the "Other" planning area. The amount of gas sales in the "Other" planning area is small and details of the sales are not included in this section.

TABLE D-4

PGandE Planning Area
Historic Natural Gas End Use Consumption
(millions of therms)

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
RESIDENTIAL	2593	2293	2489	2298	2079	2226	2093	2036	2020	1958	2034
COMMERCIAL											
Buildings	875	737	760	719	673	712	681	667	719	633	660
Other	120	125	126	114	118	116	105	104	104	103	102
Total Commercial	994	861	886	833	791	828	786	772	823	736	762
INDUSTRIAL											
M&C[1] minus SIC13[2]	27	23	28	22	18	16	14	14	15	14	13
SIC13	1	1	1	1	1	15	16	33	188	62	93
PM[3] SIC13	215	210	222	225	207	182	132	175	49	18	50
Subtotal SIC13	216	211	223	226	208	198	148	208	237	80	143
Transport	0	0	0	0	0	0	0	0	0	130	130
Total M&C	243	234	250	249	226	214	162	221	252	224	286
Process	1271	1091	1488	1484	1297	1022	803	783	1024	623	313
PM Industry	38	35	31	42	102	147	140	96	6	4	6
PM Refinery	239	201	197	220	227	180	328	341	384	323	92
PM Other	17	27	39	21	22	26	4	4	36	32	34
Subtotal PM	293	262	268	283	350	352	472	441	426	359	132
Transport	0	0	0	0	0	0	0	0	0	138	855
Total Process	1564	1353	1756	1767	1647	1374	1275	1224	1450	1120	1300
Assembly	847	797	838	715	721	571	496	491	539	450	320
PM Chemical	5	7	2	2	2	13	23	42	62	28	38
Transport	0	0	0	0	0	0	0	0	0	0	249
Total Assembly	852	804	840	717	723	584	519	533	601	478	607
Total Industry	2659	2392	2845	2733	2597	2172	1956	1978	2303	1822	2193
AG & WATER PUMPING	80	77	94	76	65	58	51	49	55	48	54
PM Ag	1	1	1	1	0	0	0	0	0	8	4
Total Ag & WP	81	78	95	77	65	58	51	49	55	56	58
UNCLASSIFIED	98	60	50	19	21	117	92	159	90	134	122
PM Unclassified	0	0	0	0	0	0	0	0	0	0	0
Total Unclassified	98	60	50	19	21	117	92	159	90	134	122
Subtotal Sales	5911	5202	5873	5449	4993	4853	4351	4337	4755	4025	3711
Subtotal PM	515	481	492	511	560	548	627	658	537	413	224
Subtotal Transport	0	0	0	0	0	0	0	0	0	268	1234
Total Consumption	6426	5683	6364	5960	5553	5401	4978	4995	5292	4706	5169

1/ M&C is Mining, Extraction, and Construction
2/ SIC13 is Oil and Gas Extraction
3/ PM is Major Gas Producer and Marketer Deliveries

Sources: All data is utility sales data from the Quarterly Fuel and Energy Reports (QFER) Form 4, except: (1) "PM" which is major gas producer and utility delivery data from QFER Form 10A, and (2) "Transport" which is data provided by PGandE.

TABLE D-5

SoCal Gas Planning Area
Historic Natural Gas End Use Consumption
(millions of therms)

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
RESIDENTIAL	3078	3142	3322	3184	2784	3006	2747	2545	2870	2507	2740
COMMERCIAL											
Buildings	810	851	882	802	783	835	782	753	855	786	840
Other	81	89	89	90	91	97	84	81	85	81	85
Total Commercial	891	940	971	892	874	932	866	834	940	867	925
INDUSTRIAL											
M&C[1] minus SIC13[2]	33	31	28	25	20	13	8	8	9	9	9
SIC13	58	58	149	105	165	120	38	53	92	74	46
PM[3] SIC13	807	786	741	799	668	670	552	777	935	891	617
Subtotal SIC13	865	844	890	905	833	790	590	830	1027	965	663
Transport	0	0	0	0	0	0	0	0	0	158	546
Total M&C	898	875	918	929	853	803	598	838	1036	1132	1218
Process	617	512	596	669	614	511	508	426	379	404	236
PM Industry	53	50	44	59	142	206	145	159	144	12	33
PM Refinery	195	164	161	180	185	147	269	279	266	257	192
PM Other	24	37	55	30	31	36	60	41	86	227	139
Subtotal PM	272	251	260	269	359	388	474	479	496	496	364
Transport	0	0	0	0	0	0	0	0	0	10	283
Total Process	889	763	856	938	973	899	982	905	875	910	883
Assembly	1324	1259	1233	1171	1131	890	805	822	838	790	686
PM Chemical	5	7	2	2	2	7	8	9	19	24	9
Transport	0	0	0	0	0	0	0	0	0	1	83
Total Assembly	1329	1266	1235	1173	1133	897	813	831	857	815	778
Total Industry	3116	2904	3008	3040	2959	2600	2392	2574	2768	2857	2879
AG & WATER PUMPING	74	65	71	65	71	61	47	52	54	44	47
PM Ag	0	0	0	0	0	0	0	0	0	0	0
Total AG & WP	74	65	71	65	71	61	47	52	54	44	47
UNCLASSIFIED	102	153	0	0	0	4	7	8	25	7	7
PM Unclassified	0	0	0	0	0	0	0	0	0	0	0
Total Unclassified	102	153	0	0	0	4	7	8	25	7	7
Subtotal Sales	6177	6159	6369	6111	5660	5536	5026	4747	5207	4702	4696
Subtotal PM	1084	1044	1003	1070	1029	1066	1034	1265	1450	1411	990
Subtotal Transport	0	0	0	0	0	0	0	0	0	169	912
Total Consumption	7261	7203	7372	7181	6688	6602	6060	6013	6657	6282	6598

1/ M&C is Mining, Extraction, and Construction
2/ SIC13 is Oil and Gas Extraction
3/ PM is Major Gas Producer and Marketer Deliveries

Sources: All data is utility sales data from the Quarterly Fuel and Energy Reports (QFER) Form 4, except: (1) "PM" which is major gas producer and utility delivery data from QFER Form 10A, and (2) "Transport" which is data provided by SoCal Gas.

TABLE D-6

SDG&E Planning Area
Historic Natural Gas End Use Consumption
(millions of therms)

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
RESIDENTIAL	299	314	357	313	289	318	296	284	317	284	331
COMMERCIAL											
Buildings	96	87	97	87	82	71	88	81	144	130	129
Other	12	17	15	13	13	14	13	17	22	21	21
Total Commercial	109	103	112	100	95	85	101	98	166	151	150
INDUSTRIAL											
M&C[1] minus SIC13[2]	2	2	2	1	1	2	2	3	3	3	3
SIC13	0	0	0	0	0	0	0	0	0	0	0
PM[3] SIC13	0	0	0	0	0	0	0	0	0	0	0
Subtotal SIC13	0	0	0	0	0	0	0	0	0	0	0
Transport	0	0	0	0	0	0	0	0	0	0	0
Total M&C	2	2	2	1	1	2	2	3	3	3	3
Process	3	3	4	4	3	2	2	2	3	2	2
PM Industry	0	0	0	0	0	0	0	0	0	0	0
PM Refinery	0	0	0	0	0	0	0	0	0	0	0
PM Other	0	0	0	0	0	0	0	0	0	0	0
Subtotal PM	0	0	0	0	0	0	0	0	0	0	0
Transport	0	0	0	0	0	0	0	0	0	0	0
Total Process	3	3	4	4	3	2	2	2	3	2	2
Assembly	36	36	36	34	33	34	25	43	56	56	67
PM Chemical	0	0	0	0	0	0	0	0	0	0	0
Transport	0	0	0	0	0	0	0	0	0	0	0
Total Assembly	36	36	36	34	33	34	25	43	56	56	67
Total Industry	41	41	42	39	37	38	29	48	62	61	72
AG & WATER PUMPING	8	4	9	9	8	3	5	5	8	7	7
PM Ag	0	0	0	0	0	0	0	0	0	0	0
Total Ag & WP	8	4	9	9	8	3	5	5	8	7	7
UNCLASSIFIED	21	23	10	6	8	33	12	18	27	2	2
PM Unclassified	0	0	0	0	0	0	0	0	0	0	0
Total Unclassified	21	23	10	6	8	33	12	18	27	2	2
Subtotal Sales	478	484	530	467	437	477	443	452	580	505	562
Subtotal PM	0	0	0	0	0	0	0	0	0	0	0
Subtotal Transport	0	0	0	0	0	0	0	0	0	0	0
Total Consumption	478	484	530	467	437	477	443	452	580	505	562

1/ M&C is Mining, Extraction, and Construction
2/ SIC13 is Oil and Gas Extraction
3/ PM is Major Gas Producer and Marketer Deliveries

Sources: All data is utility sales data from the Quarterly Fuel and Energy Reports (QFER) Form 4, except: (1) "PM" which is major gas producer and utility delivery data from QFER Form 10A, and (2) "Transport" which is data provided by SDG&E.

E. Incremental Gas Use in Cogeneration

As the QFER historical demand data include gas used in cogeneration to generate electricity, staff adjusted the QFER data to develop values for the demand excluding electrical generation. These historical levels are then consistent with the staff models which forecast demand due to space conditioning, process use and other basic demands for each sector. Table D-7 presents staff estimates used to adjust the QFER data downward.

The values of Table D-7 are staff estimates of the incremental amount of gas used in cogeneration in support of electrical generation beyond the gas required for process heat or other end use based on generation capacity in staff's Likely To Be Available (LTBA) and Qualifying Facility databases. The estimates assume an incremental heat rate of 6,000 Btu/kWh. The historical data in Section B, Forecast Results, reflect demand excluding the gas levels of Table D-7.

III. DEMAND FOR GAS IN ELECTRICITY GENERATION

A. Introduction

Natural gas is an important and valuable fuel used to meet California's electricity needs. Of the 1,800 billion cubic feet (bcf) of California's 1987 natural gas consumption, electric generation accounted for approximately 35 percent.

This section describes the Commission forecast of electric generation natural gas requirements for the 1989 Fuels Report and compares it to the forecast provided in the 1987 Fuels Report.

Nearly all of California's present gas fired electric generation capability could readily be switched to fuel oil. Most new gas fired units also include dual-fuel capability. Therefore, while this report describes the fuel requirements for these units as gas demand, these fuel requirements could be satisfied partially or totally with oil.

B. Natural Gas Requirement

The electric generation natural gas demand forecast for the 1989 Fuels Report relies on staff's simulation of the electric utility system which was carried out using production cost runs based on ER 7 resource plans. The results of these simulations are presented for selected years in Tables D-8, D-9 and D-10 for PGandE, SoCal Gas and SDG&E natural gas service areas.

TABLE D-7

Estimated Incremental Gas Supporting
Electrical Generation in Cogeneration
(millions of therms per year)

Pacific Gas and Electric Service Area

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Commercial	0.0	0.0	1.2	1.2	1.2	2.6	2.8	4.4	5.4	8.4	12.8
TCU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Process	0.0	0.0	0.0	0.0	1.9	5.5	41.7	43.6	60.8	74.9	166.4
Assembly	0.8	30.3	36.6	36.6	36.6	37.3	37.3	67.3	67.5	70.8	70.8
Mining & Extraction	0.0	0.0	0.0	0.0	0.0	0.0	2.4	3.0	15.8	43.7	56.2
Total	0.8	30.3	37.7	37.7	39.6	45.4	84.2	118.3	149.4	197.9	306.3

Southern California Gas Service Area

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Commercial	0.4	0.4	0.4	1.4	1.4	1.4	6.7	10.6	12.1	13.1	14.1
TCU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Process	0.6	0.6	0.6	0.5	1.6	10.3	28.6	37.8	43.4	101.3	126.6
Assembly	2.0	2.1	2.4	2.4	2.4	3.4	18.3	24.1	24.1	24.1	24.1
Mining & Extraction	0.0	0.0	1.7	1.7	3.0	3.1	5.2	5.2	131.4	131.7	131.9
Total	3.0	3.1	5.1	6.1	8.4	18.2	58.8	77.7	211.0	270.2	296.7

San Diego Gas and Electric Service Area

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Commercial	0.0	0.0	0.0	0.0	0.5	0.5	3.5	7.7	15.8	18.7	22.9
TCU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.2	7.2	4.2	7.2
Process	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Assembly	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.2	10.8	13.0	16.8
Mining & Extraction	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.5	0.5	3.5	22.1	33.8	35.9	46.8

For each service area, the gas requirements have been subdivided into three distinct groupings: cogeneration, combustion turbines and utility boilers. A total gas requirement for each year is also provided.

For cogeneration, only incremental fuel requirements for electricity generation are reported. Cogeneration facilities consume more fuel than facilities designed to provide only the desired quantity of process heat. The difference in fuel requirements between these two facilities referred to is defined as the incremental fuel requirement.

Combustion turbines include baseload, intermediate, and peaking facilities, but not cogeneration. This category also includes highly efficient steam injection combustion turbines which are presumed to become available in the mid-to-late 1990s.

TABLE D-8

PG and E NATURAL GAS SERVICE AREA
POTENTIAL NATURAL GAS REQUIREMENTS FOR ELECTRIC GENERATION[1]
mmcfd

Year	Cogeneration[2]	Combustion Turbines	Boilers	Total
1987[3]	27	N/A	692	719
1990	224	0	286	510
1995	280	0	301	581
2000	336	49	305	690
2005	350	63	409	822
2009	357	149	483	989

[1]Source: CEC staff ELFIN production cost runs using ER 7 resource plans, July 13, 1989.
[2]Incremental fuel requirements for electricity generation.
[3]Historic data based on 1989 California Gas Report.

The natural gas requirements for electric generation presented in Tables D-8 through D-10 are staff's estimates of gas requirements within the discrete service areas. These requirements include self generation, third party generation for utility purchase, and utility generation. The respective gas utility may not provide all the gas service to meet these requirements. Both utility and nonutility gas as well as oil may be used to satisfy the fuel demand represented by this forecast.

PGandE

Overall potential natural gas requirements for electricity generation in PGandE's service area are forecasted to grow from 719 mmcfd in 1987 to 989 mmcfd in 2009. The use of PGandE's gas and oil fired boilers are forecasted to decline substantially in the near term with gradual growth in the long term, but growth does not lead demand to surpass current requirements.

Substantial near-term growth in cogeneration more than offsets the decline in use of utility boilers.

SoCal Gas

Potential electricity generation gas requirements in SoCal Gas' service area are forecasted to grow from 912 mmcfd in 1987 to 1,397 mmcfd in 2009. The use of electric utility boilers to meet the demand for electricity declines by about half in the future. Growth in cogeneration and a long term growth in the use of combustion turbines offsets the decline in gas demand in the utility boiler use.

TABLE D-9

SOCAL GAS NATURAL GAS SERVICE AREA
POTENTIAL NATURAL GAS REQUIREMENTS FOR ELECTRIC GENERATION[1]
mmcfd

Year	Cogeneration[2]	Combustion Turbines	Boilers	Total
1987[3]	23	N/A	889	912
1990	297	57	386	740
1995	333	145	413	850
2000	320	325	417	1,063
2005	329	591	360	1,280
2009	339	757	301	1,397

[1]Source: CEC staff ELFIN production cost runs using ER 7 resource plans, July 13, 1989.
[2]Incremental fuel requirements for electricity generation.
[3]Historic data based on 1989 California Gas Report.

SDG&E

Forecasted gas demand for electricity generation in SDG&E service grows from 166 mmcfd in 1987 to 300 mmcfd in 2009. Cogeneration

demand increases slightly in the near term, then remains constant. Utility boiler requirements increase until the year 1997 then decline to below present gas demand levels. Combustion turbine fuel needs increase dramatically during the forecast period.

TABLE D-10

SDG and E NATURAL GAS SERVICE AREA
POTENTIAL NATURAL GAS REQUIREMENTS FOR ELECTRIC GENERATION[1]
mmcfd

Year	Cogeneration[2]	Combustion Turbines	Boilers	Total
1987[3]	21	N/A	145	166
1990	36	0	120	156
1995	38	4	159	201
2000	38	70	125	232
2005	38	127	95	260
2009	38	197	65	300

[1]Source: CEC staff ELFIN production cost runs using ER 7 resource plans, July 13, 1989.
[2]Incremental fuel requirements for electricity generation.
[3]Historic data based on 1989 California Gas Report.

C. Comparison of Electric Generation Forecasts

Tables D-11 and D-12 provide a statewide comparison of the forecasted gas/oil requirements for electric generation in the years 1995 and 2005. These tables compare the Fuels Report published in September 1986 (FR 1), the December 1987 Fuels Report (FR 2) and the current forecast. The tables display the demand forecast by electric utility service area and by the generic generation sectors of cogeneration, combustion turbines and utility boilers.

The tables show that the current forecast represents an increase in potential UEG gas requirements over the previous two Fuels Reports. Significantly larger fuel use in combined cycle and conventional combustion turbines are now forecasted with modest increases in cogeneration and declining use in utility steam boilers. Overall potential gas requirements in the current forecast are 20 percent higher in 1995 and 30 percent higher in 2005 than in the previous forecast.

TABLE D-11

1995 STATEWIDE COMPARISON
ELECTRIC GENERATION OIL/GAS REQUIREMENTS FORECAST
mmcfd

Electric Utility Service Area	Cogeneration[1]			Combustion Turbines			Utility Boilers			Total		
	FR 1	FR 2	FR 3	FR 1	FR 2	FR 3	FR 1	FR 2	FR 3	FR 1	FR 2	FR 3
PG&E	135	216	280	30	14	0	199	282	301	364	512	581
SCE	166	262	318	21	0	107	364	345	295	551	607	720
LADWP	18	27	15	0	0	21	109	92	113	127	119	149
SDG&E	27	54	38	51	0	4	83	81	159	110	135	201
TOTAL	346	559	651	51	14	132	755	800	868	1152	1373	1651

FR 1: September 1986 Biennial Fuels Report.

FR 2: 1987 Fuels Report, December 1987.

FR 3: Prepared for 1989 Fuels Report from ELFIN production cost model data sets using ER 7 resource plans, July 1989.

[1] Incremental fuel requirement for electricity generation.

TABLE D-12

2005 STATEWIDE COMPARISON
ELECTRIC GENERATION OIL/GAS REQUIREMENTS FORECAST
mmcfd

Electric Utility Service Area	Cogeneration[1]			Combustion Turbines			Utility Boilers			Total		
	FR 1	FR 2	FR 3	FR 1	FR 2	FR 3	FR 1	FR 2	FR 3	FR 1	FR 2	FR 3
PG&E	180	269	350	21	38	63	205	339	409	406	646	822
SCE	224	274	313	48	31	473	331	447	260	603	782	1046
LADWP	18	35	15	0	0	90	65	86	92	83	121	197
SDG&E	31	59	38	0	14	127	71	164	95	102	237	260
TOTAL	453	637	716	69	83	753	672	1066	856	1194	1786	2325

FR 1: September 1986 Biennial Fuels Report.

FR 2: 1987 Fuels Report, December 1987.

FR 3: Prepared for 1989 Fuels Report from ELFIN production cost model data sets using ER 7 resource plans, July 1987.

[1]Incremental fuel requirement for electricity generation.

In 1995, cogeneration and utility boiler requirements are about 12 percent higher in the current forecast. Combustion turbine requirements are up substantially by nearly 10 times. In 2005, combustion turbine requirements are over 9 times higher than the FR 2 forecast and utility boiler requirements are 20 percent lower. Cogeneration gas requirements in the current forecast are 12 percent higher than the FR 2 forecast.

There is a great deal of uncertainty in any forecast of UEG gas demand in California. This uncertainty arises because California meets its electricity customer demands by using a number of diverse resources. These resources include gas and oil generation, nuclear, coal, geothermal and hydroelectric generation, imports from the southwest and Pacific northwest and PURPA defined qualifying facilities.

The forecast of UEG gas demand depends quite strongly on the mix of generating equipment, or "resource plan." The availability of resources other than oil and gas units is subject to large uncertainties. For example, demand for electricity in areas which export to California continue to grow, reducing availability for purchase by California. These changes make it difficult to estimate precisely the amount of energy California will be able to import from these areas in the future. Because of reevaluation for need and economic viability, future coal and nuclear facilities used in this or other planning periods may be added to or deleted from the staff's resource plan.

Changes in the availability of nongas resources strongly affects forecasted gas and oil demand for electricity generation. This impact occurs because oil and gas units tend to be relied on more heavily in response to shortages in other generating capacity. To illustrate the impact of resource changes, it takes abut 10 mmcf to generate 1 gigawatt hour (GWH). If there is a 5,000 GWH downward shift in energy available from a potential source (about equivalent to a 800 MW facility), conceivably gas consumption could increase 50,000 mmcf annually or about 140 mmcfd.

The following section provides a detailed discussion of the underlying assumptions for the FR 2 and FR 3 electric generation forecasts. Contrasts by generic resource type for each service area highlight the differences in assumptions that lead to the increased reliance on conventional oil and gas generation.

IV. UTILITY ELECTRIC GENERATION SUPPLY PLAN METHODOLOGY AND ASSUMPTIONS

A. Introduction

In October 1989, the California Energy Commission staff presented its Draft 1989 Fuels Report forecast of gas requirements for the utility electric generation (UEG) system. The staff based that forecast on production cost results[4] obtained using resource plans developed for the UEG gas demand forecast. This section describes the methodology and assumptions used to develop those resource plans. It also compares the "CFM 7 Revised Price Forecast (RPF)" resource plans, which were the basis for the FR 2 UEG gas forecast, with the current ER 7 UEG resource plans.

B. Methodology

Twenty-year resource plans were developed for each of California's four major electrical planning areas--Northern California, Southern California Edison (SCE), San Diego Gas and Electric (SDG&E) and Los Angeles Department of Water and Power (LADWP). First, staff incorporated resources included in ER 7, with the exception that Rancho Seco was removed from Northern California, into each planning area. Additional resources were then added to meet dry year capacity requirements and average year energy requirements, and to offset the "age-derates" applied to existing utility oil and gas plants.[5] Screenning curve analysis and capacity expansion spreadsheets were used to facilitate the process of estimating the timing, sizes and types of resource additions necessary to meet ER 7 power requirements.[6]

Generation resources and demand-side management (DSM) programs, consistent with ER 7 policies, were added in three phases to meet each planning area's capacity and energy requirements. First, additional achievable conservation and generic Pacific Northwest (PNW) peaking purchases were added to the ER 7 resource plans. Second, age-derated oil/gas units were refurbished, repowered or replaced with cost-effective options.[7] Third, remaining needs were filled by generic fossil- and nonfossil-fueled capacity additions, consistent with ER 7 fuel diversity policies. Using the resulting resource plans, staff then employed the ELFIN production cost model to simulate the utility systems' energy production and to estimate their gas use.

C. Assumptions

The ER 7 UEG resource plans are based on the following general supply planning assumptions:

- Demand Forecast. Development of the ER 7 UEG resource plans relied on the adopted ER 7 demand forecast. Using ER 7 growth rates, staff extrapolated the energy and capacity requirements to estimate 2008 and 2009 requirements. ER 7 adopted transmission and distribution losses, reserve requirements and export contracts were included in the energy and capacity requirements used to develop the ER 7 UEG resource plans.

- ER 7 Resources. The ER 7 UEG resource plans include all existing, committed, nondeferrable and pending resources identified in ER 7. These include utility-owned facilities, firm contractual import and export obligations, uncommitted conservation and load management program savings, spot capacity purchases, and the adopted self-generation and third party supplier forecasts. The ER 7 UEG resource plans reflect the contract termination dates adopted in the ER 7 Electricity Supply Planning Assumptions Report (ESPAR).[8] Resource forecasts were extrapolated to estimate resource availability for 2008 and 2009.

- Out-of-State Power. The ER 7 UEG resource plans include generic out-of-state power (OSP) resources. Firm power resource availability and interstate transfer capability constraints limited the amount of generic OSP additions.

  ER 7 included only the municipal portion of the California-Oregon Transmission Project (COTP) as a pending resource. The ER 7 UEG resource plan additions includes power available to both the investor-owned and municipal utility portions of the COTP. Staff constrained generic Northwest capacity additions in accord with availability of PNW power resources and transmission availability.

- Nonfirm Energy. Projected nonfirm energy amounts under average year hydroelectric conditions were included as energy resources. Staff used transmission availability and forecasted Northwest regional energy surpluses to limit the amount available to California utilities.

- Conservation and Load Management. Beyond the committed and ER 7 nondeferrable (uncommitted) conservation and load management amounts adopted in ER 7, the UEG resource plans include "additionally achievable conservation."[9] This conservation is typically characterized as a capacity resource with little associated energy.

- Age-Derated Capacity. The ER 7 UEG resource plans embraced the age-derated capacity technique used in ER 7. ER 7 applied the probability of a gas or oil unit's continued operation to its capacity rating to estimate the expected value of the unit's capacity in each year of the planning period.[10] Hence, ER 7 derated the oil/gas capacity to account for the effects

of aging. In determining resource additions, staff considered the economics of retrofitting or modifying this derated capacity relative to the cost of other alternatives.[11]

- Nonfossil Resource Additions. ER 7 adopted two policies which guide the procurement of nonfossil resource additions. First, ER 7 recommended that only 50 percent of the total need be filled with long-term commitments in the CPUC's Biennial Report Proceeding Update (BRPU). Second, the Commission recommended that half of the amount needed for long-term commitments (50 percent of need), be allocated to nonfossil-fueled generation technologies.[12]

  The net effect of these ER 7 policies is that 25 percent of the capacity resource additions made to meet load growth are nonfossil-fueled. Staff used this criterion in selecting resource additions.

- Gas Price. The Delphi IV gas price was used in both the screening curves with which the resource plans were developed and in the ELFIN production cost simulations.

- Air Quality Constraints. ER 7 recognized the interrelationship of air quality management and energy planning. In integrating resource additions for the ER 7 UEG resource plans, staff took air quality constraints into account for the SCE and LADWP/BGP utilities in the South Coast Air Quality Management District (SCQAMD). In particular, the SCE resource plan incorporates preliminary air quality compliance plans for meeting SCAQMD's Rule 1135. Rule 1135, adopted August 4, 1989 by SCQAMD, regulates emissions from existing electric utility steam boilers.

- The ER 7 UEG resource plan additions incorporated the cost of air emission equipment for refurbished, repowered, and new facilities.

After accounting for these assumptions and constraints, staff determined the need for additional resources primarily on the basis of capacity required for reliability. Staff relied upon the relative cost, potential for fuel savings, and environmental implications to identify resource additions for the ER 7 UEG resource plans.

D. Comparison With Fuels Report 2

In contrast, the December 1987 Fuels Report (FR 2) relied on resource plans based on production cost results from CFM 7 RPF resource plans. The CFM 7 RPF assumed staff's preliminary CFM 7 electricity demand forecasts and existing and committed resources from the adopted ER 6 ESPAR. Beyond the committed conservation

category used in the CFM 7 RPF plans, the ER 7 UEG resource plans include uncommitted and additionally achievable conservation additions.

Like the CFM 7 RFP, the ER 7 UEG plans include Northwest power associated with the COTP transmission line; it includes nonfirm energy from the PNW based on average-year availability; and it extends the adopted forecasts for self-generation and qualifying facility development through the respective gas forecast horizon.

E. Summary Results - Utility Specific Comparisons

Northern California Planning Area

Table D-13 compares generation by resource type for the CFM 7 Gas forecast to the 1989 UEG resource plan. The following differences are noteworthy:

- Overall energy generation increased in the ER 7 UEG results as a consequence of a higher energy forecast. Oil-and gas-fired resources provided the flexibility necessary to respond to the higher generation requirements.

- The UEG forecast shows higher oil- and gas-fired cogeneration than the CFM 7 RPF. The higher projection is a result of higher forecasted cogeneration development.

- The removal of Rancho Seco from the resource plan reduces nuclear generation, causing oil- and gas-fired generation and imports to increase.

- The demand forecast used in the ER 7 UEG forecast is higher than that used in the CFM 7 RPF. Increased demand results in the need for additional generation. Some of this generation may be accounted for as oil- and gas-fired.

- Beyond the committed conservation included in the CFM and RPF forecasts, the ER 7 UEG forecast includes uncommitted and additionally achievable conservation. Additional conservation may reduce oil- and gas-fired generation.

TABLE D-13

Pacific Gas and Electric Service Area 1/
(Northern California Planning Area)
Comparison of Electric Generation
Sources Among Resource Plans
GWh

Generation Type	1995 CFM 7 RPF	1995 ER 7 UEG	2005 CFM 7 RPF	2005 ER 7 UEG
Nuclear	15522	12228	15639	12169
Coal 2/				
Oil/Gas 3/	9160	10329	15534	17303
QF Gas/Oil 4/	11810	15183	16826	19798
QF Other 5/	12372	12175	15477	13781
Geothermal (Utility)	12883	12778	13378	12772
Imports	11028	12298	13971	14797
Conservation 6/		3316		9843
Hydro	27788	28439	27836	29291
TOTAL	100563	106746	118661	129754

Note: May not sum due to rounding.

1/ Pacific Gas and Electric service area corresponds to the Northerr California Planning Area. It includes SMUD and several municipal utilities.
2/ MSR's portion of San Juan Coal Unit #4 is included as an import.
3/ Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
4/ Includes all QF cogeneration which use natural gas, including utility cogeneration.
5/ Includes QF biomass, geothermal, small hydro, partially gas-fired solar, and wind.
6/ The ER 7 UEG resource plan includes uncommitted and additionally achievable conservation. The CFM 7 RPF resource plan included only committed conservation which is accounted for in the demand line of both the ER 7 UEG and CFM 7 resource plans.

Southern California Edison Planning Area

Table D-14 compares generation by resource type for the CFM 7 gas forecast to the ER 7 UEG resource plan. The following differences are noteworthy:

- Overall energy generation increased in the ER 7 UEG results as a consequence of increased energy requirements. Energy requirements were also increased by adding new exports to SMUD as a result of closing Rancho Seco.

- The UEG forecast shows higher oil- and gas-fired cogeneration than the CFM 7 RPF. The higher projection is a result of higher forecasted cogeneration development.

- Beyond the committed conservation included in the CFM 7 RFP forecast, the ER 7 UEG forecast includes uncommitted and additionally achievable conservation. Additional conservation may meet some of the demand otherwise met by oil- and gas-fired resources.

- The CFM 7 RPF shows more import energy than the 1989 UEG. This is caused by a change in the Pacific Power and Light (PPL) contract, a reduction in the PNW economy energy forecasts, and differences in resource additions. The CFM 7 RPF included "Generic SW Coal Imports" additions, while the UEG added combined cycles.

TABLE D-14

Southern California Edison
Comparison of Electric Generation
Sources Among Resource Plans
GWh

Generation Type	1995 CFM 7 RPF	1995 ER 7 UEG	2005 CFM 7 RPF	2005 ER 7 UEG
Nuclear	14990	14709	15001	14709
Coal	11425	11524	11616	11487
Oil/Gas 1/	11980	14200	25426	30971
QF Gas/Oil 2/	16611	20987	17624	20745
QF Other 3/	12063	12155	13652	14222
Geothermal (Utility)	63		63	
Imports	17270	15302	17048	12093
Conservation 4/		1922		4620
Hydro	4905	4932	5038	4873
TOTAL	89307	95731	105468	113720

Note: May not sum due to rounding.

1/ Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
2/ Includes all QF cogeneration which use natural gas, including utility cogeneration.
3/ Includes QF biomass, geothermal, small hydro, solar (include partially gas-fired solar and wind.
4/ The ER 7 UEG resource plan includes uncommitted and additionally achievable conservation. The CFM 7 RPF resource plan included only committed conservation which is accounted for in the demand of both the ER 7 UEG and CFM 7 resource plans.

Table D-15 compares generation by resource type for the CFM 7 gas forecast and 1989 UEG resource plans. The following differences are noteworthy:

- Overall energy supply increased in the ER 90 UEG results as a consequence of a higher forecast of energy use. Oil- and gas-fired resources provided some flexibility necessary for responding to the higher generation requirements.

  The ER 7 UEG resource plan relied on a lower self-generation forecast than the one used in the CFM 7 RPF resource plan. This caused a reduction in the QF oil/gas generation in the ER 7 UEG from those reported for the CFM 7 RPF resource plan.

- In the LADWP ER 7 UEG resource plan, new, efficient combined cycle units were added to replace the older derated oil-/gas-fired capacity. As a result, the ER 7 UEG resource plan resulted in an increased reliance on more efficient utility oil/gas units.

  Beyond the committed conservation included in the CFM 7 RPF and UEG forecasts, the ER 7 UEG forecast includes uncommitted and additionally achievable conservation. Additional conservation displaces the need to run oil- and gas-fired resources.

- The reduction in nuclear generation reflects assumed the Palo Verde layoff, included in the CFM 7 RPF, but not in the ER 7 UEG.

- The change in coal generation reflects the RPF's resource additions being mostly "generic" coal additions, while the ER 7 UEG's resource additions were mostly out-of-state contracts and generic powerplant replacements.

TABLE D-15

Los Angeles Department of Water and Power 1/
Comparison of Electric Generation
Sources Among Resource Plans
GWh

Generation Type	1995 CFM 7 RPF	1995 ER 7 UEG	2005 CFM 7 RPF	2005 ER 7 UEG
Nuclear	1978	2181	762	2181
Coal 2/	12342	13408	19208	13830
Oil/Gas 3/	3580	4898	3105	6700
QF Gas/Oil 4/	1492	839	2255	839
QF Other 5/	164	234	164	234
Geothermal (Utility)				412
Imports	4101	4158	1943	5064
Conservation 6/		1475		2619
Hydro	2575	2448	2682	2448
TOTAL	26232	29641	30119	34327

Note: May not sum due to rounding.

1/ For comparative purposes, the generation to meet Burbank, Glendale and Pasadena loads is not included. Oil and gas generation for these utilities was included in the 1989 Fuels Report Forecast.
2/ Includes generation from Intermountain Generating Station.
3/ Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
4/ Includes all QF cogeneration which use natural gas, including utility cogeneration.
5/ Includes QF biomass, geothermal, small hydro, solar and wind.
6/ The ER 7 UEG resource plan includes uncommitted and additionally achievable conservation. The CFM 7 RPF resource plan included only committed conservation which is accounted for in the demand of both the ER 7 UEG and CFM 7 RPF resource plans.

San Diego Gas and Electric Company

Table D-16 compares generation by resource type for the CFM 7 RFP and ER 7 UEG forecasts. The following differences are noteworthy:

- Overall energy supply increased in the ER 7 UEG results as a consequence of a higher energy forecast. However, utility oil- and gas-fired generation is lower than that projected in the CFM 7 RPF results.

- ER 7 UEG shows lower oil- and gas-fired qualifying facilities than the CFM 7 RPF forecast. The most significant change is in a reduction in self-generation. The difference is attributable to the use of different self-generation forecasts[13] between the two resource plans. An offsetting effect occurred by a modest increase in QF cogeneration in the ER 7 UEG forecast.

- Increased utility geothermal generation at Heber in ER 7 UEG partly explains why the oil- gas-fired generation is lower. This is a result of additions made in response to the ER 7 policy calling for nonfossil additions.

- Increased conservation also explains why the reliance on oil- and gas-fired generation is less. In addition to committed conservation which was included in both forecasts, ER 7 UEG also includes uncommitted and additional achievable conservation programs.

TABLE D-16

San Diego Gas and Electric Company
Comparison of Electric Generation
Sources Among Resource Plans
GWh

Generation Type	1995 CFM 7 RPF	1995 ER 7 UEG	2005 CFM 7 RPF	2005 ER 7 UEG
Nuclear	2897	2814	2897	2814
Coal				
Oil/Gas 1/	3016	5503	9204	8933
QF Gas/Oil 2/	3316	2220	3861	2225
QF Other 3/	251	513	318	560
Geothermal (Utility)	263		263	2312
Conservation 4/		479		1680
Imports	6291	5269	2458	2305
Hydro				
TOTAL	16034	16798	19001	20829

Note: May not sum due to rounding.

1/ Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
2/ Includes all QF cogeneration which use natural gas, including utility cogeneration.
3/ Includes QF biomass, geothermal, small hydro, solar and wind.
4/ The ER 7 UEG resource plan includes uncommitted and additionally achievable conservation. The CFM 7 RPF resource plan included only committed conservation which is accounted for in the demand of both the ER 7 UEG and CFM 7 resource plans.

ENDNOTES

1. Core customers are those which have no alternative fuel capability. Noncore customers are those which do have alternative fuel capabilities.

2. No attempt has been made to determine the quantity of natural gas a utility might transport. The Commission's work assumes the gas utility would be indifferent as to whether the gas in its system was for sale or transport. Transport estimates have been made by the gas utilities and are published in the 1989 California Gas Report.

3. QFER requires utilities and marketers/producers to report monthly energy purchases and consumption.

4. The ELFIN production cost model was used to simulate utility operation for the specific purpose of forecasting UEG gas use.

5. Many of the utilities' oil/gas plants will reach the 30- to 40-year nominal age at which some amount of capacity becomes less reliable and less efficient. In ER 7, age-derating existing utility oil/gas plants seeks to forecast this decline. In determining the long-term need for new resources, the age-derated capacity must be offset for accounting purposes.

6. The estimating process employs information regarding the availability, size, required lead time, operating characteristics, efficiency, and relative costs for "generic" resource options. Screening curves which incorporate the capital, variable and air pollution control costs for resources at various operating levels were developed to evaluate and identify potential resource additions.

7. Following a judgement about which type of duty the age-derated capacity would serve (reserve support or intermediate load following), screening curves were employed to identify the cost-effective modification or replacement.

8. California Energy Commission, Electricity Report 7, Appendix A, July 1989.

9. "Additionally achievable conservation" presents conservation impacts that could be achieved above and beyond the levels adopted for committed and uncommitted conservation in ER 7. Energy Impacts of Uncommitted Conservation to be Included in the Commission's Least-Cost Resource Plan, California Energy Commission, Staff Testimony, Demand-Side Program Evaluation Office, Energy Efficiency and Local Assistance Division, November 3, 1988.

10. California Energy Commission, ER 7, pg. 5-9, June 1989.

11. California Energy Commission, Electricity Report 7, Appendix H, pg. H-18, July 1989.

12. California Energy Commission, ER 7, pgs. 8-6 and 8-7, June 1989.

13. The CFM 7 RPF forecast relied on three sources: The RER September 1987 forecast, a letter to Ralph Chandler from RER in July 1987, and the preliminary Staff ER 7 electricity forecast in California Energy Demand 1987-2007, Volume 7, SDG&E Planning Area, dated June 1987. The ER 7 UEG forecast was taken from the adopted ER 7 electricity demand, which was developed by SDG&E.

V. NATURAL GAS DEMAND TABLES

Tables D-17 through D-26 provide total utility and nonutility demand by gas utility geographic service area for residential, commercial and industrial sections. Tables D-27 through D-30 provide natural gas demand served by the gas utilities.

