History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Supplemental Information to June 2002
Revenue Requirement Filing

History of DWR's Net Short Energy Procurement Process Under Long-Term Contracts

Exhibit #	Document/Information	Date
1.	CAISO control area Net Short calculations	January 30, 2001
2.	Emails sent to investor owned utilities requesting net short forecast information	February 5, 2001
3.	CPUC Ruling establishing rate increase	March 27, 2001
4.	Net Short forecast and energy pricing model output	April 18, 2001 May 11, 2001
5.	Executive order for 20/20 Program	May 25, 2002
6.	Historical direct access loads for the three IOU service areas	July 23, 2002
7.	Direct access loads as a % of total customer loads	July 23, 2002
8.	Proposed CPUC Decision to suspend direct access as of July 1, 2001 (Agenda showing postponement of suspension decision)	June 15, 2001
9.	QF effective capacity status report provided by the CPUC	July-August 2001
10.	Power purchase contract status reports	March 14, 2001 April 18, 2001 May 31, 2001
11.	Historic Henry Hub, PG&E Gate, and Southern California border prices for gas	July 24, 2002
12.	Daily average price of power	July 2002
13.	CAISO stage alerts and rotating blackouts in 2001	July 24, 2002
14.	Historical generation outages	November 2001
15.	New California generation tied to DWR contracting efforts	July 2002
16.	*LA Times* article on QF Generation; *Electric Utility Week* article on QFs	April 16, 2001 May 7, 2001
17.	FERC order addressing creditworthiness tariff provisions	February 14, 2001
18.	FERC order clarifying creditworthiness tariff provisions	April 6, 2001
19.	CAISO letter to DWR regarding credit support	April 13, 2001
20.	CAISO/DWR joint clarification letter	May 10, 2001
21.	Letters from energy suppliers expressing concern regarding DWR's credit	January 26, 2001 – June 5, 2001
22.	Credit Issue memos (Treasurer's Office/Department of Finance); letters from DWR to creditors	June 21, 2001 January 18, 2001 – September 21, 2001

History of DWR's Net Short Energy Procurement Process Under Long-Term Contracts

Exhibit #	Document/Information	Date
23.	Montague Derose analysis of Commercial Bank line of credit for energy purchases	March 31, 2001
24.	Historical and current price of gas analysis	February 5, 2001
25.	Gas price forecasts	Various Dates
26.	CERS Strategy for Energy purchase portfolio design	January 29, 2001
27.	CPUC Decision 01-01-046	January 19, 2001
28.	CPUC Decision 01-04-005	April 3, 2001
29.	Request for bids for energy purchases #1	January 23, 2001
30.	Request for bids for energy purchases #2	February 1, 2001
31.	Summary of compliant energy bids	January 24, 2001
32.	Tracking sheets showing annual capacity levels	March 8, 2001
33.	Attorney General's letter	February 28, 2001
34.	Contract approval form and template	January/February 2001
35.	Methods/Assumptions for estimating Net Short energy	April 30, 2001
36.	Representative news articles concerning Summer 2001	May 21, 2001
37	Representative news articles – reactions on Summer 2001 estimated prices	May 4, 2001
38.	Presentation to CPUC/CEC (Update on energy procurement program)	May 18, 2001
39.	FERC Price Mitigation Order	June 19, 2001
40.	Average forward electricity contract price (COB and Palo Verde)	May 2002
41.	Correlation between Bloomberg spot and Nymex futures prices at COB	May 2002
42.	Evolution of Spot Market price projections	March 2001
43.	Agreements in Principle/Letters of intent which DWR entered but did not get converted into L-T contracts.	August 30, 2001
44.	September 20 direct access suspension order's impact on Net Short forecast	August 2002
45.	Summary of renegotiated contracts – press release by Governor's office	July 2002
46.	Off-System sales forecast	August 2002

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 1

CAISO Control Area Net Short Calculations

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CAISO Control Area Net Short Calculations

PRIVILEDGED AND CONFIDENTIAL
ISO DISCUSSION DOCUMENT

		Winter			Spring		Summer			Fall		Winter	
Year 2001	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	167167	162498	158997	160046	182567	217959	214692	228847	197270	178934	174099	182712
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		105196	103044	101429	101913	112298	128620	127113	133641	119079	110623	108393	112366
Est. Avg. Unmet Peak Load		7934	7020	7650	7439	8470	9388	9588	10080	8692	8344	7912	8475
NP15 MWh Peak		3261076	2885219	3144294	3057377	3481248	3858588	3940508	4142871	3572368	3429309	3251804	3483332
Daily SP15 MWh Peak		61970	59455	57568	58133	70268	89339	87579	95206	78191	68311	65706	70347
SP15 MWh Peak		1921070	1664728	1784605	1743993	2178319	2680169	2714942	2951393	2345735	2117631	1971171	2180754
Est. Avg. Unmet Peak Load		4678	4054	4346	4247	5304	6526	6611	7187	5712	5157	4800	5310
Total MWh Peak		5182163	4549947	4928900	4801370	5659568	6538757	6655451	7094264	5918102	5546940	5222975	5664085
Total Avg. Unmet Peak		12612	11074	11996	11686	13775	15915	16199	17267	14404	13500	12712	13786
MWh Off-Peak	(2200 - 0600)	62434	60624	59266	54796	63233	58451	57364	62073	51568	45467	65122	68462
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		46446	45612	44986	42924	46815	44610	44108	46280	41435	38622	47686	49226
Est. Avg. Unmet Peak Load		4319	3991	4054	4236	4425	4182	4383	4171	3885	3837	4471	4239
NP15 MWh Off-Peak		1439826	1277129	1394556	1287720	1451261	1338287	1367361	1434685	1243065	1197290	1430584	1526014
Daily SP15 MWh Off-Peak		15987	15012	14281	11872	16418	13841	13256	15793	10132	6845	17436	19235
SP15 MWh Off-Peak		495597	420338	442697	356148	508955	415233	410921	489586	303971	212202	523077	596300
Est. Avg. Unmet Peak Load		1487	1314	1287	1172	1552	1298	1317	1423	950	680	1635	1656
Total MWh Off-Peak		1935453	1697467	1837253	1643868	1960216	1753521	1778282	1924270	1547036	1409492	1953660	2122313
Total		**7117615**	**6247414**	**6766152**	**6445238**	**7619784**	**8292277**	**8433732**	**9018535**	**7465138**	**6956432**	**7176635**	**7786399**
Loads		32500	32100	31800	31400	33300	39500	39200	40500	37600	35916	33094	33832
Peak Loads		33563	33204	33366	34759	40803	44721	46376	46631	44834	36501	33247	34605
Difference		1063	1104	1566	3359	7503	5221	7176	6131	7234	585	153	773
Year 2002	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	174753	169991	166420	167489	190461	226561	223229	237667	205458	186752	181825	190614
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		108695	106499	104852	105345	115939	132587	131050	137708	122855	114228	111956	116009
NP15 MWh Peak		3369541	2981969	3250410	3160360	3594103	3977595	4062549	4268959	3685651	3541076	3358695	3596289
Daily SP15 MWh Peak		66058	63492	61568	62144	74522	93974	92179	99959	82603	72523	69869	74604
SP15 MWh Peak		2047795	1777777	1908597	1864324	2310185	2819223	2857540	3098720	2478100	2248225	2096068	2312738
		174753	169991	166420	167489	190461	226561	223229	237667	205458	186752	181825	190614
Total MWh Peak		5417335	4759746	5159007	5024684	5904288	6796818	6920089	7367679	6163751	5789300	5454763	5909027
MWh Off-Peak	(2200 - 0600)	65375	63529	62144	57584	66190	61313	60204	65008	54292	48068	68118	71525
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		47803	46952	46313	44210	48179	45929	45418	47633	42692	39822	49068	50639
NP15 MWh Off-Peak		1481893	1314643	1435701	1326301	1493541	1377880	1407962	1476633	1280753	1234474	1472029	1569812
Daily SP15 MWh Off-Peak		17572	16578	15831	13374	18011	15383	14786	17374	11600	8247	19050	20886
SP15 MWh Off-Peak		544746	464172	490773	401228	558356	461495	458362	538600	348007	255649	571504	647475
		65375	63529	62144	57584	66190	61313	60204	65008	54292	48068	68118	71525
Total MWh Off-Peak		2026638	1778815	1926474	1727529	2051897	1839375	1866324	2015233	1628760	1490123	2043534	2217287
Total		**7443974**	**6538561**	**7085482**	**6752213**	**7956186**	**8636193**	**8786413**	**9382911**	**7792511**	**7279423**	**7498297**	**8126314**
Loads		33150	32742	32436	32028	33966	40290	39984	41310	38352	36634	33756	34509
Peak Loads		34234	33868	34033	35454	41619	45615	47304	47564	45731	37231	33912	35297

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CAISO Control Area Net Short Calculations

PRIVILEDGED AND CONFIDENTIAL
ISO DISCUSSION DOCUMENT

		Winter			Spring		Summer			Fall		Winter	
Difference		1084	1126	1597	3426	7653	5325	7320	6254	7379	597	156	788
Year 2003	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	182491	177636	173994	175087	198509	235337	231940	246661	213810	194733	189703	198667
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		112263	110024	108345	108849	119650	136634	135067	141856	126706	117909	115589	119723
NP15 MWh Peak		3480162	3080680	3358695	3265475	3709161	4099013	4187080	4397537	3801193	3655177	3467685	3711414
Daily SP15 MWh Peak		70227	67611	65649	66238	78859	98703	96873	104805	87104	76824	74114	78944
SP15 MWh Peak		2177050	1893115	2035122	1987145	2444625	2961094	3003048	3248957	2613106	2381546	2223418	2447257
		182491	177636	173994	175087	198509	235337	231940	246661	213810	194733	189703	198667
Total MWh Peak		5657211	4973794	5393818	5252620	6153786	7060106	7190128	7646494	6414299	6036723	5691103	6158672
MWh Off-Peak	(2200 - 0600)	68376	66493	65081	60431	69205	64232	63102	68000	57071	50724	71172	74648
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		49187	48318	47667	45523	49569	47276	46755	49013	43973	41046	50476	52079
NP15 MWh Off-Peak		1524785	1352917	1477687	1365681	1536646	1418274	1449392	1519409	1319193	1272434	1514289	1614451
Daily SP15 MWh Off-Peak		19189	18175	17414	14908	19636	16956	16347	18987	13097	9678	20696	22569
SP15 MWh Off-Peak		594863	508893	539832	447241	608722	508694	506771	588582	392922	300004	620883	699634
		68376	66493	65081	60431	69205	64232	63102	68000	57071	50724	71172	74648
Total MWh Off-Peak		2119648	1861809	2017520	1812922	2145368	1926968	1956163	2107991	1712115	1572438	2135172	2314084
Total		**7776859.188**	**6835603.712**	**7411337.801**	**7065542.855**	**8299153.844**	**8987074.711**	**9146291.335**	**9754485.643**	**8126414.175**	**7609161.196**	**7826274.867**	**8472755.675**
Loads		33813	33397	33085	32669	34645	41096	40784	42136	39119	37367	34431	35199
Peak Loads		34919	34545	34714	36163	42451	46528	48250	48515	46645	37976	34590	36003
Difference		1106	1148	1629	3494	7806	5432	7466	6379	7526	609	159	804
Year 2004	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	190380	185432	181709	182827	206723	244287	240814	255840	222325	202867	197745	206883
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		115902	113620	111903	112419	123438	140761	139160	146089	130633	121660	119298	123512
NP15 MWh Peak		3592952	3181349	3468983	3372558	3826592	4222841	4313945	4528761	3918995	3771458	3578935	3828876
Daily SP15 MWh Peak		74479	71812	69806	70409	83285	103526	101654	109751	91692	81207	78447	83371
SP15 MWh Peak		2308839	2010742	2163988	2112266	2581836	3105780	3151285	3402287	2750752	2517415	2353409	2584505
		190380	185432	181709	182827	206723	244287	240814	255840	222325	202867	197745	206883
Total MWh Peak		5901791	5192090	5632970	5484824	6408428	7328621	7465230	7931048	6669747	6288872	5932344	6413382
MWh Off-Peak	(2200 - 0600)	71435	69516	68073	63330	72283	67210	66054	71054	59903	53430	74290	77834
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		50597	49713	49047	46860	50988	48649	48116	50421	45279	42294	51914	53548
NP15 MWh Off-Peak		1568518	1391950	1520450	1405798	1580639	1459470	1491599	1563066	1358384	1311119	1557426	1659995
Daily SP15 MWh Off-Peak		20838	19804	19026	16471	21294	18561	17938	20632	14624	11136	22376	24285
SP15 MWh Off-Peak		645963	554502	589799	494116	660127	556830	556088	639593	438716	345206	671286	752850
		71435	69516	68073	63330	72283	67210	66054	71054	59903	53430	74290	77834
Total MWh Off-Peak		2214481	1946452	2110249	1899914	2240766	2016300	2047687	2202659	1797100	1656325	2228711	2412845
Total		**8116272**	**7138542**	**7743219**	**7384738**	**8649194**	**9344921**	**9512917**	**10133707**	**8466847**	**7945198**	**8161055**	**8826227**
Loads		34489	34065	33746	33322	35338	41918	41599	42979	39901	38114	35120	35903
Peak Loads		35617	35236	35408	36887	43300	47458	49215	49485	47578	38735	35282	36723
Difference		1128	1171	1662	3565	7962	5540	7616	6506	7677	621	162	820
Year 2005	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	198433	193380	189587	190722	215104	253412	249873	265205	231014	211175	205938	215263

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CAISO Control Area Net Short Calculations

PRIVILEDGED AND CONFIDENTIAL
ISO DISCUSSION DOCUMENT

		Winter			Spring		Summer			Fall		Winter	
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		119615	117285	115536	116059	127303	144969	143337	150407	134640	125491	123076	127377
NP15 MWh Peak		3708077	3283977	3581606	3481772	3946394	4349079	4443458	4662632	4039208	3890229	3692285	3948674
Daily SP15 MWh Peak		78818	76095	74051	74663	87801	108443	106536	114797	96374	85684	82862	87887
SP15 MWh Peak		2443358	2130658	2295582	2239878	2721820	3253283	3302614	3558708	2891214	2656193	2485852	2724483
		198433	193380	189587	190722	215104	253412	249873	265205	231014	211175	205938	215263
Total MWh Peak		6151435	5414635	5877188	5721651	6668214	7602362	7746071	8221340	6930422	6546422	6178137	6673157
MWh Off-Peak	(2200 - 0600)	74557	72598	71127	66288	75422	70246	69068	74169	62794	56194	77467	81083
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		52037	51134	50455	48224	52436	50049	49506	51858	46613	43569	53379	55047
NP15 MWh Off-Peak		1613157	1431743	1564119	1446714	1625522	1501469	1534687	1607604	1398378	1350633	1601376	1706446
Daily SP15 MWh Off-Peak		22520	21464	20672	18064	22986	20197	19562	22311	16182	12625	24088	26036
SP15 MWh Off-Peak		698122	600998	640823	541924	712569	605903	606433	691633	485446	391376	722639	807125
		74557	72598	71127	66288	75422	70246	69068	74169	62794	56194	77467	81083
Total MWh Off-Peak		2311278	2032741	2204942	1988638	2338091	2107371	2141120	2299237	1883824	1742009	2324015	2513571
Total		**8462714**	**7447376**	**8082130**	**7710288**	**9006305**	**9709734**	**9887191**	**10520577**	**8814246**	**8288431**	**8502153**	**9186727**
Loads		35179	34746	34421	33988	36045	42756	42431	43839	40699	38877	35822	36621
Peak Loads		36330	35941	36116	37624	44166	48407	50199	50475	48530	39510	35988	37458
Difference		1151	1195	1695	3636	8121	5651	7768	6636	7831	633	166	837
Year 2006	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	206650	188198	184459	179466	203165	280486	276747	292957	256787	235788	200589	209796
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		123404	121026	119244	119885	131244	149263	147601	154806	138728	129393	126930	131316
NP15 MWh Peak		3825539	3388715	3696565	3596562	4068569	4477878	4575616	4798993	4161831	4011180	3807895	4070807
Daily SP15 MWh Peak		83245	80466	78384	79133	92406	113459	111517	119937	101150	90243	87365	92490
SP15 MWh Peak		2580606	2253039	2429906	2374005	2864575	3403779	3457034	3718040	3034493	2797518	2620937	2867190
		206650	201491	197628	199019	223650	262722	259118	274743	239877	219635	214294	223806
Total MWh Peak		6406145	5269544	5718229	5383980	6298115	8414580	8579157	9081667	7703610	7309428	6017670	6503676
MWh Off-Peak	(2200 - 0600)	77743	75743	74245	69396	78624	73343	72144	77342	65743	59009	80707	84395
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		53506	52584	51893	49657	53913	51477	50924	53322	47972	44867	54873	56574
NP15 MWh Off-Peak		1658701	1472354	1608693	1489718	1671293	1544319	1578654	1652969	1439173	1390872	1646203	1753802
Daily SP15 MWh Off-Peak		24237	23159	22352	19739	24711	21866	21220	24021	17770	14142	25834	27821
SP15 MWh Off-Peak		751338	648450	692906	592173	766051	655971	657807	744641	533113	438393	775017	862458
		77743	75743	74245	69396	78624	73343	72144	77342	65743	59009	80707	84395
Total MWh Off-Peak		2410040	2120804	2301599	2081891	2437343	2200289	2236461	2397610	1972286	1829265	2421220	2616260
Total		**8816185**	**7390348**	**8019828**	**7465871**	**8735458**	**10614869**	**10815618**	**11479277**	**9675896**	**9138693**	**8438890**	**9119936**
Loads		35883	35441	35110	34668	36766	43611	43280	44715	41513	39654	36538	37353
Peak Loads		37056	36660	36839	38377	45050	49376	51203	51484	49500	40300	36707	38207
Difference		1173	1219	1729	3709	8284	5765	7923	6769	7987	646	169	854
Year 2007	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	215030	209766	205821	206996	232362	272217	268547	284477	248915	228270	222826	232525
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		127269	124842	123022	123564	135262	153641	151949	159295	142895	133375	130864	135337
NP15 MWh Peak		3945337	3495563	3813693	3706925	4193116	4609238	4710421	4938157	4286864	4134621	3925928	4195444

CAISO Control Area Net Short Calculations

PRIVILEDGED AND CONFIDENTIAL
ISO DISCUSSION DOCUMENT

		Winter			Spring		Summer			Fall		Winter	
Daily SP15 MWh Peak		87761	84924	82799	83432	97100	118576	116598	125182	106020	94895	91962	97188
SP15 MWh Peak		2720584	2377886	2566764	2502958	3010102	3557267	3614547	3880645	3180588	2941753	2758852	3012821
		215030	209766	205821	206996	232362	272217	268547	284477	248915	228270	222826	232525
Total MWh Peak		6665921	5873449	6380457	6209883	7203219	8166505	8324968	8818802	7467452	7076374	6684780	7208265
MWh Off-Peak	(2200 - 0600)	80992	78951	77422	72385	81888	76502	75281	80581	68750	61881	84015	87776
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		55005	54064	53358	51035	55418	52934	52371	54815	49359	46192	56399	58133
NP15 MWh Off-Peak		1705152	1513784	1654108	1531064	1717952	1588021	1623502	1699268	1480770	1431940	1691968	1802128
Daily SP15 MWh Off-Peak		25988	24888	24064	21349	26470	23568	22910	25766	19391	15690	27616	29643
SP15 MWh Off-Peak		805613	696858	745971	640483	820570	707035	710210	798738	581718	486379	828492	918925
		80992	78951	77422	72385	81888	76502	75281	80581	68750	61881	84015	87776
Total MWh Off-Peak		2510765	2210642	2400079	2171547	2538523	2295055	2333712	2498006	2062488	1918319	2520460	2721053
Total		**9176686**	**8084091**	**8780537**	**8381430**	**9741742**	**10461560**	**10658680**	**11316807**	**9529939**	**8994693**	**9205240**	**9929318**
Loads		36601	36150	35812	35361	37501	44483	44146	45609	42343	40447	37269	38100
Peak Loads		37797	37393	37576	39144	45951	50363	52227	52514	50490	41106	37442	38971
Difference		1197	1243	1763	3783	8449	5880	8081	6905	8147	659	173	871
Year 2008	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	223573	218204	214178	215388	241252	281908	278162	294408	258138	237079	231521	241418
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		131209	128733	126876	127434	139361	158110	156383	163875	147149	137437	134874	139438
NP15 MWh Peak		4067470	3604521	3933157	3823027	4320206	4743310	4847872	5080122	4414458	4260553	4046220	4322583
Daily SP15 MWh Peak		92364	89471	87302	87954	101890	123797	121779	130533	110989	99642	96647	101980
SP15 MWh Peak		2863291	2505198	2706352	2638618	3158600	3713923	3775152	4046524	3329675	3088898	2899408	3161377
		223573	218204	214178	215388	241252	281908	278162	294408	258138	237079	231521	241418
Total MWh Peak		6930761	6109719	6639509	6461644	7478805	8457232	8623023	9126646	7744133	7349451	6945629	7483959
MWh Off-Peak	(2200 - 0600)	84305	82223	80662	75529	85218	79726	78480	83885	71818	64812	87387	91224
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		56533	55573	54853	52485	56954	54421	53846	56339	50774	47543	57954	59723
NP15 MWh Off-Peak		1752508	1556031	1700429	1574560	1765565	1632625	1669231	1746498	1523219	1473836	1738611	1851425
Daily SP15 MWh Off-Peak		27772	26651	25810	23044	28265	25305	24634	27546	21044	17269	29433	31501
SP15 MWh Off-Peak		860946	746222	800095	691306	876203	759152	763641	853924	631317	535332	882991	976526
		84305	82223	80662	75529	85218	79726	78480	83885	71818	64812	87387	91224
Total MWh Off-Peak		2613454	2302253	2500524	2265866	2641767	2391777	2432872	2600422	2154537	2009168	2621602	2827951
Total		**9544215**	**8411971**	**9140033**	**8727510**	**10120572**	**10849010**	**11055896**	**11727069**	**9898670**	**9358620**	**9567231**	**10311911**
Loads		37333	36873	36528	36069	38251	45373	45029	46521	43190	41256	38014	38862
Peak Loads		38553	38141	38327	39927	46870	51370	53271	53564	51500	41928	38190	39750
Difference		1221	1268	1799	3859	8618	5997	8243	7043	8310	672	176	888
Year 2009	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	232280	226806	222709	223934	250319	291784	287962	304545	267448	246062	240391	250486
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		135224	132700	130810	131375	143543	162665	160902	168550	151442	141580	138965	143620
NP15 MWh Peak		4191940	3715589	4055123	3941261	4449836	4879942	4987969	5225045	4543257	4388975	4168935	4452224
Daily SP15 MWh Peak		97056	94106	91899	92559	106776	129119	127060	135995	116006	104482	101426	106866
SP15 MWh Peak		3008727	2634975	2848864	2776768	3310067	3873571	3938848	4215860	3480171	3238954	3042794	3312857
		232280	226806	222709	223934	250319	291784	287962	304545	267448	246062	240391	250486

CAISO Control Area Net Short Calculations

PRIVILEGED AND CONFIDENTIAL
ISO DISCUSSION DOCUMENT

		Winter			Spring		Summer			Fall		Winter	
Total MWh Peak		7200667	6350563	6903988	6718029	7759903	8753513	8926817	9440904	8023428	7627929	7211730	7765081
MWh Off-Peak	(2200 - 0600)	87681	85558	83970	78731	88615	83012	81740	87257	74915	67800	90826	94740
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		58089	57111	56378	53962	58520	55936	55350	57894	52202	48921	59540	61345
NP15 MWh Off-Peak		1800769	1599096	1747720	1618854	1814129	1678081	1715840	1794712	1566069	1516561	1786192	1901692
Daily SP15 MWh Off-Peak		29592	28448	27592	24769	30095	27076	26390	29363	22713	18879	31286	33396
SP15 MWh Off-Peak		917338	796542	855353	743062	932948	812266	818102	910260	681386	585254	938588	1035261
		87681	85558	83970	78731	88615	83012	81740	87257	74915	67800	90826	94740
Total MWh Off-Peak		2718107	2395638	2603073	2361916	2747077	2490347	2533941	2704973	2247455	2101815	2724780	2936953
Total		**9918774**	**8746201**	**9507061**	**9079945**	**10506980**	**11243860**	**11460759**	**12145877**	**10270882**	**9729744**	**9936510**	**10702034**
Loads		38079	37610	37259	36790	39016	46280	45929	47452	44054	42081	38774	39639
Peak Loads		39324	38904	39094	40726	47807	52398	54337	54636	52530	42767	38954	40545
Difference		1245	1294	1835	3936	8791	6117	8408	7184	8476	686	180	906
Year 2010	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	241173	235583	231404	232658	259577	301867	297969	314879	277139	255230	249448	259742
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		139325	136747	134820	135398	147812	167315	165517	173315	155911	145808	143141	147888
NP15 MWh Peak		4319079	3828917	4179426	4061954	4582178	5019437	5131024	5372769	4677328	4520044	4294234	4584536
Daily SP15 MWh Peak		101848	98835	96584	97260	111765	134552	132452	141564	121228	109423	106307	111853
SP15 MWh Peak		3157283	2767393	2994106	2917792	3464702	4036564	4106001	4388469	3636827	3392101	3189199	3467456
		241173	235583	231404	232658	259577	301867	297969	314879	277139	255230	249448	259742
Total MWh Peak		7476362	6596310	7173532	6979747	8046881	9056001	9237025	9761238	8314155	7912145	7483433	8051992
MWh Off-Peak	(2200 - 0600)	91129	88962	87341	81999	92083	86366	85069	90695	78139	70851	94338	98329
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Off-Peak		59680	58680	57933	55469	60120	57483	56885	59479	53689	50328	61159	63000
NP15 MWh Off-Peak		1850066	1643038	1795917	1664070	1863709	1724490	1763433	1843859	1610674	1560166	1834775	1952995
Daily SP15 MWh Off-Peak		31450	30282	29409	26530	31964	28883	28184	31216	24450	20523	33178	35329
SP15 MWh Off-Peak		974939	847886	911669	795895	990880	866492	873712	967686	733503	636205	995355	1095205
		91129	88962	87341	81999	92083	86366	85069	90695	78139	70851	94338	98329
Total MWh Off-Peak		2825005	2490924	2707586	2459965	2854588	2590981	2637144	2811544	2344177	2196371	2830130	3048200
Total		**10301367**	**9087234**	**9881118**	**9439712**	**10901469**	**11646982**	**11874169**	**12572782**	**10658332**	**10108516**	**10313563**	**11100192**
Loads		38841	38362	38004	37526	39797	47206	46848	48401	44935	42923	39550	40432
Peak Loads		40111	39682	39875	41540	48763	53446	55424	55728	53581	43622	39733	41356
Difference		1270	1319	1871	4014	8967	6240	8576	7327	8646	699	183	924
Year 2011	**Month**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Daily MWh Peak	(0600 - 2200)	250241	244546	240274	241548	269012	312146	308171	325419	282028	264573	258680	269184
# of Days		31	28	31	30	31	30	31	31	30	31	30	31
Daily NP15 MWh Peak		143507	140881	138911	139498	152163	172055	170222	178176	158166	150116	147398	152242
NP15 MWh Peak		4448720	3944656	4306231	4184944	4717062	5161643	5276881	5523452	4744967	4653603	4421954	4719516
Daily SP15 MWh Peak		106734	103665	101364	102050	116849	140091	137949	147243	123862	114457	111281	116941
SP15 MWh Peak		3308763	2902629	3142271	3061500	3622307	4202725	4276427	4564534	3715859	3548159	3338434	3625175
		250241	244546	240274	241548	269012	312146	308171	325419	282028	264573	258680	269184
Total MWh Peak		7757483	6847285	7448503	7246443	8339370	9364368	9553308	10087985	8460826	8201762	7760388	8344691
MWh Off-Peak	(2200 - 0600)	94645	92437	90781	85329	95618	89786	88463	94202	79766	73959	97917	101990
# of Days		31	28	31	30	31	30	31	31	30	31	30	31

CAISO Control Area Net Short Calculations

PRIVILEDGED AND CONFIDENTIAL
ISO DISCUSSION DOCUMENT

		Winter			Spring		Summer			Fall		Winter	
Daily NP15 MWh Off-Peak		61301	60283	59519	57005	61750	59060	58450	61096	54439	51761	62810	64688
NP15 MWh Off-Peak		1900334	1687915	1845085	1710147	1914241	1771800	1811958	1893989	1633176	1604600	1884297	2005332
Daily SP15 MWh Off-Peak		33344	32154	31262	28324	33869	30726	30013	33105	25327	22198	35107	37302
SP15 MWh Off-Peak		1033674	900322	969118	849733	1049924	921772	930411	1026261	759796	688123	1053219	1156359
		94645	92437	90781	85329	95618	89786	88463	94202	79766	73959	97917	101990
Total MWh Off-Peak		2934007	2588237	2814203	2559879	2964165	2693572	2742368	2920250	2392973	2292723	2937517	3161691
Total		**10691491**	**9435522**	**10262706**	**9806323**	**11303535**	**12057939**	**12295676**	**13008235**	**10853798**	**10494485**	**10697905**	**11506382**
Loads		39618	39130	38764	38276	40593	48150	47785	49369	45834	43781	40341	41241
Peak Loads		40913	40475	40673	42371	49739	54515	56532	56843	54652	44495	40528	42183
Difference		1295	1346	1909	4095	9146	6365	8747	7474	8819	713	187	943

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 2

Emails Sent to Investor Owned Utilities Requesting Net Short Forecast Information

Ron Nichols

02/05/2001 03:29 PM

To: harold.ray@sce.com, rayhb@sce.com, sushnice@sce.com
cc: dyer@electricpowergroup.com
cc: dyer@electricpowergroup.com
Subject: Information Needs to Support DWR Procurement of Energy

Colin, as a follow up to the call from Jim Dyer, enclosed is the information request which Navigant Consulting sent to the CAISO for information on loads and data to calculate the estimated "net short" going forward. The CAISO is endeavoring to fill this data need. Since representatives on behalf of DWR are in negotiations for purchases, we need to be getting the best picture possible of the net short. To this end, we are asking each of SCE, PG&E and SDG&E for the data they may have immediately available to corroborate the information we are getting from the CAISO. In light of the schedule for acquisition, our needs are immediate. The highest priority is on load forecasts for 2001, with specific understanding of the manner in which curtailable load and other DSM impacts on peak (and to a lesser extent on energy) is reflected in your forecast. Any of the information requested in the enclosed list which you have available will help us.

Please contact me with any questions you may have. We would like to confirm which data you do have available and when it would be available.

We would like to receive data electronically. It can be sent to the e-mail address below. I can be reached at my cell phone number, below.

Summary of ISO Data Requirements.xl

Ron Nichols
Senior Managing Director
Navigant Consulting Inc.
916/852-1300 (O)
916/284-5681 (C)

Ron Nichols

02/05/2001 03:32 PM

To: jetrack@edge.com;avery@edge.com
cc: dyer@energypowergroup.com
Subject: Information Requests in Support of DWR Energy Purchase Program

As a follow up to the call from Jim Dyer, enclosed is the information request which Navigant Consulting sent to the CAISO for information on loads and data to calculate the estimated "net short" going forward. The CAISO is endeavoring to fill this data need. Since representatives on behalf of DWR are in negotiations for purchases, we need to be getting the best picture possible of the net short. To this end, we are asking each of SDG&E,SCE and PG&E for the data they may have immediately available to corroborate the information we are getting from the CAISO. In light of the schedule for acquisition, our needs are immediate. The highest priority is on load forecasts for 2001, with specific understanding of the manner in which curtailable load and other DSM impacts on peak (and to a lesser extent on energy) is reflected in your forecast. Any of the information requested in the enclosed list which you have available will help us.

Please contact me with any questions you may have. We would like to confirm which data you do have available and when it would be available.

We would like to receive data electronically. It can be sent to the e-mail address below. I can be reached at my cell phone number, below.

Summary of ISO Data Requirements.c

Ron Nichols
Senior Managing Director
Navigant Consulting Inc.
916/852-1300 (O)
916/284-5881 (C)

Ron Nichols

02/05/2001 03:43 PM

To: mlk4@pge.com
cc: cxg2@pge.com, dyer@electricpowergroup.com
Subject: Information Requirements in Support of DWR Energy Procurement for Calif.

Claudia:
As a follow up to the call from Jim Dyer, enclosed is the information request which Navigant Consulting sent to the CAISO for information on loads and data to calculate the estimated "net short" going forward. The CAISO is endeavoring to fill this data need. Since representatives on behalf of DWR are in negotiations for purchases, we need to be getting the best picture possible of the net short. To this end, we are asking each of PG&E, SCE and SDG&E for the data they may have immediately available to corroborate the information we are getting from the CAISO. In light of the schedule for acquisition, our needs are immediate. The highest priority is on load forecasts for 2001, with specific understanding of the manner in which curtailable load and other DSM impacts on peak (and to a lesser extent on energy) is reflected in your forecast. Any of the information requested in the enclosed list which you have available will help us.

Please contact me with any questions you may have. We would like to confirm which data you do have available and when it would be available.

We would like to receive data electronically. It can be sent to the e-mail address below. I can be reached at my cell phone number, below.

Summary of ISO Data Requirements.c

Ron Nichols
Senior Managing Director
Navigant Consulting Inc.
916/852-1300 (O)
916/284-5881 (C)

Summary of ISO Data Requirements

For all data requested below, please provide a historical perspective (years 1999 & 2000), and a forecast for 2001 through 2003.

- Hourly ISO Load for NP-15, SP-15 and ZP26. The data we have now uses a single annual factor to divide NP and SP 15 loads for each month.
- Hourly Muni Loads and Muni Generation divided into zones as describe above. Please also list ownership and type of fuel source if known.
- Hourly IOU Generation divided into zones listed above. Please also list ownership if known. The generation should be divided into QFs, Nukes, and Hydro and any thermal for each IOU.
- Total MW of installed generating capacity within California.
- Total transmission import capability into California divided into zones as describe above. Please also include major constrained paths with California. (ie Path 15 and 26)
- Reserved transmission import capability for each of the paths provided in response to the preceding request.
- Total hourly outages of generating capacity divided into the three zones as described above.
- Total Hourly Must Run Capacity on line divided by zone as described above.
- Hourly and Monthly load forecasts.
- MW of Load Curtailments (historic actual for the '99 and '00 data and assumed for forecasts)
- MW of Demand Side Management (historic actual contribution for the '99 and '00 and assumed contribution in MWh and peak reduction for forecasts)

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 3

CPUC Ruling Establishing Rate Increase

COM/LYN/abw

Mailed 3/28/01

Decision 01-03-082 March 27, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (E 3338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000)

(See Appendix A for List of Appearances.)

INTERIM OPINION REGARDING PROPOSED RATE INCREASES

I. Summary

This decision grants Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) authority to increase rates by adding to their current rates a three-cent per kilowatt-hour (kWh) surcharge in response to the current emergency in the electric industry.

After an independent accounting review, an evidentiary hearing and a full opportunity to comment and testify provided to all parties, we conclude that the utilities have established the need for additional revenues on a going-forward basis in order for those utilities to comply with their statutory duty to provide adequate electric service to their customers. Today's decision does not address recovery of past power purchase costs and other costs claimed by the utilities.

The increase will be added to the utilities' currently controlled rates and will be in addition to the emergency surcharge approved on January 4, 2001 and made permanent by with this decision. It will cost the customers of the utilities approximately $2.5 billion dollars annually.[1] The California Department of Water Resources has yet to provide the Commission with either its revenue requirement or with detailed data regarding its net short needs. We will allocate a portion of this surcharge directly to the California Department of Water Resources (CDWR) when CDWR provides this Commission a revenue requirement that documents its need for revenues in excess of those allocated by D.01-03-081.

The Federal Energy Regulation Commission (FERC) has determined that current wholesale power rates are not just and reasonable. However, both the utilities and CDWR in large measure are subject to those wholesale rates in order to assure adequate electric service. An increase in retail electric rates is necessary

[1] As explained more fully below, the usage of residential customers below 130 percent of baseline allowance will be exempted from the surcharge.

because without it the state's electricity system and its economy will be severely jeopardized. We adopt this increase effective today, but we seek parties' comments on the amount of the increase and on rate design proposals for its collection, including that which the assigned commissioner set forth in the Assigned Commissioner's Ruling issued contemporaneously.

We recognize that this rate increase will impose expense on California's citizens and businesses; in this decision we also take steps to mitigate this pain somewhat. This decision modifies accounting rules which apply to the utilities, in response to a proposal made by TURN, so that we will be able to evaluate the full consequences of the accounting rules set up to implement AB 1890 and to adjust rates in the future, if warranted. In addition, we adopt a proposal that specifically shelters low-income households eligible for the California Alternative Rates for Energy (CARE) program for the electric customers of PG&E and Edison by expanding the eligibility criteria from 150% to 175% of federal poverty guidelines.[2]

II. Background

A. Events Leading to this Decision

This decision addresses the requests of PG&E and SCE for immediate rate increases in response to extraordinary circumstances in California's wholesale power markets. We consider their requests in the context of current state law and the state's dysfunctional wholesale energy markets that have led to unconscionable, unlawful wholesale prices and an increasingly unstable supply situation.

[2] Families eligible for CARE are also severely effected by today's high gas bills and, therefore, we will move quickly to address the applicability of the changes we make here to all jurisdictional utilities.

The current industry structure evolves from Chapter 854 of the Statutes of 1996 Assembly Bill (AB) 1890 (Brulte), passed in 1996 to promote competition in California's electric market by opening generation markets. AB 1890 turned over operation of the state's transmission system to the Independent System Operator (ISO) and the pricing of unregulated generation to the Power Exchange (PX), both private nongovernmental corporations regulated by the Federal Energy Regulatory Commission (FERC), not the State of California. AB 1890 also required the utilities to file with this Commission rate plans that set electric utility rates at June 10, 1996 levels, except that bills for residential and small commercial customers were discounted by 10% from those levels, through the issuance of Rate Reduction Bonds approved by the Commission. The frozen rate levels were initially high enough to allow PG&E, SCE, and San Diego Gas & Electric Company (SDG&E) an opportunity to recover uneconomic generation costs within a specified period.

The original expectations of California decision-makers – that competitive markets would reduce power purchase prices – have not been fulfilled. Rather than dropping in response to competitive market forces, wholesale electricity prices have risen by staggering proportions since the summer of 2000. These increases accelerated their rate of ascent after the FERC eliminated wholesale electricity price caps in California markets in November and December, 2000. The uncontrolled price increases in wholesale markets have created enormous outstanding liabilities for PG&E and SCE. Indeed, SCE's and PG&E's continued financial viability and ability to serve their customers has been seriously compromised by the dramatic escalation in wholesale prices since.

B. Procedural Background

After the FERC refused to extend wholesale electricity price cap authority in California, the utility respondents filed Rate Stabilization Plans (RSPs) proposing to end the rate freeze and increase rates by 10 percent.

On December 8, 2000, the Federal Energy Regulatory Commission completely eliminated price caps in California, despite concluding that the market was dysfunctional and was being subverted by sellers' market power. Wholesale electricity prices immediately soared, peaking at $1400 per megawatt hour on December 14th. The utilities filed emergency motions to modify RSPs to provide for 30 percent rate increases on December 14, 2000. The next week the Commission issued an emergency order on December 21, setting out a schedule to address rate relief in the context of the FERC-created wholesale price emergency.

In the December 21st order, D.00-12-067, the Commission determined that expedited action was necessary to fulfill our statutory obligations to ensure that the utilities can provide adequate service at just and reasonable rates. We consolidated the applications of PG&E and Edison with TURN's Petition to Modify Resolution E-3527 and conducted hearings during the week of December 26, 2000. Those hearings were narrowly focused on PG&E's and Edison's claims that existing rates did not yield revenues sufficient to meet their cost obligations. The commission also engaged independent auditors to verify the extent of the utilities' financial hardship and cash positions.

The Commission issued D.01-01-018 on January 4, 2001, authorizing an interim rate increase to both PG&E and Edison, subject to refund, of one cent per kilowatt-hour (kWh). The decision exempted low-income customers eligible for the California Alternative Rates for Energy (CARE) program. We authorized this surcharge to be applied to recovery of future electricity procurement costs and to

be in effect for 90 days, during which time independent consultants engaged by the Commission would review the utilities' financial circumstances and all parties would have the opportunity to submit evidence and testimony regarding the proposed rate increase.

The assigned Commissioner designated the following issues as within the scope of the hearings:

(1) Review of the independent audits of PG&E and Edison, ordered in D.00-12-067, and determination of whether or not the Commission should grant further rate increases;

(2) TURN's accounting proposal to reconcile the Transition Revenue Account (TRA) and Transition Cost Balancing Account (TCGA) accounts and the Generation Memorandum Accounts (GMA);

(3) Consideration of whether the rate freeze has ended on a prospective basis only, including interim valuation of retained utility generating assets;

(4) Greenlining/Latino Forum's CARE proposal;

(5) Parties' proposals for tiered residential rates.

C. Recent Legislative Action Provides the Commission With Enhanced Authority to Raise Rates

On January 19, 2001 the Legislature passed and the Governor signed Chapter 3 of the Statutes of 2001. (Senate Bill 7x (Burton) from the First Extraordinary Session). SB7X appropriated $400 million from the General Fund to the Department of Water Resources to purchase energy for the use of utility customers. This action was necessitated by a concerted refusal of wholesale sellers to sell energy to the utilities or to the Independent System Operator, thereby endangering the supply of power for California. The legislation directed the Commission to implement emergency regulations governing the utilities' collection and remittance of customer payments for the energy purchased by

DWR. The Commission's decision implementing SB7X was issued on January 31, 2001. It allocated revenues collected by utilities to DWR in proportion to the energy delivered by DWR, and it ordered the utilities to establish accounting and billing procedures to pay DWR directly for the proportion of power DWR purchased and delivered to utility customers.

On February 1, 2001, the California Legislature enacted and the Governor signed Assembly Bill No. 1 from the First Extraordinary Session (Ch. 4, First Extraordinary Session 2001, hereafter referred to as AB1X). AB1X adds Division 27 to the Water Code, California Water Code sections 80000 et seq., which:

- Authorizes the California Department of Water Resources (CDWR) to purchase power and sell it to retail customers of PG&E, Edison, and SDG&E, as well as municipal utilities, Water Code section 80100.
- Establishes the Department of Water Resources Electric Power Fund in the State Treasury, into which are placed proceeds from power sales as well as bond proceeds and appropriations, Water Code section 80200.
- Authorizes CDWR to sell bonds to finance its power purchases, Water Code section 80130.
- Requires CDWR to establish a revenue requirement to defray the costs of its activities and to communicate that revenue requirement to the Commission, Water Code section 80134.
- Allows CDWR to recover its revenue requirement after it is communicated to the Commission, Water Code section 80110.

Pursuant to AB1X, the Commission is directed to designate a portion of the existing generation rates of PG&E, Edison, and SDG&E in effect as of January 5, 2001 as the California Procurement Adjustment (CPA). The statute anticipates that the utilities will collect the CPA revenues from retail customers and transfer some portion of those revenues to CDWR as the Fixed Department

of Water Resources Set-Aside.[3] In describing the calculation of the CPA, AB1X refers to the rates that are in effect as of January 5, 2001 as the beginning point for the calculation. In accordance with the Legislature's clear intent, we therefore make permanent the one-cent rate surcharge that the Commission authorized in D.01-01-018, which was included in the rates in effect as of January 5, 2001.

AB1X authorizes CDWR to establish revenue requirements sufficient to recover its costs and to communicate those requirements to the Commission. As AB1X requires the Commission to provide for recovery of DWR's revenue requirements, it necessarily authorizes the Commission to impose an increase in customers' electric bills, whether the increase is technically described as an increase in "rates" payable to utilities or an increase attributable to DWR's deliveries of electricity to customers.[4] AB1X somewhat limits our authority, by providing that residential customer rates cannot be increased for usage up to 130% of baseline quantities. Water Code section 80110.

III. Utility Requests for Rate Relief

SCE and PG&E continue to seek additional rate increases to improve cash flow and to pay for future costs of power for their customers. PG&E claims it needs to increase retail rates by an additional two cents-per kWh. PG&E claims that the one-cent interim rate increase granted in D. 01-01-018 has not improved its financial circumstances, that it is unable to access credit to keep current with its maturing debts, and that its bonds are now rated as junk bonds. PG&E has defaulted on some wholesale power payments and claims that it cannot pay additional power bills that are coming due. PG&E is also experiencing problems

[3] The methodology for setting the CPA is developed in a separate decision D.01-03-081.

[4] When the Commission refers to rate increases in this decision, we are not distinguishing between utility and CDWR entitlements, or inadvertently deciding any issues about how the revenue stream paid by end use customers will be divided between utilities and CDWR.

securing natural gas for its gas customers, and claims problems with trade creditors in the normal course of business.

SCE originally sought a 10% rate increase in this proceeding, which it subsequently modified to a 30 % rate increase as described above. SCE's remaining request, after the one-cent per kWh increase granted to it in D.01-01-018, totals a 20% rate increase, or two cents per kWh. SCE claims that failure to grant the remaining 20% increase will prevent the utility from meeting its past and present financial obligations.

Consumer groups argue that no additional rate increase is warranted at this time.[5] These parties generally argue that the utilities have not justified the need to burden customers with further increases given the various sources of funds and other remedies available to the utilities.

A. Independent Financial Assessments Confirm the Utilities' Current Financial Distress

In order to assess the utilities' claims concerning the extent and urgency of their financial problems, the Commission hired independent financial consultants as authorized in D.00-12-067. KPMG LLP (KPMG) conducted the review of SCE and Barrington-Wellesley Group, Inc. (BWG) conducted the review of PG&E. The consultants published their initial reports on January 29 and January 30, 2001, respectively.

[5] Parties presenting witnesses at hearing on this issue were Aglet, CLECA/CMTA, FEA, ORA, and TURN.

The reports covered the following general areas:

- Credit and Default Relationships
- Power Purchases and Cash Flows
- Cash Conservation Activities
- Accounting Mechanisms to Track Stranded Cost Recovery
- Inter-Company Cash Flows
- Affiliate Earnings in the California Energy Market
- Federal Income Tax Refunds

The reports confirm that the utilities are experiencing serious financial shortfalls in the revenues necessary to provide adequate electric service to their customers.

1. PG&E Report Findings

The BWG report concludes that PG&E has accurately described its borrowing capability, credit condition and potential events of default. BWG concludes that PG&E cannot obtain the credit it needs. BWG confirms that PG&E and its parent, PG&E Corp. have lost access to the commercial lending markets and are using their bank lines of credit to pay maturing commercial paper as it comes due.

The principal and interest payments due on PG&E's debt in 2001 total $3.2 billion. BWG reports that PG&E has exhausted its borrowing capability under existing lines of credit and is on the verge of defaulting many of its loan agreements. Under its short-term credit agreements, PG&E is required to make payments when due and will be in default if accounts payable arising in the ordinary course of business of $100 million or more become overdue. PG&E Corp.'s loan agreements contain default provisions that are similar to those of PG&E regarding the payment of debts when due.

Credit rating downgrades in January 2001 by Standard & Poor's and Moody's below minimum investment grade ratings for PG&E and PG&E Corp constitute an event of default under the PG&E Corp. bank lines of credit

agreements and under one of PG&E's bank line of credit agreements. Beginning January 16, 2001, the banks have refused to allow drawdowns under the PG&E and PG&E Corp. credit agreements, and PG&E and PG&E Corp are not paying maturing commercial paper obligations as they come due.

BWG also found that PG&E would likely have positive cash reserves at least through March 2001. BWG projected PG&E's daily cash balances for the period through March 30, 2001 using a range of market clearing prices. On March 15, the Commission reopened the record to update PG&E's financial balances. The update indicates that PG&E's cash balance increased significantly from $827 million on January 31, 2001 to $2.508 billion as of March 8, 2001.[6] During the same period, PG&E's outstanding obligations due and in default increased from $1.542 billion on January 31, 2001 to $3.324 billion on March 8, 2001. Notwithstanding the one-cent increase granted on January 4, 2001, PG&E has failed to use the revenues produced from that surcharge to pay for ongoing power purchase costs.

2. Edison Report Findings

KPMG reports that SCE has used all available lines of credit and has been unable to extend or renew credit as obligations become due. SCE's share of secured and unsecured debt due in 2001 is $242 million. Under SCE's loan agreements debt becomes immediately due and payable on default. Credit rating agencies downgraded SCE's credit ratings on most of its rated indebtedness to below investment grade during January 2001. SCE suspended payment of certain obligations, including payments for electric power, and has not declared dividends on its preferred stock that normally would have been declared in February and March 2001. Notwithstanding the one-cent increase on

[6] This balance reflects the full receipt of a $1.1 Billion tax refund that PG&E stated was due the utility on a stand-alone calculation of its taxes.

January 4, 2001, SCE has failed to use the revenues produced from that surcharge to pay for ongoing power purchase costs.

KPMG forecasted SCE's cash flow using a range of assumptions regarding power costs and payment timing. KPMG reported that under those assumptions, tested, SCE would improve its cash flow position and retain cash at least through March 31, 2001. More recent information indicates that SCE's cash balance improved slightly from $1.5 billion at the end of January 2001 to $1.6 billion by early March 2001. The amounts in default increased from $1.24 billion to $1.77 billion over the same period.

The Edison and PG&E Reports suggest that even with the emergency increase in rates and the actions of the DWR to purchase a substantial portion of the energy for their loads, the utilities' financial condition has not become stable. When the utilities begin to segregate revenues from existing rates applicable to DWR purchases and remit them to DWR pursuant to AB1X and our decision D.01-03-081 also issued today, pressure on utility finances will inevitably increase. We will order utilities to resume payments to QFs on a going-forward basis; this will ratchet up the pressure even more. We have come to the bitter moment when the record shows that additional ratepayer money must be provided to protect the taxpayers' commitments through the CDWR power purchases and to prevent utility financial meltdown.

B. Rates Must Be Increased, Subject to Certain Conditions

1. The Current Financial Emergency Requires Additional Rate Revenues

The Commission's first duty is to assure that customers of California utilities receive reliable, safe service at reasonable rates. The findings of BWG and KPMG generally confirm the utilities' claims of current financial distress. Both have defaulted on various financial commitments and find it increasingly difficult to secure any credit.

Some parties argue that the Commission should not assume that its first responsibility is to promote utility financial health. This is a legitimate observation, but the current circumstances and the action we take today do not implicate that issue. The emergency in the electric industry affects more than utility finances. The Commission must protect the state's energy system, which is essential to the state's economy and the welfare of its families and businesses. Moreover, the Commission takes expedited action to fulfill its implicit responsibility to ensure the viability of the State's General Fund pursuant to the power purchase authority granted CDWR in AB1X.

SCE's and PG&E's financial problems have compromised the integrity of the state's electrical system. The utilities are in debt to the ISO and to power sellers that will not or cannot sell additional power unless they are paid. The state's energy supply system is further compromised because some suppliers have also refused to sell PG&E natural gas that it needs to purchase for its natural gas customers. Blackouts across the state on March 19 and 20 were attributable in part to the refusal of energy suppliers, including qualifying facilities (QFs), to sell electricity to the ISO and the utilities. While the failure of some of these suppliers to provide available power to the grid may stem from their desire to maximize profits, others say they are on the verge of insolvency as a result of the

utilities' failure to pay. Whether or not the power sellers' actions are lawful, and whether or not we approve of those actions, without a rate increase it will become increasingly difficult to keep the lights on in California. However, we intend to continue to pursue remedies against power sellers charging unjust and unreasonable prices.

Although the state's wholesale markets continue to permit power sellers to receive extraordinary prices for the power they sell, the recent passage of AB1X, authorizing CDWR to purchase electric power and sell it to retail customers and local publicly owned electric utilities, has provided some financial relief to the utilities by reducing the volume of the power purchases they must make at unjust and unreasonable prices.

The utilities would rely on CDWR to purchase all of their net short electricity requirements.[7] Indeed, SCE suggests it requires no rate increase if CDWR were to purchase all of its net short power requirements. But AB1X continues the utilities' obligation to serve their customers. We cannot and will not relieve them of that fundamental statutory obligation. Further, although CDWR has assumed responsibility to purchase some of the utilities' power requirements, it has not committed to purchase all net short power requirements. For the Commission to assume here, for the purpose of setting rates, that CDWR will purchase all future net short electricity requirements would be the equivalent of ordering it to do so. Such an action would require authority the Commission does not possess. AB1X is permissive, not mandatory, with regard to CDWR's authority to purchase power for utility customers' use.

[7] "Net short" power requirements refers here to the amount of power the utilities must purchase to supply to their customers, in addition to that provided by their own generation, purchases pursuant to contracts with qualifying facilities, and purchases made pursuant to bilateral and other power purchase contracts.

Even if CDWR does purchase the entire net short, we disagree with Edison's claim that this would allow rates to remain unchanged. CDWR must be paid for the electricity it provides, and some of that power is likely to be expensive.

Rather than increasing rates, some parties propose other ways of easing the utilities' financial distress. For example, some parties advocate reducing QF prices, exploring the use of over-funded pension programs, requiring infusions of capital from the utilities' holding companies, or restructuring the way the utilities are reimbursed for nuclear power. While there may be many logical places to turn for additional cost savings or cash, our evaluation of resources necessary for continued power purchase cannot rely solely on uncertain or future possibilities. In the future we can refund revenues that exceed costs, but a bankruptcy or financial collapse of the state's energy system would cause wide-ranging, undesirable consequences.

2. This Rate Increase is Authorized Subject to Conditions

In this decision we order emergency rate relief to SCE and PG&E in order to assure the continued viability of California's electric power supply, to safeguard the viability of the State's General Fund, and to minimize credit-related supply disruptions.

We first affirm that AB1X makes permanent the one-cent rate increase granted on January 4, 2001. This amount is part of the existing rates that are allocated between CDWR and the utilities.

We also grant an increase of three cents per kWh to be collected by SCE and PG&E, subject to several conditions. Revenue generated by the rate increases will be applied only to electric power costs that are incurred after the effective date of this order. We will direct the utilities to enter the revenues from

the rate increases into balancing accounts and the revenues will be subject to refund if, at a later date, we determine that the utilities failed to use the funds to pay for future power purchases. We reiterate that the revenues the utilities have collected and continue to collect from the one-cent per kilowatt-hour rate increase authorized on January 4, 2001 must be used to pay for power purchases and not for any other costs incurred by the utilities. Upon receipt of and analysis and comment on DWR's revenue requirement, which has yet to be provided to this Commission, we will act promptly to further allocate a portion of these increases to CDWR.

As AB1X requires, the rate increase approved today will not apply to residential usage below 130% of baseline rates. In addition, we exempt CARE-eligible customers from these rate increases, as we discuss more fully below.

We impose one final condition on the utilities' authority to retain the revenues generated from this rate increase. This condition is based on the likelihood that refunds of overcharges can be obtained from generators and sellers if such refunds are aggressively sought.

The California Independent System Operator's (ISO) report of March 21, 2001 confirms many of the concerns this Commission has raised in its own proceedings and before FERC with regard to the impact on wholesale electricity market prices of generators' and power sellers' market behavior. Where these activities result in higher wholesale prices and compromise system reliability, the interests of the State's utilities, consumers and taxpayers are aligned.

We expect the utilities to join with the State and take any and all actions necessary to assure that California and its utility customers realize refunds for or repayment or disgorgement of power seller overcharges. The utilities possess market information and expertise that place them in a unique position to

understand market behavior and to pursue legal remedies. To date, however, the utilities appear to have been hesitant to take legal action against the generators and sellers who are responsible for, and have profited by, the utilities' financial distress.

We therefore make today's rate increase subject to refund in two circumstances. First, to the extent that generators and sellers make refunds for overcollections, those refunds should either be passed through ratepayers or applied to unrecovered power purchase costs, as we discuss more fully below. Second, to the extent that any administrative body or court denies refunds of overcollections in a proceeding where recovery has been hampered by a lack of cooperation from a utility, today's rate increases will also be subject to refund. The reason for this condition is simple: we cannot authorize a rate increase for the purpose of remedying the adverse consequences of the utilities' financial distress and at the same time ignore another significant source of revenue that would remedy such distress. If utilities do not actively seek to reduce the financial burden caused by the purchase of power at unjust and unreasonable prices, by pursuing refunds or recovery or disgorgement of excess profits from unlawfully obtained power prices, we will not continue to force California's consumers and businesses to shoulder that burden.

We affirm the assigned ALJ's instructions to PG&E and Edison to provide monthly reports (due on the 15th of each month) that detail their efforts to pursue FERC-related remedies and to pursue lawsuits against generators or marketers of electricity and natural gas. (TR: 34, January 10, 2001 PHC.) We direct PG&E and Edison to provide monthly reports on their efforts in state and federal forums, beginning April 1, 2001 and continuing for twelve months. A subsequent decision will analyze these reports, together with the question of specific requirements to enforce this condition.

3. AB 1890 Rate Controls Remain Effective

The actions we take today do not end the rate controls established by AB 1890. AB 1890 set up a mechanism under which utility-submitted cost recovery plans that included frozen rates would remain in effect until the Commission found that certain conditions existed or until March 31, 2002, whichever is earlier. We are not prepared to find here that the specific cost recovery requirements mandated by the statute have been met.

In addition, recent legislation enacted in January and February 2001 addresses electricity market conditions and utility financial distress that AB 1890 neither anticipated nor provided for. These new laws respond to the current emergency and provide enhanced authority for this Commission to set retail rates for electric power to provide for the recovery of revenues expended by CDWR for power purchases that it makes, despite the fact that the AB 1890 rate controls remain in effect.

Thus, while the rate control provisions of AB 1890 provide consumer protections that remain in effect, we must also respond to immediate circumstances and the potentially dire consequences of inaction. Nothing in AB 1890 provides that all limits on utility rates are ended if, for unforeseen reasons, and in response to further legislative direction, the Commission increases rates to prevent the collapse of the electric system. As we have stated consistently in our decisions, only two events end all the consequences of the rate freeze: (1) recovery of all specified transition costs,[8] or (2) March 31, 2002.

PG&E and Edison argue that the AB 1890 rate controls have ended because, they claim, their transition costs have been fully recovered under the accounting mechanisms of Resolution E-3527. They allege that all stranded costs

[8] Determination that recovery has occurred is contingent upon Commission approved valuation for these assets. (D.99-10-057, Ordering Paragraph 2.)

have been fully recovered, and therefore the law requires that the AB 1890 rate controls end on or before the date of our decision.