TABLE D-17

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

BASELINE GAS FORECAST

PACIFIC GAS AND ELECTRIC GEOGRPHICAL REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	2593.200	890.921	121.730	.000	1593.185	867.058	242.900	81.300	34.265	6424.559
1978	2292.900	746.054	126.402	.000	1370.365	784.044	233.800	77.500	20.860	5651.925
1979	2489.000	765.376	127.570	.000	1772.259	811.196	250.000	94.600	17.360	6327.362
1980	2298.100	720.664	114.230	.000	1773.683	683.130	248.600	76.600	6.755	5921.762
1981	2079.400	674.692	118.115	.000	1652.325	689.585	226.400	64.900	7.455	5512.872
1982	2225.700	729.131	119.066	.000	1406.066	562.699	214.000	58.000	40.985	5355.647
1983	2093.400	693.723	107.840	.000	1262.778	493.760	159.245	50.600	32.165	4893.512
1984	2036.300	690.351	108.675	.000	1230.548	487.484	218.315	49.300	55.755	4876.728
1985	2020.000	728.500	106.126	.000	1418.884	545.808	236.220	54.600	31.640	5141.778
1986	1958.000	648.175	106.844	.000	1086.876	424.996	180.290	56.000	46.900	4508.081
1987	2034.000	666.798	105.031	.000	1172.215	554.193	229.790	58.000	42.700	4862.726
1988	2217.230	726.194	105.368	.000	1211.241	572.098	254.668	58.796	46.504	5192.099
1989	2189.226	741.594	106.217	.000	1241.141	588.838	302.629	59.805	47.490	5276.939
1990	2161.925	756.215	106.964	.000	1270.800	598.900	348.281	61.090	48.426	5352.601
1991	2137.668	771.944	107.505	.000	1301.664	593.116	382.392	62.383	49.433	5406.105
1992	2112.525	787.004	108.150	.000	1331.323	615.031	416.503	63.682	50.398	5484.616
1993	2086.882	800.921	108.896	.000	1360.982	628.496	448.306	64.988	51.289	5550.760
1994	2061.513	816.719	109.746	.000	1390.642	643.979	480.109	66.301	52.301	5621.309
1995	2063.559	827.618	110.154	.000	1401.477	652.367	489.341	67.008	52.999	5664.523
1996	2062.821	839.234	110.975	.000	1414.720	667.890	496.266	67.722	53.742	5713.370
1997	2063.177	849.029	111.179	.000	1425.555	677.145	505.499	68.444	54.370	5754.397
1998	2063.782	859.012	111.792	.000	1437.594	689.711	514.732	69.172	55.009	5800.805
1999	2064.921	868.898	112.202	.000	1447.225	703.047	521.656	69.909	55.642	5843.500
2000	2066.429	878.627	112.610	.000	1459.264	714.511	530.889	70.653	56.265	5889.249
2001	2071.097	887.752	113.429	.000	1468.895	725.655	537.814	71.404	56.849	5932.896
2002	2076.142	896.090	114.042	.000	1482.138	736.466	537.814	72.164	57.383	5972.240
2003	2083.097	905.019	114.657	.000	1494.177	748.472	537.814	72.164	57.955	6013.355
2004	2089.892	913.301	115.168	.000	1507.420	760.685	537.814	72.164	58.485	6054.929
2005	2099.358	921.195	115.986	.000	1519.459	773.268	535.506	72.164	58.991	6095.927
2006	2107.523	928.687	116.292	.000	1531.499	784.451	537.814	72.164	59.471	6137.900
2007	2117.732	936.667	116.906	.000	1543.538	797.164	537.814	72.164	59.982	6181.967
2008	2129.844	944.022	117.519	.000	1556.780	809.878	537.814	72.164	60.453	6228.475
2009	2142.590	951.231	118.133	.000	1568.820	822.861	535.506	72.164	60.914	6272.220

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1987	-2.40	-2.86	-1.46	.00	-3.02	-4.38	-.55	-3.32	2.23	-2.75
1987 - 1994	.19	2.94	.63	.00	2.47	2.17	11.10	1.93	2.94	2.09
1987 - 2001	.13	2.07	.55	.00	1.62	1.94	6.26	1.50	2.07	1.43
1987 - 2009	.24	1.63	.54	.00	1.33	1.81	3.92	1.00	1.63	1.16

TABLE D-18

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

BASELINE GAS FORECAST

PACIFIC GAS AND ELECTRIC GEOGRPHICAL REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	677.	233.	32.	0.	416.	226.	63.	21.	9.	1677.
1978	598.	195.	33.	0.	358.	205.	61.	20.	5.	1475.
1979	650.	200.	33.	0.	463.	212.	65.	25.	5.	1651.
1980	600.	188.	30.	0.	463.	178.	65.	20.	2.	1546.
1981	543.	176.	31.	0.	431.	180.	59.	17.	2.	1439.
1982	581.	190.	31.	0.	367.	147.	56.	15.	11.	1398.
1983	546.	181.	28.	0.	330.	129.	42.	13.	8.	1277.
1984	531.	180.	28.	0.	321.	127.	57.	13.	15.	1273.
1985	527.	190.	28.	0.	370.	142.	62.	14.	8.	1342.
1986	511.	169.	28.	0.	284.	111.	47.	15.	12.	1177.
1987	531.	174.	27.	0.	306.	145.	60.	15.	11.	1269.
1988	579.	190.	28.	0.	316.	149.	66.	15.	12.	1355.
1989	571.	194.	28.	0.	324.	154.	79.	16.	12.	1377.
1990	564.	197.	28.	0.	332.	156.	91.	16.	13.	1397.
1991	558.	201.	28.	0.	340.	155.	100.	16.	13.	1411.
1992	551.	205.	28.	0.	347.	161.	109.	17.	13.	1431.
1993	545.	209.	28.	0.	355.	164.	117.	17.	13.	1449.
1994	538.	213.	29.	0.	363.	168.	125.	17.	14.	1467.
1995	539.	216.	29.	0.	366.	170.	128.	17.	14.	1478.
1996	538.	219.	29.	0.	369.	174.	130.	18.	14.	1491.
1997	538.	222.	29.	0.	372.	177.	132.	18.	14.	1502.
1998	539.	224.	29.	0.	375.	180.	134.	18.	14.	1514.
1999	539.	227.	29.	0.	378.	183.	136.	18.	15.	1525.
2000	539.	229.	29.	0.	381.	186.	139.	18.	15.	1537.
2001	541.	232.	30.	0.	383.	189.	140.	19.	15.	1548.
2002	542.	234.	30.	0.	387.	192.	140.	19.	15.	1559.
2003	544.	236.	30.	0.	390.	195.	140.	19.	15.	1569.
2004	545.	238.	30.	0.	393.	199.	140.	19.	15.	1580.
2005	548.	240.	30.	0.	397.	202.	140.	19.	15.	1591.
2006	550.	242.	30.	0.	400.	205.	140.	19.	16.	1602.
2007	553.	244.	31.	0.	403.	208.	140.	19.	16.	1613.
2008	556.	246.	31.	0.	406.	211.	140.	19.	16.	1626.
2009	559.	248.	31.	0.	409.	215.	140.	19.	16.	1637.
AVERAGE ANNUAL GROWTH RATE (%)										
1977 - 1987	-2.40	-2.86	-1.46	.00	-3.02	-4.38	-.55	-3.32	2.23	-2.75
1987 - 1994	.19	2.94	.63	.00	2.47	2.17	11.10	1.93	2.94	2.09
1987 - 2001	.13	2.07	.55	.00	1.62	1.94	6.26	1.50	2.07	1.43
1987 - 2009	.24	1.63	.54	.00	1.33	1.81	3.92	1.00	1.63	1.16

TABLE D-19

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

BASELINE GAS FORECAST

SOUTHERN CALIFORNIA GAS REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	3078.000	827.209	82.220	.000	907.365	1355.297	898.000	74.400	35.770	7258.261
1978	3142.000	878.790	92.188	.000	787.927	1306.305	874.500	64.600	53.550	7199.861
1979	3321.700	881.394	89.000	.000	855.369	1232.603	916.318	70.800	.000	7367.184
1980	3183.800	800.385	90.200	.000	937.369	1170.603	927.518	65.100	.000	7174.975
1981	2783.900	781.585	91.000	.000	971.444	1130.603	850.130	71.300	.000	6679.962
1982	3005.500	834.861	96.701	.000	889.683	894.492	799.730	60.600	1.540	6583.107
1983	2747.200	776.481	84.050	.000	955.201	796.117	592.728	47.400	2.555	6001.732
1984	2544.600	743.643	81.158	.000	868.963	808.524	833.186	52.200	2.695	5934.969
1985	2869.800	847.594	85.517	.000	836.892	838.119	904.640	53.800	8.750	6445.112
1986	2507.000	774.395	81.156	.000	810.417	792.480	1000.330	44.000	2.695	6012.473
1987	2740.000	827.342	85.751	.000	757.993	755.275	1086.120	47.000	2.450	6301.930
1988	2739.347	861.259	87.078	.000	764.876	778.115	1039.034	48.708	2.550	6320.969
1989	2771.897	884.916	88.214	.000	769.417	811.332	1246.453	50.433	2.620	6625.282
1990	2801.985	907.258	89.055	.000	776.037	841.853	1459.994	52.088	2.687	6930.957
1991	2834.459	930.307	90.287	.000	780.266	845.418	1621.935	53.750	2.755	7159.176
1992	2864.611	953.679	91.420	.000	785.691	907.511	1787.374	55.418	2.824	7448.527
1993	2894.257	976.078	92.550	.000	789.921	953.236	1958.060	57.091	2.890	7724.084
1994	2923.602	998.875	93.882	.000	794.151	980.501	2132.245	58.770	2.958	7984.983
1995	2936.859	1013.093	93.990	.000	801.321	991.031	2168.977	59.374	3.000	8067.646
1996	2945.369	1027.667	93.891	.000	808.492	1003.695	2205.710	59.983	3.043	8147.849
1997	2955.378	1040.944	94.291	.000	815.662	1016.075	2241.568	60.599	3.083	8227.599
1998	2964.286	1054.398	94.597	.000	821.637	1029.611	2277.426	61.221	3.122	8306.298
1999	2974.794	1067.690	94.692	.000	827.612	1043.284	2313.284	61.850	3.162	8386.368
2000	2985.809	1080.053	94.604	.000	834.782	1054.255	2350.017	62.485	3.198	8465.203
2001	2995.765	1090.773	94.997	.000	841.953	1066.812	2385.875	63.126	3.230	8542.532
2002	3007.366	1101.024	95.489	.000	849.123	1079.066	2383.251	63.768	3.260	8582.347
2003	3019.527	1110.856	95.781	.000	855.098	1091.157	2381.502	63.768	3.290	8620.979
2004	3033.450	1120.812	96.271	.000	859.878	1105.108	2379.753	63.768	3.319	8662.360
2005	3050.122	1129.589	96.573	.000	867.048	1117.243	2377.129	63.768	3.345	8704.817
2006	3066.195	1139.147	96.968	.000	874.219	1129.872	2375.380	63.768	3.373	8748.923
2007	3083.897	1148.190	97.458	.000	880.194	1142.348	2373.631	63.768	3.400	8792.886
2008	3104.449	1156.914	97.758	.000	887.364	1155.167	2371.007	63.768	3.426	8839.854
2009	3125.840	1165.473	98.554	.000	894.534	1168.403	2368.383	63.768	3.451	8888.406

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1987	-1.16	.00	.42	.00	-1.78	-5.68	1.92	-4.49	-23.52	-1.40
1987 - 1994	.93	2.73	1.30	.00	.67	3.80	10.12	3.24	2.73	3.44
1987 - 2001	.64	1.99	.73	.00	.75	2.50	5.78	2.13	1.99	2.20
1987 - 2009	.60	1.57	.63	.00	.76	2.00	3.61	1.40	1.57	1.58

TABLE D-20

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

BASELINE GAS FORECAST

SOUTHERN CALIFORNIA GAS REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	803.	216.	21.	0.	237.	354.	234.	19.	9.	1894.
1978	820.	229.	24.	0.	206.	341.	228.	17.	14.	1879.
1979	867.	230.	23.	0.	223.	322.	239.	18.	0.	1923.
1980	831.	209.	24.	0.	245.	306.	242.	17.	0.	1873.
1981	727.	204.	24.	0.	254.	295.	222.	19.	0.	1743.
1982	784.	218.	25.	0.	232.	233.	209.	16.	0.	1718.
1983	717.	203.	22.	0.	249.	208.	155.	12.	1.	1566.
1984	664.	194.	21.	0.	227.	211.	217.	14.	1.	1549.
1985	749.	221.	22.	0.	218.	219.	236.	14.	2.	1682.
1986	654.	202.	21.	0.	212.	207.	261.	11.	1.	1569.
1987	715.	216.	22.	0.	198.	197.	283.	12.	1.	1645.
1988	715.	225.	23.	0.	200.	203.	271.	13.	1.	1650.
1989	723.	231.	23.	0.	201.	212.	325.	13.	1.	1729.
1990	731.	237.	23.	0.	203.	220.	381.	14.	1.	1809.
1991	740.	243.	24.	0.	204.	221.	423.	14.	1.	1869.
1992	748.	249.	24.	0.	205.	237.	467.	14.	1.	1944.
1993	755.	255.	24.	0.	206.	249.	511.	15.	1.	2016.
1994	763.	261.	25.	0.	207.	256.	557.	15.	1.	2084.
1995	767.	264.	25.	0.	209.	259.	566.	15.	1.	2106.
1996	769.	268.	25.	0.	211.	262.	576.	16.	1.	2127.
1997	771.	272.	25.	0.	213.	265.	585.	16.	1.	2147.
1998	774.	275.	25.	0.	214.	269.	594.	16.	1.	2168.
1999	776.	279.	25.	0.	216.	272.	604.	16.	1.	2189.
2000	779.	282.	25.	0.	218.	275.	613.	16.	1.	2209.
2001	782.	285.	25.	0.	220.	278.	623.	16.	1.	2230.
2002	785.	287.	25.	0.	222.	282.	622.	17.	1.	2240.
2003	788.	290.	25.	0.	223.	285.	622.	17.	1.	2250.
2004	792.	293.	25.	0.	224.	288.	621.	17.	1.	2261.
2005	796.	295.	25.	0.	226.	292.	620.	17.	1.	2272.
2006	800.	297.	25.	0.	228.	295.	620.	17.	1.	2283.
2007	805.	300.	25.	0.	230.	298.	620.	17.	1.	2295.
2008	810.	302.	26.	0.	232.	301.	619.	17.	1.	2307.
2009	816.	304.	26.	0.	233.	305.	618.	17.	1.	2320.
AVERAGE ANNUAL GROWTH RATE (%)										
1977 - 1987	-1.16	.00	.42	.00	-1.78	-5.68	1.92	-4.49	-23.52	-1.40
1987 - 1994	.93	2.73	1.30	.00	.67	3.80	10.12	3.24	2.73	3.44
1987 - 2001	.64	1.99	.73	.00	.75	2.50	5.78	2.13	1.99	2.20
1987 - 2009	.60	1.57	.63	.00	.76	2.00	3.61	1.40	1.57	1.58

TABLE D-21

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

BASELINE GAS FORECAST

SAN DIEGO GAS AND ELECTRIC

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	299.100	105.491	13.241	.000	3.283	39.395	2.300	8.000	7.490	478.300
1978	313.700	95.736	18.220	.100	3.313	39.752	1.700	4.000	7.980	484.500
1979	357.000	101.222	15.115	.100	4.170	37.528	1.900	9.000	3.465	529.500
1980	313.400	89.521	13.392	.100	4.121	35.026	1.000	9.000	2.240	467.800
1981	289.100	84.281	13.408	.000	3.118	34.299	1.300	8.300	2.765	436.570
1982	317.800	82.541	16.920	.000	2.350	39.949	1.800	3.600	11.410	476.370
1983	296.400	89.334	13.978	.000	2.118	26.474	2.100	5.000	4.060	439.464
1984	283.500	79.591	14.515	.000	2.164	36.305	2.700	5.200	6.300	430.275
1985	317.300	139.378	16.623	.000	3.234	49.606	2.500	8.000	9.450	546.091
1986	283.500	112.069	16.931	.000	2.012	43.359	2.700	7.000	.700	468.271
1987	331.000	106.889	13.925	.000	2.012	50.625	2.500	7.200	.700	514.850
1988	354.495	118.662	14.317	.000	2.213	52.004	2.500	7.273	.777	552.241
1989	361.124	121.069	14.709	.000	2.414	52.912	2.500	7.347	.793	562.868
1990	367.592	123.406	15.101	.000	2.414	53.265	2.500	7.422	.808	572.509
1991	374.055	125.702	15.494	.000	2.414	52.778	2.500	7.497	.823	581.262
1992	380.003	128.068	15.886	.000	2.414	54.324	2.500	7.573	.839	591.607
1993	386.120	130.463	16.213	.000	2.414	55.260	3.000	7.650	.854	601.974
1994	392.253	132.884	16.605	.000	2.414	56.031	3.000	7.728	.870	611.786
1995	394.330	135.091	16.670	.000	2.414	56.122	3.000	7.807	.885	616.319
1996	395.742	137.479	16.605	.000	2.414	56.764	3.000	7.887	.900	620.791
1997	397.323	139.861	16.670	.000	2.414	57.268	3.000	7.967	.916	625.419
1998	399.072	142.281	16.736	.000	2.414	57.785	3.000	8.048	.932	630.268
1999	400.417	144.614	16.670	.000	2.414	58.336	3.000	8.130	.947	634.529
2000	402.409	146.858	16.736	.000	2.414	58.774	3.000	8.214	.962	639.366
2001	404.935	149.416	16.670	.000	2.414	59.383	3.000	8.297	.979	645.094
2002	408.572	151.807	16.605	.000	2.414	59.971	3.500	8.382	.994	652.246
2003	412.046	154.225	16.540	.000	2.414	60.555	3.500	8.382	1.010	658.671
2004	415.590	156.624	16.474	.000	2.414	61.221	3.500	8.382	1.026	665.231
2005	420.001	158.998	16.474	.000	2.414	61.710	3.500	8.382	1.041	672.521
2006	423.448	161.253	16.474	.000	2.414	62.440	3.500	8.382	1.056	678.967
2007	427.596	163.506	16.409	.000	2.414	63.090	3.500	8.382	1.071	685.968
2008	431.650	165.788	16.409	.000	2.414	63.727	3.500	8.382	1.086	692.956
2009	436.317	168.095	16.474	.000	2.414	64.417	3.500	8.382	1.101	700.700

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1987	1.02	.13	.50	.00	-4.78	2.54	.84	-1.05	-21.10	.74
1987 - 1994	2.46	3.16	2.55	.00	2.64	1.46	2.64	1.02	3.16	2.49
1987 - 2001	1.45	2.42	1.29	.00	1.31	1.15	1.31	1.02	2.42	1.62
1987 - 2009	1.26	2.08	.77	.00	.83	1.10	1.54	.69	2.08	1.41

TABLE D-22

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

BASELINE GAS FORECAST

SAN DIEGO GAS AND ELECTRIC

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	78.	28.	3.	0.	1.	10.	1.	2.	2.	125.
1978	82.	25.	5.	0.	1.	10.	0.	1.	2.	126.
1979	93.	26.	4.	0.	1.	10.	0.	2.	1.	138.
1980	82.	23.	3.	0.	1.	9.	0.	2.	1.	122.
1981	75.	22.	3.	0.	1.	9.	0.	2.	1.	114.
1982	83.	22.	4.	0.	1.	10.	0.	1.	3.	124.
1983	77.	23.	4.	0.	1.	7.	1.	1.	1.	115.
1984	74.	21.	4.	0.	1.	9.	1.	1.	2.	112.
1985	83.	36.	4.	0.	1.	13.	1.	2.	2.	143.
1986	74.	29.	4.	0.	1.	11.	1.	2.	0.	122.
1987	86.	28.	4.	0.	1.	13.	1.	2.	0.	134.
1988	93.	31.	4.	0.	1.	14.	1.	2.	0.	144.
1989	94.	32.	4.	0.	1.	14.	1.	2.	0.	147.
1990	96.	32.	4.	0.	1.	14.	1.	2.	0.	149.
1991	98.	33.	4.	0.	1.	14.	1.	2.	0.	152.
1992	99.	33.	4.	0.	1.	14.	1.	2.	0.	154.
1993	101.	34.	4.	0.	1.	14.	1.	2.	0.	157.
1994	102.	35.	4.	0.	1.	15.	1.	2.	0.	160.
1995	103.	35.	4.	0.	1.	15.	1.	2.	0.	161.
1996	103.	36.	4.	0.	1.	15.	1.	2.	0.	162.
1997	104.	37.	4.	0.	1.	15.	1.	2.	0.	163.
1998	104.	37.	4.	0.	1.	15.	1.	2.	0.	165.
1999	105.	38.	4.	0.	1.	15.	1.	2.	0.	166.
2000	105.	38.	4.	0.	1.	15.	1.	2.	0.	167.
2001	106.	39.	4.	0.	1.	15.	1.	2.	0.	168.
2002	107.	40.	4.	0.	1.	16.	1.	2.	0.	170.
2003	108.	40.	4.	0.	1.	16.	1.	2.	0.	172.
2004	108.	41.	4.	0.	1.	16.	1.	2.	0.	174.
2005	110.	41.	4.	0.	1.	16.	1.	2.	0.	176.
2006	111.	42.	4.	0.	1.	16.	1.	2.	0.	177.
2007	112.	43.	4.	0.	1.	16.	1.	2.	0.	179.
2008	113.	43.	4.	0.	1.	17.	1.	2.	0.	181.
2009	114.	44.	4.	0.	1.	17.	1.	2.	0.	183.
AVERAGE ANNUAL GROWTH RATE (%)										
1977 - 1987	1.02	.13	.50	.00	-4.78	2.54	.84	-1.05	-21.10	.74
1987 - 1994	2.46	3.16	2.55	.00	2.64	1.46	2.64	1.02	3.16	2.49
1987 - 2001	1.45	2.42	1.29	.00	1.31	1.15	1.31	1.02	2.42	1.62
1987 - 2009	1.26	2.08	.77	.00	.83	1.10	1.54	.69	2.08	1.41

TABLE D-23

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

BASELINE GAS FORECAST

OTHER PLANNING AREA

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	41.600	17.660	3.400	.000	1.800	2.200	.300	.900	.840	68.700
1978	47.100	16.330	3.100	.000	1.700	2.000	.300	.800	.770	72.100
1979	49.200	20.895	2.000	.000	1.800	2.100	.300	2.000	.805	79.100
1980	45.900	20.015	5.300	.000	1.400	1.800	.300	2.000	1.085	77.800
1981	44.200	6.800	.200	.000	.200	.200	.300	1.000	.000	52.900
1982	40.400	13.110	1.600	.000	.300	.900	.300	1.100	.490	58.200
1983	32.500	14.600	1.500	.000	.300	.800	.300	1.400	.000	51.400
1984	47.000	9.100	1.500	.000	.300	4.900	.300	.700	.000	63.800
1985	37.700	10.100	1.500	.000	.200	.800	.500	.600	.000	51.400
1986	47.000	9.100	1.500	.000	.300	4.900	.300	.700	.000	63.800
1987	37.700	10.100	1.500	.000	.200	.800	.500	.600	.000	51.400
1988	36.075	11.317	1.523	.000	.201	1.151	.429	.677	.000	51.372
1989	35.592	11.973	1.545	.000	.201	1.485	.357	.754	.000	51.907
1990	36.336	12.628	1.568	.000	.202	1.781	.286	.831	.000	53.632
1991	37.185	13.256	1.591	.000	.202	1.995	.214	.908	.000	55.352
1992	38.384	13.889	1.614	.000	.203	2.448	.143	.985	.000	57.666
1993	38.777	14.497	1.636	.000	.233	2.792	.071	1.063	.000	59.070
1994	39.509	15.115	1.659	.000	.233	3.123	.000	1.141	.000	60.780
1995	39.744	15.347	1.659	.000	.233	3.157	.000	1.152	.000	61.293
1996	39.862	15.581	1.659	.000	.233	3.215	.000	1.164	.000	61.715
1997	40.105	15.795	1.659	.000	.233	3.260	.000	1.176	.000	62.228
1998	40.223	16.009	1.659	.000	.233	3.317	.000	1.188	.000	62.629
1999	40.804	16.215	1.659	.000	.233	3.374	.000	1.200	.000	63.485
2000	41.034	16.404	1.659	.000	.262	3.427	.000	1.212	.000	63.999
2001	41.152	16.588	1.659	.000	.262	3.476	.000	1.224	.000	64.362
2002	41.511	16.762	1.659	.000	.262	3.523	.000	1.237	.000	64.955
2003	41.512	16.933	1.659	.000	.262	3.571	.000	1.237	.000	65.175
2004	41.513	17.103	1.659	.000	.262	3.625	.000	1.237	.000	65.400
2005	41.514	17.259	1.659	.000	.262	3.674	.000	1.237	.000	65.605
2006	41.514	17.428	1.659	.000	.262	3.719	.000	1.237	.000	65.820
2007	41.515	17.592	1.659	.000	.262	3.766	.000	1.237	.000	66.032
2008	41.516	17.753	1.659	.000	.262	3.813	.000	1.237	.000	66.241
2009	41.517	17.911	1.659	.000	.262	3.861	.000	1.237	.000	66.447
AVERAGE ANNUAL GROWTH RATE (%)										
1977 - 1987	-.98	-5.43	-7.86	.00	-19.73	-9.62	5.24	-3.97	-100.00	-2.86
1987 - 1994	.67	5.93	1.45	.00	2.23	21.48	-100.00	9.61	.00	2.42
1987 - 2001	.63	3.61	.72	.00	1.96	11.06	-100.00	5.23	.00	1.62
1987 - 2009	.44	2.64	.46	.00	1.24	7.42	-100.00	3.34	.00	1.17

TABLE D-24

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

BASELINE GAS FORECAST

OTHER PLANNING AREA

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	11.	5.	1.	0.	0.	1.	0.	0.	0.	18.
1978	12.	4.	1.	0.	0.	1.	0.	0.	0.	19.
1979	13.	5.	1.	0.	0.	1.	0.	1.	0.	21.
1980	12.	5.	1.	0.	0.	0.	0.	1.	0.	20.
1981	12.	2.	0.	0.	0.	0.	0.	0.	0.	14.
1982	11.	3.	0.	0.	0.	0.	0.	0.	0.	15.
1983	8.	4.	0.	0.	0.	0.	0.	0.	0.	13.
1984	12.	2.	0.	0.	0.	1.	0.	0.	0.	17.
1985	10.	3.	0.	0.	0.	0.	0.	0.	0.	13.
1986	12.	2.	0.	0.	0.	1.	0.	0.	0.	17.
1987	10.	3.	0.	0.	0.	0.	0.	0.	0.	13.
1988	9.	3.	0.	0.	0.	0.	0.	0.	0.	13.
1989	9.	3.	0.	0.	0.	0.	0.	0.	0.	14.
1990	9.	3.	0.	0.	0.	0.	0.	0.	0.	14.
1991	10.	3.	0.	0.	0.	1.	0.	0.	0.	14.
1992	10.	4.	0.	0.	0.	1.	0.	0.	0.	15.
1993	10.	4.	0.	0.	0.	1.	0.	0.	0.	15.
1994	10.	4.	0.	0.	0.	1.	0.	0.	0.	16.
1995	10.	4.	0.	0.	0.	1.	0.	0.	0.	16.
1996	10.	4.	0.	0.	0.	1.	0.	0.	0.	16.
1997	10.	4.	0.	0.	0.	1.	0.	0.	0.	16.
1998	10.	4.	0.	0.	0.	1.	0.	0.	0.	16.
1999	11.	4.	0.	0.	0.	1.	0.	0.	0.	17.
2000	11.	4.	0.	0.	0.	1.	0.	0.	0.	17.
2001	11.	4.	0.	0.	0.	1.	0.	0.	0.	17.
2002	11.	4.	0.	0.	0.	1.	0.	0.	0.	17.
2003	11.	4.	0.	0.	0.	1.	0.	0.	0.	17.
2004	11.	4.	0.	0.	0.	1.	0.	0.	0.	17.
2005	11.	5.	0.	0.	0.	1.	0.	0.	0.	17.
2006	11.	5.	0.	0.	0.	1.	0.	0.	0.	17.
2007	11.	5.	0.	0.	0.	1.	0.	0.	0.	17.
2008	11.	5.	0.	0.	0.	1.	0.	0.	0.	17.
2009	11.	5.	0.	0.	0.	1.	0.	0.	0.	17.

AVERAGE ANNUAL GROWTH RATE (%)

- 1987	-.98	-5.43	-7.86	.00	-19.73	-9.62	5.24	-3.97	-100.00	-2.86
- 1994	.67	5.93	1.45	.00	2.23	21.48	-100.00	9.61	.00	2.42
- 2001	.63	3.61	.72	.00	1.96	11.06	-100.00	5.23	.00	1.62
- 2009	.44	2.64	.46	.00	1.24	7.42	-100.00	3.34	.00	1.17

TABLE D-25

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

BASELINE GAS FORECAST

CALIFORNIA TOTAL

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	6011.900	1841.280	220.591	.000	2505.634	2263.949	1143.500	164.600	78.365	14229.820
1978	5795.700	1736.910	239.909	.100	2163.305	2132.101	1110.300	146.900	83.160	13408.386
1979	6216.900	1768.887	233.686	.100	2633.598	2083.427	1168.518	176.400	21.630	14303.146
1980	5841.200	1630.585	223.123	.100	2716.573	1890.559	1177.418	152.700	10.080	13642.337
1981	5196.600	1547.357	222.723	.000	2627.087	1854.687	1078.130	145.500	10.220	12682.304
1982	5589.400	1659.643	234.287	.000	2298.398	1498.041	1015.830	123.300	54.425	12473.324
1983	5169.500	1574.139	207.368	.000	2220.397	1317.151	754.373	104.400	38.780	11386.108
1984	4911.400	1522.684	205.848	.000	2101.975	1337.214	1054.501	107.400	64.750	11305.772
1985	5244.800	1725.572	209.766	.000	2259.210	1434.333	1143.860	117.000	49.840	12184.381
1986	4795.500	1543.739	206.431	.000	1899.606	1265.735	1183.620	107.700	50.295	11052.625
1987	5142.700	1611.128	206.206	.000	1932.420	1360.892	1318.910	112.800	45.850	11730.906
1988	5347.148	1717.432	208.286	.000	1978.530	1403.368	1296.631	115.454	48.875	12115.725
1989	5357.839	1759.550	210.686	.000	2013.173	1454.567	1551.939	118.339	50.074	12516.166
1990	5367.838	1799.507	212.688	.000	2049.453	1495.799	1811.061	121.432	51.211	12908.989
1991	5383.367	1841.208	214.877	.000	2084.547	1493.307	2007.041	124.538	52.398	13201.282
1992	5395.523	1882.640	217.070	.000	2119.632	1579.314	2206.519	127.658	53.577	13581.932
1993	5406.037	1921.960	219.296	.000	2153.551	1639.783	2409.437	130.792	54.696	13935.551
1994	5416.877	1963.592	221.892	.000	2187.440	1683.634	2615.353	133.940	55.881	14278.610
1995	5434.491	1991.149	222.474	.000	2205.446	1702.677	2661.319	135.341	56.665	14409.562
1996	5443.795	2019.961	223.130	.000	2225.859	1731.564	2704.976	136.755	57.485	14543.524
1997	5455.982	2045.629	223.800	.000	2243.864	1753.748	2750.067	138.186	58.215	14669.491
1998	5467.363	2071.700	224.784	.000	2261.879	1780.424	2795.158	139.629	58.957	14799.894
1999	5480.935	2097.418	225.224	.000	2277.485	1808.041	2837.941	141.089	59.689	14927.821
2000	5495.681	2121.942	225.609	.000	2296.723	1830.966	2883.906	142.564	60.387	15057.779
2001	5512.949	2144.529	226.756	.000	2313.525	1855.326	2926.689	144.052	61.030	15184.856
2002	5533.590	2165.683	227.794	.000	2333.938	1879.026	2924.565	145.551	61.632	15271.781
2003	5556.181	2187.032	228.637	.000	2351.952	1903.755	2922.816	145.551	62.239	15358.165
2004	5580.445	2207.841	229.572	.000	2369.975	1930.639	2921.067	145.551	62.831	15447.921
2005	5610.994	2227.041	230.692	.000	2389.185	1955.895	2916.135	145.551	63.378	15538.871
2006	5638.680	2246.515	231.394	.000	2408.394	1980.482	2916.694	145.551	63.932	15631.642
2007	5670.741	2265.955	232.432	.000	2426.408	2006.369	2914.945	145.551	64.485	15726.886
2008	5707.459	2284.479	233.346	.000	2446.821	2032.585	2912.321	145.551	65.012	15827.575
2009	5746.264	2302.709	234.821	.000	2466.031	2059.543	2907.389	145.551	65.531	15927.838

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1987	-1.55	-1.33	-.67	.00	-2.56	-4.96	1.44	-3.71	-5.22	-1.91
1987 - 1994	.74	2.87	1.05	.00	1.79	3.09	10.27	2.48	2.87	2.85
1987 - 2001	.50	2.06	.68	.00	1.29	2.24	5.86	1.76	2.06	1.86
1987 - 2009	.51	1.64	.59	.00	1.11	1.90	3.66	1.17	1.64	1.40

TABLE D-26

CALIFORNIA ENERGY COMMISSION
FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

BASELINE GAS FORECAST

CALIFORNIA TOTAL

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	1569.	481.	58.	0.	654.	591.	298.	43.	20.	3714.
1978	1513.	453.	63.	0.	565.	556.	290.	38.	22.	3500.
1979	1623.	462.	61.	0.	687.	544.	305.	46.	6.	3733.
1980	1525.	426.	58.	0.	709.	493.	307.	40.	3.	3561.
1981	1356.	404.	58.	0.	686.	484.	281.	38.	3.	3310.
1982	1459.	433.	61.	0.	600.	391.	265.	32.	14.	3256.
1983	1349.	411.	54.	0.	580.	344.	197.	27.	10.	2972.
1984	1282.	397.	54.	0.	549.	349.	275.	28.	17.	2951.
1985	1369.	450.	55.	0.	590.	374.	299.	31.	13.	3180.
1986	1252.	403.	54.	0.	496.	330.	309.	28.	13.	2885.
1987	1342.	421.	54.	0.	504.	355.	344.	29.	12.	3062.
1988	1396.	448.	54.	0.	516.	366.	338.	30.	13.	3162.
1989	1398.	459.	55.	0.	525.	380.	405.	31.	13.	3267.
1990	1401.	470.	56.	0.	535.	390.	473.	32.	14.	3369.
1991	1405.	481.	56.	0.	544.	390.	524.	33.	14.	3446.
1992	1408.	491.	57.	0.	553.	412.	576.	33.	14.	3545.
1993	1411.	502.	57.	0.	562.	428.	629.	34.	14.	3637.
1994	1414.	512.	58.	0.	571.	439.	683.	35.	15.	3727.
1995	1418.	520.	58.	0.	576.	444.	695.	35.	15.	3761.
1996	1421.	527.	58.	0.	581.	452.	706.	36.	15.	3796.
1997	1424.	534.	58.	0.	586.	458.	718.	36.	15.	3829.
1998	1427.	541.	59.	0.	590.	465.	730.	36.	15.	3863.
1999	1431.	547.	59.	0.	594.	472.	741.	37.	16.	3896.
2000	1434.	554.	59.	0.	599.	478.	753.	37.	16.	3930.
2001	1439.	560.	59.	0.	604.	484.	764.	38.	16.	3963.
2002	1444.	565.	59.	0.	609.	490.	763.	38.	16.	3986.
2003	1450.	571.	60.	0.	614.	497.	763.	38.	16.	4008.
2004	1456.	576.	60.	0.	619.	504.	762.	38.	16.	4032.
2005	1464.	581.	60.	0.	624.	510.	761.	38.	17.	4056.
2006	1472.	586.	60.	0.	629.	517.	761.	38.	17.	4080.
2007	1480.	591.	61.	0.	633.	524.	761.	38.	17.	4105.
2008	1490.	596.	61.	0.	639.	531.	760.	38.	17.	4131.
2009	1500.	601.	61.	0.	644.	538.	759.	38.	17.	4157.

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1987	-1.55	-1.33	-.67	.00	-2.56	-4.96	1.44	-3.71	-5.22	-1.91
1987 - 1994	.74	2.87	1.05	.00	1.79	3.09	10.27	2.48	2.93	2.85
1987 - 2001	.50	2.06	.68	.00	1.29	2.24	5.86	1.76	2.07	1.86
1987 - 2009	.51	1.64	.59	.00	1.11	1.90	3.66	1.17	1.63	1.40

TABLE D-27

PG & E UTILITY NATURAL GAS DEMAND
mmcfd

	Core			Noncore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	TOTAL
1987	531	155	114	57	310	25	80	678	1950
1988	579	168	103	62	280	30	95	766	2083
1989	571	171	109	63	295	36	195	350	1790
1990	564	174	114	64	308	41	224	286	1775
1991	558	177	117	65	317	47	248	291	1820
1992	551	180	118	66	320	52	255	287	1829
1993	545	183	122	68	330	51	268	284	1851
1994	538	187	126	69	340	50	273	292	1875
1995	539	189	127	70	344	49	280	301	1899
1996	538	191	129	71	348	48	288	308	1921
1997	538	194	131	72	353	47	306	309	1950
1998	539	196	132	72	358	45	318	316	1976
1999	539	198	134	73	363	44	329	325	2005
2000	539	199	136	74	367	43	336	354	2048
2001	541	202	137	75	371	42	339	369	2076
2002	542	204	139	75	376	41	342	383	2102
2003	544	205	141	76	380	40	345	408	2139
2004	545	207	143	76	385	39	347	435	2177
2005	548	208	144	77	390	38	351	472	2229
2006	550	210	146	77	395	37	352	510	2277
2007	553	212	148	79	399	36	353	556	2336
2008	556	214	149	79	404	36	355	604	2397
2009	559	215	151	80	409	36	357	652	2459

Source: DAO Natural Gas Forecast for the 1989 Fuels Report, June 1, 1989.
Revised ER 8 UEG Forecaast, July 13, 1989.
NARG model run, November 6, 1989.

TABLE D-28

SOCAL GAS UTILITY NATURAL GAS DEMAND
mmcfd

	Core			Noncore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	TOTAL
1987	715	143	97	96	215	236	77	843	2422
1988	715	149	91	100	203	219	153	544	2175
1989	723	153	95	102	211	202	284	393	2163
1990	731	157	99	104	221	185	297	443	2237
1991	740	161	101	107	225	168	312	455	2269
1992	748	164	105	110	233	151	322	435	2268
1993	755	168	109	112	243	145	325	474	2332
1994	763	172	112	115	249	140	329	522	2402
1995	767	174	114	116	253	134	333	558	2449
1996	769	176	115	118	257	129	340	593	2497
1997	771	179	117	119	260	123	340	608	2517
1998	774	181	119	120	264	116	328	661	2562
1999	776	183	120	122	267	108	318	712	2606
2000	779	185	122	123	271	100	320	742	2641
2001	782	187	123	124	274	93	321	792	2696
2002	785	188	125	125	278	85	323	851	2760
2003	788	190	127	126	282	78	325	888	2803
2004	792	191	128	128	284	72	327	913	2835
2005	796	193	130	128	289	65	329	951	2880
2006	800	194	131	129	292	59	332	975	2912
2007	805	196	133	130	295	52	334	1000	2945
2008	810	197	134	132	299	48	337	1035	2992
2009	816	199	136	132	302	43	339	1058	3025

Source: DAO Natural Gas Forecast for the 1989 Fuels Report, June 1, 1989.
Revised ER 8 UEG Forecaast, July 13, 1989.
NARG model run, November 6, 1989.

TABLE D-29

SDG & E UTILITY NATURAL GAS DEMAND
mmcfd

	Core			Noncore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	TOTAL
1987	86	25	11	7	5	0	12	145	291
1988	93	27	12	8	5	0	22	107	275
1989	94	28	12	8	5	0	30	126	303
1990	96	28	12	8	5	0	36	120	305
1991	98	29	12	8	5	0	36	122	310
1992	99	29	12	8	5	0	36	124	313
1993	101	30	12	8	5	0	36	130	322
1994	102	30	12	9	6	0	38	126	323
1995	103	30	12	9	6	0	38	163	361
1996	103	31	12	9	6	0	38	186	385
1997	104	32	12	9	6	0	38	184	385
1998	104	32	12	9	6	0	38	187	388
1999	105	33	12	9	6	0	38	188	391
2000	105	33	12	9	6	0	38	195	398
2001	106	34	12	9	6	0	38	211	416
2002	107	34	13	10	6	0	38	222	430
2003	108	34	13	10	6	0	38	224	433
2004	108	35	13	10	6	0	38	226	436
2005	110	35	13	10	6	0	38	222	434
2006	111	36	13	10	6	0	38	228	442
2007	112	37	13	10	6	0	38	236	452
2008	113	37	14	10	6	0	38	253	471
2009	114	37	14	11	6	0	38	262	482

Source: DAO Natural Gas Forecast for the 1989 Fuels Report, June 1, 1989.
Revised ER 8 UEG Forecaast, July 13, 1989.
NARG model run, November 6, 1989.

TABLE D-30

CALIFORNIA STATEWIDE UTILITY NATURAL GAS DEMAND
mmcfd

	Core			Concore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	TOTAL
1987	1332	323	222	160	530	260	169	1666	4663
1988	1387	345	206	169	489	249	270	1417	4533
1989	1388	352	215	173	511	237	509	869	4256
1990	1391	358	225	177	534	226	557	849	4317
1991	1396	366	230	181	547	214	596	868	4398
1992	1398	373	235	184	559	203	613	846	4410
1993	1401	381	243	188	579	196	629	888	4505
1994	1403	390	250	193	595	190	640	940	4600
1995	1409	393	253	195	603	183	651	1022	4709
1996	1410	399	256	197	611	176	666	1087	4803
1997	1413	405	260	200	619	170	684	1101	4852
1998	1417	408	263	202	627	161	684	1164	4926
1999	1420	414	266	204	636	152	685	1225	5002
2000	1423	417	270	206	643	144	694	1291	5087
2001	1429	422	272	209	651	135	698	1372	5188
2002	1434	426	277	210	660	126	703	1456	5292
2003	1440	429	280	212	668	118	708	1520	5375
2004	1445	433	283	214	676	111	712	1574	5448
2005	1454	436	287	215	685	103	718	1645	5543
2006	1461	439	290	217	693	95	722	1713	5631
2007	1470	445	293	219	701	88	725	1792	5733
2008	1479	448	297	221	709	83	730	1892	5860
2009	1489	451	301	223	717	79	734	1972	5966

Source: DAO Natural Gas Forecast for the 1989 Fuels Report, June 1, 1989.
Revised ER 8 UEG Forecaast, July 13, 1989.
NARG model run, November 6, 1989.

APPENDIX E

NATURAL GAS SUPPLY AND PRICE FORECAST

APPENDIX E

NATURAL GAS SUPPLY AND PRICE FORECAST

This Appendix provides the basic assumptions and methodology used to generate the natural gas supply and price forecast. There are three parts to this Appendix. Part I presents the natural gas supply forecast and discusses the underlying assumptions and methodologies. Similarly Part II concerns the natural gas price forecast. Finally, Part III presents detailed natural gas supply and price tables.

I. NATURAL GAS SUPPLY FORECAST

The basic tool used to develop the natural gas supply forecast was the North America Regional Gas model (NARG). This model simulates the US and Canadian natural gas markets, solving for end use and wellhead prices that will balance gas demand with supply.

In simplistic terms the model starts with a natural gas supply and moves it from the production areas through the transportation and distribution networks to end users. A price is determined that the gas customers would be willing to pay for that quantity of gas. This price is then passed back through the distribution and transportation systems to determine how much natural gas the producers are willing to produce at that price. If the resultant production is equivalent to the previous gas supply that passed through the system then equilibrium has been reached. If the quantities are not the same the model will go through additional iterations that shifts supply incrementally closer to the production levels until a specified level of equilibrium has been reached. The model does this simultaneously for all supply and demand areas.

A. Natural Gas Supply Forecast Assumptions

Important features that were included in the assumptions concern new and existing pipeline capacity and transport costs, natural gas demand, oil price forecast, and natural gas resources. These parameters were drawn from the various pipeline cases and sensitivity cases determined in the An Economic Evaluation of Alternative Interstate Pipeline Projects to Serve California and the subsequent additional sensitivity cases. Deviations from these are discussed below.

Pipeline Assumptions Four proposed pipelines were included in the base supply case. These were the PGT expansion to Southern California, a Rocky Mountain pipeline to EOR with links to the local distribution companies, the scaled down Altamont project which would deliver gas from Alberta, Canada to the Rocky Mountain pipe-

line, and the proposed Mojave pipeline which would deliver gas from both El Paso Natural Gas and Transwestern pipeline systems to enhanced oil recovery (EOR). The start up dates, capacities and levelized transport costs are given in Table E-1.

TABLE E-1

ASSUMPTIONS FOR PROPOSED NEW PIPELINES

Pipeline	Availability	Capacity mmcfd	Transport Cost $/mcf
PGT Loop	1993	700	0.65
Rocky Mountain	1993	700	0.50
Altamont	1993	700	0.60
Mojave	1993	400	0.35

Modifications to transport cost and configurations were made in the NARG for Northern Border and Trail Blazer pipeline systems. These modifications are based on current discussions between the pipe lines and their customers. These two pipelines would compete with California suppliers for gas supplies from Alberta Canada and the Rocky Mountain supply region. The results of these modifications would place these two pipelines in a better competitive position.

Northern Border Pipeline, which transports gas from Alberta to the Midwest is near a settlement which would significantly reduce its transport costs. Additionally, it has been proposed to expand this pipeline's capacity from 1.5 bcfd to 2 bcfd by adding compression facilities on the existing system. This will have the effect of further reducing transport costs. It is also anticipated that the pipeline will be extended to the East North Central Region, opening up additional demand to be served.

For the supply forecast it was assumed that the result of the Northern Border settlement and expansion would provide a transport cost of $0.65 per mcf and would be effective by 1991. It was assumed the pipeline would be extended to serve the East North Central region with a capacity of 1 bcfd, and would be operational by 1993 at a cost of $0.75 per mcf.