Both also cite policy reasons why the Commission should declare an end to AB 1890 rate controls. PG&E states that nothing is to be gained, and much is potentially lost, by prolonging the uncertainty over whether the AB 1890 controls have met their statutory triggers. Specifically, PG&E asserts that continuing AB 1890 rate controls exacerbates the concerns of lenders and creditors that their position may deteriorate if they do not take PG&E into bankruptcy. Edison states that there is a broad consensus among parties, citing to TURN and ORA, to end these rate controls and that no legal or policy reason exists to delay.

ORA states that the AB 1890 rate controls have ended on a prospective basis because AB1X and AB6X together make retail ratepayers responsible for the cost of any wholesale power procured by CDWR, whether a rate freeze is needed or not. Without this intervening legislation, ORA argues that the AB 1890 rate freeze could only be lifted if the Commission fails to adopt TURN's accounting proposal.

TURN states that AB1X renders the AB 1890 rate freeze largely irrelevant and, therefore, the Commission should declare the freeze over as of the date of the statute's enactment. TURN states that AB1X is premised on the notion that each utility's generation rate component will exceed the costs of its own generation resources, providing a component that will become the California Procurement Adjustment that flows to CDWR, rather than additional revenue made available to the utility for transition cost recovery. Further, AB1X provides for rate increases if the generation rate component is insufficient to meet CDWR's procurement costs, a provision that cannot be reconciled with a continuing rate

freeze. In the absence of AB1X, TURN states the rate freeze would not be over for either utility under any reasonable set of assumptions and appropriate accounting practices.

Parties that do not support a determination that the rate freeze has ended for either PG&E or Edison include Aglet, CIU, CLECA, CMTA, Farm Bureau, Los Angeles, and SMUD. All state that the conditions of AB 1890 have not been met. In addition, Farm Bureau cautions the Commission against arbitrarily ending the rate controls without the utilities accepting that costs incurred during the rate freeze cannot be recovered from customers. SMUD urges the Commission to adopt measures to mitigate the real and potential exercise of market power by PG&E and other generators prior to lifting the rate controls. CLECA states the Commission would be best served by awaiting further guidance from the administration and the Legislature before deciding whether the conditions of AB 1890 have been met.

FEA, while not taking a position on whether the conditions necessary for lifting the rate the rate freeze, states that the Commission needs to reaffirm clearly that, consistent with the intent and requirements of AB 1890 and prior decisions, any uncollected balances at the end of rate freeze cannot be collected from customers and must be written off by the utilities under Financial Accounting Standards Board (FASB) 71.

We find that under AB 1890 the rate freeze has not ended for either PG&E or Edison. As discussed in Section IV below, we will require SCE and PG&E to "true-up" their operating costs and profits for the period of the AB 1890 rate controls, as proposed by TURN. SCE and PG&E have not recovered all of their stranded costs under any scenario put forth by any party, given these accounting adjustments.

We recognize that, conceptually, the rate freeze mandated in AB 1890 may be incompatible with recent legislation. Further, we agree with CIU that to find existing AB 1890 statutes inconsistent with AB1X, and to take action based on that conclusion, would be to repeal by implication. These statutes can be harmonized by recognizing that the commonly referred to "AB 1890 rate freeze" is actually a term of art for a complex set of accounting and cost recovery standards that when met, could usher in a new method of ratemaking, largely left undefined by the provisions of AB 1890.

To end the rate control mechanisms imposed by AB 1890 would require us to address the disposition of the balances in the Transition Cost Balancing Account (TCBA). We intend to monitor the balances remaining in the TCBA and will consider how to address remaining balances as we continue with these proceedings. We recognize that the magnitude of remaining balances may not have been contemplated in the AB 1890 cost recovery schemes. We will consider other approaches. For example, as we stated early in this decision, to the extent that generators and sellers make refunds for overcharges, those refunds should either be passed on to ratepayers or applied to capital cost recovery. In addition, legislative and negotiated changes relating to enhanced stranded cost recovery are now underway and may significantly affect the ultimate treatment and disposition of these costs. In this period of legislative re-examination of the premises and operation of AB 1890's restructuring statutes, it would be premature and unwise to opine as to the ultimate disposition and treatment of these accounts. We direct the utilities to maintain the regulatory accounting mechanisms as detailed below, but we explicitly draw no conclusions as to the ultimate treatment flowing from legislative or regulatory changes that could well involve the amounts tracked in those accounts. Indeed, as with so many aspects of AB 1890, the extent of the actual consequences of the legislation may well have

been unintended and certainly unforeseen by those supporting the AB 1890 stranded cost recovery constraints at the time.

IV. Current Regulatory Accounting Mechanisms Overstate Power Purchase Liabilities Which Should Be Netted Against Power Sales Revenues

The "rate freeze" created by AB 1890 refers to a specific term of art. The AB 1890 rate freeze constitutes controls on rates to be filed with the Commission during a transition period from historic methods or rate regulation to a post-transition period. At its essence, the rate freeze allowed rates to remain higher than would have been justified in cost-based rates in order to allow the utilities the opportunity to recover costs associated with moving from cost-of-service regulation to a competitive regulatory scheme. The "AB 1890 rate freeze" is shorthand for a set of specific accounting and cost recovery triggers that could operate to induce market-based rates. The imposition of AB 1890's consumer protections, commonly called the rate freeze, ends when the utilities collect their remaining capital costs which were assumed at the time to be uneconomic or stranded. The utility reduces these generation asset capital costs after accounting for all other authorized costs (which can be analogized to operating costs, such as those associated with distribution, transmission and energy procurement).

A. Current Regulatory Accounting Mechanisms Fail to Match Operating Costs Against Operating Revenues

The Commission established two accounts to track costs and revenues: the Transition Cost Balancing Account (TCBA) and the Transition Revenue Account (TRA) established by D.97-10-057. Three sources of revenue originally flowed into and were tracked by the TCBA account:

1. "headroom," or the revenues remaining from customers' bill payments after a utility's authorized operating costs were paid;

2. revenue from sales of utility power plants to private owners, and
3. revenues from the sales of electric power provided by remaining utility-owned generation.

The TCBA tracks accelerated depreciation of all the undepreciated capital costs from the utilities' power plants. These amounts, along with costs of above-market QF contracts and other specific costs, were added together to produce the TCBA balance. When that balance dropped or was paid down to zero, that zeroing out triggers the lifting of the AB 1890 rate controls.[9] The TCBA balance is reduced when generation assets are sold for greater than net book value. The Commission also established generation memorandum accounts that track the costs and revenues of operating in the marketplace. Prior to D.01-01-018, revenues in excess of costs from these accounts were credited to the TCBA annually.

A second account, the TRA, tracks a utility's operating costs and revenues. The operation of this account permits calculation of headroom revenues remaining after operating costs are paid out of customer bill revenues. The purpose of the TRA is to match the amount of billed revenues against the amount of the separated revenue requirement and Commission-approved obligations. Separated revenue requirements include transmission, distribution, public purpose programs, and nuclear decommissioning. Commission-approved obligations include of Independent System Operator (ISO) charges and Power Exchange (PX) charges. For PG&E, Commission-approved obligations also include Diablo Canyon-related ICIP exclusions. The TRA assures that PG&E recovers all approved costs for distribution operations, nuclear decommissioning and public purpose programs. Edison's distribution revenues fluctuate according to sales. The TRA ensures Edison recovers nuclear decommissioning

[9] CPUC-authorized valuation is also required before the rate control trigger is lifted.

and public purpose costs.

The TRA and TCBA interact because headroom is calculated through the TRA and credited monthly to the TCBA. The Commission has recognized that there may be months where operating costs exceed revenues, because the costs of energy vary on an hourly basis.[10] The Commission allowed these unrecovered costs to be carried over in the TRA from month to month, and allowed revenues to be applied to these accumulated undercollections first before being transferred to the TCBA. When the AB 1890 rate controls expire, any undercollection in the TRA cannot be thereafter recovered. (D.99-10-057 and D.00-03-058.)

B. TURN's Petition to Modify the TRA and TCBA Accounting Mechanisms Accurately Reflects True Costs and Profits

The current accounting rules under Resolution E-3527 prohibit the transfer of TRA liabilities to the TCBA. TURN asserts that this rule is inconsistent with the intent of AB 1890.

TURN proposes that we modify the current accounting rules to require that each month the balance in each utility whether negative or positive, be transferred to the TCBA. The effective date of the proposed accounting changes would be January 1, 1998, when Resolution E-3527 took effect. The TURN proposal would require reconciliation or a "true-up" of utility operating costs and profits for the AB 1890 rate control period, otherwise known as the rate freeze.

[10] The energy charge used for the headroom calculation is an average rate.

TURN and several other parties[11] maintain that this simple change will properly capture the concept of "headroom" over the entire rate-control period. This true-up allows the Commission to accurately capture the "rate freeze compact"and assess the recovery of transition costs over the entire rate control period, as was intended by the Legislature.

TURN believes that this change will recognize the billions of dollars the utilities have realized both on their sales of capital assets and in revenues from selling electricity generated by their own plants.[12] This true-up is necessary to correct inequities in the current accounting rules which make it appear that the utilities have fully collected their stranded capital costs, while at the same time recording monthly liabilities of billions of dollars in operating costs.

TURN also asserts that its proposed accounting change will correct the erroneous treatment of revenues associated with the rate reduction bonds (RRBs) authorized by AB 1890. TURN observes that the Commission's current accounting treatment does not achieve the "indifference" outcome reflected in the Commission's decisions on Rate Reduction Bonds when TRA undercollections are accumulating. TURN contends that allowing the transfer of

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[11] The Office of Ratepayer Advocates (ORA), Aglet Consumer Alliance (Aglet), California Farm Bureau Federation (Farm Bureau), California Industrial Users ("CIU"), California Large Energy Consumers Association ("CLECA"), California Manufacturers & Technology Association ("CMTA"), City and County of San Francisco, Enron Energy Services, Inc. (Enron), Federal Executive Agencies ("FEA"), Greenlining Institute and Latino Issues Forum (Greenlining/LIF), Golden State Power Cooperative ("GSPC"), Los Angeles County, Sacramento Municipal Utility District unanimously urge the Commission to adopt TURN's proposed accounting changes.

[12] As LAC/ISD and ORA point out, the November 1, 2000 FERC order (Order Proposing Remedies for California Wholesale Electric Markets, FERC Order Docket No. EL00-95-000, November 1, 2000, p. 11), recognizes that "[t]he utilities have reported about $4.6 billion in unrecovered wholesale costs of which about $2 billion reflects sales of electricity sold from generation which they still own.

TRA undercollections merely reduces prior revenues recorded in the TCBA, thereby affecting only the amount of transition cost recovery achieved to date, not the amount of actual transition costs recorded in the TCBA.

In addition, TURN and the non-utility parties urge the Commission to true-up the accounting practices that track the costs and revenues from the utilities' fossil and hydroelectric generating plants in separate memorandum accounts until the end of the year. These parties point out that rising revenues reflected in these memo accounts are directly attributable to the same high-energy prices that have resulted to the growing TRA undecollections.

PG&E and Edison contend that this true-up is unlawful and would artificially extend the transition period. The utilities argue that such a true-up would force them to absorb the operating expenses incurred to provide service to their customers and would require the utilities to write off billions of dollars of transition costs. In essence, the utilities maintain that this (1) true-up would result in operating expenses being transformed into transition costs; (2) AB 1890 did not subject the utilities to the risk of non-recovery of FERC and CPUC-approved costs of providing service to their customers; (3) the accounting changes would be tantamount to retroactive ratemaking; and (4) the changes could deprive the utilities of a fair rate of return and result in confiscating rates. Edison states that the true-up would have a material impact on a case now pending before a federal court.

We disagree. We believe this true-up is critical in correcting an accounting anomaly.[13] As EPUC, CMTA, WPTF, CIU, Enron, and ORA point out, the utilities

[13] Later in this decision we order PG&E and Edison to restate their TCBA, TRA, and GMA account balances, on a monthly basis, in a manner consistent with this decision. Under the rules for current accounting mechanisms, the TCBA was overcollected in certain months in 1998. The AB 1890 rate controls obviously were not lifted then. The

are wrong in claiming that the filed rate doctrine would be violated if the relief they seek were not granted.

FERC was aware of the "AB 1890 rate freeze" concept when it approved California's restructuring plan. In fact, FERC authorized market-based rates based on utilities' claims that the California "rate freeze" would mitigate the utilities' incentive to raise PX prices.

PG&E and Edison understood that their ability to collect their transition costs was tied directly to their operating costs, including wholesale electricity costs.

By adopting this true-up, i.e., by requiring that either the debit or credit balance determined through the TRA calculation be recorded in the TCBA, we give full effect to the "rate freeze" principle, properly apply the matching principle, and adhere to the requirements of Public Utilities Code § 368(a).

It is inconsistent with the intent of AB 1890 to continue to allow the utilities to appear to incur substantial liabilities in their operating costs on the one hand, while they continue to recover substantial amounts for accelerated capital costs on the other. The utilities insist that shareholders have achieved full recovery of transition costs and are therefore not at any risk. At the same time, the utilities demand that ratepayers now be required to reimburse the utilities for energy procurement costs, even while recognizing that rates were "frozen" at an artificially high level to ensure that the utilities recover their prior transition costs. The true-up we adopt today corrects this inequity.

As stated in Resolution E-3527, Edison has previously proposed the approach we now take:

AB 1890 rate controls will not be lifted as a result of any restated balance with or unless other conditions for ending the rate freeze are met.

> Edison finds the ED's proposed approach inequitable because 'at the same time that the payments to the ISO and PX are increasing, potentially making the TRA balance negative, additional funds from the sales of Edison's generation output to the PX are being directly credited to the TCBA which will result in a direct benefit to the customers by immediately reducing transition costs recorded in the TCBA.' Edison argues that with an increase in the PX price, the ED's proposal results in the utilities bearing the risk of debit balances in the TRA while the benefits of the increased in the market price related to sale of their generation output to the PX are entirely reflected in the TCBA. (Resolution E-3527, mimeo at p. 5.)

Resolution E-3527 rejected Edison's arguments by stating that such treatment would be equivalent to treating the TRA debits as transition costs, which would be unlawful pursuant to § 367(a). The Resolution also declined to address the disposition of debits remaining in the TRA at the end of the transition period, as being beyond the scope of the Resolution.

In retrospect, Edison was correct in noting how E-3527 negated the matching principle. We believe the Resolution prematurely characterized the nature of TRA debit transfers. Applying the principles set forth in D.99-10-057 and upheld in D.00-03-058 requires that we take a closer look at the accounting anomalies caused by the treatment established by Resolution E-3527. We do not intend to further foster such inequities. As we have previously stated, the Commission has devised the TCBA and TRA accounting mechanisms and it is within our purview to change these mechanisms when inequities in accounting treatment become apparent.

Moreover, this true-up does not have the effect of treating TRA undercollections as an additional category of transition costs. Instead, it merely reduces prior revenues recorded in the TCBA, thereby affecting only the amount

of transition cost recovery achieved to date. It does not affect the amount of transition costs recorded in the TCBA.[14] Aglet also correctly points out that debits in the TCBA include many non-transition costs.[15]

In D.97-11-074, the Commission determined the costs and categories of costs for generation-related capital costs and obligations that had the potential of becoming uneconomic as a result of transitioning in to a competitive generation market. These Commission-authorized costs and obligations will not increase, except as they may have been modified by other Commission decisions. Instead, transferring the TRA balance to the TCBA on a monthly basis, whether that balance is an under- or overcollection, simply matches operating costs and revenues appropriately. The effect of this true-up is fully consistent with AB 1890 and several prior Commission decisions, including D.97-10-057, D.99-10-057, and D.00-03-058.

In other proceedings at this Commission and before FERC, PG&E and Edison have long recognized the risk that the variable energy costs may create. For example, in early 1997, PG&E and Edison asserted to FERC that market-based rates were appropriate because they had no incentive to exercise market power. The utilities recognized that any increase in revenues obtained as a seller of energy in the PX would be offset by a greater loss in headroom revenues.[16] In its order conditionally approving the ISO and PX, FERC adopted market-based wholesale rates and confirmed that the existence of the "AB 1890 rate freeze," the fixed transition cost recovery period, and the mandatory sale of energy by the

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[14] Florio, TURN, RT Vol. 15 at 2055 and 2056.

[15] McManus, PG&E, RT Vol. 10 at 1353; Fellows, Edison, RT Vol. 13 at 1773.

[16] Phase II Market Power Filing of Pacific Gas and Electric Company, Docket No. ER96-1663-000, March 31, 1997, pp. 8-9 and Southern California Edison Company's Proposed Market Power Mitigation Strategies, Docket ER 96-1663-001, March 31, 1997, p. 13.

utilities into the PX helped to mitigate market power concerns. (Order Conditionally Authorizing Limited Operation of an Independent System Operator and Power Exchange, Pacific Gas and Electric Company, et al., Docket No. EC96-19-001, et al; 81 FERC ¶ 61,546, October 30, 1997.)

It is true that adopting this accounting true-up will increase the remaining level of unrecovered capital costs relating to generation assets. This is appropriate: the level of recorded transition cost recovery at any given time should reflect the fact that the utilities must first pay off operating costs incurred in providing service during the rate freeze and then may apply any remaining revenues to capital or stranded cost recovery.

PG&E now contends that while AB 1890 exposed them to the risk of recovering its transition costs, it did not subject them to the risk of not recovering of FERC-approved costs. PG&E argues that adopting TURN's proposal would do exactly that and is therefore unlawful. Similarly, Edison contends that federal law requires states to pass through to retail customers federally tariffed charges and, to the extent that TURN's proposal denies Edison the ability to recover procurement costs, it would contravene against the filed rate doctrine.

As stated above, we reject the utilities' contention that allowing the transfer of the TRA undercollections will somehow transform energy procurement costs into transition costs. In adopting this accounting true-up, we merely reduce prior revenues recorded in the TCBA, thereby affecting only the amount of stranded cost recovery achieved to date. Under TURN's proposed accounting mechanism, the utilities will achieve full recovery of their PX costs and any other FERC-approved costs incurred during the rate control period.

To be clear, the true-up we adopt today does not disallow the utilities' recovery of the cost of procuring and transmitting electricity in retail rates. Since the true-up alone does not disallow FERC-approved costs, there can be no

violation of the filed rate doctrine in our adoption of the true-up accounting method.

PG&E and Edison assert that the true-up accounting method will deny them the ability to recover the TRA undercollections and that this would result in a "taking" under the California and United States Constitutions. Edison argues that nothing in AB 1890 changes the principle that a regulated company is entitled to a fair opportunity to recover its just and reasonable cost of operation. Both utilities claim constitutional right to retail rates that are not confiscatory.

PG&E maintains that any change of Commission's rules that would result in an indirect disallowance of PG&E's reasonable utility costs of service, whether the costs are operating costs or transition costs, is unlawful. According to Edison, TURN proposes that the TRA undercollection be transferred to the TCBA, where generation revenues are to offset them. Edison argues that TURN's proposal would deny Edison the ability to recover its procurement costs, and is therefore confiscatory.

These assertions are not persuasive. Under AB 1890, the utilities are at risk for the recovery of transition costs. Accordingly, the fact that this risk has now come to pass does not mean that there has been an unconstitutional taking. In short, the utilities' argument is premature. The AB 1890 rate controls are not over yet. Although the true-up accounting method will reduce prior transition cost recovery, no definitive landscape yet exists in which to ascertain the existence or extent of unrecovered costs.

Edison's argument about procurement costs adds nothing to PG&E's argument. Furthermore, in prior decisions we have consistently stressed that if we were to allow the utilities to recover procurement costs incurred during the rate-control period after rate controls end, the utilities' rates during the rate-control period would be made – retroactively – to exceed those in effect on

June 10, 1996. This action would result in a recovery exceeding transition costs, an outcome inconsistent with AB 1890.

PG&E contends that the proposed true-up is illegal retroactive ratemaking because it changes the "rules of the game" after the fact. However, PG&E construes this prohibition too broadly. Even if this accounting change were a change in the rules of the game, it would not constitute prohibited retroactive ratemaking. As the California Supreme Court explained in Southern California Edison Company v. Public Utilities Commission (1978) 20 Cal.3d 813 (Edison), not every order involving rates that has a retroactive effect is prohibited retroactive ratemaking.

In Edison, the Court concluded that an adjustment of rate that does not involve general ratemaking may have a retroactive effect without violating the rule against retroactive ratemaking. Here, as in Edison, the accounting change at issue does not involve general ratemaking. In Edison, while the accounting rules changed in a way that Edison argued was detrimental, the changed rules, together with the required refund, simply carried out the Commission's original intent to allow Edison to recover its increased fuel costs on a dollar-for-dollar basis. Similarly, here, the effect of this accounting change is to carry out the original intent of AB 1890, i.e., that the utilities be at risk for recovery of transition costs during the transition period.

There are additional related reasons why TURN's proposal does not constitute prohibited retroactive ratemaking. First, no rates are being changed here. Unlike the situation in Edison, where refunds were ordered, here the utilities' rates remain frozen at the same level both before and after implementation of TURN's proposal. Second, the prohibition on retroactive ratemaking is a general statutory prohibition imposed by § 728. (See Edison, 20 Cal.3d at 816.) The accounting changes we adopt here are required to carry out a

more specific and more recently enacted statute, AB 1890. Thus, even if there were a conflict between the retroactive ratemaking prohibition imposed by section 728 and the requirement of AB 1890 that the utilities be at risk for recovery of transition costs during the transition period, the more recently enacted and more specific requirements of AB 1890 would control.

The Commission established the TRA and TCBA based on our authority to implement the provisions of AB 1890. In retrospect, the accounting treatment we adopted in Resolution E-3527 contravenes the principles promulgated in AB 1890. We therefore find it necessary to modify our accounting approach in the manner proposed by TURN. The Commission has the authority to do so, and contrary to the utilities' claims that authority is not preempted by any law.

Edison asserts that when the Commission has cited the TURN proposal as a basis for dismissing the federal lawsuit, it is inappropriate for the Commission to grant TURN's request before the federal court has ruled. This argument is not persuasive under an estoppel theory or any other analysis.

Even if this argument were colorable, it would be defeated by the fact that Edison filed its federal lawsuit <u>after</u> TURN filed its accounting proposal with the Commission. We agree with the non-utility parties that accepting Edison' s contention and failing to act now on TURN's proposal would deny TURN its due process rights.

Moreover, the Commission's authority and responsibility to regulate utilities does not grind to a halt just because the utilities sue it. The Commission's authority to do its job continues, and our consideration of the proposed accounting true-up is a timely exercise of our ratemaking authority.

On a technical note, we agree with TURN's contention that current accounting treatment negates the neutrality of the rate reduction bond (RRB) transactions because the utilities' TRA accounts are undercollected. The

Financing Order,[17] which governed the 10% rate reduction and the issuance of the RRBs, adopted a ratemaking approach designed to render the RRB transactions neutral as to when rate controls end and to prevent cost-shifting among residential customers, small commercial customers and large customers.[18] Since the TRA undercollections began to accrue, there has been no transition recovery from rate revenues.[19] Absent the financed 10% rate reduction, the total amount of revenues collected from residential and small commercial customers would have been applied to offset the undercollections in the TRA.[20] But because of the adopted RRB transactions and the Commission's current accounting mechanism, the utilities continue to impute to the TCBA revenues related to the RRBs. Consequently, residential and small commercial customers continue to contribute to transition cost recovery by the amount of the imputed revenues, despite the lack of headroom. As a result, the utilities have recorded a greater amount of transition cost recovery than they would have had absent the RRB transaction and the residential and small commercial customers are paying a disproportionate share of the utilities' transition cost recovery,[21] an outcome that contradicts the objectives of the Financing Order. Adopting the proposed accounting true-up therefore has the additional advantage of ensuring that ratepayers are made indifferent as to how the revenues associated with the RRBs are treated.

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[17] D.97-09-056 for Edison, D.97-09-055 for PG&E.

[18] D.97-09-054, mimeo at 22.

[19] McManus, PG&E, RT Vol. 11 at 1465; Dominski, Edison, RT Vol. 14 at 1869.

[20] Id., at RT Vol. 11 at 1466; RT Vol. 14 at 1869.

[21] Ex. 72 (Florio Testimony), at 14.

We will also modify our approach to generation revenues tracked and recorded in the generation memorandum accounts. D.97-11-074 allowed the utilities to credit these accounts to the TCBA on an annual basis, in part to address Edison's concerns regarding the seasonal nature of its costs and revenues. TURN and other parties propose that the balance--whether overcollected or undercollected--in generation-related memorandum accounts be transferred to the TCBA monthly rather than annually. On the other hand, proposes that a portion of the retained generation revenues accruing in the TCBA accounts and generation memorandum accounts should be credited to the TRA undercollection. Enron agrees that to the extent we reject the accounting true-up, all generation revenue should first flow into the TRA to offset the utilities' operating costs on a monthly basis.

In D.01-01-018, we ordered the utilities to segregate the generation memorandum account balances, which otherwise would have been credited to the TCBA at year-end 2000. Because we are now transferring the balance in the TRA to the TCBA on a monthly basis, we will also now require the utilities to restate and record overcollected generation memorandum account balances to the TRA before any transfer to the TCBA. This should be done on a monthly basis. This is appropriate because it will match the costs of procuring power on a monthly basis with the revenues resulting from generating that power. We will consider any adjustments, including addressing monthly GMA undercollections, needed as we consider the interaction of AB6X, AB1X, and § 367(c) with regard to recording the monthly balance.

V. Care Discount

Greenlining/LIF presented testimony on specific changes to the California Alternative Rates for Energy (CARE) program for eligible low-income residential customers. Greenlining/LIF proposes to:

(1) Exempt CARE-eligible customers from the current surcharge and any increases that result from implementation of AB1X 1. Greenlining/LIF maintain that because low-income households often consist of multiple families living in sub-standard housing, electricity usage above the 130% baseline is often unavoidable;

(2) Increase the CARE discount from 15 to 25%, applicable to all Edison and PG&E customers, including PG&E's gas customers;

(3) Increase the CARE eligibility criteria from 150% to 175% of federal poverty guidelines. The effect of increasing eligibility would allow a family of three to earn up to $25,000 and still qualify for the discount. Adoption of an increase in eligibility criteria essentially acknowledges the reality of California's high cost of living;

(4) Rule favorably on Greenlining/LIF's motion for Clarification of D.01-01-018 regarding application of the EPS exemption.

TURN supports these proposals, stating that § 382 authorizes the Commission to ensure that the CARE program is funded at a level that will serve customers' needs. TURN provides evidence that customer need for such assistance may well be far higher than what is being provided today. CCSF also supports Commission consideration of financial assistance programs for low-income customers.

ORA and CMTA do not support further changes to the CARE discount during this phase of the proceeding because (1) CARE customers are already exempt from the 9% EPS increase applicable to residential customers; and (2) the Legislature is considering bills that increase the CARE discount. CMTA explains that CARE customers are already receiving an effective discount of 22.5% due to their exemption from the EPS and current CARE rates are 13% lower than they were in 1993. If additional discounts to CARE customers are adopted, CMTA fears that non-CARE customers will be forced to bear the increased cost burden.

PG&E supports increasing the CARE discount level to 25% for the electric portion of CARE customer bills if the Commission adopts PG&E's requested two

cent per kWh increase in customer electric rates. Absent the Commission's adoption of a two cent per kWh rate increase, PG&E supports continuation of the current discount and the exemption for CARE customers from the one-cent per kWh increase (EPS) adopted in D. 01-01-018.

PG&E states that it may be appropriate to revisit the income threshold for participation in the CARE program, as well as other issues raised by Greenlining/LIF in its testimony, in the ongoing low-income proceeding. There consistency can be assured between gas and electricity customers, and among the state's investor-owned utilities. Edison asserts that the Commission should either retain the current EPS exemption for CARE customers or increase the CARE discount, but not both.

Edison is opposed to raising the income-eligibility guidelines for the CARE program because under the proposed guidelines Edison states that this would place over one-fourth of its residential customers as eligible for CARE, placing substantial additional burdens on the remaining ratepayers to cover these costs due to the potential increase in spending to fund the program.

Greenlining/LIF explains that low-income ratepayers tend to be renters rather than owners, reside in older housing that is less energy efficient, and who may have larger families or live in multi-family households. As Greenlining/LIF explains, under current CARE guidelines a family of three living in San Francisco and earning $21,505 per year would not qualify for the energy discount. (Greenlining/LIF Brief, p.4.) Low-income households are struggling now to meet the cost of utility energy services, which includes both their electric and gas usage bills. Greenlining/LIF has demonstrated that the poor (as defined by federal poverty level guidelines) bear a disproportionate energy burden. For

example, according to a recent Rand Institute Study,[22] the percentage of household income devoted to energy services is far greater for low-income households.

The following table demonstrates current guidelines for the CARE program (at 150% of Federal Poverty Level) and the proposed new guidelines (at 175% of Federal Poverty Level):

Family/Household Size	**Current Guidelines (150% of Federal Poverty Level)**	**Proposed Guidelines (175% of Federal Poverty Level)**
1 – 2	$18,200	$21,233 (round to $21,250)
3	$21,500	$25,083 (round to $25,000)
4	$25,800	$30,100
Each additional person	$ 4,300	$5,016 (round to $5,000)

It is reasonable to adopt Greenlining/LIF's revised guidelines for eligibility in the CARE program to help relieve the energy burden of low-income households. We will increase the CARE eligibility levels from 150% of federal poverty guidelines to 175% for electric customers of PG&E and Edison. By adopting these new guidelines, we increase the number of households who may be eligible for this important program. As we expand the eligibility for this important program, it is crucial to make eligible people aware of the program. Therefore, consumer education and notice becomes imperative. We are impressed that Greenlining/LIF and Edison were able to negotiate a Memorandum of Understanding regarding customer notification. We direct PG&E and Edison to consult with Greenlining/LIF and our Public Advisor's Office so that notification by bill inserts or other agreed upon methods can occur

[22] Exhibit 66, Attachment A: *The Public Benefit of California's Investments in Energy Efficiency.*

expeditiously. We will consider other issues related to consumer education in our current low-income proceedings, A.00-11-009, et al.

We do not increase the CARE discount from 15% to 25% at this time. While we propose to adopt a significant rate increase, we will consider the issue of an increased discount for both electric and gas customers in current related proceedings, A.00-11-009, et al.

We adopt Greenlining/LIF's proposal to exempt eligible CARE customers from this rate increase. We will determine whether similar exemptions apply to any additional increases that result from implementation of AB1X. It is clear that AB1X continues the exemption of CARE customers from the EPS, based on the statute's references to rates in effect as of January 5, 2001, and we affirm that finding here.

VI. Residential Tiering and Rate Design Proposals

The issue of tiered residential rates was included in the January 26th ACR setting the scope of this phase of these proceedings. Parties initially presented detailed proposals on this issue. At the February 2nd PHC, TURN voiced its concern that if PG&E and Edison presented their originally served rate design testimony in Phase 1, this issue would be addressed at a level of detail which would be inappropriate and would extend hearings beyond the time available within the schedule.

Subsequent to this discussion, PG&E and Edison notified parties that they were withdrawing their rate-design testimony based on TURN's comments and an understanding that if the Commission adopts a rate increase in this phase, the Commission must use some rate design and revenue allocation principles to allocate the increase.[23] All parties who address rate design in this phase, except

[23] See February 2, 2001 PHC-2 RT 114 and February 6, 2001 letter from PG&E.

FEA, propose we use the equal cent/kWh approach that we adopted for the EPS in D.01-01-018.

While we adopt a rate increase today, we decline to adopt a specific residential tiering approach in the absence of an overall rate-design proposal and sufficient record evidence to so act. The assigned Commissioner's ACR, issued concurrently, sets forth a proposal for tiered rate design and ask for comments. Conceptually, we agree that it is time to adopt a tiered approach for those customer classes that do not have rates structured on a time-of-use (TOU) basis. Residential customers whose usage is below 130% of baseline are now statutorily exempt from rate increases that were not in effect as of January 5, 2001.

VII. Issuance of the Alternate Proposed Decision

Both the proposed decision and this proposed alternate decision were issued on March 26, 2001. Parties' appeared for final oral argument (FOA) before a quorum of the Commission on Monday, March 26, 2001. Pub. Util. Code § 311(e) requires that an alternate item to a proposed decision shall be subject to public review and comment before it may be voted upon. Rule 77.6(f) provides that the assigned Commissioner or ALJ may waive or reduce the comment period in any of the circumstances described in Rule 77.7(f)(1-9). In this case, Rule 77.7(f)(9) is applicable. For an alternate decision, the Commission may shorten the public review and comment period where it determines that public necessity so requires.

In this matter, the public interest in the Commission adopting a decision before expiration of the 30-day review and comment period outweighs the public interest in having the full comment period. We will hold oral argument on March 26th in lieu of providing for written comments on the alternate decision. In addition, we will allow for comment on the rate design discussed herein.

Findings of Fact

1. Edison and PG&E seek additional rate increases to improve cash flow and pay fo future costs of power for their customers. We consider these requests in the context of current state law and the state's dysfunctional wholesale markets that have led to unconscionable, unlawful wholesale prices and an increasingly unstable supply situation.

2. The current industry structure evolves from AB 1890 passed in 1996 to promote competition in California's electric market by opening generation markets.

3. AB 1890 turned over operation of the state's transmission system to the Independent System Operator (ISO) and the pricing of unregulated generation to the Power Exchange (PX), both private nongovernmental corporations regulated by the Federal Energy Regulatory Commission (FERC), not the State of California.

4. AB 1890 required the utilities to file with this Commission rate plans that set electric utility rates at June 10, 1996 levels, except that bills for residential and small commercial customers were discounted by 10% from those levels, through the issuance of Rate Reduction Bonds approved by the Commission.

5. The frozen rate levels were initially high enough to allow PG&E, SCE, and SDG&E an opportunity to recover uneconomic generation costs within a specified period.

6. The original expectations of California decision-makers that competitive markets would reduce generation prices have not been fulfilled. Rather than dropping in response to competitive market forces, wholesale electricity prices in California have risen by staggering proportions since the beginning of 2000.

7. The uncontrolled price increases in wholesale markets have created enormous outstanding liabilities for PG&E and SCE.

8. SCE's and PG&E's continued financial viability and ability to serve their customers has been seriously compromised by the dramatic escalation in wholesale prices since November 1.

9. On February 1, 2001, the California Legislature enacted and the Governor signed AB1X, which authorizes DWR to purchase power and sell it to retail customers of PG&E, Edison and SDG&E.

10. AB1X directs the Commission to designate a portion of existing generation rates as the CPA.

11. In describing the calculation of the CPA, AB1X refers to the rates that are in effect as of January 5, 2001 as the beginning point for the calculation. In accordance with the Legislature's clear intent, we therefore make permanent the one-cent rate surcharge that the Commission authorized in D.01-01-018, which was included in the rates in effect as of January 5, 2001.

12. The Barrington-Wellesley Group, Inc. (BWG) conducted an independent review of PG&E, and KPMG LLP (KPMG) conducted an independent review of Edison focusing on their cash liquidity, credit capacity, and solvency.

13. The BWG and KPMG report findings regarding the utilities' cash flow difficulties and inability to obtain additional credit, generally confirm that the financial problems facing the utilities are serious in nature, and could potentially lead to bankruptcy proceedings for the utilities.

14. PG&E's debt principal and interest payments due in 2001 total $3.2 billion. BWG reports that PG&E has exhausted its borrowing capability under existing lines of credit and is one the verge of default under the provisions of many of its loan agreements.

15. Credit ratings downgrades in January 2001 by Standard & Poor's and Moody's below minimum investment grade ratings for PG&E and PG&E Corp constitute an event of default under the PG&E Corp. bank lines of credit agreements and under one of PG&E's bank line of credit agreements.

16. BWG's update indicates that PG&E's cash balance increased significantly from $827 million on January 31, 2001 to$2.508 billion as of March 8, 2001. During the same period, its outstanding obligations due and in default increased from $1.542 billion on January 31, 2001 to $3.324 billion on March 8, 2001.

17. KPMG reports that SCE has exercised all available lines of credit and has been unable to extend or renew credit as obligations become due. SCE's share of secured and unsecured debt that is due in 2001 is $242 million. SCE's loan agreements provide for specific clauses with respect to default whereby the underlying debt becomes immediately due and payable. Credit rating agencies downgraded SCE's credit ratings on most of its rated indebtedness to below investment grade during January 2001.

18. Since the KPMG Report was released, several creditors have formed an informal credit committee that threatens to force SCE into involuntary bankruptcy. To help alleviate liquidity concerns, SCE suspended payment of certain obligations, including payments for electric power, and has not declared dividends on its preferred stock that normally would have been paid in February and March 2001.

19. KPMG's update indicates that SCE's cash balance improved slightly from $1.5 billion at the end of January 2001 to $1.6 billion as of March 8, 2001. The amounts in default increased from $1.24 billion to $1.77 billion over the same period.

20. Even with the emergency increase in rates and the actions of DWR to procure a substantial portion of energy for their loads, the utilities' financial condition remains unstable.

21. Pressure on utility finances will increase when the utilities' begin to segregate revenues applicable to DWR purchases from existing rates and remit these revenues directly to DWR, as required by AB1X and our decisions.

22. Requiring the utilities to resume payments to QFs on a going forward basis will also increase pressure on utility finances.

23. Additional ratepayer money must be provided to protect the taxpayers' commitments through DWR purchases and to prevent utility financial collapse.

24. SCE and PG&E's financial problems have compromised the integrity of the state's electrical system. The utilities are increasingly in debt to the ISO and to power sellers that will not or cannot sell additional power into California's grid.

25. The state's energy supply system is further compromised because some suppliers have also refused to sell natural gas to PG&E, which it needs to purchase on behalf of its natural gas customers.

26. Blackouts across the state on March 19 and 20 were attributable in part to the refusal of energy suppliers, including QFs, to sell electricity to the ISO and the utilities because of concerns that they might not be paid.

27. Although the state's wholesale markets continue to permit power sellers to receive extraordinary prices for the power they sell, the recent passage of AB1X has provided some financial relief to the utilities by reducing the volume of the power purchases they must make at unjust and unreasonable prices.

28. Although CDWR has assumed responsibility to purchase significant portions of the utilities' requirement, it has not stated a commitment to purchase all net short power requirements.

29. CDWR must be paid for the electricity it provides, some of which is likely to be expensive.

30. While there may be many logical places to turn for additional cost savings or cash, our evaluation of resources necessary for continued power purchase cannot rely solely on uncertain future possibilities.

31. In the future we can refund revenues that exceed costs, but a bankruptcy or financial collapse of the state's energy system would cause wide-ranging, undesirable consequences.

32. Revenue generated by the rate increases will be applied only to electric power costs that are incurred after the effective date of this order. The revenues will be subject to refund if, at a later date, we determine that the utilities failed to use the funds to pay for future power purchases.

33. The revenues the utilities have collected and continue to collect from the one-cent per kilowatt-hour rate increase authorized on January 4, 2001 must be used to pay for power purchases and not for any other costs incurred by the utilities.

34. Upon receipt of and comment on DWR's revenue requirement, which has yet to be provided to this Commission, we will act promptly to further allocate a portion of these increases to CDWR.

35. As AB1X requires, the rate increase approved today will not apply to residential usage below 130% of baseline rates.

36. We expect the utilities to join with the State and take any and all actions necessary to assure that California and its utility customers realize refunds for or repayment or disgorgement of power seller overcharges.

37. The utilities possess market information and expertise that place them in a unique position to understand market behavior and to pursue legal remedies.

38. To date, the utilities appear to have been hesitant to take legal action against the generators and sellers who are responsible for, and have profited by, the utilities' financial distress.

39. To the extent that generators and sellers make refunds for overcollections, those refunds should either be passed through ratepayers or applied to unrecovered power purchase costs.

40. To the extent that any administrative body or court denies refunds of overcollections in a proceeding where recovery has been hampered by a lack of cooperation from a utility, today's rate increases will also be subject to refund.

41. The action we take today does not end the AB 1890 rate controls.

42. AB 1890 set up a mechanism under which utility-submitted cost recovery plans that included frozen rates would remain in effect until the Commission found that certain conditions existed or until March 31, 2002, whichever is earlier.

43. We will require SCE and PG&E to "true-up" their operating costs and profits for the period of the AB 1890 rate controls, as proposed by TURN. SCE and PG&E have not recovered all of their stranded costs under any scenario put forth by any party, given the accounting adjustment we are requiring.

44. The Commission established the TCBA to track the accelerated cost recovery of generation assets and other authorized transition cost, and also established the TRA to track the residual calculation of the CTC and to ensure that headroom is properly calculated and credited to the TCBA.

45. Three sources of revenue originally flowed into and were tracked by the TCBA account: "headroom," or the revenues remaining from customers' bill payments after a utility's authorized operating costs were paid; revenue from sales of utility power plants to private owners, and revenues from the sales of electric power provided by remaining utility-owned generation.

46. In Resolution E-3527, the Commission allowed unrecovered operating costs to be carried over in the TRA from month to month, and allowed revenues to be applied to these accumulated undercollections first before being transferred to the TCBA. Our current rules provide that to the extent that after the rate freeze ends (i.e., transition costs are fully collected and final market valuation is established by the Commission), any undercollection in the TRA cannot be recovered.

47. In A.00-10-028, TURN recognizes the interaction of the TRA and the TCBA and focuses on Resolution E-3527, which prohibits the transfer of any TRA undercollection to the TCBA on a monthly basis. TURN proposes that this ratemaking be revised to allow such a transfer.

48. At its essence, the AB 1890 rate control allowed rates to remain higher than they would have been in order to allow the utilities the opportunity to recover costs associated with moving from cost-of-service regulation to a competitive regulatory scheme.

49. The utilities' assertions regarding potential violations of the filed rate doctrine are premature. FERC was aware of the rate freeze concept when it approved California's restructuring plan, FERC, in fact, authorized market-based rates based on utilities' claims that the California "rate freeze" would mitigate the utilities' incentive to raise PX prices.

50. PG&E and Edison understood that the ability to fully collect their transition costs was tied directly to their operating costs, including wholesale electricity costs.

51. Adopting the accounting true-up that TURN proposes in A.00-10-028 corrects an anomaly that was adopted in Resolution E-3527. By requiring that either the debit or credit balance determined through the TRA calculation be recorded in the TCBA, we give full effect to the rate freeze principle, properly

apply the matching principle, and adhere to the requirements of § 368(a). This approach also properly offsets generation revenues and costs of procurement.

52. Resolution E-3527 incorrectly characterized the nature of transfers of debits in the TRA to the TCBA. Applying the principles set forth in D.99-10-057 and upheld in D.00-03-058 requires that we take a closer look at the accounting anomalies caused by the treatment provided for in Resolution E-3527, as TURN requests.

53. The transfer of TRA undercollections to the TCBA does not transform energy procurement costs into transition costs, but merely reduces the prior revenues recorded in the TCBA.

54. Adopting the accounting treatment proposed in A.00-10-028 will properly recognize the risks that variable energy costs may create.

55. Transferring the TRA balance to the TCBA each month allows us to consider the net impacts of operating cost recovery and transition cost recovery. This adjustment will delay transition cost recovery. The restated TCBA for Edison will show unrecovered costs of approximately $3.7 billion. The restated TCBA for PG&E would show approximately $6.3 billion in unrecovered costs.

56. Under TURN's proposed accounting mechanism, the utilities would achieve full recovery of their PX costs and any other FERC-approved costs incurred during the rate freeze.

57. We have consistently stressed that if we were to allow the utilities to recover procurement costs incurred during the rate control period after rate controls end, the utilities' rates during the rate freeze period would have effectively exceeded those in effect on June 10, 1996. This action would result in recovery of excess transition costs, an outcome inconsistent with AB 1890.

58. Although TURN has proposed an accounting change, the effect of this change is to carry out the original intent of AB 1890, that the utilities are at risk for recovery of transition costs during the transition period.

59. The Commission established the TRA and TCBA based on our authority as an administrative agency to implement the provisions of AB 1890.

60. Our consideration of the proposed accounting true-up is a timely exercise of our ratemaking authority.

61. We accept TURN's contention that current accounting treatment negates the neutrality of the rate reduction bond (RRB) transactions since the utilities' TRAs are undercollected.

62. Since the TRA undercollections began to accrue, there has been no transition recovery from rate revenues.

63. Because of the adopted RRB transactions and the Commission's current accounting mechanism, the utilities continue to impute into the TCBA revenues related to the RRBs. Consequently, residential and small commercial customers continue to contribute to transition cost recovery by the amount of the imputed revenues, despite the lack of headroom.

64. The utilities have recorded a greater amount of transition cost recovery than they would have had absent the RRB transaction and the residential and small commercial customers are paying a disproportionate share of the utilities' transition cost recovery, an outcome that contradicts the objectives of the Financing Order.

65. Adopting the proposed accounting true-up therefore has the additional advantage of ensuring that ratepayers are made indifferent as to how the revenues associated with the RRBs are treated.

66. In D.01-01-018, we ordered the utilities to segregate the generation memorandum account balances, which otherwise would have been credited to the TCBA at year-end 2000.

67. Because we are now transferring the balance in the TRA to the TCBA on a monthly basis, we will also now require the utilities to restate and record overcollected generation memorandum account balances to the TRA before any transfer to the TCBA. This should be done on a monthly basis. This is appropriate because it will match the costs of procuring power on a monthly basis with the revenues resulting from generating that power.

68. We will consider any adjustments needed, including addressing GMA monthly undercollections, as we consider the interaction of AB 6, AB 1X, and § 367(c) on appropriately recording the monthly balance.

69. Low-income ratepayers tend to be renters rather than owners, reside in older housing stock that is less energy efficient, and who may have larger families or live in multi-family households.

70. Low-income households are struggling now to meet the cost of utility energy services, which includes both their electric and gas usage bills.

71. Greenlining/LIF has demonstrated that the poor (as defined by Federal Poverty Level Guidelines) bear a disproportionate energy burden; i.e., the percentage of household income devoted to energy services is far greater for low-income households.

72. We will increase the CARE eligibility levels from 150% of federal poverty guidelines to 175% for electric customers of PG&E and Edison.

73. By adopting these new guidelines, we increase the number of households who may be eligible for this important program. As we expand the eligibility for this important program, it is crucial to increase penetration.

74. Consumer education and notice becomes imperative in order to notify eligible customers.

75. We do not increase the CARE discount from 15% to 25% at this time. While we propose to adopt a very significant rate increase, we wish to consider the increased discount for both electric and gas customers in A.00-11-009 et al.

76. We adopt Greenlining/LIF's proposal to exempt eligible CARE customers from this rate increase.

77. While we adopt a rate increase today, we decline to adopt a specific residential tiering approach in the absence of an overall rate design proposal. The assigned Commissioner's companion ACR issued concurrently sets forth a proposal for tiered rate design for review.

78. Conceptually, we agree it is time to adopt a tiered approach for those customer classes that do not have rates structured on a time-of-use (TOU) basis.

Conclusions of Law

1. AB1X refers to rates that are in effect as of January 5, 2001. We therefore make permanent the rate increase the Commission authorized in D.01-01-018.

2. The Commission's first duty is to assure that customers of California public utilities receive reliable, safe service at reasonable rates.

3. The emergency in the electric industry affects more than the utility finances. The Commission must protect the state's energy system, which is essential to the continued health of the state's economy and the welfare of individuals and businesses.

4. AB1X expressly continues the utilities' of their obligation to serve their customers. We cannot and will not relieve them of that fundamental obligation.

5. The Commission cannot assume that CDWR will purchase all net short electricity requirements for the purpose of setting rates; this action would be the equivalent of ordering CDWR to procure all net short electricity requirements. We do not have such authority.

6. We are not prepared in this decision to find that the requirements of AB 1890 for ending the rate control period have been met.

7. This rate increase is within our authority in light of existing financial conditions, and in response to more recent legislation, such as AB1X and AB6X.

8. Since AB1X requires the Commission to provide for recovery of DWR's revenue requirement, it necessarily authorizes the Commission to impose an increase on customers' electric bills, whether that increase is described as an increase in "rates" payable to utilities or an increase attributable to DWR's delivery of electricity.

9. The legislation enacted in January and February 2001 addresses electricity market conditions and utility financial distress that AB 1890 neither anticipated nor provided for. These new laws respond to the current emergency and provide enhanced authority for this Commission to set retail rates for electric power to provide for the recovery of revenues expended by CDWR for power purchases that it makes, despite the fact that the AB 1890 rate controls remain in effect.

10. While the rate control provisions of AB 1890 provide certain consumer protections that we continue to recognize, we must supplement these consumer protections with our response to immediate circumstances and the potentially dire consequences of inaction. Nothing in AB 1890 provides that if, for unforeseen reasons, in response to additional legislation, the Commission increased rates to prevent the collapse of the electric system, all limits on utility rates are ended.

11. It is reasonable to order emergency relief to both utilities in order to assure the continued viability of California's electric system and to minimize the effects of the dysfunctional energy market on utility customers, both today and in the longer term.

12. It is reasonable to grant a rate surcharge of not more than three cents per kWh to SCE and to PG&E with several conditions.

13. It is reasonable that revenue generated by the rate increases will apply only to power costs that are incurred after the effective date of this order.

14. It is reasonable to direct the utilities to enter the revenues from the rate increases into balancing accounts and the revenues will be subject to refund if at a later date we determine that the utilities failed to use the funds to pay for future power purchases.

15. It is reasonable that a certain amount of the revenues from the rate increases will be provided to DWR for its power costs, once DWR provides us with its revenue requirement.

16. Residential customers whose usage is below 130% of baseline are now statutorily exempt from rate increases not in effect as of January 5, 2001. CARE customers should be exempt from the additional surcharge we impose today.

17. To the extent that generators and sellers make refunds for overcharges, it is reasonable to require that those refunds should either be passed onto ratepayers or potentially could be applied to stranded costs.

18. To the extent that any administrative body or court denies refunds of overcollections in a proceeding where the Commission has been hampered by the lack of cooperation from utilities, it is reasonable to make the proposed rate increases subject to refund.

19. It would not be reasonable to authorize a rate increase for the purpose of remedying the adverse consequences or utilities financial distress and at the

same time ignore another potential source of funding that would remedy such distress; therefore, if utilities do not actively seek to relieve themselves of their financial burden by pursuing refunds we will not step in and relieve their burden with a price increase.

20. Consistent with the requirements of AB 1890, the level of recorded transition cost recovery at any given time should reflect the total revenues collected to date during the rate freeze, as well as the total costs incurred to date in providing service during the rate freeze.

21. Adopting TURN's true-up proposal does not constitute retroactive ratemaking. Rates obviously have not changed. The TCBA is a balancing account and the TRA is simply an accounting mechanism used to determine the residual calculation of CTC.

22. The California Supreme Court in Southern California Edison Company v. Public Utilities Commission (1978) 20 Cal.3d 813 concluded that an adjustment of rates, which does not involve general ratemaking, may be retroactive in effect without violating the rule against retroactive ratemaking.

23. Because TURN's proposed accounting change at issue does not involve general ratemaking, the Commission may adopt the change without violating the prohibition against retroactive ratemaking.

24. In retrospect, the accounting treatment we adopted in Resolution E-3527 contravenes the principles promulgated in AB 1890. Given the change in circumstances, we find it necessary to modify our accounting approach, as proposed by TURN. The Commission has the authority to do so and is not preempted by any law, contrary to the claims proffered by the utilities.

25. We direct the utilities to maintain the regulatory accounting mechanisms, but we explicitly draw no conclusions as to the ultimate treatment flowing from legislative or regulatory changes that could well involve the amounts tracked in those accounts.

26. The true-up we adopt today, in and of itself, does not disallow the recovery of the utilities' cost of procuring and transmitting electricity in retail rates. Since the true-up alone does not disallow FERC-approved costs, there can be no violation of the filed rate doctrine in our adoption of the true-up at this time.

27. Under AB 1890 the utilities are at risk for the recovery of transition costs. Accordingly, we do not believe that the fact that some portion of this risk has now come to pass necessarily means that there has been an unconstitutional taking. The utilities' argument is premature. We do not find that the AB 1890 rate controls are over yet. Therefore, while adopting the accounting true-up proposal reduces prior transition cost recovery, no definitive landscape exists yet in which to ascertain the existence or extent of unrecovered costs.

28. It is reasonable to increase the CARE eligibility levels from 150% of federal poverty guidelines to 175% for electric customers of PG&E and Edison.

29. CARE changes for gas customers of PG&E, SDG&E, and Southern California Gas Company, as well as an increase in the CARE discount should be addressed expeditiously in A.00-11-009 et al.

30. It is clear that AB1X 1 continues the exemption of CARE customers from the EPS, based on the statute's references to rates in effect as of January 5, 2001, and we affirm that finding here.

31. For an alternate decision, the Commission may reduce the public review and comment period where it determines that public necessity so requires. Pursuant to Rule 77.7(f)(9), the public interest in the Commission adopting a

decision before expiration of the 30-day review and comment period outweighs the public interest in having the full comment period. It is reasonable to hold oral argument on March 26th in lieu of providing for written comments on the alternate decision. In addition, we will allow for comment on the rate increase.

32. This order should be effective today in order to allow the rate surcharge and accounting true-ups to go into effect expeditiously.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas & Electric Company's (PG&E) and Southern California Edison Company's (Edison) request for rate relief is granted to the extent set forth herein. The rate surcharge of three-cents per kilowatt-hour (kWh) shall be applied to power costs incurred after the effective date of this decision. The three-cents per kWh shall be added to generation-related rates for PG&E and Edison that are adopted in Ordering Paragraph 1 of our companion decision in this docket only for the purpose of all calculations required by that decision dealing with the transfer of funds to CDWR. (D.01-03-081.) PG&E and Edison shall provide revenues from the generation-related rates and the three-cent surcharge to the DWR immediately, consistent with D.01-03-081.

2. PG&E and Edison shall enter the revenues from the rate increases into balancing accounts and the revenues shall be subject to refund if, at a later date, we determine that the utilities failed to use the funds to pay for future power purchases. The revenues the utilities have collected and continue to collect from the one-cent per kilowatt-hour rate increase authorized on January 4, 2001 shall be used to pay for power purchases and not for any other costs incurred by the utilities. Within five days after the effective date of this decision, PG&E and

Edison shall file advice letters to establish these balancing accounts, which will be effective upon approval by the Energy Division.

3. PG&E and Edison shall join with the State and take any and all actions necessary to assure that California and its utility customers realize refunds for or repayment or disgorgement of power seller overcharges.

4. To the extent that generators and sellers make refunds for overcollections, those refunds shall either be passed through ratepayers or applied to unrecovered power purchase costs. To the extent that any administrative body or court denies refunds of overcollections in a proceeding where recovery has been hampered by a lack of cooperation from a utility, today's rate increases shall also be subject to refund.

5. PG&E and Edison shall continue to provide monthly reports on their efforts in state and federal forums, beginning April 1, 2001 and continuing for twelve months.

6. The one-cent rate surcharge that the Commission authorized in Decision 01-01-018 is now permanent.

7. The Petition to Modify Resolution E-3527, filed by The Utility Reform Network (TURN), and docketed as Application (A.) 00-10-028 is granted. The balance in PG&E's and Edison's respective Transition Revenue Account (TRA) shall be transferred on a monthly basis to each utility's respective Transition Cost Balancing Account (TCBA). This action shall be effective as of January 1, 1998.

8. PG&E and Edison shall file advice letters within 15 days of the effective date of this decision to revise their tariffs as necessary. PG&E and Edison shall attach reports that restate the TRA, TCBA, and Generation Memorandum Accounts in compliance with this decision. The advice letters shall be deemed in compliance with this decision only upon the written approval of Energy Division.

9. Under Assembly Bill 1890, the rate freeze has not ended for either PG&E or Edison.

10. The California Alternative Rates for Energy (CARE) eligibility guidelines shall be updated according to the following table:

Family/Household Size	**Current Guidelines (150% of Federal Poverty Level)**	**Adopted Guidelines (175% of Federal Poverty Level)**
1 – 2	$18,200	$21,233 (round to $21,250)
3	$21,500	$25,083 (round to $25,000)
4	$25,800	$30,100
Each additional person	$ 4,300	$5,016 (round to $5,000)

11. PG&E and Edison shall consult with Greenlining Institute, Latino Issues Forum, /LIF and our Public Advisor's Office so that notification by bill inserts of the revised CARE guidelines shall occur expeditiously.

12. Eligible CARE customers are exempt from the surcharge we impose today.

13. Eligible CARE customers shall continue to be exempt from the Emergency Procurement Surcharge adopted in Decision 01-01-018, based on the Assembly Bill 1X references to rates in effect as of January 5, 2001.

This order is effective today.

Dated March 27, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
RICHARD A. BILAS
CARL W. WOOD
GEOFFREY F. BROWN
Commissioners

I will file a concurring opinion.

/s/ RICHARD A. BILAS
Commissioner

Appendix A

APPENDIX A

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(END OF APPENDIX A)

A.00-11-038 et al.
D.01-03-082

Commissioner Bilas, concurring:

I have been advocating an increase in rates and asking whether the rate freeze has already ended since last fall. Now that the General Fund finds itself in the same position as the utilities, economic reality has finally sunk in. We are finally transfusing some blood into the utility turnips since the Department of Water Resources (DWR) now shares their turnip patch.

We have no choice but to act to raise rates. The PX is in Chapter 11 because it cannot collect its costs and pay its debts. The ISO is not getting paid and is spending money to cover the net short like a drunken sailor. It will be spending much more this summer when we run short of hydroelectric power due to drought conditions. The proper economic signals to conserve are not being sent so some citizens simply are not conserving. We have had two days of statewide rolling blackouts coinciding with warm spring, not hot summer, weather. Energy Secretary Abraham has forecast a 5000 megawatt shortage in California this summer.

Natural gas prices have quadrupled. Natural gas is the predominate fuel for California generation. Under regulation, with the attendant ECACs, these costs would have already been passed through to ratepayers. Deregulation eliminated that adjustment. So those who call for reregulation would still get fuel related rate increases. New York last year raised rates 30 percent and its power authority is arranging for expensive peakers this summer. Maine raised rates even more. This year Bonneville Power expects to raise its rates up to 60 percent. This is not just a California phenomenon.

The utilities' lenders are not getting paid and are tired of forebearing on all of the utilities' events of default. We have told the utilities that they cannot conserve cash by laying anyone off. The QFs are shutting down because they are not getting paid, and the gas fired ones cannot afford the natural gas to run. QFs are circulating an involuntary bankruptcy petition. Just today we have ordered the utilities to pay the QFs on a going forward basis under our new Malin based formula. We have also just voted out an order requiring the utilities to pay the DWR a proportionate share of utility revenue to staunch the flow of taxpayer General Fund blood. Additionally, we have today obligated the utilities to implement SB 970 energy efficiency programs and transmission upgrades and to find the cash to do them. I voted against the SB 970 order because it did not include a surcharge to cover utility costs and to ensure these programs are implemented by this summer.