The Trail Blazer system transports gas from the Rocky Mountains, to the East North Central Region. As is the case for Northern Border, this pipeline system[1] is in the process of reaching a transport cost settlement with its customers. The result of these negotiations would be to provide a significantly lower transport cost than is presently available. For this supply forecast it was

assumed this settlement would lead to a transport cost of $0.61 per mcf.

The El Paso Natural Gas Company is presently moving gas by displacement from the San Juan Basin to the Permian Basin. It is possible that because of potentially increasing San Juan production, gas could sometime in the future physically move from the San Juan Basin in El Paso's pipeline to the Permian Basin, thence into the Gulf Coast or northward into the MidWest and Eastern seaboard. The model was modified to allow this to occur after the year 1992 at a price of $0.15 per mcf.

In previous analysis, British Columbia natural gas production was not able to flow directly to California. Modifications to the model's pipeline network have been made that now allow for direct flow of this gas to California.

Natural Gas Demand Assumptions Natural gas demand assumptions are discussed in Appendix D. A compilation of the demand forecasts served by gas utility and non gas utility entities are provided at the end of Appendix D.

Oil Price Assumptions The Delphi V oil price forecast was used in generating the natural gas price and supply forecast. In the NARG model the crude oil price forecast was used to set a ceiling on noncore natural gas prices. This was uniformly applied across all demand areas except in California. In the California local distribution service areas a 10 percent premium was applied. For California's EOR market the premium was not applied. In addition, a constraint was added to inhibit oil use in the Los Angeles Basin, following the policy recommendation of Southern California Air Quality Management District (SCAQMD) on burning cleaner fuels. Appendix F discusses the methodology and assumptions for the Delphi V oil price forecast.

Natural Gas Resource Assumptions Coal seam and conventional natural gas resource estimates for the San Juan Basin were updated.

It is apparent from the rapid development that is occurring, natural gas production from the San Juan Basin Fruitland Formation coal seams will be an important resource used to help meet California's future natural gas supply needs. Lacking current information on the characteristics of this resource a joint study was undertaken.

The study was performed by the Commission Staff, then reviewed and commented on by a Southwest Coal Seam Study Group. The group was headed by the New Mexico Oil Conservation Commission with representatives from El Paso Natural Gas Company, Enron and several of the major coal seam gas producers. Comments of the group were incorporated into the study.

The coal seam resource cost curve provided on Figure E-1 is a product of the study.[2] As the curve indicates the coal seam resource is an apparently abundant and cheap resource. Nearly 15 Tcf are potentially available for a capital cost of $0.20 per mcf and an additional 14 Tcf for $0.60 per mcf.

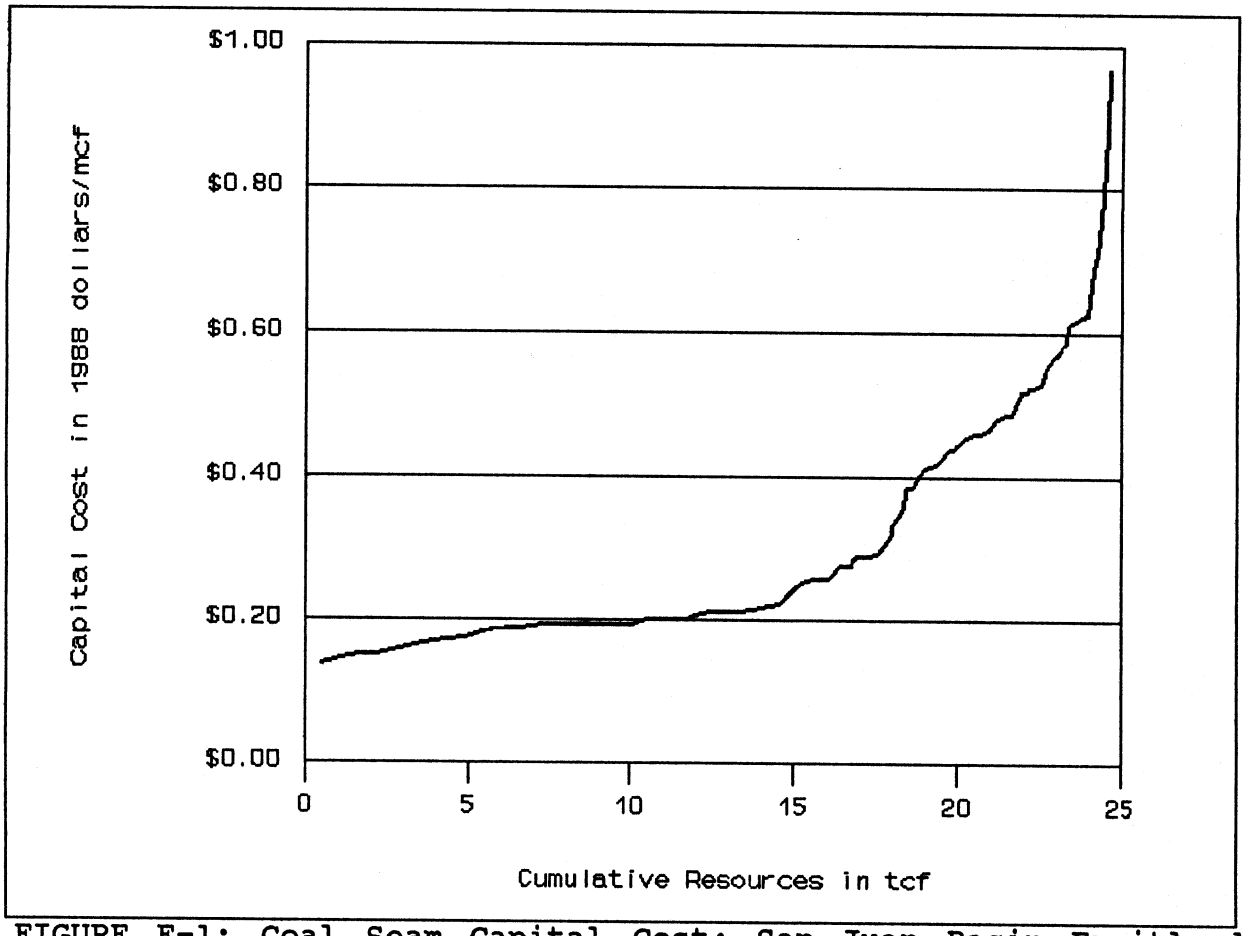


FIGURE E-1: Coal Seam Capital Cost; San Juan Basin Fruitland Formation

The resource portion of the curve is principally based on the ICF-Lewin report A Geologic Assessment of Natural Gas from Coal Seams in the Fruitland Formation, San Juan Basin. This report provides information on the areal extent of the resource, concentration, coal seam thickness and depth to the coal seams. The capital cost portion of the curve is based both on 1987 API drilling statistics for the San Juan Basin and the First Boston E & P Perspective Fruitland Coal Seam Gas: An Unconventional Resource Revitalizes the San Juan Basin issued on December 22, 1988.

The general procedure used to develop the resource cost curve was to estimate recoverable resources for each Township within a defined area and the respective capital cost for development,

treatment and delivering gas to a pipeline. The potential recoverable resource curve was determined by accumulating recoverable resources by ascending unit capital costs. Important assumptions include recovery factors from 50 to 70 percent, four wells per section, and high drilling success rates.

In running NARG with the new coal seam resource estimates it was found that in the unconstrained mode the coal seam resources were being developed at rates far above present day levels. Recoverable reserve additions were constrained to 1.1 Tcf per year. This would represent the completion of about 500 average new wells each year.

The conventional San Juan resources were updated to reflect proven reserves as published by the New Mexico Oil Conservation Division.

B. Natural Gas Supply Forecast

The natural gas supply forecast provides for all of the gas utility core requirements and about 88 percent of the noncore gas requirements. While gas supplies are plentiful, the price bumps into the alternative fuel oil prices. This causes the noncore customers to fuel switch from natural gas to fuel oil. EOR continues to consume some quantities of oil but to a lesser extent than presently.

As Figure E-2 indicates the southwest continues to be the largest supplier of natural gas to California. Of the Southwest supply sources, the San Juan Basin will play a greater role in meeting California's future supply needs. The coal seams production from the San Juan Basin is a major contributor to that supply. Its importance may be seen in Figure E-3 which provides a comparison between San Juan conventional and coal seam forecasted production levels.

The San Juan Basin will also continue to supply a portion of the West North Central natural gas requirements. The reversal of the El Paso Permian to San Juan Basin pipeline in the NARG allowed substantial quantities of San Juan natural gas to flow east (see Figure E-4).

The other traditional southwest supply areas, including the Permian and Anadarko Basins, do not play a major role in supplying gas to California. While production in these basins increases (see Figure E-5), the flow is to other demand centers.

Canadian supply increases its share of the California market as the result of including a looping of the PGT system and expansion into Southern California. Both Alberta and British Columbia contribute increasing Canadian gas supplies to California. Table E-2 shows forecast estimates of British Columbia and Alberta supply coming to California.

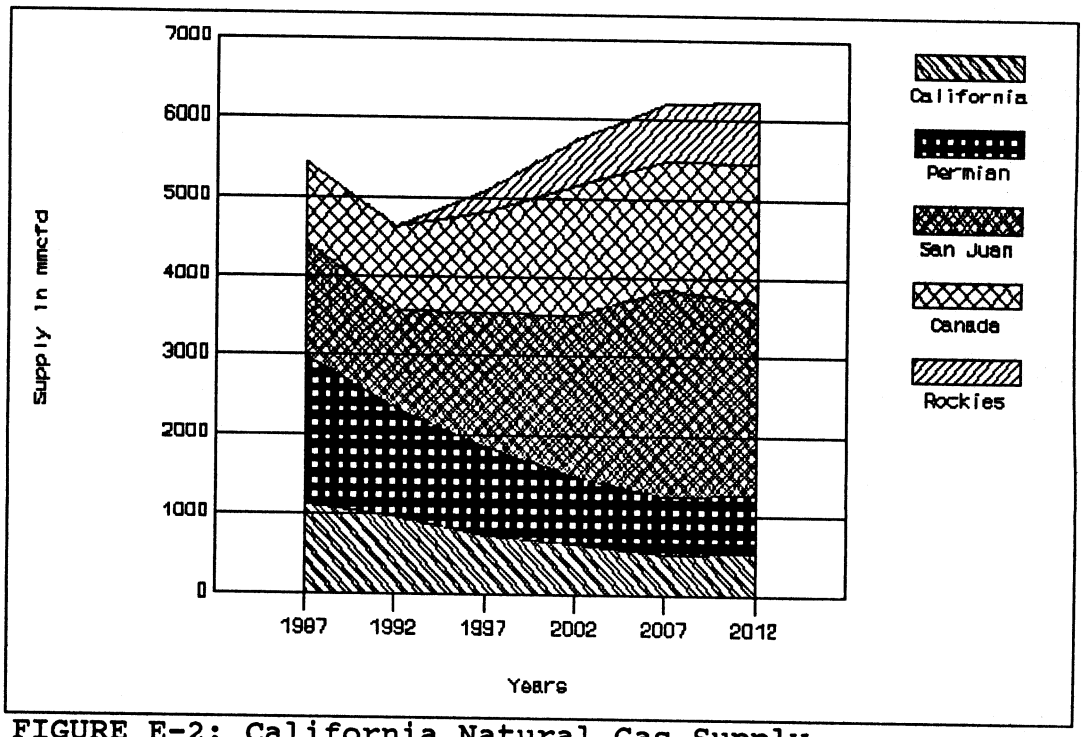


FIGURE E-2: California Natural Gas Supply

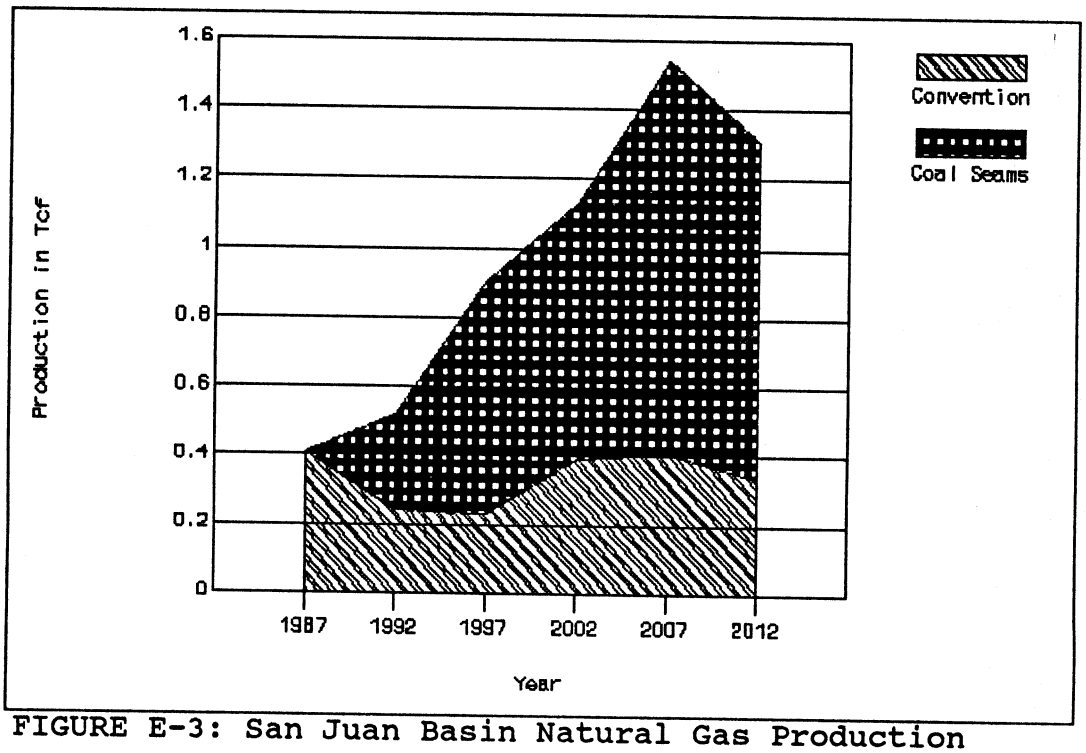


FIGURE E-3: San Juan Basin Natural Gas Production

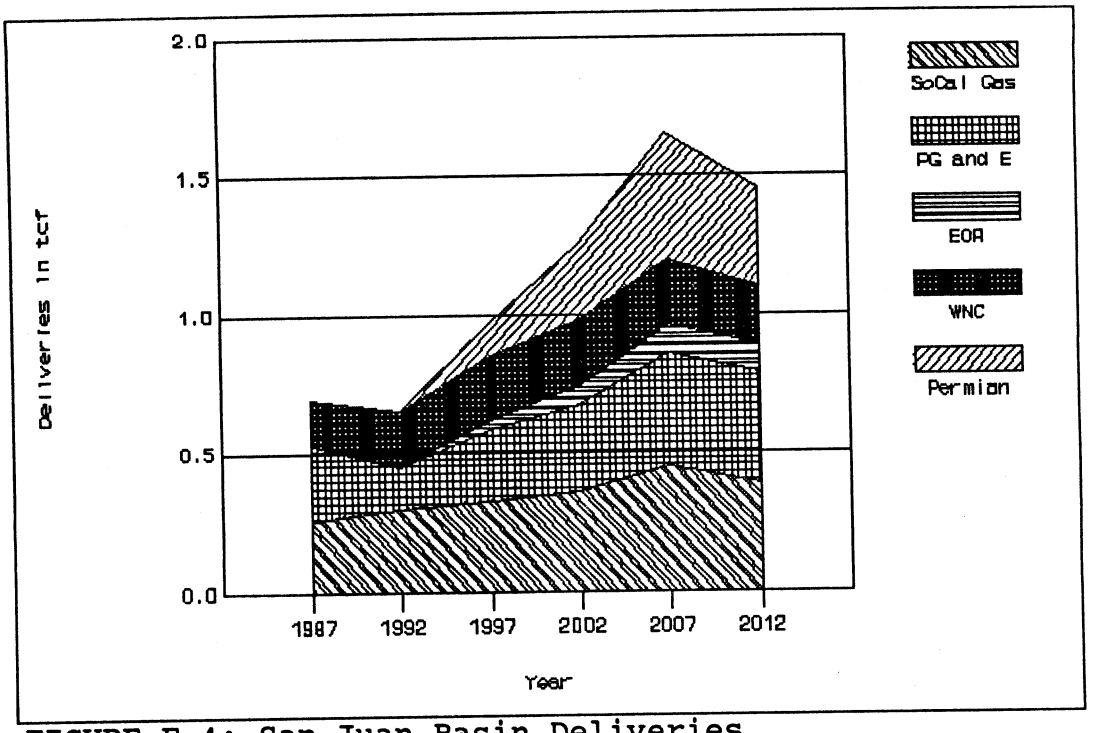


FIGURE E-4: San Juan Basin Deliveries

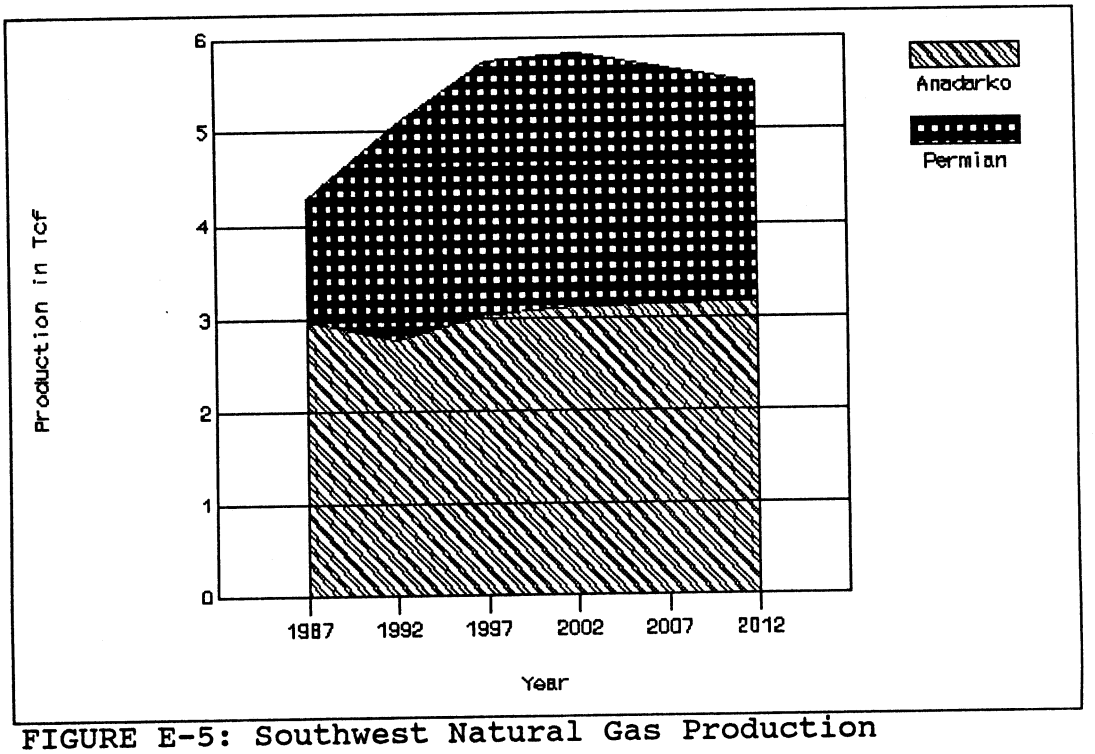


FIGURE E-5: Southwest Natural Gas Production

TABLE E-2

ALBERTA AND BRITISH COLUMBIA SUPPLY SPLITS
mmcfd

Year	British Columbia	Alberta	Total
1997	140	1,140	1,280
2002	200	1,430	1,630
2007	220	1,410	1,630
2012	480	1,280	1,760

Source: NARG Model Run, November 6, 1989.

Because of the inclusion of the Rocky Mountain Pipeline, gas supplies from the Rockies flow directly to California and grow in importance. While the Altamont project does feed gas into the Rocky Mountain supply area it is impossible to tell what portions of this supply would come to California or flow elsewhere. California onshore and offshore production hold constant for a short period before declining.

Northern California Supply As seen on Figure E-6, Canada contributes a major portion of northern California's natural gas supply. Both Alberta and British Columbia provide gas supplies via the existing PGT system and its parallel looping.

Southwest supply to Northern California grows after 1992. This is principally due to low cost coal seam gas production from the San Juan Basin. Eastern New Mexico and Western Texas production increases but flows to eastern demand centers.

Northern California only slightly benefits from the Rocky Mountain Pipeline. Northern California production continues its recent decline well into the future years.

Southern California Supply Figure E-7 displays the supply forecast for Southern California. While southwest supplies decline they continue to provide the majority of Southern California's natural gas supply. Coal seam gas production plays a major part in the southwest's contribution to Southern California.

The PGT loop and Rocky Mountain pipelines offset the declining southwest supply. Both of these supply sources grow in importance after the 1992 time period.

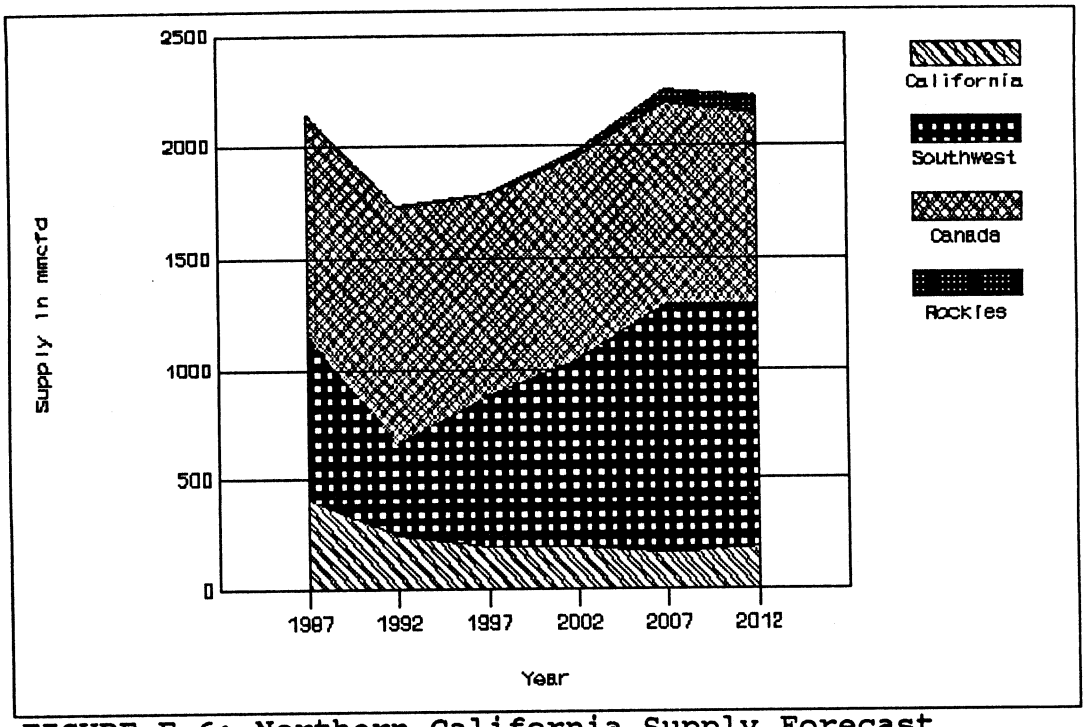


FIGURE E-6: Northern California Supply Forecast

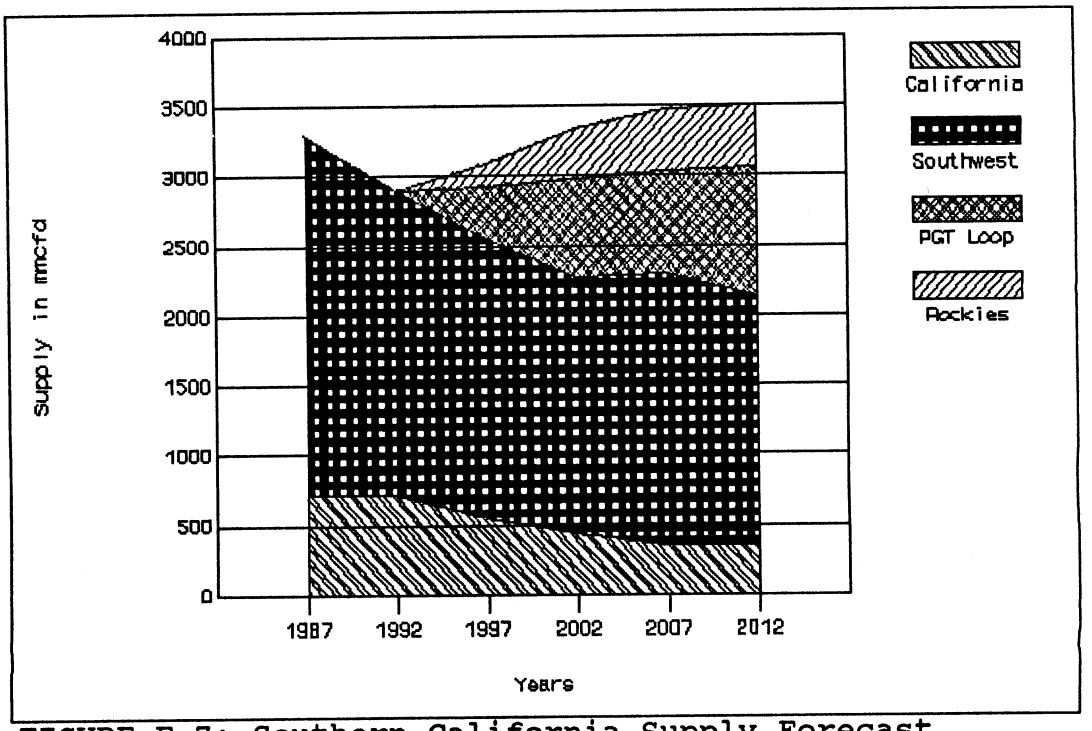


FIGURE E-7: Southern California Supply Forecast

Southern California production maintains its present level of production for about another five years. There after production declines.

<u>EOR Gas and Oil Use</u> California's EOR demand for gas and oil is estimated to grow for the next few years before peaking in the 2005 time frame.[3] Figure E-8 provides a visual display of the forecast for EOR gas and oil supply.

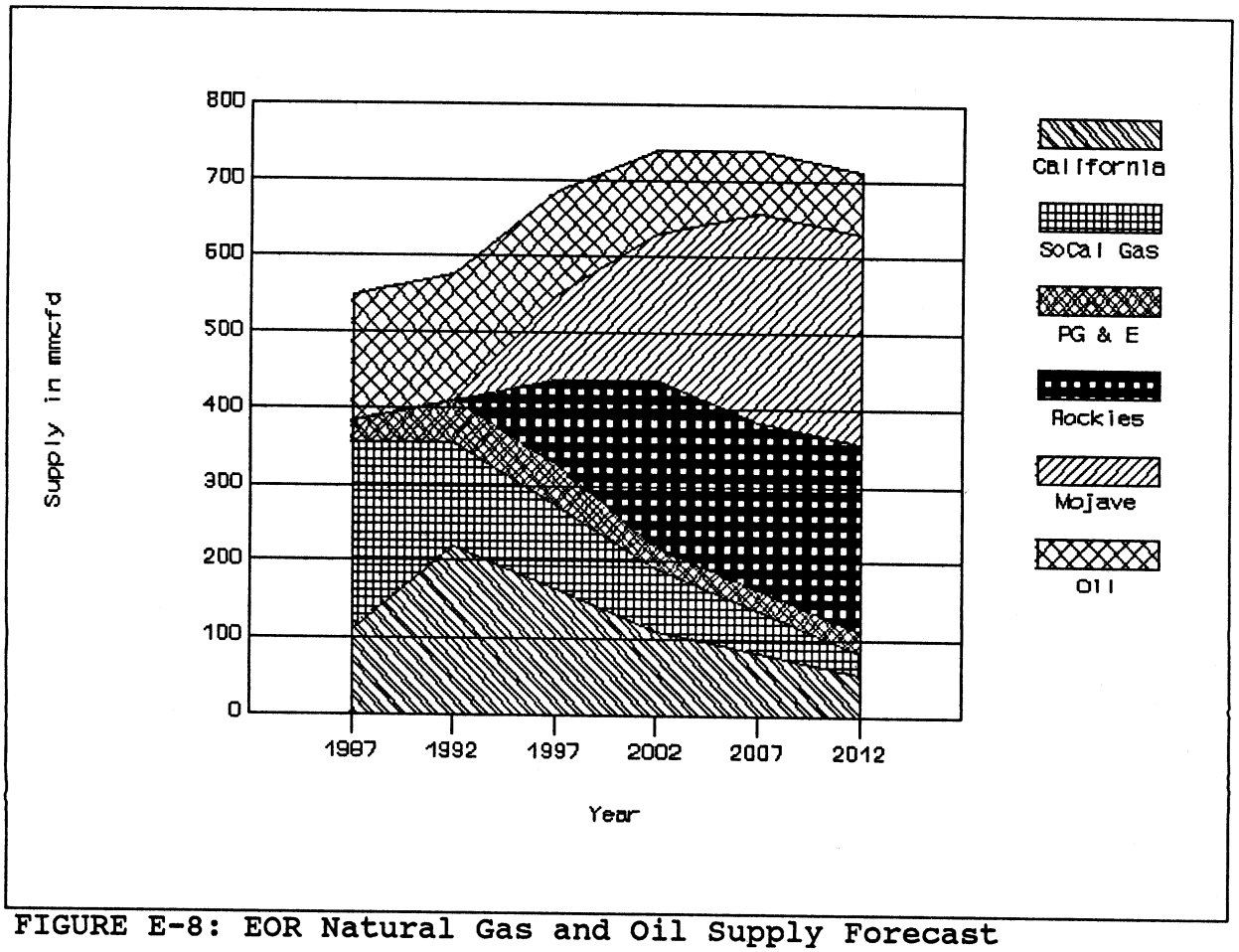


FIGURE E-8: EOR Natural Gas and Oil Supply Forecast

In this forecast California direct sales to the EOR market peak in the early 1990s and then gradually decline. Sales and transport by SoCalGas and PGandE decline after the Rocky Mountain and Mojave pipeline systems become operational. These new projects become the major sources of EOR gas supplies.

II. NATURAL GAS PRICE FORECASTS

This section discusses assumptions and procedures used to determine the end use price forecast. The key assumptions concerning the price forecast are, first, in the long term, average natural gas purchased costs at the border (commodity costs) for core and non-core supply will be the same. Second, the gas utility will be indifferent to whether it sells or transports gas to its end users. In either case the contribution to fixed costs will be the same. Finally the fixed distribution costs were allocated to the various sectors based on recent CPUC decisions.

A. Assumptions

The NARG model was used to determine natural gas border costs. Individual utility distribution costs were then added to obtain a total cost of acquiring and delivering gas to the end use customers. End use prices for each sector were then determined by applying CPUC end use pricing policies. The following section discusses the procedures in greater detail.

Border Cost Assumptions The NARG model was used to determine the cost of gas delivered to the California border. As indicated earlier the NARG determines a well head price for each of the supply areas, allocates the gas with the corresponding wellhead price to each of the pipeline systems serving the supply area, and then adds on transportation and fuel costs to obtain the average border price from each supply area. The transportation costs on the pipelines serving California from the Southwestern supply regions were modified to reflect only the volumetric charges. The demand charges were included with the local distribution company margins for the respective utilities.

Border price and supply are simultaneously determined. The assumptions concerning resources and transportation used in the NARG were discussed under the natural gas supply assumptions in the previous section.

Utility Distribution Costs The utility distribution costs represent those costs which are associated with the operation, maintenance and administration of their system. These costs do not include the cost of purchasing natural gas but they do include demand charges the gas utilities pay to the interstate pipelines. Accordingly, these demand charges have been subtracted from the costs to transport interstate gas to California. Table E-3 provides a summary of the distribution costs used by the Commission in this forecast.

Several methods were used to forecast the distribution cost escalation rates for the gas utilities. For PGandE the escalation rate from the last Fuels Report was used.[4] The 1989 California Gas

Report provides a commodity cost and system average cost forecast for SoCalGas. These cost forecasts, coupled with the sendout forecast, were used to estimate the SoCalGas distribution cost escalation rates. SDG&E provided its forecast on the fixed costs that were developed for the SDG&E and SCE merger filings with the CPUC. These costs were used to determine an escalation rate for SDG&E.

TABLE E-3

ANNUAL FORECASTED DISTRIBUTION COSTS
1989 $ in Millions

Year	PGandE[1]	SoCalGas[2]	SDG&E[3]
1989[4]	1,411	1,628	218.6
1990	1,431	1,805	217.5
1995	1,533	2,025	235.6
2000	1,631	2,219	246.1
2005	1,740	2,325	255.1
2009	1,810	2,545	256.1

[1]Based on 1987 Fuels Report.
[2]Based on 1989 California Gas Report.
[3]Based on SDG&E and SCE merger.
[4]Based on CPUC Decision 87-12-039

While several methods were used to forecast the utilities distribution costs, they each had CPUC Decision 87-12-039 in common. The 1989 base year distribution costs were obtained from this decision. The escalation rates were then applied to the 1989 base year cost to arrive at the forecasted distribution costs. From the CPUC Decision allocation factors were determined to spread the distribution costs across the core and noncore sectors. Allocation factors used in generating the price forecasts are provided in Table E-4.

In this forecast economic fuel switching to oil in the noncore sector occurs. Fuel switching may have an effect on the gas utilities ability to collect all of its distribution expenses. In the end use gas price tables provided in this Appendix contributions to distribution costs are represented on a unit $ per mcf basis. In actuality they would also be collected on a lump sum basis in the form of monthly and annual demand charges.

It was assumed that uncollected noncore distribution costs resulting from fuel switching would be transferred to the core customers. The potential under collection of distribution costs was determined by multiplying the unit distribution charge times the equivalent volume of gas that was switched to alternative fuels. It was assumed that 50 percent of the potential loss of distribution cost revenues would be paid by the fuel switchers in the form of demand charges. The remaining 50 percent would not be paid by the noncore customers due to either of the following two reasons. First, demand charges would not be paid by noncore customers leaving the system; or second, the customers would not pay the volumetric charges for volumes not taken.

TABLE E-4

DISTRIBUTION COST ALLOCATION FACTORS[1]

	PGandE	SCG	SDG&E
Core	.699	.769	.677
Noncore	.301	.231	.323
Com/Ind	.461	.291	.120
TEOR	.001	.034	N/A
Cogen	.180	.247	.131
UEG	.358	.428	.749

[1]Based on CPUC Decision 87-12-039.

The noncore customers also had a variable cost applied to them. It was assumed that these costs would be $0.15 per mcf for noncore commercial, industrial, EOR and UEG customers. As this charge represents primarily compressor fuel it was escalated in parallel with the gas utilities commodity costs. Variable charges were not applied to the core customers.

B. End Use Price Forecast

Table E-5 provides a summary of the price forecast by sector and utility. Tables at the end of this Appendix provide additional details on the price forecast.

TABLE E-5

CALIFORNIA END USE PRICE SUMMARY BY SECTOR
1989 $ per mcf

	Core			Noncore					System
	Res	Com	Ind	Com	Ind	TEOR	Cogen	UEG	Average
PGandE									
1989	5.45	5.45	5.45	3.61	3.61	2.14	2.97	2.95	3.95
1990	5.35	5.35	5.35	3.61	3.61	2.18	3.14	3.18	4.10
1995	5.94	5.94	5.94	3.92	3.92	2.51	3.62	3.62	4.71
2000	6.53	6.53	6.53	4.41	4.41	2.98	4.00	4.00	5.14
2005	7.19	7.19	7.19	5.01	5.01	3.53	4.48	4.48	5.59
2009	7.82	7.82	7.82	5.62	5.62	4.07	4.96	4.96	6.16
SoCalGas									
1989	5.82	5.82	5.82	3.30	3.30	2.52	3.18	3.61	4.07
1990	6.25	6.25	6.25	3.46	3.46	2.65	3.33	3.64	4.46
1995	6.90	6.90	6.90	3.88	3.88	3.21	3.84	3.84	5.29
2000	7.62	7.62	7.62	4.40	4.40	3.86	4.26	4.26	5.74
2005	8.31	8.31	8.31	5.07	5.07	4.82	4.82	4.82	6.29
2009	9.17	9.17	9.17	5.73	5.73	5.91	5.43	5.43	7.05
SDG&E									
1989	5.47	5.47	5.47	4.11	4.11	0.00	3.45	3.39	4.41
1990	5.56	5.56	5.56	4.21	4.21	0.00	3.55	3.53	4.59
1995	6.13	6.13	6.13	4.67	4.67	0.00	3.75	3.84	5.34
2000	6.68	6.68	6.68	5.16	5.16	0.00	4.19	4.24	5.67
2005	7.20	7.20	7.20	5.76	5.76	0.00	4.81	4.83	6.16
2009	7.71	7.71	7.71	6.33	6.33	0.00	5.35	5.35	6.76

ENDNOTES

1. The Trail Blazer system consists of three pipeline segments, the Overthrust Pipeline, Wyoming Interstate, and the Trail Blazer Pipeline.

2. The costs provided by this study reflect capital costs associated with drilling and developing the Fruitland coal seam resource and conditioning the natural gas stream. Other costs such as banking, royalties, taxes, operation and maintenance, profits and tax incentives were not included.