DWR is not even buying the full net short position of the utilities, but the General Fund is being depleted at an alarming rate. Our State Controller has stated it must stop. Both

Democrat and Republican Legislators are now calling for rate increases. So is the State Treasurer. This is no longer a partisan fight. Instead it is a fight to maintain the economic vitality of the State and its citizens. As Assemblymember Wright declared at today's Commission meeting, the transactional losses from rolling blackouts far exceed the utilities' power bills. Those transactional losses affect jobs and therefore paychecks. We can craft rate designs that spare residential ratepayers the pain of drastic increases. But, if workers have no paychecks because their employers cannot operate or have left the state, they will not be able to pay any bills. Absent today's rate increase, the utilities will be in bankruptcy court. The consequences to ratepayers will be far worse if that happens. A rate increase designed by this Commission is far superior to one designed by a bankruptcy judge. I commend President Lynch on her proposal for a rate design with tiered rates for those not on time of use meters. And I call on the Legislature to do all it can to incent the spread of time of use meters. I also urge us to carefully consider the impact on jobs and paychecks of rate design for the large commercial and industrial classes.

Today's rate increase is long overdue. I regret that we were not able to act sooner. Had we done so, we could have avoided rate increases of the magnitude we impose today and the depletion of the General Fund. Assemblymember Wright also expressed that view at today's meeting. I concur with his statement that had this Commission kept the utilities solvent, we would be looking at lower numbers in this order. I share his concerns about piecemealing increase on top of increase. Further decisions in our docket on AB1X will determine whether his fears are justified. I hope they are not. It is my hope that by raising rates today we will finally place some discipline on dysfunctional wholesale markets as a result of consumer backlash and conservation. Nothing else has worked. Maybe consumer fury will.

There continues to be one economic reality this Commission has not faced. When will the rate freeze end? Under the TURN proposal we adopt today, can it ever end? I believe it still can because TURN asserts the rate freeze is over even though its accounting proposal is adopted. I agree with TURN that AB 1X signals the end of the rate freeze. We must deal forthrightly with this issue soon.

/s/ RICHARD A. BILAS_
RICHARD A. BILAS
Commissioner

San Francisco, California
March 27, 2001

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 4

Net Short Forecast and Energy Pricing Model Output

Table A-2

CDWR Total Average Cost for Net Short (additional sensitivities)

		Case 1a (High Spring, Early Summer Pricing)	Case 2a: Case 1a without Price Elasticity Demand Reduction	Difference from Case 1a	Case 3a: Case 1a without Price Elasticity Demand Reduction, without Load Curtailment Programs	Difference from Case 1a	Difference due to Loss of Load Curtailment Programs	Case 4a: Case 1a without Price Elasticity Demand Reduction, with Summer Peak Prices (2001-2002)	Difference from Case 1a	Difference due to Incremental High Summer Peak Prices	Case 5a QFs Generation at 70% from Jun-01 to Oct-01 (High Spring, Early Summer Pricing)
2001 PG&E	cost	$ 7,231,229,536	$ 7,730,794,773	$ 499,565,237	$ 8,218,510,768	$ 987,281,232	$ 487,715,996	$ 8,127,694,099	$ 896,464,563	$ 396,899,326	$ 7,850,296,356
	$/Mwh	$ 235	$ 237	$ 3	$ 252	$ 18	$ 15	$ 250	$ 15	$ 12	$ 239
SCE	cost	$ 3,986,441,352	$ 4,314,337,026	$ 327,895,675	$ 4,543,420,762	$ 556,979,411	$ 229,083,736	$ 4,411,303,010	$ 424,861,659	$ 96,965,984	$ 4,520,151,373
	$/Mwh	$ 179	$ 182	$ 3	$ 193	$ 14	$ 11	$ 186	$ 7	$ 4	$ 184
SDG&E	cost	$ 1,583,744,230	$ 1,662,817,626	$ 79,073,397	$ 1,743,014,155	$ 159,269,926	$ 80,196,529	$ 1,697,186,355	$ 113,442,125	$ 34,368,728	$ 1,667,499,267
	$/Mwh	$ 178	$ 182	$ 4	$ 192	$ 14	$ 10	$ 185	$ 8	$ 4	$ 183
STATE	cost	$12,801,415,117	$ 13,707,949,425	$ 906,534,308	$ 14,504,945,686	$1,703,530,569	$ 796,996,261	$ 14,236,183,464	$ 1,434,768,347	$ 528,234,039	$ 14,037,946,996
	$/Mwh	$ 206	$ 210	$ 3	$ 223	$ 16	$ 13	$ 218	$ 11	$ 8	$ 211
										$ -	
2002 PG&E	cost	$ 4,121,416,339	$ 4,669,364,725	$ 547,948,386	$ 4,876,716,013	$ 755,299,674	$ 207,351,287	$ 4,728,939,675	$ 607,523,336	$ 59,574,949	
	$/Mwh	$ 133	$ 138	$ 4	$ 143	$ 10	$ 6	$ 139	$ 6	$ 2	
SCE	cost	$ 3,365,998,732	$ 3,774,218,646	$ 408,219,915	$ 3,833,183,057	$ 467,184,325	$ 58,964,410	$ 3,837,947,123	$ 471,948,392	$ 63,728,477	
	$/Mwh	$ 127	$ 131	$ 4	$ 134	$ 6	$ 3	$ 133	$ 6	$ 2	
SDG&E	cost	$ 1,306,527,246	$ 1,399,656,918	$ 93,129,672	$ 1,415,845,438	$ 109,318,192	$ 16,188,520	$ 1,420,266,986	$ 113,739,740	$ 20,610,068	
	$/Mwh	$ 125	$ 129	$ 4	$ 131	$ 6	$ 2	$ 131	$ 6	$ 2	
STATE	cost	$ 8,793,942,316	$ 9,843,240,290	$ 1,049,297,973	$ 10,125,744,508	$1,331,802,191	$ 282,504,218	$ 9,987,153,783	$ 1,193,211,467	$ 143,913,494	
	$/Mwh	$ 130	$ 134	$ 4	$ 138	$ 8	$ 4	$ 136	$ 6	$ 2	
2003 PG&E	cost	$ 3,459,503,842	$ 3,649,281,933	$ 189,778,091							
	$/Mwh	$ 102	$ 102	$ 0							
SCE	cost	$ 2,812,177,269	$ 2,918,487,907	$ 106,310,638							
	$/Mwh	$ 92	$ 92	$ 1							
SDG&E	cost	$ 1,047,131,186	$ 1,061,808,483	$ 14,677,296							
	$/Mwh	$ 92	$ 92	$ 1							
STATE	cost	$ 7,318,812,297	$ 7,629,578,322	$ 310,766,025							
	$/Mwh	$ 96	$ 97	$ 1							
2004 PG&E	cost	$ 3,033,311,947	$ 3,114,007,913	$ 80,695,966							
	$/Mwh	$ 88	$ 88	$ (0)							
SCE	cost	$ 3,121,247,257	$ 3,154,462,862	$ 33,215,604							
	$/Mwh	$ 79	$ 79	$ 0							
SDG&E	cost	$ 1,073,235,582	$ 1,069,649,646	$ (3,585,936)							
	$/Mwh	$ 79	$ 79	$ 0							
STATE	cost	$ 7,227,794,786	$ 7,338,120,421	$ 110,325,635							
	$/Mwh	$ 83	$ 83	$ 0							
2005 PG&E	cost	$ 3,034,086,244	$ 3,067,457,857	$ 33,371,613							
	$/Mwh	$ 79	$ 79	$ (0)							
SCE	cost	$ 2,506,947,786	$ 2,521,479,972	$ 14,532,186							
	$/Mwh	$ 66	$ 66	$ 0							
SDG&E	cost	$ 850,384,244	$ 849,634,461	$ (749,783)							
	$/Mwh	$ 66	$ 66	$ 0							
STATE	cost	$ 6,391,418,274	$ 6,438,572,290	$ 47,154,016							
	$/Mwh	$ 72	$ 72	$ (0)							

		Case 1a (High Spring, Early Summer Pricing)
2006 PG&E	cost	$ 2,869,609,040
	$/Mwh	$ 70
SCE	cost	$ 2,457,561,777
	$/Mwh	$ 62
SDG&E	cost	$ 806,594,963
	$/Mwh	$ 62
STATE	cost	$ 6,133,765,780
	$/Mwh	$ 66
2007 PG&E	cost	$ 3,031,447,470
	$/Mwh	$ 68
SCE	cost	$ 2,525,298,656
	$/Mwh	$ 63
SDG&E	cost	$ 800,385,285
	$/Mwh	$ 62
STATE	cost	$ 6,357,131,412
	$/Mwh	$ 65
2008 PG&E	cost	$ 3,204,826,031
	$/Mwh	$ 67
SCE	cost	$ 2,660,937,164
	$/Mwh	$ 63
SDG&E	cost	$ 822,577,695
	$/Mwh	$ 63
STATE	cost	$ 6,688,340,890
	$/Mwh	$ 65
2009 PG&E	cost	$ 3,277,976,919
	$/Mwh	$ 66
SCE	cost	$ 2,757,728,630
	$/Mwh	$ 64
SDG&E	cost	$ 837,806,241
	$/Mwh	$ 63
STATE	cost	$ 6,873,511,790
	$/Mwh	$ 65
2010 PG&E	cost	$ 3,413,131,397
	$/Mwh	$ 67
SCE	cost	$ 2,890,821,498
	$/Mwh	$ 64
SDG&E	cost	$ 863,244,887
	$/Mwh	$ 64
STATE	cost	$ 7,167,197,782
	$/Mwh	$ 65

CDWR Total Average Cost for Net Short
(additional sensitivities)
All Current Contracts (5/11/01)

		Case 1a (High Spring, Early Summer Pricing)	Case 2a: Case 1a without Price Elasticity Demand Reduction	Difference from Case 1a	Case 3a: Case 1a without Price Elasticity Demand Reduction, without Load Curtailment Programs	Difference from Case 1a	Difference due to Loss of Load Curtailment Programs	Case 4a: Case 1a with Higher Energy Demand with Higher Summer Peak Prices (2001-2002)	Difference from Case 1a	Difference due to Incremental High Summer Peak Prices
2001 PG&E	cost	$ 4,847,035,773	$ 5,495,627,892	$ 648,592,119	$ 6,035,726,944	$ 1,188,691,171	$ 540,099,052	$ 5,831,461,275	$ 984,425,501	$ 335,833,382
	$/Mwh	$ 213	$ 223	$ 10	$ 244	$ 31	$ 22	$ 236	$ 23	$ 14
SCE	cost	$ 2,649,951,496	$ 2,929,971,744	$ 280,020,248	$ 3,094,231,714	$ 444,280,219	$ 164,259,970	$ 2,964,307,669	$ 314,356,173	$ 34,335,925
	$/Mwh	$ 144	$ 149	$ 5	$ 161	$ 17	$ 12	$ 151	$ 7	$ 2
SDG&E	cost	$ 812,031,008	$ 864,280,952	$ 52,249,945	$ 907,790,560	$ 95,759,552	$ 43,509,608	$ 873,382,547	$ 61,351,540	$ 9,101,595
	$/Mwh	$ 143	$ 149	$ 5	$ 159	$ 16	$ 11	$ 150	$ 7	$ 2
STATE	cost	$ 8,309,018,276	$ 9,289,880,589	$ 980,862,312	$ 10,037,749,218	$ 1,728,730,942	$ 747,868,630	$ 9,669,151,491	$ 1,360,133,214	$ 379,270,902
	$/Mwh	$ 177	$ 185	$ 8	$ 202	$ 25	$ 17	$ 193	$ 15	$ 8
										$ -
2002 PG&E	cost	$ 4,372,226,941	$ 4,940,541,511	$ 568,314,570	$ 5,119,635,815	$ 747,408,874	$ 179,094,304	$ 4,981,873,286	$ 609,646,346	$ 41,331,775
	$/Mwh	$ 129	$ 133	$ 4	$ 138	$ 8	$ 5	$ 134	$ 5	$ 1
SCE	cost	$ 3,379,491,907	$ 3,680,267,987	$ 300,776,080	$ 3,693,034,503	$ 313,542,596	$ 12,766,516	$ 3,715,924,436	$ 336,432,529	$ 35,656,449
	$/Mwh	$ 122	$ 125	$ 2	$ 126	$ 4	$ 2	$ 126	$ 4	$ 1
SDG&E	cost	$ 1,197,579,155	$ 1,244,002,649	$ 46,423,494	$ 1,242,787,324	$ 45,208,168	$ (1,215,326)	$ 1,254,443,928	$ 56,864,773	$ 10,441,279
	$/Mwh	$ 121	$ 123	$ 2	$ 124	$ 3	$ 1	$ 124	$ 3	$ 1
STATE	cost	$ 8,949,298,003	$ 9,864,812,147	$ 915,514,144	$ 10,055,457,642	$ 1,106,159,639	$ 190,645,494	$ 9,952,241,651	$ 1,002,943,648	$ 87,429,504
	$/Mwh	$ 125	$ 128	$ 3	$ 132	$ 6	$ 3	$ 130	$ 4	$ 1
2003 PG&E	cost	$ 3,432,885,653	$ 3,598,179,233	$ 165,293,580						
	$/Mwh	$ 94	$ 95	$ 1						
SCE	cost	$ 3,091,756,033	$ 3,159,621,548	$ 67,865,515						
	$/Mwh	$ 95	$ 95	$ 0						
SDG&E	cost	$ 1,047,248,902	$ 1,047,302,806	$ 53,904						
	$/Mwh	$ 95	$ 95	$ 0						
STATE	cost	$ 7,571,890,588	$ 7,805,103,588	$ 233,213,000						
	$/Mwh	$ 95	$ 95	$ 0						
2004 PG&E	cost	$ 3,014,882,619	$ 3,076,115,442	$ 61,232,822						
	$/Mwh	$ 78	$ 78	$ 1						
SCE	cost	$ 3,430,394,047	$ 3,456,542,952	$ 26,148,905						
	$/Mwh	$ 82	$ 82	$ (0)						
SDG&E	cost	$ 1,184,268,406	$ 1,177,184,087	$ (7,084,319)						
	$/Mwh	$ 81	$ 81	$ (0)						
STATE	cost	$ 7,629,545,071	$ 7,709,842,480	$ 80,297,409						
	$/Mwh	$ 80	$ 80	$ 0						
2005 PG&E	cost	$ 2,884,144,552	$ 2,912,398,310	$ 28,253,758						
	$/Mwh	$ 68	$ 68	$ 0						
SCE	cost	$ 2,496,874,199	$ 2,510,074,134	$ 13,199,934						
	$/Mwh	$ 63	$ 63	$ 0						
SDG&E	cost	$ 849,473,082	$ 848,281,355	$ (1,191,727)						
	$/Mwh	$ 63	$ 63	$ 0						
STATE	cost	$ 6,230,491,833	$ 6,270,753,798	$ 40,261,966						
	$/Mwh	$ 65	$ 66	$ 0						

		Case 1a (High Spring, Early Summer Pricing)
2006 PG&E	cost	$ 2,918,862,680
	$/Mwh	$ 66
SCE	cost	$ 2,494,487,526
	$/Mwh	$ 61
SDG&E	cost	$ 821,414,770
	$/Mwh	$ 61
STATE	cost	$ 6,234,764,976
	$/Mwh	$ 63
2007 PG&E	cost	$ 3,112,918,694
	$/Mwh	$ 66
SCE	cost	$ 2,581,616,132
	$/Mwh	$ 62
SDG&E	cost	$ 821,785,852
	$/Mwh	$ 61
STATE	cost	$ 6,516,320,677
	$/Mwh	$ 64
2008 PG&E	cost	$ 3,276,345,591
	$/Mwh	$ 65
SCE	cost	$ 2,688,811,439
	$/Mwh	$ 62
SDG&E	cost	$ 833,892,214
	$/Mwh	$ 62
STATE	cost	$ 6,799,049,244
	$/Mwh	$ 63
2009 PG&E	cost	$ 3,385,831,782
	$/Mwh	$ 65
SCE	cost	$ 2,771,025,211
	$/Mwh	$ 62
SDG&E	cost	$ 843,819,998
	$/Mwh	$ 62
STATE	cost	$ 7,000,676,990
	$/Mwh	$ 63
2010 PG&E	cost	$ 3,542,085,502
	$/Mwh	$ 65
SCE	cost	$ 2,892,381,447
	$/Mwh	$ 63
SDG&E	cost	$ 865,339,142
	$/Mwh	$ 63
STATE	cost	$ 7,299,806,091
	$/Mwh	$ 64

NOTE: 2001 data above is for May-Dec only

2001 Actual Statewide Data to Date

Jan (1-17)	cost	$ 549,141,593
	$/Mwh	$ 332
Feb	cost	$ 1,441,938,673
	$/Mwh	$ 304
Mar	cost	$ 1,801,484,301
	$/Mwh	$ 261
Apr	cost	$ 1,859,537,000
	$/Mwh	$ 283

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 5

Executive Order for 20/20 Program

Please click here to return to the previous page.

Executive Order

EXECUTIVE DEPARTMENT

STATE OF CALIFORNIA

EXECUTIVE ORDER D-36-01
by the
Governor of the State of California

WHEREAS, on January 17, 2001, I proclaimed a State of Emergency to exist due to the energy shortage in the State of California; and

WHEREAS, the shortage of available electricity supply will continue to cause rolling blackouts throughout California affecting millions of Californians; and the imminent threat of disruption of electrical power to California's schools, hospitals, homes businesses and roadways constitutes a condition of extreme peril to the safety of persons and property; and

WHEREAS, the State has implemented a comprehensive conservation and demand reduction campaign involving all segments of the public and private sectors, yet all reasonable conservation, allocation, and load curtailment measures will not eliminate this energy supply emergency until sufficient new supply can be brought on line; and

WHEREAS, this energy supply emergency requires the State to seek expertise in expediting the siting of new powerplants and emergency peaking facilities, to increase the output from or restarting existing powerplants in order to ensure reliability of the grid and delivery of power in the State.

WHEREAS, this emergency has caused wholesale power suppliers to discontinue energy sales to these utilities, resulting in the State assuming the obligation to procure electricity for the end use customers of these utilities thereby necessitating the State to acquire the services of energy consultants, bond counsel, legal and financial advisors; and

NOW, THEREFORE, I, GRAY DAVIS, Governor of the State of California, by virtue of the power and authority vested in me by the Constitution and statutes of the State of California, do hereby issue this order to become effective immediately:

IT IS ORDERED that the Department of Water Resources (DWR) facilitate the expeditious implementation of the conservation initiatives enacted by Senate Bill 5X and Assembly Bill 29X of the 2001-02 First Extraordinary Session and the 20/20 Program established by Executive Order D-30-01. Revenues from the Electric Power Fund shall be used to fund these essential activities.

IT IS FURTHER ORDERED that DWR retain appropriate expert resources for the implementation and financing of its power purchase program as enacted by Assembly Bill 1X of the 2001-02 First Extraordinary Session.

IT IS FURTHER ORDERED that the State and Consumer Services Agency (hereinafter "Agency"), the Department of General Services (hereinafter "DGS"), and the Energy Commission implement, coordinate, and promote an aggressive energy conservation and demand reduction initiative involving leadership from the State and local governments, schools, and the commercial, industrial, and agricultural sectors, as well as organizers for broad community involvement statewide.

IT IS FURTHER ORDERED that the DWR and the Department of Finance (hereinafter "DOF") conduct essential and critical activities on an ongoing basis, including energy demand forecasts, energy cost forecasts, financial analysis, rate modeling and design, and other activities related to the Stateâ€™s negotiations with investor-owned electric utilities and

power suppliers, to ensure a sufficient supply of power at just and reasonable prices to meet the power demand of California consumers.

IT IS FURTHER ORDERED that the DGS provide essential legal and related services to advise and assist the State in pending rate litigation, its negotiations with the investor-owned electric utilities related to, among other things, the utilities' undercollections, drafting of legislation and contracts related to the acquisition of power, and matters before the Federal Energy Regulatory Commission related to, among other things, wholesale prices charged by power suppliers.

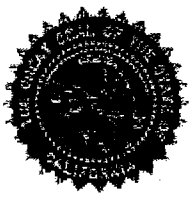
IT IS FURTHER ORDERED that the Energy Commission act as the project manager in coordinating and ensuring timeliness in the state permitting, siting, finance, design, and construction or restart of electrical generating facilities.

IT IS FURTHER ORDERED that unless otherwise specified above, revenues available in the Disaster Response-Emergency Operations Account of the Special Fund for Economic Uncertainties shall be used to fund all essential activities of the Agency, DGS, DWR, DOF, and Energy Commission pursuant to this order.

IT IS FURTHER ORDERED that the Agency, DGS, DWR, DOF, and Energy Commission shall enter into contracts in furtherance of this order as expeditiously as possible, and is hereby authorized to do so, notwithstanding the provisions of the Government Code and the Public Contracts Code applicable to state contracts, including, but not limited to, advertising and competitive bidding requirements, which provisions are suspended pursuant to Government Code Section 8571 to the extent that they would prevent, hinder, or delay the prompt mitigation of the effects of this emergency. Moreover, any agreement commenced after January 17, 2001, that would otherwise be authorized under this order is hereby affirmed and ratified.

IT IS FURTHER ORDERED that this order shall expire on December 31, 2001, unless extended by further executive order responding to the continued need for emergency action to deal with the electricity emergency or unless terminated by proclamation of the Governor or concurrent resolution of the Legislature that the state of emergency has ended.

I FURTHER DIRECT that as soon as hereafter possible, this order be filed in the Office of the Secretary of State and that widespread publicity and notice be given to this order.



IN WITNESS WHEREOF I have hereunto set my hand and caused the Great Seal of the State of California to be affixed this the twenty-fifth day of May 2001.

/s/ Gray Davis

Governor of California

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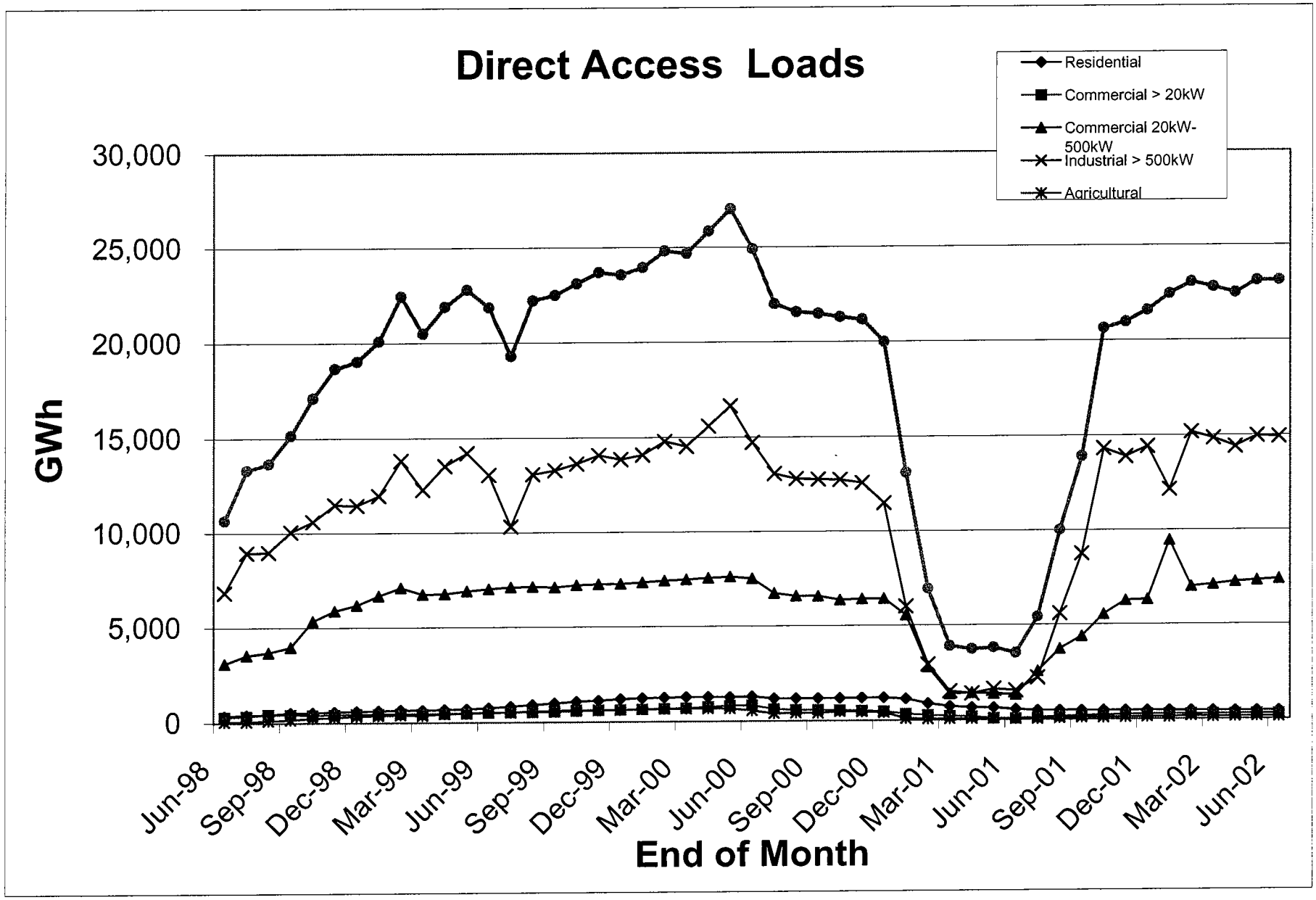
History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 6

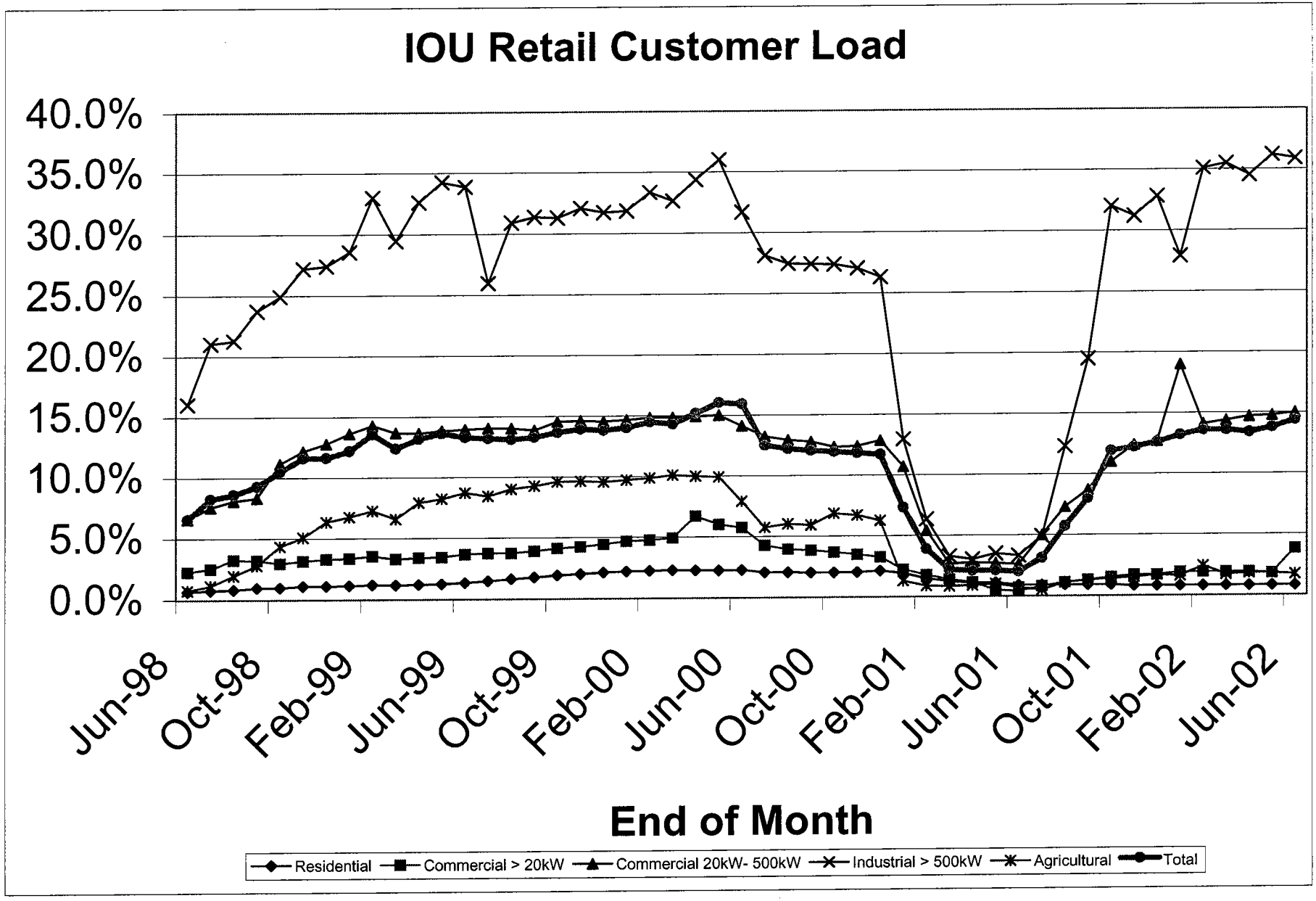
Historical Direct Access Loads for the three IOU Service Areas


Direct Access Loads
Residential
Commercial > 20kW
Commercial 20kW-500kW
Industrial > 500kW
Agricultural
GWh
30,000
25,000
20,000
15,000
10,000
5,000
0
Jun-98
Sep-98
Dec-98
Mar-99
Jun-99
Sep-99
Dec-99
Mar-00
Jun-00
Sep-00
Dec-00
Mar-01
Jun-01
Sep-01
Dec-01
Mar-02
Jun-02
End of Month

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 7

Direct Access Loads as a Percent of Total Customer Loads


IOU Retail Customer Load
40.0%
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
Jun-98
Oct-98
Feb-99
Jun-99
Oct-99
Feb-00
Jun-00
Oct-00
Feb-01
Jun-01
Oct-01
Feb-02
Jun-02
End of Month
Residential
Commercial > 20kW
Commercial 20kW- 500kW
Industrial > 500kW
Agricultural
Total

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 8

Proposed CPUC Decision to Suspend Direct Access as of July 1, 2001

(Agenda showing postponement of suspension decision)

STATE OF CALIFORNIA GRAY DAVIS, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

June 15, 2001

Items H-26 & H-26a
6/28/2001

TO: PARTIES OF RECORD IN APPLICATION 98-07-003 ET AL.

This is the draft decision of Administrative Law Judge (ALJ) Barnett and alternate draft decision of Commissioner Bilas. It will be on the Commission's agenda at the meeting on June 28, 2001. The Commission may act then, or it may postpone action until later.

When the Commission acts on these items, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

As noted in the draft decision, pursuant to Rule 77.7(f)(9), comments on the draft decision of the ALJ must be filed within 10 days of its mailing and no reply comments will be accepted. Pursuant to Rule 77.7(f)(9), comments on the alternate draft decision must be filed within nine days of its mailing and reply comments filed by noon, June 27, 2001, will be permitted.

In addition to service by mail, parties should send comments in electronic form to those appearances and the state service list that provided an electronic mail address to the Commission, including ALJ Barnett at rab@cpuc.ca.gov, Ann Watson at anw@cpuc.ca.gov and Linda Serizawa at lss@cpuc.ca.gov. Finally, comments must be served separately on the Assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious methods of service.

/s/ LYNN T. CAREW
Lynn T. Carew, Chief
Administrative Law Judge

LTC:sid

Attachments

Decision **DRAFT DECISION OF ALJ BARNETT** **(Mailed 6/15/2001)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for verification, consolidation, and approval of costs and revenues in the transition revenue account.	Application 98-07-003 (Filed July 1, 1998)
In the Matter of The Revenue Adjustment Proceeding (RAP) application of San Diego Gas and Electric Company (U 902-E) for approval of 1) Consolidated changes in 1999 authorized revenue and revised rate components; 2) the CTC rate component and associated headroom calculations; 3) RGTCOMA balances; 4) PX credit computations; 5) disposition of various balancing/memorandum accounts; and 6) electric revenue allocation and rate design changes.	Application 98-07-006 (Filed July 1, 1998)
Application of Southern California Edison Company (U 338-E) to: 1) consolidate authorized rates and revenue requirements; 2) verify residual competition transition charge revenues; 3) review and dispose of amounts in various balancing and memorandum accounts; 4) verify regulatory balances transferred to the transition cost balancing account on January 1, 1998; and 5) propose rate recovery for Santa Catalina Island diesel fuel costs.	Application 98-07-026 (Filed July 1, 1998)

OPINION

Pursuant to Rule 47 of the Rules of Practice and Procedure, Southern California Edison Company (SCE) requests review on an expedited basis and modification of Decision (D.) 99-06-058. Specifically, SCE requests authorization to temporarily suspend payment of Power Exchange (PX) energy credits to energy service providers (ESPs) and direct access customers until a solution to the current energy crisis and SCE's current liquidity crisis has been achieved. SCE asserts that this temporary suspension is necessitated by the radical increase in the PX energy charge in recent months. SCE says the dramatically inflated market rates that it must pay for electricity for its customers and its current financial crisis, require expeditious action.

In the restructured electricity market in California, customers may subscribe to "bundled service" from the utility distribution company or "direct access" service from an ESP. Customers who purchase bundled service from the utility pay a PX energy charge to cover the utility's power supply costs. For these bundled service customers, the customer's total "bundled" bill (that is, a bill that includes charges for all utility services, including distribution and transmission charges), is capped at 1996 levels during the rate freeze period. In other words, if the PX energy charge and transmission and distribution charges exceed the frozen rates, the customer does not pay the full PX energy charge but instead pays the capped rate.[1]

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[1] This frozen rate now is supplemented by the 1¢/kWh surcharge adopted in D.01-01-018, and the 3¢/kWh surcharge adopted in D.01-03-082.

Customers who elect direct access service currently receive a credit on their bills in the form of a PX energy credit. This credit is intended to offset the energy costs included in the bundled rate. There is no current cap on the amount of the PX energy credit given to direct access customers, *i.e.*, the credit is exactly equal to the PX energy charge.

Prior to D.99-06-058, all three utilities' tariffs provided that when a direct access customer's PX energy credit exceeded the amount of the otherwise applicable bundled bill, the customer's total utility charges would be equal to zero. The customer would receive a "zero minimum bill" and the PX energy credit would be capped at the amount of transmission and distribution charges. Thus, the customer would not receive a negative bill (and would not receive a refund or credit), even if the PX energy charge exceeded the total bill. (D.99-06-058, at mimeo. 18-19.)

The Commission approved this provision in Resolution E-3510, finding that the zero minimum bill was essentially approved by D.97-08-056. (*Id.*, p. 20.) In Application (A.) 98-07-026 (the 1998 RAP proceeding), the Western Power Trading Forum (WPTF) proposed eliminating the zero minimum bill, arguing that it was a disincentive to direct access. Pursuant to a compromise and stipulation between SCE, WPTF, and Enron, which was approved in D.99-06-058, the parties agreed to the elimination of the zero minimum bill provision of SCE's tariffs so that direct access customers would start receiving credits for the entire negative amount of the bill.[2] SCE interpreted the stipulation as requiring a cash payment when the credit exceeded the minimum bill.

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[2] PG&E and SDG&E entered into similar stipulations with WPTF and Enron.

SCE states that due to the recent extremely high energy (PX) prices in California, direct access customers have been receiving large payments of PX energy credits for the past several months.[3] These credit payments have been provided both directly to the direct access customer and to the ESP (who is then required to pass on any credits owing to the direct access customer), depending on the method of billing used to serve the direct access customer. SCE states that due to its current financial condition, it simply cannot continue to sustain the payment of these PX energy credits. SCE suspended payment of any PX energy credits January 5, 2001. In January 2001, the PX ceased operations.

Accordingly, SCE seeks modification of D.99-06-058 to temporarily suspend all PX energy credits to ESPs and direct access customers. SCE proposes to continue to reflect the accumulated PX energy credits on the customer's bill, but will not send refund checks to these customers to the extent the total PX energy credits exceed other charges on the monthly bill.[4] This temporary measure will enable SCE to concentrate its resources to continue to provide transmission and distribution services to all customers, rather than passing on credits to ESPs and their direct access customers.

Enron Corp. (Enron) opposes SCE's petition. Enron states that suspension of the stipulation between SCE, WPTF, and Enron (approved in D.99-06-058) violates the stipulation. (The stipulation is Appendix A.) Further, Enron argues

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[3] For example, recent electricity prices have ranged from 25¢/kWh ($250 per MWh) to 50¢/kWh ($500 per MWh) compared to 8¢/kWh ($80 per MWh) in late October 2000. Since June 2000, SCE has made payments of PX energy credits in the amount of $157 million to direct access customers and ESPs.

[4] SCE will notify ESPs and direct access customers through a bill message that refund checks will not be issued for PX energy credits.

that SCE's petition is so ambiguous that it is impossible to discern the extent to which SCE seeks to forego its obligation to pay PX energy credits. In this regard, SCE requests that the following language be added as a modifier to the Commission's approval of the stipulation:

> [F]rom the time period beginning January 5, 2001 and continuing until the date that a solution to the energy crisis is reached and Edison has recovered from its liquidity crisis, payments of PX Energy Credits to ESPs and direct access customers shall be suspended.

From this language, Enron believes it is not clear what SCE means by the term "suspended." Is it SCE's intent to track the PX energy credits owed to direct access customers from January 5, 2001 forward and to pay the accumulated debt at a future time, or is it SCE's intent to restart payment of PX energy credits at a future time, but not to pay the debt which has accumulated in the interim period? Enron opposes any relief that disturbs the fundamental agreement expressed in the stipulation (i.e., SCE's obligation to pay the totality of the PX energy credit) which was approved by the Commission.

Additionally, argues Enron, regardless of the form the requested suspension takes, SCE is seeking to have such suspension of its obligation to make payments of the PX energy credits in place for an indefinite, unknown period of time. Enron asks: Who decides that a solution to the energy crisis has been reached? Who determines that SCE has recovered from its liquidity crisis? Such subjective criteria for determining when payments to direct access customers and ESPs will recommence places direct access customers and ESPs last in line to be paid by SCE. Enron claims that ESPs cannot continue to shoulder this debt, which continues to grow, indefinitely. New West Energy Corporation makes much the same argument.

Discussion

We grant the petition.

To understand the direct access issue, an example is appropriate. In simplified form: assume the bundled rate for electricity in SCE's territory is 15¢/Kwh, which is separated into an electric energy charge of 5¢ and a transmission and distribution charge of 10¢.[5] During the rate freeze, a bundled customer pays 15¢/Kwh regardless of an increase in the energy charge. The responsibility for the deficit is yet to be determined.

A direct access customer is one who buys electric energy from an entity other than a public utility (an ESP), and has that energy transported over the public utility's transmission and distribution lines. If, in our example, the ESP energy charge fluctuated with the spot market, the direct access customer could win or lose. If the ESP charged the direct access customer 4¢/Kwh for energy the customer has benefitted. If, however, the cost of energy rises above 5¢/Kwh, then the customer would be better off remaining with the public utility. To encourage direct access, this Commission authorized an energy credit to the direct access customer so that it would not be harmed by an increase in the price of energy.[6] This is embodied in the stipulation set forth in D.99-06-058. For example, the comparison is:

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[5] The electric energy charge is the total frozen rate less distribution, transmission, public purpose programs, nuclear decommissioning, and trust transfer amounts.

[6] D.99-06-058, at mimeo. 19.

Bundled Rate

Electric Energy	5¢/Kwh
Transportation and Distribution	10¢
Total bundled rate	15¢/Kwh

Assume electric energy PX cost of 20¢/Kwh

Utility Customer Bill		Direct Access Customer
Electric Energy	20¢/Kwh	20¢
T&D	10¢	10¢
	30¢/Kwh	30¢
Bundled rate	-15¢	
Deficit	15¢/Kwh	

If there were no credit, the direct access customer would be better off staying with the utility. To encourage direct access, we authorized a credit of the price paid by the utility for electric energy to be offset against the bundled rate. If the credit is in excess of the bundled rate, including transmission and distribution, the excess is a credit to the direct access customer. In effect, transmission and distribution services are not paid for by the direct access customer, although the utility renders these services.

The direct access customer credit is determined:

Electric energy	20¢	Bundled rate	(15¢)/Kwh
T&D	10¢	Credit	20¢/Kwh
Total	30¢	Net to direct Access Customer	5¢/Kwh
Utility Deficit			
T&D not received	10¢/Kwh		
Credit to Direct Access Customer	5¢		
	15¢/Kwh		

Since the actual bill sent to the direct access customer by the utility is for transmission and distribution only (in our example) the bill would be 10¢/Kwh. Because the customer is entitled to a credit (utility cost of electric energy (20¢) less the bundled rate (15¢)), SCE credits him with the 5¢/Kwh balance. This 5¢ was usually paid in cash. Thus, the direct access customer pays 20¢/Kwh to its ESP and receives a 5¢/Kwh credit from the public utility – net 15¢/Kwh, the same as a bundled utility customer.

For direct access to succeed, the ESP must provide energy at a cost less than that of the PX. If the PX price is 20¢/Kwh, the ESP's price should be less. If the ESP charges 18¢/Kwh, the direct access customer pays (in our example) 18¢ to the ESP and receives at 5¢ credit from the utility for a net payment of 13¢/Kwh. However, the utility has incurred costs of the 5¢/Kwh credit to the direct access customer. In effect, the utility is subsidizing direct access.

Recent events in the California electric market have caused a radical change in the area of direct access. First, the Governor's Proclamation of January 17, 2001, found that an emergency exists in the electricity market in California threatening "the solvency of California's major public utilities, ..." Second, on February 1, 2001, Assembly Bill (AB) 1X was signed into law which, among other things, requires that the Department of Water Resources (DWR)

procure electricity on behalf of California utilities. In regard to direct access, AB 1X adds Section 80110 to the Water Code:

> "After the passage or such period of time after the effective date of this section as shall be determined by the commission, the right of retail end use customers pursuant to Article 6 (commencing with Section 360) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code to acquire service from other providers shall be suspended until the department [the Department of Water Resources] no longer supplies power hereunder." The section was effective February 1, 2001.

AB 1X, Section 7 states:

> "This act is an urgency statute necessary for the immediate preservation of the public peace, health, or safety within the meaning of Article IV of the Constitution and shall go into immediate effect. The facts constituting the necessity are: In order to address the rapid, unforeseen shortage of electric power and energy available in the state and rapid and substantial increases in wholesale energy costs and retail energy rates, that endanger the health, welfare, and safety of the people of this state, it is necessary for this act to take effect immediately."

It is uncontroverted that SCE has paid in excess of $157 million since mid-1999 to direct access customers. It is clear to us that during the rate freeze period, should a direct access customer pay less than the PX energy price to its ESP, the direct access customer is being subsidized by the public utility and, perhaps, by the public utility's ratepayers.

We note that in the stipulation between SCE, Enron, and WPTF, there is no mention of a cash refund to direct access customers - the reference is to a credit.

The operative portion of the stipulation states:

> "Specifically, SCE agrees to delete the direct access zero minimum bill provision from its tariffs and bill direct access customers without this mechanism, provided that (1) SCE is

> only required to implement this change to its bills when its billing systems are otherwise capable of making this change (which is expected to occur on or before July 1, 1999); and (2) SCE will refund (without interest), in the form of a credit to the bill, any amounts which are charged to the Direct Access Customers, that otherwise would not be charged, solely due to imposition of the minimum bill for the time period beginning with the effective date of a decision approving elimination of the minimum bill, and ending with the date on which the billing change is made assuming that SCE's billing system is unable to make this change by the time a decision is rendered in this proceeding. SCE expects that refunds of this nature would not be necessary due to billing system constraints beyond July 1, 1999." (Emphasis added.)

We find no provision in the stipulation which would require SCE to make a cash payment in lieu of a credit. Although we interpret the stipulation narrowly, if given a broader interpretation requiring cash payments, we would still suspend the payment of cash in lieu of a credit. As proclaimed by the Governor, as found in Water Code § 8000, *et seq.*, and as set forth in Pub. Util. Code § 330, especially § 330(g) ("Reliable electric service is of utmost importance to the safety, health, and welfare of the state's citizenry and economy." ...) Our primary duty is to ensure reliable electric service. Utility cash, which is in short supply, should be conserved to provide reliable service, not subsidize direct access.

SCE informs us that there is currently due direct access customers as of mid-February 2001, credits in excess of $202 million. In the current energy crisis, SCE should not be preferring the direct access customer; rather it should be focusing on purchasing sufficient energy to keep the lights on in Southern California. The Legislature has directed this Commission to suspend direct access until DWR no longer procures power for the retail end-users, and we find it should be stopped effective July 1, 2001.

Written contracts for direct access signed before July 1, 2001 are exempt from the suspension. Because of the current emergency, this order suspending payment of cash refunds to direct access customers and the right to contract for direct access should apply to PG&E and SCE. This order does not apply to SDG&E because its rate freeze has ended and a direct access credit is no longer required.

Comments

Suspending the right to contract for direct access protects DWR and the electric utilities in their endeavor to secure long-term contracts to acquire electric energy, with a reasonable opportunity to recover their costs of power. We have determined on our own motion that public necessity require reduction of the usual 30-day period for public review and comment to 10 days. (Rule 77.7(f)(9).) Reply comments are waived. The Water Code sections regarding the purchase of electric energy by the Department of Water Resources has an urgency statute which provided for the suspension of direct access. The legislature found that immediate implementation of the statute was needed to protect the "health, welfare, and safety of the people of this state ...." Our urgency is no less. Parties in R.94-04-031 and I.94-04-032 may file comments to this draft decision in this docket.

Findings of Fact

1. An emergency exists in the electricity market in California.
2. Under the rate freeze, direct access customers are being subsidized by SCE.
3. There is no requirement for SCE to make cash refunds to direct access customers or ESPs in lieu of a bill credit.

4. Pursuant to Water Code § 80110, this Commission must determine when the right of retail end use customers to acquire service from other providers shall be suspended.

5. The right to contract for direct access should be suspended effective July 1, 2001, except for written contracts executed prior to July 1, 2001.

Conclusions of Law

1. The petition of SCE should be granted.

2. SCE should not make cash payments to direct access customers or ESPs to satisfy the PX credit.

3. The determinations we make today should apply to PG&E, SDG&E, as well as SCE.

4. This order should be served on the parties to R.94-04-031 and I.94-04-032, who may file comments to the draft decision in this docket.

5. The right to contract for direct access should be suspended effective July 1, 2001, except for written contracts executed prior to July 1, 2001.

6. This order should be effective today so that our findings may be implemented expeditiously.

O R D E R

IT IS ORDERED that:

1. The petition of Southern California Edison Company (SCE) to modify Decision 99-06-058 is granted to the extent set forth in Ordering Paragraphs 2 and 3.

2. This order shall apply to Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E).

3. SCE, PG&E, and SDG&E shall not make any payments of cash to direct access customers or energy service providers to satisfy the customers' Power Exchange credit balance.

4. SCE, PG&E, and SDG&E shall notify their customers that the right of retail end users to acquire service from other providers, except the Department of Water Resources, is suspended until the Department no longer supplies power pursuant to Water Code §§ 80000, *et seq.*, effective July 1, 2001, except for written contracts executed prior to July 1, 2001.

5. This proceeding is closed.

This order is effective today.

Dated _____, at San Francisco, California.

(See Formal Files for Appendix A.)

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 9

QF Effective Capacity Status Report Provided by the CPUC

PUC Reported QF EFFECTIVE CAPACITY STATUS - SHUTDOWN, OR OFFLINE FOR MAINTENANCE (OR FORCED OUTAGE)

Service Territory	As of Monday, 6/04/01 Shutdown (Financial) (MW)	Maintenance (or Forced Outage) (MW)	Total (MW)	As of Monday, 5/28/01 Shutdown (Financial) (MW)	Maintenance or Forced Outage (MW)	Total (MW)	As of Monday, 4/23/01 Shutdown (Financial) (MW)	Maintenance or Forced Outage (MW)	Total (MW)
PG&E	* 47 (5 QFs)	6 (1 QF)	53	59 (6 QFs)	25 (5 QFs)	84	618 (25 QFs)	193 (8 QFs)	811
SCE	** 178 (8 QFs)	169 (5 QF)	347	178 (8 QFs)	2 (1 QF)	180	225 (11 QFs)	473 (7 QFs)	698
SDG&E	0 (0 QFs)	0 (0 QFs)	0	0 (0 QFs)	0 (0 QFs)	0	151 (4 QFs)	0 (0 QFs)	151
Total	225	175	400	237	27	264	994	666	1,660
N.Cal.	47	6	53	59	25	84	618	193	811
S.Cal.	178	169	347	178	2	180	376	473	849

* In addition, two PG&E QFs have reduced their effective output by about 40 MW.

** In addition, four Edison QFs have reduced their deliveries by an amount not yet quantified, but less than 40 MW.

Cycling QFs: 5 PG&E QFs representing 258 MW of effective capacity are cyclying off during off-peak periods.
4 SDG&E QFs representing 151 MW of firm capacity are cycling off during off-peak periods.

Contract Termination:
28 PG&E QFs representing 726 MW of effective capacity are seeking contract termination or suspension.
9 Edison QFs representing 225 MW of firm capacity are seeking contract termination or suspension.

Sources: All data are based on written reponses to Energy Division data requests.

QF EFFECTIVE CAPACITY STATUS - SHUTDOWN, OR OFFLINE FOR MAINTENANCE (OR FORCED OUTAGE)

Monday, 5/07/01

Service Territory	**As of Monday, 5/07/01**			As of Monday, 4/30/01			As of Monday, 4/23/01		
	Shutdown (Financial) (MW)	**Maintenance (or Forced Outage) (MW)**	**Total (MW)**	Shutdown (Financial) (MW)	Maintenance or Forced Outage (MW)	Total (MW)	Shutdown (Financial) (MW)	Maintenance or Forced Outage (MW)	Total (MW)
PG&E	**109 (8 QFs)**	**82 (13 QFs)**	**191**	637 (27 QFs)	103 (5 QFs)	740	618 (25 QFs)	193 (8 QFs)	811
SCE	**225 (11 QFs)**	**274 (8 QFs)**	**499**	225 (11 QFs)	292 (8 QFs)	517	225 (11 QFs)	473 (7 QFs)	698
SDG&E	**0 (0 QFs)**	**0 (0 QFs)**	**0**	151 (4 QFs)	0 (0 QFs)	151	151 (4 QFs)	0 (0 QFs)	151
Total	**334**	**356**	**690**	1013	395	1,408	994	666	1,660
N.Cal.	**109**	**82**	**191**	637	103	740	618	193	811
S.Cal.	**225**	**274**	**499**	376	292	668	376	473	849

Sources: All data are based on written reponses to Energy Division data requests.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 10

Power Purchase Contract Status Reports

STATE OF CALIFORNIA

SUMMARY OF CALIFORNIA DEPARTMENT OF WATER RESOURCES POWER PURCHASE CONTRACT EFFORTS

Prepared by
California Department of Water Resources

MARCH 14, 2001

TABLE OF CONTENTS

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2. Power Purchase Portfolio Summary 2
3. Overview of the "Net Short" Energy Requirements of California 3
4. Objectives of Power Purchase Negotiating Team 5
5. Overview of CDWR Strategy and Market Response 6
6. Summary of Contracts and Agreements in Principle 7
7. Nature of Agreements 14
8. Rights to Terminate Agreements 15
9. 2001 Peaking Capacity Additions 16
10. On-going Energy Contracting 17
11. Remaining Challenges 18

CALIFORNIA'S ELECTRICITY ACTION PLAN

- Create a power purchase portfolio to reduce dependence on spot market, provide price stability and certainty.
- Expedite construction of new power plants, peaking facilities and distributed generation.
- Implement aggressive conservation and demand management program.
- Optimize use of existing transmission and expand transmission grid.
- Augment natural gas supplies, pipelines, and storage facilities.

POWER PURCHASE PORTFOLIO SUMMARY

- Increased California Department of Water Resources (CDWR) forward purchases by the end of February to 75% in the day-ahead and 95% in the day- and hour-ahead markets, substantially reducing dependence on the real-time market.
- Reduced CDWR average cost of spot market purchases from $330 per megawatt hour (MWh) to a portfolio averaging $228/MWh by the end of February.
- Reduced the risk of blackouts and brownouts.
- Assembled a diversified portfolio of agreements that meet the goal of reducing dependence on spot market and price stability. The ten-year average portfolio price $69/MWh.
- Agreements result in expediting construction of new power plants with 10,000 megawatt (MW) slated to come on-line with 24 months, as much as 5,000 MW as early as this year.
- Seasonal power exchanges between California and the Pacific Northwest which offer significant operational benefits and reduce dependence on the spot market.
- Agreements for 7,000 MW for 2001; average of approximately 9,000 MW per year for the next ten years.

OVERVIEW OF THE "NET SHORT" ENERGY REQUIREMENTS OF CALIFORNIA

Under AB 1X, CDWR has proceeded to purchase the amount of energy not otherwise supplied by the combination of:

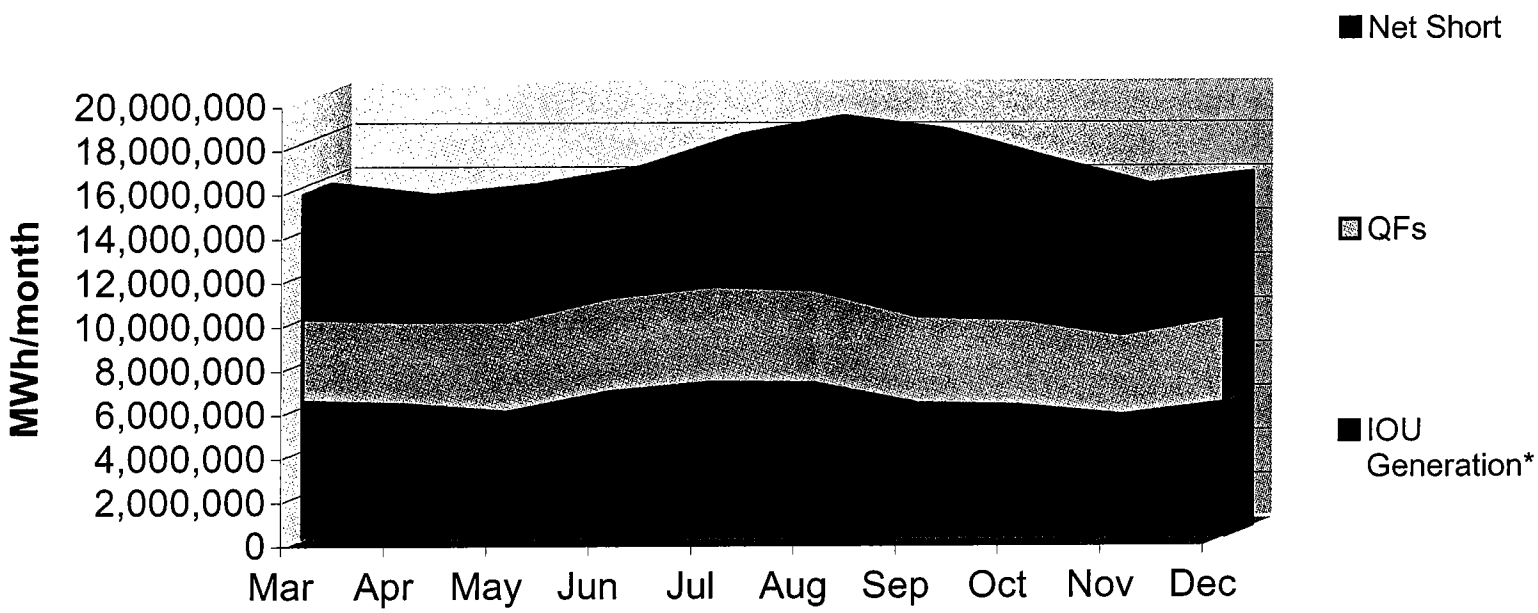
- Retained generation resources of the three investor-owned utilities (IOUs) in California, most of which is either hydroelectric or nuclear generation.
- Capacity and energy from the remaining Qualifying Facilities (QFs) under contract to the three IOUs (either renewable energy resources or cogeneration facilities operating under standard offer agreements with the IOUs).
- Certain existing power purchase agreements (PPA) or "bilateral" contracts held by the IOUs.

The difference between the energy needs of the state's electric utility customers and the sum of the above sources of supply is the "Net Short" requirement which CDWR is meeting through a combination of spot market and a mixture of short-, intermediate-, and long-term bilateral contracts for energy purchase.

Figure 1 provides a representative summary of the combined estimated Net Short for the three IOUs, excluding any of the bilateral energy purchase contracts held by CDWR. These Net Short projections were derived from data provided by the IOUs and the California Independent System Operator (CAISO) and are subject to further review. The projections assume average hydroelectric energy supply availability and continued operation of all existing QFs under contract to the IOUs at their contract rate of delivery.

Figure 1
Preliminary Estimate of Monthly Load and Resources (Excluding CDWR Contracts)
Investor Owned Utilities Combined

2001



*IOU generation includes nuclear, hydro, fossil generation and IOU bilateral power purchase agreements.

OBJECTIVES OF POWER PURCHASE NEGOTIATING TEAM

- Meet as much of remaining 2001 energy needs under contracts with known costs as possible.
- Optimize long-term commitments for energy purchase, with short- and intermediate-term purchases recognizing that longer-term contracts will reduce near-term prices relative to spot market.
- Provide a portfolio of short-, intermediate-, and long-term contracts and peak, intermediate, and base load supplies.
- Obtain a combination of fixed price and "tolling" agreements.
- Seek contracts which result in expedited construction of new generation capacity to enhance near-term system reliability.
- Match intra-state regional needs (north and south of Path 15 transmission constraint) to locations of supply.
- Seek contracts from suppliers in neighboring states for power imports and for summer/winter seasonal exchanges of power with suppliers in the Pacific Northwest.

OVERVIEW OF CDWR STRATEGY AND MARKET RESPONSE

- Bids received from a diverse group of suppliers—in-state and out-of-state, existing and new power plants.
- CDWR strategy—build a diverse portfolio of different durations. Give priority to contracts that result in construction of new power plants and offer long-term price stability. Limit ten-year contracts to entities that can provide power supplies starting in 2001.
- Issued two competitive solicitations for power supply and responded to numerous unsolicited offers.
- Several developers of future power projects targeted for operation in 2003 and beyond submitted bids for projects either recently permitted, under permit review, or yet to be proposed to the California Energy Commission for certification (providing no benefit for immediate energy supply and cost certainty).
- Most suppliers for 2001 summer season delivery tied to longer-term sales with increasing obligations to purchase in later years, generally requesting seven to ten years or longer.
- Longer term transactions provide for levelized prices which are significantly lower than short-term contract prices.