3. EOR gas and oil demand for steaming are based on the CEC Biennial Fuels Report, Appendices, Sept 1986.

4. CEC, Fuels Report Appendices, Appendix C, Dec 1987.

III. DETAILED NATURAL GAS PRICE AND SUPPLY TABLES

TABLE E-6

CALIFORNIA GAS SUPPLY COST
1989 $ per mcf

Source	1987	1992	1997	2002	2007	2012
Northern Calif Prod	1.72	2.03	2.51	3.05	3.71	4.42
Southern Calif Prod	1.44	2.25	2.77	3.37	4.08	4.84
California Offshore	1.85	2.41	2.97	3.56	4.31	5.00
El Paso	1.79	2.16	2.50	3.02	3.51	4.47
Transwestern	1.71	2.21	2.69	3.34	3.95	4.70
PGT	1.58	1.83	2.41	2.94	3.61	4.40
Rocky Mountain Pl	--	--	2.54	3.05	3.66	4.48
Mojave	--	--	2.54	3.07	3.55	4.52

TABLE E-7

CALIFORNIA NATURAL GAS SUPPLY SUMMARY
mmcfd

Source	1987	1992	1997	2002	2007	2012
Northern Calif Prod	411	247	192	192	164	192
Southern Calif Prod	630	630	493	384	301	274
California Offshore	82	82	55	55	55	82
El Paso	2548	2000	2192	2274	2712	2521
Transwestern	767	603	493	411	356	356
PGT	986	1068	1288	1644	1616	1753
Rocky Mountain PL	0	0	274	603	712	767
Mojave	0	0	110	192	274	274
Total	5425	4630	5096	5753	6192	6219

TABLE E-8

NORTHERN CALIFORNIA NATURAL GAS SUPPLY
mmcfd

Source	1987	1992	1997	2002	2007	2012
Northern Calif Prod	411	247	192	192	164	192
El Paso	740	411	685	849	1123	1096
PGT	986	1068	904	904	904	849
Rocky Mountain PL	0	0	0	27	55	82
Total	2137	1726	1781	1973	2247	2219

TABLE E-9

SOUTHERN CALIFORNIA NATURAL GAS SUPPLY
mmcfd

Source	1987	1992	1997	2002	2007	2012
Southern Calif Prod	630	630	493	384	301	274
California Offshore	82	82	55	55	55	82
El Paso	1808	1589	1507	1425	1589	1425
Transwestern	767	603	493	411	356	356
PGT	0	0	384	712	740	932
Rocky Mountain PL	0	0	164	356	438	438
Total	3288	2904	3096	3342	3479	3507

TABLE E-10

CALIFORNIA EOR NATURAL GAS SUPPLY
mmcfd

Source	1987	1992	1997	2002	2007	2012
Southern Calif Prod	123	205	175	123	79	52
SoCal Gas	219	151	123	85	52	30
PG and E	30	52	47	41	36	36
Rocky Mountain PL	0	0	110	213	227	242
Mojave	0	0	110	187	283	268
Total	372	408	565	649	677	628

TABLE E-11

PG and E END USE PRICE SUMMARY BY SECTOR
1989 $ per mcf

	Core			Noncore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	System Ave
1989	5.45	5.45	5.45	3.61	3.61	2.14	2.97	2.95	3.95
1990	5.35	5.35	5.35	3.61	3.61	2.18	3.14	3.18	4.10
1991	5.47	5.47	5.47	3.65	3.65	2.21	3.20	3.26	4.29
1992	5.54	5.54	5.54	3.69	3.69	2.25	3.29	3.40	4.44
1993	5.68	5.68	5.68	3.76	3.76	2.34	3.42	3.48	4.54
1994	5.82	5.82	5.82	3.83	3.83	2.43	3.55	3.55	4.63
1995	5.94	5.94	5.94	3.92	3.92	2.51	3.62	3.62	4.71
1996	6.09	6.09	6.09	4.02	4.02	2.60	3.71	3.71	4.82
1997	6.19	6.19	6.19	4.11	4.11	2.69	3.78	3.78	4.90
1998	6.31	6.31	6.31	4.21	4.21	2.78	3.86	3.86	4.98
1999	6.42	6.42	6.42	4.31	4.31	2.88	3.94	3.94	5.05
2000	6.53	6.53	6.53	4.41	4.41	2.98	4.00	4.00	5.14
2001	6.62	6.62	6.62	4.51	4.51	3.07	4.08	4.08	5.20
2002	6.73	6.73	6.73	4.60	4.60	3.17	4.17	4.17	5.28
2003	6.87	6.87	6.87	4.73	4.73	3.29	4.27	4.27	5.37
2004	7.01	7.01	7.01	4.86	4.86	3.41	4.38	4.38	5.47
2005	7.19	7.19	7.19	5.01	5.01	3.53	4.48	4.48	5.59
2006	7.29	7.29	7.29	5.12	5.12	3.65	4.56	4.56	5.66
2007	7.43	7.43	7.43	5.25	5.25	3.77	4.66	4.66	5.76
2008	7.63	7.63	7.63	5.44	5.44	3.90	4.81	4.81	5.96
2009	7.82	7.82	7.82	5.62	5.62	4.07	4.96	4.96	6.16

TABLE E-12

PG AND E CORE PRICE FORECAST
1989 $ per mcf

	Residential Core Demand				Commercial Core Demand				Industrial Core Demand			
Year	Fixed	Varible	Commodity	Total	Fixed	Varible	Commodity	Total	Fixed	Varible	Commodity	Total
1989	3.49	0.00	1.96	5.45	3.49	0.00	1.96	5.45	3.49	0.00	1.96	5.45
1990	3.35	0.00	2.00	5.35	3.35	0.00	2.00	5.35	3.35	0.00	2.00	5.35
1991	3.44	0.00	2.04	5.47	3.44	0.00	2.04	5.47	3.44	0.00	2.04	5.47
1992	3.46	0.00	2.08	5.54	3.46	0.00	2.08	5.54	3.46	0.00	2.08	5.54
1993	3.52	0.00	2.16	5.68	3.52	0.00	2.16	5.68	3.52	0.00	2.16	5.68
1994	3.57	0.00	2.25	5.82	3.57	0.00	2.25	5.82	3.57	0.00	2.25	5.82
1995	3.60	0.00	2.33	5.94	3.60	0.00	2.33	5.94	3.60	0.00	2.33	5.94
1996	3.67	0.00	2.42	6.09	3.67	0.00	2.42	6.09	3.67	0.00	2.42	6.09
1997	3.68	0.00	2.51	6.19	3.68	0.00	2.51	6.19	3.68	0.00	2.51	6.19
1998	3.71	0.00	2.60	6.31	3.71	0.00	2.60	6.31	3.71	0.00	2.60	6.31
1999	3.72	0.00	2.70	6.42	3.72	0.00	2.70	6.42	3.72	0.00	2.70	6.42
2000	3.74	0.00	2.79	6.53	3.74	0.00	2.79	6.53	3.74	0.00	2.79	6.53
2001	3.74	0.00	2.89	6.62	3.74	0.00	2.89	6.62	3.74	0.00	2.89	6.62
2002	3.75	0.00	2.98	6.73	3.75	0.00	2.98	6.73	3.75	0.00	2.98	6.73
2003	3.77	0.00	3.10	6.87	3.77	0.00	3.10	6.87	3.77	0.00	3.10	6.87
2004	3.79	0.00	3.22	7.01	3.79	0.00	3.22	7.01	3.79	0.00	3.22	7.01
2005	3.86	0.00	3.34	7.19	3.86	0.00	3.34	7.19	3.86	0.00	3.34	7.19
2006	3.83	0.00	3.45	7.29	3.83	0.00	3.45	7.29	3.83	0.00	3.45	7.29
2007	3.86	0.00	3.57	7.43	3.86	0.00	3.57	7.43	3.86	0.00	3.57	7.43
2008	3.89	0.00	3.74	7.63	3.89	0.00	3.74	7.63	3.89	0.00	3.74	7.63
2009	3.91	0.00	3.91	7.82	3.91	0.00	3.91	7.82	3.91	0.00	3.91	7.82

TABLE E-13

PG AND E GAS NONCORE PRICE FORECAST
1989 $ per mcf

Commercial/Industrial Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	1.50	0.15	1.96	3.61
1990	1.46	0.15	2.00	3.61
1991	1.46	0.16	2.04	3.65
1992	1.45	0.16	2.08	3.69
1993	1.43	0.17	2.16	3.76
1994	1.41	0.17	2.25	3.83
1995	1.41	0.18	2.33	3.92
1996	1.42	0.19	2.42	4.02
1997	1.41	0.19	2.51	4.11
1998	1.41	0.20	2.60	4.21
1999	1.41	0.21	2.70	4.31
2000	1.41	0.21	2.79	4.41
2001	1.40	0.22	2.89	4.51
2002	1.39	0.23	2.98	4.60
2003	1.40	0.24	3.10	4.73
2004	1.40	0.25	3.22	4.86
2005	1.42	0.26	3.34	5.01
2006	1.40	0.26	3.45	5.12
2007	1.41	0.27	3.57	5.25
2008	1.41	0.29	3.74	5.44
2009	1.41	0.30	3.91	5.62

UEG Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	1.14	0.15	1.66	2.95
1990	1.22	0.15	1.80	3.18
1991	1.18	0.16	1.93	3.26
1992	1.17	0.16	2.08	3.40
1993	1.15	0.17	2.16	3.48
1994	1.13	0.17	2.25	3.55
1995	1.11	0.18	2.33	3.62
1996	1.10	0.19	2.42	3.71
1997	1.08	0.19	2.51	3.78
1998	1.06	0.20	2.60	3.86
1999	1.03	0.21	2.70	3.94
2000	0.99	0.21	2.79	4.00
2001	0.97	0.22	2.89	4.08
2002	0.96	0.23	2.98	4.17
2003	0.93	0.24	3.10	4.27
2004	0.91	0.25	3.22	4.38
2005	0.89	0.26	3.34	4.48
2006	0.85	0.26	3.45	4.56
2007	0.82	0.27	3.57	4.66
2008	0.78	0.29	3.74	4.81
2009	0.75	0.30	3.91	4.96

Cogen Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	0.86	0.15	1.96	2.97
1990	0.99	0.15	2.00	3.14
1991	1.01	0.16	2.04	3.20
1992	1.05	0.16	2.08	3.29
1993	1.10	0.17	2.16	3.42
1994	1.13	0.17	2.25	3.55
1995	1.11	0.18	2.33	3.62
1996	1.10	0.19	2.42	3.71
1997	1.08	0.19	2.51	3.78
1998	1.06	0.20	2.60	3.86
1999	1.03	0.21	2.70	3.94
2000	0.99	0.21	2.79	4.00
2001	0.97	0.22	2.89	4.08
2002	0.96	0.23	2.98	4.17
2003	0.93	0.24	3.10	4.27
2004	0.91	0.25	3.22	4.38
2005	0.89	0.26	3.34	4.48
2006	0.85	0.26	3.45	4.56
2007	0.82	0.27	3.57	4.66
2008	0.78	0.29	3.74	4.81
2009	0.75	0.30	3.91	4.96

TABLE E-14

SOCAL GAS END USE PRICE SUMMARY BY SECTOR
1989 $ per mcf

	Core			Noncore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	System ave
1989	5.82	5.82	5.82	3.30	3.30	2.52	3.18	3.61	4.07
1990	6.25	6.25	6.25	3.46	3.46	2.65	3.33	3.64	4.46
1991	6.34	6.34	6.34	3.55	3.55	2.78	3.44	3.64	4.69
1992	6.59	6.59	6.59	3.66	3.66	2.92	3.63	3.72	5.03
1993	6.59	6.59	6.59	3.70	3.70	3.01	3.69	3.74	5.06
1994	6.75	6.75	6.75	3.79	3.79	3.11	3.78	3.78	5.19
1995	6.90	6.90	6.90	3.88	3.88	3.21	3.84	3.84	5.29
1996	7.25	7.25	7.25	4.02	4.02	3.33	3.95	3.95	5.51
1997	7.35	7.35	7.35	4.10	4.10	3.43	4.02	4.02	5.57
1998	7.46	7.46	7.46	4.20	4.20	3.57	4.10	4.10	5.64
1999	7.54	7.54	7.54	4.30	4.30	3.71	4.17	4.17	5.69
2000	7.62	7.62	7.62	4.40	4.40	3.86	4.26	4.26	5.74
2001	7.73	7.73	7.73	4.51	4.51	4.01	4.34	4.34	5.82
2002	7.84	7.84	7.84	4.62	4.62	4.18	4.41	4.41	5.89
2003	8.00	8.00	8.00	4.77	4.77	4.38	4.54	4.54	6.02
2004	8.15	8.15	8.15	4.92	4.92	4.60	4.68	4.68	6.16
2005	8.31	8.31	8.31	5.07	5.07	4.82	4.82	4.82	6.29
2006	8.53	8.53	8.53	5.23	5.23	5.08	4.97	4.97	6.46
2007	8.74	8.74	8.74	5.40	5.40	5.35	5.13	5.13	6.63
2008	8.95	8.95	8.95	5.56	5.56	5.62	5.27	5.27	6.84
2009	9.17	9.17	9.17	5.73	5.73	5.91	5.43	5.43	7.05

TABLE E-15

SOCAL GAS CORE PRICE FORECAST
1989 $ per mcf

	Residential Core Demand				Commercial Core Demand				Industrial Core Demand			
Year	Fixed	Varible	Commodity	Total	Fixed	Varible	Commodity	Total	Fixed	Varible	Commodity	Total
1989	3.62	0.00	2.19	5.82	3.62	0.00	2.19	5.82	3.62	0.00	2.19	5.82
1990	3.97	0.00	2.28	6.25	3.97	0.00	2.28	6.25	3.97	0.00	2.28	6.25
1991	3.96	0.00	2.37	6.34	3.96	0.00	2.37	6.34	3.96	0.00	2.37	6.34
1992	4.13	0.00	2.46	6.59	4.13	0.00	2.46	6.59	4.13	0.00	2.46	6.59
1993	4.05	0.00	2.54	6.59	4.05	0.00	2.54	6.59	4.05	0.00	2.54	6.59
1994	4.13	0.00	2.61	6.75	4.13	0.00	2.61	6.75	4.13	0.00	2.61	6.75
1995	4.21	0.00	2.69	6.90	4.21	0.00	2.69	6.90	4.21	0.00	2.69	6.90
1996	4.49	0.00	2.77	7.25	4.49	0.00	2.77	7.25	4.49	0.00	2.77	7.25
1997	4.51	0.00	2.84	7.35	4.51	0.00	2.84	7.35	4.51	0.00	2.84	7.35
1998	4.51	0.00	2.94	7.46	4.51	0.00	2.94	7.46	4.51	0.00	2.94	7.46
1999	4.49	0.00	3.05	7.54	4.49	0.00	3.05	7.54	4.49	0.00	3.05	7.54
2000	4.47	0.00	3.15	7.62	4.47	0.00	3.15	7.62	4.47	0.00	3.15	7.62
2001	4.48	0.00	3.25	7.73	4.48	0.00	3.25	7.73	4.48	0.00	3.25	7.73
2002	4.49	0.00	3.36	7.84	4.49	0.00	3.36	7.84	4.49	0.00	3.36	7.84
2003	4.50	0.00	3.50	8.00	4.50	0.00	3.50	8.00	4.50	0.00	3.50	8.00
2004	4.51	0.00	3.64	8.15	4.51	0.00	3.64	8.15	4.51	0.00	3.64	8.15
2005	4.52	0.00	3.78	8.31	4.52	0.00	3.78	8.31	4.52	0.00	3.78	8.31
2006	4.60	0.00	3.93	8.53	4.60	0.00	3.93	8.53	4.60	0.00	3.93	8.53
2007	4.67	0.00	4.07	8.74	4.67	0.00	4.07	8.74	4.67	0.00	4.07	8.74
2008	4.74	0.00	4.21	8.95	4.74	0.00	4.21	8.95	4.74	0.00	4.21	8.95
2009	4.82	0.00	4.35	9.17	4.82	0.00	4.35	9.17	4.82	0.00	4.35	9.17

TABLE E-16

SOCAL GAS NONCORE PRICE FORECAST
1989 $ per mcf

Commercial/Industrial Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	0.96	0.15	2.19	3.30
1990	1.02	0.16	2.28	3.46
1991	1.01	0.16	2.37	3.55
1992	1.03	0.17	2.46	3.66
1993	0.99	0.17	2.54	3.70
1994	1.00	0.18	2.61	3.79
1995	1.01	0.18	2.69	3.88
1996	1.07	0.19	2.77	4.02
1997	1.06	0.19	2.84	4.10
1998	1.06	0.20	2.94	4.20
1999	1.05	0.21	3.05	4.30
2000	1.04	0.22	3.15	4.40
2001	1.04	0.22	3.25	4.51
2002	1.03	0.23	3.36	4.62
2003	1.03	0.24	3.50	4.77
2004	1.03	0.25	3.64	4.92
2005	1.03	0.26	3.78	5.07
2006	1.04	0.27	3.93	5.23
2007	1.05	0.28	4.07	5.40
2008	1.07	0.29	4.21	5.56
2009	1.08	0.30	4.35	5.73

UEG Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	1.05	0.15	2.41	3.61
1990	1.06	0.16	2.42	3.64
1991	1.03	0.16	2.45	3.64
1992	1.09	0.17	2.46	3.72
1993	1.02	0.17	2.54	3.74
1994	0.99	0.18	2.61	3.78
1995	0.97	0.18	2.69	3.84
1996	0.99	0.19	2.77	3.95
1997	0.99	0.19	2.84	4.02
1998	0.95	0.20	2.94	4.10
1999	0.92	0.21	3.05	4.17
2000	0.89	0.22	3.15	4.26
2001	0.86	0.22	3.25	4.34
2002	0.82	0.23	3.36	4.41
2003	0.80	0.24	3.50	4.54
2004	0.79	0.25	3.64	4.68
2005	0.78	0.26	3.78	4.82
2006	0.78	0.27	3.93	4.97
2007	0.78	0.28	4.07	5.13
2008	0.78	0.29	4.21	5.27
2009	0.78	0.30	4.35	5.43

Cogen Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	0.84	0.15	2.19	3.18
1990	0.89	0.16	2.28	3.33
1991	0.90	0.16	2.37	3.44
1992	1.00	0.17	2.46	3.63
1993	0.98	0.17	2.54	3.69
1994	0.99	0.18	2.61	3.78
1995	0.97	0.18	2.69	3.84
1996	0.99	0.19	2.77	3.95
1997	0.99	0.19	2.84	4.02
1998	0.95	0.20	2.94	4.10
1999	0.92	0.21	3.05	4.17
2000	0.89	0.22	3.15	4.26
2001	0.86	0.22	3.25	4.34
2002	0.82	0.23	3.36	4.41
2003	0.80	0.24	3.50	4.54
2004	0.79	0.25	3.64	4.68
2005	0.78	0.26	3.78	4.82
2006	0.78	0.27	3.93	4.97
2007	0.78	0.28	4.07	5.13
2008	0.78	0.29	4.21	5.27
2009	0.78	0.30	4.35	5.43

TABLE E-17

SDG AND E END USE PRICE SUMMARY BY SECTOR
1989 $ per mcf

	Core			Noncore					
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	UEG	System Ave
1989	5.47	5.47	5.47	4.11	4.11	0.00	3.45	3.39	4.41
1990	5.56	5.56	5.56	4.21	4.21	0.00	3.55	3.53	4.59
1991	5.61	5.61	5.61	4.27	4.27	0.00	3.64	3.63	4.78
1992	5.84	5.84	5.84	4.44	4.44	0.00	3.77	3.78	5.09
1993	5.96	5.96	5.96	4.53	4.53	0.00	3.84	3.84	5.19
1994	6.08	6.08	6.08	4.56	4.56	0.00	3.75	3.95	5.26
1995	6.13	6.13	6.13	4.67	4.67	0.00	3.75	3.84	5.34
1996	6.21	6.21	6.21	4.74	4.74	0.00	3.84	3.83	5.40
1997	6.31	6.31	6.31	4.81	4.81	0.00	3.92	3.93	5.47
1998	6.48	6.48	6.48	4.95	4.95	0.00	4.04	4.04	5.56
1999	6.57	6.57	6.57	5.05	5.05	0.00	4.13	4.16	5.62
2000	6.68	6.68	6.68	5.16	5.16	0.00	4.19	4.24	5.67
2001	6.73	6.73	6.73	5.25	5.25	0.00	4.27	4.30	5.73
2002	6.78	6.78	6.78	5.31	5.31	0.00	4.38	4.38	5.79
2003	6.91	6.91	6.91	5.46	5.46	0.00	4.52	4.52	5.91
2004	7.03	7.03	7.03	5.58	5.58	0.00	4.67	4.66	6.01
2005	7.20	7.20	7.20	5.76	5.76	0.00	4.81	4.83	6.16
2006	7.35	7.35	7.35	5.91	5.91	0.00	4.95	4.97	6.29
2007	7.47	7.47	7.47	6.05	6.05	0.00	5.06	5.10	6.42
2008	7.59	7.59	7.59	6.19	6.19	0.00	5.20	5.22	6.59
2009	7.71	7.71	7.71	6.33	6.33	0.00	5.35	5.35	6.76

TABLE E-18

SDG AND E CORE PRICE FORECAST
1989 $ per mcf

	Residential Core Demand				Commercial Core Demand				Industrial Core Demand			
Year	Fixed	Varible	Commodity	Total	Fixed	Varible	Commodity	Total	Fixed	Varible	Commodity	Total
1989	3.25	0.00	2.23	5.47	3.25	0.00	2.23	5.47	3.25	0.00	2.23	5.47
1990	3.24	0.00	2.32	5.56	3.24	0.00	2.32	5.56	3.24	0.00	2.32	5.56
1991	3.19	0.00	2.42	5.61	3.19	0.00	2.42	5.61	3.19	0.00	2.42	5.61
1992	3.32	0.00	2.52	5.84	3.32	0.00	2.52	5.84	3.32	0.00	2.52	5.84
1993	3.37	0.00	2.59	5.96	3.37	0.00	2.59	5.96	3.37	0.00	2.59	5.96
1994	3.41	0.00	2.67	6.08	3.41	0.00	2.67	6.08	3.41	0.00	2.67	6.08
1995	3.39	0.00	2.74	6.13	3.39	0.00	2.74	6.13	3.39	0.00	2.74	6.13
1996	3.39	0.00	2.82	6.21	3.39	0.00	2.82	6.21	3.39	0.00	2.82	6.21
1997	3.42	0.00	2.89	6.31	3.42	0.00	2.89	6.31	3.42	0.00	2.89	6.31
1998	3.49	0.00	3.00	6.48	3.49	0.00	3.00	6.48	3.49	0.00	3.00	6.48
1999	3.47	0.00	3.10	6.57	3.47	0.00	3.10	6.57	3.47	0.00	3.10	6.57
2000	3.48	0.00	3.20	6.68	3.48	0.00	3.20	6.68	3.48	0.00	3.20	6.68
2001	3.42	0.00	3.31	6.73	3.42	0.00	3.31	6.73	3.42	0.00	3.31	6.73
2002	3.37	0.00	3.41	6.78	3.37	0.00	3.41	6.78	3.37	0.00	3.41	6.78
2003	3.37	0.00	3.54	6.91	3.37	0.00	3.54	6.91	3.37	0.00	3.54	6.91
2004	3.35	0.00	3.68	7.03	3.35	0.00	3.68	7.03	3.35	0.00	3.68	7.03
2005	3.39	0.00	3.81	7.20	3.39	0.00	3.81	7.20	3.39	0.00	3.81	7.20
2006	3.40	0.00	3.94	7.35	3.40	0.00	3.94	7.35	3.40	0.00	3.94	7.35
2007	3.39	0.00	4.08	7.47	3.39	0.00	4.08	7.47	3.39	0.00	4.08	7.47
2008	3.37	0.00	4.22	7.59	3.37	0.00	4.22	7.59	3.37	0.00	4.22	7.59
2009	3.34	0.00	4.37	7.71	3.34	0.00	4.37	7.71	3.34	0.00	4.37	7.71

TABLE E-19

SDG AND E NONCORE PRICE FORECAST
1989 $ per mcf

Commercial/Industrial Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	1.74	0.15	2.23	4.11
1990	1.73	0.16	2.32	4.21
1991	1.69	0.16	2.42	4.27
1992	1.75	0.17	2.52	4.44
1993	1.76	0.17	2.59	4.53
1994	1.72	0.18	2.67	4.56
1995	1.74	0.18	2.74	4.67
1996	1.73	0.19	2.82	4.74
1997	1.72	0.19	2.89	4.81
1998	1.75	0.20	3.00	4.95
1999	1.74	0.21	3.10	5.05
2000	1.74	0.22	3.20	5.16
2001	1.72	0.22	3.31	5.25
2002	1.67	0.23	3.41	5.31
2003	1.68	0.24	3.54	5.46
2004	1.66	0.25	3.68	5.58
2005	1.70	0.26	3.81	5.76
2006	1.70	0.27	3.94	5.91
2007	1.70	0.27	4.08	6.05
2008	1.68	0.28	4.22	6.19
2009	1.66	0.29	4.37	6.33

UEG Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	1.09	0.15	2.15	3.39
1990	1.09	0.16	2.28	3.53
1991	1.07	0.16	2.40	3.63
1992	1.09	0.17	2.52	3.78
1993	1.08	0.17	2.59	3.84
1994	1.10	0.18	2.67	3.95
1995	0.91	0.18	2.74	3.84
1996	0.83	0.19	2.82	3.83
1997	0.84	0.19	2.89	3.93
1998	0.84	0.20	3.00	4.04
1999	0.85	0.21	3.10	4.16
2000	0.82	0.22	3.20	4.24
2001	0.77	0.22	3.31	4.30
2002	0.74	0.23	3.41	4.38
2003	0.74	0.24	3.54	4.52
2004	0.74	0.25	3.68	4.66
2005	0.76	0.26	3.81	4.83
2006	0.76	0.27	3.94	4.97
2007	0.75	0.27	4.08	5.10
2008	0.71	0.28	4.22	5.22
2009	0.69	0.29	4.37	5.35

Cogen Noncore Price

Year	Fixed	Varible	Commodity	Total
1989	1.08	0.15	2.23	3.45
1990	1.07	0.16	2.32	3.55
1991	1.06	0.16	2.42	3.64
1992	1.08	0.17	2.52	3.77
1993	1.07	0.17	2.59	3.84
1994	0.90	0.18	2.67	3.75
1995	0.82	0.18	2.74	3.75
1996	0.83	0.19	2.82	3.84
1997	0.83	0.19	2.89	3.92
1998	0.84	0.20	3.00	4.04
1999	0.82	0.21	3.10	4.13
2000	0.77	0.22	3.20	4.19
2001	0.74	0.22	3.31	4.27
2002	0.74	0.23	3.41	4.38
2003	0.74	0.24	3.54	4.52
2004	0.75	0.25	3.68	4.67
2005	0.75	0.26	3.81	4.81
2006	0.74	0.27	3.94	4.95
2007	0.70	0.27	4.08	5.06
2008	0.69	0.28	4.22	5.20
2009	0.69	0.29	4.37	5.35

APPENDIX F

CEC DELPHI V OIL PRICE SURVEY RESULTS

APPENDIX F

CEC DELPHI V OIL PRICE SURVEY RESULTS

I. INTRODUCTION

Thirty-four energy experts affiliated with industry, government, private consulting firms, and academic and financial institutions participated in the 1989 Delphi V oil price survey panel. The distribution of respondents by institutional affiliation was as follows:

Industry = 8
Government = 8
Private consulting firms = 12
Academic = 4
Financial = 2

Eight of these 34 panelists were from outside the United States.

Following are the results after the second round of the Delphi V survey. Included are: a brief summary; rates of change of average oil price forecasts; mean and median forecasts for most likely, high and low oil price forecasts; and panelists' estimates of the importance of various factors in high and low oil price paths.

II. SUMMARY

In round one, conducted in November 1988, Delphi V survey panelists were asked to estimate the most likely path that oil prices would follow over the period 1989-2009 and to indicate their confidence in the accuracy of their forecast. They were asked to estimate a high price path such that 90 percent of possible price paths would lie below their projection, and to estimate the importance of various factors in causing the high price path. They were also asked for a low price path such that 90 percent of possible price paths would be above the estimate, and to estimate the importance of various factors in causing the low price path. In round two conducted in February 1989, Delphi panelists were given the opportunity to revise their estimates based on aggregate first round results. Final Delphi V results based on this second iteration of the survey are presented below.

Delphi V annual rates of change of most likely mean oil price forecasts were below 1 percent for 1989-90 and between 3-4 percent through 1994. Following two years of increases over 6 percent, the annual rate of change varied between 2-4 percent from 1997-2009

(See Table F-1). The average rate over the entire forecast period was 3.17 percent.

The average Delphi V most likely oil price forecast was $21.52 for the year 2000, and $28.10 for 2009 (see Table F-2). Panelists' estimates of the probability that their most likely forecasts would be generally correct averaged 44.8 percent. Panel variability, measured by standard deviations of the most likely forecast, was $5.85 for the year 2000, and $9.65 for the year 2009.

The Delphi V annual rates of change for the high oil price path were greatest in the first and second years (13.38 percent and 9.66 percent respectively), then varied between about 4 to 8 percent through 1998. Starting in 1999, the rate increased fairly steadily from 3.67 percent to 7.43 percent at the end of the forecast period.

The Delphi V annual rates of change for the low oil price path were negative for 1989-1991, then began to slowly climb to about 2.3 percent by the year 2000. After that the rate remained nearly stable, between 2.2 and 2.4 percent.

Median forecasts are reported in Table F-3. For the most likely case, median forecasts are higher than the mean forecasts for the period 1988-1994. From 1995 on, the mean forecasts are higher. For the high case, median forecasts are lower than mean forecasts through the entire forecast period (except the 1988 base year). For the low case, median forecasts are higher than mean forecasts through 1999, after which they remain lower.

Average estimates of the importance of various factors in determining high and low price boundaries indicated the importance of OPEC supply in both cases (see Tables F-4 and F-5). A distinct group of important secondary factors can also be isolated for both price paths, including oil demand in industrial and developing countries, future oil discoveries, and Middle East political/military events. Other factors appeared to make only relatively minor, although cumulatively significant, contributions to conditions delineating price forecast boundaries.

TABLE F-1

DELPHI V MOST LIKELY, HIGH AND LOW RATES OF CHANGE OF MEAN OIL PRICE FORECASTS

Delphi V
(percentage change from previous year)

	Most Likely	High	Low
1989	0.69	13.38	-8.33
1990	0.52	9.66	-4.36
1991	3.32	7.32	-0.76
1992	3.00	6.49	0.29
1993	3.78	6.73	1.05
1994	3.60	6.66	1.52
1995	6.07	6.57	2.06
1996	6.60	4.65	2.08
1997	2.07	6.18	2.17
1998	2.38	7.52	2.29
1999	3.71	3.67	2.09
2000	4.04	4.52	2.30
2001	2.80	4.26	2.31
2002	3.12	4.97	2.34
2003	3.15	5.20	2.37
2004	3.10	5.46	2.32
2005	3.04	5.82	2.22
2006	3.02	6.20	2.25
2007	2.90	6.51	2.28
2008	2.94	6.83	2.31
2009	2.99	7.43	2.34

TABLE F-2

DELPHI V MOST LIKELY, HIGH AND LOW MEAN OIL PRICE FORECASTS
(1988$/Barrel)

Delphi V
{mean (standard deviation)}

	Most Likely		High		Low	
1988	14.58	(1.08)	14.58	(1.08)	14.58	(1.08)
1989	14.68	(1.62)	16.54	(2.95)	13.41	(2.24)
1990	14.76	(2.27)	18.14	(4.09)	12.82	(3.16)
1991	15.25	(2.89)	19.46	(4.99)	12.73	(3.39)
1992	15.71	(3.23)	20.73	(5.88)	12.76	(3.53)
1993	16.30	(3.48)	22.12	(7.07)	12.90	(3.75)
1994	16.88	(3.86)	23.60	(8.59)	13.10	(4.02)
1995	17.91	(4.40)	25.15	(10.23)	13.36	(4.29)
1996	19.09	(6.39)	26.31	(10.78)	13.64	(4.59)
1997	19.49	(5.74)	27.94	(11.07)	13.94	(4.92)
1998	19.95	(5.43)	30.04	(12.22)	14.26	(5.29)
1999	20.69	(5.59)	31.15	(12.61)	14.56	(5.59)
2000	21.52	(5.85)	32.55	(13.60)	14.89	(5.92)
2001	22.13	(6.21)	33.94	(14.67)	15.24	(6.21)
2002	22.82	(6.52)	35.62	(16.05)	15.59	(6.53)
2003	23.54	(6.87)	37.48	(17.89)	15.96	(6.86)
2004	24.27	(7.28)	39.52	(20.28)	16.33	(7.21)
2005	25.01	(7.72)	41.82	(23.30)	16.69	(7.57)
2006	25.76	(8.19)	44.42	(27.09)	17.07	(7.92)
2007	26.51	(8.62)	47.31	(31.83)	17.46	(8.29)
2008	27.29	(9.11)	50.54	(37.69)	17.86	(8.68)
2009	28.10	(9.65)	54.16	(44.87)	18.28	(9.08)

FIGURE F-1

DELPHI V OIL PRICE FORECASTS

(MEAN VALUES FROM DELPHI SURVEY)

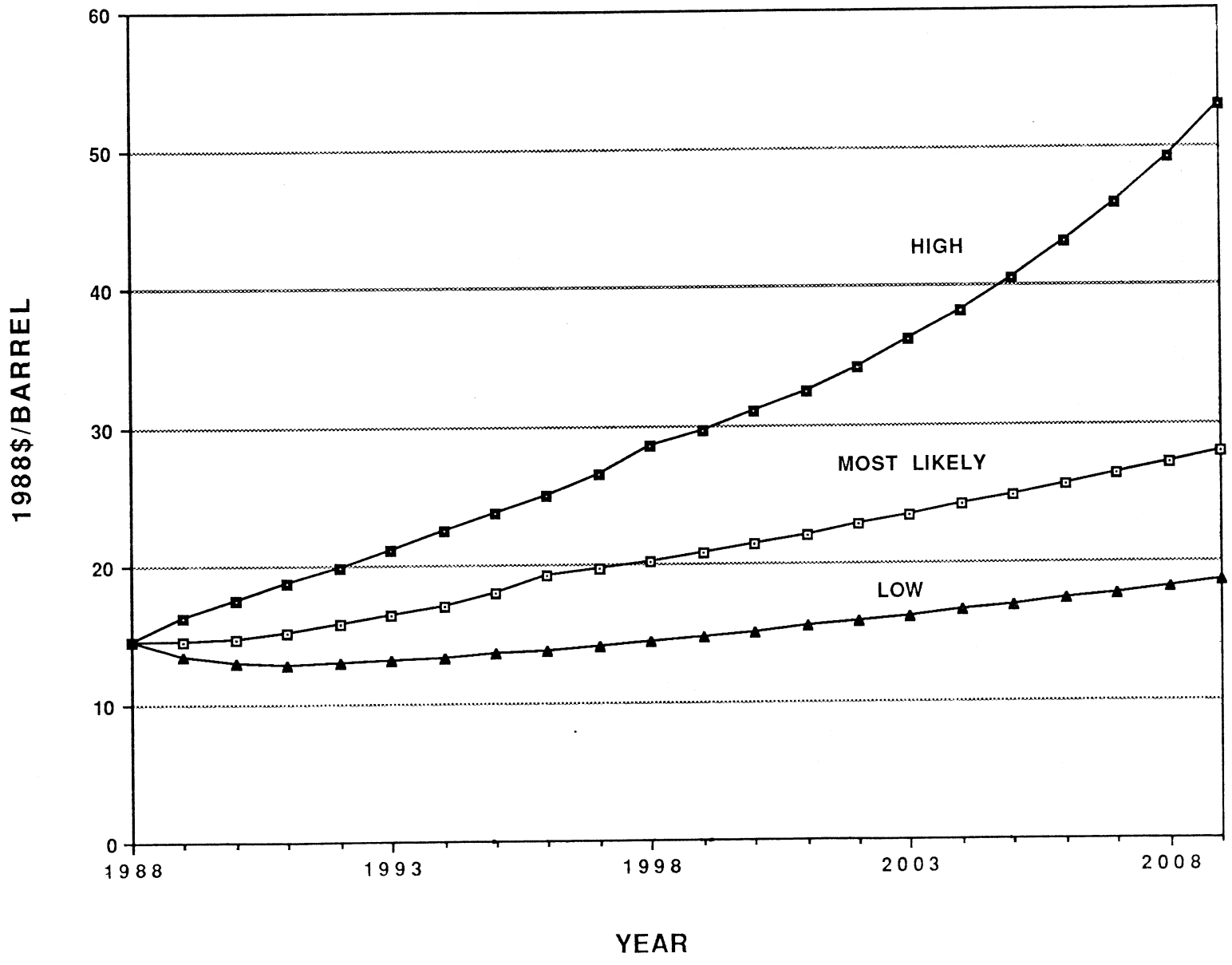


TABLE F-3

DELPHI V MOST LIKELY, HIGH AND LOW MEDIAN OIL PRICE FORECASTS
(1988$/Barrel)

	Delphi V (medians)		
	Most Likely	High	Low
1988	14.75	14.75	14.75
1989	14.86	16.20	13.92
1990	15.20	17.20	13.21
1991	15.52	18.63	13.50
1992	15.92	20.01	13.79
1993	16.45	21.51	14.00
1994	16.91	22.73	14.00
1995	17.45	23.55	14.19
1996	18.33	24.40	14.52
1997	18.71	25.00	14.53
1998	19.11	27.00	14.55
1999	19.82	28.55	14.56
2000	20.61	30.00	14.58
2001	21.35	30.00	14.85
2002	22.42	30.24	15.00
2003	23.25	32.36	15.00
2004	24.00	32.65	15.00
2005	24.94	32.65	15.00
2006	25.16	34.51	15.14
2007	25.76	38.30	15.44
2008	26.37	42.52	15.75
2009	26.41	46.90	16.07

FIGURE F-2

DELPHI V OIL PRICE FORECASTS

(MEDIAN VALUES FROM DELPHI SURVEY)

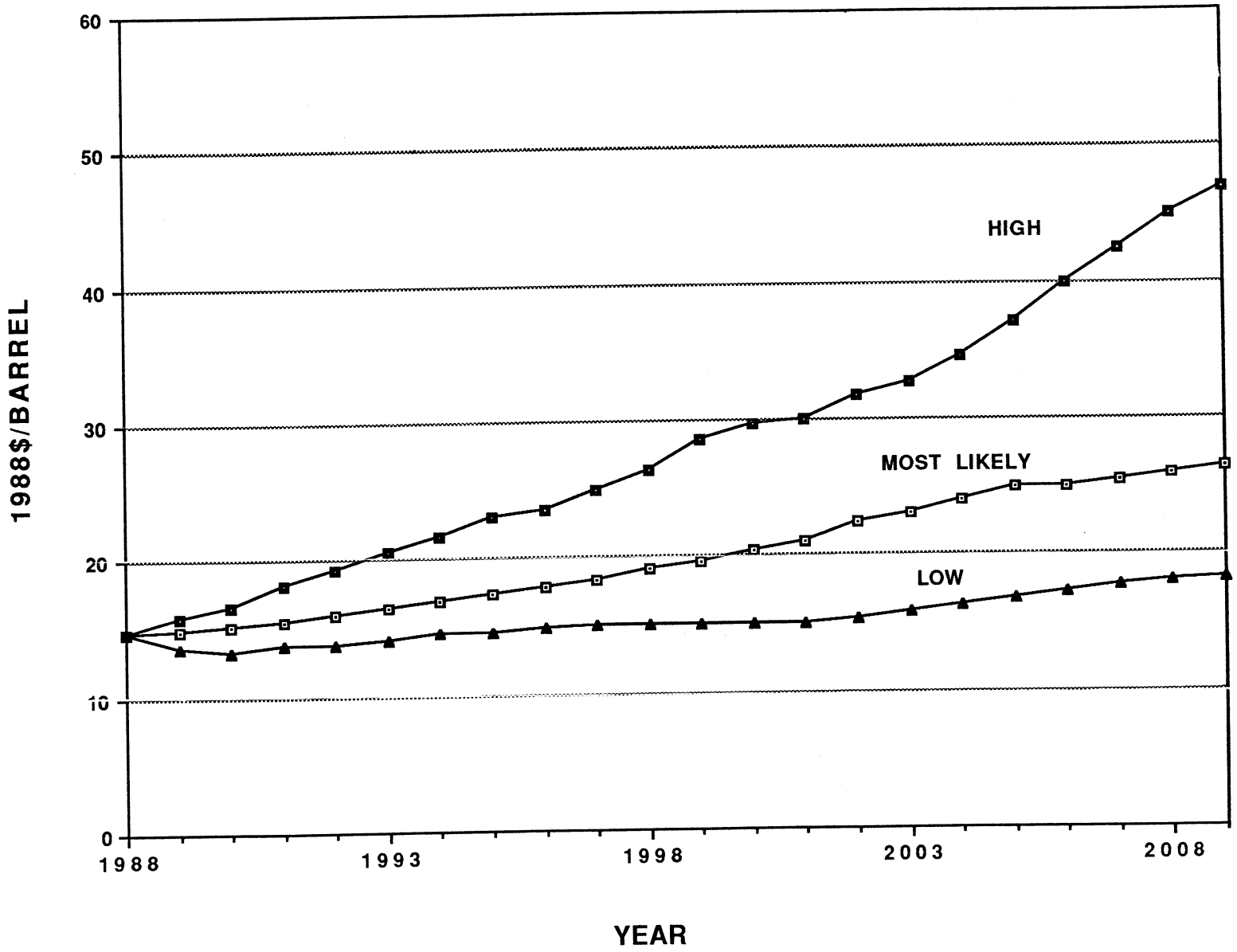


TABLE F-4

AVERAGE CONTRIBUTION OF FACTORS CAUSING A HIGH OIL PRICE PATH

Factors {Bar graph codes in brackets}	Contribution (%)
Long-term adherence by OPEC countries to strict production quotas {OPEC}	29.27
Greater oil demand in developing countries {D-DMD}	12.65
Greater oil demand in industrialized countries {I-DMD}	12.11
Continuing military conflict and/or political instability in the Middle East {WAR}	11.55
Limited discoveries of major new non-OPEC oil fields {DISC}	10.82
Limited development of substitutes for oil {ALTS}	7.21
Limited opportunities for further conservation {CONS}	6.82
Political restrictions on production in non-OPEC oil-exporting countires {N-OPEC}	5.45
Additional environmental restrictions on development of known U.S. oil resources	2.45
Other	1.67
	100.00

FIGURE F-3

FACTORS CONTRIBUTING TO HIGH PRICE PATH

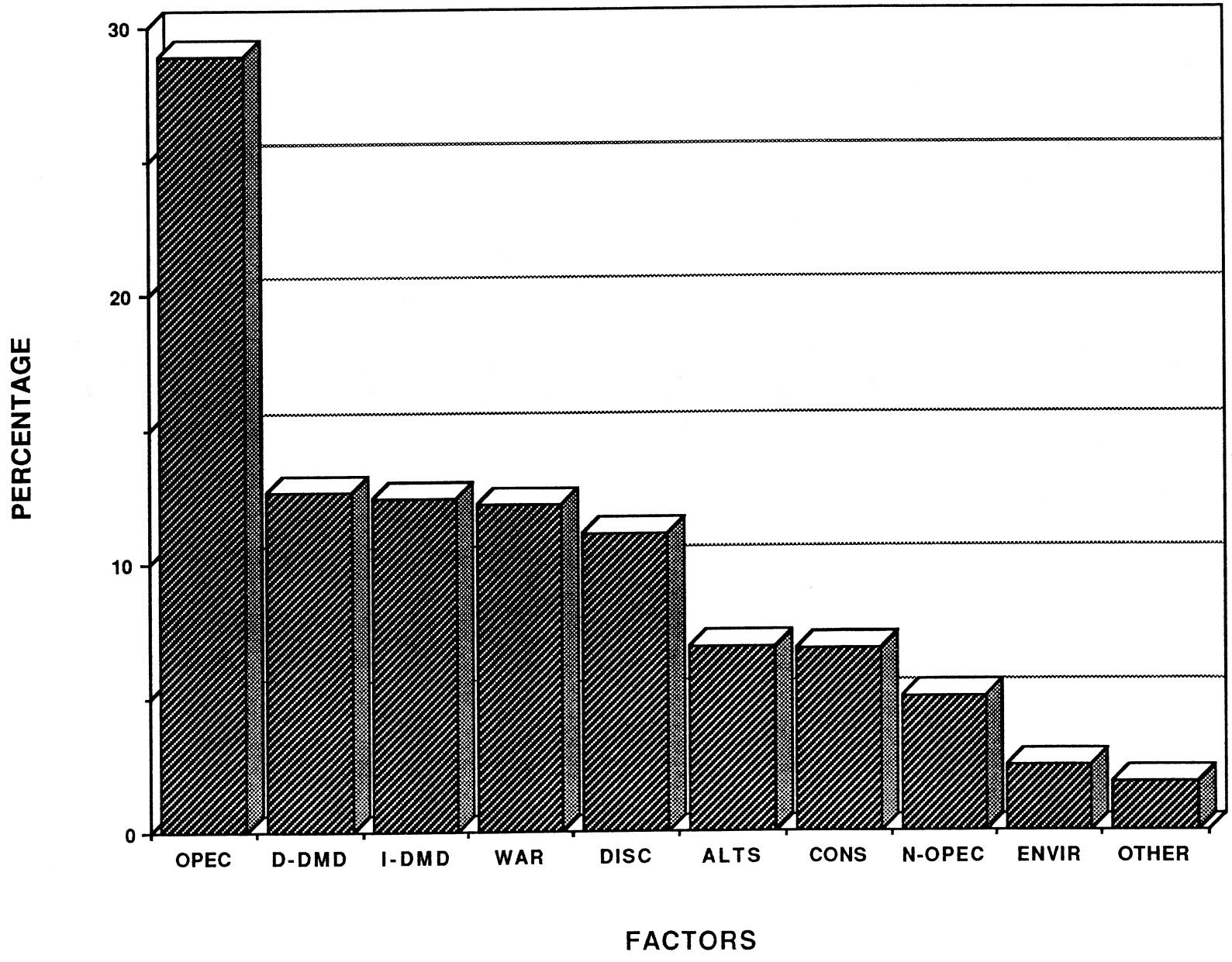


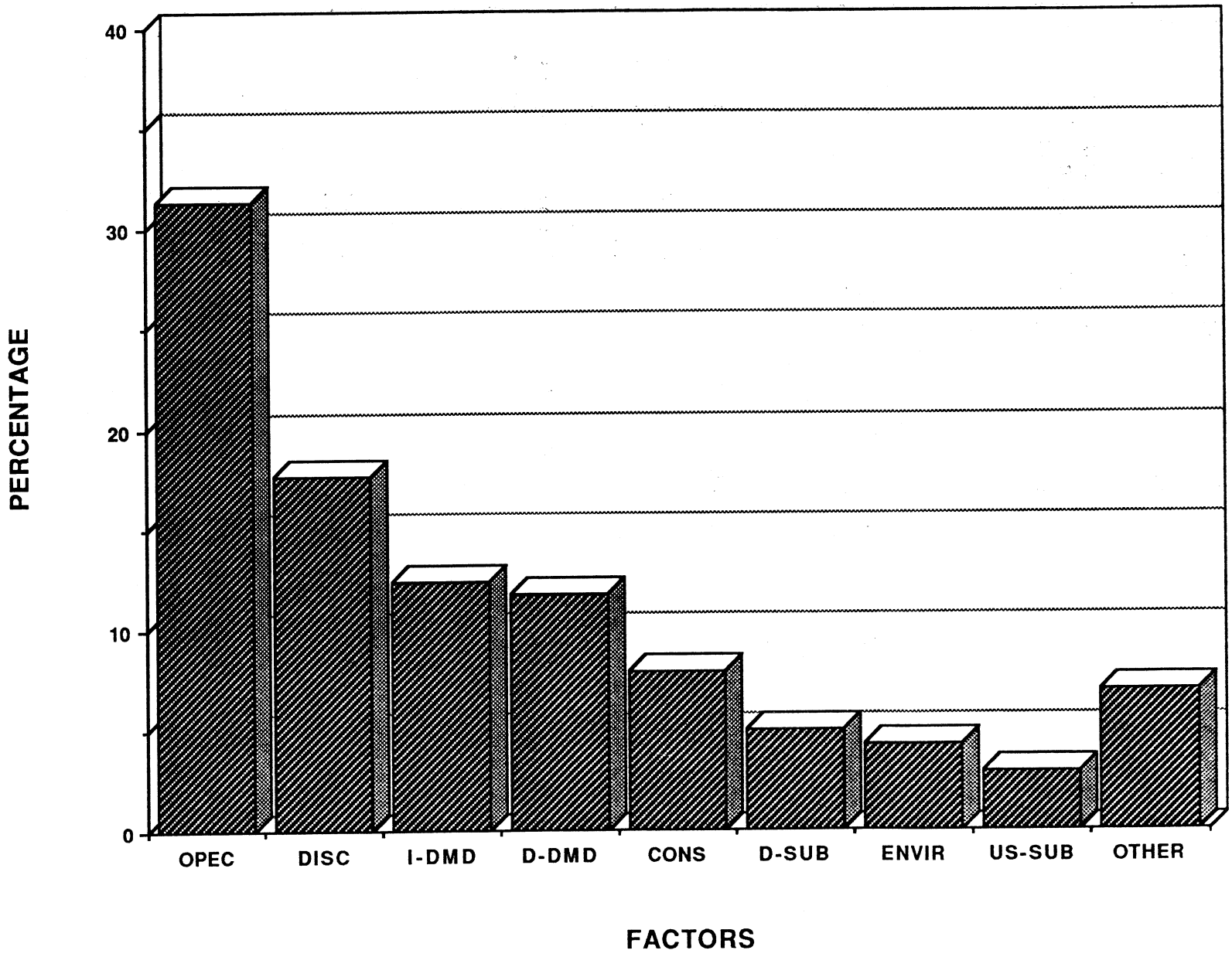
TABLE F-5

AVERAGE CONTRIBUTION OF FACTORS CAUSING A LOW OIL PRICE PATH

Factor {Bar graph codes in brackets}	Contribution (%)
Permanent collapse of OPEC production quota system {OPEC}	32.03
Worldwide oil resources prove to be larger than currently estimated {DISC}	17.52
Lower oil demand in industrialized countries {I-DMD}	12.50
Lower oil demand in developing countries {D-DMD}	11.59
Successful government policies and/or private actions to induce conservation {CONS}	6.94
Subsidies in developing countries for oil exploration and development {D-SUB}	4.97
Relaxation of U.S. environmental restrictions on development of known oil resources {ENVIR}	4.36
Subsidies for U.S. oil exploration and development {US-SUB}	3.06
Other	7.03
	100.00

FIGURE F-4

FACTORS CONTRIBUTING TO LOW PRICE PATH



III. PRODUCT PRICE PROJECTIONS BASED ON DELPHI V RESULTS

Energy Commission staff have developed petroleum product price projections based on Delphi V oil price survey results. Table F-6 shows real price projections (in 1988 dollars per gallon) for transportation fuels, including regular unleaded and premium unleaded gasoline, and diesel. Retail prices are for self-serve (excluding taxes), and wholesale prices are for average dealer buying prices. Table F-7 shows refinery prices (in 1988 dollars per mmBtus) for jet fuel, diesel, and residual fuel oils at various sulfur levels (.25 percent, .5 percent, and >.5 percent).