SUMMARY OF CONTRACTS AND AGREEMENTS IN PRINCIPLE

- CDWR has entered into approximately 19 final power supply contracts with seven suppliers and over 25 agreements in principle with various suppliers providing an average of over 8800 MW of electric capacity over the next ten years.
- Figure 2 presents the total peak capacity in MW under these contracts, by year. This is an approximation, as the amount of capacity under some contracts is contingent upon available hours of operation or the completion of new generation capacity.
- Figure 3 shows the amount of energy CDWR would purchase based on the final contracts and the agreements in principle compared to a preliminary estimate of a range of annual quantities of "net short" energy requirements.
- The energy volumes under contract to CDWR in Figure 3 are subject to change based upon those agreements in principle which do not close (reductions) and new agreements based upon continuing introduction of new supply opportunities (increases).
- The amount of energy under contract peaks in the 2004 through 2006 period and declines after 2006 due to: (a) the ramp up of energy purchases under the long-term contracts, (b) the expiration of some of the five to six-year contracts, and (c) a strategy to acquire the balance of energy requirements from the market in later years when low-cost supply options increase.

SUMMARY OF CONTRACTS AND AGREEMENTS IN PRINCIPLE (CONTINUED)

- Figure 4 presents the average annual cost per MWh for all energy under the combined contracts and agreements in principle. This cost is for the melded combination of base load, intermediate, peaking, and summer super peak contracts, the mixture of which changes over the ten-year period.
- Table 1 shows the product (base load, peak, summer super peak, off-peak), term (length) and quantity of each of the contracts and agreements in principle. The status of each contract (contract or agreement in principle) is also shown.
- Table 2 shows power supply proposals under discussion but not yet to the point of agreement in principle. None of the potential power supply arrangements in Table 2 are included in the power contracts quantities shown in Figures 2 and 3 nor the related average prices shown in Figure 4.

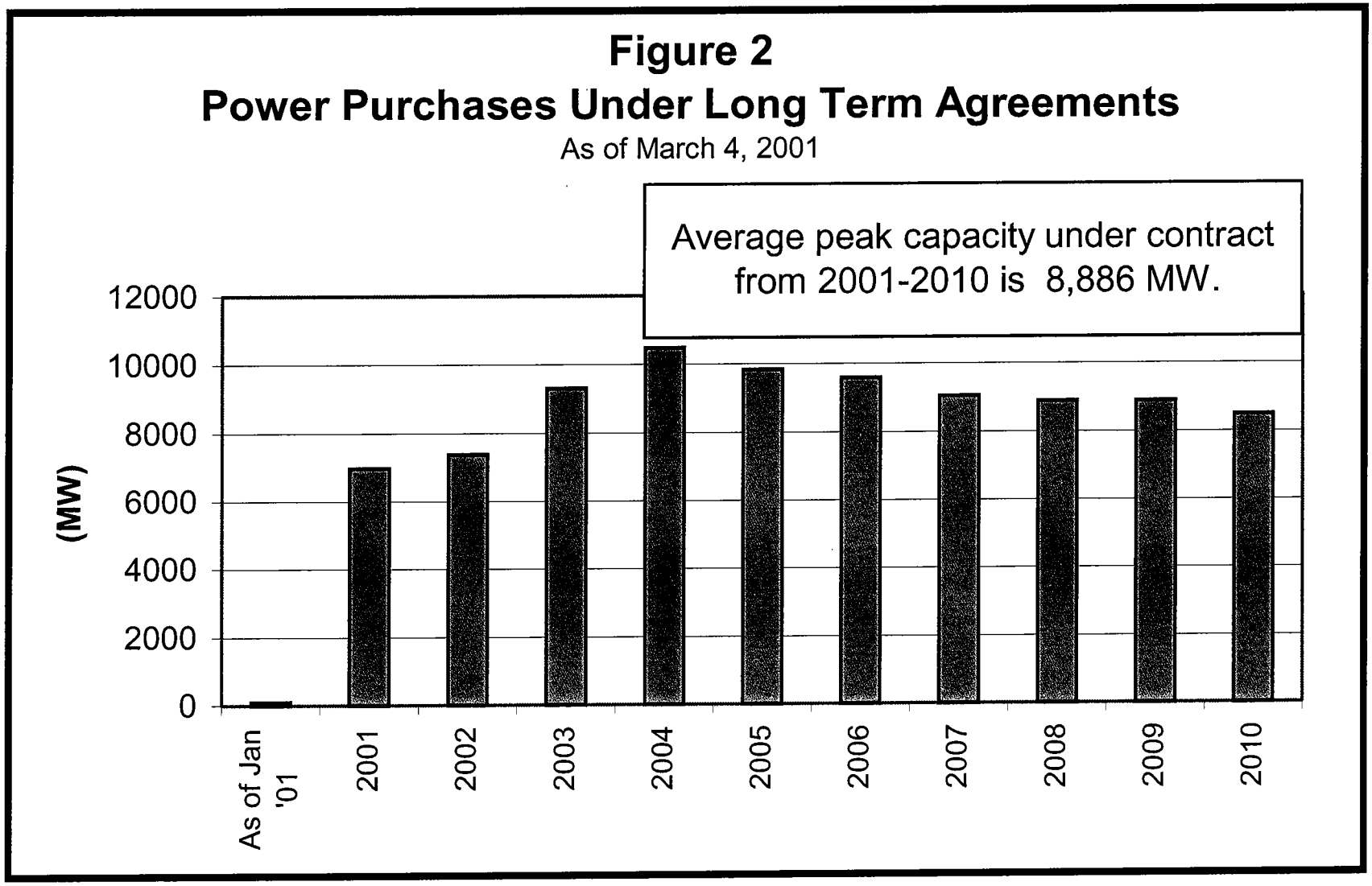
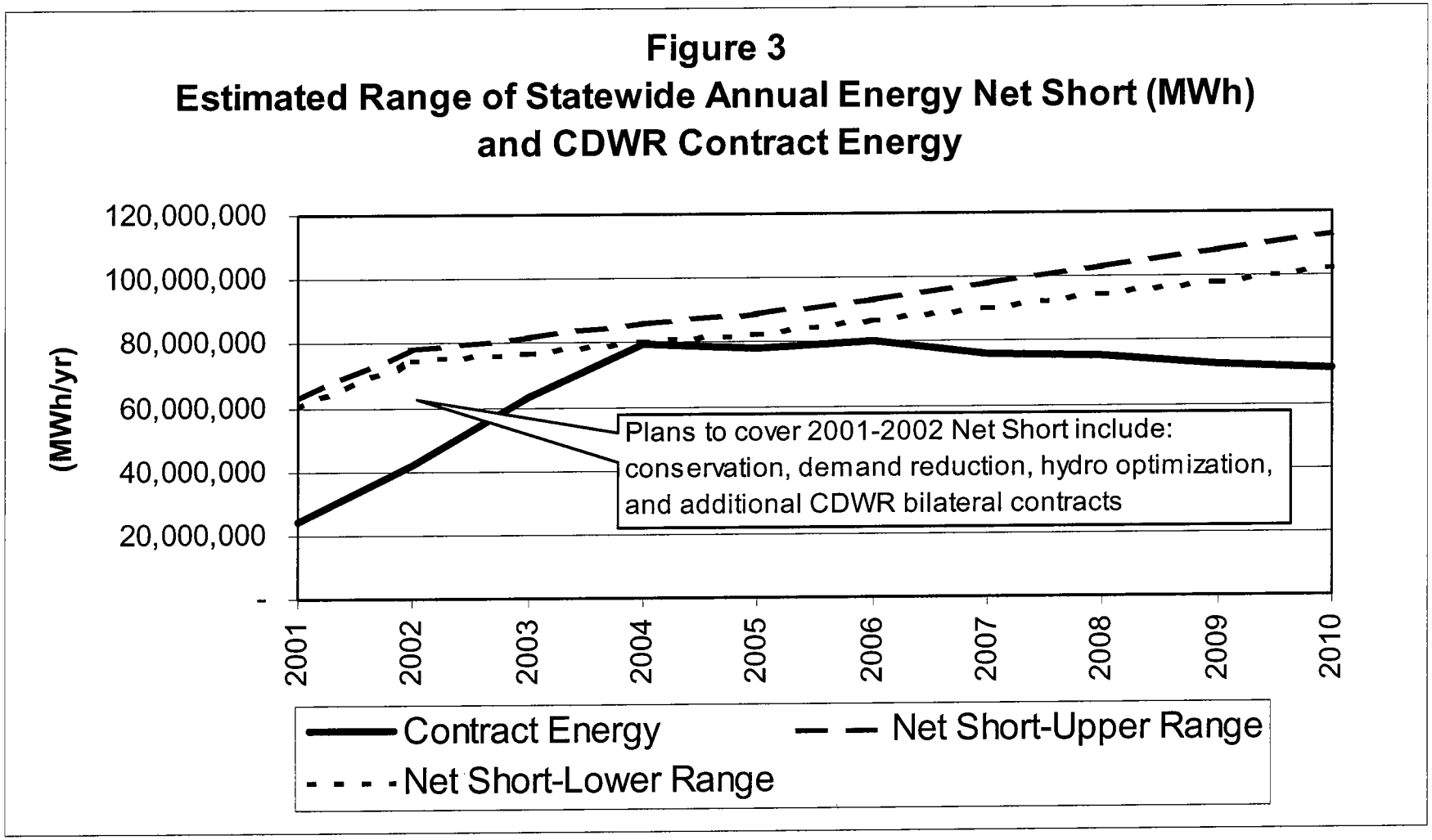


Figure 2
Power Purchases Under Long Term Agreements
As of March 4, 2001
Average peak capacity under contract from 2001-2010 is 8,886 MW.
(MW)
12000
10000
8000
6000
4000
2000
0
As of Jan '01
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010



Notes:
1. 2001 based on March through December data
2. Net Short ranges based on +/- 2.5% in 2001, growing to +/- 5% in 2010

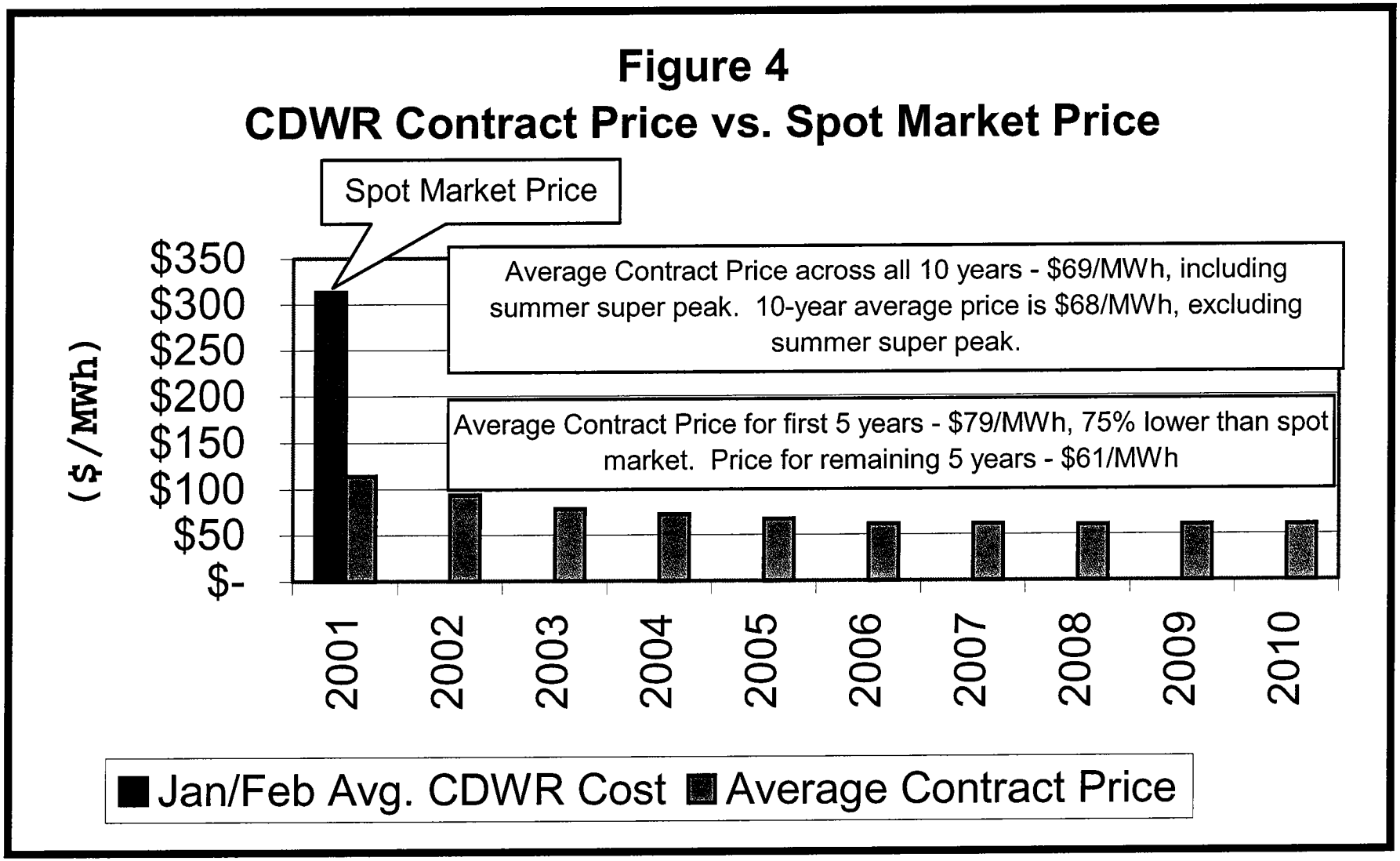


Figure 4
CDWR Contract Price vs. Spot Market Price
Spot Market Price
Average Contract Price across all 10 years - $69/MWh, including summer super peak. 10-year average price is $68/MWh, excluding summer super peak.
Average Contract Price for first 5 years - $79/MWh, 75% lower than spot market. Price for remaining 5 years - $61/MWh
($/MWh)
$350
$300
$250
$200
$150
$100
$50
$-
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Jan/Feb Avg. CDWR Cost
Average Contract Price

Insert Table 1 Here

Table 2
Proposals Under Discussion

CDWR POWER BIDS STATUS
AS OF March 8

	GENERAL TERMS									
Contact No.	Start	Term	Product	Zone	MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10
LONG TERM										
1	3/16/01	2.75 yr	Base	SP15	1000					
2	5/1/01	2.5 yr	Base	NP15	12	12	12			
3	7/1/01	10 yr	Peak	SP15	210	310	210	210	210	210
4	7/1/02	10 yr	Base	SP15		100	525	700	700	700
5	7/1/01	Bal. '01	OffPeak	NP15	*					
6	7/1/01	9.75 yr	As-avail.	SP15	44	44	44	44	44	44
7	1/2/02	9 yr	Base	SP15		50	100	100	100	100
8	2/9/02	5 yr	Base	SP15		25	25	25	25	25
9	5/1/02	9 yr	Base	NP15		690	690	690	690	690

Long-Term Under Discussion						
NP15	12	702	702	690	690	690
SP15	1,254	529	904	1,079	1,079	1,079
Total	1,266	1,231	1,606	1,769	1,769	1,769

NATURE OF AGREEMENTS

The contracts and agreements in principle held by CDWR include:

- The sale of standard energy products of: (a) base load (7days/week, 24 hours/day), (b) year around peaking (6 days/wk, 16 hrs/day), and (c) summer super peak (6 days per week, 10 hours per day, June through October summer peak season).
- Some of the above contracts are associated with specific generation assets and others are "market" transactions with firm energy delivery from sources at the discretion of the supplier.
- "Unit contingent" agreements where the output of the plant is provided up to its rated capacity, with energy deliveries subject to industry standard outages for scheduled events and outages for reasons beyond the generator's control.
- "Unit availability"contracts to provide as-available generation from one or more generators whose operations are limited by prior agreements to sell to others, or due to operating limits such as emission limitations which cannot be precisely predicted.
- Agreements with firm energy prices regardless of fuel costs and trends.
- Agreements with pricing tied to heat rate (efficiency) levels of a plant and gas prices in the market.
- "Tolling" agreements where CDWR can request the seller to nominate gas to fuel the plant for conversion to electricity at a specified efficiency of conversion, or for CDWR to arrange for fuel to be delivered for that purpose.
- Agreements where CDWR pays for specified capacity and can dispatch the generation at times of system need at a specified cost plus the cost of fuel for specified hours or in specified times of the year.

RIGHTS TO TERMINATE AGREEMENTS

Various agreements provide for termination by one party or the other prior to the full term of the agreement, which could result in changes in the energy supply portfolio from that presented in this summary.

Seller Termination
Termination rights by the seller in some of the agreements include, but are not limited to:

- Lack of maintenance of investment grade credit.
- Failure by CDWR to issue the bonds contemplated by AB1X prior to a set date (such as July 1, 2001).
- Failure to make energy payments within specified days after CDWR's receipt of an invoice.

Buyer's Termination:
Termination rights by the buyer (CDWR) in some of the agreements include, but are not limited to:

- Failure of a new generation unit to meet commercial operating date deadlines within a specified window.
- Failure to achieve certain operating standards (primarily unit availability) at specified levels for specified periods.
- Failure to operate a generating unit within "prudent industry practice" after notice and opportunity to cure such failure.

2001 PEAKING CAPACITY ADDITIONS

California ISO Summer Reliability Agreement Conversions

- CAISO entered into approximately 32 contracts with 12 developers to provide for up to about 1400 MW of summer 2001 peaking capacity (Summer Reliability Agreements or SRAs) with capacity payments, assuming energy would be sold into the spot market at open market prices, placing further upward pressure on energy prices.
- Purchases by the CAISO were to be paid by the IOUs.
- Concerns by sellers with lack of IOU creditworthiness caused developers to question moving forward to meet summer 2001 commercial operation.
- CDWR has aggressively acted to convert CAISO's SRAs to bilateral agreements with CDWR for capacity, and for energy at controlled prices.
- As of this week, approximately 800 MW of this SRA capacity is either under a definitive agreement in principle or in final negotiations and over 250 MW of remaining capacity is in preliminary negotiation stages. Approximately 675 MW of this capacity is included in the CDWR contract capacity presented in this summary (in Figures 2 and 3).

New Emergency Peaking Additions

- CDWR is in discussions with developers of over 600 MW of additional emergency peaking generators indicating ability to install or restart capacity this year. This additional capacity is not included in the portfolio CDWR contracts described in this summary.

ON-GOING ENERGY CONTRACTING

- CDWR continues efforts to contract for additional supplies for 2001 including peaking capacity.
- CDWR's energy trading desk will continue to purchase short-term and balance of month supplies to meet loads and fill in the portfolio to meet the net short energy requirements.
- Opportunities will continue to be sought for seasonal exchanges of summer energy purchases by CDWR and winter energy returns to the winter peaking Pacific Northwest region.
- In addition to energy purchases, CDWR will coordinate with the CAISO demand responsive load reduction program and the CPUC's proposed demand responsive load reduction plans to provide the option to reduce loads this summer on an economic and voluntary basis
- CDWR is also considering additional day-ahead bidding processes for load reduction as an alternative to paying extraordinarily high summer spot market prices for energy

REMAINING CHALLENGES

- Purchases to meet the remaining uncovered peak summer needs will cost more on the average than the long-term contracts.
- A plan and strategy is needed for hedging and/or acquiring fuel supplies to minimize costs under the tolling agreements.
- State maybe liable for certain additional costs under some fixed price contracts, such as additional taxes due to governmental actions, or termination rights of sellers due to credit requirements.
- Need to aggressively identify and pursue opportunities to obtain future cost-based power supply resources expected to come on line after 2003.
- Additional efforts are warranted to promote and encourage more renewable resources such as wind and biomass to create energy supply diversity.
- CDWR will need to expand its organization to actively manage and administer over 40 executed agreements to minimize cost.

STATE OF CALIFORNIA

SUMMARY OF CALIFORNIA DEPARTMENT OF WATER RESOURCES POWER PURCHASE CONTRACT EFFORTS

Prepared by
California Department of Water Resources

APRIL 18, 2001

TABLE OF CONTENTS

1. California's Electricity Action Plan 1
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CALIFORNIA'S ELECTRICITY ACTION PLAN

- Create a power purchase portfolio to reduce dependence on spot market, provide price stability and certainty.
- Expedite construction of new power plants, peaking facilities and distributed generation.
- Implement aggressive conservation and demand management program.
- Optimize use of existing transmission and expand transmission grid.
- Augment natural gas supplies, pipelines, and storage facilities.

POWER PURCHASE PORTFOLIO SUMMARY

- Increased California Department of Water Resources (CDWR) forward purchases by the end of February to 75% in the day-ahead and 95% in the day- and hour-ahead markets, substantially reducing dependence on the real-time market.
- Reduced CDWR average cost of spot market purchases from $330 per megawatt hour (MWh) to a portfolio averaging $228/MWh by the end of February.
- Reduced the risk of blackouts and brownouts.
- Assembled a diversified portfolio of agreements that meet the goal of reducing dependence on spot market and price stability. The ten-year average portfolio price $71/MWh.
- Agreements result in expediting construction of new power plants with 10,000 megawatt (MW) slated to come on-line within 24 months, as much as 5,000 MW as early as this year.
- Seasonal power exchanges between California and the Pacific Northwest which offer significant operational benefits and reduce dependence on the spot market.
- Agreements for 5,500 MW for 2001; average of approximately 9,700 MW per year for the next ten years.

OVERVIEW OF THE "NET SHORT" ENERGY REQUIREMENTS OF CALIFORNIA

Under AB 1X, CDWR has proceeded to purchase the amount of energy not otherwise supplied by the combination of:

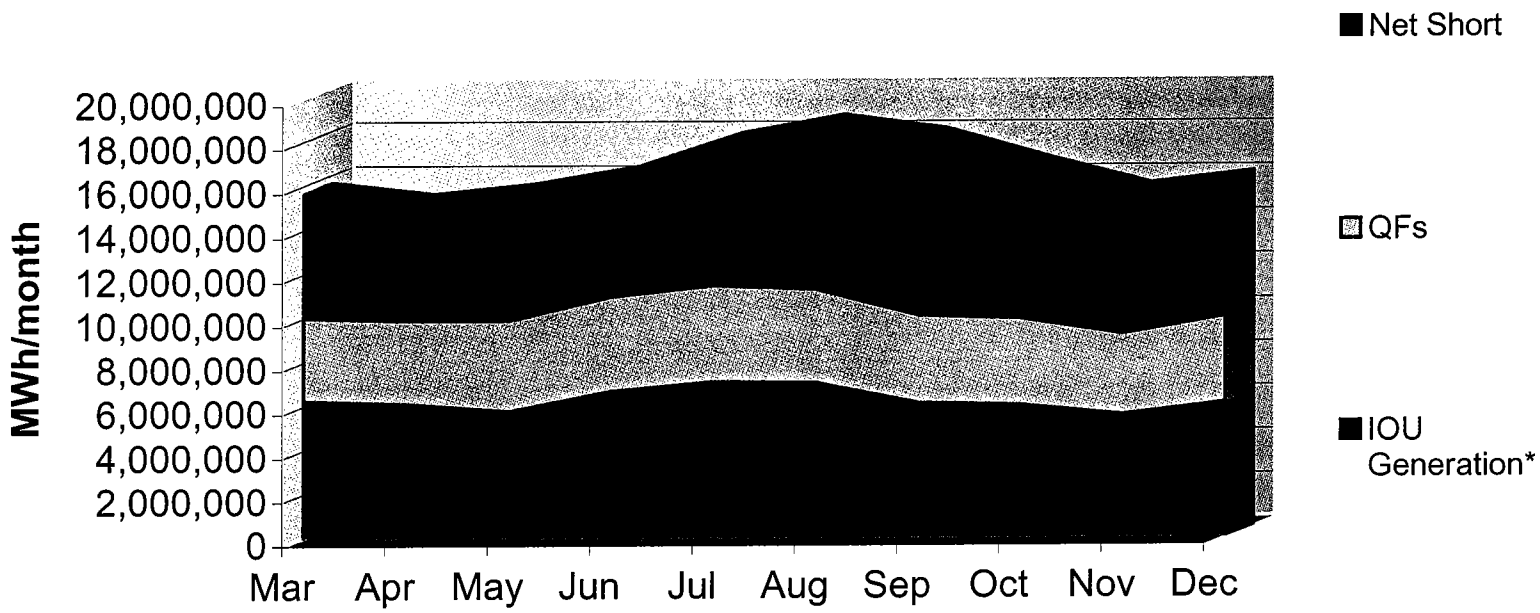
- Retained generation resources of the three investor-owned utilities (IOUs) in California, most of which is either hydroelectric or nuclear generation.
- Capacity and energy from the remaining Qualifying Facilities (QFs) under contract to the three IOUs (either renewable energy resources or cogeneration facilities operating under standard offer agreements with the IOUs).
- Certain existing power purchase agreements (PPA) or "bilateral" contracts held by the IOUs.

The difference between the energy needs of the state's electric utility customers and the sum of the above sources of supply is the "Net Short" requirement which CDWR is meeting through a combination of spot market and a mixture of short-, intermediate-, and long-term bilateral contracts for energy purchase.

Figure 1 provides a representative summary of the combined estimated Net Short for the three IOUs, excluding any of the bilateral energy purchase contracts held by CDWR. These Net Short projections were derived from data provided by the IOUs and the California Independent System Operator (CAISO) and are subject to further review. The projections in Figure 1 assume average hydroelectric energy supply availability and continued operation of all existing QFs under contract to the IOUs at their contract rate of delivery.

Figure 1
Preliminary Estimate of Monthly Load and Resources (Excluding CDWR Contracts)
Investor Owned Utilities Combined

2001



*IOU generation includes nuclear, hydro, fossil generation and IOU bilateral power purchase agreements.

OBJECTIVES OF POWER PURCHASE NEGOTIATING TEAM

- Meet as much of remaining 2001 energy needs under contracts with known costs as possible.
- Optimize long-term commitments for energy purchase, with short- and intermediate-term purchases recognizing that longer-term contracts will reduce near-term prices relative to spot market.
- Provide a portfolio of short-, intermediate-, and long-term contracts and peak, intermediate, and base load supplies.
- Obtain a combination of fixed price and "tolling" agreements.
- Seek contracts which result in expedited construction of new generation capacity to enhance near-term system reliability.
- Match intra-state regional needs (north and south of Path 15 transmission constraint) to locations of supply.
- Seek contracts from suppliers in neighboring states for power imports and for summer/winter seasonal exchanges of power with suppliers in the Pacific Northwest.

OVERVIEW OF CDWR STRATEGY AND MARKET RESPONSE

- Bids received from a diverse group of suppliers—in-state and out-of-state, existing and new power plants.
- CDWR strategy—build a diverse portfolio of different durations. Give priority to contracts that result in construction of new power plants and offer long-term price stability. Limit ten-year contracts to entities that can provide power supplies starting in 2001.
- Issued two competitive solicitations for power supply and responded to numerous unsolicited offers.
- Several developers of future power projects targeted for operation in 2003 and beyond submitted bids for projects either recently permitted, under permit review, or yet to be proposed to the California Energy Commission for certification (providing no benefit for immediate energy supply and cost certainty).
- Most suppliers for 2001 summer season delivery tied to longer-term sales with increasing obligations to purchase in later years, generally requesting seven to ten years or longer.
- Longer term transactions provide for levelized prices which are significantly lower than short-term contract prices.

SUMMARY OF CONTRACTS AND AGREEMENTS IN PRINCIPLE

- CDWR has entered into approximately 24 final power supply contracts with 10 suppliers and 25 agreements in principle with various suppliers providing an average of over 9,700 MW of electric capacity over the next ten years.
- Figure 2 presents the total peak capacity in MW under these contracts, by year. This is an approximation, as the amount of capacity under some contracts is contingent upon available hours of operation or the completion of new generation capacity.
- Figure 3 shows the amount of energy CDWR would purchase based on the final contracts and the agreements in principle compared to a preliminary estimate of a range of annual quantities of "net short" energy requirements.
- The energy volumes under contract to CDWR in Figure 3 are subject to change based upon those agreements in principle which do not close (reductions) and new agreements based upon continuing introduction of new supply opportunities (increases).
- The amount of energy under contract peaks in the 2004 through 2006 period and declines after 2006 due to: (a) the ramp up of energy purchases under the long-term contracts, (b) the expiration of some of the five to six-year contracts, and (c) a strategy to acquire the balance of energy requirements from the market in later years when low-cost supply options increase.

SUMMARY OF CONTRACTS AND AGREEMENTS IN PRINCIPLE (CONTINUED)

- Figure 4 presents the average annual cost per MWh for all energy under the combined contracts and agreements in principle. This cost is for the melded combination of base load, intermediate, peaking, and summer super peak contracts, the mixture of which changes over the ten-year period.
- Table 1 shows the product (base load, peak, summer super peak, off-peak), term (length) and quantity of each of the contracts and agreements in principle. The status of each contract (contract or agreement in principle) is also shown.
- Table 2 shows power supply proposals under discussion but not yet to the point of agreement in principle. None of the potential power supply arrangements in Table 2 are included in the power contracts quantities shown in Figures 2 and 3 nor the related average prices shown in Figure 4.

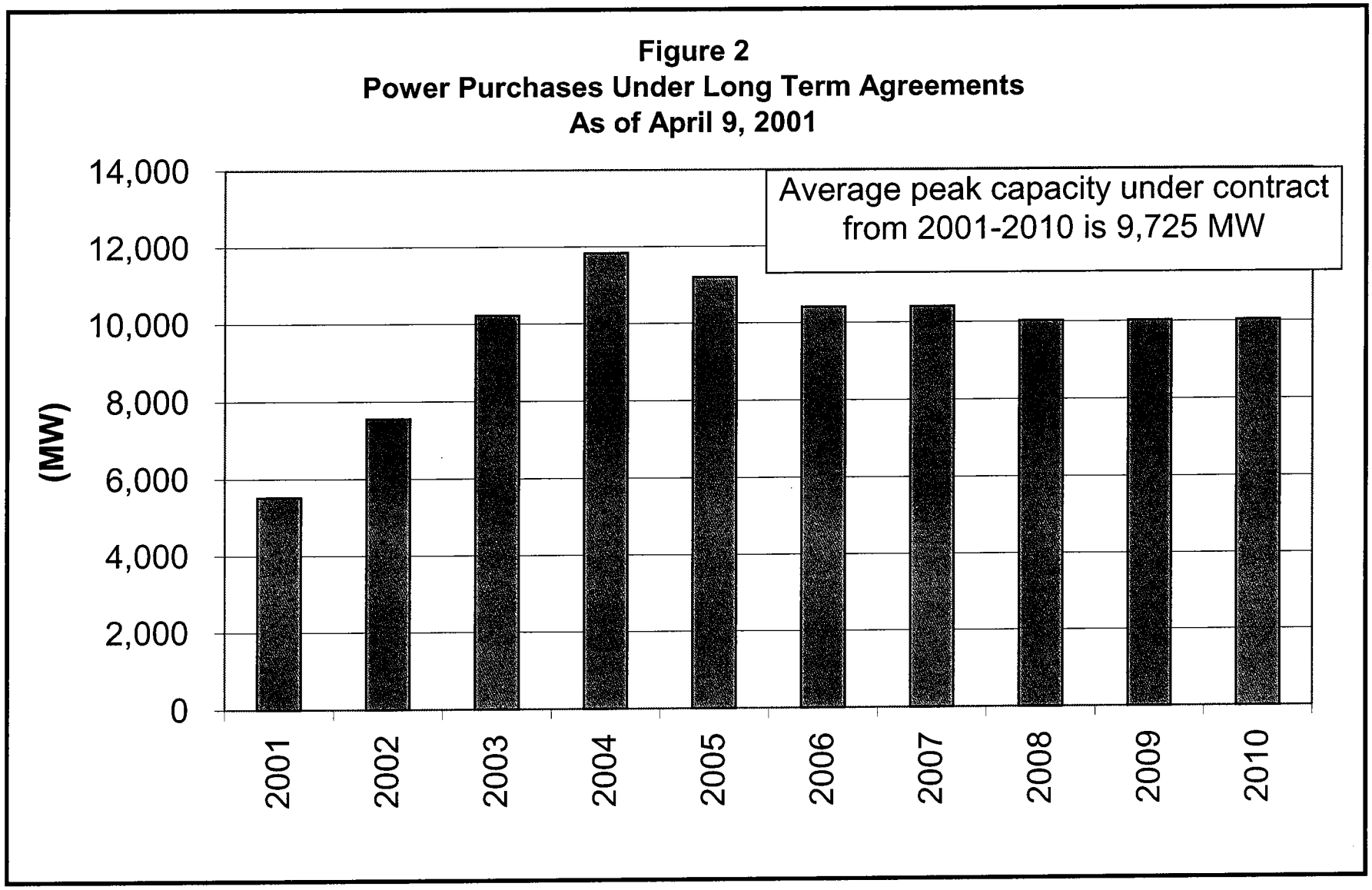
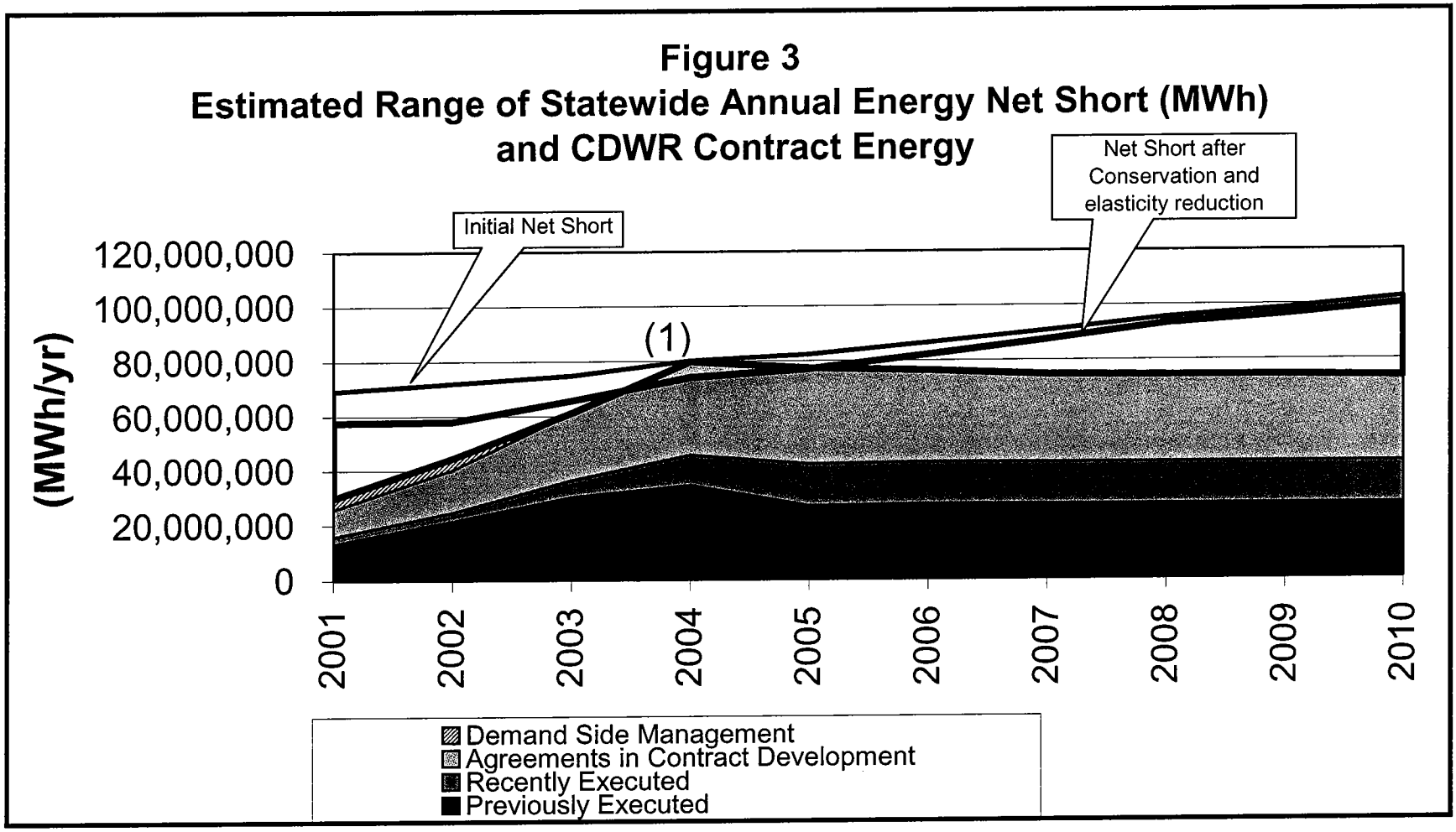


Figure 2
Power Purchases Under Long Term Agreements
As of April 9, 2001
Average peak capacity under contract from 2001-2010 is 9,725 MW
(MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010



Notes:

1. Some portion of the energy presented in this curve is dispatchable and would not be called upon for operation if the net short energy needs are less than available contract delivery quantities.
2. 2001 based on March through December data.

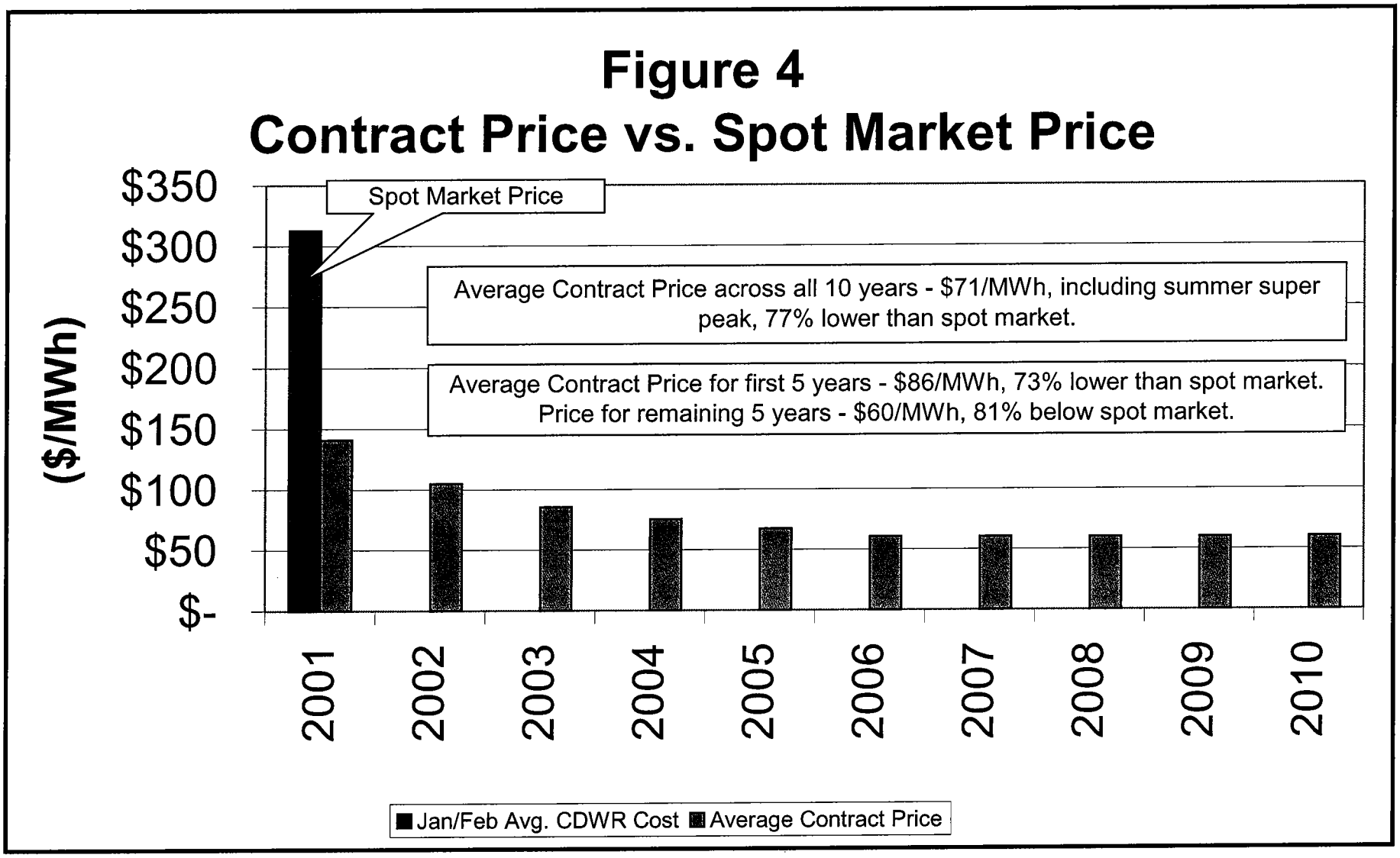


Figure 4
Contract Price vs. Spot Market Price
($/MWh)
$350
$300
$250
$200
$150
$100
$50
$-
Spot Market Price
Average Contract Price across all 10 years - $71/MWh, including summer super peak, 77% lower than spot market.
Average Contract Price for first 5 years - $86/MWh, 73% lower than spot market. Price for remaining 5 years - $60/MWh, 81% below spot market.
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Jan/Feb Avg. CDWR Cost
Average Contract Price

Insert Table 1 Here

Table 2
Proposals Under Discussion

CDWR POWER BIDS STATUS
AS OF April 9

					GENERAL TERMS					
Contact No.	Start	Term	Product	Zone	MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10
LONG TERM										
1	5/1/01	2.5 yr	Base	NP15	12	12	12			
2	7/1/01	3.5 yr	Dispatch	SP15	495	495	1,190	1,190		
3	7/1/01	3.5 yr	Base	SP15	250	250	300	300		
4	7/1/01	4.5 yr	Base-Peak	NP15	250	500	500	500	500	
5	7/1/01	9.75 yr	As-avail.	SP15	66	66	66	66	66	66
6	9/1/01	10.25 yr	Dispatch	NP15	88	340	430	430	430	430
7	2/9/02	5 yr	Base	SP15		25	25	25	25	25
	Total Long-Term Under Discussion									
	NP15				350	852	942	930	930	430
	SP15				811	836	1,581	1,581	91	91
	Total				1,161	1,688	2,523	2,511	1,021	521

NATURE OF AGREEMENTS

The contracts and agreements in principle held by CDWR include:

- The sale of standard energy products of: (a) base load (7days/week, 24 hours/day), (b) year around peaking (6 days/wk, 16 hrs/day), and (c) summer super peak (6 days per week, 10 hours per day, June through October summer peak season).
- Some of the above contracts are associated with specific generation assets and others are "market" transactions with firm energy delivery from sources at the discretion of the supplier.
- "Unit contingent" agreements where the output of the plant is provided up to its rated capacity, with energy deliveries subject to industry standard outages for scheduled events and outages for reasons beyond the generator's control.
- "Unit availability" contracts to provide as-available generation from one or more generators whose operations are limited by prior agreements to sell to others, or due to operating limits such as emission limitations which cannot be precisely predicted.
- Agreements with firm energy prices regardless of fuel costs and trends.
- Agreements with pricing tied to heat rate (efficiency) levels of a plant and gas prices in the market.
- "Tolling" agreements where CDWR can request the seller to nominate gas to fuel the plant for conversion to electricity at a specified efficiency of conversion, or for CDWR to arrange for fuel to be delivered for that purpose.
- Agreements where CDWR pays for specified capacity and can dispatch the generation at times of system need at a specified cost plus the cost of fuel for specified hours or in specified times of the year.

RIGHTS TO TERMINATE AGREEMENTS

Various agreements provide for termination by one party or the other prior to the full term of the agreement, which could result in changes in the energy supply portfolio from that presented in this summary.

Seller Termination
Termination rights by the seller in some of the agreements include, but are not limited to:

- Lack of maintenance of investment grade credit.
- Failure by CDWR to issue the bonds contemplated by AB1X prior to a set date (such as July 1, 2001).
- Failure to make energy payments within specified days after CDWR's receipt of an invoice.

Buyer's Termination:
Termination rights by the buyer (CDWR) in some of the agreements include, but are not limited to:

- Failure of a new generation unit to meet commercial operating date deadlines within a specified window.
- Failure to achieve certain operating standards (primarily unit availability) at specified levels for specified periods.
- Failure to operate a generating unit within "prudent industry practice" after notice and opportunity to cure such failure.

2001 PEAKING CAPACITY ADDITIONS

California ISO Summer Reliability Agreement Conversions

- CAISO entered into approximately 32 contracts with 12 developers to provide for up to about 1400 MW of summer 2001 peaking capacity (Summer Reliability Agreements or SRAs) with capacity payments, assuming energy would be sold into the spot market at open market prices, placing further upward pressure on energy prices.
- Purchases by the CAISO were to be paid by the IOUs.
- Concerns by sellers with lack of IOU creditworthiness caused developers to question moving forward to meet summer 2001 commercial operation.
- CDWR has aggressively acted to convert CAISO's SRAs to bilateral agreements with CDWR for capacity, and for energy at controlled prices.
- As of this week, over 600 MW of this SRA capacity is either under a definitive agreement in principle or in final negotiations, and these MW are included in the CDWR contact capacity presented in this summary (in Figures 2 and 3). Approximately 500 MW of remaining capacity is in on-going negotiations.

New Emergency Peaking Additions

- CDWR is in discussions with developers of over 1,000 MW of additional emergency peaking generators indicating ability to install or restart capacity this year. This additional capacity is not included in the portfolio CDWR contracts described in this summary.

ON-GOING ENERGY CONTRACTING

- CDWR continues efforts to contract for additional supplies for 2001 including peaking capacity.
- CDWR's energy trading desk will continue to purchase short-term and balance of month supplies to meet loads and fill in the portfolio to meet the net short energy requirements.
- Opportunities will continue to be sought for seasonal exchanges of summer energy purchases by CDWR and winter energy returns to the winter peaking Pacific Northwest region.
- In addition to energy purchases, CDWR will coordinate with the CAISO demand responsive load reduction program and the CPUC's proposed demand responsive load reduction plans to provide the option to reduce loads this summer on an economic and voluntary basis
- CDWR is also considering additional day-ahead bidding processes for load reduction as an alternative to paying extraordinarily high summer spot market prices for energy

REMAINING CHALLENGES

- Purchases to meet the remaining uncovered peak summer needs will cost more on the average than the long-term contracts.
- A plan and strategy is needed for hedging and/or acquiring fuel supplies to minimize costs under the tolling agreements.
- State maybe liable for certain additional costs under some fixed price contracts, such as additional taxes due to governmental actions, or termination rights of sellers due to credit requirements.
- Need to aggressively identify and pursue opportunities to obtain future cost-based power supply resources expected to come on line after 2003.
- Additional efforts are warranted to promote and encourage more renewable resources such as wind and biomass to create energy supply diversity.
- CDWR will need to expand its organization to actively manage and administer over 40 executed agreements to minimize cost.

Table 1
Agreements Executed and In Contract Development

CDWR POWER BIDS STATUS
AS OF April 9

Contact No.	Start	Term	Product	Zone	GENERAL TERMS MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10	STATUS Submitted	Agreement in Principle	Signed Contract
					(MW shown reflect July capacity, before transmission losses)								
LONG TERM													
1	2/9/01	5 yr	Peak	SP15	50	50	50	50	50		2/6/01	2/7/01	2/13/01
2	2/9/01	5 yr	Peak	NP15	50	50	50	50	50		2/6/01	2/7/01	2/13/01
3	2/13/01	14 mos	Base	NP15	12	*							2/01
4	2/15/01	5 yr	Base	SP15	50	50	50	50	50		2/6/01	2/7/01	2/20/01
5	2/7/01	Bal. '01	Op. Res.	NP15	Unspec.						2/9/01	2/14/01	2/20/01
6	2/23/01	3/30/06	Peak	NP15	200	200	200	200	200		2/6/01	2/7/01	2/22/01
7	3/1/01	Bal '01	Peak	SP15	1000						2/22/01	2/23/01	3/2/01
8	3/1/01	Bal. '01	OffPeak	SP15	**						2/22/01	2/23/01	3/2/01
9	4/1/01	10 yr	Peak	SP15	175	200	250	250	300	300	2/5/01	2/6/01	2/16/01
10	6/1/01	4.5 yr	Peak	SP15	140	160	240	320	400		2/9/01	2/9/01	2/21/01
11	6/1/01	9.5 yr	Base	SP15	35	40	60	80	100	600	2/9/01	2/9/01	2/21/01
12	7/1/01	9.5 yr	Base	NP15	200	1,000	1,000	1,000	1,000	1,000		2/21/01	2/27/01
13	8/1/01	20 yr	Peak	NP15	*	450	495	495	495	495		2/21/01	2/27/01
14	10/1/01	10 yr	Base	NP15	*	350	600	1,000	1,000	1,000	1/24/01	2/6/01	2/6/01
15	1/1/02	3 yr	Base	SP15		200	200	200			2/22/01	2/23/01	3/2/01
16	1/1/02	3 yr	Peak	SP15		600	600	600			2/22/01	2/23/01	3/2/01
17	1/1/02	3 yr	Peak	SP15		500	500	500			2/22/01	2/23/01	3/2/01
18	1/1/02	3 yr	OffPeak	SP15		**	**	**			2/22/01	2/23/01	3/2/01
19	1/1/03	8 yr	Peak	SP15			500	500	500	500			2/21/01
20	7/1/03	8.25 yr	Base	SP15			730	730	730	730	2/27/01	2/28/01	3/15/01
21	4/1/01	2.25 yr	Peak	SP15	200	200	*				2/27/01	2/28/01	3/15/01
22	3/15/01	6 mos	Peak	SP15	250						2/12/01	2/26/01	3/26/01
23	10/1/01	10.25 yr	Base	SP15	*	250	250	500	1,000	1,000	2/12/01	2/26/01	3/26/01
24	6/1/01	2.5 yr	Base	SP15	16	16	16				2/6/01	2/7/01	3/13/01
25	3/1/01	4 mos	Base	SP15	*						2/12/01	2/15/01	
26	3/1/01	Bal. '01	Peak	NP15	500							Jan	
27	4/1/01	1.5 yr	Peak	NP15	400	400					2/23/01	2/26/01	
28	4/1/01	Bal. '01	Peak	SP15	925							Jan	
29	5/1/01	4.5 yr	Base	NP15	13	13	13				2/6/01	2/15/01	
30	6/1/01	10.3 yr	Peak	SP15	250	300	350	700	700	700		2/28/01	
31	7/1/01	5 yr	Peak	SP15	450	450	450	450	450		2/16/01	3/2/01	
32	7/1/01	5 yr	Base	SP15	90	90	90	90	90		2/16/01	3/2/01	
33	7/1/01	10 yr	Base	NP15	100	200	200	400	400	400	2/9/01	2/12/01	
34	7/15/01	17 mos	SSPeak	SP15	325	325					2/15/01	3/2/01	
35	6/1/03	8 yr	Base	SP15			542	542	542	542	2/15/01	3/2/01	
36	1/1/02	9 yr	Base	SP15		300	300	300	300	300	1/24/01	2/28/01	
37	1/1/02	9 yr	Base	NP15		250	500	500	500	500	1/24/01	2/28/01	
38	4/1/02	9.5 yr	Base	SP15		150	1,000	1,200	1,200	1,200		2/28/01	
39	4/1/01	11.25 yr	Peak	NP15		150	375	550	550	550		3/16/01	
40	4/1/01	11.25 yr	Peak	SP15	150	150	200	200	200	200		3/16/01	
41	7/1/02	10 yr	Base	NP15		50	50	50	50	50		3/16/01	
42	7/1/02	10 yr	Base	SP15		50	50	50	50	50		3/16/01	
43	8/1/01	10 yr	Sum. Peak	SP15	*	80	80	80	80	80		2/26/01	
44	9/1/01	10 yr	SSPeak	NP15	*	96	96	96	96	96		2/28/01	
45	9/1/01	10 yr	SSPeak	SP15	*	144	144	144	144	144		2/28/01	
46	11/1/01	10 yr	Peak	NP15	*	*	*	*	*	*		2/28/01	
47	11/1/01	10 yr	Peak	SP15	*	*	*	*	*	*		2/28/01	
48	8/1/01	6.25 yr	Peak	SP15	*	95	95	95	95	95	3/1/01	3/27/01	
49	6/15/01	10yr	Peak	NP15	49	94	94	94	94	94		4/9/01	
				NP15	1,524	3,303	3,673	4,435	4,435	4,185			
				SP15	4,106	4,400	6,747	7,631	6,981	6,441			
				Total	5,630	7,703	10,420	12,066	11,416	10,626			

	MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10
Agreements Being Negotiated	3,252	3,387	4,629	5,541	5,541	5,001
Weekly Progress - Agreements Executed Since 3/14	466	466	996	1,230	1,730	1,730
Executed Agreements	1,912	3,850	4,795	5,295	4,145	3,895
	5,630	7,703	10,420	12,066	11,416	10,626

Notes: Lines 26 and 28 represent the Block Forward contracts assumed by CDWR.
* Capacity provided during year, but not in July (month of maximum statewide net short)
** Off-Peak capacity is not part of peak MW tabulation

Update of California Department of Water Resources Power Purchase Contract Efforts

Prepared by

California Department of Water Resources

May 31, 2001

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Estimated Net Short Energy Requirements

- DWR is purchasing the net short energy requirements for retail electric customers (Customers) of the California investor-owned utilities (IOUs). The net short energy requirements represent the difference between the Customers' total electricity requirements and the amount of energy provided by the IOUs' retained generation, which includes:
  - Generating resources owned by the IOUs (nuclear, hydroelectric, and some fossil-fueled generation located both in California and out of state)
  - Capacity and energy from Qualifying Facilities (QFs) under contract to the three IOUs (renewable energy resources or cogeneration facilities operating under standard offer agreements with the IOUs)
  - Certain existing power purchase agreements (PPA) or "bilateral" contracts held by the IOUs.
- The amount of the net short energy requirements, in any given month, is dependent upon the Customers' total electric energy requirements and the amount of energy produced by the utility retained generation.
- Reduced hydroelectric generation capability in California in 2001 has also reduced the energy produced by the utility retained generation, increasing net short energy requirements for 2001 as compared to average conditions. These increases are also reflected in the projected net short energy requirements.
- The net short energy requirements presented herein are based on forecasts created earlier this year and are subject to adjustment based upon actual Customer demand and any future changes in utility retained generation energy production, and changes in Customer direct access trends. Such updates will be completed before DWR issues bonds for the energy procurement program.
- In the enclosed Appendix, are tables and figures of estimated total IOU Customer electric loads and energy requirements and net short energy requirements.

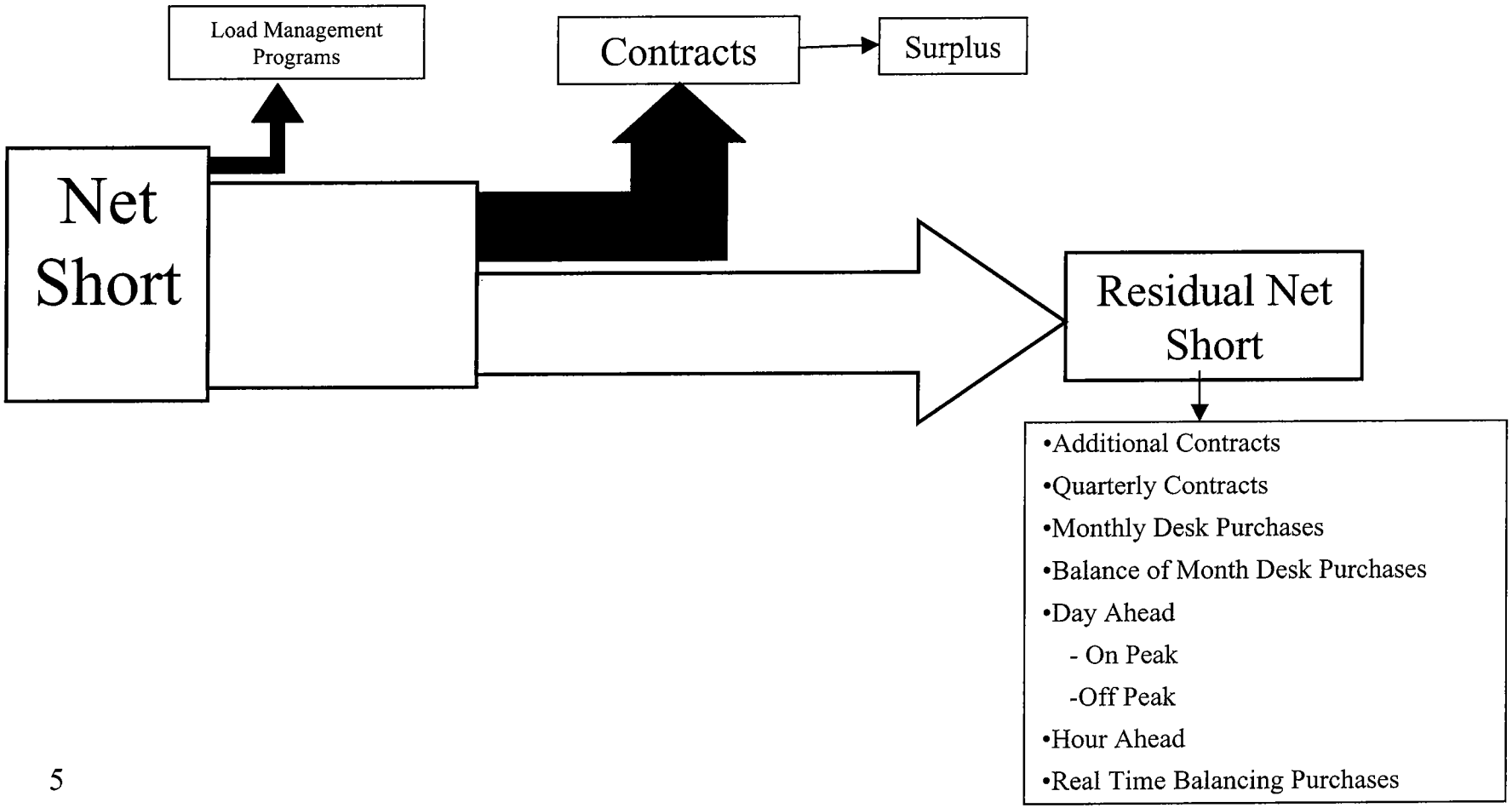
DWR's Methods to Meet Net Short Energy Requirements

DWR's approach to meeting the net short energy requirements, as shown conceptually on Figure 1, is multi-faceted:

- First, DWR's analysis incorporates assumed reductions provided by load management programs (Governor's 20/20 Program, various legislatively established conservation programs, and several voluntary load curtailment programs).
- Second, DWR has entered in a significant number of contracts and continues to negotiate long-term power contracts. Initial contracting activity succeeded in drastically reducing the amount of energy subject to spot market prices. Current activity is focused on achieving further reductions in the peak load aspect of the net short through dispatchable resources to follow peak load.
- The "residual net short" is the amount of power needs currently remaining after accounting for DWR's long-term contracting activities. DWR will meet these remaining power needs through the strategic balancing of a variety of options, including:
  - Additional long-term contracting;
  - "Short-term" contracting performed by DWR's trading desk to take advantage of changing market conditions (e.g. contracts for Quarterly, Monthly, Balance-of-Month, Day-Ahead, Hour-Ahead); and
  - Real-time supply through the ISO.

Components of DWR Purchases of Net Short Energy

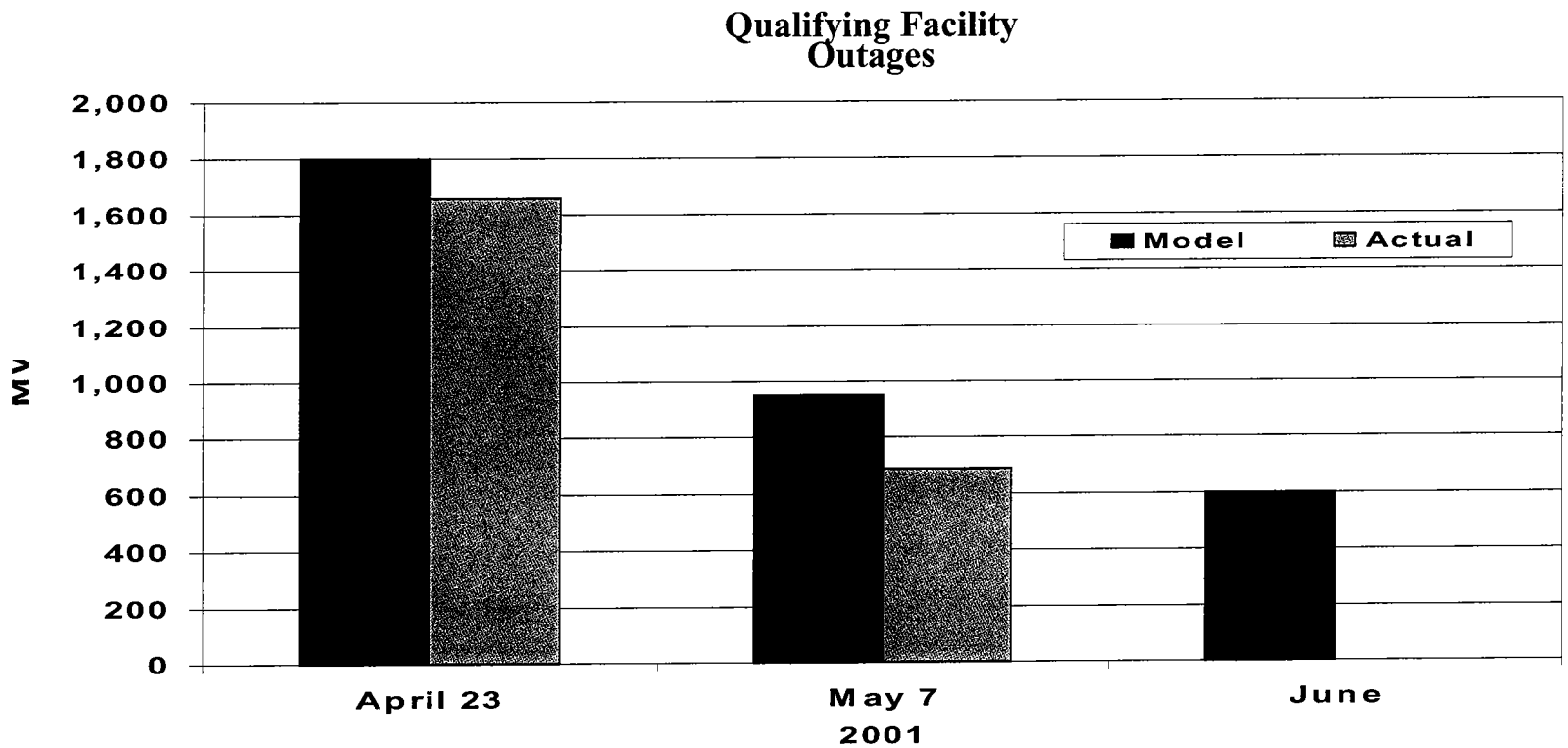
Figure 1



Qualifying Facility Capacity Return to Operation

- In prior projections, QF capacity was estimated to be reduced by 1,800 MW in April 2001, 950 MW in May, and approximately 550 MW in June 2001, with similar reductions to the June level thereafter.
- As shown in Figure 2, the QF capacity has returned to levels better than these projections, as of the first week of May.

Figure 2



DWR Power Contract Progress

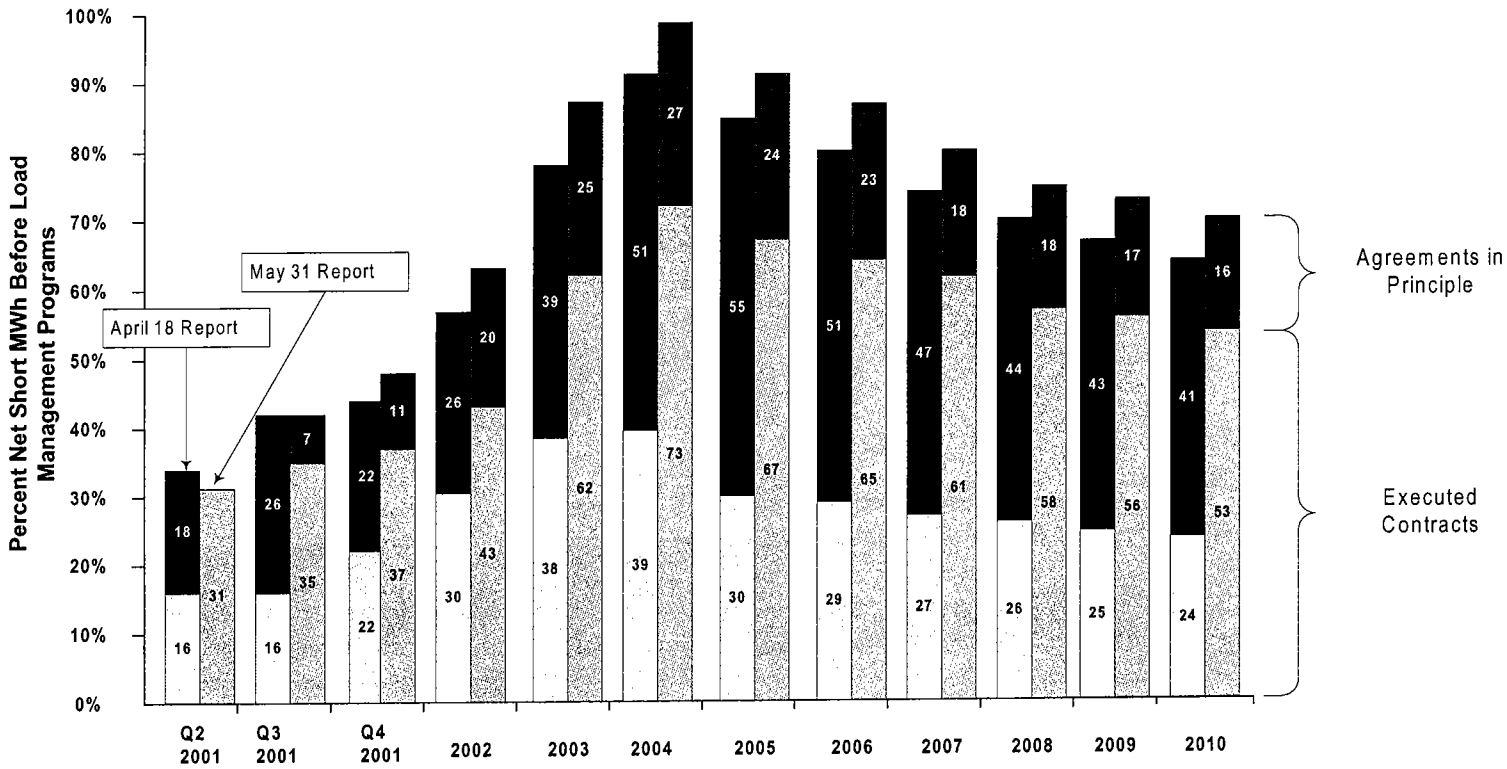
- Figure 3 shows the changes in contract additions since the April 18 update report provided by DWR.

- Note that this depiction of the contract annual energy volumes includes energy available from dispatchable generating units. For dispatchable contracts, DWR typically pays a fixed monthly or annual capacity payment and has rights to dispatch (require operation) of the unit, typically intended for peak hours. This figure shows the amount of energy if all the available dispatchable energy was requested.

DWR Power Contract Progress (cont'd)

Figure 3

Long-term Agreements	# Executed	# Agreed-in-Principle	Total #
April 18 Update:	24	25	49
May 31 Update:	38	23	61



Summary of Changes from April 18, 2001 Update

- Average annual capacity under contract for 2001-2010 increased from 9,725 MW to 10,950 MW (including Executed agreements and Agreements in Principle).
- A net 14 additional agreements were Executed, providing a net additional 2,160 MW in 2001, and an annual average of 2,080 net additional MW during 2001-2010. Sources of the changes were:
  - 8 Agreements in Principle were converted to Executed Contracts
  - 5 new agreements which went directly to final Executed contracts without an intermediate Agreement in Principle
  - 2 PX Block Forward agreements were reclassified as Executed*
  - reduction of 1 Executed agreement which had an option for a term extension which was not exercised
- There was a net decrease of 2 Agreements in Principle. Sources of the changes were:
  - 11 new Agreements in Principle
  - 10 Agreements in Principle moved to the Executed category
  - 3 Agreements in Principle were cancelled
- Contracted energy (Executed and Agreements in Principle) has grown from 70% to 77% of the total net short energy requirements during peak hours of the period from 2001 through 2010.

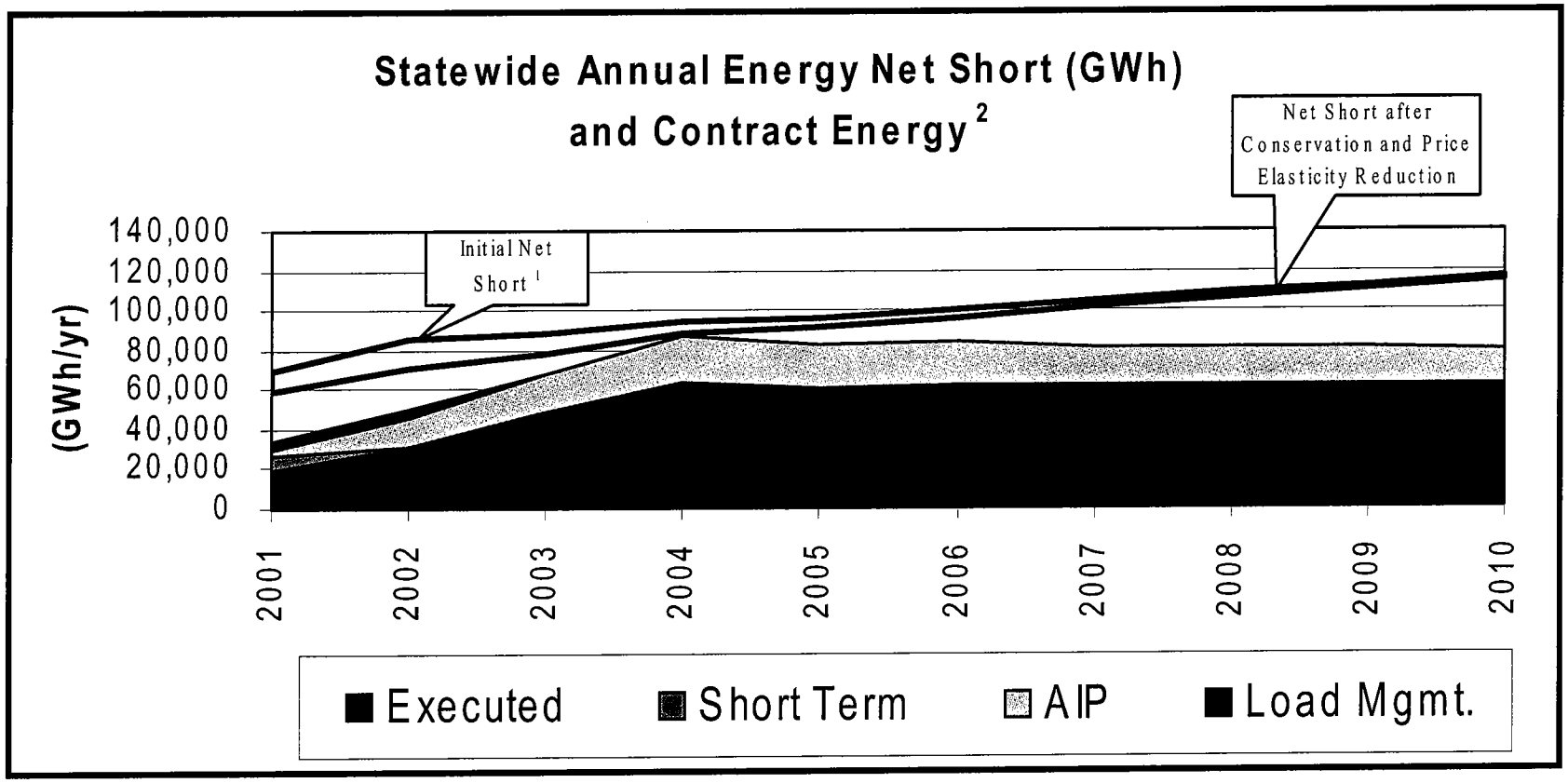
*While these agreements have fixed prices and power is being delivered, their final valuation is subject to dispute

Annual Net Short Energy Projection

- Figure 4 shows the updated projected annual net short energy needs and the amount of the estimated requirements to be met by energy conservation, funded load management and the energy under contract with DWR
- In the past few weeks, DWR's trading desk has increased its activity in purchasing energy on a "balance of month", monthly and quarterly basis. These purchases are shown as "Short Term" on Figure 4 and are reflected in the so-named shaded area during 2001. These short-term contract purchases reduce DWR's exposure to the spot (day-ahead and intra-day purchases) market.
- The Short-Term contracts are also executed contracts.

Annual Net Short Energy Requirements and Contract Energy

Figure 4



1. Some portion of the energy resented in this curve is dispatchable and would not be called upon for operation if the net short energy needs are less than available contract delivery quantities
2. 2001 based on May through December data.
3. "AIP" = Agreement in Principle

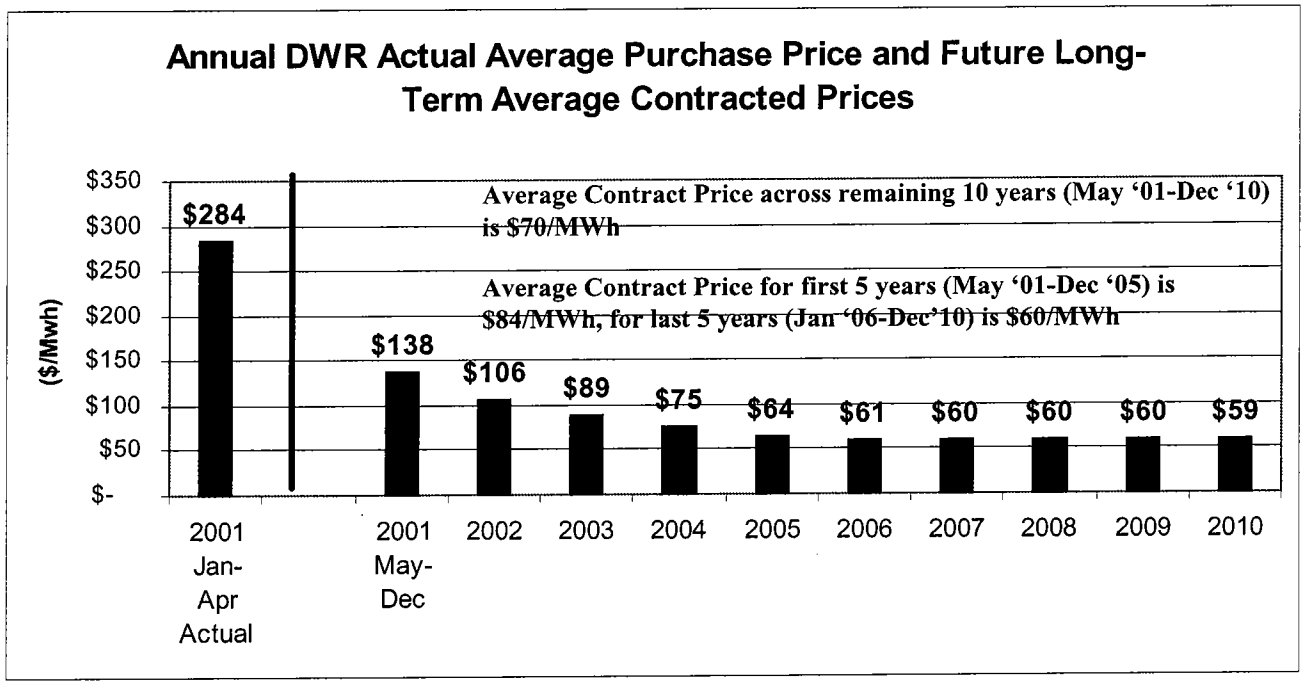
With Increased Contract Volumes, Prices are Stablized

- Figure 5 shows the average annual long-term contract costs including the increased quantities.

- Figure 6 shows the quarterly average contract prices for 2001 through 2003.

Annual Average Cost of Contract Energy 2001-2010

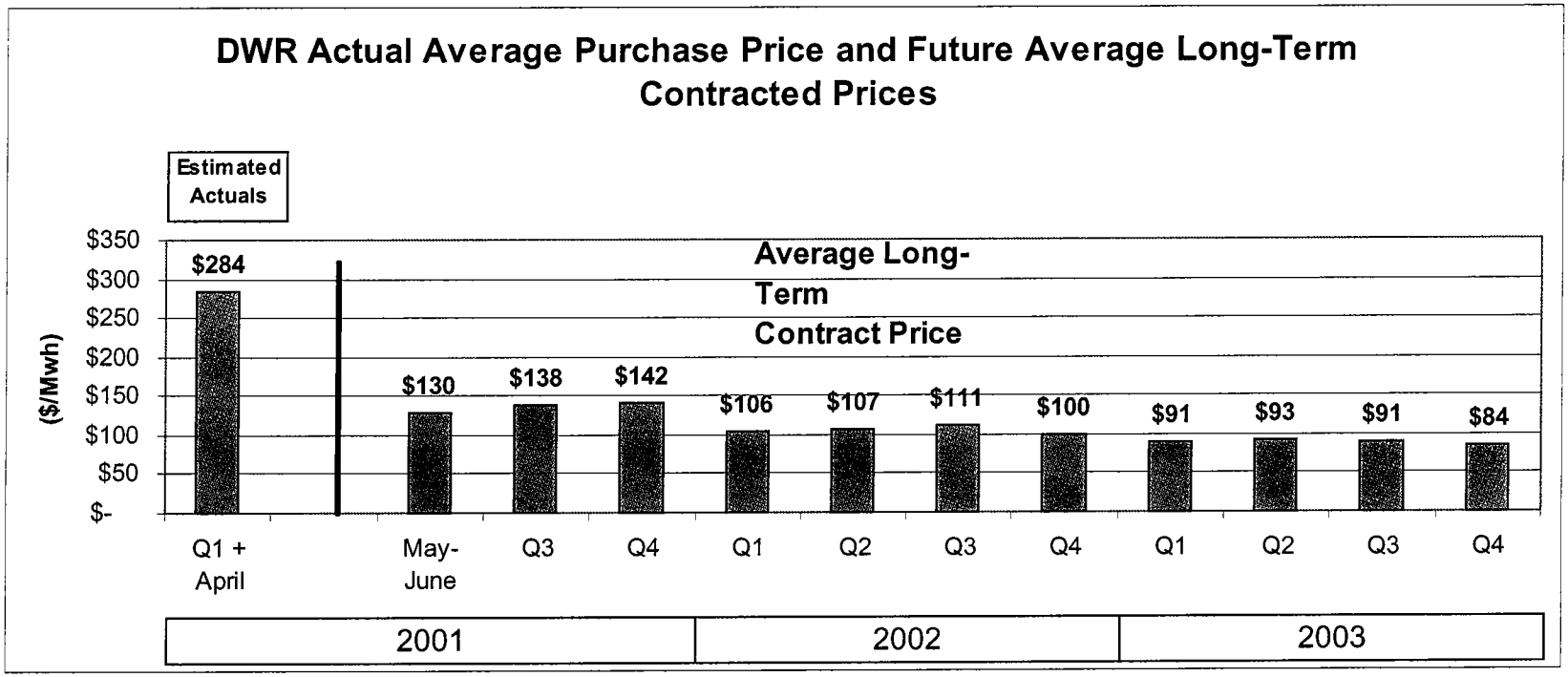
Figure 5



Note: Estimated actuals are subject to final accounting and CAISO settlement process

Quarterly Average Cost of Contract Energy 2001-2003

Figure 6



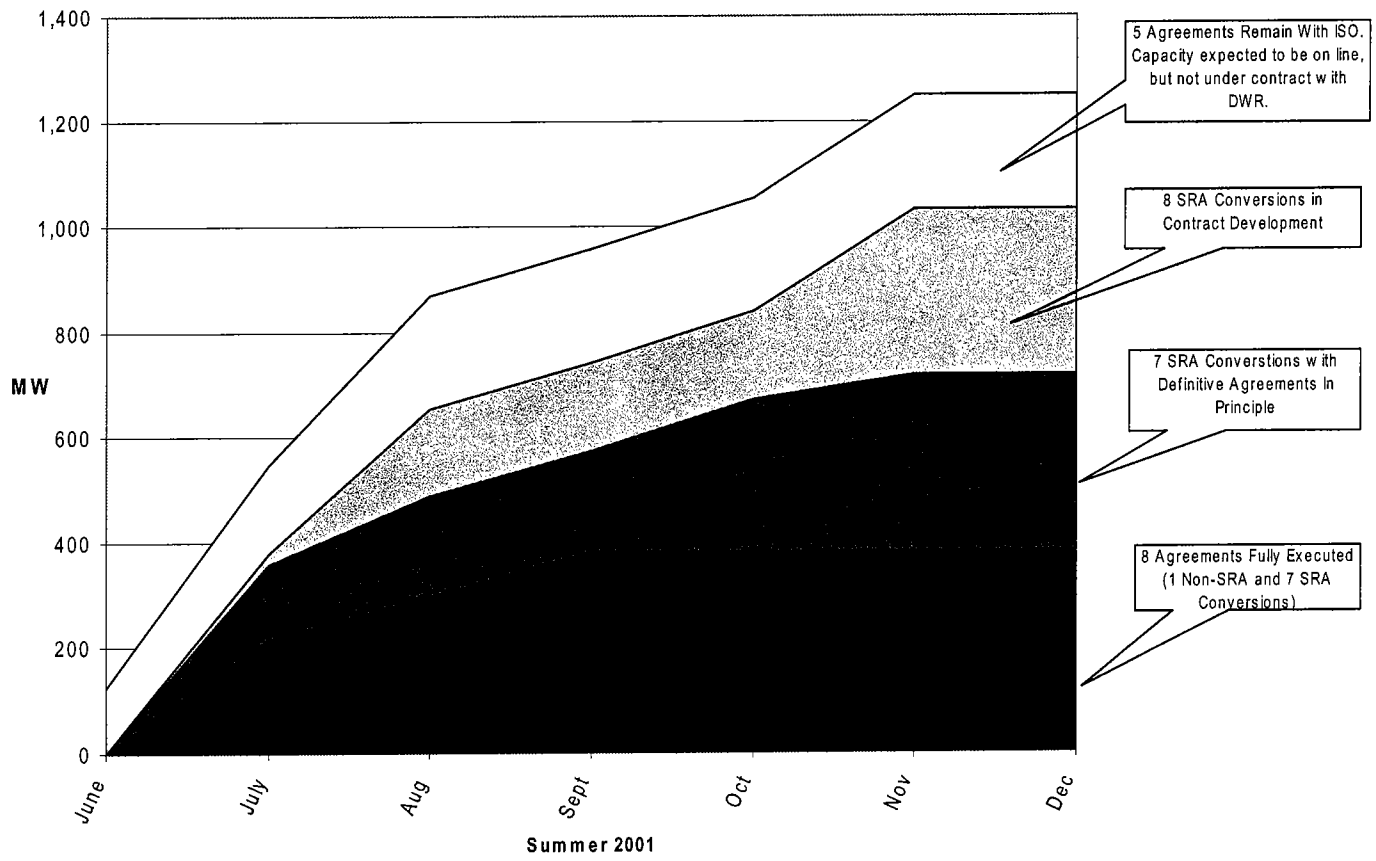
Note: Estimated actuals are subject to final accounting and CAISO settlement process

Summer Peaking Additions Under Contract

- Starting in February 2001, DWR has been negotiating with parties who had "Summer Reliability Agreements" (SRA) with the California Independent System Operator (CaISO) to convert those agreements to bilateral dispatchable peaking agreements with DWR.
- This conversion was undertaken because of the uncertainty of the CaISO's ability to provide payment for the contracts due to the concerns about the creditworthiness of the IOUs, who would have been responsible for payment of the capacity under the contracts.
- In addition, DWR has negotiated contracts with other Non-SRA parties for accelerated development of peaking generation for commercial operation in 2001 to increase available peaking capacity to help meet the net short energy requirements.
- Figure 7 shows the monthly additions of peaking capacity from the combination of the (a) the non-SRA peaking units under contract with DWR, (b) the converted SRAs with fully executed agreements or agreements in principle, and (c) the developers who retained their SRAs with the CaISO. The SRA contract status information is summarized in more detail in the Appendix to this report.

Summer Peaking Additions Under Contract (cont'd)

Figure 7



Summer Peaking Additions Under Contract (cont'd)

- Fully Executed/Agreement in Principle SRA Conversions - Three (3) SRA developers, representing 14 generating units for a total of approximately 640 MW have entered into either fully executed contracts or definitive agreements in principle for the sale of capacity and associated energy to DWR. Two developers representing 7 units with a total of approximately 300 MW have fully executed agreements. Final agreements for the seven (7) SRA projects agreed to in principle are expected by early June.
- Contract Development SRA Conversions - Two (2) SRA developers, representing eight (8) generating units for a total of approximately 340 MW are continuing to develop detailed contract terms for the sale of capacity and associated energy to DWR.
- Remaining with CaISO SRA - Three (3) of the SRA developers, representing 5 generating units and a total of 215 MW have elected to retain their SRAs with the CaISO and are expected to be operational this year.
- Fully Executed Agreements with Non-SRAs - As of the date of this report, DWR has entered into a fully executed agreement with one Non-SRA Party representing an additional summer peaking unit with a capacity of 88 MW in 2001 and 340 MW by the summer of 2002.

Percent of Net Short Capacity Needs Met by Contracts (MW)

Table 1

	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
Peak Net Short (Mw)	10,290	9,871	10,285	11,079	12,878	10,269	9,708	8,428
Executed Contracts (Mw)	3,215	4,249	4,496	4,768	4,937	3,902	3,714	3,714
AIP Contracts (Mw)	0	12	671	1,084	1,572	1,730	1,817	1,859
% of NS Met by Executed Contracts	31%	43%	44%	43%	38%	38%	38%	44%
% of NS Met by AIP Contracts	0%	0%	7%	10%	12%	17%	19%	22%
% of NS Met by Contracts	31%	43%	50%	53%	51%	55%	57%	66%

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
Peak Net Short (Mw)	9,481	9,781	9,420	9,380	10,197	10,673	11,677	12,377	14,041	11,704	11,169	9,470
Executed Contracts (Mw)	3,603	3,603	3,505	3,929	3,929	4,649	5,790	5,835	5,835	5,610	4,919	4,919
AIP Contracts (Mw)	2,666	2,672	2,680	2,689	2,874	2,853	3,148	3,141	3,140	3,134	3,127	3,122
% of NS Met by Executed Contracts	38%	37%	37%	42%	39%	44%	50%	47%	42%	48%	44%	52%
% of NS Met by AIP Contracts	28%	27%	28%	29%	28%	27%	27%	25%	22%	27%	28%	33%
% of NS Met by Contracts	66%	64%	66%	71%	67%	70%	77%	73%	64%	75%	72%	85%

	2003	2004	2005	2006	2007	2008	2009	2010
Peak Net Short (Mw)	13,304	14,839	15,722	16,585	17,400	17,778	18,164	19,768
Executed Contracts (Mw)	8,241	9,524	8,887	8,825	8,825	8,531	8,531	8,237
AIP Contracts (Mw)	4,495	4,691	3,010	3,010	2,554	2,554	2,554	2,554
% of NS Met by Executed Contracts	62%	64%	57%	53%	51%	48%	47%	42%
% of NS Met by AIP Contracts	34%	32%	19%	18%	15%	14%	14%	13%
% of NS Met by Contracts	96%	96%	76%	71%	65%	62%	61%	55%

* Net short is energy requirements before effects of funded programmatic load management and load curtailment.
Peak Net Short is the Max Net Short for the Average Week of each Month (for 2003-10 Month shown is July)
AIP - Agreement in Principle

On-Peak vs. Off-Peak Net Short Needs Met by Contracts

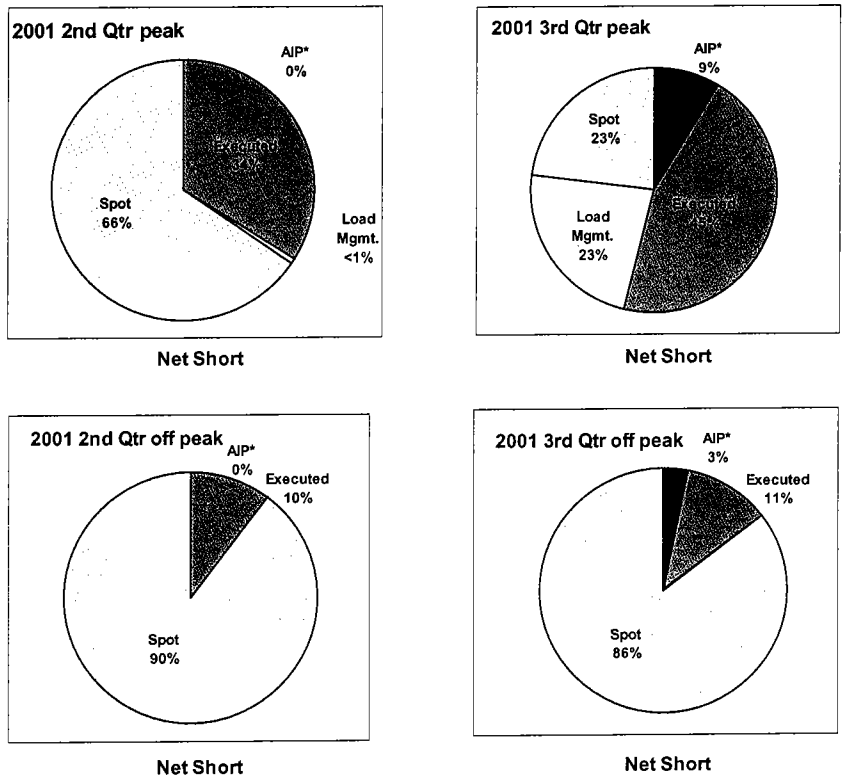
- Net short met by a combination of contracts, load management and spot market purchases.
- Load management programs are expected to meet a significant part of the peak hour net short energy needs for the summers of 2001 and 2002 as shown on Figures 8, 9 and 10 comparing typical months for the 2nd and 3rd quarter residual net short energy requirements on-peak and off-peak for 2001, 2002, and 2003, respectively. These figures show the long-term contract purchases. In addition, a portion of what is shown as "spot" purchases are already covered by short-term purchases DWR's trading desk has executed.
- If the load management programs do not have their projected effect, the spot market purchases for the summer of 2001 and 2002 will increase.
- In Summer 2001, a significantly higher percentage of long-term contracts are for the on-peak period, reducing the amount of more costly on-peak energy that needs to be purchased in the short-term or spot market

DWR has Focused its Purchases for Summer 2001 on Peak Energy Needs - Limiting Exposure to Peak Spot Prices

Figure 8

2001 Typical 2nd Qtr vs 3rd Qtr Monthly Energy Sources to Meet Net Short Energy Requirements

(Comparison of On-Peak and Off-Peak, Long Term Contracts)



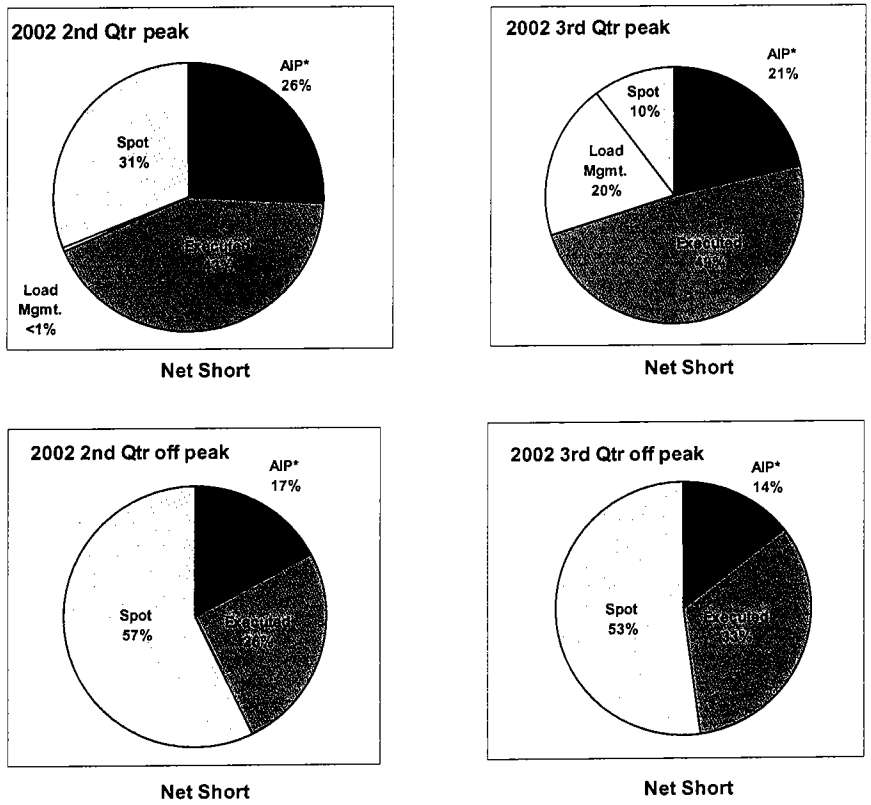
*Agreements in Principle

2002 Summer Peak Spot Price Exposure is Less Than 2001

Figure 9

2002 Typical 2nd Qtr vs 3rd Qtr Monthly Energy Sources to Meet Net Short Energy Requirements

(Comparison of On-Peak and Off-Peak, Long Term Contracts)



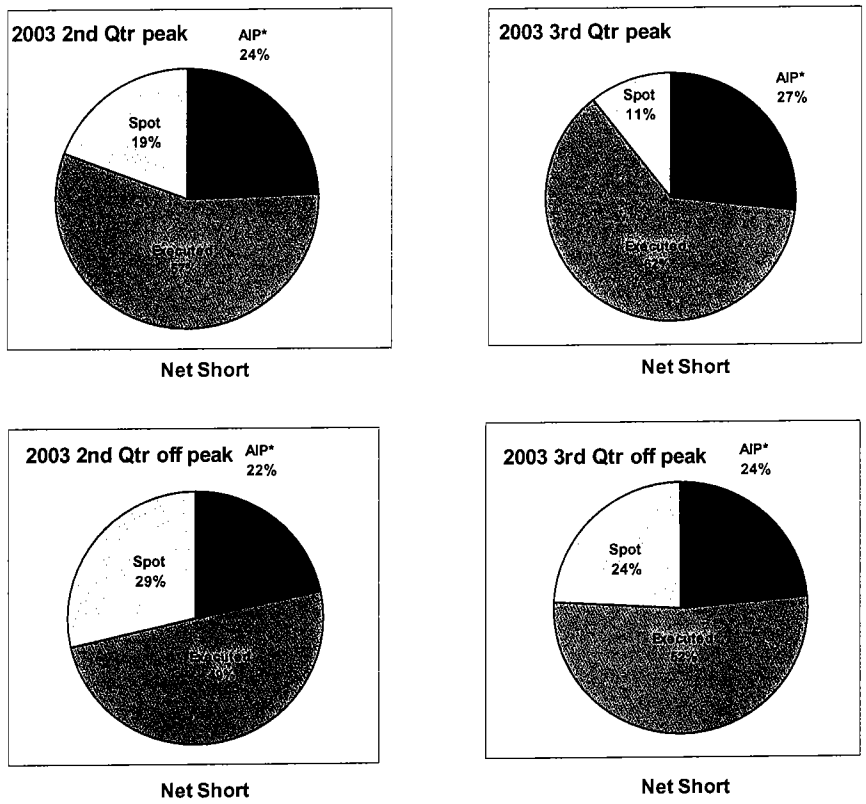
*Agreements in Principle

By 2003, without Load Management Programs, Spot Market Exposure is Essentially Eliminated

Figure 10

2003 Typical 2nd Qtr vs 3rd Qtr Monthly Energy Sources to Meet Net Short Energy Requirements

(Comparison of On-Peak and Off-Peak, Long Term Contracts)



*Agreements in Principle

Targeted Contract Arrangements to Complete DWR's Power Supply Portfolio

- Based on contracts entered into to date, absent modification of existing contracts, DWR has no need for additional 7 x 24, baseload contracts on a year-around basis after 2001, or possibly a small amount in NP-15 in 2002.
- In NP-15 (north of the Path 15 transmission constraint), DWR is still seeking some limited summer 6 X 16 (6 days a week, 16 hours per day) power resources for 2001 and 2002, with flexibility to reduce on-peak hour obligations to take energy after 2002.
- For SP-15 (south of the Path 15 transmission constraint), DWR is only seeking fully dispatchable resources, wherein DWR will purchase capacity and pay for energy on an as-scheduled basis to follow demand.
- DWR remains interested in seasonal exchanges and will consider same day or intra-month off-peak for on-peak exchanges with suppliers out of state.
- There is minor interest in reasonably priced new peaking generation for deliveries starting in May 2002. The extent of this need is being evaluated based upon the final disposition of converting existing agreements in principle to fully executed power supply contracts.
- In addition to the contract energy presented in tables and figures herein, DWR is in negotiation with several other parties, representing over 1,000 MW of capacity not reflected in agreements in principle. The outcome of those discussions will also effect DWR's interest in any further contracts for 2002.

Appendix

May 31, 2001

Update to DWR Power Purchasing Contract Efforts

Supporting Data

Estimated Net Short Energy Requirements

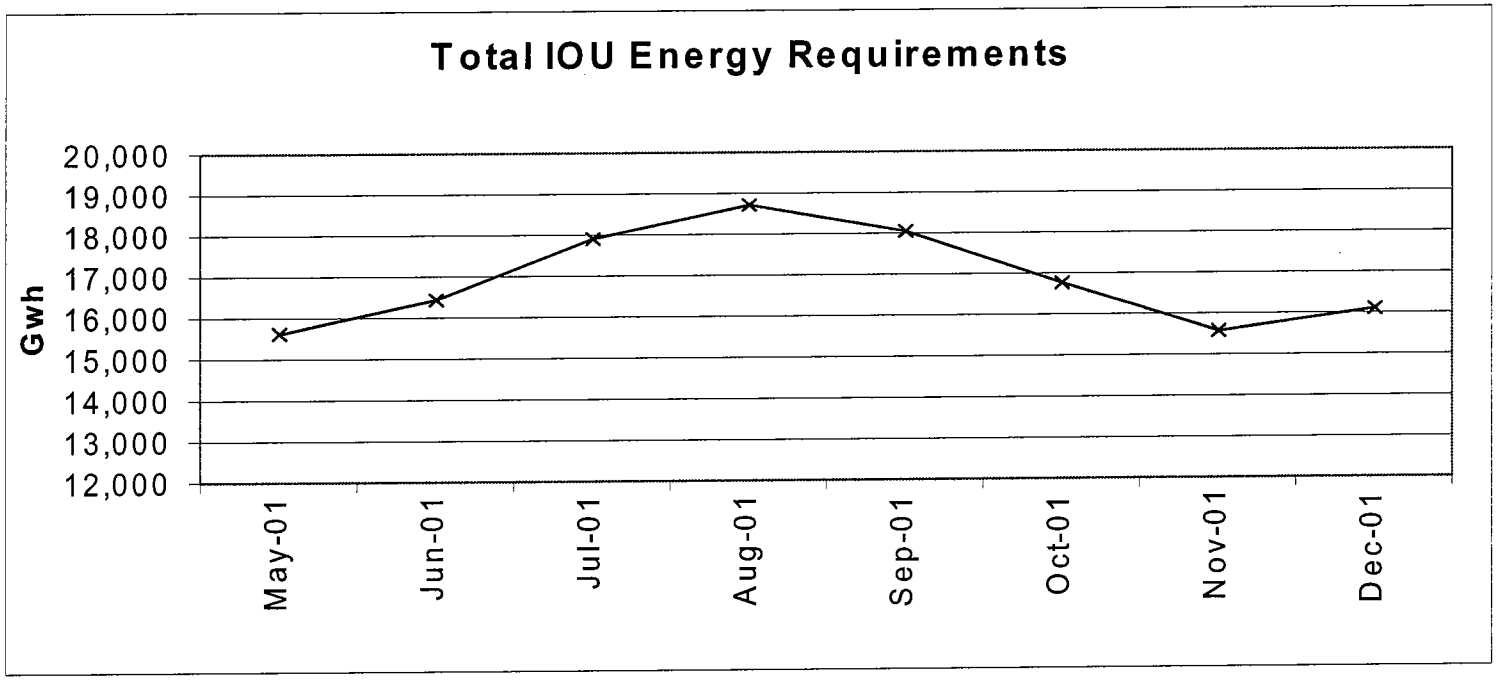
- Table A-1 and Figure A-1 present the combined total monthly energy requirements of the Customers on an actual basis for January through April, and a projection for May through December 2001. (These figures are for total Customer requirements rather than the net short energy requirements).
- The projected total energy requirements for May through December in Table A-1 and Figure A-1 is prior to any adjustment for change in energy consumption behavior by the Customers.
- Table A-2 and Figure A-2 provide the same estimate for annual energy requirements 2001 through 2010.
- Table A-3 and Figure A-3 show the estimated impact on energy requirements of Customer behavior due to (a) the present energy supply and general cost conditions, and (b) the expected price elasticity effects of the electric retail rate increase announced by the California Public Utilities Commission (PUC) on March 27, 2001, and proposed more specifically by rate class on May 9, 2001.
- The general Customer response to the current energy situation in California is estimated to reduce Customer demand by 4% across all hours. As of June 1, when retail rates will impact Customer utility rates by an average of about 30%, an additional 3%, for a total of 7% reduction in demand in all hours is expected as reflected in Table A-3 and Figure A-3.
- The above 7% reduction in demand is expected to last through 2002 and thereafter the effects are expected to decline as energy supplies increase and energy prices decline.

Table A-1

Total Projected IOU Energy Requirement (Gwh)*

	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
2001 Total Projected IOU Load	15,634	16,424	17,924	18,717	18,068	16,763	15,559	16,117

Figure A-1



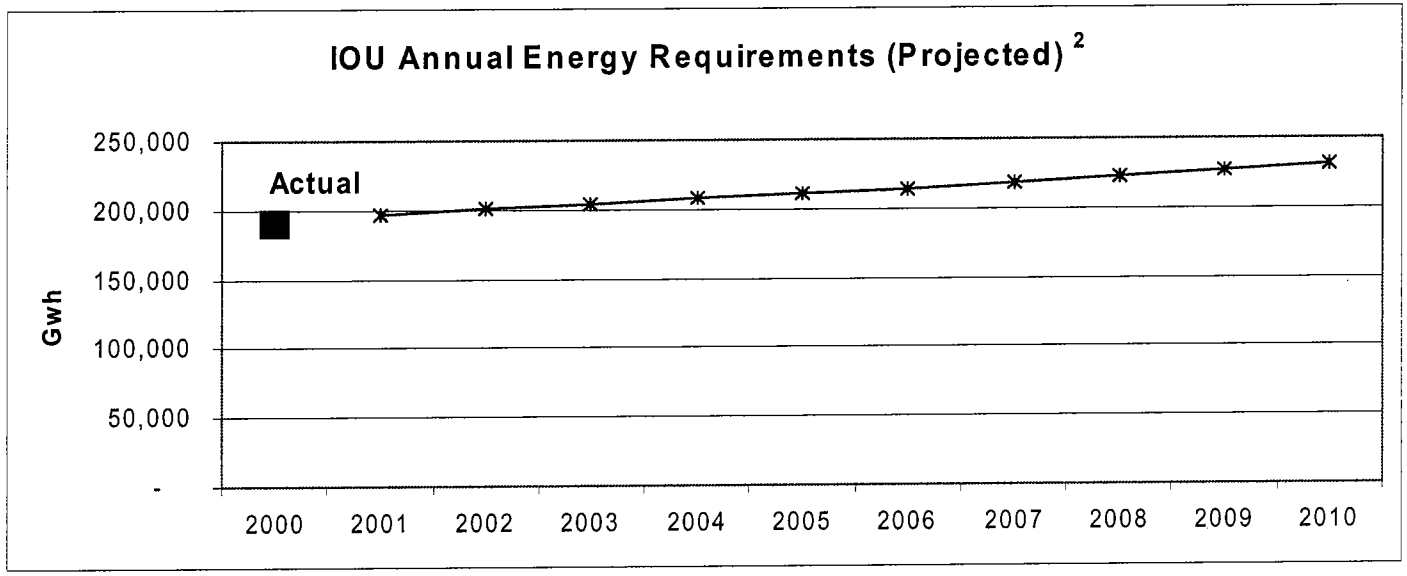
*Excluding observed and future expected customer usage changes due to interim energy shortage and retail rate increases, based on normal weather conditions

Table A-2

Total IOU Projected Annual Energy Requirement (GWh)[1]

	(Actual) 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Total IOU Annual Projected Energy Requirement	189,983	196,797	200,524	204,360	208,015	210,500	214,448	218,688	223,263	226,848	230,927

Figure A-2



[1] Excluding observed and future expected customer usage changes due to interim energy shortage and retail rate increases, based on normal weather conditions

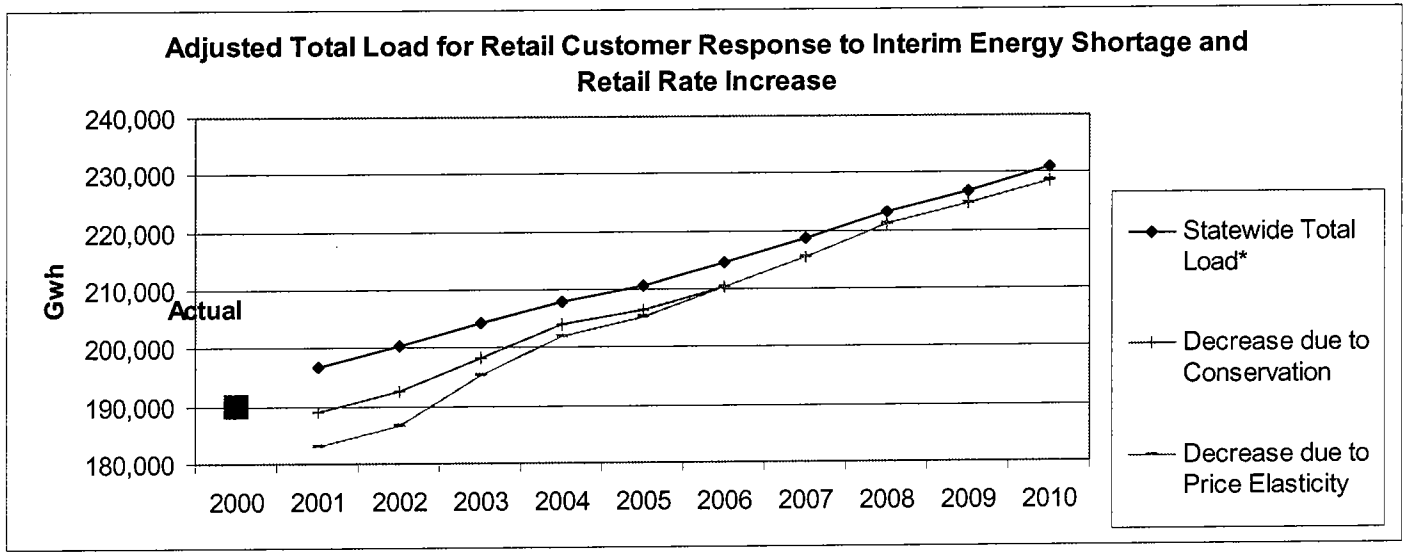
[2] Approximately 2% load growth for 2002-2010

Table A-3

Adjusted Total Load for Retail Customer Response to Interim Energy Shortage and Retail Rate Increase (Gwh)

	(Actual) 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Statewide Total Load*	189,983	196,797	200,524	204,360	208,015	210,500	214,448	218,688	223,263	226,848	230,927
Decrease due to Conservation		7,872	8,021	6,131	4,160	4,210	4,289	3,280	2,233	2,268	2,309
Decrease due to Price Elasticity		5,904	6,016	3,065	2,080	1,053	0	0	0	0	0
Total Adjusted Load		183,021	186,488	195,164	201,774	205,238	210,159	215,407	221,030	224,579	228,618

Figure A-3



* Excluding observed and future expected customer usage changes due to interim energy shortage and retail rate increases, based on normal weather conditions

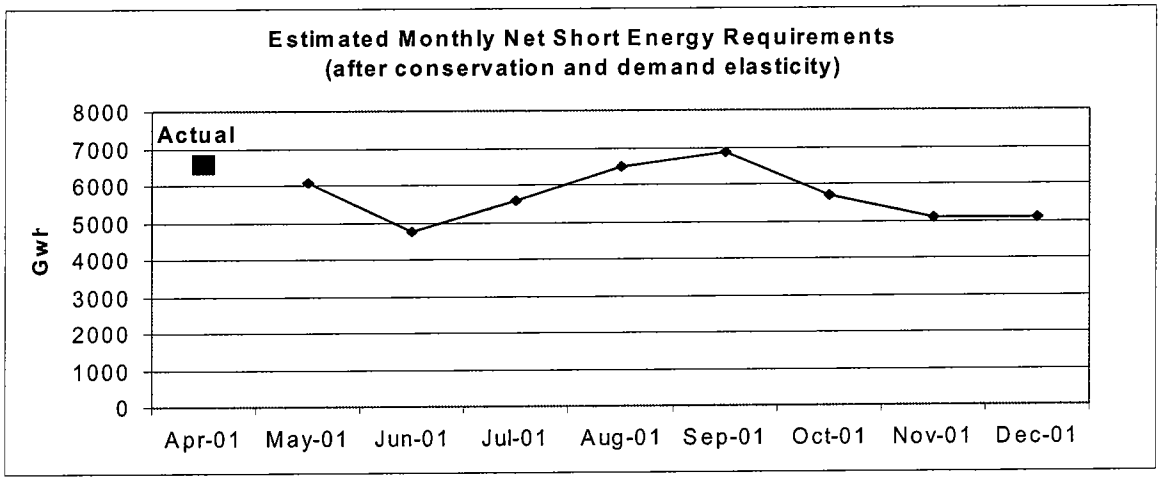
Table A-4 and Figure A-4 present the estimated monthly net short energy requirements for the Customers for 2001, after non-funded Customer conservation and estimated demand reductions after the effects of price elasticity from retail rate increases.

Table A-4

Estimated Monthly Net Short Energy Requirements for 2001 (Gwh)

		Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
Total Net Short after Conservation and Demand Elasticity*	Actual	6,582								
	Forecasted		6,064	4,750	5,589	6,508	6,868	5,685	5,081	5,103

Figure A-4



*Excludes effects of funded, programmatic load management and voluntary load curtailment, based on normal weather conditions

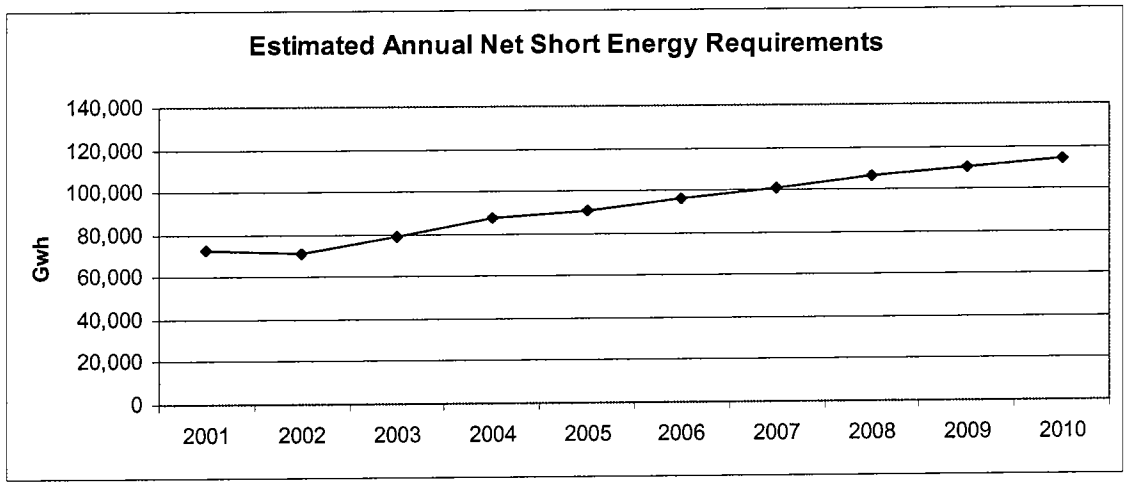
Table A-5 and Figure A-5 show similar annual estimates of the net short energy requirements for 2001 through 2010.

Table A-5

Estimated Annual Net Short Energy Requirements for 2001-2010 (Gwh)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Total Net Short after Load Reduction and Elasticity*	72,755	71,272	78,689	87,873	91,027	95,976	101,224	106,682	110,411	114,436

Figure A-5



*Excludes effects of funded, programmatic load management and voluntary load curtailment, based on normal weather conditions

Agreements Executed and Agreed to in Principle

Table A-6

AS OF May 31

Contact No.	Start	Term	Product	Zone	GENERAL TERMS MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10	STATUS Submitted	Agreement In Principle	Signed Contract
					(MW shown reflect July capacity, before transmission losses)								
LONG TERM													
1	2/9/2001	5 yr	Peak	SP15	50	50	50	50	50		2/6/2001	2/7/2001	2/13/2001
2	2/9/2001	5 yr	Peak	NP15	50	50	50	50	50		2/6/2001	2/7/2001	2/13/2001
3	2/13/2001	14 mos	Base	NP15	18	*							2/01
4	2/15/2001	5 yr	Base	SP15	50	50	50	50	50		2/6/2001	2/7/2001	2/20/2001
5	2/7/01	Bal. '01	Op. Res.	NP15	Unspec.						2/9/2001	2/14/2001	2/20/2001
6	3/1/2001	Bal '01	Peak	SP15	1000						2/22/2001	2/23/2001	3/2/2001
7	3/1/2001	Bal. '01	OffPeak	SP15	**						2/22/2001	2/23/2001	3/2/2001
8	4/1/2001	10 yr	Peak	SP15	175	200	250	250	300	300	2/5/2001	2/6/2001	2/16/2001
9	6/1/2001	4.5 yr	Peak	SP15	140	160	240	320	400		2/9/2001	2/9/2001	2/21/2001
10	6/1/2001	9.5 yr	Base	SP15	35	40	60	80	100	600	2/9/2001	2/9/2001	2/21/2001
11	7/1/2001	9.5 yr	Base	NP15	200	1,000	1,000	1,000	1,000	1,000		2/21/2001	2/27/2001
12	8/1/2001	20 yr	Peak	NP15	*	450	495	495	495	495		2/21/2001	2/27/2001
13	10/1/2001	10 yr	Base	NP15	*	350	600	1,000	1,000	1,000	1/24/2001	2/6/2001	2/6/2001
14	1/1/2002	3 yr	Base	SP15		200	200	200			2/22/2001	2/23/2001	3/2/2001
15	1/1/2002	3 yr	Peak	SP15		600	600	600			2/22/2001	2/23/2001	3/2/2001
16	1/1/2002	3 yr	Peak	SP15		500	500	500			2/22/2001	2/23/2001	3/2/2001
17	1/1/2002	3 yr	OffPeak	SP15		**	**	**			2/22/2001	2/23/2001	3/2/2001
18	1/1/2003	8 yr	Peak	SP15			500	500	500	500			2/21/2001
19	7/1/2003	8.25 yr	Base	SP15			840	840	840	840	2/27/2001	2/28/2001	3/15/2001
20	4/1/2001	2.25 yr	Peak	SP15	200	200	*				2/27/2001	2/28/2001	3/15/2001
21	3/15/2001	6 mos	Peak	SP15	250						2/12/2001	2/26/2001	3/26/2001
22	10/1/2001	10.25 yr	Base	SP15	*	250	250	500	1,000	1,000	2/12/2001	2/26/2001	3/26/2001
23	6/1/2001	2.5 yr	Base	SP15	16	16	16				2/6/2001	2/7/2001	3/13/2001
24	3/1/2001	Bal. '01	Peak	NP15	500							Jan	***
25	4/1/2001	Bal. '01	Peak	SP15	925							Jan	***
26	8/1/2001	10 yr	Sum. Peak	SP15	*	80	80	80	80	80		2/26/2001	4/24/2001
27	1/1/2003	1 yr	Peak	NP15			150						4/27/2001
28	6/1/2001	10.3 yr	Peak	SP15	250	300	350	700	700	700		2/28/2001	5/4/2001
29	4/1/2002	9.5 yr	Base	SP15		150	1,000	1,200	1,200	1,200		2/28/2001	5/4/2001
30	5/1/2001	4.5 yr	Base	NP15	13	13	13	13	13		2/6/2001	2/15/2001	5/4/2001
31	9/1/2001	11.25 yr	Peak	NP15	*	340	430	430	430	430			5/11/2001
32	6/1/2001	1.5 yr	Peak	NP15	500	500							5/22/2001
33	4/1/2001	11.25 yr	Peak	NP15		150	375	550	550	550		3/16/2001	5/25/2001
34	4/1/2001	11.25 yr	Peak	SP15	150	150	200	200	200	200		3/16/2001	5/25/2001
35	7/1/2002	10 yr	Base	NP15		50	50	50	50	50		3/16/2001	5/25/2001
36	7/1/2002	10 yr	Base	SP15		50	50	50	50	50		3/16/2001	5/25/2001
37	6/1/2001	3 mos	Peak	SP15	40								5/16/2001
38	5/3/2001	5 mos	OffPeak	SP15	**								5/16/2001
39	3/1/2001	4 mos	Base	SP15	*						2/12/2001	2/15/2001	
40	9/1/2001	5 yr	Peak	SP15	*	270	270	270	270		2/16/2001	3/2/2001	
41	9/1/2001	5 yr	Base	SP15	*	180	180	180	180		2/16/2001	3/2/2001	
42	7/1/2001	10 yr	Base	NP15	100	200	200	400	400	400	2/9/2001	2/12/2001	
43	8/1/2001	17 mos	SSPeak	SP15	*	325					2/15/2001	3/2/2001	
44	6/1/2003	8 yr	Base	SP15			560	560	560	560	2/15/2001	3/2/2001	
45	1/1/2002	9 yr	Base	SP15		300	300	300	300	300	1/24/2001	2/28/2001	
46	1/1/2002	9 yr	Base	NP15		250	500	500	500	500	1/24/2001	2/28/2001	
47	7/1/2001	10 yr	SSPeak	NP15	48	144	144	144	144	144		2/28/2001	
48	8/1/2001	10 yr	SSPeak	SP15	*	192	192	192	192	192		2/28/2001	
49	11/1/2001	10 yr	Peak	NP15	*	*	*	*	*	*		2/28/2001	
50	11/1/2001	10 yr	Peak	SP15	*	*	*	*	*	*		2/28/2001	
51	6/1/2001	10 yr	Base	NP15	12	12	12	12	12	12		5/8/2001	
52	12/31/2001	12 yr	As Avail	SP15		66	66	66	66	66		5/8/2001	
53	12/31/2001	12 yr	As Avail	SP15		53	53	53	53	53		5/8/2001	
54	12/31/2001	12 yr	As Avail	SP15		43	43	43	43	43		5/8/2001	
55	7/2/2002	15 yr	Disp	SP15		159	288	288	288	288		5/3/2001	
56	7/1/2001	3.25 yr	Disp	SP15	525	745	1,490	1,490				5/15/2001	
57	7/1/2001	4 yr	Disp	NP15	**	180	225	225				5/15/2001	
58	9/11/2001	5 yr	Base	NP15	*	15	15	15	15	15		5/11/2001	
59	10/1/2001	9.75 yr	As Avail	SP15	*	66	66	66	66	66		4/24/2001	
60	9/30/2001	10 yr	Peak	SP15	*	13	13	13	13	13		5/23/2001	
61	9/30/2001	10 yr	Peak	NP15	*	17	17	17	17	17		5/23/2001	
			NP15		1,441	3,721	4,276	4,901	4,676	4,613			
			SP15		3,806	5,438	8,757	9,641	7,501	7,051			
			Total		5,247	9,159	13,033	14,542	12,177	11,664			
			Agreements Being Negotiated		685	3,260	4,634	4,834	3,119	2,569			
			Contract Progress-Agreements Executed Since 4/18 Report		953	1,763	2,698	3,273	3,273	3,260			
			Previously Executed Agreements		3,609	4,116	5,701	6,435	5,785	5,735			
					5,247	9,159	13,033	14,542	12,177	11,664			

Notes:

* Capacity provided during year, but not in July (month of maximum statewide net short)

** Off-Peak capacity is not part of peak MW tabulation

*** Lines 24 and 25 represent the PX Block Forward contracts assumed by CDWR. They were reflected as Agreements in Principle in prior reports but are shown as Executed here

Summer Peaking Agreements 1-15 on Table 7 are represented in the agreements in this table.