TABLE F-6

TRANSPORTATION FUELS PRICE PROJECTIONS BASED ON DELPHI V
(1988$ PER GALLON)

	RETAIL [SELF-SERVE EXCLUDING TAXES]			WHOLESALE [DEALER BUYING PRICE]		
YEAR	DIESEL	REG UNLD	PREM UNLD	DIESEL	REG UNLD	PREM UNLD
1988	0.674	0.664	0.816	0.533	0.608	0.690
1989	0.676	0.667	0.818	0.535	0.610	0.692
1990	0.677	0.668	0.819	0.537	0.612	0.693
1991	0.685	0.679	0.829	0.547	0.622	0.703
1992	0.693	0.688	0.839	0.556	0.631	0.712
1993	0.703	0.701	0.851	0.569	0.644	0.723
1994	0.713	0.713	0.863	0.580	0.656	0.734
1995	0.730	0.735	0.884	0.602	0.677	0.754
1996	0.750	0.760	0.908	0.626	0.701	0.776
1997	0.757	0.768	0.916	0.634	0.710	0.784
1998	0.764	0.778	0.926	0.643	0.719	0.792
1999	0.777	0.793	0.941	0.658	0.735	0.807
2000	0.791	0.811	0.958	0.676	0.752	0.822
2001	0.801	0.824	0.970	0.688	0.764	0.834
2002	0.813	0.838	0.985	0.702	0.779	0.847
2003	0.825	0.853	0.999	0.717	0.794	0.861
2004	0.837	0.869	1.014	0.732	0.809	0.875
2005	0.849	0.884	1.029	0.747	0.824	0.889
2006	0.862	0.900	1.045	0.762	0.840	0.903
2007	0.875	0.916	1.060	0.778	0.855	0.918
2008	0.888	0.932	1.076	0.794	0.872	0.932
2009	0.901	0.950	1.093	0.810	0.888	0.948

TABLE F-7

REFINERY PRICES OF PETROLEUM PRODUCTS BASED ON DELPHI V
(1988$ PER MILLION BTUS)

YEAR	JET FUEL	DIESEL	RESIDUAL FUEL OIL .25%	.5%	>.5%
1988	3.713	3.277	2.172	2.036	1.876
1989	3.730	3.293	2.186	2.049	1.890
1990	3.743	3.306	2.198	2.059	1.900
1991	3.823	3.386	2.266	2.123	1.967
1992	3.899	3.461	2.330	2.184	2.030
1993	3.996	3.558	2.413	2.261	2.110
1994	4.092	3.653	2.494	2.337	2.189
1995	4.261	3.821	2.638	2.472	2.329
1996	4.455	4.014	2.804	2.627	2.489
1997	4.521	4.079	2.860	2.679	2.543
1998	4.596	4.154	2.924	2.740	2.606
1999	4.718	4.275	3.027	2.837	2.706
2000	4.855	4.411	3.144	2.946	2.819
2001	4.955	4.511	3.229	3.026	2.902
2002	5.068	4.624	3.326	3.116	2.996
2003	5.187	4.741	3.426	3.211	3.094
2004	5.307	4.861	3.529	3.306	3.193
2005	5.428	4.982	3.632	3.403	3.294
2006	5.552	5.104	3.737	3.502	3.396
2007	5.675	5.227	3.842	3.600	3.498
2008	5.803	5.354	3.951	3.702	3.604
2009	5.937	5.487	4.065	3.809	3.714

APPENDIX G

CEC STAFF COAL PRICE FORECASTS

APPENDIX G

CEC STAFF COAL PRICE FORECASTS

I. SUMMARY

Real delivered coal prices at seven existing coal-fired power plants that provide electricity to California are projected to increase 21.2 to 36.2 percent, depending on the plant, between the baseline year (1987) and the end of the forecast period (2009). The average increase for these existing plants is 30.4 percent. Prices at the proposed White Pines power plant are projected to increase 35.1 percent between 1990 and 2009. The highest delivered price of coal (in 1988$) in 2009 is projected to be $3.06 per million Btus at Coronado power plant, and the lowest is projected to be $1.20 per million Btus at Navajo power plant.

II. METHODOLOGY

Prices for the forecast period (1988-2009) were derived by applying projected real escalation rates to 1987 estimated baseline costs. Baseline costs consist of a commodity (mine-mouth coal) cost element and a transportation cost element, each element having separate escalation assumptions and rates. Five factors were considered to be important in developing cost escalation rates: historical costs, existing contract terms, expected demand for western U.S. coal, transportation constraints, and expected future mining and reclamation costs.

Historical prices, coal quality analysis data and county of origin were obtained from Department of Energy/Energy Information Administration sources, Cost and Quality of Fuels for Electric Utility Plants and Electric Power Quarterly. Fuel supply managers at major utility owners of coal-fired plants were contacted to determine or confirm baseline conditions, ownership, coal sources and delivery systems, and factors involved in recent historical price trends. Other sources of baseline information include the Keystone Coal Industry Manual, the 1986 Biennial Fuels Report, Coal Data, and Coal Traffic. Utility estimates of fuel cost escalation rates at several plants were obtained from CFM VII Supply Forms and Energy Cost Adjustment Clause filings.

III. ANALYSIS

Demand for western U.S. coal is not expected to create pressure for price increases in the short- to mid-term due to competitive market factors. Proved U.S. coal reserves will last over 300 years at current rates of production. U.S. reserves grew 28.2 percent between 1981-87, while U.S. consumption grew only 14.2 percent and

exports fell 29.3 percent. Current low prices for oil and natural gas, though higher than coal on a Btu basis, are not expected to be sufficient to induce more conversion to coal use than has already occurred since the mid-1970's. Growing foreign markets in Japan and other Pacific Rim countries are expected to be supplied by high Btu coal from Australia, South Africa and China in the 1990's rather than the U.S., primarily because of transportation costs. European markets are more likely to be supplied by sources in the eastern U.S. than by western U.S. fields for the same reasons.

Mines with access to railroad lines such as those supplying coal to the Coronado, North Valmy and Intermountain plants may ultimately develop significant export markets. However, source mines for several of the power plants analyzed in this forecast are not served by major rail lines. These mines have an even more restricted market than railroad-accessible mines and may be essentially captive to the utility. Coal slurry is delivered from Black Mesa Mine to the Mohave power plant by pipeline. The Four Corners and San Juan power plants are located adjacent to Navajo and San Juan Mines, respectively. Coal from Kayenta Mine is delivered to the Navajo power plant by a utility-owned electric railroad.

For the next several years, these western U.S. coal mines are expected to be dependent on the steady market provided by the power plants. In some cases, the contract to serve the power plant may be one of the mine's most valuable assets. The utilities in question have in several cases begun seeking less expensive alternative sources of coal, although they tend to be very conservative, and still overwhelmingly prefer long-term contracts.

In the short-term, transportation cost increases for both truck- and railroad-delivered coal have eased due to relatively low fuel costs. Also, railroad rate adjustments allowed by the Staggers' Rail Act of 1980 have slowed from the sharp increases of the early 1980's. This forecast assumes that the railroads will continue to restrain future adjustments to deflect pressure to reinstitute tighter regulatory controls. However, rising fuel costs during the mid 1990's are expected to raise transportation cost escalation rates for coal delivered to power plants dependent on rail or truck delivery systems more than for those using utility-owned delivery systems.

In the long-term commodity escalation rates for coal are assumed to increase. In part this will be due to expected increases in costs of oil and natural gas, competing fuels in electric generation which do not have as high a reserves-to-production ratio as coal. Economies of scale in large-scale coal production technologies are believed to have generally peaked for coal mining. Reclamation costs are expected to increase due to growing sensitivity over the on-site environmental costs of coal production, especially strip mining. These commodity escalation rate increases

are projected to take effect during the mid-1990's and to accelerate shortly after the year 2000.

Legislation and regulatory air quality initiatives, including tighter air quality standards, and measures to deal with acid rain and the "greenhouse effect", have the potential to severely impact the demand for coal and coal prices. Because of the many inherent uncertainties involved in predicting the nature and extent of such actions, as well as the effectiveness and cost of abatement technology, the current coal price forecast does not attempt to incorporate these potential impacts.

IV. COAL PRICE FORECASTS

Historical and projected prices of coal delivered to the following power plants from 1980 through 2009 are summarized in Table G-1 and Figure G-1:

- San Juan (New Mexico)
- Mohave (Nevada)
- Four Corners (New Mexico)
- Coronado (Arizona)
- Navajo (Arizona)
- North Valmy (Nevada)
- Intermountain (Utah)
- White Pines (proposed new plant, Nevada)

Tables G-2 through G-9 contain information by power plant on: plant location and ownership; coal sources, delivery systems, physical analysis and historical prices; and coal price escalation rates and assumptions. Figures G-2 through G-9 display the transportation and commodity cost components of historical and projected coal prices by power plant.

TABLE G-1

HISTORICAL AND PROJECTED COAL PRICES AT SOUTHWEST POWER PLANTS
(1988$/MMBTUS)

YEAR	San Juan	Mohave	Four Corners	Coronado	Navajo	North Valmy	Intermountain	White Pines
1980	1.233	1.292	.610	2.300	.951			
1981	1.143	1.093	.771	2.322	.944	2.221		
1982	1.183	1.086	.783	2.421	1.023	2.338		
1983	1.130	1.192	.861	2.400	1.060	2.285		
1984	1.214	1.130	.888	2.463	.907	2.305		
1985	1.215	1.128	1.065	2.279	.951	2.246		
1986	1.416	1.089	.984	2.349	.949	2.004	1.401	
1987	1.618	1.080	.980	2.279	.930	1.916	1.349	
1988	1.525	1.022	.943	2.195	.984	1.887	1.400	
1989	1.540	1.023	.943	2.195	.984	1.887	1.400	
1990	1.556	1.023	.943	2.195	.984	1.887	1.400	
1991	1.571	1.031	.952	2.217	.994	1.906	1.414	
1992	1.587	1.038	.962	2.239	1.003	1.925	1.428	2.000
1993	1.604	1.046	.972	2.269	1.012	1.950	1.444	2.026
1994	1.622	1.054	.981	2.299	1.022	1.976	1.460	2.053
1995	1.640	1.062	.991	2.330	1.031	2.002	1.476	2.081
1996	1.658	1.069	1.001	2.365	1.041	2.032	1.497	2.112
1997	1.676	1.077	1.011	2.401	1.051	2.062	1.519	2.144
1998	1.699	1.085	1.021	2.437	1.061	2.093	1.541	2.176
1999	1.723	1.093	1.031	2.474	1.071	2.125	1.563	2.209
2000	1.747	1.101	1.042	2.511	1.081	2.157	1.585	2.242
2001	1.771	1.117	1.060	2.549	1.091	2.189	1.608	2.276
2002	1.795	1.133	1.079	2.588	1.102	2.222	1.631	2.311
2003	1.829	1.149	1.099	2.638	1.122	2.266	1.668	2.356
2004	1.862	1.165	1.119	2.690	1.144	2.311	1.705	2.402
2005	1.897	1.181	1.139	2.742	1.165	2.357	1.744	2.449
2006	1.932	1.198	1.159	2.796	1.187	2.404	1.783	2.497
2007	1.968	1.215	1.180	2.851	1.210	2.451	1.823	2.547
2008	2.004	1.233	1.201	2.907	1.233	2.500	1.865	2.597
2009	2.041	1.250	1.223	2.964	1.256	2.550	1.907	2.648

FIGURE G-1
HISTORICAL AND PROJECTED COAL PRICES

SOUTHWEST POWER PLANTS

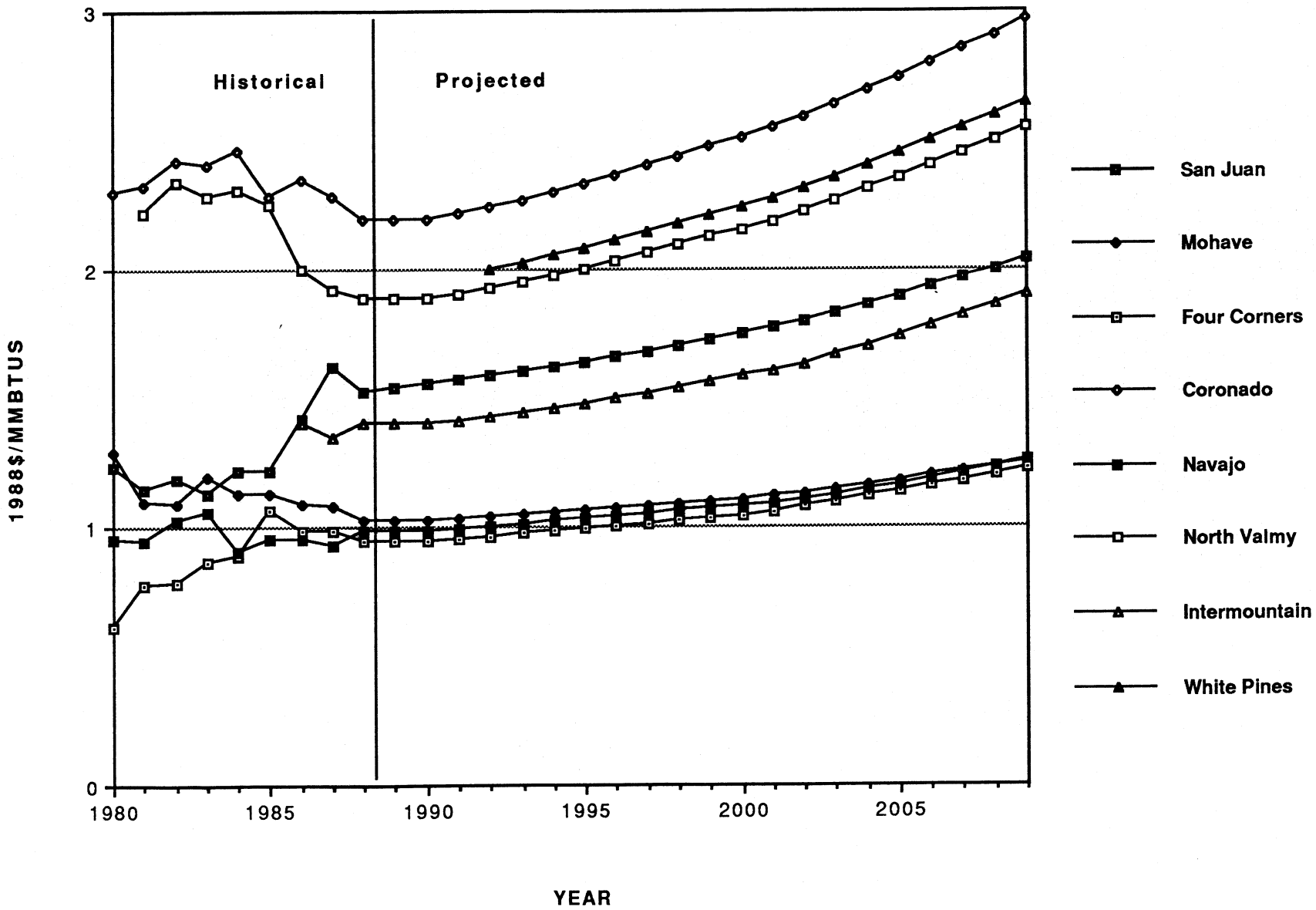


TABLE G-2

BASELINE DATA AND ESCALATION RATES
San Juan Power Plant

Location:	Waterflow, New Mexico.
Ownership:	Jointly owned by Public Service of New Mexico, Tuscon Gas and Electric, Los Angeles County, and the cities of Farmington, Modesto, Santa Clara and Redding.
Coal Source:	San Juan and La Plata Mines, San Juan County, New Mexico; suface-mined from BLM land. Deliveries from La Plata Mine began in 1986.
Delivery:	Mine mouth plant for San Juan Mine coal; La Plata Mine coal delivered by truck.
Coal Analysis:	9,426 Btu/lb and .78% Sulfur (1987 average).

Historical Coal Costs (1988$)

Year	$/mmBtu	$/ton
1980	1.233	22.60
1981	1.143	21.39
1982	1.183	22.73
1983	1.130	21.26
1984	1.214	22.77
1985	1.215	23.16
1986	1.416	26.76
1987	1.618	30.51

1988 Estimated Baseline Costs (1988$)

Mine Mouth Coal Costs (93%)	1.418	27.04
Transportation Costs (7%)	0.107	2.04
Total Delivered Costs	1.525	29.08

Escalation Rate Projections

Period	Commodity	Transportation
1989-1992	1.0%	1.0%
1993-1997	1.0%	2.4%
1998-2002	1.3%	2.4%
2003-2009	1.8%	2.4%

FIGURE G-2

HISTORICAL AND PROJECTED COAL PRICES

SAN JUAN POWER PLANT

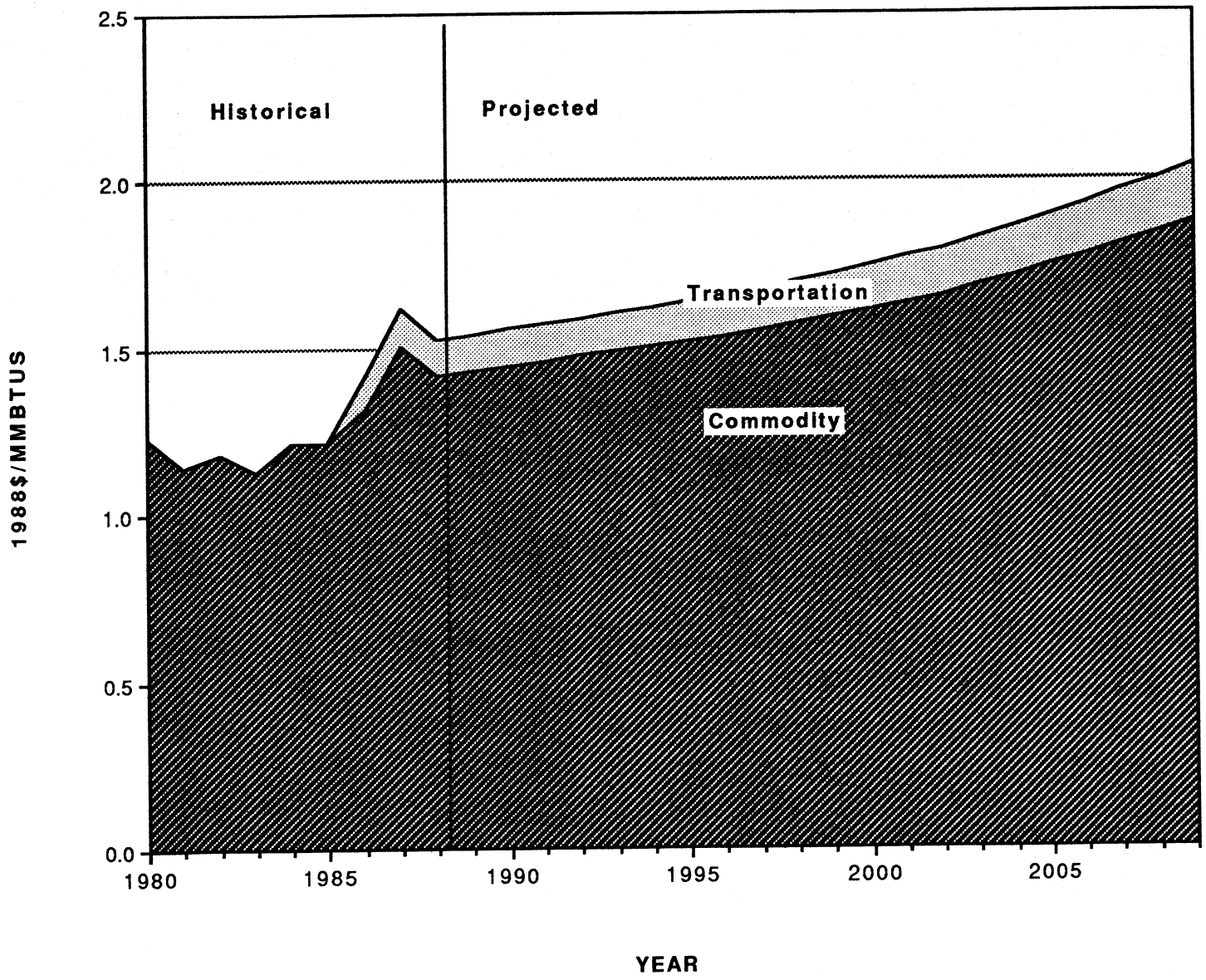


TABLE G-3

BASELINE DATA AND ESCALATION RATES
Mohave Power Plant

Location:	Laughlin, Nevada.
Ownership:	Southern California Edison (56%), LADWP (20%), Nevada Power (14%), and Salt River Project (10%).
Coal Source:	Black Mesa Mine, Navajo County, Arizona; surface-mined from Navajo Reservation land.
Delivery:	Slurry pipeline.
Coal Analysis:	10,984 Btu/lb and .53% Sulfur (1987 average).

Historical Coal Costs (1988$)

Year	$/mmBtu	$/ton
1980	1.292	28.22
1981	1.093	23.95
1982	1.086	23.67
1983	1.192	26.05
1984	1.130	24.75
1985	1.128	24.73
1986	1.089	23.96
1987	1.080	23.73

1988 Estimated Baseline Costs (1988$)

Mine Mouth Coal Costs (84%)	0.858	18.89
Transportation Costs (16%)	0.164	3.60
Total Delivered Costs	1.022	22.49

Escalation Rate Projections

Period	Commodity	Transportation
1989-1990	0.0	0.4
1991-2000	0.8	0.4
2001-2009	1.6	0.4

FIGURE G-3
HISTORICAL AND PROJECTED COAL PRICES
MOHAVE POWER PLANT

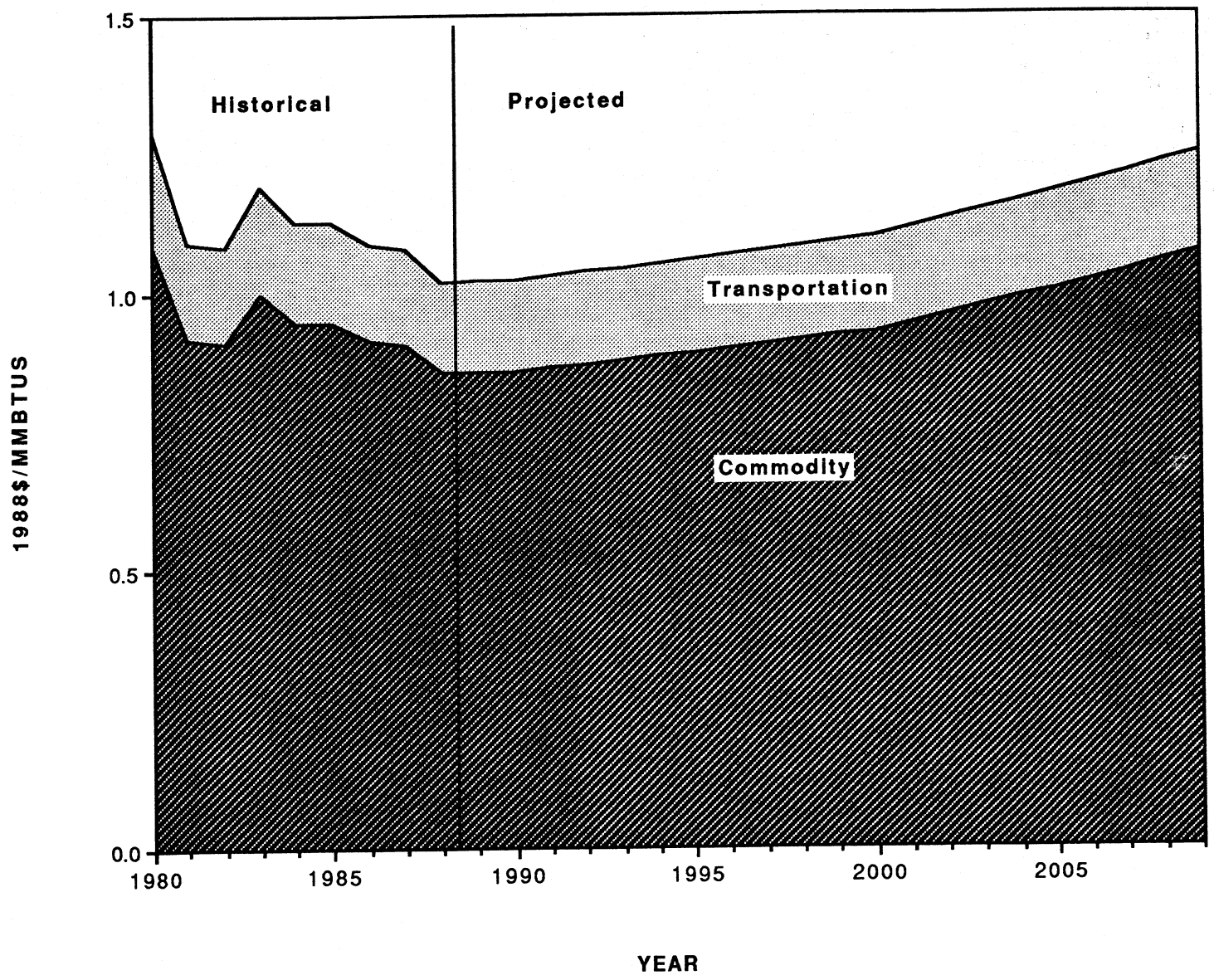


TABLE G-4

BASELINE DATA AND ESCALATION RATES
Four Corners Power Plant

Location:	Fruitland, New Mexico.
Ownership:	Southern California Edison (48%), Arizona Public Service (15%), Public Service of New Mexico (13%), Salt River Project (10%), El Paso Electric (7%), Tuscon Gas and Electric (7%).
Coal Source:	Navajo Mine, San Juan County, New Mexico; surface-mined from Navajo Reservation land.
Delivery:	Mine-mouth plant.
Coal Analysis:	8,786 Btu/lb and .77% Sulfur (1987 average).

Historical Coal Costs (1988$)

Year	$/mmBtu	$/ton
1980	0.610	10.63
1981	0.771	15.01
1982	0.783	13.81
1983	0.861	15.26
1984	0.888	15.50
1985	1.065	18.69
1986	0.984	17.31
1987	0.980	17.22

1988 Estimated Baseline Costs (1988$)

Total Delivered Costs	0.943	16.43

Escalation Rate Projections

Period	Commodity
1989-1990	0.0
1991-2000	1.0
2001-2009	1.8

FIGURE G-4

HISTORICAL AND PROJECTED COAL PRICES

FOUR CORNERS POWER PLANT

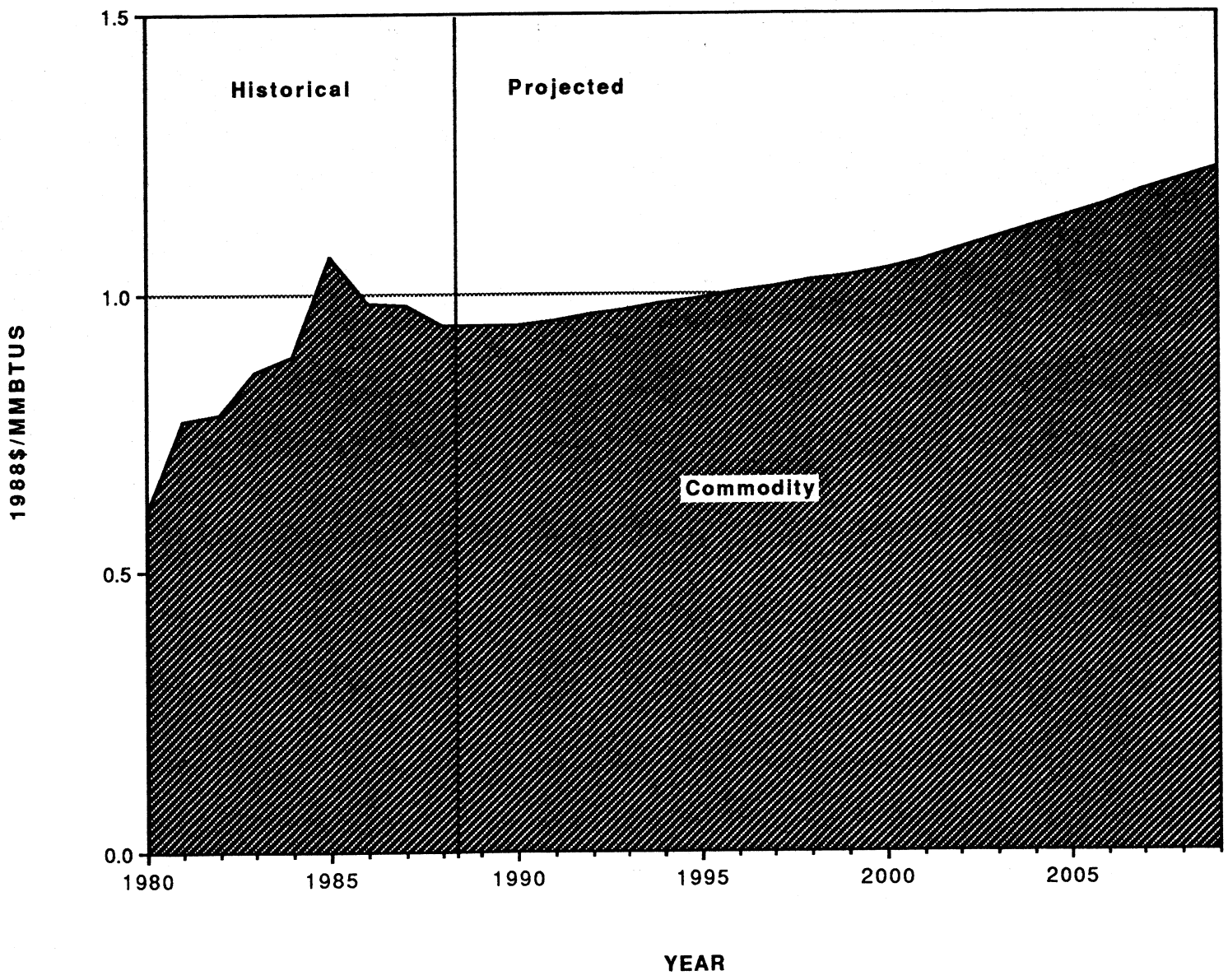


TABLE G-5

BASELINE DATA AND ESCALATION RATES
Coronado Power Plant

Location: St. Johns, Arizona.
Ownership: Salt River Project.
Coal Source: McKinley Mine, McKinley County, New Mexico (72% in 1987), surface-mined; York Canyon Mine, Colfax County, New Mexico (28% in 1987), underground-mined.
Delivery: Railroad.
Coal Analysis: 10,343 Btu/lb and .49% Sulfur (1987 average).

Historical Coal Costs (1988$)

Year	$/mmBtu	$/ton
1980	2.300	50.22
1981	2.322	49.07
1982	2.421	51.08
1983	2.400	50.15
1984	2.463	52.25
1985	2.279	47.38
1986	2.349	48.56
1987	2.279	47.14

1988 Estimated Baseline Costs (1988$)

Mine Mouth Coal Costs (45%)	0.988	20.70
Transportation Costs (55%)	1.207	25.29
Total Delivered Costs	2.195	45.99

Escalation Rate Projections

Period	Commodity	Transportation
1989-1990	0.0	0.0
1991-1992	1.0	1.0
1993-1995	1.0	1.6
1996-2002	1.4	1.6
2003-2009	2.4	1.6

FIGURE G-5

HISTORICAL AND PROJECTED COAL PRICES

CORONADO POWER PLANT

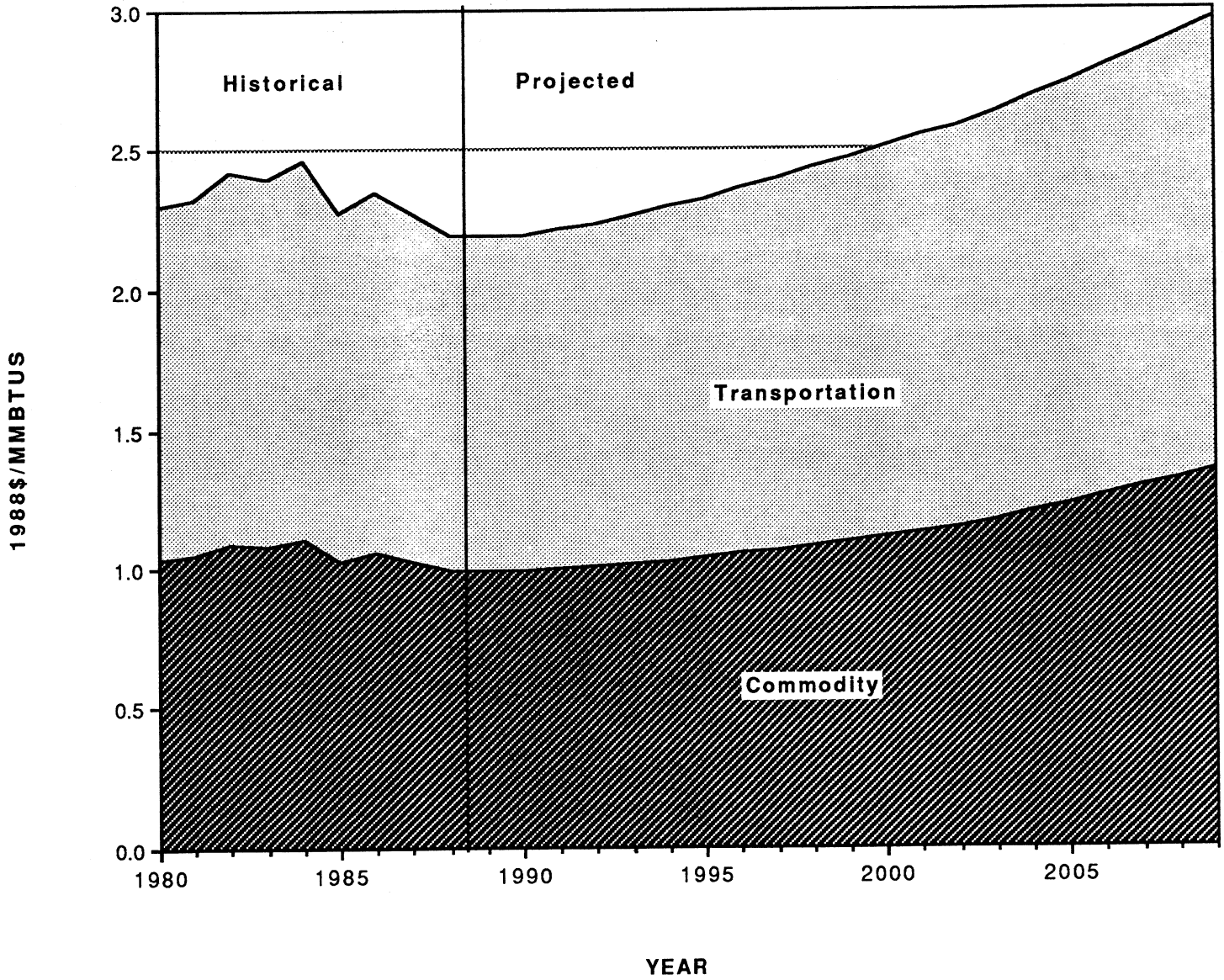


TABLE G-6

BASELINE DATA AND ESCALATION RATES
Navajo Power Plant

Location:	Page, Arizona.
Ownership:	Salt River Project, operator (21.7%), Bureau of Reclamation (24.3%), LADWP (21.2%), Arizona Public Service (14%), Nevada Power (11.3%), and Tuscon Electric (7.5%).
Coal Source:	Kayenta Mine, Navajo County, Arizona; surface-mined from Navajo Reservation land.
Delivery:	Utility-owned electric railroad.
Coal Analysis:	11,012 Btu/lb and .49% Sulfur (1987 average).

Historical Coal Costs (1988$)

Year	$/mmBtu	$/ton
1980	0.951	20.67
1981	0.944	20.54
1982	1.023	22.49
1983	1.060	23.59
1984	0.907	20.01
1985	0.951	21.04
1986	0.949	20.95
1987	0.930	20.47

1988 Estimated Baseline Costs (1988$)

Mine Mouth Coal Costs (92%)	0.905	20.00
Transportation Costs (8%)	0.079	1.74
Total Delivered Costs	0.984	21.74

Escalation Rate Projections

Period	Commodity	Transportation
1989-1990	0.0	0.2
1991-2000	1.0	0.2
2001-2002	1.0	0.5
2003-2009	2.0	0.5

FIGURE G-6

HISTORICAL AND PROJECTED COAL PRICES

NAVAJO POWER PLANT

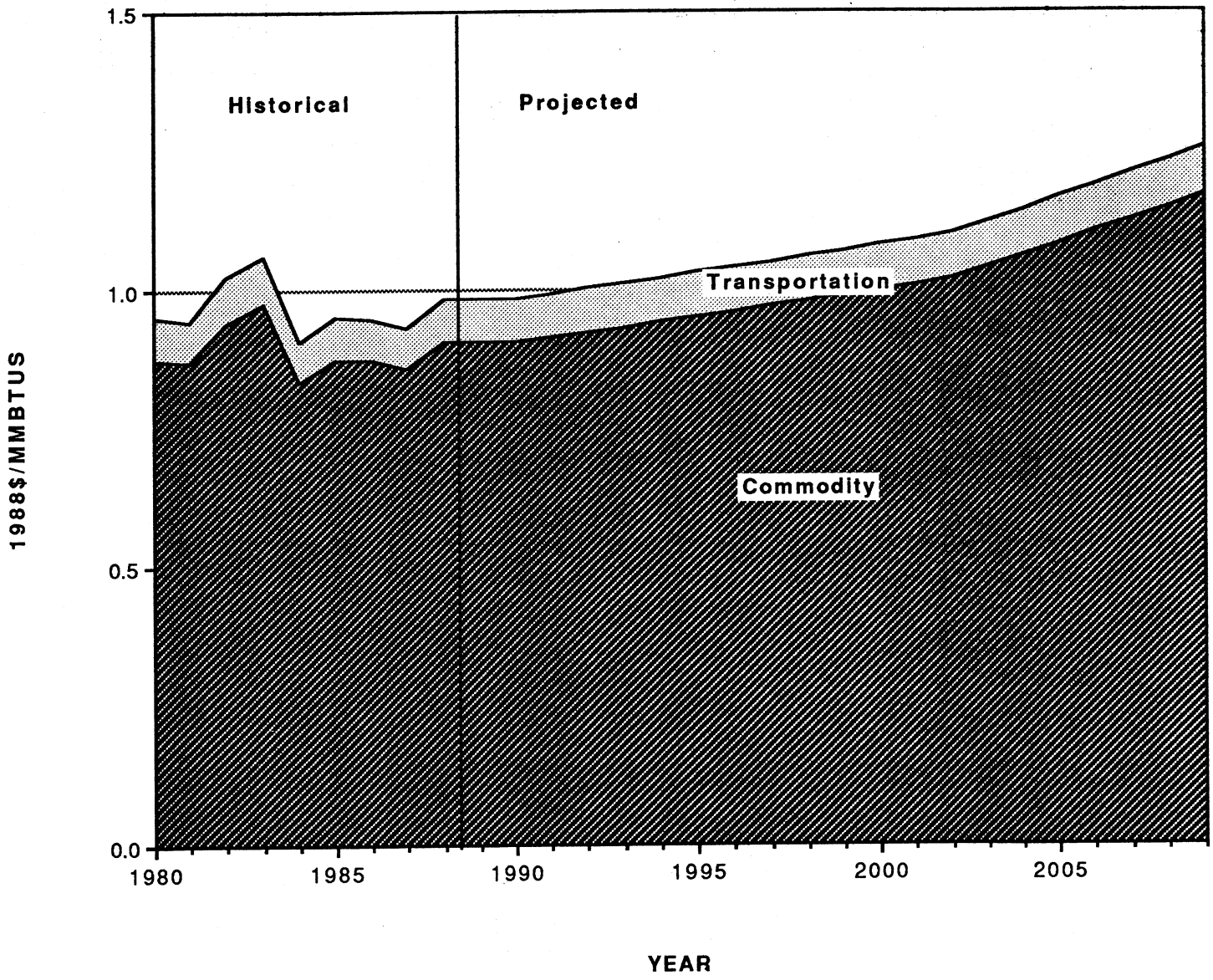


TABLE G-7

BASELINE DATA AND ESCALATION RATES
North Valmy Power Plant

Location:	Valmy, Nevada.
Ownership:	Sierra Pacific Power Co. (50%) and Idaho Power Co. (50%).
Coal Source:	Southern Utah Fuel Co. Mine #1, Sevier County, Utah (78% in 1987), underground-mined; Black Butte Mine, Sweetwater County, Wyoming (22% in 1987), strip-mined.
Delivery:	Railroad.
Coal Analysis:	10,964 Btu/lb and .39% Sulfur (1987 average).