Summer Peaking Additions Under Contract

Table A-7

As of May 31

Project Number	Unit MW	Term	Zone	Start	June	July	Aug	Sept	Oct	Nov	Dec	Contract Status	Signed Contract	Status/Comments
				GENERAL TERMS										
Fully Executed Summer Peaking Additions with Non-SRA Parties														
1	88	11yr	NP15	9/1/2001				88	88	88	88	PPA Executed	5/11/2001	
Fully Executed SRA Conversions														
2	40	10 yr	SP15	8/1/2001			40	40	40	40	40	PPA Executed	4/25/2001	
3	40	10 yr	SP15	8/1/2001			40	40	40	40	40	PPA Executed	4/25/2001	
4	43	11.25 yr	SP15	7/1/2001		43	43	43	43	43	43	PPA Executed	5/25/2001	
5	43	11.25 yr	SP15	7/1/2001		43	43	43	43	43	43	PPA Executed	5/25/2001	
6	43	11.25 yr	SP15	7/1/2001		43	43	43	43	43	43	PPA Executed	5/25/2001	
7	43	11.25 yr	SP15	7/1/2001		43	43	43	43	43	43	PPA Executed	5/25/2001	
8	43	11.25 yr	SP15	7/1/2001		43	43	43	43	43	43	PPA Executed	5/25/2001	
Agreement in Principle SRA Conversions														
9	49.3	10 yr	SP15	7/31/2001		48	48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA-Exp. Early June
10	49.3	10 yr	SP15	7/31/2001		48	48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA-Exp. Early June
11	49.3	10 yr	SP15	9/30/2001					48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA-Exp. Early June
12	49.3	10 yr	SP15	11/30/2001						48	48	LOI Signed	5/7/2001	Negotiating Final PPA-Exp. Early June
13	49.3	10 yr	NP15	7/15/2001		48	48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA-Exp. Early June
14	49.3	10 yr	NP15	8/15/2001			48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA-Exp. Early June
15	49.3	10 yr	NP15	11/15/2001					48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA-Exp. Early June
Contract Development SRA Conversions														
16	21.3	10 yr	NP15	7/1/2001		21.3	21.3	21.3	21.3	21.3	21.3	LOI	Est. 6/7/01	Drafting LOI
17	49	10 yr	NP15	8/1/2001			49	49	49	49	49	LOI	Est. 6/7/01	Drafting LOI
18	49	10 yr	NP15	8/7/2001			49	49	49	49	49	LOI	Est. 6/7/01	Drafting LOI
19	49	10 yr	NP15	8/15/2001			49	49	49	49	49			Negotiating Terms
20	24	10 yr		TBD										Negotiating Terms
21	49	6 yr	NP15	11/1/2001						49	49			Lost Original Equipment - Re-Negotiating Term Sheet
22	49	6 yr	NP15	11/1/2001						49	49			Lost Original Equipment - Re-Negotiating Term Sheet
23	49	6 yr	NP15	11/1/2001						49	49			Lost Original Equipment - Re-Negotiating Term Sheet
Remaining with CalISO SRA														
24	48.6	10 yr	NP15	6/1/2001	48.6	48.6	48.6	48.6	48.6	48.6	48.6			Indicated intent to stay with ISO Contract
25	48.6	10 yr	NP15	9/1/2001			48.6	48.6	48.6	48.6	48.6			Indicated intent to stay with ISO Contract
26	44		SP15	6/15/2001	44	44	44	44	44	44	44			Indicated intent to stay with ISO Contract
27	44		SP15	7/15/2001		44	44	44	44	44	44			Indicated intent to stay with ISO Contract
28	30		SP15	6/1/2001	30	30	30	30	30	30	30			Indicated intent to stay with ISO Contract
				NP15	49	118	362	450	498	645	645			
				SP15	74	429	509	509	557	605	605			
				Total MW	123	547	871	959	1,055	1,250	1,250			

	June	July	Aug	Sept	Oct	Nov	Dec
Indicated intent to stay with ISO SRA	123	167	215	215	215	215	215
Contract Development	0	21	168	168	168	315	315
Agreements In Principle	0	144	192	192	288	336	336
Fully Executed	0	215	295	383	383	383	383
Total MW	123	547	871	959	1,055	1,250	1,250

Note: Summer Peaking Agreements 1-15 on this table are represented in the Agreements in Table 6

Percent of Net Short Energy Needs Met by Long-Term Contracts(MWh)

Table A-8

	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
Net Short (Gwh)	6,064	4,750	5,589	6,508	6,868	5,685	5,081	5,103
Executed Contracts (Gwh)	1,592	1,982	2,145	2,286	2,209	2,012	1,884	1,923
AIP Contracts (Gwh)	0	8	327	454	582	691	558	515
% of NS Met by Executed Contracts	26%	42%	38%	35%	32%	35%	37%	38%
% of NS Met by AIP Contracts	0%	0%	6%	7%	8%	12%	11%	10%
% of NS Met by Contracts	26%	42%	44%	42%	41%	48%	48%	48%

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
Net Short (Gwh)	5,395	5,226	4,847	5,085	5,799	5,240	6,554	7,257	7,537	6,651	5,980	5,700
Executed Contracts (Gwh)	1,985	1,782	1,916	2,092	2,166	2,380	3,285	3,304	3,149	3,228	2,813	2,883
AIP Contracts (Gwh)	988	904	1,006	1,109	1,351	1,013	1,265	1,457	1,387	1,376	1,298	1,075
% of NS Met by Executed Contracts	37%	34%	40%	41%	37%	45%	50%	46%	42%	49%	47%	51%
% of NS Met by AIP Contracts	18%	17%	21%	22%	23%	19%	19%	20%	18%	21%	22%	19%
% of NS Met by Contracts	55%	51%	60%	63%	61%	65%	69%	66%	60%	69%	69%	69%

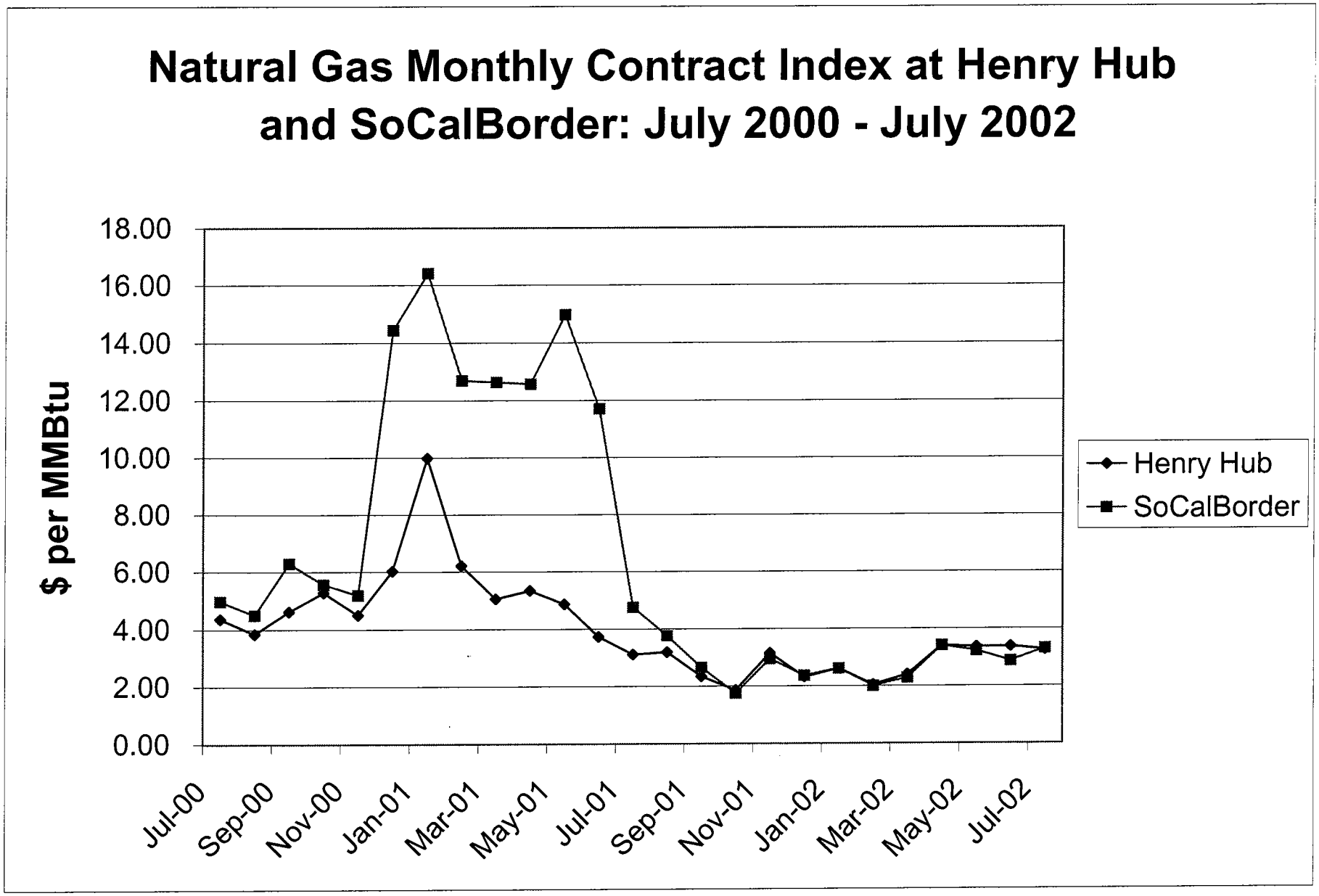
	2003	2004	2005	2006	2007	2008	2009	2010
Net Short (Gwh)	79	88	91	96	101	107	110	114
Executed Contracts (Gwh)	48	64	61	62	62	62	62	61
AIP Contracts (Gwh)	20	23	22	22	19	19	19	19
% of NS Met by Executed Contracts	62%	73%	67%	65%	61%	58%	56%	53%
% of NS Met by AIP Contracts	25%	27%	24%	23%	18%	18%	17%	16%
% of NS Met by Contracts	87%	99%	91%	87%	80%	75%	73%	70%

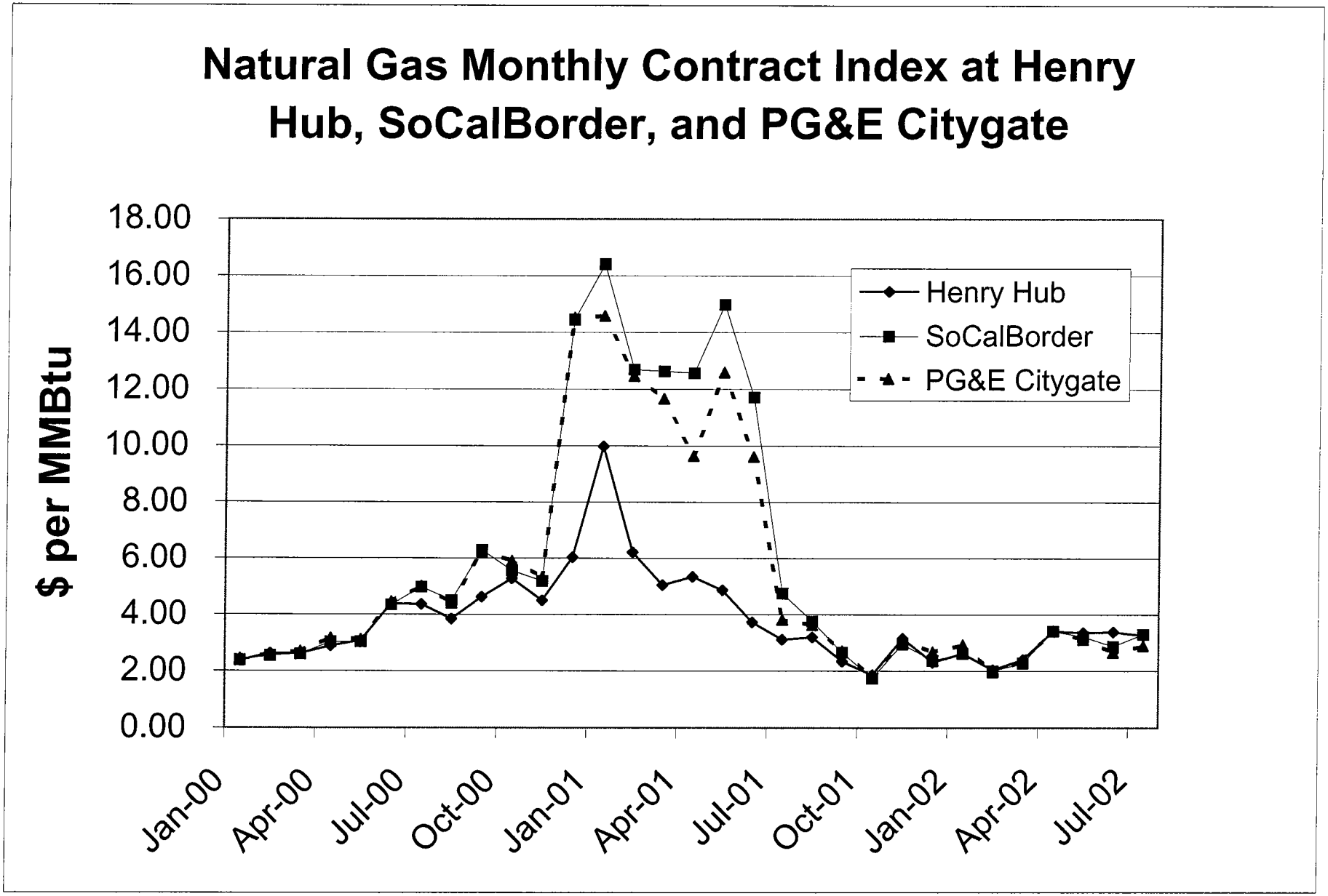
* Net short is energy requirements before effects of funded programmatic load management and load curtailment.
AIP - Agreement in Principle

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 11

Historic Henry Hub, PG&E Gate, and Southern California Border Prices for Gas


Natural Gas Monthly Contract Index at Henry Hub and SoCalBorder: July 2000 - July 2002
$ per MMBtu
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Henry Hub
SoCalBorder

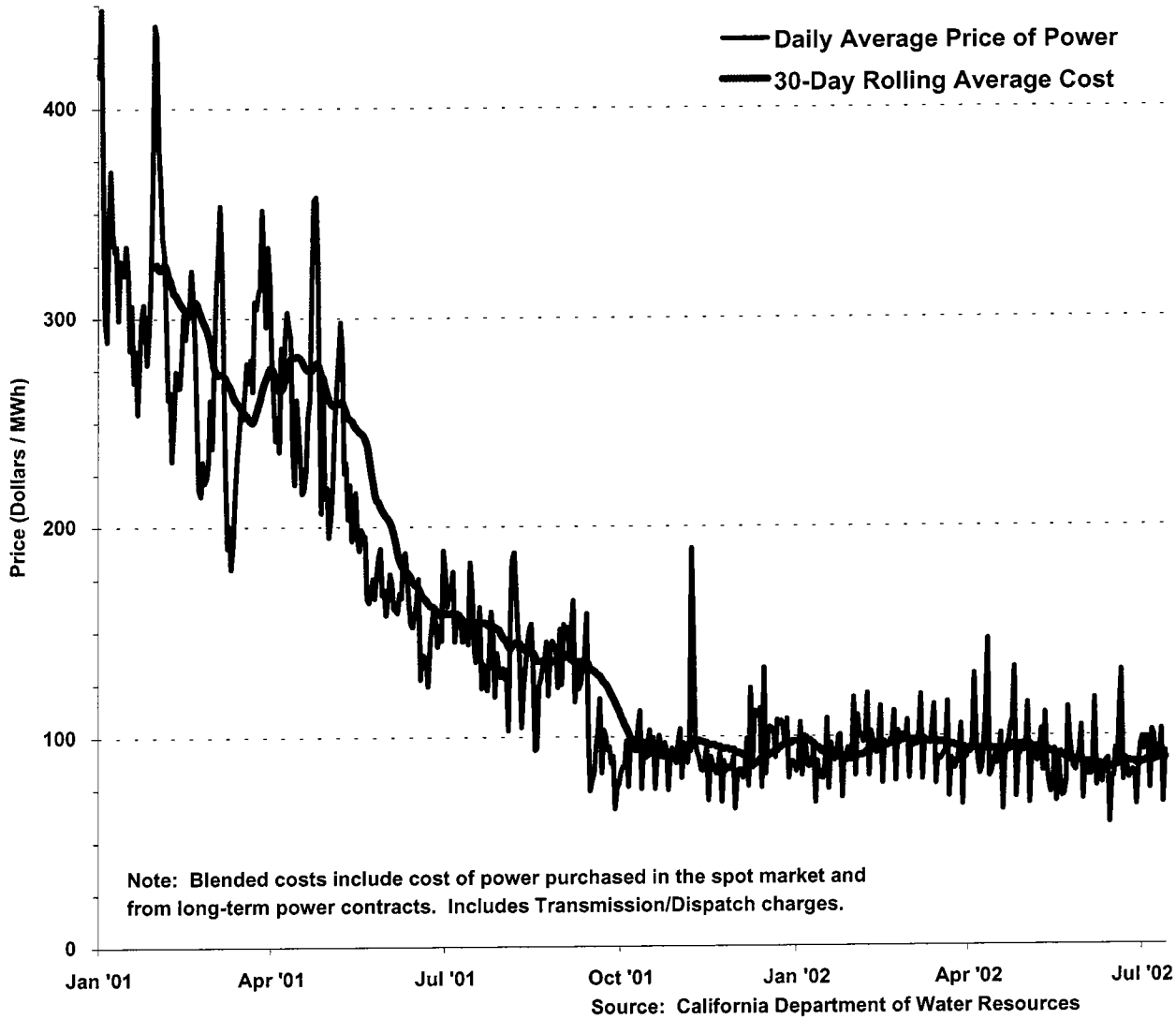

Natural Gas Monthly Contract Index at Henry Hub, SoCalBorder, and PG&E Citygate
$ per MMBtu
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jan-00
Apr-00
Jul-00
Oct-00
Jan-01
Apr-01
Jul-01
Oct-01
Jan-02
Apr-02
Jul-02
Henry Hub
SoCalBorder
PG&E Citygate

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

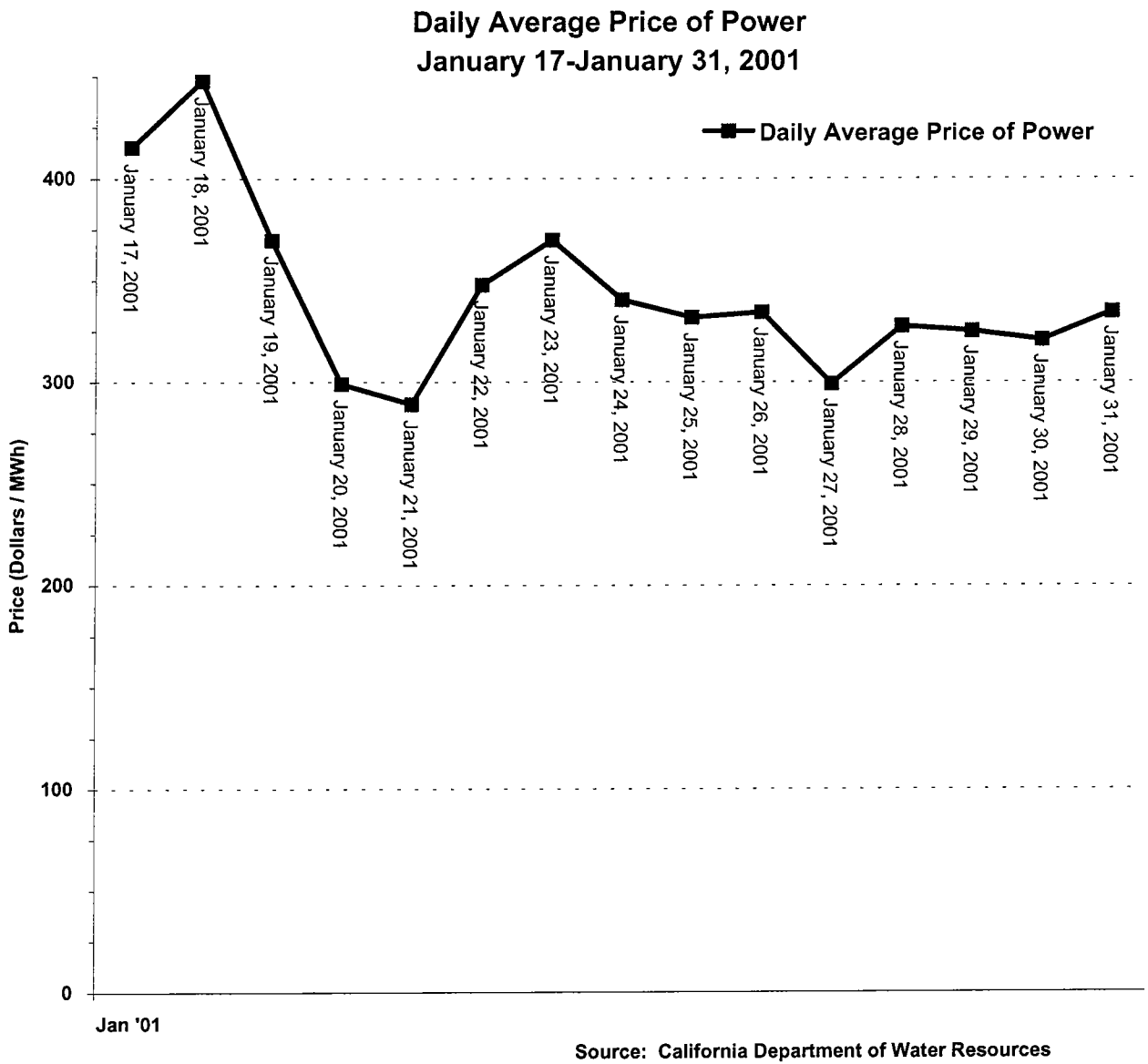
Exhibit 12

Daily Average Price of Power

Daily DWR Blended Unit Power Costs Since January 2001



Source: California Department of Water Resources

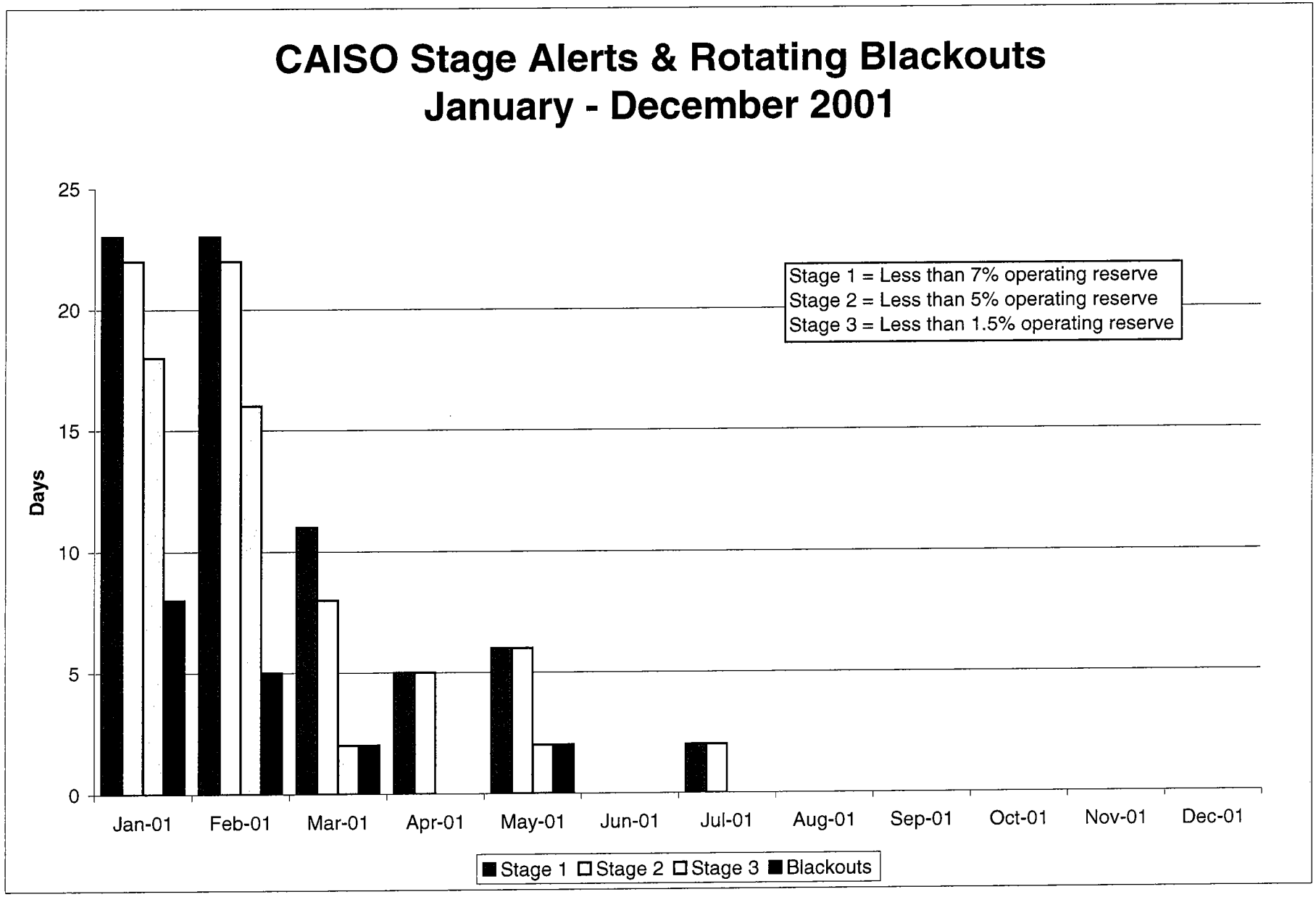


Source: California Department of Water Resources

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 13

CAISO Stage Alerts and Rotating Blackouts in 2001

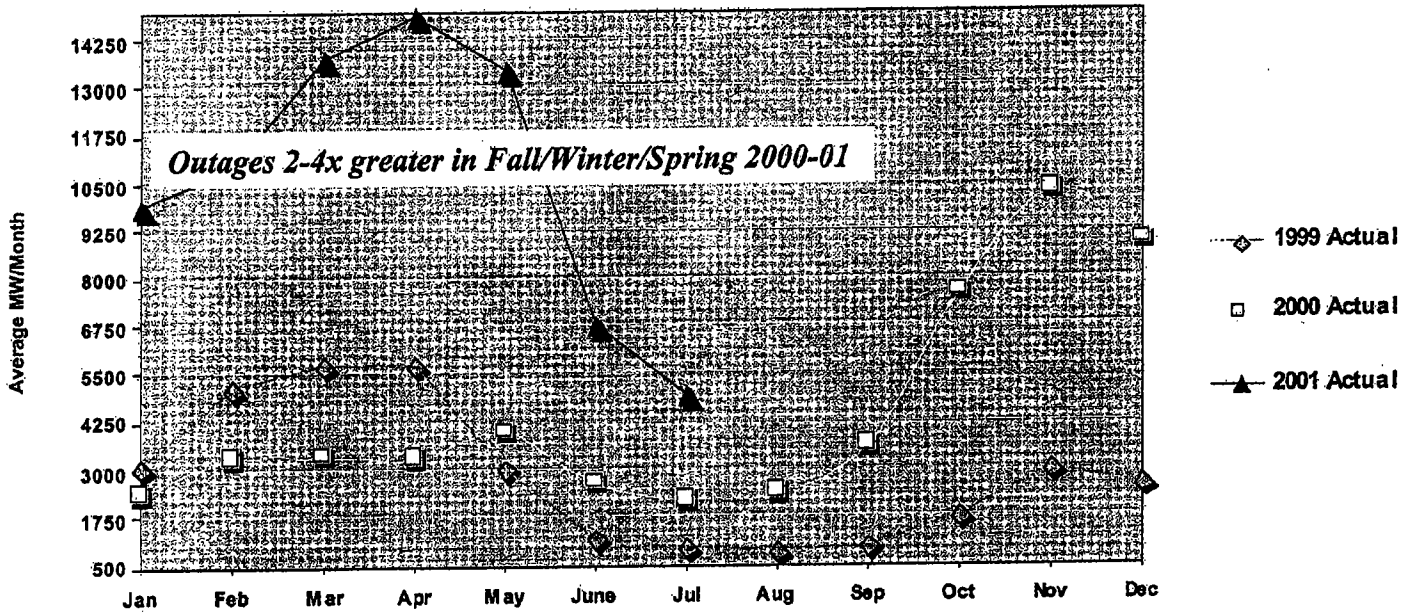

CAISO Stage Alerts & Rotating Blackouts
January - December 2001
Days
25
20
15
10
5
0
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Jun-01
Jul-01
Aug-01
Sep-01
Oct-01
Nov-01
Dec-01
Stage 1 = Less than 7% operating reserve
Stage 2 = Less than 5% operating reserve
Stage 3 = Less than 1.5% operating reserve
Stage 1
Stage 2
Stage 3
Blackouts

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 14

Historical Generation Outages

Historical Generation Outages Scheduled and Forced (Average MW/Month)



Welcome to the California Energy Commission

Statewide Average Daily Forced or Scheduled Megawatts Off-Line in California by Month, 1999-2002

1999		2000		2001		2002	
Month	Average of Total Megawatts Off-Line	Month	Average of Total Megawatts Off-Line	Month	Average of Total Megawatts Off-Line	Month	Average of Total Megawatts Off-Line
Jan	3,068	Jan	2,423	Jan	9,940	Jan	11,166
Feb	5,096	Feb	3,243	Feb	10,895	Feb	12,702
Mar	5,740	Mar	3,389	Mar	13,737	Mar	12,753
Apr	5,739	Apr	3,329	Apr	14,911	Apr	11,385
May	3,032	May	4,012	May	13,431	May	10,309
Jun	1,216	Jun	2,683	Jun	6,758	Jun	7,672
Jul	963	Jul	2,233	Jul	5,044	Jul	
Aug	878	Aug	2,434	Aug	4,229	Aug	
Sep	1,195	Sep	3,621	Sep	5,278	Sep	
Oct	1,761	Oct	7,633	Oct	8,805	Oct	
Nov	2,988	Nov	10,343	Nov	12,199	Nov	
Dec	2,569	Dec	8,988	Dec	11,112	Dec	

Source: California Energy Commission Compiled From ISO Data

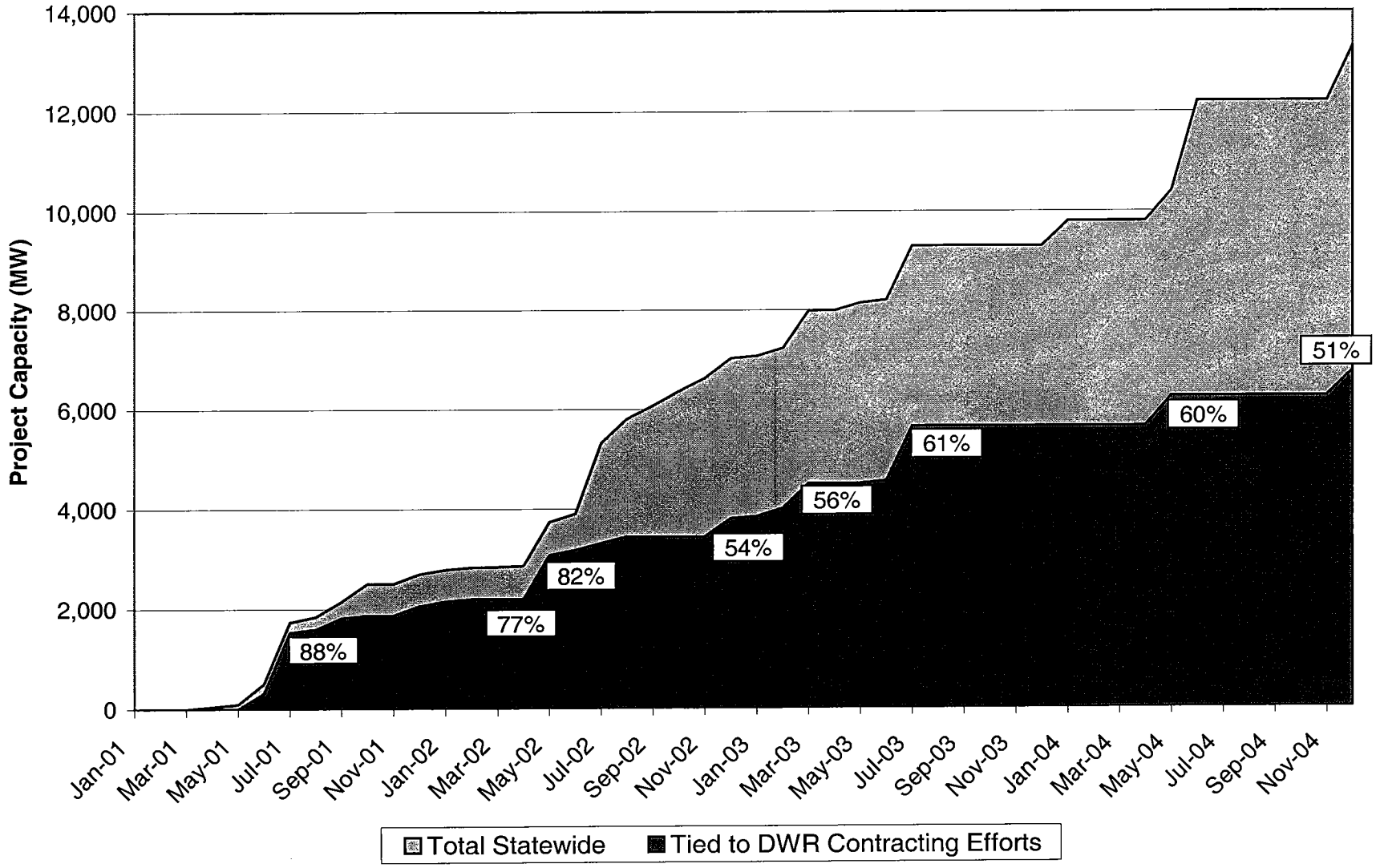
Filings of outages with the ISO have varied in consistency since June 1998, with incentives existing to both over- and under-report. The data, especially for periods prior to November 2000, may differ from outage values reported by other sources and in other documents, and should be considered indictative of general trends in unit outages, not as a precise measure of unavailable capacity.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 15

New California Generation Tied to DWR Contracting Efforts

New California Generation with Amount Tied to DWR Contracting Efforts



History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 16

LA Times Article on QF Generation; *Electric Utility Week* Article on QFs

California and the West; Utilities to Resume Paying Producers; Electricity: Some small companies that provide power say the new rate plans are not enough to get them back online.

The Los Angeles Times; Los Angeles, Calif.; Apr 16, 2001; JULIE TAMAKI;

DC_ABS

The company, EF Oxnard Inc., sued Edison last week, alleging that the utility owes it more than $13.5 million for past electricity deliveries. The lack of payment, according to EF Oxnard officials, prompted natural gas suppliers to cut them off in February, forcing Oxnard to stop producing electricity.

The court is expected to rule today on CalEnergy's request for roughly $100 million in payments it is owed by Edison, and could also act on an Edison request that Cal- Energy be required to resume selling power to the utility.

An Edison spokesman said his company sent payments totaling $206 million to small producers Friday, but said he did not know whether checks were sent to producers that have gone offline. A spokesman for PG&E estimates that the monthly bill to small producers will total $200 million to $400 million.

DC_FULLTEXT

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The state's two biggest utilities are scheduled to resume paying hundreds of small power producers this week, but at least some producers say they plan to remain offline.

Jay Henneberry, an attorney representing a small gas-fired power plant in Oxnard, said his client does not plan to start generating electricity again for Southern California Edison today, because of a controversial new rate plan that he said would force his client to operate at a loss.

The company, EF Oxnard Inc., sued Edison last week, alleging that the utility owes it more than $13.5 million for past electricity deliveries. The lack of payment, according to EF Oxnard officials, prompted natural gas suppliers to cut them off in February, forcing Oxnard to stop producing electricity.

Henneberry noted that the new rate plan fails to address the utilities' past debt to producers, which who are collectively owed more than $1.8 billion.

"Those payments are only on a going-forward basis," Henneberry said. "They do nothing for $13.5 million owed to my client."

The situation underscores the problems the state faces as it tries to get California's nearly 700 producers of alternative and renewable energy paid and, in cases such as EF Oxnard, back in business.

These companies, which include producers of solar, wind and thermal power, provide more than a quarter of the electricity consumed in California. But their output has been cut by as much as half in recent weeks due in part to the payment problems.

A new rate plan approved by the Public Utilities Commission last month to help get those producers paid has triggered a growing number of gas-fired power producers to sue Pacific Gas & Electric and Edison to get out of their contracts with the utilities. The power suppliers say the new rate plan would force them to operate at a loss, because it does not adequately compensate them for rising natural gas

costs.

"We are not going to run our plants if we can't run them profitably," said Marty Quinn, executive vice president and chief operating officer of Ridgewood Power LLC, which owns three small gas- fired generators in California that are not operating.

In a related matter, a hearing is scheduled today in a legal battle between Edison and a small geothermal producer. An Imperial County judge previously freed CalEnergy from its contract with Edison because of the utility's failure to pay the company, which has since been selling its supplies on the wholesale power market.

The court is expected to rule today on CalEnergy's request for roughly $100 million in payments it is owed by Edison, and could also act on an Edison request that Cal- Energy be required to resume selling power to the utility.

"If Edison shows that it is credit-worthy and capable of making payments on a going-forward basis, I'm sure the judge will take that into account," said CalEnergy official Jonathan Weisgall. "But one of our concerns is how long will Edison continue to make these payments."

An official with Sierra Pacific Industries, which received court permission earlier this month to sell power generated by six plants it owns in California to a buyer other than PG&E, said Sierra Pacific does not plan to resume transmitting electricity to the utility.

"From our point of view we have terminated those contracts," said Bob Ellery, Sierra Pacific's director of energy resources.

Henneberry said he doubts that Edison plans to pay EF Oxnard because the new rate arrangement covers only deliveries made in April and beyond.

An Edison spokesman said his company sent payments totaling $206 million to small producers Friday, but said he did not know whether checks were sent to producers that have gone offline. A spokesman for PG&E estimates that the monthly bill to small producers will total $200 million to $400 million.

Ridgewood, Oxnard and Sierra Pacific generate a total of 140 megawatts of electricity, or enough power to serve more than 105,000 typical homes. State officials have at times been forced to replace the lost deliveries by purchasing power on the pricey wholesale and spot markets.

The California Independent System Operator, which oversees the state's power grid, said it received about 3,800 megawatts of power Friday from small producers, compared to the 6,000 megawatts the small producers usually deliver. In recent weeks the group's output has dipped as low as 3,000 megawatts.

Credit: TIMES STAFF WRITER

DC_SUBTITLE: [Home Edition]
DC_EDITION: Record edition
DC_STPAGE: A.3
ISSN: 04583035
DC_SUBJTERM: Payments

threaten national parks and other language in the bill could allow facilities to operate outside safety concerns. Fellow senior Democrat Rep. Rick Boucher of Virginia said alternative legislation would have to be drafted to provide consumer protections that FERC has not offered to ensure "just and reasonable" prices.

Several Democrats also took the opportunity to criticize FERC for its price mitigation plan for California. FERC's order of April 26 offers price mitigation for California short-term wholesale transactions only during emergencies when supply reserves dip below 7.5%. Should California fail to file an RTO plan by June 1, the mitigation plan expires.

"FERC is abdicating its responsibility to ensure just and reasonable rates," Boucher said.

Commissioner William Massey, who alone dissented on the mitigation order, because he said it should impose broader price caps, countered that the bill should include a temporary cap for Western states, pointing to economic damage already done and warning that matters could get worse this summer. Massey also urged Congress to pass a mandatory electric reliability measure as soon as possible. Commissioner Linda Breathitt told the subcommittee, as did Massey, that Congress should transfer transmission siting authority to the FERC, but otherwise supported Barton's bill.

"Unless there are dramatic improvements, we're likely to see shortages of supply and out-of-control prices in the West," Massey told the lawmakers. "Frankly, I fear for the worst. We need a time-out in the dysfunctional electricity market."

Projecting that only 2,600 MW of generation will be added to the grid this summer, California energy officials Thursday called on the subcommittee, in a second hearing, to urge FERC to "do its job" and mitigate wholesale power prices.

Richard Sklar, senior energy advisor to Calif. Gov. Gray Davis (D), and California Energy Commission Chairman William Keese told the subcommittee that Barton's bill actually would create more troubles for the energy-short West, which faces its biggest struggle this summer. The only ways the federal government can help the situation is by requiring FERC to ensure "just and reasonable" wholesale prices and promoting more conservation and energy efficiency, they said.

"What we need from you desperately to do is to tell the FERC to do its job..." said Sklar.

Barton, who introduced the bill Tuesday, tried to hit a conciliatory note with the state officials. "We are sincerely interested in doing anything at the federal level that actually helps," he said. "This is not a time for political gamesmanship."

Sklar and Keese told Barton that the bill lacks coordination with state initiatives and could confuse or delay California's efforts to address transmission constraints or to form a regional transmission organization.

Barton said his QF provision is the most important because it could help California as early as this summer by encouraging these units to return to the grid. The state officials said that QFs contribute from 4,000 to 8,000 MW. Sklar said that efforts were under way to get all the QFs paid and all brought back on-line by the end of this week. But even if all the QFs were running, he said, it might not be enough capacity to prevent blackouts this summer.

QFs are "a piece of the problem," Sklar said. Avoiding blackouts will also depend on the number of units down for forced outages, the new units brought on-line, and conservation efforts, he said. "We've got a shot at [avoiding blackouts], but I would not bet on it," said Sklar.

Keese said California would add only 800 to 900 MW of capacity by June, 2,600 MW by July and 4,500 MW by mid- to late September. Davis earlier this year was seeking to have 5,000 MW added by summer.

Bonneville Power Administration Vice President Jeff Stier said his agency is concerned that the bill that would allow BPA's directly served customers to sell unused power into the market at premium prices. Stier told the panel that BPA is already 3,000 MW short heading into the summer and will be forced to buy power on the spot market to fill its contracts. BPA anticipates raising rates by more than 200% this fall.

Michael Kenny of the California Air Resources Board objected to provisions in the bill that would allow generating plants to operate under temporary waivers of the Clean Air Act Amendments without public comment. Kenny said his agency already offers sufficient flexibility in its regulations and air quality standards have not interfered with the development of new generation.

Barton asserted that the Clean Air Act waivers were explicitly limited to two years and were included in the bill for governors to request to keep the lights on in an emergency. "We're not trying to get around the Clean Air Act or backdoor it on a permanent basis," he said.

QF PROBLEM REMAINS TOUGH FOR CALIF. AS WRANGLING OVER PAYMENT CONTINUES

A group of financial institutions with investments in California qualifying facilities has thrown its support behind a California Cogeneration Council request that the Federal Energy Regulatory Commission let QFs break their supply contracts with utilities and sell power to third-party buyers.

The group's activity counters opposition to the contract-breaking idea from the state's utilities and policymakers.

In a May 2 filing, the Qualifying Facilities Lenders Council, which includes such companies as John Hancock Financial Services, Prudential Insurance, and CIGNA Investments, said the relief requested by the CCC is "desperately needed to help alleviate the potentially catastrophic electricity crisis that faces" California. The group also said it supports CCC's request that FERC overturn a March 27 California Public Utilities Commission decision that would effectively reduce QF payments from utilities.

Saying that QFs have received no, or only partial, payments for power they have supplied since November, the group told FERC that "companies that invested in the QF industry in California did so with the expectation that the sanctity of contracts under which the QFs served their customers would be supported by regulators and the courts." The PUC order, it added, "will discourage lenders from financing additional power generating capacity to serve the state."

"Preserving the sanctity of the contracted pricing formulas and allowing QFs the right in the event of non-payment to sell power to parties that are able and willing to pay sufficient

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prices is critical to allowing the QFs to repay investors that financed the construction of these plants," the group added.

FERC has allowed some QFs to sell to other parties than the utilities they have contracts with, and it has been reported that the Bush administration is considering a blanket authorization in the energy policy package it is to release next week. Rep. Joe Barton (R-Texas) has included such a provision in the California-aid bill he is considering.

California state and utility officials spoke out strongly against the idea. Davis' financial advisor Joseph Fichera called the idea "idiotic." He said allowing the QFs to escape from their utility contracts would force the state to buy that power in the open market at a considerably higher price. It would, he added, be "a budget-busting idea in California."

"You do the math," he said. "That power today, under contract, is 15 cents/kWh. On the open market it would be 40 cents/kWh, and the state would have to buy it."

In a letter to Vice President Cheney, Southern California Edison CEO Stephen Frank claimed the proposal would do nothing to help California's crisis: "While the result will be a windfall for QFs and power marketers selling at market-based prices that are today roughly four times higher than existing contract prices, the result for the state will be to make power supply and price situation worse, not better."

Gov. Gray Davis met late last week with QF representatives to try working out a plan whereby they would get paid for their past and ongoing power sales to the utilities. According to the state's Independent System Operator, about 3,000 MW of QF power is off-line in recent days. Some of that outage is attributable to nonpayment, the rest to other reasons, and it is unclear how much is caused by the utilities' financial problem. In QF-related news last week, Calpine, one of the largest suppliers of QF power in the state, asked FERC to overturn a March 28 PUC ruling that lowered the price state utilities must pay for QF power.

In its request to FERC, the company argued that the PUC decision, which changed the natural gas purchase price on which QF payments are based, violated the Public Utility Regulatory Policies Act because it "delinks the rates California utilities are paying QFs from the costs the utility is able to avoid by purchasing QF power" (Docket No. EL01-71). The PUC decision, Calpine added, "sets avoided costs based on a gas purchase price which does not reflect the actual cost of natural gas used to serve gas-fired generation in California."

The decision, the company said, is "not based on any evidence" of what gas prices actually are, but is "driven by the unlawful intent to 'slash' payments to QFs."

Calpine said that the PUC decision, if not overturned, will likely mean that none of the QF capacity that has shut down in the state because of non-payment will return to service this summer, and it will probably lead more QFs to "make the painful, albeit necessary, decision to cease operating."

The ruling, Calpine told FERC, also violates PURPA by subjecting QFs to [state] rate regulation and sets payments at price levels that make it impossible for QFs to economically generate power, contrary to the PURPA objective of encouraging cogeneration."

"Given the critical importance of avoided-cost determinations to PURPA's intended encouragement of alternative generation sources, [FERC] did not leave the setting of avoided costs to the whim and fancy of state regulatory commissions, or to be unduly influenced by the prevailing political view."

San Diego Gas & Electric sued three small cogeneration facilities owned by Sithe Energy on April 30 in San Diego County Superior Court. The three plants, totaling 102 MW, had been shut down since March and Sithe notified SDG&E on April 2 it had no obligation to deliver energy generated by the plants.

Sithe told SDG&E in a teleconference April 4, according to SDG&E's lawsuit, that the PUC decision on QF prices was the crucial factor in shutting down. SDG&E said the three units began operating again on May 2.

FERC said it is seeking expedited comment on whether and how it can prevent California utilities from denying transmission access to QFs that want to sell power to third parties. Both Ridgewood Power and the California Cogeneration Council earlier this year asked FERC to require the state's utilities to grant transmission access to QFs that want to sell power on the open market.

FERC is asking for comments by May 10 and said it has launched its own investigation into the issue under Sec. 210(d) of the Federal Power Act.

BUSH ORDERS FEDERAL ENERGY SAVING; DAVIS CALLS DIRECTIVE INADEQUATE

Flanked by Dept. of Defense Deputy Secretary Paul Wolfowitz and Energy Secretary Spencer Abraham, President Bush Thursday said federal facilities across the country would be directed to review ways to reduce energy usage, warning that "we are running out of energy in America. ... We are confronting a major problem."

In comments to reporters following a meeting with administration officials on the California energy crisis, Bush warned that the U.S. needs to not only improve existing infrastructure to meet its energy needs, but also "build new supplies." He added, "We need to be honest with the American people."

Bush also defended comments earlier in the week by Vice President Dick Cheney outlining an emerging energy policy that the vice president said would place a heavy reliance on supply over conservation. "Conservation has got to be an integral part ... but we can't conserve our way to energy independence," said Bush.

In order to ease California's predicted energy woes this summer, Wolfowitz said DOD would take measures to reduce its energy consumption in California during peak-use periods this summer by 10%, or a total of 200 MW. Wolfowitz said the reduction should expand to 15% of peak consumption by next summer. Of this year's demand reduction, 75% would come from energy efficiency and 25% from "new power sources," including reactivation of an idled wind generator at Edwards Air Force base, Wolfowitz said.

Bush's order includes directives to turn off lights, use florescent light bulbs and shut down escalators, according to an Energy Dept. spokeswoman.

Abraham also said he had asked government facilities in California to put together a plan within 30 days on how they

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History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 17

FERC Order Addressing Creditworthiness Tariff Provisions

94 FERC ¶ 61,132

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Curt Hébert, Jr., Chairman;
William L. Massey, and Linda Breathitt.

California Independent System Operator Corporation	Docket No. ER01-889-000
California Power Exchange Corporation	Docket No. ER01-902-000
San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents, et al.	Docket No. EL00-95-006 Docket No. EL00-98-006 Docket No. EL00-104-002 Docket No. EL00-107-003 Docket No. EL01-1-003

ORDER ADDRESSING CREDITWORTHINESS TARIFF PROVISIONS PROPOSED BY THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR AND CALIFORNIA POWER EXCHANGE

(Issued February 14, 2001)

In this order, we conditionally accept proposed Amendment No. 36 to the tariff of the California Independent System Operator Corporation (ISO) for filing to become effective January 4, 2001, subject to clarification and guidance provided below. We reject proposed Amendment No. 22 to the tariff of the California Power Exchange Corporation (PX). Also, we act on various requests for clarification on creditworthiness issues.

California energy markets are in state of great turmoil. The proposed amendments and clarifications are intended to address the sinking credit ratings of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SoCal Edison) and relax the creditworthiness standards of the ISO and PX tariffs. We accept the amendments to the extent they allow PG&E and SoCal Edison to continue to schedule

transactions from generation and over transmission they own to serve their own load. We deny the amendments to the extent they allow PG&E and SoCal Edison to continue to schedule transactions from third-party suppliers without adequate assurance of payment. We clarify that PG&E and SoCal Edison may continue to schedule third-party transactions if they obtain financial backing from creditworthy counterparties. These actions, in the aggregate, should help in maintaining the reliability of system operations and in encouraging the entry of lower-cost supply into California markets.

I. Background

Docket No. ER01-889-000

On January 4, 2001, acting on reports that Standard & Poor's Corporation (S&P) and Moody's Investors Service (Moody's) were on the verge of reducing the credit ratings of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SoCal Edison), the ISO filed Amendment No. 36 to revise the Approved Credit Rating requirements of its tariff. [1] PG&E and SoCal Edison are California investor-owned utility distribution companies (UDCs) that schedule their transmission service through the ISO. The ISO states that a reduction in the credit ratings of SoCal Edison and PG&E would result in these entities no longer meeting the creditworthiness requirements of the ISO tariff and would preclude SoCal Edison and PG&E from scheduling transactions with the ISO, absent the posting of security sufficient to cover those entities' full liability to the ISO. The ISO argues that the reliability of the California electric grid will be threatened if UDCs are no longer eligible to schedule transactions, even transactions that involve use of their own transmission facilities and their own generation.

Proposed Amendment No. 36 gives the ISO temporary authority to waive the requirement that UDCs without an Approved Credit Rating post security. Until March 3, 2001, the ISO proposes to grant such a waiver if the UDC (or its Scheduling Coordinator): (1) had an Approved Credit Rating on January 3, 2001; and (2) was an Original Participating Transmission Owner or a Scheduling Coordinator for an Original Participating Transmission Owner.

The ISO announced in its filing that it was implementing Amendment No. 36 immediately, and it requests waiver of notice requirements and approval of the Amendment effective January 4, 2001. The ISO states that it was necessary to take this immediate action in order to ensure that the UDCs could continue to serve their electric

[1] Except for federal and state agencies, the ISO tariff ties a party's Approved Credit Rating to the rating it receives from S&P, Moody's, or other credit rating agencies. See ISO tariff, Appendix A, "Master Definitions Supplement," and Sections 2.2.3.2 and 2.2.7.3.

consumers. The ISO notes the conflict between imposing appropriate credit requirements to maintain the financial security of transactions and maintaining the reliability of the California grid. The ISO asks for further Commission guidance regarding the appropriate resolution of this conflict. The ISO states that until such guidance is received, in order to ensure the continued functioning of the California markets, the ISO proposes to publish a day-by-day grace period for the affected UDCs prior to the imposition of trading limits.

Docket No. ER01-902-000

On January 5, 2001, the PX filed an amendment to its creditworthiness requirements. Under the existing PX tariff, PG&E and SoCal Edison must maintain short-term credit ratings of A-1 from S&P or P-1 from Moody's to obtain unsecured credit.[2] Under the PX's proposed Amendment No. 22, PG&E and SoCal Edison could continue trading without posting collateral if their ratings fell below A-1 and P-1 but remained above "junk" status; however, the PX could use settled outstanding amounts due in one market as collateral in another market. If PG&E's and SoCal Edison's ratings fell to junk status, they would have to post 100 percent collateral. However, Amendment No. 22 would also give new power to the PX's Governing Board to waive the tariff's collateral requirements.

Amendment No. 22 would also make changes in the creditworthiness provisions of the PX tariff to reflect the order the Commission issued on December 15, 2000 to remedy dysfunctions in California's wholesale bulk power markets (December 15 Order).[3] To obtain unsecured credit under the existing PX tariff, the UDCs not only must maintain ratings of A-1 or P-1, they also must remain mandated full-requirement customers of the PX who receive all exchange, scheduling, settlement, and clearing services from the PX. The December 15 order released the UDCs from the obligation to obtain all services through the PX.[4] Accordingly, Amendment No. 22 would revise the creditworthiness standards for the UDCs to require simply that the UDC originally was a mandated, full-requirement customer and that it continues to receive at least some exchange, scheduling, settlement, and clearing services from the PX.

The PX announced in its filing that it was implementing Amendment No. 22 immediately, and it requests waiver of notice requirements and approval of the Amendment effective January 5, 2001.

Docket No. EL00-95-006, et al.

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[2]See PX tariff, Schedule 2.

[3]San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,294 (2000), reh'g pending.

[4]See id. at 62,001.

On December 22, 2000, Dynegy filed a motion for clarification of the December 15 Order. The issues raised by Dynegy relating to creditworthiness are discussed below.

First, Dynegy states that the Commission should maintain a policy of allowing the principles of generally applicable commercial law--including principles related to creditworthiness--to govern the commercial aspects of jurisdictional services. Dynegy argues that, in keeping with those principles, the Commission should ensure that generators are not required to sell to buyers who admit they are on the verge of bankruptcy, unless commercially reasonable assurances of payment are provided. Dynegy points out that the existing ISO tariff does provide some such assurance through its requirement that utilities with less than Approved Credit Ratings post collateral. Dynegy, which filed its motion before the ISO filed Amendment No. 36, urges the Commission not to relax these creditworthiness provisions of the ISO tariff.