Historical Coal Costs (1988$)

Year	$/mmBtu	$/ton
1981	2.221	49.24
1982	2.338	52.82
1983	2.285	51.65
1984	2.305	52.85
1985	2.246	50.73
1986	2.004	44.76
1987	1.916	42.00

1988 Estimated Baseline Costs (1988$)

Mine Mouth Coal Costs (48%)	0.906	19.18
Transportation Costs (52%)	0.981	20.78
Total Delivered Costs	1.887	39.96

Escalation Rate Projections

Period	Commodity	Transportation
1989-1990	0.0	0.0
1991-1992	1.0	1.0
1993-1995	1.0	1.6
1996-2002	1.4	1.6
2003-2009	2.4	1.6

FIGURE G-7
HISTORICAL AND PROJECTED COAL PRICES

NORTH VALMY POWER PLANT

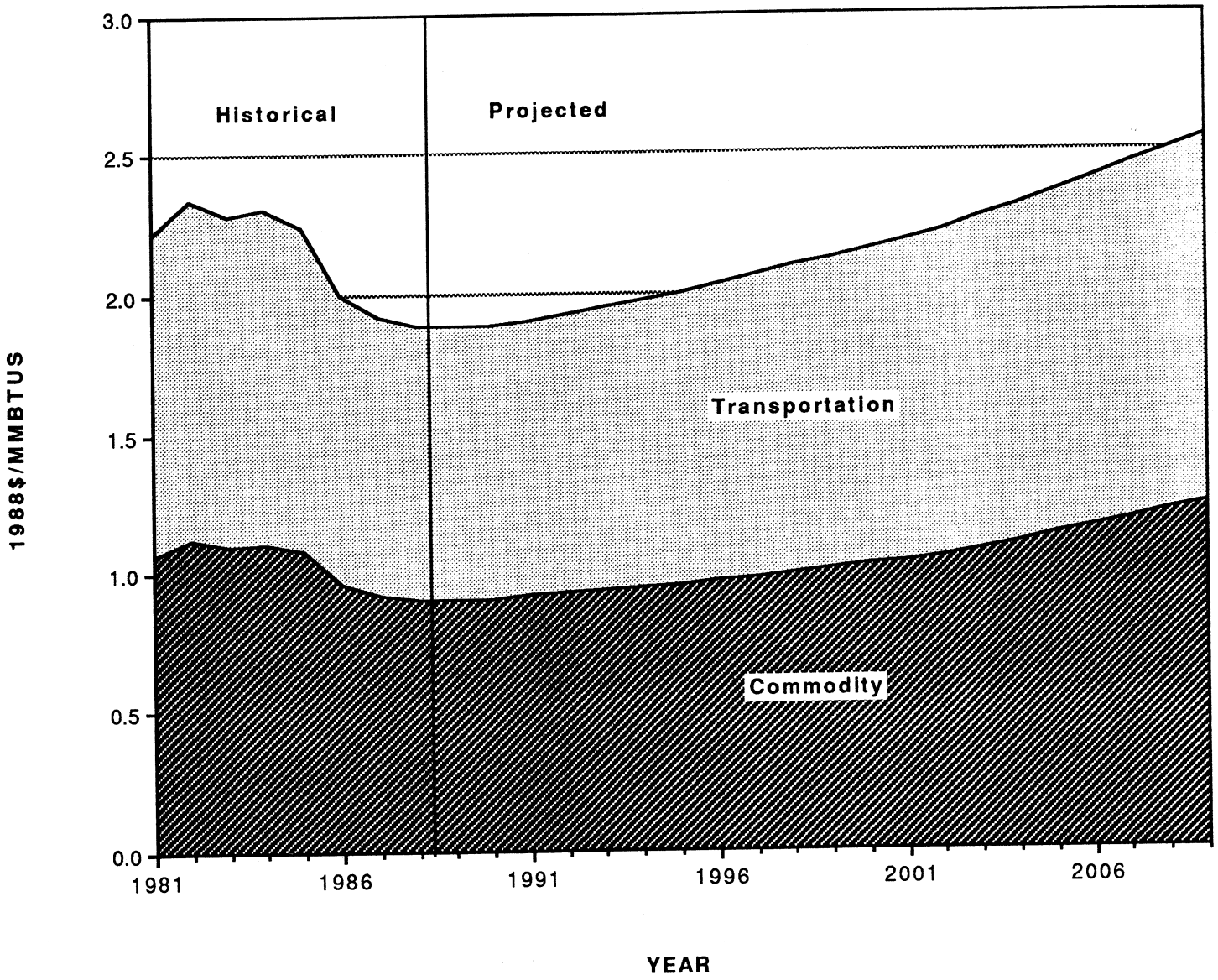


TABLE G-8

BASELINE DATA AND ESCALATION RATES
Intermountain Power Plant

Location:	Delta, Utah.
Ownership:	Intermountain Power Agency: active parties include LADWP and cities of Glendale, Burbank, Pasadena, Anaheim and Riverside.
Coal Source:	Skyline, Star Point #2, Pinnacle and Hiawatha Mines, Carbon County, Utah (91% in 1987), term contracts; and Emery County, Utah (9% in 1987), spot purchases; all sources underground-mined.
Delivery:	Railroad.
Coal Analysis:	11,859 Btu/lb and .56% Sulfur (1987 average).

Historical Coal Costs (1988$)

Year	$/mmBtu	$/ton
1986	1.401	32.90
1987	1.349	31.98

1988 Estimated Baseline Costs (1988$)

Mine Mouth Coal Costs (82%)	1.148	27.03
Transportation Costs (18%)	0.252	5.93
Total Delivered Costs	1.400	32.96

Escalation Rate Projections

Period	Commodity	Transportation
1989-1990	0.0	0.0
1991-1992	1.0	1.0
1993-1995	1.0	1.6
1996-2002	1.4	1.6
2003-2009	2.4	1.6

FIGURE G-8

HISTORICAL AND PROJECTED COAL PRICES

INTERMOUNTAIN POWER PLANT

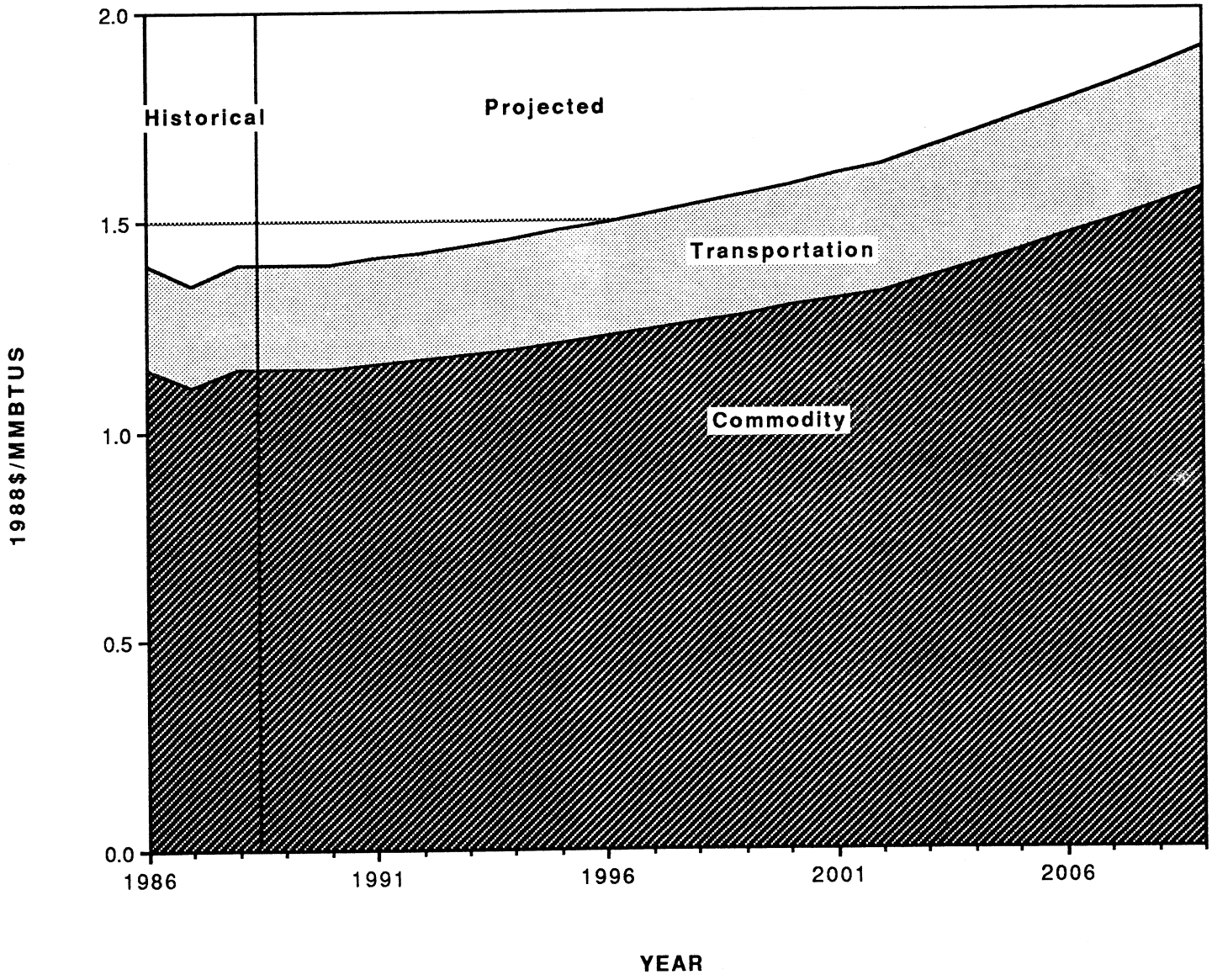


TABLE G-9

BASELINE DATA AND ESCALATION RATES
White Pines Power Plant (Proposed)

Location:	Ely, Nevada.
Ownership:	Unknown.
Coal Source:	Central Utah; underground-mined.
Delivery:	Railroad.
Coal Chax:	10,964 Btu/lb and .39% Sulfur (same as North Valmy).

1992 Estimated Baseline Costs (1988$)

[Assumes White Pines would be on the same scale and dependent on similar sources as North Valmy (although probably with more spot purchases), and with slightly higher transportation costs due to somewhat longer distances involved.]

	$/mmBtu	$/ton
Mine Mouth Coal Costs (46%)	0.920	20.17
Transportation Costs (54%)	1.080	23.68
Total Delivered Costs	2.000	43.85

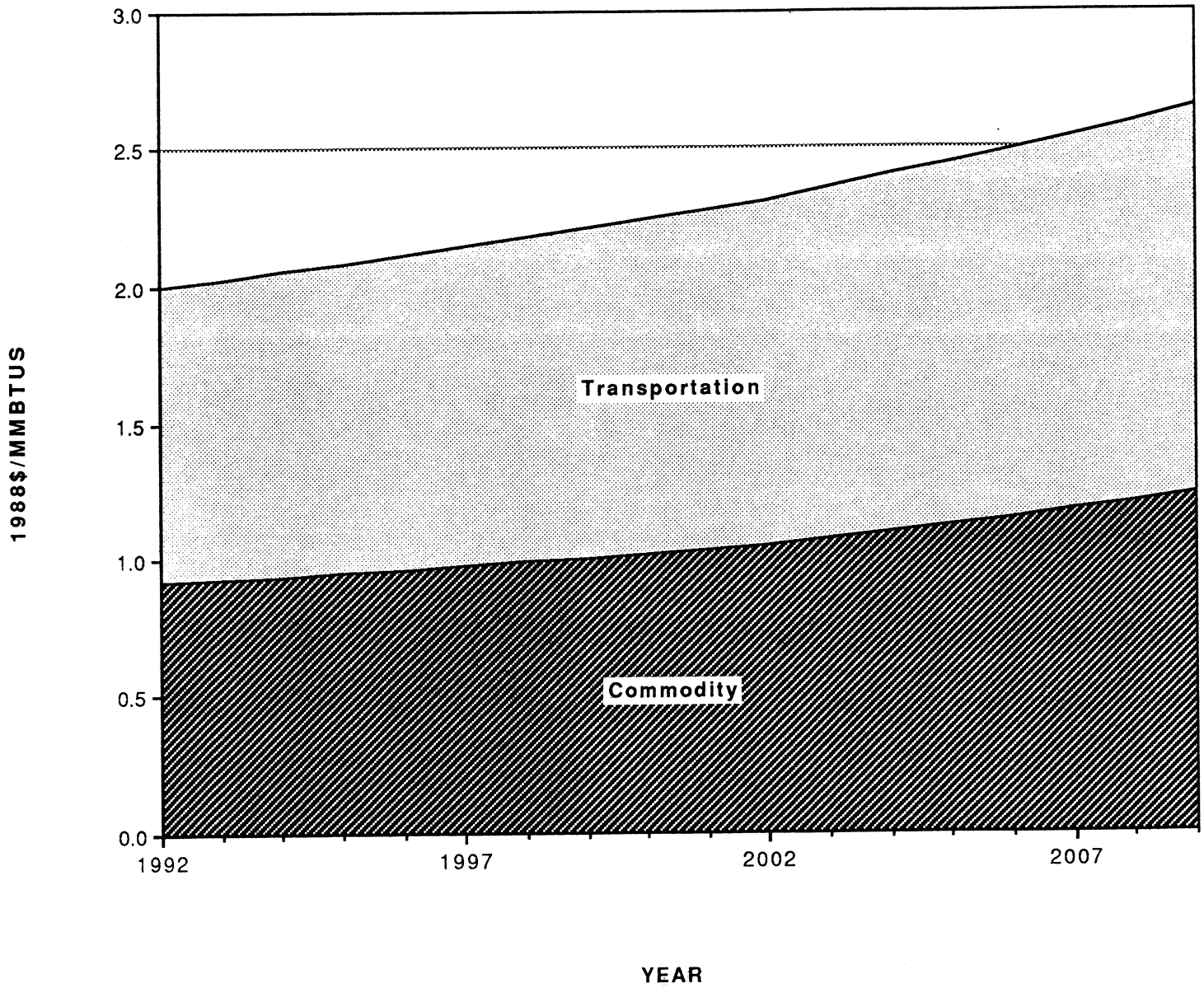
Escalation Rate Projections

Period	Commodity	Transportation
1993-95	1.0	1.6
1996-2002	1.4	1.6
2003-2009	2.4	1.6

FIGURE G-9

PROJECTED COAL PRICES

WHITE PINES POWER PLANT (PROPOSED)



APPENDIX H

FUELING TRANSPORTATION IN CALIFORNIA: A COMPLEX OF ENERGY, ENVIRONMENTAL AND ECONOMIC CHALLENGES

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FUELING TRANSPORTATION IN CALIFORNIA: A COMPLEX OF ENERGY ENVIRONMENTAL AND ECONOMIC CHALLENGES

I. INTRODUCTION

A combination of critical public priorities must be faced to provide California's future transportation fuel needs. Maintaining transportation fuel supplies adequate to meet growing demand, while attempting a transition to nonpetroleum sources, poses the state's most difficult energy problem. Transportation fuel uses have recently been growing at a rapid rate, reaching new record levels each year. Virtually all of these uses are supplied with petroleum products, accounting for over three-fourths of the state's oil needs and most of the growth in its oil imports. Slowing this fuel market growth and substituting commercial alternatives to petroleum products are formidable energy goals for California in the coming years.

At the same time, a second important condition must be satisfied by any transportation fuel option--the ability to reduce air pollutant emissions. Until recently, this meant meeting or bettering specified levels of "criteria" pollutants responsible for air quality problems in urban areas. New emphasis on the possible global warming problem, caused by "greenhouse gases," could add another element to evaluating air quality impacts of transportation fuels. Considerable environmental importance surrounds these additional pollutants, traditionally emitted on an uncontrolled basis from fuel production as well as combustion. Despite impressive progress already made in vehicular emission control effectiveness, the need for further emission reductions to reach urban air quality standards and to reverse the build-up of greenhouse gases will maintain pressure for "cleaner" transportation energy technologies. Other environmental concerns dictate that any options employed must also have acceptable impacts on water resources and on human health and safety.

Even though current market trends show few signs of adequate progress, the search for new transportation energy options has produced some encouraging results. The technological capability now exists to power most existing forms of transportation with other types of energy than petroleum fuels. Much untapped potential also exists for further improving the efficiency of transportation energy use. And most of these new transportation technologies offer at least some margin of environmental benefit. Even if the highest environmental quality goals prevail, there are options under development that appear capable of meeting the most severe requirements. How quickly any of these technologies are perfected

and brought to market, and adopted widely enough to effect significant energy and environmental change, depends on economic factors.

No matter how compelling the case for energy and environmental advances in transportation, economic realities continue to shape the path of progress. Even with the added public concern over worsening traffic congestion, steps toward transportation improvement cannot expect a "blank check" with respect to economic considerations. Direct cost implications as well as secondary economic and marketplace factors weigh heavily in all public decisions regarding transportation changes. California's overall economic circumstances, including the state's major interests in both conventional and alternative transportation energy forms, add a vital element to such decisions.

Satisfying any one of the requisite components for future transportation energy supply--energy, environmental, or economic--will not be easy. Designing strategies that can effectively address all of these needs must be viewed as an enormous responsibility. Proper understanding of the interrelated factors involved is obviously a key to sound strategizing. The remainder of this paper explores some of the important transportation energy issues currently under consideration in California, and attempts to contribute to an improved perspective on these issues.

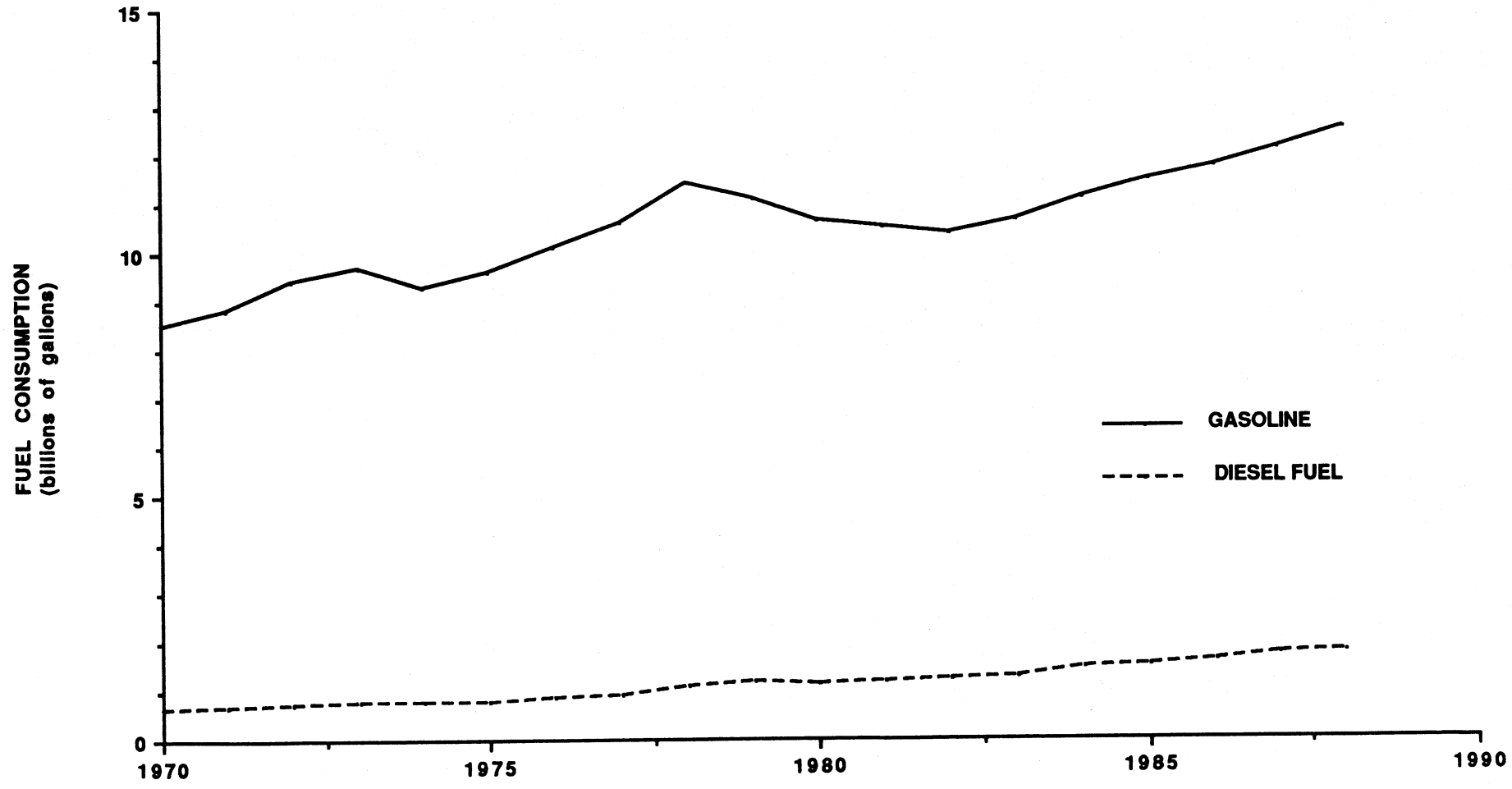
II. MOTOR VEHICLES AS ENERGY USERS AND AIR POLLUTERS

The focus on the automobile as the main demon in today's energy and air pollution picture has some valid rationale and a degree of misconception. On one hand, private and commercial passenger vehicles do in fact account for significant fractions of the state's petroleum fuel use and air pollution. On the other hand, dramatic improvements have been realized within the last two decades in automotive fuel economy, and even more profoundly in automotive emissions control.

A. Highway Gasoline Use: Trends and Projections

About 97 percent of California's 21 million registered highway motor vehicles currently burn gasoline. As a result, highway gasoline use alone amounts to 57 percent of transportation energy use and nearly one-fourth of all state energy use. As shown in Figure H-1, on-road gasoline consumption has been growing at a significant rate, topping 12.5 billion gallons in 1988. Since 1982, when gasoline demand reached the low point of a four-year downward trend, growth has averaged three percent per year, for a total demand increase of about 20 percent during this six-year period.

Figure H-1
CALIFORNIA HIGHWAY FUEL CONSUMPTION
1970-1988



Source: Caltrans and State Board of Equalization

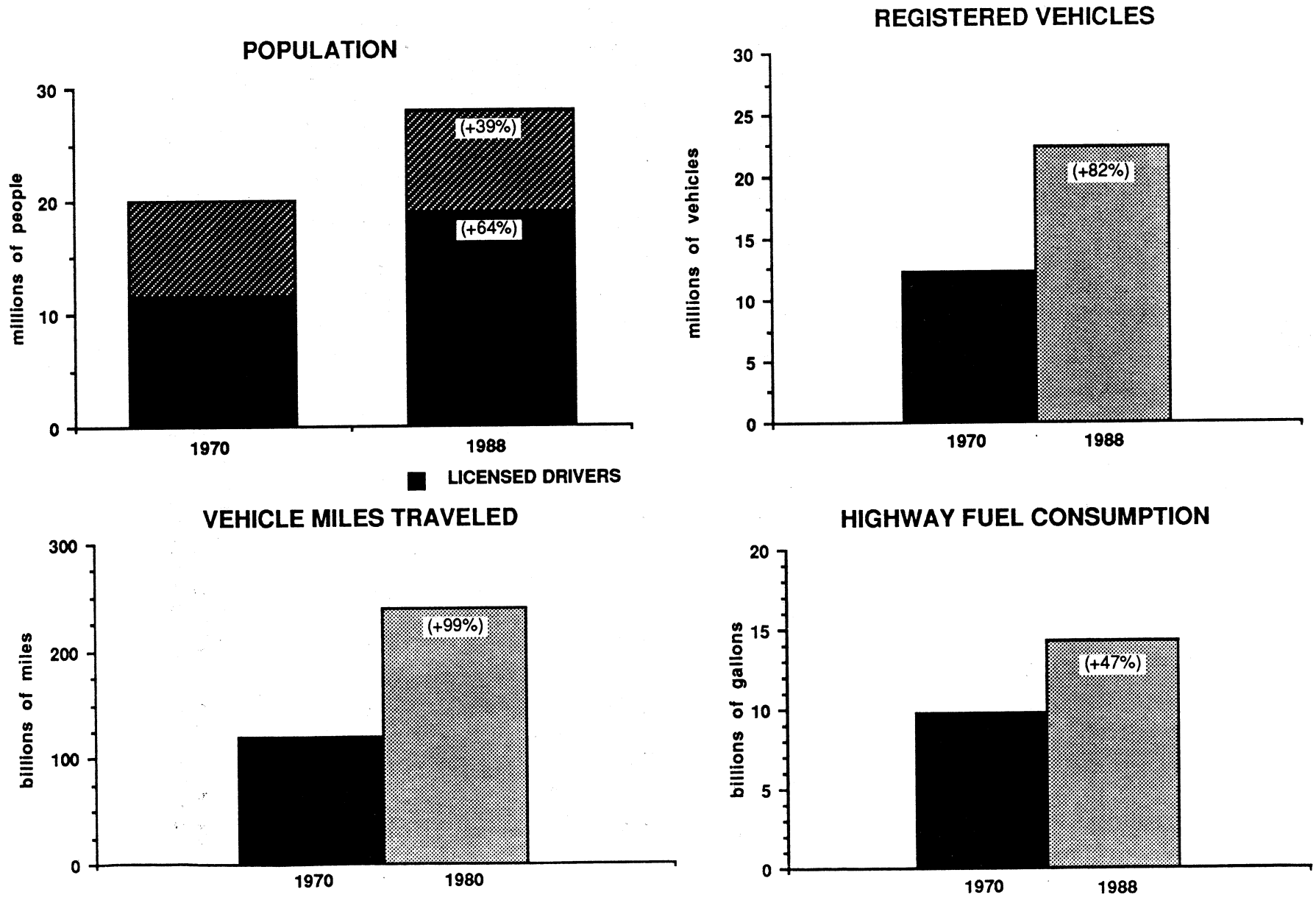
The growth in highway gasoline demand has occurred despite substantial automotive fuel economy gains. The average gasoline vehicle on the road in California today travels almost 50 percent more miles per gallon than cars on the road in the early 1970s. Today's average new car achieves virtually double the fuel economy of cars sold then. A revealing comparison of trends is provided in Figure H-2, showing how highway gasoline use has been influenced by enormous growth in vehicle miles traveled (VMT). From 1970 to 1988, the state's population has grown by about 40 percent. But VMT estimates indicate a much higher increase in travel--close to a doubling--during this same period. Ironically, vehicles that go further on a gallon of gasoline must share part of the blame for this steep travel increase, while also receiving credit for the lower growth rate in fuel demand.

Many other factors contribute to the high VMT growth. Favorable gasoline supply and price are widely regarded as the chief influence. Figure H-3 tracks the inflation-adjusted price of gasoline since before the first (1973) energy crisis, showing that the consumer value of this fuel has indeed re-established itself to a "buyer's market" level. Other recognized influences include upswings in licensed drivers and vehicle ownership, multiple-income families, longer commute distances, and healthy economic conditions. California appears to have successfully resumed a pattern of unrestrained gasoline market behavior, leaving behind the concerns that prompted the last downturn in demand ten years ago.

Will the recent growth rate for gasoline demand be sustained in the years to come? The first half of 1989 saw about a 2 percent increase over consumption in the first half of 1988. This was despite a significant price spike that saw retail pump prices jump as much as 20 cents per gallon within one month after the Exxon Valdez oil spill. Although a slight dip in monthly gasoline sales was noted for the month of May, the current year appears headed for another all-time record level of gasoline sales, possibly the first year in which over a billion gallons is sold in every single month.[1]

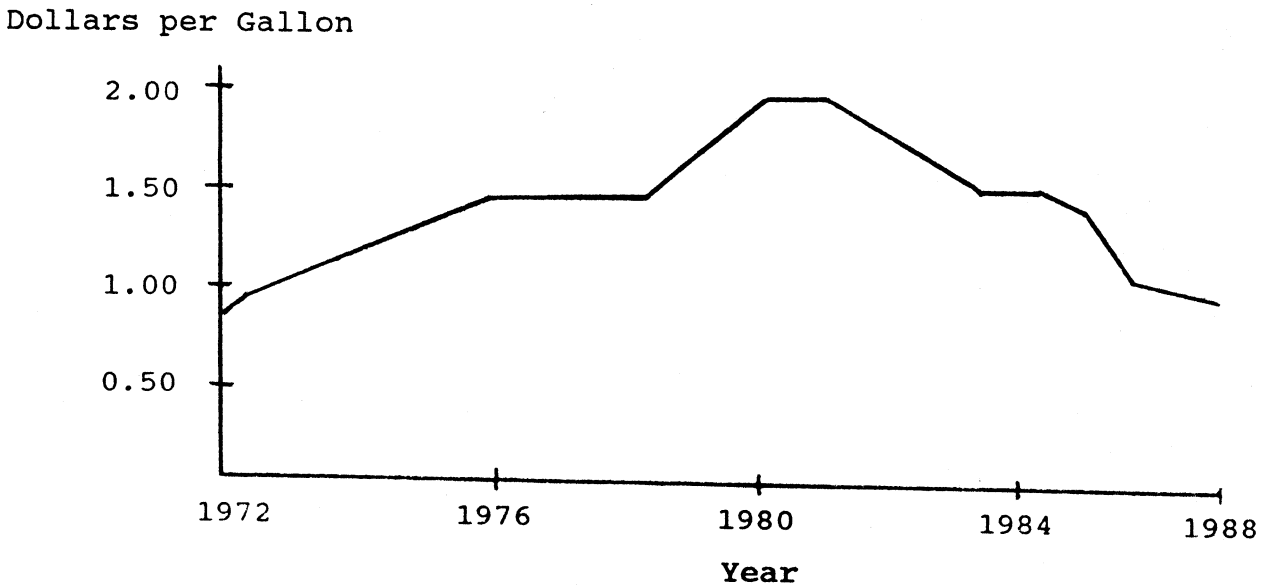
Forecasting future gasoline demand is obviously fraught with uncertainties. Expectations of continued growth in population and economic activity generally correlate with more highway travel. But higher gasoline prices coupled with further progress in vehicle fuel economy should serve to moderate the resulting fuel demand growth. Other factors, such as the effects of increasing traffic congestion, trends in residence-to-workplace distance, results of programs to encourage ridesharing and telecommuting, and a number of additional variables affecting per-mile and per-capita fuel use, will assert both upward and downward influences. The complexity and unpredictability of all these determinants of demand weigh against any firm forecasts of future gasoline use. However, it is useful to consider and compare some recent projections that span a range of possible outcomes.

Figure H-2
California Growth in Transportation-Related Factors
1970-1988



Source: CALTRANS MVSTFF Report , 12/88

FIGURE H-3
HISTORICAL GASOLINE PRICES
(Retail)

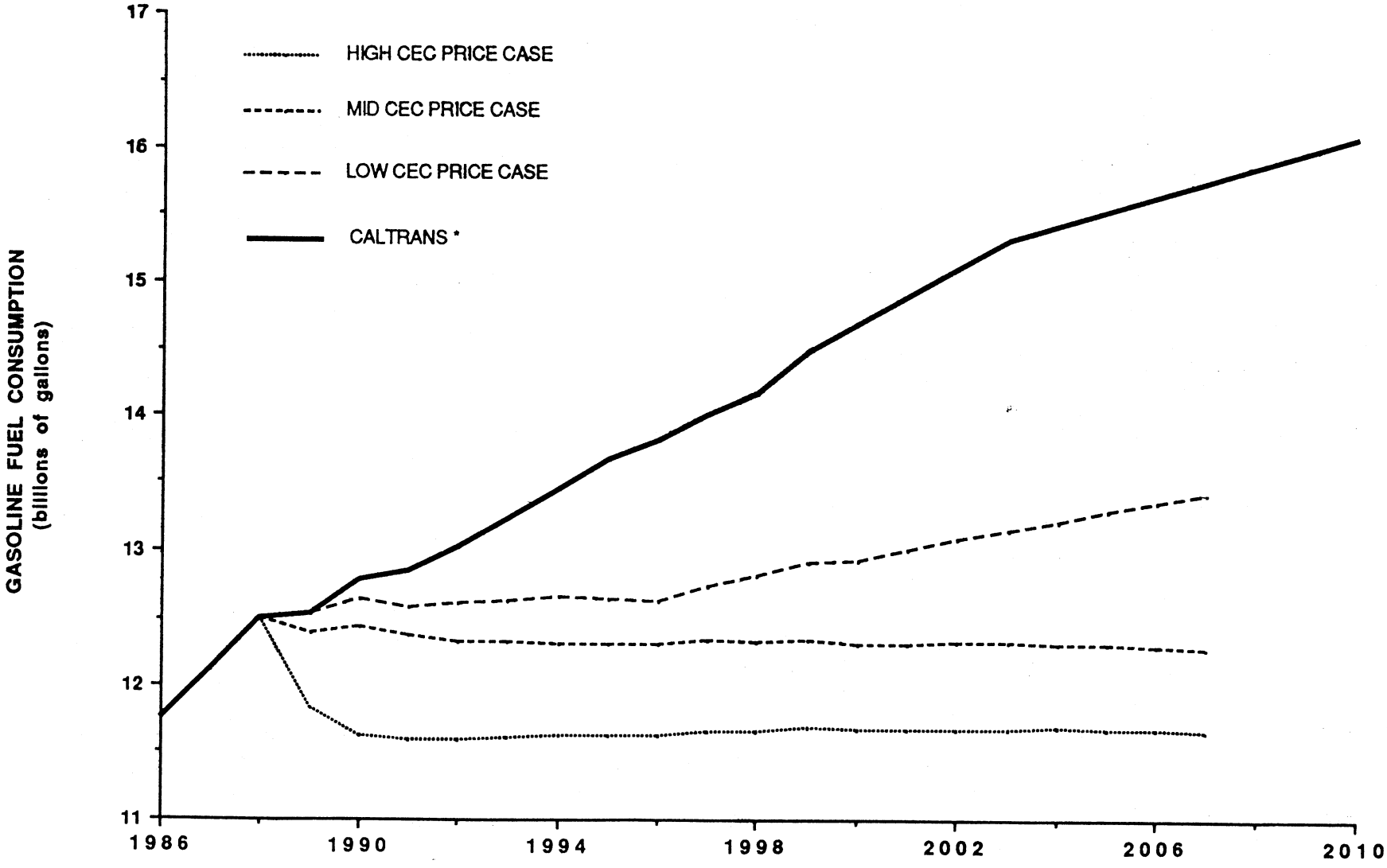


Sources: Platt's Oilgram Price Service (1972-77), U.S. Bureau of Labor Statistics (1978-84), Caltrans (1985-88) [regular gasoline through 1977, regular unleaded after]

The California Department of Transportation (Caltrans) annually conducts a computer modeling study that results in their "California Motor Vehicle Stock, Travel and Fuel Forecast" (MVSTAFF). Caltrans has also applied this same methodology to develop gasoline demand projections for three scenarios corresponding to CEC's current high-, low-, and mid-range oil price forecast. Other organizations, including major oil companies, also regularly prepare such projections. Figure H-4 shows the results of the Caltrans/Energy Commission modeling results, along with the most recent Caltrans MVSTAFF forecast. Due largely to the influence of the different gasoline price assumptions employed (shown in Table H-1), these exercises reveal sharply contrasting results. The Caltrans/Energy Commission cases--based upon the Energy Commission's high-, mid- and low-range forecast prices--result in net changes in gasoline demand from 1988 to 2007 ranging from a 7 percent increase to a 7 percent decrease.

The Caltrans/MVSTAFF case, using lower prices than those in the Energy Commission's forecast, yields a 24 percent increase in demand from 1988 to 2005.[2] Chevron USA's current outlook assumes continuing demand growth at a rate of about 1.5 percent per year,

Figure H-4
COMPARISON of CALIFORNIA GASOLINE DEMAND FORECASTS



Source: 1988 MVSTAFF

TABLE H-1

COMPARISON OF GASOLINE PRICE PROJECTIONS
USED IN DEMAND FORECASTS
($/gallon, 1988 $)

Year	CEC Low	CEC Mid	CEC High	Caltrans
1988				0.642
1989	0.731	0.768	0.931	0.605
1990	0.734	0.780	1.034	0.572
1991	0.748	0.799	1.044	1.562
1992	0.761	0.820	1.055	0.543
1993	0.779	0.843	1.065	0.524
1994	0.796	0.864	1.075	0.505
1995	0.826	0.888	1.096	0.488
1996	0.861	0.909	1.117	0.489
1997	0.873	0.935	1.137	0.490
1998	0.886	0.963	1.158	0.492
1999	0.908	0.992	1.179	0.493
2000	0.933	1.024	1.199	0.495
2001	0.950	1.053	1.220	0.496
2002	0.970	1.083	1.251	0.497
2003	0.992	1.115	1.272	0.499
2004	1.013	1.148	1.292	0.500
2005	1.035	1.183	1.324	0.501
2006	1.057	1.219	1.344	0.502
2007	1.079	1.258	1.375	0.504
2008	1.102	1.298	1.407	0.505
2009	1.126	1.339	1.439	0.506
2010	1.151	1.381	1.472	0.508

NOTE: Prices are for regular unleaded gasoline, self-service retail, without taxes.

resulting in net growth slightly exceeding that of the Caltrans/ MVSTAFF case.

Adequately interpreting and drawing conclusions from any of these estimates of future demand would require much more in-depth examination than this paper can provide. However, several observations can be offered regarding the degree of confidence to be placed in these or any other attempts to forecast highway gasoline demand:

- A strong relationship between gasoline price changes and demand is traditionally the predominant factor in these projections, usually explaining most or all of the differences between results. Yet, there may be an evolving real-world phenomenon of diminishing price impact on demand, particularly in the range of most current price projections (which suggest continued "affordability"). As fuel economy progress continues to reduce the fuel component of driving costs, and other attractive travel options are slow to develop, highway vehicle travel may very well be becoming less sensitive to moderate upward gasoline price movement.

- The significant effect of vehicle fuel economy improvements that have already been achieved promises some degree of further extension, but sooner or later (perhaps sooner without further regulation), must begin to diminish.

- Past forecasting theories have often held that a reduction or reversal of gasoline demand growth was imminent, or at least inevitable. The rationale has often included not only the expectation of price increases, but also the concept that vehicle travel will begin to reach a "saturation" level. However, with the seventh year of steady growth apparently in progress--potentially the fourth consecutive year to set a new record for consumption--the prospects for a downward or even stable demand trend seem rather distant.

- The average annual growth in gasoline demand since 1982 (about 3 percent per year), if continued, would result in net growth of 38 percent by the year 2000 and 70 percent by 2007. Clearly, most actual forecasts of future gasoline demand rely on growth-slowing events beyond any that are presently in evidence.

- The implications of underestimating versus overestimating future demand growth may suggest considering (if not preparing for) a "worst-case" outcome based on continuation of current trends.

How is it that major increases in population, vehicle travel and motor fuel consumption can occur together with a major reduction in vehicular air pollution? The answer lies in the high degree of

emission control effectiveness that has been progressively incorporated in new vehicles. Today's passenger cars must meet a state hydrocarbon (HC) exhaust standard of 0.4 grams per mile, compared to circa 1970s (uncontrolled) vehicles that emitted up to 10 grams per mile or more. Thus, the new vehicle may emit only 4 percent as much exhaust hydrocarbons per mile as the old vehicle, requiring 25 miles of travel to equal the same ozone air quality impact of 1 mile in the old car. For carbon monoxide (CO) and oxides of nitrogen (NOx), the other two major criteria pollutants, control effectiveness has been somewhat less extreme, but still results in emissions of perhaps only 10-20 percent of older car levels. With these emissions ratios of from 5:1 to 25:1 in favor of new cars, it has therefore been possible to substantially reduce the highway motor vehicle contribution to urban air pollution (as shown in Figure H-7), even with nearly twice as much vehicle travel as before. Less emission control progress with other transportation and stationary pollution sources has kept the level of highway vehicle improvement from being matched with overall emissions and air quality improvement.