Second, Dynegy argues that in light of the financial insecurity of the UDCs, the Commission should provide the following additional protections for suppliers: (1) shorten the ISO's payment calendar to include a 30-day rather than a 75-day payment lag; and (2) require the ISO to offset amounts owing against amounts owed.

Third, Dynegy seeks clarification that the ISO tariff penalties for failure to comply with emergency dispatch instructions do not apply when purchasers fail to meet the tariff creditworthiness requirements.

Finally, Dynegy's motion raises issues involving, e.g., the applicability of the federal preemption doctrine. This order addresses only the creditworthiness aspects of Dynegy's motion, and we will address the other aspects of its motion in a future order.

Other Matters

On December 14, 2001, the Secretary of the Department of Energy, acting under section 202(c) of the Federal Power Act, [5] ordered that certain suppliers provide electricity to California utility companies when the ISO certifies that there is inadequate

[5] 16 U.S.C. 824a(c) (1994).

electrical supply. [6] Subsequent orders extended this requirement to February 7, 2001 (orders collectively referred to as the DOE Order). [7]

On January 17, 2001, the Governor of California issued an emergency proclamation giving the California Department of Water Resources (DWR) authority to enter into arrangements to purchase power in order to mitigate the effects of electrical shortages in the state. [8] DWR began purchasing under this authority the next day. On January 19, 2001, the Governor signed a bill appropriating $400 million (DWR Appropriation) from the General Fund for DWR's purchases for sale to SoCal Edison and PG&E. [9]

On January 16, 2001, Moody's and S&P lowered the credit and debt ratings of SoCal Edison to junk or "near junk" status. On January 16 and 17, 2001, these rating services downgraded PG&E's credit and debt ratings to junk status. On January 16, 2001, SoCal Edison filed a Form 8-K with the Securities and Exchange Commission (SEC), disclosing that it would suspend indefinitely certain obligations including a $215 million payment to the PX and $151 million payment due to the Qualifying Facilities (QFs). On January 21, 2001, the PX suspended the trading rights of SoCal Edison and PG&E. On February 1, 2001, PG&E filed an SEC Form 8-K stating its intention to default on payments of over $1 billion due to QFs and the PX.

II. Notices, Interventions, and Responses

Docket No. ER01-889-000

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[6] DOE Order Pursuant to Section 202(c) of the Federal Power Act (Dec. 14, 2000).

[7] Amended Order Pursuant to Section 202(c) of the Federal Power Act (Dep't Energy Dec. 20, 2000); Amendment No. 2 to December 14, 2000, Order Pursuant to Section 202(c) of the Federal Power Act (Dep't Energy Dec. 27, 2000); Amendment No. 3 to December 14, 2000, Order Pursuant to Section 202(c) of the Federal Power Act (Dep't Energy Jan. 5, 2001); Order Pursuant to Section 202(c) of the Federal Power Act (Dep't Energy Jan. 11, 2001); Amended Order Pursuant to Section 202(c) of the Federal Power Act (Dep't Energy Jan. 17, 2001); and Amendment No. 2 to January 11, 2001, Order Pursuant to Section 202(c) of the Federal Power Act (Dep't Energy Jan. 23, 2001).

[8] Proclamation, Cal. Gov. (Jan. 17, 2001).

[9] S.B. 7, 2001-2002 Legis., 1st Ex. Sess. (Cal.) (to be codified at CAL. WATER CODE § 200).

Notice of the ISO's filing was published in the Federal Register, [10] with comments, protests, and motions to intervene due on or before January 25, 2001.

Timely unopposed motions to intervene were filed by: El Paso Merchant Energy LP (El Paso); Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. (Reliant); PG&E; Williams Energy Marketing & Trading Company (Williams); Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC (Duke); the PX; the Turlock Irrigation District; the City of Vernon, California (Vernon); the Modesto Irrigation District; the Sacramento Municipal Utility District (SMUD); Mirant California, LLC (Mirant); the Northern California Power Agency (NCPA); the Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (Cities/M-S-R); SoCal Edison; the California Electricity Oversight Board (Board); Tucson Electric Power Company (Tucson Electric); San Diego Gas & Electric Company (SDG&E); and Dynegy. The Public Utilities Commission of the State of California (California Commission) and the Illinois Commerce Commission filed timely notices of intervention. Puget Sound Energy, Inc. (Puget) filed a motion to intervene four days out of time.

Reliant and Duke included motions for a cease-and-desist order in their filings. Dynegy filed a motion for expedited action.

On January 16, 2001, the ISO filed an answer to Reliant's motion for a cease-and-desist order. On February 9, 2001, the ISO filed an additional answer to the protests.

Docket No. ER01-902-000

Notice of the PX's filing was published in the Federal Register, [11] with comments, protests, and motions to intervene due on or before January 26, 2001.

Timely unopposed motions to intervene were filed by PG&E, SMUD, Vernon, Williams, SDG&E, Reliant, and Duke. Mirant filed a motion to intervene 17 days out of time.

PG&E included a request for modification of Amendment No. 22 and immediate action in its filing, and later filed a supplement. SDG&E and Reliant included protests in their filings.

The PX filed an answer to the protests on February 9, 2001.

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[10] 66 Fed. Reg. 4,014 (2001).

[11] 66 Fed. Reg. 4,810 (2001).

The ISO and PG&E filed timely answers to Dynegy's motion. NCPA and Duke filed answers to the motion out of time.

III. Positions of the Parties

Docket No. ER01-889-000

Reliant and Duke argue that the ISO's proposed Amendment No. 36 jeopardizes any prospect of stabilizing California electricity markets. Reliant states that releasing the UDCs from the ISO tariff's credit requirements fundamentally changes the terms on which market participants elected to participate in the ISO markets, including the terms of the Participating Generator Agreements (PGAs), which provides among other things for in-state generators to supply power in emergencies. Reliant suggests that absent assurances of payment, the sellers in the California market will suffer from their own credit problems and that their suppliers will demand credit support or simply stop supplying. Finally, Reliant states that there can be no justification for the sellers to be forced to finance the continuing purchases of electricity by the ISO on behalf of the defaulted UDCs when the UDCs' lenders refuse to extend credit for payment of the supplied electricity.

NCPA, SDG&E, Williams, Mirant, Tucson Electric, Dynegy and Cities/M-S-R protest the proposed amendment citing the need for balanced financial protections to ensure suppliers into the ISO market are paid. Although NCPA does not request rejection of the proposed amendment, it nevertheless protests the discriminatory nature of lowering the UDCs' creditworthiness requirements, arguing that these requirements have had a disproportionately large impact on small entities and that the proposed amendment aggravates this situation.

Dynegy filed a motion for expedited action stating that it does not oppose the implementation of the proposed amendment on a temporary basis through February 7, 2001, because the State of California has provided some short-term credit assurances through the DWR purchases and because the DOE Order expires on that date. Dynegy argues that the Commission should not extend the waiver past February 7, 2001, because such an extension, absent another DOE Order or consent of the suppliers, requires suppliers to accept unreasonable risks.

Although SDG&E states that it has no desire to see rolling blackouts in any part of California as a result of creditworthiness issues, it argues against the proposed amendment. SDG&E argues that the ISO's unilateral action is causing financial harm to

California electricity markets and in particular SDG&E's customers. SDG&E speculates that the risk premiums added to the price of power due to default concerns have increased the price SDG&E pays for power in the ISO markets and for bilateral transactions. SDG&E concludes that if the proposed amendment is approved, the Commission should condition its approval to ensure that no market participant will be required to bear losses it could not have anticipated at the time it sold into the ISO markets. In addition, SDG&E contends that any amendment to the ISO tariff should allow SoCal Edison and PG&E to use their own generation and their bilateral contracts to serve their customers' requirements.

Mirant and Tucson Electric generally oppose Amendment No. 36 because it unilaterally imposes great risk on sellers in the market and thereby undercuts the stability of the market at a time when the stability and financial viability of all market participants is critically important. Mirant notes that the DWR Appropriation has restored some of the financial stability to the California markets during its implementation. Mirant states that the Commission should condition acceptance of the proposed amendment by requiring such credit support arrangements, either by using DWR as a purchasing entity or the substitution of an equally creditworthy party. [12] Finally, Mirant contends that the Commission should require that the ISO provide some concrete assurance that suppliers will be paid in full for energy deliveries made between the ISO's unilateral implementation of the proposed amendment and the day that DWR began providing credit support.

The California Commission, the Board, and PG&E fully support the proposed amendment. PG&E argues that the ISO must have the authority to modify its creditworthiness standards in view of the unsettled market conditions in California in order to protect the ability of the UDCs to continue to serve millions of customers.

SoCal Edison supports Amendment No. 36, stating that it is the minimum measure necessary for the UDCs to continue to serve their customers. SoCal Edison argues that failure to relax the ISO tariff creditworthiness standards will have a devastating impact on health and welfare of the State of California. SoCal Edison suggests modifying the proposed amendment to include a provision allowing 30 days for the UDCs to obtain the necessary security to meet the requirements of the ISO, and a provision waiving all credit and security requirements with respect to the self-provided load of the UDCs.

The ISO's answer to Reliant's motion for a cease-and-desist order argues that the continued service of tens of millions of California customers outweighs Reliant's concerns. In addition, the ISO states that Reliant has not made a showing of harm nor

[12] Mirant Motion at 7.

plausibly explained how the temporary waiver of creditworthiness standards will endanger Reliant over the long run.

Docket No. ER01-902-000

PG&E argues that the PX's proposal does not adequately loosen creditworthiness requirements, because it would still require PG&E to post collateral once its credit rating was downgraded to junk status. PG&E states that it is unable to post collateral; therefore, to prevent disruption of services to millions of customers, the PX should relax its creditworthiness standards consistent with the ISO's proposal.

SDG&E and Reliant argue that the PX's proposal overly weakens creditworthiness requirements, and raise the same basic objections as they do to the ISO's proposed Amendment No. 36.

Docket No. EL00-95-006, et al.

The ISO and PG&E oppose Dynegy's motion. With regard to maintaining the creditworthiness provisions of the tariff, the ISO makes many of the same arguments as in Docket No. ER01-607-001 about the need to relax those standards in order to ensure continued electric service to Californians.

On the question of shortening the ISO's billing lag time and offsetting amounts owing against amounts owed, the ISO argues that it is impractical to shorten its billing lag time because it takes 60 days to obtain and process the meter data on which billings are based and the ISO has no reliable method of developing estimates. The ISO also notes that the current 75-day lag time has the benefit of allowing the UDCs time to work with their creditors and the California Commission to try and prevent default. The ISO further states that it already offsets amounts owing against amounts owed. PG&E argues that neither of Dynegy's proposed changes can be made without either a filing of a tariff amendment by the ISO or a finding by the Commission that the existing tariff provisions are unjust and unreasonable.

IV. Discussion

A. Procedural Matters

In Docket No. ER01-889-000, the notices of intervention by the California Commission and the Illinois Commerce Commission in serve to make them parties, as provided in Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2000). The timely, unopposed intervention motions filed in that same docket make the persons who filed them parties as well. No disruption would result from

allowing Puget to intervene at this stage; therefore, we grant its out-of-time motion. As provided in Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (2000), we will accept the ISO's January 16 answer to Reliant's motion for a cease-and-desist order and reject the ISO's February 9 answer to the protests.

In Docket No. ER01-902-000, the timely, unopposed interventions of the following persons make them parties: PG&E, SMUD, Vernon, Williams, SDG&E, Reliant, and Duke. No disruption would result from allowing Mirant to intervene at this stage; therefore, we grant its out-of-time motion. We reject the PX's answer.

In Docket No. EL00-95-006, et al., we will accept the answers of NCPA and Duke, although filed one and four days out of time, respectively, as provided in Rule 213(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(d)(1) (2000).

B. Self-Scheduling Under Proposed ISO Amendment

The creditworthiness requirements in the ISO tariff apply not only when a UDC is scheduling delivery of power purchased from a third party, but also when a UDC or its Scheduling Coordinator is scheduling its own generation and using its own transmission resources that are now controlled by the ISO. [13] We commend the ISO for striving to meet its primary obligation, ensuring system reliability, during times of severe electrical supply and financial instability in the California market. The California market situation is evolving with unprecedented speed with major developments unfolding daily. We believe that to the extent Amendment No. 36 allows SoCal Edison and PG&E to continue to deliver their own resources and access their own transmission facilities to serve their load, the Amendment is reasonable and necessary for maintaining the reliability of the ISO grid. We further recognize that without the unilateral implementation of Amendment No. 36, electrical service to California consumers would have suffered, possibly resulting in additional blackouts. Accordingly, we will accept Amendment No. 36 and find good cause to grant a limited waiver of our notice requirements but only to the extent the Amendment applies to SoCal Edison's and PG&E's ability to access their own transmission facilities to deliver their resources to their load.

C. Third-Party Transactions Under Proposed ISO and PX Amendments

Nevertheless we will deny the ISO's and the PX's proposals to relax creditworthiness standards to the extent they affect third-party suppliers. The

[13] As we noted in the December 15 Order at 61,993, the three UDCs in California own or control, under contract, approximately 25,000 MWs of resources.

Commission has long accepted creditworthiness requirements consistent with applicable provisions of commercial law. [14]

The ISO and PX tariffs, in their original forms, were designed to incorporate creditworthiness protections that were consistent with applicable provisions of commercial law. In fact, in the proceeding originally authorizing operation of the ISO and PX, we specifically rejected requests to relax the creditworthiness standards in the ISO tariff, finding the filed standards reasonable and consistent with the open access requirements of Order No. 888. [15]

More recently, the Commission Staff Report on the 1998 price abnormalities in the Midwest noted that the June price spike provided a wake-up call to many market participants on the issue of creditworthiness. The staff study team concluded that "In a competitive market, market participants must take responsibility for inquiring into the creditworthiness of their counterparties to ensure contract performance." [16]

As previously noted, third-party suppliers negotiated over, and agreed to do business with the ISO and PX subject to, tariff provisions that included standard financial protections. We find that by simply lowering the standards for the two largest buyers in these markets, the proposed amendments entail an inappropriate unilateral shifting of unacceptable financial risks to both large and small third-party suppliers. Moreover, we are concerned that a lowering of the financial creditworthiness standard, without some assurance of payment for third party sales, would further increase prices paid by consumers. This is because, as SDG&E recognizes, the tariff revisions likely would increase the risk premium added to the price of power due to the exposure of non-payment. Further, the consequences of relaxing creditworthiness standards only for the three large investor-owned UDCs may be disproportionately severe as applied to small municipal customers, such as NCPA and Cities/M-S-R. These small municipal customers both generate and purchase power and will shoulder a burden that is proportionately greater relative to their size.

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[14] See Section 11 of the Pro Forma Open Access Transmission Tariff, Order No. 888, at Appendix D, 61 Fed. Reg. 21,540, FERC Statutes and Regulations ¶ 31,036, at 31, 926 (1996). See also New York State Electric & Gas Corp., 78 FERC ¶ 61,114, at 61,436 (1997) (approving additional creditworthiness provisions demonstrated to conform to standard commercial practices).

[15] See Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,122, at 61,510 (1997).

[16] Staff Report to the Federal Energy Regulatory Commission on the Causes of the Pricing Abnormalities in the Midwest during June 1998, at 4-4 to 4-5 (1998).

In summary, we reject the PX's proposed Amendment No. 22. We also reject application of the ISO's proposed Amendment No. 36 beyond the UDCs and their Scheduling Coordinators self-scheduling their own generation and accessing their own transmission facilities.

D. Requests for Further Clarification

With regard to the ISO's request for further guidance, we find that although Amendment No. 36 as currently drafted is unacceptable as applied to third-party transactions, a relaxation of the restrictions on UDCs with less-than Approved Credit Ratings would be acceptable if combined with appropriate support from creditworthy counterparties. Credit-support arrangements, such as the type proposed by Mirant or some comparable credit backing by a state agency or specific state bond issued for the purpose of backing the power purchases of the UDCs, are necessary to ensure adequate assurance of payment for third-party suppliers. DWR has served as a creditworthy counterparty with the backing of state appropriations, keeping the California market functioning through much of January. Such financial backing for that portion of the power that is not self-supplied by the UDCs would provide immediate financial stability to the market.

We deny Dynegy's additional requests for clarification. With regard to 75-day payment lag in the ISO market, we point out that the PX was a trading floor that relied on instantaneous transaction data to calculate billing, whereas the ISO must collect meter data to perform its billing function. Given these facts, we find that a 75-day lag is appropriate for the ISO. With regard to netting amounts owing against amounts owed, such a provision is already incorporated in the ISO tariff.[17] Finally, the penalty provision for which Dynegy seeks clarification was added to the ISO tariff by Amendment No. 33, which we accepted on an emergency basis on December 8, 2000, in California Independent System Operator Corporation, 93 FERC ¶ 61,239 (2000) (December 8 order). Dynegy and others have filed requests for rehearing of that order, and we will address the arguments Dynegy has raised in the instant proceeding in our order on the rehearing requests of the December 8 order.

Therefore, we direct the ISO to submit a compliance filing within 15 days of the date of this order to change the provisions of Amendment No. 36 to allow for a waiver of the creditworthiness requirements to allow for self-scheduling of the UDCs' own resources and to incorporate provisions for an acceptable form of a credit support that provides adequate assurances of payment for third-party suppliers, as discussed above.

[17] See ISO tariff, Section 11.9.

Under our order, the ISO can continue to accept the UDCs' schedules to supply their load with their own resources, and DWR's authority to purchase on behalf of the UDCs is acceptable. Thus, the unresolved creditworthiness issues relate to the UDCs' residual load that is served through the ISO's imbalance energy market. Under current conditions, there is a bid insufficiency in the ISO's energy imbalance market causing the ISO to issue emergency dispatch instructions in order to meet this residual load and balance the system. By maintaining appropriate creditworthy standards that ensure payment for services by a creditworthy counterparty such as DWR, this order should increase the supply in the energy imbalance market and reduce the need for emergency dispatch instructions.

We understand that the PX has closed its Day-Ahead and Day-Of energy markets. Therefore, revision of the creditworthiness provisions of the PX tariff is no longer an issue. Consequently, we will reject the PX's proposed tariff amendment.

The Commission orders:

(A) The ISO's proposed Amendment No. 36 is hereby accepted in part for filing to become effective on January 4, 2001, subject to modification as discussed in the body of this order.

(B) The ISO is hereby directed to file modifications to the ISO tariff in compliance with this order within 15 days of the date of this order, pursuant to the procedures discussed in the body of this order.

(C) The PX's proposed Amendment No. 22 is hereby rejected.

(D) Dynegy's motion for clarification is hereby granted in part and denied in part, as discussed in the body of this order.

By the Commission.

(SEAL)

David P. Boergers,
Secretary.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 18

FERC Order Clarifying Creditworthiness Tariff Provisions

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

95 FERC ¶ 61,024

Before Commissioners: Curt Hébert, Jr., Chairman;
William L. Massey, and Linda Breathitt.

California Independent System Operator Corporation	Docket No. ER01-889-002
California Power Exchange Corporation	Docket No. ER01-902-002
San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents, et al.	Docket No. EL00-95-021 Docket No. EL00-98-020 Docket No. EL00-104-004 Docket No. EL00-107-005 Docket No. EL01-1-005

ORDER GRANTING MOTION

(Issued April 6, 2001)

In this order, we grant a motion filed by a group of California generators [1] to require the California Independent System Operator Corporation (ISO) to comply with the Commission's order on creditworthiness issued February 14, 2001. [2]

[1] This group includes Dynegy Power Marketing, Inc.; Mirant Delta, LLC and Mirant Potrero, LLC; Reliant Energy Power Generation, Inc.; El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Power I LLC and Cabrillo Power II LLC; Duke Energy North America and Duke Energy Trading and Marketing LLC; and Williams Energy Marketing and Trading Company (collectively California Generators).

I. Background

In response to imminent credit downgrades for Southern California Edison Company and Pacific Gas and Electric Company (PG&E), the ISO filed proposed Amendment No. 36 to relax its tariff creditworthiness requirements for the California investor-owned utility distribution companies (UDCs). The February 14 Order, inter alia, accepted Amendment No. 36 in part, subject to modification.[3]

Specifically, the Commission held that the ISO could not relax the creditworthiness provisions of the ISO tariff in a way that "entails an inappropriate unilateral shifting of unacceptable financial risks" to suppliers that sell into the California market.[4] The Commission authorized the ISO to waive the creditworthiness provisions of its tariff as applied to UDCs accessing their own transmission facilities to deliver their resources to their loads, but specifically held that the ISO may not relax those creditworthiness provisions where third-party suppliers are affected. For transactions involving third-party suppliers, the Commission required a creditworthy counterparty, such as the California Department of Water Resources (DWR), noting that the DWR had served in this capacity with the backing of state appropriations since January 19, 2001. We found in the February 14 Order that the credit crisis in California is restricting supplies due to the risk of non-payment, which, in turn, places upward pressure on prices. In addition, the February 14 Order was intended to increase the supply in the energy imbalance market and reduce the need for emergency dispatch instructions.

II. The California Generators' Motion

On February 22, 2001, the California Generators filed an emergency motion to compel the ISO to comply with the February 14 Order. The California Generators maintain that the ISO has failed to take any action to comply with the February 14 Order. The California Generators also state that the ISO has argued in various federal court

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[2] California Independent System Operator Corporation, et al., 94 FERC 61,132 (2001), reh'g pending (February 14 Order).

[3] On March 1, 2001, the ISO submitted a compliance filing revising the tariff creditworthiness provisions. We will address this filing, as well as requests for clarification or rehearing, in a separate order.

[4] February 14 Order at 61,510.

proceedings that the February 14 Order does not apply to "large portions of transactions involving third party suppliers, and specifically excludes all real-time purchases" and "did not require the ISO to make any changes in its practices of billing power acquired through emergency dispatch instructions to the California utilities." [5] The California Generators state that the ISO's decision to ignore the February 14 Order further undermines the fragile California market. The California Generators request that the Commission act to enforce the February 14 Order by again directing the ISO to provide a creditworthy counterparty for all transactions with third-party suppliers.

III. Responses and Positions of the Parties

The Northern California Power Agency (NCPA), the California Electricity Oversight Board (Board), the Public Utilities Commission of the State of California (California Commission), PPL EnergyPlus, LLC and PPL Montana, LLC (PPL Parties), and the ISO filed answers to the California Generators' motion on or before March 9, 2001. [6]

The ISO maintains that the February 14 Order addressed only the ISO's proposal to continue accepting schedules on behalf of the UDCs, and leaves unresolved the creditworthiness requirements of its real-time imbalance market. Further the ISO states that the February 14 Order was not intended to affect the explicit obligation of suppliers to respond without regard to the creditworthiness of purchasers when the ISO issues an emergency dispatch order. The ISO argues that the California Generators are magnifying out of proportion their risk of nonpayment for real-time energy and indicates that it has recently been able to reduce the frequency of real-time emergency dispatch orders. Finally, the ISO states that it is essential for the Commission to appreciate that the California Generators' request is really an attempt to increase their bargaining leverage in negotiating power supply contracts with the State of California.

The Board and the California Commission filed answers supporting the position elaborated by the ISO in its answer. The answers filed by NCPA and PPL Parties support the California Generators' motion.

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[5] Motion at p. 2 and 4.

[6] PG&E also filed an answer in which it requests Commission review of certain issues in light of a recent agreement between the ISO and DWR. We will address PG&E's requests in a separate order.

IV. Discussion

A. Procedural Matters

We will accept the answers of NCPA, the Board, the California Commission, PPL Parties, and the ISO as provided in Rule 213(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. . 385.213(d)(1) (2000).

B. Creditworthiness Standards for Scheduled and Unscheduled Transactions

We will grant the California Generators' motion. The ISO has misinterpreted our order. Contrary to the ISO's interpretation, the February 14 Order did not exempt any transactions from the requirement to have in place a creditworthy buyer. Instead our order provided third-party suppliers assurances of a creditworthy buyer for all energy delivered to the loads through the ISO. [7]

The ISO's interpretation enables continuation of the over-reliance on the real-time market by increasing use of emergency dispatch instructions to serve load, contrary to the Commission's goal of increasing the amount of load that is supplied by schedules in the forward markets. We take administrative notice of the ISO's statement in Docket No. EL01-34-000, that the current real time market supplies approximately 15 percent of the load. This is far higher than our stated goal of limiting the amount of load supplied in the real-time market to no more than 5 percent. [8]

The Commission orders:

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[7] To the extent the February 14 Order references only scheduled transactions, the Commission did not intend to exempt any third-party transactions from requiring a creditworthy buyer. The ISO's creditworthiness requirements apply whether transactions are scheduled or not, and we created no exception in our February 14 Order.

[8] See San Diego Gas & Electric Company, et al., 93 FERC . 61,294 at 62,002 (2000), reh'g pending.

The California Generators' motion is hereby granted and the ISO is ordered to comply with the February 14 Order as discussed in the body of this order.

By the Commission. Commissioner Massey concurred with a separate statement attached.

(SEAL)

Linwood A. Watson, Jr.,
Acting Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	Docket No. ER01-889-002
California Power Exchange Corporation	Docket No. ER01-902-002
San Diego Gas & Electric Company, Complaint, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondent, et al.	Docket No. EL00-95-021 Docket No. EL00-98-020 Docket No. EL00-104-004 Docket No. EL00-107-005 Docket No. EL01-1-005

(Issued April 6, 2001)

MASSEY, Commissioner, concurring:

I am reluctantly reaching the conclusion that the current ISO creditworthiness standards must apply to all transactions, scheduled as well as unscheduled.

I would agree that, generally, creditworthiness standards are a necessary component of a market and should be viewed as sacrosanct. My concern in this case is that a strict application of the ISO's existing creditworthiness standards may prevent the

California ISO from performing its fundamental task of keeping the system in balance and thereby maintaining the reliability of the grid. If the ISO is unable to purchase power for the unscheduled load of the largest utilities in California, I worry that the ISO may not be able to do its job. I am voting for today's order, but am troubled by the seemingly irreconcilable conflict between assuring sellers that they will be paid and precluding the ISO from accomplishing its fundamental mission.

The extraordinary events in California were not foreseen when the present creditworthiness rules were written. No one expected that the two largest utilities in California would have their credit ratings slip below investment grade and be facing bankruptcy. The Commission relied on this point in our recent order addressing the unreasonableness of applying the California PX's chargeback mechanism in such adverse

and unforeseen market conditions.[1] The same rationale may have some weight in our evaluation of the creditworthiness issue in this case.

For these reasons, I concur with today's order. I am not completely confident that we reach the correct conclusion.

William L. Massey
Commissioner

[1]Pacific Gas & Electric Company, et al v. California Power Exchange Corporation, Docket No. EL01-29-000.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 19

CAISO Letter to DWR Regarding Credit Support

CALIFORNIA ISO

California Independent
System Operator

Terry M. Winter
President and Chief Executive Officer

April 13, 2001

Mr. Ray Hart
Deputy Director
CA Department of Water Resources
3310 El Camino Ave., Ste. 120
Sacramento, CA 95821-9001

Dear Ray:

This letter confirms the agreement between the ISO and DWR concerning credit support by DWR for ISO purchases. The terms of the agreement are set forth in the attached draft notice to market participants. If the attached notice accurately reflects our agreement, please signify your consent by signing this letter as indicated below and return the original to me. Your signature will also constitute your authorization that the notice may be issued.

Thank you for your continued cooperation in these times of challenge.

Very truly yours,

Terry M. Winter

Terry M. Winter
President and Chief Executive Officer

Agreed:

Peter Stein for

Ray Hart
CA Department of Water Resources

DRAFT

Market Notice re Credit Issues

In response to the FERC order of April 6, 2001 re the issue of creditworthiness, the California Department of Water Resources (DWR) has authorized the ISO to make the following statement. To the extent (and only to the extent) that a purchase is not otherwise paid by any party or payable by another party meeting the credit standards set forth in the ISO Tariff (another "Qualified Party"), DWR will assume financial responsibility for all purchases by the ISO in its ancillary services and imbalance energy markets based on bids or other offers determined to be reasonable. Such determination of reasonableness will be made by DWR on a case by case basis and communicated to the ISO. All bids into the ancillary services and imbalance energy markets will be deemed to be contingent on the acceptance of financial responsibility by DWR, to the extent not paid or payable by another Qualified Party. Unless a supplier is otherwise notified, any bid accepted by the ISO will be deemed to have the financial support of another Qualified Party or DWR as specified in this notice. In addition to the foregoing, DWR will assume financial responsibility for all purchases resulting from the issuance by the ISO of emergency dispatch instructions, to the extent not paid or payable by another Qualified Party. Payment for such purchases shall be made according to the rate specified in the ISO Tariff for emergency dispatch instructions. The ISO and/or DWR reserve the right to rescind or modify the foregoing arrangements at any time and for any reason, including a successful rehearing or appeal from the April 6 order.

As the FERC determined in its February 14 order that DWR is a creditworthy counterparty, the ISO believes that the foregoing arrangements meet the requirements of FERC's April 6 Order. Accordingly, the ISO expects that suppliers will honor their obligations under the ISO Tariff and related agreements to respond to ISO dispatch instructions.

DRAFT

- Letter Agreements

CDWR and ISO Agreement

The following agreement has been struck by the California Department of Water Resources ("CDWR") and the California Independent System Operator ("ISO").

Under the authority granted in SB7X, CDWR has been appropriated $400 million to purchase power for the benefit of electric consumers in California. CDWR and the ISO wish to apprise the Market Participants of an agreement reached under which CDWR will purchase power for the ISO's real-time market.

The process for bilateral transactions and the ISO's real-time market will be as follows:

1. The ISO will determine the need based on the net requirement between Pacific Gas & Electric Company's (" PG&E's") generation and load, and Southern California Edison Company's ("SCE's") generation and load. This need on an hourly basis for a seven-day period will be communicated to DWR.
2. The generators are required to offer their generation at reasonable rates.
3. CDWR will procure such amounts as bi-lateral transactions to be scheduled on a day-ahead basis with the ISO.
4. Any subsequent resource requirements identified by ISO operations that can be determined up to three hours in advance of the operating hour will be communicated to CDWR trader to execute bilateral trades with any remaining offers in the same priority of the next day order to the extent the limited infrastructure of CDWR can execute these trades to meet the scheduling timelines of the Hour-Ahead market.
5. The ISO will be responsible for balancing adjustments made in the real-time market and the ISO expects all uncommitted generation to be bid into the ISO real-time market. CDWR will purchase power for the ISO's real-time balancing adjustments to meet the changing load requirements of the PG&E and SCE service areas. CDWR will determine the acceptability of these offers.
6. The ISO will provide a daily report to DWR stating the amount procured in real-time under this agreement, including dollars and amount of energy.

This agreement is effective 12:01 a.m. January 21, 2001. CDWR or the ISO may terminate this agreement at any time if the bids are deemed unreasonable by CDWR or the amount of the appropriation has been extinguished. DWR will apprise Market Participants shortly of the structure for procurement of the forward energy component.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 20

CAISO/DWR Joint Clarification Letter

STATE OF CALIFORNIA – THE RESOURCES AGENCY

GRAY DAVIS, *Governor*

DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET, P.O. BOX 942836
SACRAMENTO, CA 94236-0001
(916) 653-5791

May 10, 2001

Mr. Terry M. Winter
President and Chief Executive Officer
California Independent System Operator
P.O. Box 639014
Folsom, California 95763-99014

Dear Mr. Winter:

The Department of Water Resources has no objection to the wording of the notice to market participants in the attached document and DWR has no objection to the California Independent System Operator issuance of the market notice.

Sincerely,

Raymond D. Hart
Deputy Director

Attachment

cc: Gary Heath
Electricity Oversight Board
770 L Street, Suite 1250
Sacramento, California 95814

Erik Saltmarsh
Electricity Oversight Board
770 L Street, Suite 1250
Sacramento, California 95814

UNION LABEL

CALIFORNIA ISO

California Independent
System Operator

Terry M. Winter
President and Chief Executive Officer

May 10, 2001

Mr. Ray Hart
Deputy Director
CA Department of Water Resources
3310 El Camino Ave., Ste. 120
Sacramento, CA 95821-9001

Dear Ray:

This letter supplements the agreement between the ISO and DWR concerning credit support by DWR for ISO purchases. The additional terms of the agreement are set forth in the attached draft notice to market participants. If the attached notice accurately reflects our agreement, please signify your consent by signing this letter as indicated below and return the original to me. Your signature will also constitute your authorization that the notice may be issued.

Thank you for your continued cooperation in these times of challenge.

Very truly yours,

Terry M. Winter

Terry M. Winter
President and Chief Executive Officer

Agreed:

_____

Ray Hart
CA Department of Water Resources

cc: Gary Heath, EOB
Erik Saltmarsh, EOB

Draft- Privileged & Confidential, Attorney Work-Product

Supplemental Market Notice re Credit Issues
May 10, 2001

On April 13, 2001, the ISO sent out a Market Notice explaining how the ISO will comply with FERC's April 6, 2001 order, 95 FERC ¶ 61,024, on creditworthiness. In that Market Notice, the ISO was authorized to make the following statement on behalf of the California Department of Water Resources (CDWR):

> To the extent (and only to the extent) that a purchase is not otherwise paid by any party or payable by another party meeting the credit standards set forth in the ISO Tariff (another "Qualified Party"), CDWR will assume financial responsibility for all purchases by the ISO in its ancillary services and imbalance energy markets based on bids or other offers determined to be reasonable. Such determination of reasonableness will be made by CDWR on a case by case basis and communicated to the ISO. All bids into the ancillary services and imbalance energy markets will be deemed to be contingent on the acceptance of financial responsibility by CDWR, to the extent not paid or payable by another Qualified Party. Unless a supplier is otherwise notified, any bid accepted by the ISO will be deemed to have the financial support of another Qualified Party or CDWR as specified in this notice. In addition to the foregoing, CDWR will assume financial responsibility for all purchases resulting from the issuance by the ISO of emergency dispatch instructions, to the extent not paid or payable by another Qualified Party. Payment for such purchases shall be made according to the rate specified in the ISO Tariff for emergency dispatch instructions. The ISO and/or CDWR reserve the right to rescind or modify the foregoing arrangements at any time and for any reason, including a successful rehearing or appeal from the April 6 order.

Pending rehearing, unless the ISO can provide reasonable assurances that a party meeting the ISO's credit requirements will support a specific transaction, the ISO will not enter into the transaction with respect to any resource. This includes (1) awarding capacity bids in the forward Ancillary Service ("AS") markets and (2) dispatching Imbalance Energy bids in the real time market. Therefore, the ISO will not award AS capacity bids nor will it dispatch Imbalance Energy bids above the prices for which CDWR will agree to provide credit backing. Imbalance Energy bids above the prices for which CDWR has agreed to provide credit backing, though not accepted, shall remain in the "BEEP" stack. Accordingly, in accordance with ISO Tariff §§5.1.3 and 11.2.4, resources will not be subject to Out-Of-Market calls unless the ISO has secured a creditworthy buyer for these unawarded Supplemental Energy Bids. See, e.g., ISO Tariff §§ 5.6.2 and 5.1.3. A separate notice will be issued regarding Reliability Must Run.

Don Fuller
Director, Client Relations

California ISO
Phone: 916-608-7055
E-Mail: dfuller@caiso.com

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 21

Letters from Energy Suppliers Expressing Concern Regarding DWR's Credit

P. O. Box 52025
Phoenix, AZ 85072-2025
(602) 236-5900
www.srpnet.com

May 18, 2001

Mr. Raymond D. Hart
Deputy Director
California Department of Water Resources
1416 Ninth Street
Post Office Box 942836
Sacramento, California 94236

Re: Credit Assurance for Energy Sales by Salt River Project

Dear Mr. Hart:

This letter is to confirm our understanding of California Department of Water Resources ("CDWR") credit assurances to Salt River Project ("SRP"). SRP will rely on these assurances in making all energy sales to CDWR. Specifically CDWR has represented to us that:

1. CDWR will pay the agreed upon price for all energy purchases and waives all claims that an agreed upon price is not reasonable or otherwise should not be paid in full on the scheduled payment date.

2 CDWR will not make purchases from SRP unless sufficient funds exist in the California Department of Water Resources Electric Power Fund and/or exist in the form of expected revenues from the utility distribution companies ("Available Funds").

3. CDWR may lawfully use Available Funds for the purchase of energy from SRP and the use of Available Funds is not subject to any condition that would reduce payment to SRP.

Please confirm our understanding of these assurances by signing and returning this letter to us. By requesting these assurances SRP is not making any power sale commitment to CDWR nor is SRP waiving any right to request additional assurances, in its sole discretion.

Very truly yours,

Dean K. Yee
Manager, Financial Services

Agreed to this 18 day of May, 2001

Department of Water Resources
By Raymond D. Hart
Its Deputy Director

Reliant Energy

February 19, 2001

California Department of Water Resources
3310 El Camino
Sacramento, CA 95821-9000

Re: Amendment to February 16th Agreement

Dear California Department of Water Resources:

Reliant Energy Services, Inc. ("RES") and the California Department of Water Resources ("CDWR") are Parties to an agreement dated February 16, 2001 for the purchase and sale of energy ("hereafter, the "February 16th Agreement"). Pursuant to the terms of the February 16th Agreement, the Delivery Period will commence on the day following RES' receipt of payment for deliveries already made by RES to CDWR from January 22, 2001 through and including February 19, 2001 (Paragraph 2 of the Special Provisions to such Agreement). In Paragraph 2 of the Special Provisions, however, it states that payment for the referenced deliveries is due with the first Daily Energy Costs Invoice, but the invoice is not to be sent until after energy is called on by CDWR and delivered by RES. Thus, as drafted, the Delivery Period does not commence until payment is received and payment is not due until an invoice for deliveries is sent. This is not the intent of the Parties.

RES and CDWR therefore desire to amend the February 16th Agreement to provide that: (i) the Delivery Period will commence at hour ending 0100 on Wednesday, February 21, 2001; and (ii) payment for all deliveries made by RES to CDWR from January 22, 2001 through February 19, 2001 is due to RES on or before Thursday, February 22, 2001. Thus, RES agrees to commence deliveries prior to receipt of payment provided, however, if RES does not receive payment for past deliveries by close of business Thursday, February 22, 2001, RES may terminate the February 16th Agreement and/or suspend further deliveries thereunder until such time as payment is received. Payment shall be wired to the account indicated on the invoices sent to CDWR by RES.

In addition, the Parties agree to amend the February 16th Agreement to add the following:

> "To the extent that actual deliveries of energy result in charges payable that are less than amounts paid pursuant to invoices submitted by RES to CDWR, such payments shall be netted against amounts otherwise due by

CDWR to RES for energy hereunder. The parties shall only be obligated to indemnify one another in connection with this transaction to the extent permitted by law."

No other terms or conditions of the February 16th Agreement are revised, modified or otherwise affected hereby.

THIS AMENDMENT IS AGREED TO AND ACCEPTED THIS 19TH DAY OF FEBRUARY 2001 BY THE BELOW LISTED INDIVIDUALS, WHO REPRESENT AND WARRANT THAT THEY ARE DULY AUTHORIZED TO ENTER INTO THIS AMENDMENT.

DHK

Reliant Energy Services, Inc.

By: _____
Jack L. Farley
President, West Region

California Department of Water Resources

By: _____

Nevada Power

February 14, 2001

Ms. Perla Neto-Brown
California Department of
Water Resources (CDWR)
P.O. Box 942836
Sacramento, California 94236-0001

Dear Ms. Brown:

The recent failures of two large California electric utilities to pay large bills due for wholesale electric power to the California Power Exchange ("CAPX") has resulted in substantial charge backs to both Nevada Power Company ("NPC") and Sierra Pacific Power Company ("SPPC"), subsidiaries of Sierra Pacific Resources Corporation ("SPR"). These failures led to California legislation that provides for the California Department of Water Resources ("CDWR") to acquire and pay for power required for California loads. The purchase of this power, as SPR understands it, is done under provision of the Western Systems Power Pool ("WSPP") using CDWR's membership. We also understand that transactions conducted by CDWR for this purpose are accounted for separately from CDWR's other transactions that supply water pumping for its water contractors. The separate new account is named California Energy Resources Scheduling ("CERS").

NPC and SPPC are concerned that payment for power sold to CDWR for use to serve CERS or CDWR loads may not be forthcoming in view of the continuous declining conditions in the California electric power market. Accordingly, we require a written detailed explanation as to how funding, contracts, billing, and payments are to be accomplished for CERS's and CDWR's other obligations, and how certainty of payment can be assured.

Until such explanation is made, both companies may be forced to suspend further power sales to CDWR. Depending on CDWR's explanation and further degredation in the wholesale markets, the companies may demand a form of securitization available under Section 27, "Creditworthiness" of the WSPP Agreement dated February 1, 2001.

6226 West Sahara Avenue, Las Vegas, NV 89146 • P.O. Box 230, Las Vegas NV 89151-0001
702.367.5555 • www.nevadapower.com

Ms. Perla Neto-Brown
California Department of Water Resources
Page two (2)
February 14, 2001

If you have any questions, please contact me at AC 775/834-5600.

Sincerely,

Gary Baythom for

Mike Smart
Vice President
Resource Management

FAX 775-834-3841

Joe Bob Perkins
President
Chief Operating Officer
Wholesale Group

February 6, 2001

The Honorable Gray Davis
Governor of the State of California
State Capitol
Sacramento, CA 95814

Dear Governor Davis:

Unless an immediate change in direction occurs, the California ISO and the Department Water Resources have set the stage today for a return to credit-driven blackouts in California. This results from the apparent decision to withhold the credit of the DWR from the ISO's real-time energy purchases. To avoid this result, immediate action by you is necessary to ensure that the DWR stands behind these purchases.

Reliant understood that the passage of AB1X was intended to provide the necessary credit assurances that would support both short- and long-term generation for the State. To confirm this, we prepared the attached letter, which was sent yesterday after a long period of ambiguity on behalf of the ISO and the DWR. As of the time of this letter, we have received no response to our letter sent yesterday. In fact, the strategy of the ISO appears to invite or compel the generators to supply power on the strength of the credit of the virtually bankrupt investor-owned utilities, as in the past. In the case of Reliant alone, we are already owed approximately $300 million for deliveries previously made to the ISO to meet the needs of California's near bankrupt utilities.

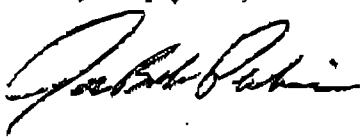
We are very concerned about the supply implications of this apparent policy, for supplies to California from suppliers both inside and outside of California. This credit-driven problem is, we believe, precisely the kind of issue that AB1X was intended to head off.

P.O. Box 4567 Houston, TX 77210-4567, 713 207 5670, Fax, 713 207 9192

Reliant Energy

This is a matter that calls for responsible action on all sides. Reliant remains ready, willing and able to do what it can to address California's supply problems. We believe the legislature has begun to address the credit problem through AB1X. What is called for now is for that intention to be implemented by the ISO and the DWR. It is in this spirit that we are urgently appealing to you to help resolve this issue.

Very truly yours,



Attachment
cc: Attached List

Mirant Americas Energy Marketing, LP
1155 Perimeter Center West, Atlanta, Georgia 30338-5416
T 678 579 5000 F 678 579 5001 U www.mirant.com
steve.brown@mirant.co

SECOND REQUEST

February 2, 2001

VIA FACSIMILE
Attn: Mr. Ray Hart
Deputy Director
California Department of Water Resources
Fax (916) 574- 2441

Re: Credit Assurances

Dear Mr. Hart:

I am the Director of Trading Control at Mirant Americas Energy Marketing, LP (formerly, Southern Company Energy Marketing L.P., "Mirant"), whose function it is to review all counterparties for creditworthiness. Specifically, I wish to ascertain the degree of creditworthiness of the California Department of Water Resources ("CDWR"). As of the end of January, Mirant has sold power to CDWR, which has resulted in over $68.5 million in accounts receivable.

In light of the recent appropriation by the California Assembly to CDWR, and as required by Mirant's risk policy, I must ascertain whether such appropriation will be sufficient to allow CDWR to perform under all transactions into which it has entered heretofore. We would like you to verify whether this is the case and, if not, whether CDWR will provide further assurances in order for Mirant to continue delivery

Mirant and CDWR currently transact under the Western Systems Power Pool Agreement ("WSPP"). Pursuant to Section 27 of the WSPP, "Should a Party's creditworthiness, financial responsibility, or performance viability become unsatisfactory to the other Party in such other Party's reasonably exercised discretion with regard to any transaction pursuant to this Agreement and any Confirmation Agreement (after the transaction is agreed to or begins), the dissatisfied Party (the "First Party") may require the other Party (the "Second Party") to provide, at the Second Party's option (but subject to the First Party's acceptance based upon reasonably exercised discretion), either (1) the posting of a Letter of Credit, (2) a cash prepayment, (3) the posting of other acceptable collateral or security by the Second Party, (4) a Guarantee Agreement executed by a creditworthy entity; or (5) some other mutually agreeable method of satisfying the First Party."

If the CDWR fails to provide such reasonably satisfactory assurances of its ability to perform a transaction hereunder within three (3) Business Days of this notice, then it will be considered an Event of Default under Section 22 of the WSPP and Mirant shall have the right to exercise any of the remedies provided for under that Section 22.

Your response is requested by 5:00 P.M. EST on Tuesday February 6, 2001. You may reach me at (678) 579-3061.

Sincerely,

Steven Brown
Director, Trading Control

cc: Randy Harrison
Rob Lamkin

1/2 - Credit Issue

Memo to File
Credit Issue with Bonneville Power
March 27, 2001

On March 27, we received an invoice from Bonneville for approximately $17 million and demanding payment on the next day.

As we had a credit limit of $40 million with Bonneville, I told staff that we should pay it on Friday instead of Wednesday, as we had available credit. I also exchanged voice mails with Rod Ross of Bonneville, informing him of the payment plan. In a voice mail response the said that he wanted to talk about the issue and understand why we were waiting to pay until Friday, because one other time they had gotten next day turnaround.

At 6pm on March 27, I was talking to Ray Hart, and he told me that we had gone into Stage 2 because Bonneville had refused to pay. I told him the information in 2nd paragraph above.

On the morning of March 28, I called Rod Ross of Bonneville to get some clarification as to why we had been cut off. During the conversation he said that Bonneville had reduced our credit limit (he didn't say to what level) and that the $17 million had to cleared up. The reduction in credit limit was news to us at the Department.

I agreed that we would pay Bonneville on Thursday, and that we would have a conference call with Rod and the Account Manger, who was out of town this week, on Monday April 2 to discuss credit issues in more detail.

Jim Olson

Memo to File
TransAlta
March 30, 2001

We have had the unwritten policy of paying TransAlta on Friday after getting an invoice on Tuesday.

On Thursday, March 29th I received a phone call around noon from Howard Mello that TransAlta was cutting us off because of credit problems. I called Maureen Piercey, TransAlta Credit officer, and she said that she was unaware of any problem and knew that we were making a payment the following day.

At 4pm Maureen called back to say that there was a credit problem and that because our total exposure, unpaid amounts plus current commitments, exceeded their imposed credit limit they were cutting us off until the payment was received on Friday.

On Friday morning, March 30th, Howard Mello called to say that because of the credit problem with TransAlta, we had to make extra purchases from Powerex and that the price had been in excess of $600 per hour.

Jim Olson

JAMES E OLSON

From: CDWR [CDWR2@caiso.com]
Sent: Saturday, February 10, 2001 5:20 AM
To: 'J.OLSON'
Cc: Garris, Pete; 'Jim Blood'
Subject: CREDIT

I hate beating a dead horse, but while doing my surveys last night the following companies cited credit problems as the reason for not selling directly to CDWR/CERS.

CHPD – Chelan County
PACW – Pacificorp
PGE – Portland Gas
PSPL – Puget Sound
PPLM – Montana

PPLM/Tom said that they would like to sell directly to us, as they currently are sending quite a lot to us through marketers, and gave me a name and number to call. Mickey Palmer @406-533-3528

G.Solberg

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 22

Credit Issue Memos (Treasurer's Office/Department of Finance); Letters from DWR to Creditors

PHILIP ANGELIDES
Treasurer
State of California

June 21, 2001

Mr. Thomas Hannigan
Director
Department of Water Resources
1416 9th Street, 11th Floor
Sacramento, CA 95814

Dear Mr. Hannigan:

At the request of the Department of Water Resources ("DWR"), pursuant to an Executive Order of the Governor issued on June 18, 2001 and consistent with AB1X, my office has arranged interim financing for DWR power purchase costs in the initial amount of $4.55 billion from various banking institutions. The interim financing will be funded on June 26, 2001, at which time the net proceeds will be deposited into the DWR Electric Power Fund.

All of the net proceeds of this loan will be available to DWR to pay the cost of future power purchases; none of the proceeds will be used to reimburse the General Fund of the State for previous power purchases. The loan provides the working capital financing requested by DWR to satisfy the conditions of its power purchase contracts.

The Credit and Security Agreement securing the loan provides for the interim borrowing to be increased to a maximum amount of $6.0 billion at a later date. This Agreement also provides that the power purchase costs of DWR as due are payable prior to payments due to the lenders. If not retired through a subsequent financing, the loan will be repaid solely through ratepayer revenues received by DWR and is not payable from the General Fund. In accordance with its terms, the loan has received private letter ratings in the investment grade category.

It has been my pleasure to be of assistance to DWR in this matter.

Sincerely,

Philip Angelides
State Treasurer

CREDIT

Sent to McKinsey & Blackstone 4/1/01

CONFIDENTIAL DRAFT

March 31, 2001

To: Tim Gage, Director
Department of Finance

From: Raymond D. Hart, Deputy Director
Department of Water Resources

Re: Credit Issues

This memorandum is to describe an ongoing "credit issue" that has caused the State considerable expense in its energy acquisition program. Most counter parties to CDWR's "spot market" energy purchases have set credit limits on sales to limit their credit exposure to California. Many of these counter parties are owed significant sums of moneys by two quasi-State agencies, the bankrupt Cal PX and the Cal ISO (which only paid a small percentage of its outstanding debt last month). For the most part, it is the out-of-state generators that feel most vulnerable. Thus, most of them have set relatively low credit limits – in comparison to CDWR's average monthly purchases from those entities, often ranging from $10 to $40 million. These generators are, for the most part, paid on a 14-day basis, or less, except when we run up to our credit limit. When that happens, an immediate payment is usually demanded before any more energy will be sold to CDWR. For example, this past week our credit was reduced (see attached memo) causing a need for an immediate payment, which was not made, and the delivery of energy was cut off (1100 mw) causing a Stage II alert. That alert immediately drove prices up by an average of $75/mwh, causing the State to pay $500,000 extra to replace that energy for just those few hours. When the prices run up, our credit problems are compounded by the fact that we burn through the credit at a faster clip causing more counter parties to demand immediate payment.

Credit issues still remain the single largest obstacle to purchasing energy out-of-state. Many out-of-state generators are refusing to sell to California at all. It is CDWR's belief that some other arrangement for guaranteeing payment for energy received would eliminate this obstacle and make it possible for more energy to be acquired. This is especially important now and through this summer, as CDWR needs to have those out-of-state resources maximized to help minimize and avoid blackouts.

The main reason this issue has not been addressed to date is concern expressed by our legal counsel as to "most favored nations" clauses in CDWR's long-term contracts for energy. We have revisited this issue and believe there may be a way to avoid having that conflict. Attached is a memorandum by our Financial Advisor, Doug Montague that describes a process that could provide the guarantees our "spot market" counter parties require while not exposing the State to MFN provisions in our long-term contracts. Implementation of this solution will likely save the State $100's of millions of dollars in credit premiums (currently paid to third party marketers willing to take the risk and in

increased energy costs during staged emergencies) and make available more energy from out-of-state resources during times of shortage.

Cc: Tom Hannigan, Director
Department of Water Resources

Perla Netto-Brown, Controller
Department of Water Resources

GRAY DAVIS, Governor

STATE OF CALIFORNIA – THE RESOURCES AGENCY

EPARTMENT OF WATER RESOURCES

California Energy Resources Scheduling
PO Box 219001
3310 El Camino Avenue, Suite 120
SACRAMENTO, CA 95821-9001
(916)574-1291

June 29, 2001

Market Participants

I am writing to provide you with an update on the status of the Department of Water Resources Electric Power Fund (DWREPF) that was established on January 19, 2001, and trades under the WSPP ID "CERS".

Background

In response to the energy crisis faced by the State of California, in January 2001, the State began purchasing power on behalf of the customers of California's investor owned utilities. On January 19, 2001, Senate Bill 7X was enacted, appropriating $400 million to DWREPF for the purchase of power. On February 1, 2001, Assembly Bill 1X was enacted, appropriating $500 million to DWREPF. The legislation allows for the appropriation of additional funds by the Director of Finance with a 10-day notice to the Legislature. Through June 26, 2001, an additional $5 billion in cash was transferred to DWREPF using this procedure.

Through June 26, 2001, DWREPF had committed $8.6 billion for power purchases of which $6.2 billion has already been paid. The Fund has received $1.1 billion in ratepayer revenues collected for the Department by the investor owned utilities. This leaves $1.3 billion in outstanding power commitments for which future payments will be made.

Interim Financing

On June 18, 2001, Governor Gray Davis signed Executive Order D-42-01 that authorized the Department of Water Resources to enter into an interim financing of up to $5 billion. The Department is authorized under the order to utilize the proceeds of the loan to purchase electric power and natural gas and to fund other financing related costs. The proceeds of the loan cannot be used to reimburse the State's General Fund for power purchase expenditures made prior to June 18, 2001.

On June 26, 2001, DWREPF closed an interim financing with a group of five domestic and international lenders for a total of $4.3 billion. The lending

Market Participants group was led by Morgan Guaranty and Trust Company of New York and included JP Morgan Chase & Co., Lehman Brothers, CommerzBank Aktiengesellschaft and Bayerische Landesbank Girozentrale. This loan constitutes the first external borrowing for the DWREPF. The proceeds of the borrowing have been deposited in the DWREPF for future power and natural gas purchases. The securing of third party financing in the form of the interim loan satisfies the requirement in a number of the Department's power purchase contracts that the Department issue "bonds" by July 1, 2001.

As part of the interim loan process and to comply with the requirements of Assembly Bill 1X, the State made presentations to Moody's Investors Service, Standard and Poor's Rating Group and Fitch Investors Service and requested investment grade rating indications from the rating agencies. The State requested the rating indications on a private, confidential basis and received indications from all three rating agencies that the State's energy purchase program, were it to be publicly rated, would be investment grade.

Attached is a letter from California State Treasurer, Philip Angelides regarding the interim financing.

Long Term Financing

The Department projects that the $4.3 billion in proceeds from the interim loan, combined with revenues received from ratepayers, will be sufficient to meet the power purchase obligations of DWREPF up until the $13.4 billion of long-term financing is completed in the Fall of 2001. As part of the long-term financing process, the Department will secure public long-term investment grade ratings for the bonds. The long-term financing will refinance the interim loan, reimburse the State's General Fund for prior power purchases and provide additional funding for future power purchases. This long-term financing was authorized by Assembly Bill 1X and Senate Bill 31X.

Ratepayer Revenues

DWREPF continues to receive monies from Pacific Gas and Electric Company (PG&E), Southern California Edison, and San Diego Gas and Electric under California Public Utility Commission (CPUC) Decision 01-03-081, dated March 27, 2001. This decision requires the investor owned utilities to make payments, at specified rates for megawatt hours delivered to DWREPF 45 days after delivery to end-use customers.

As mentioned above, through June 26, 2001, DWREPF had received $1.08 billion in ratepayer revenues collected for the Department by the investor owned utilities. The payments received to date include monies received daily from PG&E since it filed for bankruptcy. The Chapter 11 filing by PG&E in no way relieves the utility of its obligation to comply with the CPUC's order to remit payments for power provided by DWREPF.

Power Costs

The Department's cost of power has dropped dramatically in the month of June as supply under long-term contracts has become available and conservation by end users has reduced net short purchasing requirements. June power purchase expenditures have been below the Department's projections. The Department expects its power costs to remain manageable throughout the summer, due to the same positive inputs.

In summary, the Department continues to make strong progress in the implementation of the power purchase program. With the successful closing of the $4.3 billion interim financing, which required stringent credit review of the Department's program by the rating agencies and lenders, we are prepared to implement the balance of the long-term financing plan. It is our hope that this update will provide you with additional comfort regarding the high creditworthiness of DWREPF.

If you have any additional questions, please contact me at (916) 574-2733.

Sincerely,

Nija Patel

for Raymond D. Hart
Deputy Director

Attachment

GRAY DAVIS, Governor

STATE OF CALIFORNIA – THE RESOURCES AGENCY

DEPARTMENT OF WATER RESOURCES

California Energy Resources Scheduling
PO Box 219001
3310 El Camino Avenue, Suite 120
SACRAMENTO, CA 95821-9001
(916)574-1291

June 15, 2001

Market Participants:

This letter is to update you about the Department of Water Resources Electric Power Fund (DWREPF) that was established on January 19, 2001, and trades under the WSPP ID "CERS".

On January 19, 2001, Senate Bill 7X was enacted, appropriating $400 million to DWREPF. On February 1, 2001, Assembly Bill 1X was enacted, appropriating $500 million to DWREPF. The legislation allows for the appropriation of additional funds by the Director of Finance with a 10-day notice to the Legislature. Through May 31, 2001, an additional $6 billion had been authorized using this procedure. A summary financial report of DWREPF as May 31, 2001 is attached.

The Director of Finance is able to appropriate additional monies to the DWREPF without Legislative authorization. This is accomplished through the issuance of notification to the Legislature ten days before the funds are needed for additional power purchase commitments. It would take legislation, signed by the Governor, to remove the authority granted to the Director of Finance to increase appropriations to DWREPF. No such legislation is under consideration.

DWREPF continues to receive monies from Pacific Gas and Electric Company (PG&E), Southern California Edison, and San Diego Gas and Electric under California Public Utility Commission (CPUC) Decision 01-03-081, dated March 27, 2001. This decision requires the investor owned utilities to make payments, at specified rates for megawatt hours delivered, to DWREPF 45 days after delivery to end-use customers. Through May 31, 2001, DWREPF had received $768 million from the investor owned utilities. The payments received to date include monies received daily from PG&E since it filed for bankruptcy. The Chapter 11 filing by PG&E in no way relieves the utility of its obligation to comply with the CPUC's order to remit payments for power provided by the DWREPF.

Through May 31, 2001, DWREPF had committed $7.651 billion for power purchases of which $5.944 billion has already been paid, leaving $1.707 billion in cash to pay for power already purchased. As of May 31, 2001, DWREPF had nearly $440 million available for purchasing power. As of the date of this letter, an additional $1 billion for power purchases has been made available to DWREPF as a result of additional funds being appropriated by the Director of Finance.