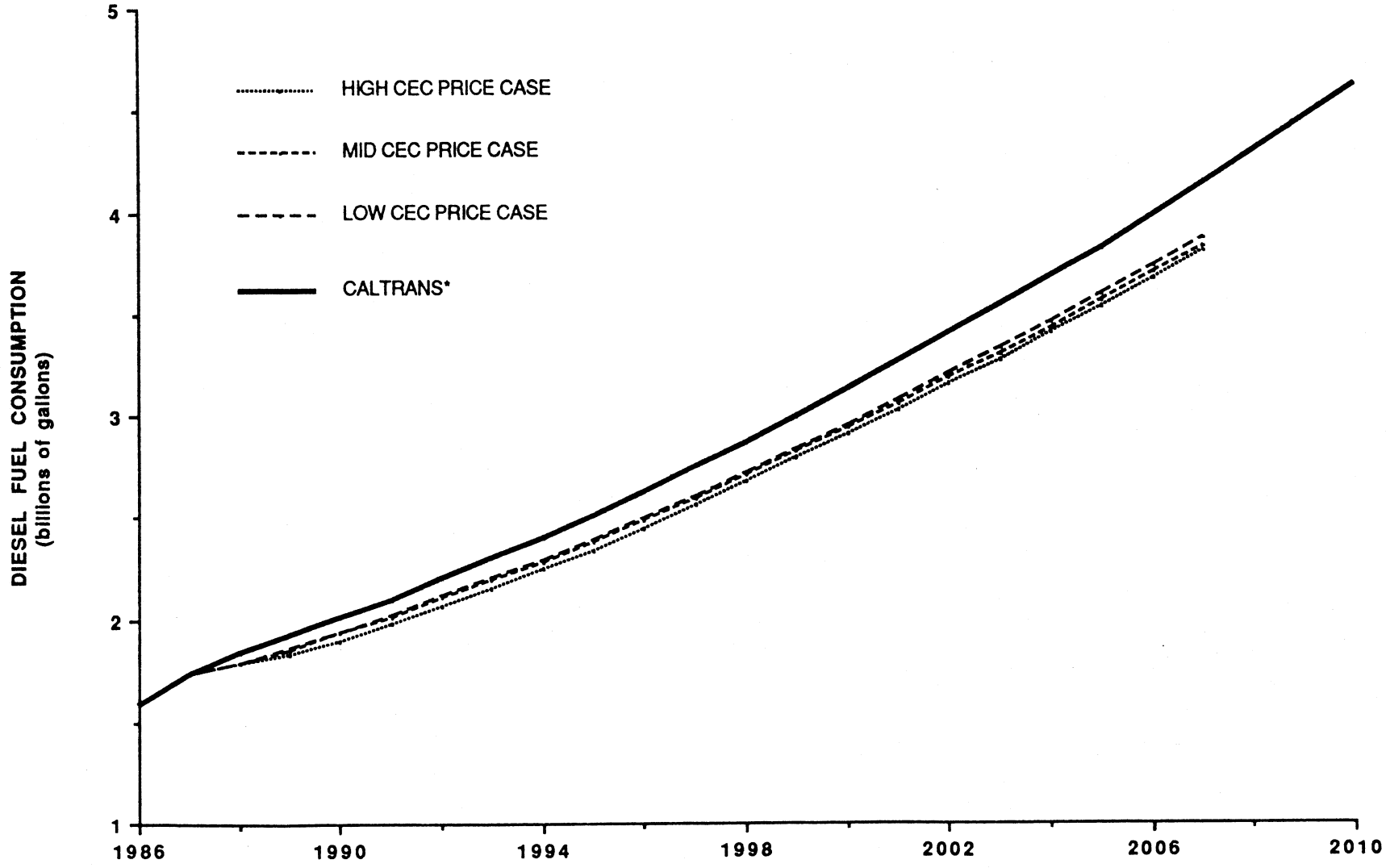
B. Highway Diesel Use: Trends and Projections

Compared with gasoline, highway diesel fuel represents a considerably smaller but faster-growing portion of California's transportation fuel picture. Diesel fuel consumption in 1988 was about 1.8 billion gallons, or about 12 percent of all highway fuel use. However, compared with the 20 percent growth in gasoline demand since 1982, diesel fuel demand has grown by more than 40 percent. Also, as shown in Figure H-1, historical diesel demand growth has occurred at a much steadier rate than gasoline demand, even defying the effects of the 1979 oil crisis which sent gasoline demand into several declining years. In fact, state demand for diesel fuel has just about doubled in the last 10 years.

The majority of highway diesel fuel (over 70 percent) is used by large trucks over 33,000 pounds, gross vehicle weight (GVW). About 20 percent is used by medium- and heavy-duty trucks in lower weight categories. Included in this category are transit buses, which are believed to comprise less than 5 percent of total diesel fuel use. Autos and light-duty trucks (6,000 lbs. GVW and under) account for a diminishing fraction--now about 7 percent--of diesel use.

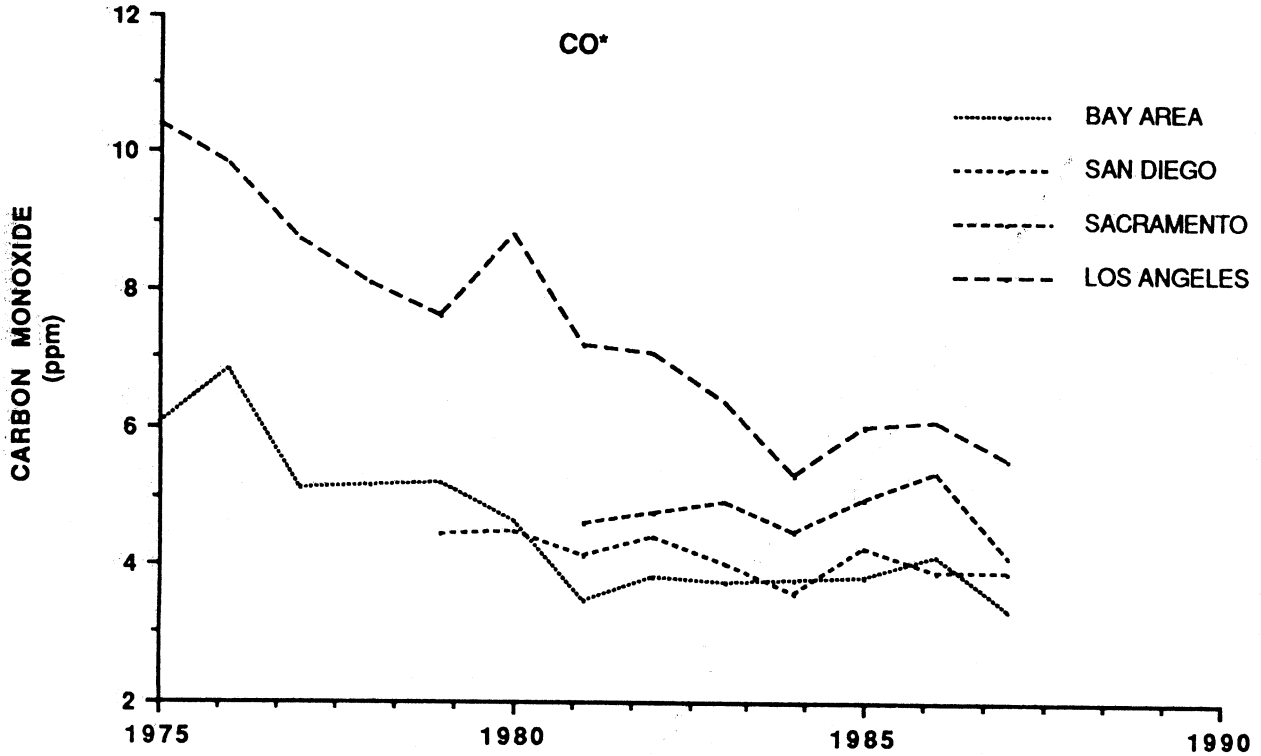
Projections for highway diesel fuel use (see Figure H-5) tend to be much more consistent than for gasoline, showing a continuing steep growth trend. All of the different fuel price cases examined in the Caltrans/MVSTAFF and Caltrans/CEC modeling studies project between 63 percent and 70 percent growth by the year 2000, and a doubling of demand within less than 20 years. Most of the growth is expected to be in the large truck category. This reflects a strong relationship between truck activity and economic growth, largely independent of fuel prices. Also, little improvement in

Figure H-5
COMPARISON of CALIFORNIA DIESEL DEMAND FORECASTS

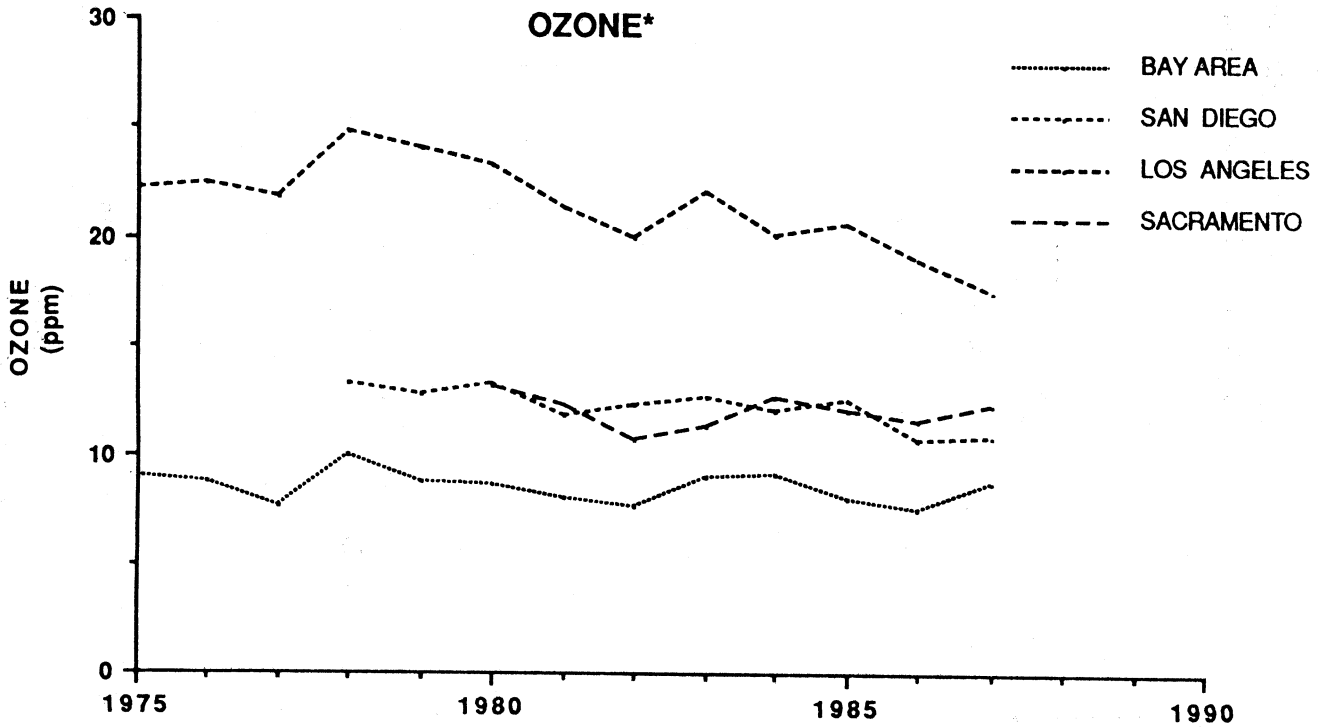


Source: 1988 MVSTAFF

Figure H-6
AIR QUALITY TRENDS in URBAN AIR BASINS



*mean of 4 to midnight carbon monoxide concentration of top 30 days in year



*mean of maximum-hour ozone concentration of top 30 days in year

Source: CARB data

fuel economy of these vehicles--typically around five miles per gallon--is predicted. If these projections prove accurate, diesel fuel will continue to be a rapidly-growing portion of transportation fuel demand, increasing its share of highway fuel use to over 20 percent.

C. Motor Vehicle Emissions and Urban Air Quality Trends

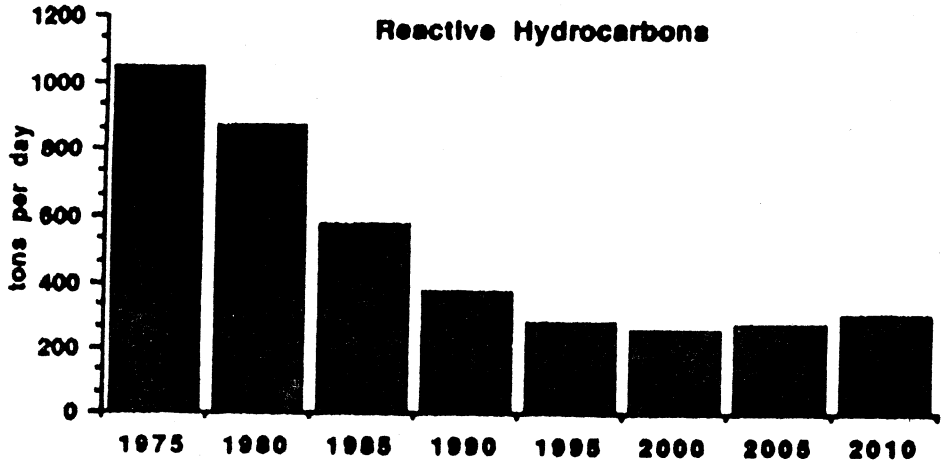
The substantial growth in statewide vehicle travel and highway fuel use tends to invite the conclusion that motor vehicles are increasing contributors to deteriorating urban air quality conditions in the state. However, California Air Resources Board data (Figure H-6) indicates, to the contrary, that air quality, as indicated by ozone and carbon monoxide trends, has been steadily improving, at least in Los Angeles. In San Francisco, Sacramento, and San Diego, progress is not as evident, but the data trends seem to point more toward improvement than deterioration.

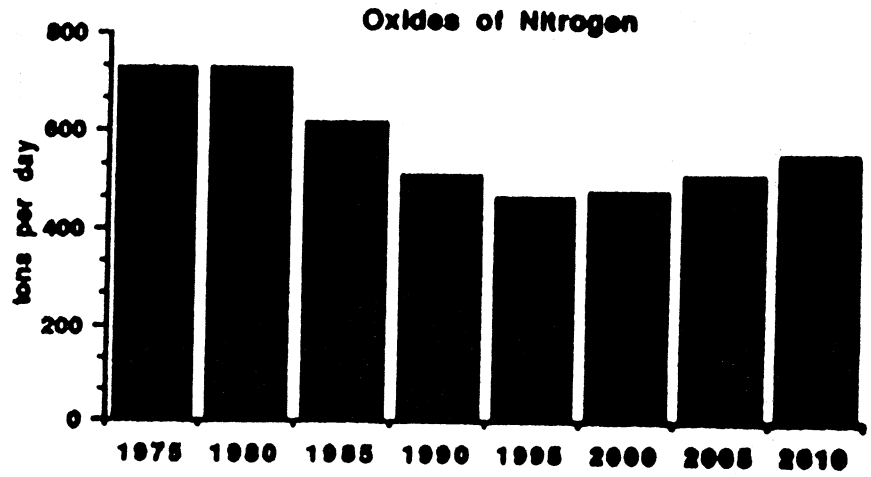
Even with the tremendous advances in vehicular emission control, motor vehicles remain an important focus for further emission reduction measures. This is partly due to their still-large contribution to pollution and to continuing growth trends, and partly due to opportunities that exist for further improvements. The dim prospect that some cities may never meet air quality standards forces consideration of more and more drastic measures to control all emission sources. Air quality studies have shown that removing all transportation emission sources--or conversely, all stationary sources--from the Los Angeles basin would still fail to accomplish full compliance with federal air quality standards. Therefore, even though automotive emissions have achieved a greater margin of improvement than many other sources, much further control of all sources, and probably complete elimination of some, must be an ongoing objective.

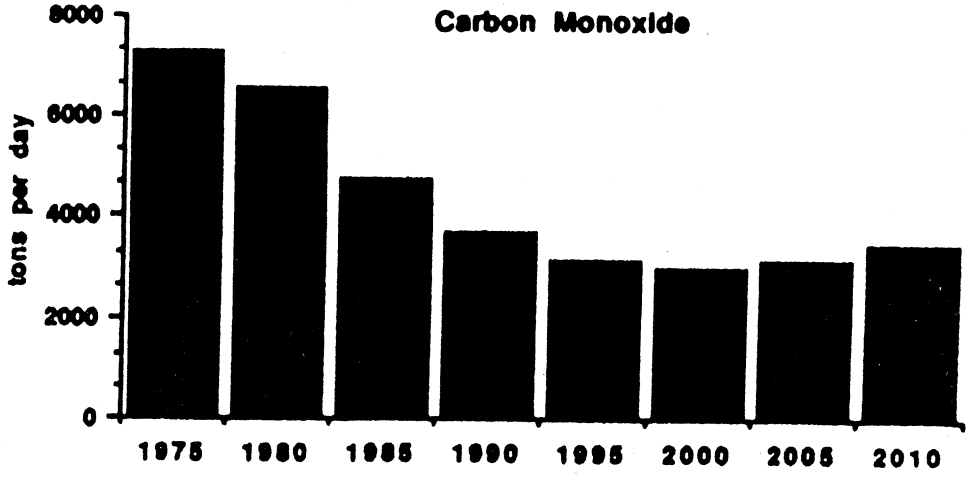
D. The Greenhouse Effect

While recognized scientifically for many years, serious concern regarding impacts of the build-up of carbon dioxide (CO_2) and other so-called "greenhouse gases" has only recently become a major public issue. So far, there is still considerable uncertainty and debate regarding the imminence of the global warming problem and the need for instituting control measures on contributing sources, including motor vehicles. There is not yet a standard or other formal objective for controlling vehicular CO_2. However, there is increasing acknowledgement that automotive CO_2 emissions may become an important part of worldwide efforts to reverse the build-up of greenhouse gases. A significant indicator of what is to come may be the movement underway to eliminate the use in auto air conditioners of chlorofluorocarbons (CFCs), identified as a particularly offensive atmospheric pollutant.

Figure H-7
South Coast Air Basin Motor Vehicle Emission Trends projected to the year 2010







Source: CARB Emission Inventory Projection of Jan. 4, 1989;
based on vehicular emission control measures adopted as of that date,
VMT as forcast by Caltrans.

Transportation sources may be responsible for up to one-third of all CO_2 emissions in the U.S. Even so, California's own motor vehicle contribution to the global warming problem (as well as the potential for a solution inherent in this contribution) must be viewed as incidental. Thus, it may be unrealistic to expect traditional state air quality regulatory approaches to be effectively applied toward solving this global problem. However, as a world leader in both motor vehicle gasoline consumption and motor vehicle emission regulation, California's response to environmental arguments for reducing automotive CO_2 emissions stands to determine an overall response.

E. Fuel Economy Regulations versus Emission Regulations

Two independent sets of regulations have separately guided the development of automotive fuel economy and emission control. Federal Corporate Average Fuel Economy (CAFE) standards require each auto maker to meet minimum miles-per-gallon averages for all autos and light trucks sold in any model year. Federal and state emission standards require all autos to meet the same grams-per-mile levels for the criteria pollutants (HC, CO, NO_x). The result is a disconnection between the amount of fuel a vehicle uses and its emissions of criteria pollutants. Certain emission control options may even cause a fuel economy penalty (and vice versa). However, auto companies have managed to successfully engineer and certify vehicles to meet progressively more stringent levels of both standards. At the same time, the auto companies have also complied with a third important set of regulations, federal safety standards.

The interactive nature of fuel economy and emission standards (and to a lesser extent, safety standards), has been the subject of much recent examination and debate. Interest in the greenhouse effect and the unregulated status of CO_2 emissions has contributed to this debate. Arguments have been forwarded for adopting a new regulatory basis to directly link vehicle fuel economy and all pollutant emissions--for example, changing from grams-per-mile to grams-per-gallon emission standards.[3] Others simply advocate higher CAFE standards as a key to less fuel consumption and proportionally less CO_2 emissions.[4] Specific proposals for government action to simultaneously address fuel economy and emission objectives are receiving increasing attention.[5,6] While these various viewpoints and proposals may suggest somewhat different directions, several compelling points seem to emerge from the overall debate:

- Further technological progress in automotive emissions control and fuel economy continues, affording much additional potential for commercialized improvements in both.

- Continuing to implement more stringent versions of the current independent regulatory schemes for fuel economy and emissions may indeed work somewhat at cross purposes.

- Methods for further reductions in vehicle emissions of criteria pollutants are much more advanced than for reductions in greenhouse gases.

- Regulating higher vehicle fuel economy, compared with regulating vehicle emissions, involves much more of a confrontation with consumer market preferences, versus simply a "technology-forcing" function (for further discussion, see Section V).

- California has numerous options to consider in establishing goals for further vehicle emission control and fuel economy progress and determining an effective state approach to these goals.

III. THE PURSUIT OF FURTHER AUTOMOTIVE EMISSIONS PROGRESS

Major new actions are being undertaken at both the state and federal levels to further improve the emissions performance of new automobiles and light trucks. Heavy duty trucks and buses are also the focus of new, more stringent federal standards. The traditional approach involving on-vehicle emission control systems is being supplemented with an additional approach that seeks to improve the emissions-producing characteristics of fuels, including the substitution of inherently cleaner fuels.

A. New Initiatives for Controlling Conventional Vehicle Emissions

Probably the most significant event of late (though not highly publicized) has been the adoption by the California Air Resources Board (CARB) of tighter emission standards for new cars and light trucks sold in the state beginning in 1993. Besides the reduction in passenger car HC levels from 0.4 to 0.25 grams per mile, and similar tightening of the light truck standard, CARB took an important additional step by extending the in-use emissions certification requirement from 50,000 to 100,000 miles. This means that current levels of emission degradation as vehicles age will be severely curtailed, and a current source of excess emissions (due to high mileage emission control failures) will be greatly reduced. Together with the previous adoption of a 0.4 grams per mile NO_x standard, and a rigorous biennial inspection and maintenance program, this assures that another generation of cleaner vehicles is yet to come and that light-duty (gasoline fueled) vehicles will continue to decline as a contributor to the overall inventory of pollutant emissions.

The U.S. Environmental Protection Agency (EPA) has also established more severe heavy-duty vehicle emissions standards. Beginning in 1991 for buses and 1994 for trucks, new diesel vehicles must meet extremely low levels of particulate matter emissions, virtually eliminating the visible smoke in diesel exhaust. An accompanying increment of further NO_x emission reduction will also be required. Table H-2 summarizes the progression to date of state and federal emission standards for all vehicle categories.

California is also moving further to improve the air pollution-related fuel specifications for gasoline and diesel fuel. As shown in Table H-3, current fuel regulations will likely be supplemented with others that will result in additional emission reductions by: 1) directly lowering combustion emissions; 2) helping assure emission control system effectiveness and durability; and 3) reducing evaporative emissions from fuel handling, on-board the vehicle and throughout the distribution system. Included is a proposed limit on benzene, a recognized carcinogen, marking the initial attempt at controlling toxic contaminants from motor fuels, along with conventional air pollutants. Oil companies are also moving on their own to improve their fuel formulations, either to stay ahead of regulations or to aid in product marketing. An example is provided by ARCO's recent announcement to completely eliminate its leaded gasoline sales and substitute a new gasoline formulation for use in older cars. The new product will include the methanol-based additive, MTBE, and have lower benzene and vapor pressure levels.

Other opportunities for "reformulating" petroleum products deserve further consideration as potential emission-reducing strategies. A joint research and testing program being undertaken by the three major domestic automobile manufacturers and fourteen oil companies to evaluate the wide range of fuels for use in both current and future cars and trucks. The purposes of the program are to develop data necessary to allow informed decisions on air quality matters affecting the two industries' customers who buy vehicles and fuels. The first phase, funded for $11.3 million, will evaluate reformulated gasolines usable in existing vehicles that will be in use in the 1990s and methanol/gasoline mixtures usable in fuel flexible vehicles. The first phase is scheduled to be completed in mid-1990. The second phase will evaluate future gasolines usable in future prototype vehicles with advanced emission control systems and advanced methanol, as well as other alternative, fuels and vehicles. The second phase is planned to begin in early 1990.

B. Emissions Improvement Potential of Alternative Fuels

Past reservations about the technical capabilities for minimizing emissions from motor vehicles running on gasoline and diesel fuel gave rise to the term "clean fuels." This term has been generally applied to non-petroleum fuels with inherent properties that offer

TABLE H-2
EVOLUTION OF VEHICLE EMISSION STANDARDS
(California and Federal)

Passenger Cars

Model Year	Hydrocarbons	CO	NO	
Uncontrolled	10.6	84	4.1	
1970-71 (F)[a]	4.1	34	NR	
1971 (C)	4.1	34	5.8	
1972(F)	3.0	28	NR	
1972(C)	3.0	28	3.2	
1973	3.0	28	3.1	
1974(F)	3.0	28	3.1	
1974(C)	3.0	28	2.1	
1975-76(F)	1.5	15	3.1	
1975-76(C)	0.9	9	2.0	
1977-79(F)	1.5	15	2.0	
1977-79(C)	0.41	9	1.5	
1980(F)	0.41	7	2.0	
1980(C)	0.39[c]	9	1.0	
1981(F)	0.41	3.4[b]		1.0[d]
1981(C)	0.39[c]	7	0.7	
1982(F)	0.41	3.4[b]		1.0[d]
1982(C)	0.39[c]	7	0.7	

[a] Measured by the CV5-CH Federal Test Procedure. (F) = Federal regulations; (C) = California regulations.
[b] Certain engine facilities have received a 7-g/mile waiver.
[c] Nonmethane hydrocarbon standard.
[d] Certain diesel engine facilities have received a 1.5-g NO_x waiver.

Source: J.T. Kummer, Ford Motor Co., "Fuel Economy and Emissions," in Hilliard and Springer, Fuel Economy, Pleman Press, 1984.

Newer California Standards:
1989: NO_x - 0.4 g/mi
effective 1993: HC - 0.25 g/mi

Heavy Duty Vehicles

		Federal				California			
		HC +	NO_x	CO	PM	HC +	NO_x	CO	PM
	1973	16.0		40.0	--	--	--	--	
	1975	16.0		40.0	--	10.0		30.0	--
	1977	16.0		40.0	--	1.0	7.5	25.0	--
	1979	1.5		25.0	--	1.0	7.5	25.0	--
	1980	1.5		25.0	--	1.0	6.0	25.0	--
	1989	1.3	10.7	15.5	0.6	1.3	6.0	15.5	
Proposed	1990	1.3	6.0	15.5	0.6	1.3	6.0	15.5	
Proposed Bus	1991	1.3	5.0	15.5	0.1	1.3	5.0	15.5	0.1
Proposed Truck	1991	1.3	5.0	15.5	0.25	1.3	5.0	15.5	0.25
Proposed Bus	1994	1.3	5.0	15.5	0.1	1.3	5.0	15.5	0.1
Proposed Truck	1994	1.3	5.0	15.5	0.1	1.3	5.0	15.5	0.1

Source: Bass Dyer, Central Contra Costa Transit Authority, testimony at CEC Fuels Report Hearing, June 13, 1989.

TABLE H-3

CURRENT AND PLANNED GASOLINE AND DIESEL FUEL REGULATIONS

Current Regulations

Gasoline

RVP (1971)	9 psi
Bromine No. (SCAB 1971)	30 maximum
Lead Content (1982)	0.8 gm/gal
EPA Lead (1985)	0.1 gm/gal

Unleaded Gasoline

Lead Content (1976)	0.05 gm/gal
Sulfur Content (1975)	300 ppm
Manganese (1977)	Prohibited
Phosphorus (1982)	.005 gm/gal

Diesel

Sulfur Content (SCAB 1981)	500 ppm
Sulfur (other areas 1981)	5000 ppm

Future Strategies

Diesel

Sulfur (statewide) to 500 ppm and
Aromatics 10 to 20 percent

Gasoline

Reduction in RVP
Reduction in Benzene
Reduction in Aromatics
Oxygenated Blends
Fuel Detergents and Additives

Source: Dean Simeroth, CARB, testimony at CEC Fuels Report hearing, June 13, 1989.

an advantage for controlling one or more of the criteria pollutants. With the evolution of increasingly effective motor vehicle emission control technologies, and the rising concern over other, noncriteria pollutants, the ability of any fuel to earn a clear-cut designation as a "clean fuel" has diminished. The end-result of using particular fuels in combination with specific combustion and emission control technologies, considering all air quality implications, has become a more complex concept than was once the case. Thus, the term "low-emission vehicle" has come into play. This term has been invented, and applied by CARB, to better define vehicle/fuel combinations that offer emission improvements over vehicles that simply meet the prevailing emission standards. In effect, this allows for various fuels and/or other emission-reducing strategies to demonstrate a superior result for air quality, rather than classifying particular fuels as clean.

State legislation (AB 234, 1987) created a specific low-emission vehicle definition, providing criteria that CARB has attempted to apply to establish a qualifying basis for various fuels. Essentially, the legislation defines a low-emission vehicle as one that emits one-half or less of the ozone smog-forming hydrocarbons as a gasoline vehicle meeting the normal standard. This can be accomplished by either: a) meeting one-half the hydrocarbon exhaust level of the standard, running on gasoline, or b) using methanol or other nonpetroleum fuel in such a way as to show the same ozone-reducing effect. Unfortunately, the legislative definition does not extend to other criteria or noncriteria pollutant categories (except to say that a low-emission vehicle must at least meet the other applicable emission standards) nor does it adequately cover heavy-duty vehicles. Thus, the legislation represents only a partial step toward fully establishing the full comparative air quality benefits of different fuel and vehicle technologies.

CARB has issued a staff report with findings of its initial study of low-emission vehicle/fuel candidates. Table H-4 summarizes the key results, based on emissions testing and hydrocarbon reactivity (ozone-forming potential) analysis of different alternative fueled vehicles. Although these numeric results have already been invalidated for 1993 vehicles and beyond by the adoption of the new 0.25 gram per mile HC standard--which means all low-emission vehicles will then have to meet a more severe test--some fundamental findings of the study include:

- A vehicle running on compressed natural gas (dedicated CNG) showed the lowest ozone-forming potential of the internal-combustion engine vehicles studied (except for hydrogen), only 36 percent as much as a standard gasoline vehicle.

- A methanol (M-85) vehicle also showed a significant reduction in ozone-forming potential, 50 to 56 percent as much as a standard gasoline vehicle.

TABLE H-4

CARB AB 234 REPORT FINDINGS
Recommended Criteria and "Ozone Reactivity" Factors
for Low-Emission Motor Vehicles

Fuel Type	(A) Maximum Allowable Exhaust ROG Rate[a] (g/mi)	(B) Ozone Reactivity Factor[b]	(A * B) Maximum Allowable Ozone Reactivity Rate (g/mi)
Gasoline	.195	1.0	.195
M85	.35	.56	.195
M85-15 mg/mi Formaldehyde	.39	.5	.195
LPG (Dual-Fueled)[d]	.23	.85	.195
LPG (Dedicated)[e]	.29	.67	.195
CNG (Dual-Fueled)	.39[c] (.43)	.5 (.45)	.195
CNG (Dedicated)	.39[c] (.54)	.5 (.36)	.195

a To be considered a low-emission motor vehicle, ROG exhaust emissions at 50,000 miles must not exceed the value listed for each fuel. In addition, the vehicle must comply with all other applicable emission standards and requirements. Vehicles which emit at the rates shown in this column all have the same ozone forming potential.

b The ozone reactivity factor provides a relative comparison of the ozone forming potential of each fuel type when compared to gasoline. For example, M85 emissions are 56 percent as reactive as gasoline emissions. Values greater than 1.0 indicate the non-methane emissions are more reactive than gasoline emissions. The product of the Ozone Reactivity Factor (column B), and the Maximum Allowable Exhaust ROG Rate (column A) always equals 0.195, which is the definition of a low-emission gasoline vehicle provided in the statute. (Note the value will change if the current non-methane hydrocarbon standard for light-duty vehicles of 0.39 g/mi is changed.)

c The calculated maximum allowable exhaust ROG rate is in parenthesis; however, emissions in excess of the existing NMHC certification standard of .39 g/mi are not allowed since all vehicles must meet all applicable emission standards.

d Since LPG/gasoline dual-fueled vehicles would still emit evaporative emissions, it is assumed that evaporative emission rates from dual-fueled vehicles would be equivalent to those from gasoline-powered cars.

e It is assumed that dedicated LPG-fueled vehicles would have negligible evaporative emissions. Refueling losses from these vehicles are not addressed in this analysis.

- An LPG (dedicated propane) vehicle showed 67 percent as much ozone-forming potential as a standard gasoline vehicle.

- A calculated estimate for electric vehicles yielded by far the best result for any of the options studied; the power plant emissions assumed to result from electricity production amounted to only 1.5 percent of the per-mile emissions from a standard gasoline vehicle.

- Testing results for ethanol and hydrogen vehicles are described in the report, but do not appear to reflect satisfactory vehicle operating conditions on which to base a valid conclusion for these fuels; however, hydrogen still appears to comfortably surpass the other fuels, even in a vehicle with no emission control equipment; ethanol is speculated to ultimately show a slightly smaller improvement than methanol.

While the CARB low-emission study results must be considered preliminary and interpreted with considerable care, they provide some further confirmation that all six fuels studied offer some degree of potential benefit for ozone reduction. Only electricity and hydrogen, however, seem to offer a margin of improvement that transcends the additional need for highly effective vehicular emission control technologies. All of the other fuels--CNG, methanol, LPG, and ethanol--appear capable of achieving incremental ozone benefits over gasoline in fully emission-controlled vehicles properly prepared for each fuel.

As gasoline vehicles continue to achieve lower hydrocarbon emission levels, the incremental percentages of improvement offered by these fuels should still be realizable, possibly even higher percentages if engines are more optimally engineered for these fuels. At the same time, the actual magnitude of difference (or, the measurable emissions benefit that can be credited to the fuel alone) will inevitably shrink. This realization, together with outstanding arguments over the costs versus benefits of various options, strengthens the case for low emission vehicle goals rather than clean fuel goals, as a route to further air quality progress.

IV. ALTERNATIVE TRANSPORTATION ENERGY SOURCES: OPPORTUNITIES AND OBSTACLES

Beginning with the first oil crisis in 1973, and boosted further by the second crisis of the late 1970s, California, the United States, and other countries have mounted efforts to develop and introduce nonpetroleum transportation fuels. These efforts, though not sustained by the same sense of energy-related urgency that initiated them, have produced substantial technological progress in alternative fuels applications. The technical capability for using methanol, ethanol, natural gas, propane, electricity, and even hydrogen to power motor vehicles has been greatly advanced

during this period. Still, market inroads for any of these alternatives, at least in the United States, remain negligible. The economic incentive that would bring about marketplace success for any of the substitutes for petroleum fuels has simply not materialized.

Now, reinforced by vigorous new initiatives to improve air quality, California and the nation are placing renewed emphasis on alternative transportation energy sources, with the original energy purpose matched, or even superceded, by the air quality impetus. Many long-time researchers and advocates of the energy benefits of these alternatives now find themselves devoting more of their attention to the air quality benefits. Clearly, the perceived vital need responsible for the current resurgence of public interest in alternative fuels is to "clean up" the air. This surge of environmental momentum, added to the original energy basis, may provide the critical element necessary to finally begin the serious commercial introduction of alternative fuels that has eluded energy objectives alone.

The fact that there are a number of alternatives available with both energy and air quality advantages is indeed promising. Nevertheless, the extent to which energy and environmental goals can be fully served through alternative fuels introduction, along with possible ways in which the paths to these goals might diverge, both warrant further examination. For example, what if emissions control progress with petroleum fuels and vehicles further diminishes the margin of air quality benefits that can be claimed for alternative fuels? Presumably, the goals involving strictly energy purposes would continue to validate the pursuit of alternative fuels. Thus, it seems important to fully understand the conditions--favorable and unfavorable--that stand to affect the market selection of alternative fuels, even if their air quality implications are neutral.

A. Cost and Availability: Results of Energy Commission's AB 234 Study

The Commission has completed its part of the study directed by the AB 234 legislation, production of a 1989 report entitled "Cost and Availability of Low-Emission Motor Vehicles and Fuels." This report presents cost estimates for gasoline and alternative fuel, light-duty vehicle ownership and operation--including methanol, ethanol, CNG, LPG and electric vehicles--projected for the years 1993 and 2000. A more qualitative examination of supply availability and implications of potential new motor fuel demand is also provided for each fuel. Tables H-5 and H-6 summarize the results of this study, the former dealing with findings on cost and supply of just the fuels themselves, and the latter with the overall economics of their vehicular applications. Figure H-8 is a graphic presentation

TABLE H-5

CEC AB 234 REPORT FINDINGS
ESTIMATES OF RETAIL, PUBLIC REFUELING FUEL PRICES
(1988 Dollars)

1993

Fuel	$/Unit	$/mmBtu	$/gallon gasoline equivalent
Gasoline			
Unleaded	1.07/gallon	9.30	1.07
Premium	1.21/gallon	10.52	1.21
Methanol (M-85)	0.82/gallon	12.48	1.44[a]
Ethanol[b]	1.01-1.64/gallon	13.11-21.45	1.51-2.47[a]
Natural Gas	0.612/therm	6.12	0.71
Liquified Petroleum Gas	0.67/gallon	7.62	0.88
Electricity Time-of-Use, Off-Peak	0.0462/kWh	13.54	1.56

[a] Up to 40 percent of the 1993 retail differential between premium gasoline and alcohol fuels is attributable to differences in the dealer margin. Factors affecting the actual margins imposed by the dealer during the initial market introduction of alcohol fuels are complex, speculative, and in need of more in-depth analysis.

[b] Ethanol fuel price with and without federal fuel tax credit.

2000

Fuel	$/Unit	$/mmBtu	$/gallon gasoline equivalent
Gasoline			
Unleaded	1.25/gallon	10.79	1.25
Premium	1.39/gallon	12.02	1.39
Methanol (M-85)	0.77-0.93/gallon	11.75-14.14	1.36-1.63
Ethanol	1.55/gallon	20.20	2.33
Natural Gas	0.727/therm	7.27	0.84
Liquified Petroleum Gas	0.75/gallon	8.52	0.98
Electricity Time-of-Use, Off-Peak	0.0388/kWh	11.37	1.31

TABLE H-6
CEC AB 234 REPORT FINDINGS
VEHICLE USER COST SUMMARY*
Cents Per Mile, 1988 Dollars, 20,000 Miles Annually

YEAR 1993

	Unleaded Gasoline OEM	Premium Gasoline OEM	Methanol OEM	Ethanol OEM	CNG *** Retrofit	LPG Retrofit	EV OEM
Private Individual							
Car	22.4	22.9	-	-	22.5-24.2	22.9	-
Truck	18.6	19.1	-	-	19.2-20.9	18.8	-
Small Private Fleet							
Car	25.5	26.0	27.0	27.3-30.5	22.5-25.2	23.3	-
Truck	21.8	22.2	-	-	19.1-21.9	19.2	-
Delivery Van	31.4	32.1	-	-	28.3-31.0	28.8	36.8
Delivery Van	37.9	38.6 **					46.3-51.1 **
Large Private Fleet							
Car	23.2	23.6	24.6	24.9-28.1	23.6	23.2	-
Truck	19.5	19.9	-	-	20.3	19.1	-
Delivery Van	29.1	29.7	-	-	29.4	28.4	36.8
Delivery Van	34.9	35.5 **					46.2-51.1 **
Government Fleet							
Car	22.0	22.4	23.4	23.8-27.0	22.8	22.1	-
Truck	18.5	18.9	-	-	18.9	18.3	-
Delivery Van	27.8	28.3	-	-	28.6	27.2	35.1
Delivery Van	33.3	33.9 **					44.0-49.0 **

YEAR 2000

Private Individual							
Car	22.7	23.2	22.7-23.5	25.7	23.0-24.5	23.0	-
Truck	19.0	19.5	-	-	19.7-21.2	19.0	-
GSM Vehicle ****	29.1	29.9			28.5-30.2		
Small Private Fleet							
Car	25.9	26.3	25.7-26.6	28.7	23.0-25.5	23.5	-
Truck	22.1	22.6	-	-	19.6-22.2	19.4	-
Delivery Van	32.0	32.6	-	-	28.9-31.5	27.3	36.8
Passenger Van	30.4	30.9	-	-	-	-	28.7
GSM Vehicle ****	32.2	33.0			28.5-31.2		
Large Private Fleet							
Car	23.6	24.0	23.3-24.2	26.3	23.9	23.3	-
Truck	19.9	20.3	-	-	20.6	19.2	-
Delivery Van	29.7	30.3	-	-	29.9	27.1	36.8
Passenger Van	28.2	28.6	-	-	-	-	28.7
GSM Vehicle ****	29.9	30.6			29.7		
Government Fleet							
Car	22.4	22.8	22.2-23.1	25.3	23.1	22.0	-
Truck	18.9	19.3	-	-	19.2	18.3	-
Delivery Van	28.3	28.9	-	-	29.0	25.9	35.1
Passenger Van	26.9	27.4	-	-	-	-	27.9
GSM Vehicle ****	27.9	28.6			28.1		

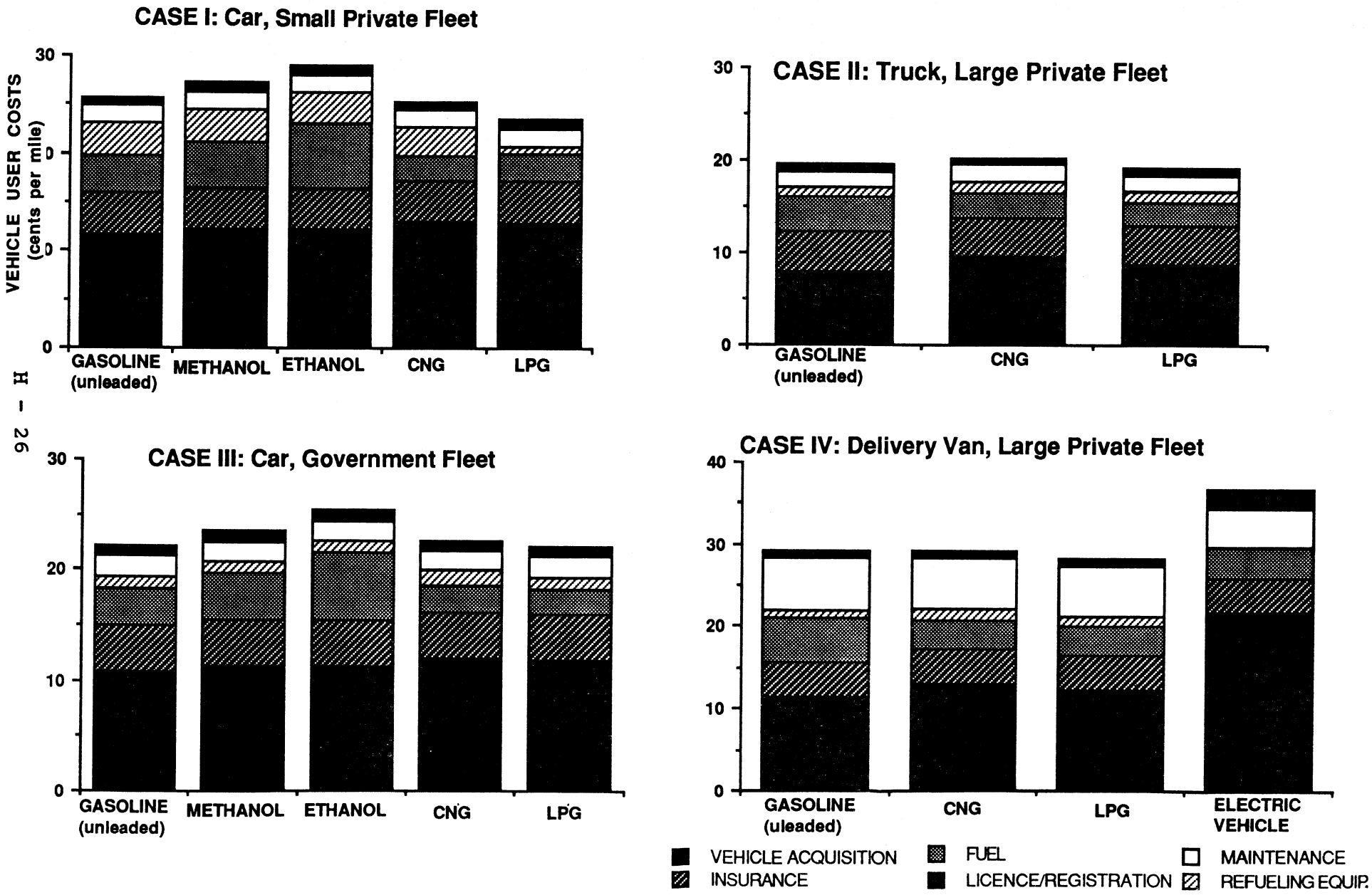
* To determine vehicle user costs some demand/supply relationships were assumed and not subject to iterative evaluation.

** Delivery Van: 15,000 miles annually

*** CNG range: with Public Refueling - without Public Refueling

**** Dedicated natural gas vehicle manufactured by an OEM company, GSM Limited.

Figure H-8
Cost Comparison of Alternative Fuel Vehicles
for 1993 based on 20,000 miles/year in 1988 dollars



of some of the more detailed breakdowns of total vehicle operating costs estimated in the study.

Even though fuel cost by itself tells only part of the story, Table H-5 offers an interesting comparison between projected gasoline prices[7] and those of the various alternative fuels. This shows how the delivered price of equivalent amounts of these various energy forms might compare in the future, exclusive of any additional costs associated with their use in vehicles. The results indicate that natural gas should remain the least-costly fuel for conventional auto engines, priced about one-third less than regular gasoline. LPG is also expected to maintain a price advantage of 17 to 20 percent less than regular gasoline. Methanol is projected to be 20 to 35 percent more expensive than the regular/premium gasoline price range in 1993. By the year 2000, however, methanol's comparative price is seen improving, possibly becoming slightly less than premium gasoline at the lower estimate and within 17 to 30 percent above the regular/premium gasoline price range at the upper estimate. Ethanol, absent its current federal tax credit, is expected to remain the most expensive fuel studied, at least 25 percent and possibly over two times higher than the range of regular and premium gasoline prices.

Electricity, as a vehicular "fuel," poses a unique price comparison with gasoline, since the energy value of electricity used to charge electric vehicle (EV) batteries cannot be directly compared to the energy value of fuel burned in an internal combustion engine. Also, electricity is the only form of vehicle energy studied that currently escapes all of the state and federal taxes, which comprise as much as 30 percent of the retail prices for other fuels. Another difference is that electricity is sometimes priced differently depending on when it is purchased. "Off-peak" (evening) time-of-use electricity price projections are thus used for comparison with gasoline prices. These prices amount to a considerably lower vehicle energy cost than for gasoline, also lower than any of the other alternative fuels included in the study.[8]

Fuel supply considerations were investigated in the study, to determine whether expanded vehicle application of any of the alternative fuels might face supply constraints. While the different fuels each require their own supply and distribution provisions to accommodate new transportation applications, the overall conclusion is that fuel supply is not likely to be a limiting factor for any of the options during the study period. This is based on an appraisal of existing supply capacity for each fuel and its potential for near-term expansion, in comparison with realistic rates of growth in fuel demand for vehicles conceivably operating on each fuel by the year 2000. The study stops short of attempting specific quantitative estimates of future fuel demand or supply, and does not project the ultimate, long-term supply potential of any of the fuels. However, it supports the viewpoint that significant introductory alternative fuel vehicle market levels can be developed

over the next twelve years with reasonable assurances of fuel supply adequacy.

The total cost of alternative vehicle acquisition and operation, compared to gasoline vehicles (Table H-6), combines the effect of fuel cost along with the strong influences of capital costs associated with the vehicle and any necessary fuel dispensing equipment. In 1993, the continued higher cost of most types of alternative fuel vehicles will weigh against overall cost-competitiveness with gasoline vehicles, under common conditions of vehicle ownership and fueling by the general public, as well as many fleet applications. However, there appear to be exceptions where LPG and CNG vehicles could present cost-saving opportunities. The savings in cost of these fuels versus gasoline could potentially outweigh the initial capital cost for vehicle conversion when enough miles (e.g. 20,000 miles per year) are accumulated. This would be especially true in cases where direct investment in fueling facilities is avoided or minimized, either by supplier-operated commercial stations or by large fleet operations that can spread this investment cost across a large number of vehicles.

By the year 2000, reduced differential capital costs are projected for "fuel-flexible," alcohol/gasoline vehicles with expected commitments by auto manufacturers to mass-produce these vehicles. The operative assumption is that sufficient quantities and economics of production will be achieved by that time to make the cost of these vehicles equal to gasoline-only vehicles. Reaching this goal, together with an improving methanol-versus-gasoline fuel cost relationship as described above, would result in the total cost of using methanol becoming virtually the same as for gasoline. Ethanol would also benefit from the same reduction in vehicle cost, but the higher fuel cost would continue to make this option more expensive. LPG and CNG vehicles, which are assumed to remain conversion options (as opposed to manufacturer-produced), maintain a margin of competitiveness with gasoline vehicles in some applications and show higher overall cost in others. Certain types of electric vehicles may likewise begin to compete with overall gasoline vehicle costs, at least in some applications, by the year 2000.

The results of the Commission's AB 234 study, while establishing a useful methodology for examining and comparing alternative-fueled versus gasoline-fueled vehicle economics, cannot be viewed as the final, definitive answer on what the future costs of these various options will actually be. Many of the variables that will ultimately affect this outcome could not be accurately estimated nor evaluated. For example, a host of factors related to consumer choice and marketplace behavior are recognized to play a major role in how various fuel and vehicle options will be priced in relation to each other. Yet it is impossible to predict how the marketplace will respond to the different characteristics of these new products. Other unknowns will also affect the rate at which demand for the various alternative fuels develops and, in turn, have a

bearing on the cost and market pricing of fuels and vehicles. Nevertheless, the findings provide a strong indication that some economical, near-term opportunities for alternative fuel vehicle applications already exist, with even more favorable future prospects in sight.

B. Environmental and Health and Safety Factors

New transportation energy sources face a great deal of continuing environmental scrutiny, with respect to both their advantages and their disadvantages. This is partly attributable to valid concerns that require resolution, and partly to the inevitable resistance and controversy that surrounds unfamiliar technologies. Sorting out the "fact" from the "fiction" involving the extent of benefits and hazards associated with the various alternative fuels is thus an important, but difficult undertaking. During the past year, two two-day workshops have been held toward this very objective (by the South Coast Air Quality Management District and the AB 234 Advisory Board on Air Quality and Fuels). Yet, there continues to be disagreement over the nature and magnitude of certain fuels' environmental and health and safety impacts.

In the realm of regulated, criteria air pollution (as discussed earlier, based on CARB's study of low-emission vehicles) there appears to be a reasonable consensus that all of the alternatives--methanol, ethanol, CNG, LPG, electricity and hydrogen--offer generally positive potential effects. However, the degree of actual air quality improvement offered by future applications of these fuels continues to be studied and debated. More vehicle emissions testing with these fuels, further progress with fuel-specific emission control technologies, and additional air quality modeling studies are among the activities needed to better confirm the extent of achievable benefits.

Implications of the different fuels with respect to the greenhouse effect have been much less explored. Here, the consideration must be extended to emissions from the entire fuel production and supply cycle in order to properly assess the net impact. And very different greenhouse gas implications may even result from different supply methods for the same fuel--for example, methanol produced from natural gas versus from coal. If today's concerted emphasis on improving urban air quality is ultimately extended to reversing the accumulation of carbon dioxide and other greenhouse gases, the basis for comparing air quality effects of alternative transportation fuels may need to be modified.

Other categories of environmental effects of alternative fuels also remain under review. A lack of widespread field experience often precludes a conclusion as to whether fuel characteristics known to be different from petroleum fuels represent a positive or negative net change. One particularly illustrative example involves the

potential water quality impacts of methanol compared with gasoline. The heightened environmental attention that has recently been focused on gasoline and petroleum as pollutants of both surface and ground water resources has prompted greater attention to the differences that methanol would pose in this regard. Significant differences between the chemical properties of the fuels have been identified as favorable or unfavorable for methanol. While it seems clear enough that spills or leaks of either fuel should be avoided via the best protective measures available, opinions among technical researchers remain divided as to which fuel is the more serious aquatic pollutant, especially in the case of ground water contamination. Resolution of issues such as this one seem to depend less on settling questions of which fuel is better or worse than on what reasonable protection and mitigation measures are needed for each fuel.

A range of health and safety-related fuel characteristics are further subjects of continuing study. Examples include toxic effects from ingestion, vapor inhalation or skin contact, and fire safety. Again, major technical differences among the various fuels are identifiable, but do not easily translate into conclusions regarding the degree of overall hazard they would present in everyday use. It has been effectively pointed out that gasoline is perhaps such a hazardous product that it might fail to receive commercial acceptance if it was a new fuel facing today's regulations. Nevertheless, each fuel has its own somewhat unique set of attributes that make for potentially dangerous conditions when distributed and applied to motor vehicle use. Varying amounts of worldwide experience to date with applications of each fuel suggest that none poses any new hazard that should impede expanded use. Still, there may be some significant additional precautions to be specified once the results of further research and field experience become known.

C. Remaining Technology Development Needs

The status of technology development and commercial market availability varies greatly among the alternative fuels under consideration. At one extreme is the example of LPG vehicles, with millions of vehicles in worldwide operation and considerable availability of commercial refueling. At the other extreme is hydrogen, with only a handful of experimental vehicles in existence and no fuel supply provisions whatsoever. But all of the fuel options continue to be subjects of research, development and demonstration (RD&D) activities around the world, with progress toward better vehicular and fuel supply technology occurring on all fronts. Table H-7 lists some of the more important outstanding RD&D areas being pursued for each fuel. Some of these are aimed at improving environmental and health and safety characteristics. Others address technical characteristics involving vehicle performance and consumer acceptance factors. Sustained efforts in all these RD&D

TABLE H-7
RESEARCH, DEVELOPMENT, AND DEMONSTRATION NEEDS FOR ALTERNATIVE FUELS

Methanol

- Further demonstration, technology advancement, and cost-reduction for fuel-flexible vehicles.
- Expanded demonstration, manufacturer involvement, and technology improvement for diesel engine transit but and heavy-duty truck applications.
- More conclusive determination of air quality and health and safety implications, including resolution of technical concerns regarding control of formaldehyde emissions and evaporative emissions associated with methanol-gasoline blends.
- Extended research on future methanol fuel supply sources, including their cost and availability.
- Further development of a statewide methanol distribution.

CNG

- Demonstration of automotive industry-produced CNG vehicles, including light-and heavy-duty applications.
- Improvement of on-board CNG vehicle fuel storage capability to extend refueling range.
- Better determination of CNG vehicle emission characteristics and resolution of remaining technical concerns (e.g., NO_x emissions).
- Field demonstration and commercial development of small-scale CNG compressor refueling system
- Evaluation of natural gas supply and market implications of CNG fueled transportation.
- Comprehensive technology evaluation covering economics, performance, and health and safety subjects.

Hydrogen

- Expanded research on electrolytic fuel production to reduce fuel cost
- Development and testing of advanced on-board vehicle storage systems to extend vehicle range
- Field vehicle demonstration, including resolution of performance and safety issues.

Electric Vehicles

- Development and demonstration of more effective storage battery technologies to extend electric vehicle range
- Fleet demonstration of electric cargo and passenger vans by various auto companies
- Development of additional vehicle applications and configurations (including hybrid gasoline-electric models)
- Studies of the long-term electric utility generation and distribution system effects of electric vehicle use
- Further evaluation of electric vehicle market potential and related economic, environmental, and social implications

LPG

- Development and testing of advanced, computer-controlled, fuel injected vehicle applications to resolve performance and emissions issues
- Commercial market demonstration of new, auto industry-manufactured vehicles
- Investigation of LPG supply and price prospects and factors affecting motor fuel market penetration

Ethanol

- Better characterization of emissions and air quality implications of ethanol as a neat fuel and in gasoline blends
- Continued examination of the economics and supply potential for ethanol, including in-state production opportunities.

Source: CEC 1988 Energy Development Report

areas, including expanded vehicle field testing and demonstrations, are vital to the ultimate marketplace success of alternative fuels.

D. Forging Market Inroads

Any significant change in prevailing market economics caused by abundant, affordable supplies of petroleum fuels and familiarity with their vehicular use will not occur without a combination of regulatory intervention and market incentives. Indeed, the predominant market position of gasoline in the United States seems likely to be maintained for some time. The best opportunities for early commercial success with alternative fuels appear to lie in establishing some critical market inroads that offer potential for continued expansion. The South Coast Air Quality Management District (SCAQMD) is currently developing a low-emission motor vehicle fleet rule. The rule will require low-emission motor vehicles to be an increasing percentage of fleets operating in the South Coast Air Basin. In addition, low-emission motor vehicles weigh heavily in the SCAQMD attainment plan for reducing basin-wide emissions from the transportation sector.

Some encouraging case studies exist, in California and elsewhere, to guide the near-term exploitation of markets that are advantageous for alternative fuels. Examples include:

- LPG vehicle fleets operated by a variety of businesses (such as Coca Cola, Sears, L.A. Times).
- CNG fleet and fueling station programs sponsored by gas utilities (such as the State of Arizona fleet, in cooperation with Southwest Gas Company).
- The acquisition of methanol and other alternative fueled buses for transit and school district fleets.
- Use of methanol for production of the gasoline additive MTBE.
- Ethanol/gasoline blending under provisions of the federal ethanol tax credit.
- Electric vehicle marketing programs by the Southern California electric utilities.
- The City of Los Angeles electric vehicle initiative to purchase 10,000 electric vehicles by the year 1995.

V. CONTROLLING FUEL DEMAND GROWTH: A CRITICAL PRIORITY

If the more optimistic forecasts of stable or declining demand prove to be accurate, California faces a much more manageable

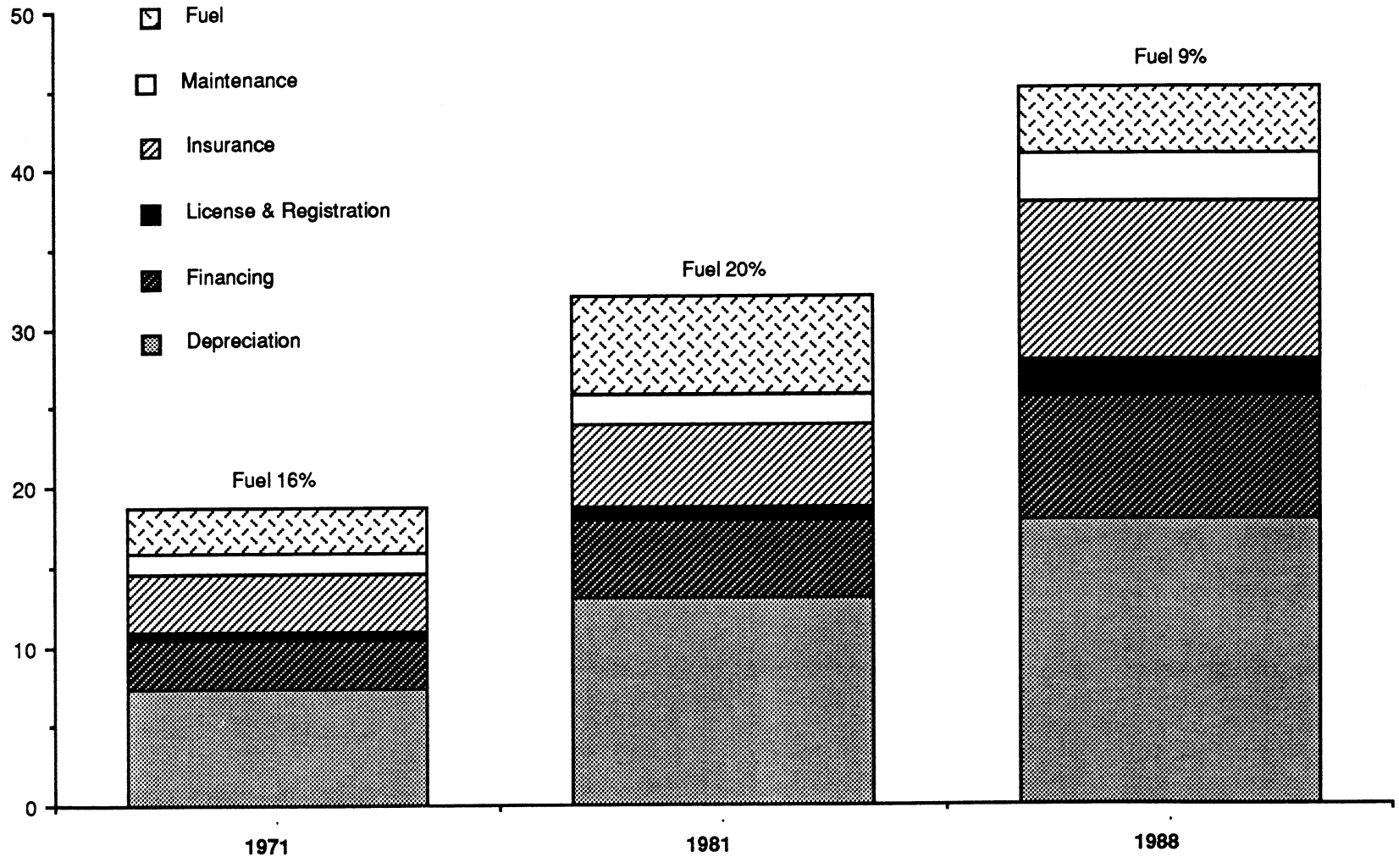
(although still far from easy) task of supplying motor vehicle fuels in a progressive manner with respect to energy and air quality goals. However, if the growth trend that has prevailed since 1982 (about three percent per year) continues, this task takes on near-hopeless proportions. The state could easily find its progress with alternative fuels introduction by the year 2000--even under the most aggressive schemes--effectively overwhelmed by growth. Petroleum fuel requirements might end up higher than today's levels, even after substitution of one-third or more of current uses with alternatives. Therefore, measures directed at gaining control of fuel demand growth deserve greater priority alongside complementary actions on behalf of fuel substitutes. Even as petroleum fuels are ultimately replaced with new resources, keeping consumption in check will remain important due to environmental, economic, and resource depletion issues.

Should the impact of petroleum price increases be inadequate to stabilize demand, it is difficult to foresee other imminent changes that might have this result. Unfortunately, measures that have failed to harness demand growth in the past seem unlikely to suddenly become adequate. Further improvements in vehicle fuel economy, expanded mass transit, ridesharing programs, and other steps can continue to exert an important moderating influence, but cannot be counted on as a complete solution to demand growth. Newer approaches, such as telecommuting and parking restrictions can provide valuable additions to the list of growth-countering measures. A combination of alternative fuels and growth-countering measures needs to be put forth if an adequate solution is to be developed. Meanwhile, many of the factors contributing to the growth rate--population, licensed drivers, vehicle ownership, suburban sprawl, priority on convenience, etc.--continue on an upswing. And, as shown in Figure H-9, the fuel component of driving cost has declined significantly, suggesting that fuel could remain affordable to most drivers, even if prices substantially increase. If the specter of continuing rapid fuel demand growth, unrestrained by price increases, becomes reality, California will need to resort to fundamental changes beyond any underway today in order to maintain adequate supplies, reduce petroleum dependence, and further improve air quality.

A. Traffic Congestion as an Impetus for Change

At this time, the major force toward altering trends in state transportation activity appears to be rising concern over traffic congestion. California automobile drivers lose 300,000 hours per day due to congestion, with costs estimated at $2.16 million per day. The number of hours motorists are delayed is expected to increase by 174 percent by 1995, climbing another 65 percent by 2005. The need for measures to address this worsening situation is often coupled directly to energy and air quality needs. But the immediate energy effects of congestion--the incremental "waste" of fuel

Figure H-9
Changing Contribution of Fuel Cost to Overall Driving Cost



Source: American Automobile Association, annual reports of driving cost
(based on a typical, privately-owned sedan driven 10,000 miles/yr)

in traffic jams--is probably far less important than what steps are taken in response to this problem. Whether the congestion solutions ultimately pursued involve basic changes to existing transportation technology and travel patterns, or simply expansion of the current system, holds profoundly different implications for energy.

Caltrans, the state agency charged with confronting this problem, admits that congestion will continue to worsen, in the absence of any readily-available, near-term remedies. A variety of possible long-term directions are under active study. These include some advanced technologies such as automated highway systems that, if widely implemented and employ alternative (e.g. electric) vehicle propulsion, could result in future highway travel without congestion, petroleum use or vehicular emissions. However, the commitment to employ such new technology is still uncertain, and the results of even the most accelerated undertaking possible are obviously many years away. Meanwhile, a strong advocacy for addition to the conventional highway system seems destined to prevail. Even though Caltrans acknowledges that more highway capacity cannot hope to be a major solution to congestion, wide support for new construction is apparent. Recent legislation to increase the state's highway gasoline tax, shows that obtaining more revenue to support further development of the existing system remains a high priority.[9]

An innovative concept being studied involves imposing toll charges on an increasing number of new and existing highway segments. One legislative proposal would even authorize private companies to build new highways (or add to existing ones) and operate them as profit-making toll roads. While this and other toll road ideas are generally conceived as a way of funding new highway system capacity and/or improvements, the concept also lends itself to further consideration of various "travel pricing" formulas. By converting more new and existing highways to tollways, the capability to apply "time-of-use" pricing--with higher charges for peak period use--could become a means of reducing congestion. Technology for electronically registering vehicle passage at given checkpoints is already being demonstrated, offering the potential for later billing rather than toll booths.

Actually, toll charges are already an established practice on many state bridges, with differential pricing (e.g., free passage for carpoolers) also employed in some cases. Toll highways (or "turnpikes") are also common in the eastern states, as well as in many foreign countries. The potential for differential toll charges as means of discouraging concentrated, peak-period travel behavior seems very promising. Extending the toll principle to achieve overall travel and energy demand reductions, as some researchers propose, may be more problematic. This would require modifying not only the motoring public's decisions about <u>when</u> to drive but also <u>how much</u> to drive. Analogous to consideration of higher fuel

prices as a demand deterrent, there is presumably a highway use fee structure that would begin to discourage highway travel. Whether highway "user charges" versus simply taxing the purchase of fuel, would be any more effective is subject to debate.

One potential advantage of moving toward a system of "travel taxes" rather than fuel taxes would be to disconnect highway funding revenue from the effect of improving vehicle fuel economy. A major reason behind proposals for higher gasoline taxes has been the proportionately smaller increase in fuel tax revenue than in highway vehicle travel because of the progress in vehicle fuel economy. In effect, more miles-per-gallon has an upward influence on travel activity but a downward impact on transportation system funding. A per-mile instead of a per-gallon revenue mechanism would thus eliminate one source of argument against higher vehicle fuel economy. Nevertheless, how the revenue is used--whether collected from fuel taxes or highway tolls--may ultimately have the most serious energy implications. Unless public spending for highway systems is redirected more toward other types of transportation, highway vehicle activity will most likely continue to grow as the predominant mode of travel. And alleviating traffic congestion could end up correlating with more, rather than less fuel demand.

B. Vehicle Fuel Economy: The CAFE Standards Debate

A renewed battle is developing over Federal Corporate Average Fuel Economy (CAFE) Standards, which regulate the average fuel economy of all new autos and light trucks sold by each of the manufacturers. There are presently various proposals in Congress that seek to make the standards more severe on one hand, or even to eliminate them completely at the other extreme. Meanwhile, the effective standard remains at 26.5 mpg for 1989 passenger cars and 20.5 mpg for light-duty trucks. Much debate has centered around the so-called "rollback" of the standard, a decision by the federal administration to keep the applied standard below the legislatively-established level of 27.5 mpg (21.5 for light trucks) originally set for attainment by 1985. Despite requesting and receiving this concession, the auto industry by and large achieved the 27.5 mpg CAFE level for the 1988 model year, with only Ford falling below this level. The United States manufacturer average for 1988 cars was 27.3 mpg and the import average 31.2 mpg, for a combined average of 28.7 mpg. Since the level of compliance can only be ascertained after model year sales are complete, 1989 figures are still being awaited with considerable interest. Some analysts predict a higher level than for 1988 and some expect a reduction.

In effect, the rollback has provided a "cushion" for the domestic manufacturers, allowing the average mpg of United States-made cars to reach the standard on a longer timetable than originally called for. However, since the original target now appears to have been essentially reached (arguably, on a permanent basis), the more

important focus becomes the future of automotive fuel economy or without further regulatory intervention.

Figure H-10 charts the progression of average fuel economy for new automobiles and for all autos in use in the United States from 1974 to 1988. The new car average has gone from about 14 mpg to over 28 mpg during this period. The on-road vehicle population exhibits a considerable lag behind new vehicle mpg, but continues to catch up as older vehicles are replaced. California vehicles are believed to exceed the national mpg average by a significant margin, due to disproportionately high sales of import cars. Caltrans data (based on the MVSTAFF modeling methodology previously described) indicates that the average automobile on the road today in California gets about 20.5 mpg, and the average light-duty truck about 18 mpg.

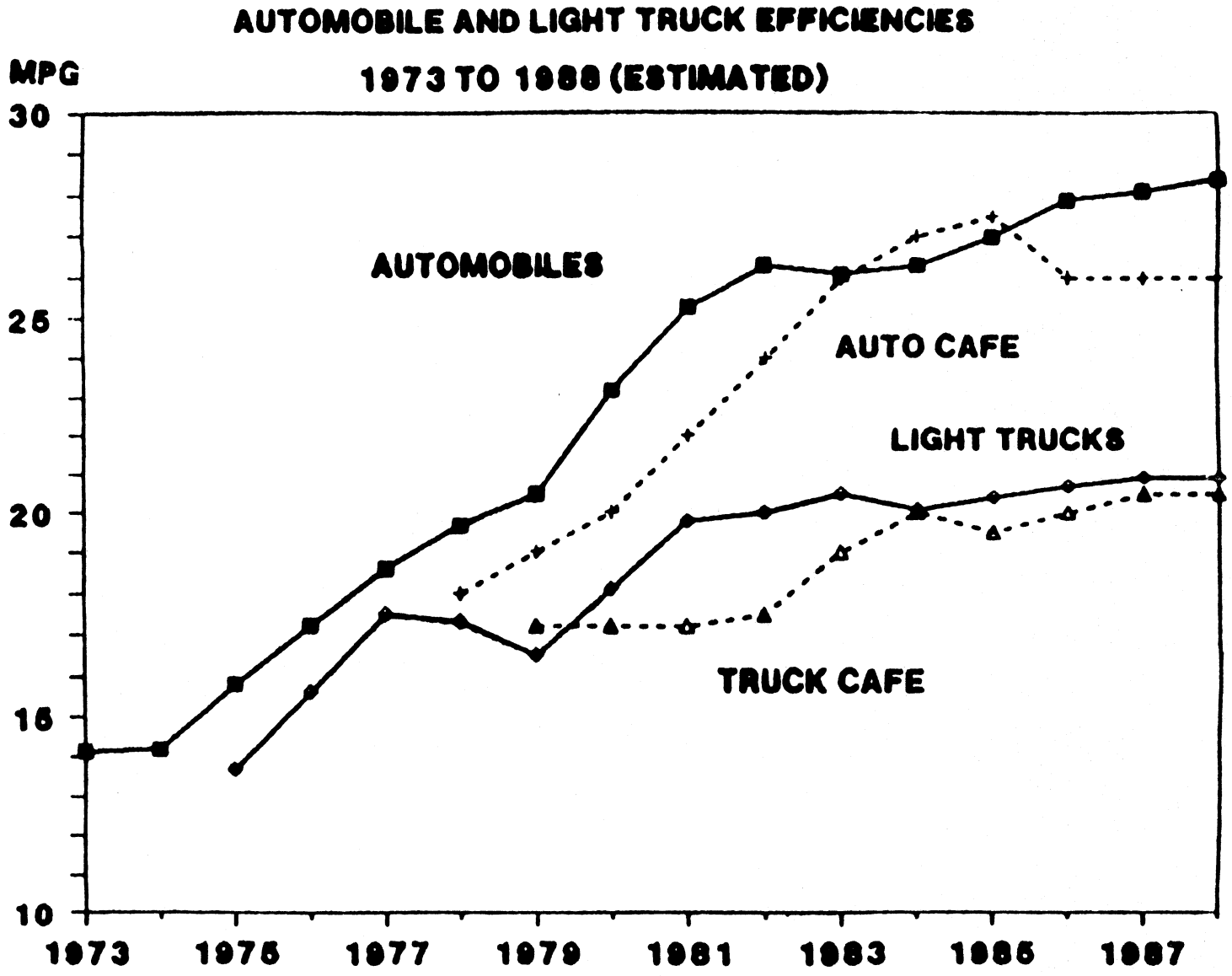
What will happen to automotive fuel economy if no higher CAFE Standards (or replacement system of regulations) are adopted? While there is no uniform opinion, three different organizations' projections are compared in Table H-8. All of these estimates, which assume no tightening of CAFE Standards, sharp oil price increases or other major changes, point to a further improvement of between 5 percent and 20 percent in new car fuel economy by the year 2000. Caltrans modeling projection for California is consistent with the upper end of this range. This correlates with a projected improvement of in-use automobile fuel economy of about 15 percent after 20 more years of vehicle turnover.

Clearly, this expected rate of improvement in new and in-use veehicle fuel economy will not completely offset expected growth in vehicle miles travelled. Both national and state (Caltrans) forecasts of VMT show a diminishing rate of growth over the next few years, but still indicate a two to three percent per year average increase through the turn of the century. In the Caltrans outlook, automobile VMT grows by over 50 percent during the same 20 years that on-road fuel economy increases only 15 percent.

The potential for achieving higher than the above "business as usual" levels of fuel economy improvement, and the various implications of influencing greater progress via government action, has been the subject of a number of recent studies, including some noteworthy examples cited below.[10,11,12,13] While the strength of the arguments for (or against) further regulations vary greatly, a number of key points seem to be apparent from the various assessments:

- The capability to produce high mpg vehicles is already well-demonstrated, with some commercially marketed models at up to 60 mpg and prototype vehicles at up to 100 mpg. Low market

FIGURE H-10



SOURCE: See Note 13.

TABLE H-8

COMPARISON OF FUTURE NEW VEHICLE FUEL ECONOMY ESTIMATES

	EIA[a]	DRI[b]	EEA[c]	OTA[d]
1988 Model Year Avg.				
Automobiles			28	
Light Trucks			21	
2000 Model Year Avg.				
Automobiles	34	30.1[b]	31.3	32[d]
Light Trucks	25.3	---	23	24[d]

[a] Energy Information Administration, 1989 Annual Energy Outlook.

[b] Data Resources, Inc., Energy Review, Winter 1988-89 (estimate is for domestically-produced autos only).

[c] Energy and Environmental Analysis, Inc., The Motor Fuel Consumption Model, Fourteenth Periodical Report, Draft, for Martin Marietta Energy Systems, Inc., December 6, 1988.

[d] Office of Technology Assessment, ref. cited in footnote 11 (OTA's extrapolation from the above three organizations' estimates).

demand for these models (all of which are small cars) appears to be the immediate constraint on their CAFE impact, more so than lack of industry offerings.

- The potential for further technological fuel efficiency progress, as opposed to achieving higher mpg via market shifts to smaller vehicles, is also considerable. Development continues on a wide range of new technologies that offer adddi-tional increments of mpg improvement on vehicles of all types and sizes.

- The economic cost-effectiveness of higher fuel economy achieved technologically will inevitably diminish with further progress (i.e. as the less costly, more effective options are applied).

- Higher fuel economy can be achieved via market shifts without increasing economic cost, but with other impacts on consumer choice, and vehicle safety, comfort, and utility. One popularly-discussed market option for higher fuel economy, diesel vehicles, may not be prudent for California due to air quality reasons.

- The issue of domestic-versus-imported vehicle fuel economy is a major factor in arguments over higher fuel economy standards. However, this issue may diminish in importance with the continuing evolution of an international auto industry and a greater emphasis on technology-based versus market shift improvements.

- Fuel economy as a consumer selection criterion may never again be as significant as in the past. Even with higher fuel prices, the impact of successively higher fuel economy standards reduces the sensitivity to relative mpg differences.

- Special fuel economy regulatory provisions or exemptions for alternative-fueled vehicles may require closer scrutiny to maintain their consistency with overall vehicle efficiency objectives.

These points are not intended to suggest that further regulatory approaches to improve vehicle fuel economy should not be considered. In fact, California may find that a more aggressive state role in this area becomes necessary if its highway fuel demand growth persists and federal action remains stalemated. However, any new fuel economy initiatives, whether based on the traditional CAFE standard concept or on alternative approaches, need to be fully evaluated to assure that their intended and unintended results are understood.

VI. THE IMPORTANCE OF NON-HIGHWAY TRANSPORTATION

This paper has concerned itself almost exclusively with the highway motor vehicle portion of transportation fuel use. While this sector certainly occupies the spotlight for most of today's transportation-related debate, it is becoming increasingly necessary to turn some of the emphasis to the other, nonhighway transportation sectors. These activities--including aviation, rail, and marine transport, and many off-highway ground vehicle applications--currently comprise about one-third of the state's use of transportation energy (see Figure H-11).

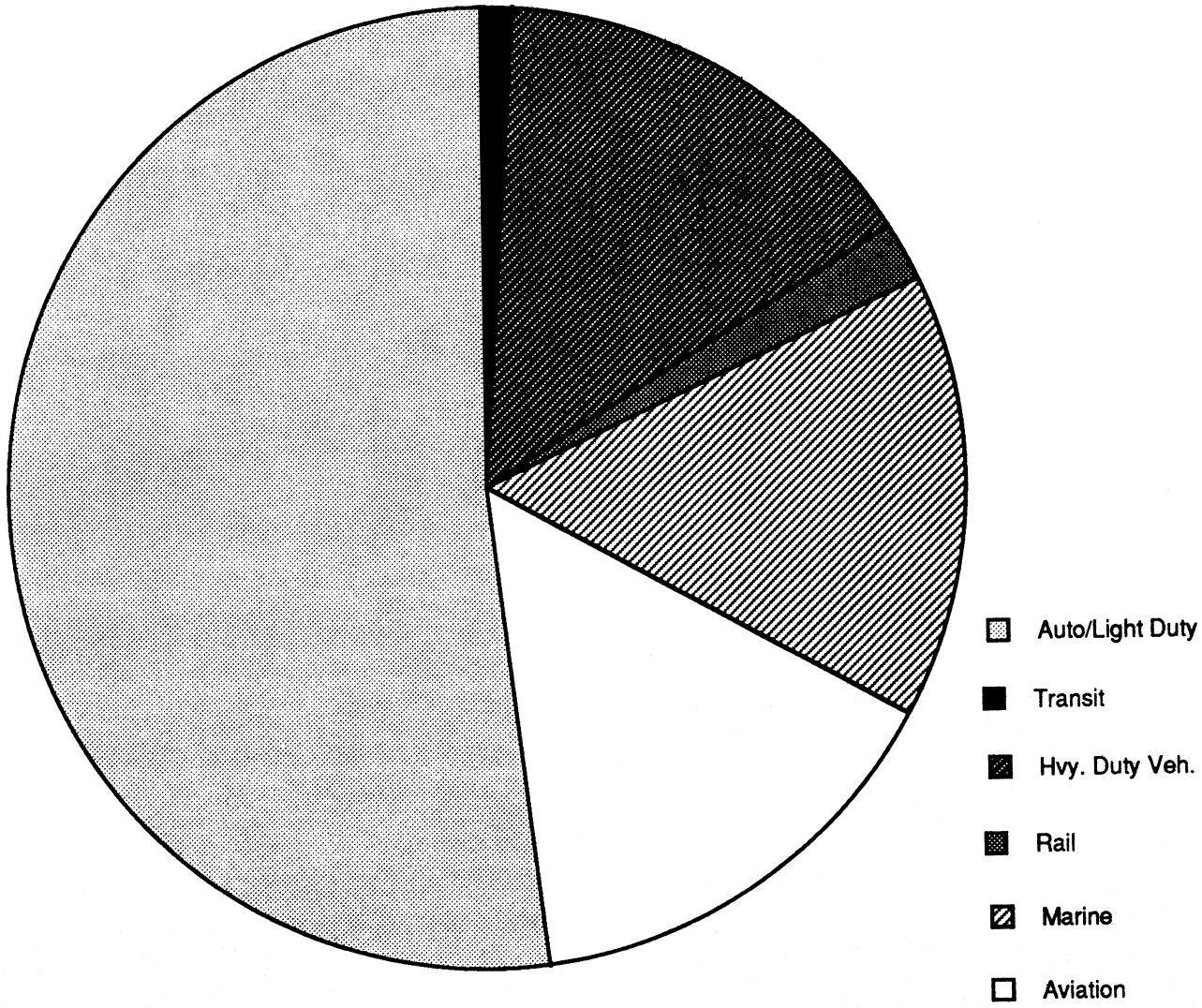
There are a number of reasons why these other uses of transportation energy deserve more attention. Growth in some of these activities appears to be as high or even higher than highway travel. Commercial air passenger travel in the state, for example, increased over 30 percent just from 1984 to 1988. Fuel demand for these types of transportation may be less affected by fuel price increases than highway fuel use. Also, improvements in fuel efficiency have not occurred for these other mobile technologies at the same rate as for automobiles.

Emission control is also generally much less effective for these other transportation forms, some operated with virtually no emission control hardware. As highway vehicle emission control continues to improve, these other sources of transportation emissions become more significant contributors. A CARB study of railroad locomotive emissions (directed by the AB 234 legislation of 1987) is currently underway.

Shifts between various modes of transportation may be occurring with little attention to unfavorable energy implications. Reduced freight movement by rail, replaced by less efficient truck transport, provides one example. Sharp increases in air-freight and air-passenger travel, as substitutes for highway, marine, and rail transport may involve even greater energy inefficiencies. In some cases, development of new transportation system facilities appears to be undertaken without full consideration of energy-related impacts and options. For instance, all new light-rail lines completed and planned in the state rely on instantaneously-generated electricity used heavily at on-peak times, even though various storage options could permit use of off-peak electricity.

Development of alternative fuels applications is much less advanced for non-highway modes of transportation. However, it is recognized that concentrating on gasoline substitution is a limited strategy for reducing crude oil requirements. Eventually, effective petroleum displacement will necessitate finding substitutes for the entire range of fuels produced from the crude oil barrel.

Figure H-11
California Transportation Fuel Demand - 1986



VII. CONCLUSIONS

The intent of this paper is to stimulate greater awareness and in-depth deliberation of a wide range of transportation energy issues, rather than to advocate a particular course of action. However, these concluding thoughts are offered, in hopes of fostering further reflection on state transportation energy policies and strategies:

- Recognizing the likelihood that petroleum will continue to be a major source of transportation fuels well into the future, California's approach to transportation energy should incorporate:

  -realistic goals for controlling demand growth and accomplishing an orderly transition to alternative energy sources

  -a broad strategy package employing multiple options for demand and supply progress, avoiding over-optimistic reliance on individual options or rivalry among options

  -a long-term energy focus, coupled productively with environmental and transportation system progress, but not dependent on these objectives for success.

- If "cleaning up the air" reaches the point where air pollution from transportation combustion sources must be essentially eliminated, a more fundamental technology transition than that being pursued today will be necessary. Only two known options, electric propulsion and hydrogen fuel, appear to offer

  this potential, and neither is being developed at a rate that assures widespread future application.

- Opportunities for incremental (energy and environmental) progress exist now, in the form of alternative fuels with limited, but favorable market potential. Examples include LPG and alcohols used in gasoline blends, both of which occupy small, economically-determined market shares that could be expanded.

- Transportation energy efficiency stands to be further improved via a number of different approaches. These can include more government intervention in the marketplace, as well as more technology development. California should weigh the varying implications of the different options and decide what direction to take in this area.

- Expanded involvement of the transportation products and energy supply industries will be increasingly required to bring about a successful transportation energy transition. Government can

help to bring about a successful transportation energy transition. Government can help to bring this about in various ways, including:

- additional cooperative RD&D programs
- establishing supportive regulatory structures
- using government fleets as introductory markets

o Other sectors of transportation beyond the realm of highway motor vehicles need to be included in designing any new transportation energy strategy.

ENDNOTES

1. Highway gasoline consumption accounts for about 96 percent of total gasoline sales.

2. It should be noted that the Caltrans/Energy Commission scenarios and the Caltrans/MVSTAFF scenario are based on the same modeling assumptions, except for the different gasoline prices. This includes state population projections by the California Department of Finance, and an assumption that vehicle fuel economy improvement will maintain a constant per mile fuel cost. For further details, see the Caltrans publication entitled CA Motor Vehicle Stock, Travel and Fuel Forecast, December, 1988.

3. 1989 Fuels Report Hearing Docket 89-FR-1, testimony of Daniel Khazoom.

4. 1989 Fuels Report Hearing Docket 89-FR-1, testimony of Chris Calwell.

5. 1989 Fuels Report Hearing, Docket 89-FR-1, testimony of Marc Ross.

6. 1989 Fuels Report Hearing, Docket 89-FR-1, testimony of Leo Levenson.

7. The projected gasoline prices used in the AB 234 Report were the projections labeled CEC MID as given in Table H-1.

8. Although the actual study results, expressed on an equivalent energy basis, show Btus of electric energy to cost more than Btus of gasoline energy, the lower energy requirement for EVs (around 10-15 kilowatt-hours to substitute for one gallon of gasoline) makes electricity the less expensive form of energy.

9. SB300 of 1989 will (if the electorate approves a spending referendum in the June 1990 general election) increase the state gasoline tax from 9 cents to 18 cents per gallon in phases from 1990 to 1994. About 16 percent of the additional revenue is designated for mass transit.

10. Deborah Bleviss, The New Oil Crisis and Fuel Economy Technologies: Preparing the Light Transportation Industry for the 1990s, Quorum Books, New York, 1988.

11. Steven Plotkin, United States Office of Technology Assessment, Increasing the Efficiency of Automobiles and Light Trucks, Congressional Testimony, May 1989.

12. Carmen Difiglio (U.S.D.O.E.) et al, Cost Effectiveness of Future Fuel Economy Improvements, submitted to Energy Journal, January 1989.

13. David Greene, Oak Ridge National Laboratory, Transportation Efficiency and Alternative Fuels, ACEEE Asilomar Conference, September 1988.