The Department and the State Treasurer are working on a long-term financing program and expect to have revenue bonds sold by September 30, 2001.

DWREPF is and continues to be a credit worthy fund.

If you have any questions or wish to discuss this further please call me at (916) 574-1297

Sincerely,

Jim Olson

Jim Olson
Deputy Controller

Enclosure

GRAY DAVIS, *Governor*

STATE OF CALIFORNIA -- THE RESOURCES AGENCY

DEPARTMENT OF WATER RESOURCES
416 NINTH STREET, P.O. BOX 942836
SACRAMENTO, CA 94236-0001
(916) 653-5791

April 11, 2001

Market Participants

This letter is to update you about the Department of Water Resources Electric Power Fund (DWREPF) that was established on January 19, 2001, and trades under the WSPP ID "CERS".

On January 19, 2001, Senate Bill 7X was enacted, appropriating $400 million to DWREPF. On February 1, 2001, Assembly Bill 1X was enacted, appropriating $500 million to DWREPF. The legislation allows for the appropriation of additional funds by the Director of Finance with a 10-day notice to the Legislature. Through March 31, 2001, an additional $3 billion had been authorized using this procedure. A schedule listing the appropriations, which totaled $3.9 billion under the two laws as of March 31, 2001, is attached.

The Director of Finance is able to appropriate additional monies to the DWREPF without an additional legislative appropriation. This is accomplished through the issuance of notification to the Legislature ten days before the funds are needed for additional power purchase commitments. It would take legislation, signed by the Governor, to remove the authority granted to the Director of Finance to increase appropriations to DWREPF. No such legislation is under consideration.

DWREPF is receiving cash from Pacific Gas and Electric Company (PG&E), Southern California Edison, and San Diego Gas and Electric under California Public Utility Commission (CPUC) Decision 01-03-081, dated March 27, 2001. This decision requires the investor owned utilities to make payments, at specified rates for megawatt hours delivered, to DWREPF 45 days after delivery to end-use customers. Through March 31, 2001, DWREPF had received $240 million from the investor owned utilities. The payments received to date include monies received daily from PG&E since it filed for bankruptcy. The Chapter 11 filing by PG&E in no way relieves the utility of its obligation to comply with the CPUC's order to remit payments for power provided by the DWREPF.

Through March 31, 2001, DWREPF had committed $3.488 billion for power purchases of which $2.338 billion has already been paid, leaving $1.150 billion in cash to pay for power already purchased. As of March 31, 2001, DWREPF had nearly $647 million available for purchasing power. In early April, an additional $500 million for power purchases was made available to DWREPF as a result of additional funds being appropriated by the Director of Finance.

The Department and the State Treasurer are working on a long-term financing program and expect to have revenue bonds sold by June 30, 2001.

DWREPF is and continues to be a credit worthy fund.

Sincerely,

Raymond D. Hart
Deputy Director

Enclosure

DWR Electric Power Fund
Funds Available for Power Purchases as of March 31, 2001

Appropriations under SB7X	$399,000,000	(1)
Appropriations under AB1X		
Original Appropriation - February 1	$495,755,000	(2)
First Director of Finance Notice - Effective February 15	$500,000,000	
Second Director of Finance Notice - Effective February 23	$500,000,000	
Third Director of Finance Notice - Effective March 4	$500,000,000	
Fourth Director of Finance Notice - Effective March 12	$500,000,000	
Fifth Director of Finance Notice - Effective March 19	$500,000,000	
Sixth Director of Finance Notice - Effective March 29	$500,000,000	
	$3,495,755,000	
Revenue from IOUs	$240,000,000	
Total Appropriations and Revenue	$4,134,755,000	
Purchases	($3,488,000,000)	
Appropriations Available as of March 31, 2001	$646,755,000	

Note 1: An additional $1 million was appropriated for administrative expenses

Note 2: An additional $4.245 million was appropriated for administrative expenses

Sent to McKinsey & Blackstone 4/1/01

File - Credit Issues

xc Tom Hannigan
Perla
Sent 4/12/01

CONFIDENTIAL DRAFT

March 31, 2001

To: Tim Gage, Director
Department of Finance

From: Raymond D. Hart, Deputy Director
Department of Water Resources

Re: Credit Issues

This memorandum is to describe an ongoing "credit issue" that has caused the State considerable expense in its energy acquisition program. Most counter parties to CDWR's "spot market" energy purchases have set credit limits on sales to limit their credit exposure to California. Many of these counter parties are owed significant sums of moneys by two quasi-State agencies, the bankrupt Cal PX and the Cal ISO (which only paid a small percentage of its outstanding debt last month). For the most part, it is the out-of-state generators that feel most vulnerable. Thus, most of them have set relatively low credit limits – in comparison to CDWR's average monthly purchases from those entities, often ranging from $10 to $40 million. These generators are, for the most part, paid on a 14-day basis, or less, except when we run up to our credit limit. When that happens, an immediate payment is usually demanded before any more energy will be sold to CDWR. For example, this past week our credit was reduced (see attached memo) causing a need for an immediate payment, which was not made, and the delivery of energy was cut off (1100 mw) causing a Stage II alert. That alert immediately drove prices up by an average of $75/mwh, causing the State to pay $500,000 extra to replace that energy for just those few hours. When the prices run up, our credit problems are compounded by the fact that we burn through the credit at a faster clip causing more counter parties to demand immediate payment.

Credit issues still remain the single largest obstacle to purchasing energy out-of-state. Many out-of-state generators are refusing to sell to California at all. It is CDWR's belief that some other arrangement for guaranteeing payment for energy received would eliminate this obstacle and make it possible for more energy to be acquired. This is especially important now and through this summer, as CDWR needs to have those out-of-state resources maximized to help minimize and avoid blackouts.

The main reason this issue has not been addressed to date is concern expressed by our legal counsel as to "most favored nations" clauses in CDWR's long-term contracts for energy. We have revisited this issue and believe there may be a way to avoid having that conflict. Attached is a memorandum by our Financial Advisor, Doug Montague that describes a process that could provide the guarantees our "spot market" counter parties require while not exposing the State to MFN provisions in our long-term contracts. Implementation of this solution will likely save the State $100's of millions of dollars in credit premiums (currently paid to third party marketers willing to take the risk and in

increased energy costs during staged emergencies) and make available more energy from out-of-state resources during times of shortage.

Cc: Tom Hannigan, Director
Department of Water Resources

Perla Netto-Brown, Controller
Department of Water Resources

Memo to File
Credit Issue with Bonneville Power
March 27, 2001

On March 27, we received an invoice from Bonneville for approximately $17 million and demanding payment on the next day.

As we had a credit limit of $40 million with Bonneville, I told staff that we should pay it on Friday instead of Wednesday, as we had available credit. I also exchanged voice mails with Rod Ross of Bonneville, informing him of the payment plan. In a voice mail response the said that he wanted to talk about the issue and understand why we were waiting to pay until Friday, because one other time they had gotten next day turnaround.

At 6pm on March 27, I was talking to Ray Hart, and he told me that we had gone into Stage 2 because Bonneville cut off power deliveries to CDWR. I told him the information in 2nd paragraph above.

On the morning of March 28, I called Rod Ross of Bonneville to get some clarification as to why we had been cut off. During the conversation he said that Bonneville had reduced our credit limit (he didn't say to what level) and that the $17 million had to cleared up. The reduction in credit limit was news to us at the Department.

I agreed that we would pay Bonneville on Thursday, and that we would have a conference call with Rod and the Account Manger, who was out of town this week, on Monday April 2 to discuss credit issues in more detail.

Jim Olson

STATE OF CALIFORNIA – THE RESOURCES AGENCY

GRAY DAVIS, *Governor*

DEPARTMENT OF WATER RESOURCES
16 NINTH STREET, P.O. BOX 942836
SACRAMENTO, CA 94236-0001
(916) 653-5791

February 15, 2001

Market Participants

This letter is to inform you about the establishment of the Department of Water Resources Electric Power Fund (DWREPF) and its enabling legislation. We are a creditworthy institution with an impeccable long-standing reputation for maintaining the best possible credit ratings with credit rating agencies. As an example, the State Water Resources Development System revenue bonds, administered by the Department, are rated AA by both Standard and Poor's and Moody's Investor Service.

Department of Water Resources Electric Power Fund
(WSPP ID "CERS")

On January 19, 2001, the Governor signed legislation (SB7X) forming DWREPF. DWREPF was established to purchase and sell electric power in the State of California. The legislation also provided an appropriation of $400 million for the purchase of power through February 1, 2001.

Legislation established the DWREPF as a continuously appropriated fund, requiring all revenues payable to the Department under the legislation to be deposited in DWREPF accounts. The bill also required the Public Utilities Commission to adopt and implement emergency regulations to provide for delivery and payment mechanisms for the sale of electric power, purchased by DWREPF, directly or indirectly to the Independent System Operator, public utilities, or retail end-use customers.

On February 1, 2001, the Governor signed additional legislation (AB1X). A portion of this legislation appropriated another $495.8 million for the purchase of power in the short term. The bill continued the DWREPF on a permanent basis with continuously appropriated moneys and all revenues payable to the Department under Division 27 of the Water Code are required to be deposited into the DWREPF.

Section 6 of the legislation permits the Department of Finance to authorize additional monies with a 10-day notice. Under that authority, an additional $500 million has been made available for short-term purchases beginning February 15, 2001. A second letter, dated February 13, 2001, authorizing another $500 million has been sent to the Legislature.

The legislation also authorizes the DWREPF, in conjunction with the State Treasurer, to issue revenue bonds for long term financing of the DWREPF.

Copies of the enabling legislation may be found on the web. Instructions on how to access the legislation are enclosed with this letter.

CERS (California Energy Resources Scheduler) is the scheduling coordinator identification that the Department is using to make purchases for the DWREPF.

...

As mentioned above, the California Department of Water Resources also administers the State Water Resources Development System (SWRDS). SWRDS purchases and sells power on behalf of the State Water Project and was established by legislation enacted in the 1960s. The scheduling coordinator ID used by the Department for SWRDS is "CDWR".

I hope you found this letter to be helpful in better understanding who and what we are.

Sincerely,

Raymond D. Hart
Deputy Director

Enclosure

Department of Water Resources Electric Power Fund

Procedures to Access Enabling Legislation from Web

For ABx1

- Go to www.sen.ca.gov web site
- Click on "Legislation"
- Under the "Bill Number" category, type in "ABx1 1", and then click "Search." This will bring up a listing of bills the first of which is "ABx1 1"
- Click on "ABx1 1", then click on "Chaptered" selection and download the legislation in either the HTML or PDF format

For SX7X

- Go to www.sen.ca.gov web site
- Click on "Legislation"
- Under the "Bill Number" category type in "SB7X" and when the next page comes up, select the fourth item "SBX1 7" and go to the "Chaptered" selection.

If you have any questions regarding the DWREPF, please contact Jim Olson, DWR Deputy Controller at (916) 574-2659 or jolson@water.ca.gov.

STATE OF CALIFORNIA -- THE RESOURCES AGENCY

GRAY DAVIS, *Governor*

DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET, P.O. BOX 942836
ACRAMENTO, CA 94236-0001
(916) 653-5791

February 7, 2001

Via Facsimile: (713) 207-0159

Jack Farley
Reliant Energy
Post Office Box 61867
Houston, Texas 77208

Dear Mr. Farley:

This is to follow-up our conversation yesterday and in reply to Mr. Mike Jine's faxed letter of February 5, 2001 to the California Department of Water Resources ("CDWR") and the California Independent System Operator ("CAISO") requesting clarification concerning the Department of Water Resources' role, in light of the passage of AB 1X, regarding purchasing power supplied to the CAISO on a real time basis. This is to confirm that CDWR is in fact, making such purchases as described by our joint letter of January 20, 2001 to Dynegy et.al. The following paragraph sets forth the criteria that CDWR uses in determining "acceptability of these offers" for supplemental energy.

In addition, pursuant to our agreement yesterday, to help generation companies understand what they have been paid by the CDWR for supplemental energy , CAISO will be supplying CDWR daily with a listing by Scheduling Coordinator of each Scheduling Coordinator's aggregate dollars and aggregate megawatt-hours of each prior day's transactions. These summaries will be provided to generation companies approximately 24 hours from the time of the last transaction for a 24-hour period. This will be an interim procedure until more automated processes can be developed by the CDWR and CAISO.

Regarding the valuation of Supplemental Energy bids, CDWR uses the following items to evaluate the acceptability of the offers. On a daily basis CDWR assesses the value of energy based on estimated fuel costs (daily gas), heat rates for various plants, NOx costs, capital and operations & maintenance costs. Beyond these criteria, no additional information on the price at which CDWR is willing to make real-time purchases will be released. This price is within CDWR's sole discretion to determine and bids above this price may not be backed by CDWR.

With regard to your other inquiry, CDWR will continue to monitor its purchases to ensure that they remain within budgetary appropriations. As you know, AB1X appropriated substantial funds to CDWR that will enable CDWR to not only enter into long-term contracts, but also establish a cash flow to handle both reasonably priced real-time and forward market purchases. To that end, CDWR expects to arrange for interim financing in the next few weeks and long-term financing by this summer. Finally, CDWR wishes to clearly point out that it is currently able to pay for any and all of its commitments for energy delivered now and in the future to the extent that the bids are acceptable to CDWR based on the criteria addressed above.

This additional reporting of information to CDWR by CAISO will begin February 7, 2001. If you have any questions, please contact me at (916) 653-8043.

Sincerely,

Raymond D. Hart
Deputy Director
CA Department of
Water Resources

Cc: Mr. Mike Jines
Law Department
Reliant Energy

James O'Brien
Senior Staff Counsel
CDWR

JAMES E OLSON

From: JAMES E OLSON [jolson@water.ca.gov]
Sent: Friday, February 02, 2001 11:30 AM
To: steve.brown@mirant.com
Cc: Hart, Ray; veronica@water.ca.gov
Subject: California Department of Water Resources

Steve,

This confirms that we talked by phone today in response to your letter of February 2, 2001 to Ray Hart, Deputy Director. During that conversation, we discussed the current operations and funding of the California Department of Water Resources Electric Power Fund. We also discussed the related legisation. If you have additional questions or concerns please call me at 916.574.2659.

Jim Olson

02/02/2001

STATE OF CALIFORNIA -- THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET, P.O. BOX 942836
SACRAMENTO, CA 94236-0001
(916) 653-5791
GRAY DAVIS, Governor

January 20, 2001

Mr. Lynn Lednicky
Sr. Vice President
Dynegy Marketing & Trade
1000 Louisiana Street
Ste. 5800
Houston, TX 77002

Mr. John Stout
Vice President
Reliant Energy
1111 Louisiana Street
Houston, TX 77002

Mr. Bill Hall
Vice President, General Manager
Duke Energy North America
1290 Embarcadero Road
Morro Bay, CA 93442

Mr. Randy Harrison
Southern Energy, Inc.
1350 Treat Blvd., Suite 500
Walnut Creek, CA 94596

Dear Sirs:

Under the authority granted in SB7X, the California Department of Water Resources ("CDWR") has been appropriated $400 million to purchase power for the benefit of electric consumers in California. CDWR and the California Independent System Operator ("ISO") wish to apprise you of an agreement reached under which CDWR will purchase power for the ISO's real-time market.

The process for bilateral transactions and the ISO's real-time market will be as follows:

1. The ISO will determine the need based on the net requirement between Pacific Gas & Electric Company's (" PG&E's") generation and load, and Southern California Edison Company's ("SCE's") generation and load. This need on an hourly basis for a seven-day period will be communicated to DWR.
2. The generators are required to offer their generation at reasonable rates.
3. CDWR will procure such amounts as bi-lateral transactions to be scheduled on a day-ahead basis with the ISO.
4. Any subsequent resource requirements identified by ISO operations that can be determined up to three hours in advance of the operating hour will be communicated to CDWR trader to execute bilateral trades with any remaining offers in the same priority of the next day order to the extent the limited infrastructure of CDWR can execute these trades to meet the scheduling timelines of the Hour-Ahead market.

5. The ISO will be responsible for balancing adjustments made in the real-time market and the ISO expects all uncommitted generation to be bid into the ISO real-time market. CDWR will purchase power for the ISO's real-time balancing adjustments to meet the changing load requirements of the PG&E and SCE service areas. CDWR will determine the acceptability of these offers.
6. The ISO will provide a daily report to DWR stating the amount procured in real-time under this agreement, including dollars and amount of energy.

This agreement is effective 12:01 a.m. January 21, 2001. CDWR or the ISO may terminate this agreement at any time if the bids are deemed unreasonable by CDWR or the amount of the appropriation has been extinguished. DWR will apprise you shortly of the structure for procurement of the forward energy component.

Sincerely,

Raymond D. Hart
Deputy Director
CA Department of
Water Resources

Terry M. Winter
President & Chief Executive Officer
California ISO

STATE OF CALIFORNIA -- THE RESOURCES AGENCY

GRAY DAVIS, *Governor*

DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET, P.O. BOX 942836
ACRAMENTO, CA 94236-0001
(916) 653-5791

January 18, 2001

Mr. Doug Calvert
Manager, Systems Operation and Reliability
Sacramento Municipal Utility District
Sacramento, California

Dear Mr. Calvert,

This is to confirm that the Department of Water Resources will pay for power purchased from SMUD within 20 days after receipt of your invoice. Based upon my understanding the purchase of power will cost approximately $3 million.

If you have any questions, please contact me at 653-6148.

Sincerely,

James E Olson

James E. Olson
Deputy Controller

Cc: Perla Netto-Brown, Chief Division of Fiscal Services

Mailed by FAX January 18, 2001 – Noon 732-7026

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 23

Montague Derose Analysis of Commercial Bank Line of Credit for Energy Purchases

MONTAGUE DEROSE
AND ASSOCIATES

Memorandum

To: Ray Hart, Deputy Director,
California Department of Water Resources

From: Montague DeRose and Associates

Date: March 31, 2001

Subject: **Commercial Bank Line of Credit for Energy Purchases**

The following memorandum describes a possible approach to easing the California Department of Water Resources' ("DWR") current problem relating to credit premiums and limitations on energy sales imposed by out-of-state generators and third party energy marketers.

Background

In early January 2001, DWR was been given responsibility for making energy purchases to cover the imbalance or "net short" in the California energy system. The need for these purchases has arisen as a result of credit deterioration of the investor owned utilities ("IOUs").

In late January and early February, DWR put in place large bank facilities to provide suppliers with performance letters of credit ("LOCs") guaranteeing the State's payment for power purchases. These performance LOCs gave the State access to a broad universe of energy suppliers, helped DWR avoid demands for same-day or next-day payment for power and helped reduce the credit penalty paid by the State. The performance LOC program was suspended by the State due to concerns that it violated the "most favored nations" ("MFN") clauses of many of the recently negotiated long-term power contracts. Violation of the MFN clauses would require DWR to provide similar credit enhancement to all suppliers with MFN provisions in their contracts on all energy supplied under those contracts.

Because of the continuing dysfunctionality of the California energy market, energy suppliers continue to have the ability to extract large energy price concessions from DWR and have the ability to dictate the terms of power purchases. Key among their demands has been the acceleration of energy purchase payments and the imposition of strict internal credit limits for the State. Many large suppliers have now reduced the State's credit limit to as little as $15 million. When DWR's energy purchases reach these limits, energy sales are suspended and not continued until payment is wired by the State. In recent weeks, these suspensions of energy sales have resulted in Stage 2 power alerts and significant increases in energy purchase costs for DWR.

These constraining factors have prompted DWR to ask for research into alternatives to the performance LOC program that can be implemented without violating the MFN provisions of the long-term contracts. We believe the following approach has merit and warrants further analysis.

Commercial Bank Line of Credit

As a variation on the performance LOC product, in which the commercial bank guarantees DWR's timely payment for energy purchases, DWR could secure a revolving line of credit with a single or group of commercial banks. The revolving line of credit would be used to pay energy suppliers instead of paying them directly from the State's Power Purchase Fund. The bank line of credit would be paid-down or replenished from time to time with Power Purchase Fund revenues, State appropriations or the proceeds of long-term bonds. Energy suppliers would look first to the bank line of credit for payment and, if there were no capacity available in the line of credit for payment, suppliers would have a claim on revenues available in the Power Purchase Fund.

While results are not guaranteed, it is the view of the DWR staff who are responsible for negotiating the State's energy purchases that energy suppliers will view the commercial bank line of credit backstopped by revenues in the Power Purchase Fund more favorably than they currently view the Power Purchase Fund alone. This "double-barreled" credit feature should expand the universe of suppliers willing to sell power to DWR, reduce the credit premium currently being demanded by suppliers and, might possibly result in higher credit limits for the State being established by the suppliers.

Preliminary discussions with legal counsel indicate that this line of credit structure could be executed without violating the MFN provisions of DWR's long-term power contracts.

Timing and Cost

It is our estimate that a bank line of credit for approximately $500 million could be solicited, negotiated, documented and closed in a matter of two to three weeks after receiving necessary authorization from the State. While the implementation of a credit facility such as this would normally take several times longer than this time estimate, DWR's recent negotiations with a number of qualified domestic and international banks in connection with the securing of performance letters of credit lead us to believe that there are several banks ready and willing to provide the State with a credit facility or line of credit.

The interest rate that the bank would charge on draws under the line of credit would be in the range of 50-75 basis points over the London Interbank Borrowing Rate ("LIBOR"). 30-day LIBOR is currently approximately 5.20%. DWR's current cost of borrowing would, therefore, be approximately 5.70-5.95%. We would anticipate that the bank would charge a fee of approximately $100,000 for loan origination plus reimbursement for legal fees and out-of-pocket expenses. Legal fees for the bank could be as high as $60,000 but out-of-pocket expenses would be minimal. In addition, DWR would have its own legal and financial advisory fees to pay. These fees could total another $100,000.

The amount of energy cost savings or the increase in the reliability of the State's energy supply cannot be accurately forecast. However, it is highly likely that the benefits would exceed the minimal costs of structuring the line of credit that are outlined above.

Bank Capacity

It should be understood that there is a finite amount of bank credit enhancement and lending capacity that will be available to DWR and the State as they proceed with the implementation of the energy purchase program. This capacity is currently estimated at $2.5-$3 billion. Therefore, a decision to use a significant portion of DWR's bank capacity for this program will mean the capacity may not be available for other aspects of the long-term borrowing program (unless this program is phased-out after a short period of time and the bank capacity is redeployed as part of the long-term debt structure).

Conclusion

We recommend that DWR conduct more detailed research into the feasibility of securing a commercial bank line of credit including additional legal research and informal survey of energy suppliers to ascertain if the line of credit product will achieve the desired results. We would be pleased to assist DWR in this conducting this additional research.

If you have any questions, please contact Douglas Montague at (818) 262-3144, James Bemis at (818) 262-3172 or Darlene DeRose at (925) 256-9797.

Letters of Credit Issued

LOC REDUCTION

	$30,000,000 HELABA 1	$400,000,000 HELABA 2	Jan. 31	Feb. 5	Feb. 2	Feb. 6	TOTAL	Collateral Reduction
POWEREX	$30,000,000	$50,000,000	$18,000,000			$48,000,000	$146,000,000	
EUGENE		10,000,000	10,000,000	20,000,000			40,000,000	
SEMPRA		100,000,000				40,000,000	140,000,000	
LADWP		40,000,000			64,000,000		104,000,000	
TOTAL	$30,000,000	$200,000,000	$28,000,000	$20,000,000	$64,000,000	$88,000,000	$430,000,000	
							$430,000,000	

Letters of Credit Outstanding
February 8, 2001

Powerex	146,000,000
Sempra	140,000,000
Eugene	40,000,000
LADWP	104,000,000
	430,000,000

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 24

Historical and Current Price of Gas Analysis

California Basis Drivers
February 5, 2001
Katie Elder, Tom Owens

Basis is the difference between national average gas prices and gas prices delivered to the Northern and Southern California borders. This basis has averaged about $0.35/MMBtu over the last five years. With the energy crisis in California, this basis has jumped to in excess of $6.00/MMBtu.

Basis is driven by a number of variables including hydro conditions, power prices, gas storage levels, interstate pipeline capacity and intrastate pipeline capacity, all of which drive the balance of demand versus supply in California versus alternative markets that suppliers could seek.

> Hydro conditions tend in impact the amount of gas fired generation required to meet electric loads. In good hydro years, hydro generation in California and the Pacific Northwest would be plentiful.
>
> Power prices tend to set an upper limit for gas prices, or at least influence the prices power generators can pay for gas and still make reasonable margins. In today's high priced power markets, gas prices can be quite high and still be economic for power generation.
>
> Gas storage impacts gas prices by increasing the demand for gas during the summer refill season and can dampen prices during high demand periods. If gas storage is low, more gas has to be injected and less gas is available for winter demands driving gas prices higher.
>
> Interstate pipeline capacity delivers 85% of California's gas with 15% coming from in state production. If there is a surplus of pipeline capacity between two points, basis should approximate the variable cost of transportation. If there is a lack of pipeline capacity, the price differences will rise. In winter months, interstate pipeline capacity is insufficient to meet in-state demand and withdrawal of gas from underground storage that was filled during summer months is mandatory.
>
> Intrastate pipeline capacity is required to move gas from the California border to the power plants. For increases in interstate capacity to be effective in driving basis down, there must be corresponding increases in intrastate pipeline capacity.

The apparent status of each of these drivers is given below:

> Hydro conditions in 2001 will be poor, both in California and the Pacific Northwest. Beyond 2001, hydro conditions should follow past random patterns.
>
> Power prices in California are high now and appear to be staying high for the rest of this year. Beyond 2001, we do not have a forecast.
>
> High summer 2001 gas demand as a result of poor hydro conditions will prevent underground gas storage from being refilled. Given high power prices and limited hydro, we expect gas storage to be low in 2002 and likely low in 2003. Recovery starts with additional pipeline capacity toward the end of 2002.
>
> Interstate pipeline capacity will not increase until late 2002 if the relatively small expansions planned by PG&E GTN and Kern River are built. Additional expansions will be necessary in order to bring gas supply and demand into balance by 2003-2004..
>
> Intrastate pipeline capacity additions are expected to match interstate capacity expansions.

Forecasting the basis level is a subjective, judgemental exercise and represents our best professional opinions. Starting from the current basis level of $6/MMBtu and the current status of the other basis drivers, we do not anticipate a reduction in 2001. By 2002, if hydro improves and power prices come down, the base case and low case could drop to $4/MMBtu. As things improve in 2003 and beyond, basis could again drop to more normal levels, in the $0.50 range.

Year	High	Base	Low
2001	6	6	6
2002	6	4	4
2003	4	2	1
2004	2	1	.5
2005	1	.5	.35
Beyond	1	.5	.35

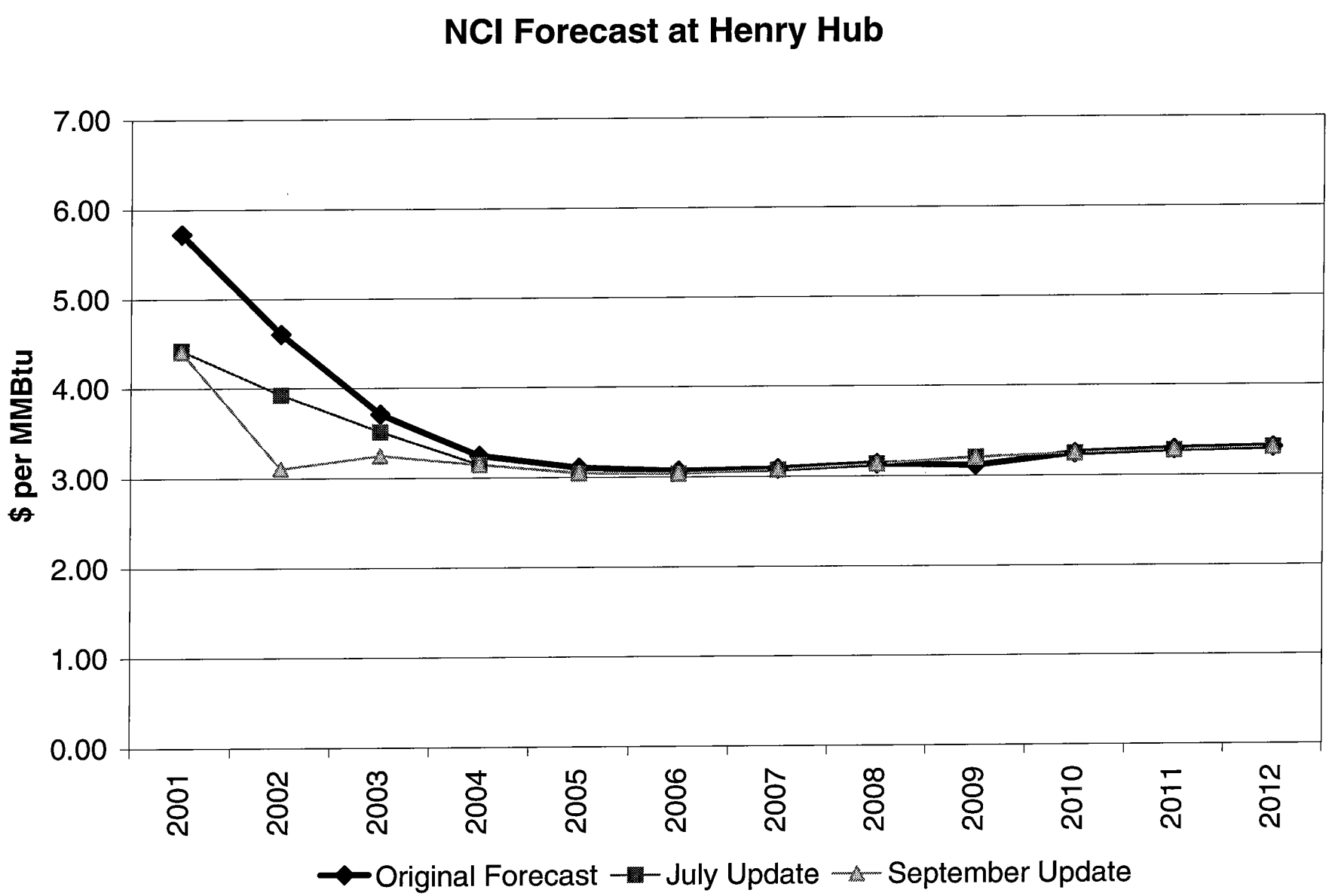
History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

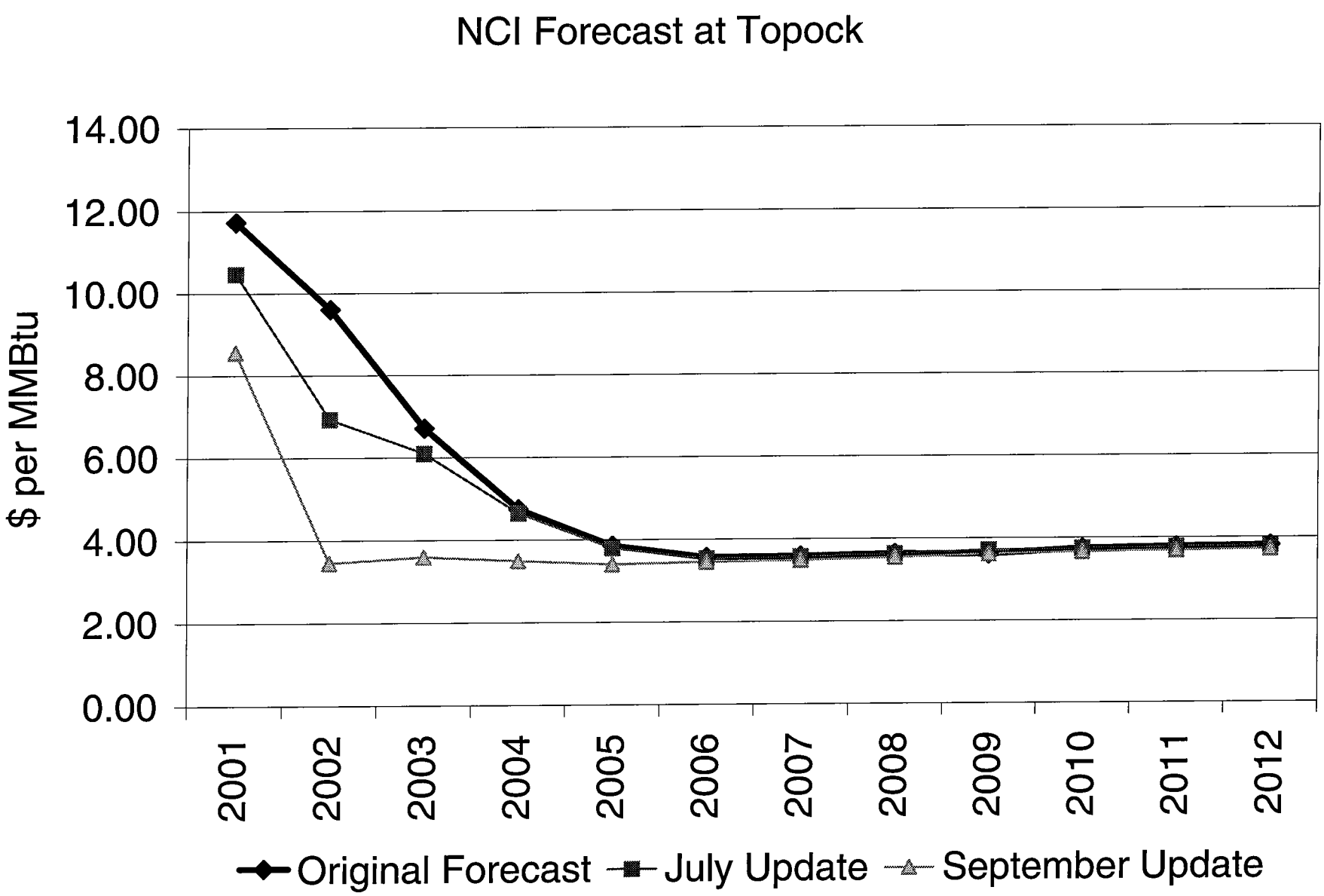
Exhibit 25

Gas Price Forecasts

The gas price forecast used to develop the revenue requirement is contained in the Excel spreadsheet "DWR Gas Price Forecast Updated Mar 02 – CORRECTED.xls." This spreadsheet includes the original gas price forecast as well as each update. The forecast begins with Henry Hub prices in the tab marked "Henry." A basis differential reflecting the assumed difference in prices between Southern California and Henry Hub is depicted on the tab marked "BastoSoCal" – basis differentials for the High, Base, and Low cases are shown. The tab marked "SoCalBorder" adds the assumed basis differentials for each case to the Henry Hub price shown in the previous tab to calculate the Topock price. The next tab, "Malin v Topock" establishes the price differential between the Southern California border and the northern California entry location for Canadian gas supply, by assuming that Malin is "X" percent of Topock. While two scenarios are shown, only the first one (in columns H through U) has been used so far.

Next, "WSCC Basis – Base" computes prices delivered to different locations across the WSCC (now WECC). Included are prices at Malin, the PG&E Citygate, the Pacific Northwest, Rockies, and Arizona/Nevada. These locations correspond to price nodes for which ProSym requires natural gas price inputs. Malin is computed using the percentage assumed on the previous tab; PG&E Citygate is calculated as an average of 50% Topock plus 50% Malin, plus the corresponding rates for backbone transmission service on PG&E. The other locations: Pacific Northwest, Rockies, and AZ/NV are calculated as an assumed basis differential from Henry Hub plus an assumed cost for interstate transportation. These assumptions were designed to capture the price differential likely to be observed between gas delivered to California versus other gas-fired generators in the WSCC at a very general level, without looking specifically at what each generating plant's actual purchased cost of gas would be. As indicated previously, output for the current forecast and all previous versions are present in this tab. Last, "WSCC Basis – High and Low" computes the high and low cases for each of the base cases at each additional WSCC price location needed by ProSym.


NCI Forecast at Henry Hub
$ per MMBtu
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Original Forecast
July Update
September Update


NCI Forecast at Topock
$ per MMBtu
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
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2002
2003
2004
2005
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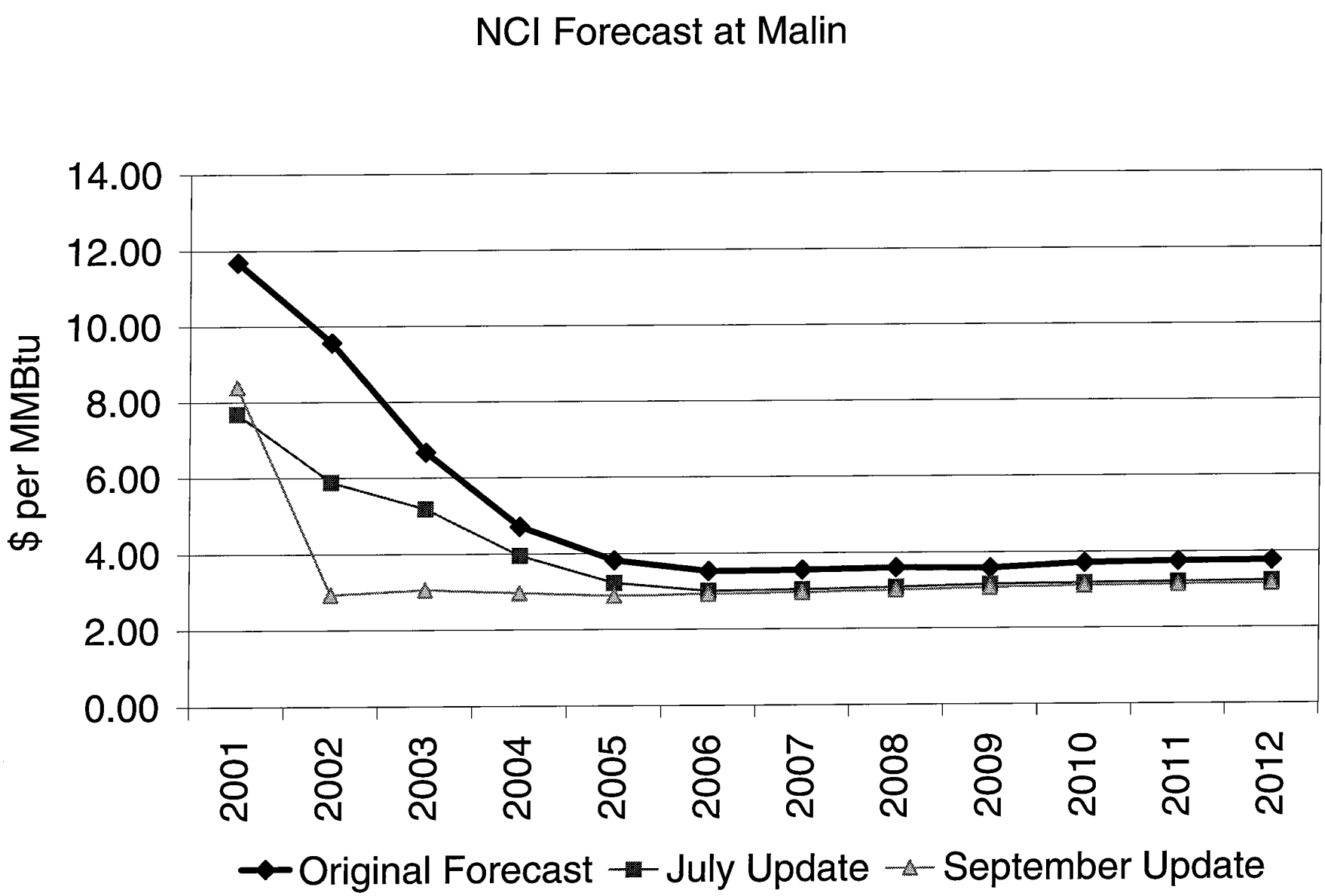
2011
2012
Original Forecast
July Update
September Update


NCI Forecast at Malin
$ per MMBtu
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Original Forecast
July Update
September Update

Henry Hub Prices

January 2001 -- Original Forecast

	5.73	4.61	3.71	3.25	3.11	3.07	3.09	3.14	3.12	3.25	3.29	3.31
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	6.30	5.07	4.08	3.58	3.42	3.38	3.40	3.45	3.43	3.58	3.62	3.64
Feb	5.44	4.38	3.52	3.09	2.95	2.92	2.94	2.98	2.96	3.09	3.13	3.14
Mar	5.16	4.15	3.34	2.93	2.80	2.76	2.78	2.83	2.81	2.93	2.96	2.98
April	5.39	4.33	3.49	3.06	2.92	2.89	2.90	2.95	2.93	3.06	3.09	3.11
May	5.62	4.52	3.64	3.19	3.05	3.01	3.03	3.08	3.06	3.19	3.22	3.24
June	6.25	5.02	4.04	3.54	3.39	3.35	3.37	3.42	3.40	3.54	3.59	3.61
July	6.13	4.93	3.97	3.48	3.33	3.28	3.31	3.36	3.34	3.48	3.52	3.54
August	5.10	4.10	3.30	2.89	2.77	2.73	2.75	2.79	2.78	2.89	2.93	2.95
Sept	5.16	4.15	3.34	2.93	2.80	2.76	2.78	2.83	2.81	2.93	2.96	2.98
October	5.50	4.43	3.56	3.12	2.99	2.95	2.97	3.01	3.00	3.12	3.16	3.18
November	6.30	5.07	4.08	3.58	3.42	3.38	3.40	3.45	3.43	3.58	3.62	3.64
December	6.36	5.12	4.12	3.61	3.45	3.41	3.43	3.49	3.46	3.61	3.65	3.67
AVG	5.73	4.61	3.71	3.25	3.11	3.07	3.09	3.14	3.12	3.25	3.29	3.31

July 2001 Update --

	4.43	3.93	3.52	3.15	3.05	3.04	3.08	3.14	3.21	3.25	3.28	3.31
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	4.87	4.32	3.87	3.47	3.36	3.34	3.39	3.45	3.53	3.58	3.61	3.64
Feb	4.21	3.73	3.34	2.99	2.90	2.89	2.93	2.98	3.05	3.09	3.12	3.14
Mar	3.99	3.54	3.17	2.84	2.75	2.74	2.77	2.83	2.89	2.93	2.95	2.98
April	4.16	3.69	3.31	2.96	2.87	2.86	2.90	2.95	3.02	3.06	3.08	3.11
May	4.34	3.85	3.45	3.09	2.99	2.98	3.02	3.08	3.15	3.19	3.21	3.24
June	4.83	4.28	3.84	3.43	3.32	3.31	3.36	3.42	3.50	3.54	3.58	3.61
July	4.74	4.21	3.77	3.37	3.26	3.25	3.30	3.36	3.43	3.48	3.51	3.54
August	3.94	3.50	3.13	2.80	2.71	2.71	2.74	2.79	2.86	2.89	2.92	2.95
Sept	3.99	3.54	3.17	2.84	2.75	2.74	2.77	2.83	2.89	2.93	2.95	2.98
October	4.25	3.77	3.38	3.02	2.93	2.92	2.96	3.01	3.08	3.12	3.15	3.18
November	4.87	4.32	3.87	3.47	3.36	3.34	3.39	3.45	3.53	3.58	3.61	3.64
December	4.92	4.36	3.91	3.50	3.39	3.37	3.42	3.49	3.56	3.61	3.64	3.67
AVG	4.43	3.93	3.52	3.15	3.05	3.04	3.08	3.14	3.21	3.25	3.28	3.31

September 2001 Update --

	4.41	3.11	3.25	3.15	3.05	3.04	3.08	3.14	3.21	3.25	3.28	3.31
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	9.98	3.42	3.58	3.46	3.36	3.35	3.39	3.45	3.53	3.58	3.61	3.64
Feb	6.21	2.95	3.09	2.99	2.90	2.89	2.93	2.98	3.05	3.09	3.12	3.14
Mar	5.05	2.80	2.93	2.83	2.75	2.74	2.77	2.82	2.89	2.93	2.96	2.98
April	5.34	2.92	3.06	2.96	2.87	2.86	2.89	2.95	3.02	3.06	3.09	3.11
May	4.87	3.04	3.19	3.09	2.99	2.98	3.02	3.07	3.14	3.19	3.22	3.24
June	3.73	3.39	3.54	3.43	3.33	3.32	3.36	3.42	3.50	3.55	3.58	3.61
July	3.11	3.32	3.48	3.37	3.27	3.26	3.29	3.36	3.43	3.48	3.51	3.54
August	3.19	2.77	2.89	2.80	2.72	2.71	2.74	2.79	2.85	2.89	2.92	2.95
Sept	2.34	2.80	2.93	2.83	2.75	2.74	2.77	2.82	2.89	2.93	2.96	2.98
October	2.70	2.98	3.12	3.02	2.93	2.92	2.96	3.01	3.08	3.12	3.15	3.18
November	3.02	3.42	3.58	3.46	3.36	3.35	3.39	3.45	3.53	3.58	3.61	3.64
December	3.38	3.45	3.61	3.50	3.39	3.38	3.42	3.48	3.56	3.61	3.65	3.67
AVG	4.41	3.10	3.25	3.15	3.05	3.04	3.08	3.13	3.21	3.25	3.28	3.31

Janurary 2001 Forecast

So California Border Base Case

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	12.30	11.07	8.08	5.58	4.42	3.88	3.90	3.95	3.93	4.08	4.12	4.14
Feb	11.44	10.38	7.52	5.09	3.95	3.42	3.44	3.48	3.46	3.59	3.63	3.64
Mar	11.16	10.15	7.34	4.93	3.80	3.26	3.28	3.33	3.31	3.43	3.46	3.48
April	11.39	10.33	7.49	5.06	3.92	3.39	3.40	3.45	3.43	3.56	3.59	3.61
May	11.62	10.12	7.24	4.99	3.95	3.51	3.53	3.58	3.56	3.69	3.72	3.74
June	12.25	10.22	7.24	5.14	4.19	3.85	3.87	3.92	3.90	4.04	4.09	4.11
July	12.13	9.73	6.77	4.88	4.03	3.78	3.81	3.86	3.84	3.98	4.02	4.04
Aug	11.10	8.50	5.70	4.09	3.37	3.23	3.25	3.29	3.28	3.39	3.43	3.45
Sept	11.16	8.15	5.34	3.93	3.30	3.26	3.28	3.33	3.31	3.43	3.46	3.48
Oct	11.50	8.43	5.56	4.12	3.49	3.45	3.47	3.51	3.50	3.62	3.66	3.68
Nov	12.30	9.07	6.08	4.58	3.92	3.88	3.90	3.95	3.93	4.08	4.12	4.14
Dec	12.36	9.12	6.12	4.61	3.95	3.91	3.93	3.99	3.96	4.11	4.15	4.17
Avg	11.73	9.61	6.71	4.75	3.86	3.57	3.59	3.64	3.62	3.75	3.79	3.81

July Forecast

So California Border Base Case

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	16.41	7.32	6.87	5.47	4.36	3.84	3.89	3.95	4.03	4.08	4.11	4.14
Feb	12.69	6.73	6.34	4.99	3.90	3.39	3.43	3.48	3.55	3.59	3.62	3.64
Mar	12.63	6.54	6.17	4.84	3.75	3.24	3.27	3.33	3.39	3.43	3.45	3.48
April	12.57	6.69	6.31	4.96	3.87	3.36	3.40	3.45	3.52	3.56	3.58	3.61
May	14.98	6.85	6.45	4.89	3.89	3.48	3.52	3.58	3.65	3.69	3.71	3.74
June	11.71	7.28	6.64	5.03	4.12	3.81	3.86	3.92	4.00	4.04	4.08	4.11
July	7.74	7.21	6.37	4.77	3.96	3.75	3.80	3.86	3.93	3.98	4.01	4.04
Aug	6.94	6.50	5.53	4.00	3.31	3.21	3.24	3.29	3.36	3.39	3.42	3.45
Sept	6.99	6.54	5.37	3.84	3.25	3.24	3.27	3.33	3.39	3.43	3.45	3.48
Oct	7.25	6.77	5.38	4.02	3.43	3.42	3.46	3.51	3.58	3.62	3.65	3.68
Nov	7.87	7.32	5.87	4.47	3.86	3.84	3.89	3.95	4.03	4.08	4.11	4.14
Dec	7.92	7.36	5.91	4.50	3.89	3.87	3.92	3.99	4.06	4.11	4.14	4.17
Avg	10.48	6.93	6.10	4.65	3.80	3.54	3.58	3.64	3.71	3.75	3.78	3.81

September Forecast

So California Border Base Case

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	16.41	3.77	3.93	3.81	3.71	3.80	3.84	3.90	3.98	4.03	4.06	4.09
Feb	12.69	3.30	3.44	3.34	3.25	3.34	3.38	3.43	3.50	3.54	3.57	3.59
Mar	12.63	3.15	3.28	3.18	3.10	3.19	3.22	3.27	3.34	3.38	3.41	3.43
April	12.57	3.27	3.41	3.31	3.22	3.26	3.29	3.35	3.42	3.46	3.49	3.51
May	14.98	3.39	3.54	3.44	3.34	3.38	3.42	3.47	3.54	3.59	3.62	3.64
June	11.71	3.74	3.89	3.78	3.68	3.72	3.76	3.82	3.90	3.95	3.98	4.01
July	4.75	3.67	3.83	3.72	3.62	3.61	3.64	3.71	3.78	3.83	3.86	3.89
Aug	3.76	3.12	3.24	3.15	3.07	3.06	3.09	3.14	3.20	3.24	3.27	3.30
Sept	2.65	3.15	3.28	3.18	3.10	3.09	3.12	3.17	3.24	3.28	3.31	3.33
Oct	3.20	3.33	3.47	3.37	3.28	3.37	3.41	3.46	3.53	3.57	3.60	3.63
Nov	3.52	3.77	3.93	3.81	3.71	3.80	3.84	3.90	3.98	4.03	4.06	4.09
Dec	3.88	3.80	3.96	3.85	3.74	3.83	3.87	3.93	4.01	4.06	4.10	4.12
Avg	8.56	3.45	3.60	3.50	3.40	3.45	3.49	3.55	3.62	3.66	3.69	3.72

Original Forecast

Malin

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	12.27	11.04	8.05	5.54	4.39	3.84	3.86	3.92	3.90	4.04	4.08	4.11
Feb	11.41	10.34	7.49	5.05	3.92	3.38	3.40	3.45	3.43	3.55	3.59	3.61
Mar	11.12	10.11	7.30	4.89	3.76	3.23	3.25	3.29	3.27	3.39	3.43	3.44
April	11.35	10.30	7.45	5.02	3.89	3.35	3.37	3.42	3.40	3.52	3.56	3.58
May	11.58	10.08	7.20	4.95	3.91	3.47	3.49	3.54	3.52	3.65	3.69	3.71
June	12.21	10.19	7.21	5.11	4.15	3.81	3.83	3.89	3.87	4.01	4.05	4.07
July	12.10	9.70	6.73	4.84	3.99	3.75	3.77	3.82	3.80	3.94	3.99	4.01
Aug	11.06	8.47	5.67	4.06	3.33	3.20	3.22	3.26	3.24	3.36	3.39	3.41
Sept	11.12	8.11	5.30	3.89	3.26	3.23	3.25	3.29	3.27	3.39	3.43	3.44
Oct	11.47	8.39	5.53	4.09	3.45	3.41	3.43	3.48	3.46	3.59	3.62	3.64
Nov	12.27	9.04	6.05	4.54	3.89	3.84	3.86	3.92	3.90	4.04	4.08	4.11
Dec	12.33	9.08	6.08	4.57	3.92	3.87	3.89	3.95	3.93	4.07	4.12	4.14
	11.69	**9.57**	**6.67**	**4.71**	**3.82**	**3.53**	**3.55**	**3.60**	**3.58**	**3.71**	**3.75**	**3.77**

July Update

Malin	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	13.89	6.22	5.84	4.65	3.70	3.27	3.30	3.36	3.43	3.46	3.49	3.52
Feb	10.03	5.72	5.39	4.24	3.31	2.88	2.91	2.96	3.02	3.05	3.07	3.10
Mar	8.37	5.56	5.24	4.11	3.18	2.75	2.78	2.83	2.88	2.91	2.93	2.96
April	7.43	5.69	5.36	4.22	3.29	2.85	2.89	2.93	2.99	3.02	3.05	3.07
May	10.00	5.82	5.48	4.15	3.31	2.96	2.99	3.04	3.10	3.13	3.16	3.18
June	5.98	6.19	5.64	4.28	3.51	3.24	3.28	3.33	3.40	3.44	3.46	3.49
July	5.28	6.12	5.41	4.05	3.37	3.19	3.23	3.28	3.34	3.38	3.41	3.44
Aug	5.80	5.52	4.70	3.40	2.82	2.72	2.76	2.80	2.85	2.88	2.91	2.93
Sept	5.94	5.56	4.56	3.26	2.76	2.75	2.78	2.83	2.88	2.91	2.93	2.96
Oct	6.16	5.76	4.57	3.42	2.91	2.91	2.94	2.99	3.04	3.08	3.10	3.13
Nov	6.69	6.22	4.99	3.80	3.28	3.27	3.30	3.36	3.43	3.46	3.49	3.52
Dec	6.73	6.26	5.02	3.82	3.30	3.29	3.33	3.39	3.45	3.49	3.52	3.55
	7.69	**5.89**	**5.19**	**3.95**	**3.23**	**3.01**	**3.04**	**3.09**	**3.15**	**3.19**	**3.21**	**3.24**

September Update

Malin	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	16.41	3.20	3.34	3.24	3.15	3.23	3.26	3.32	3.38	3.42	3.45	3.48
Feb	12.69	2.81	2.92	2.84	2.76	2.84	2.87	2.92	2.97	3.01	3.03	3.05
Mar	12.63	2.67	2.79	2.71	2.63	2.71	2.74	2.78	2.84	2.87	2.90	2.91
April	12.57	2.78	2.90	2.81	2.74	2.77	2.80	2.85	2.90	2.94	2.96	2.98
May	14.98	2.89	3.01	2.92	2.84	2.88	2.91	2.95	3.01	3.05	3.08	3.10
June	11.71	3.18	3.31	3.21	3.13	3.16	3.19	3.25	3.31	3.35	3.38	3.41
July	4.75	3.12	3.26	3.16	3.08	3.07	3.10	3.15	3.22	3.26	3.28	3.31
Aug	3.76	2.65	2.76	2.68	2.61	2.60	2.63	2.67	2.72	2.76	2.78	2.80
Sept	2.25	2.67	2.79	2.71	2.63	2.63	2.65	2.70	2.75	2.79	2.81	2.83
Oct	2.72	2.83	2.95	2.87	2.79	2.87	2.90	2.94	3.00	3.04	3.06	3.08
Nov	2.99	3.20	3.34	3.24	3.15	3.23	3.26	3.32	3.38	3.42	3.45	3.48
Dec	3.30	3.23	3.37	3.27	3.18	3.25	3.29	3.34	3.41	3.45	3.48	3.50
	8.40	**2.94**	**3.06**	**2.97**	**2.89**	**2.94**	**2.97**	**3.02**	**3.08**	**3.11**	**3.14**	**3.16**

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 26

CERS Strategy for Energy Purchase Portfolio Design

Elements of Strategy in CERS Portfolio Design

In making decisions under uncertainty consider:

- Diversification of Product/Operations Risk
  - Term – ladder portfolio terms allowing out-year rollovers
  - Resource
    - Incent efficient resource development through sub-portfolio acquisitions of new capacity additions
    - Seek alternative prime energy resources
  - Product mix
    - Fixed Price
      - Fixed and variable term
      - Fixed and variable quantity
    - Tolling
      - Capacity, Variable O&M
      - Gas market
        - Basis
        - Acquisition
          - Firm supply
          - Storage
          - Transportation
        - Outsource gas sub-portfolios
  - Market participants/intermediaries
    - Generators
    - Traders
      - Asset-based
      - Financial
    - Brokers
- Market Risk Exposure
  - Minimize exposure of locked-in physical resources to
    - Future uneconomic dispatch
    - Emission constrained operations
  - Hedge against future uneconomic portfolio performance
  - Seek imports to
    - Enhance transmission productivity and
    - Balance portfolio
  - Balance exchange traded products with OTC bilateral contracts
- Reliability Services
  - Acquire PTO grid functional resources to
    - Foster pure-play merchant competition
    - Establish uplift for grid services generation (e.g. reliability must run)
  - Invest in grid upgrades to alleviate congestion

CONFIDENTIAL – DISCUSSION DRAFT

POWER PURCHASE PLAN

1. *Complete negotiations with low bidders in DWR solicitation completed on 1/24/01 (up to 2000 MW)

2. *Acquire utility block forward contracts (PG&E 100-500MW, $100 Million below market, $67-76/MWh non-summer, $131/MWh Summer; SCE 450-900MW, $200 Million below market, $54-62/MWh non-summer, $101/MWh summer). January-December 2001.

3. *Acquire ISO peaking generation contracts for summer 2001 (1279MW of contracts, up to 800MW could be operable this year; $255 Million/year for 1279MW, June-October, 3 years).

4. Develop integrated power portfolio plan.

5. Acquire resources pursuant to plan through bilateral negotiations and bidding.

6. *Pursue non-compliant bids totaling over 3000MW.

7. *Pursue gas contracts and emission credits for non-compliant bids.

*Time sensitive – needs immediate action to preserve options.

NOTE: Preliminary data. Need confirmations. Based on discussions with Navigant, ISO.

1/29/01

CONFIDENTIAL – DISCUSSION DRAFT

POWER PORTFOLIO MANAGEMENT PLAN

1) Augment DWR staff with experts from utilities to:
   a) Develop portfolio plan
   b) Negotiate contracts
   c) Manage power portfolio
      - Scheduling
      - Trading (Day-Ahead, Short-Term)
      - Settlements
      - Financial Management
      - Contract Administration
2) Assign responsibility for managing function until it can find a permanent home

1/29/01

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 27

CPUC Decision 01-01-046

COM/LYN/epg **Mailed 1/19/2001**

Decision 01-01-046 January 19, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (E 3338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000)

INTERIM OPINION AFFIRMING THE OBLIGATION TO SERVE AND ISSUING TEMPORARY RESTRAINING ORDER

I. Summary

In this interim decision, we are issuing a temporary restraining order (TRO) preventing Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison) from refusing to provide adequate service to all of their customers. We issue this TRO to maintain the status quo so as to avoid further degradation of provision of electric service and to avoid the irreparable harm to the public health and safety that would be caused by further degradation of service. We affirm that regulated California utilities must serve their customers. This requirement, known as the "obligation to serve" is

mandated by state law. A utility's obligation to serve is part and parcel of the entire regulatory scheme under which the Commission regulates and controls utilities under the Public Utilities Act.

A bankruptcy filing or the threat of insolvency has no bearing on this aspect of state law. Even utilities that file for reorganization must serve their customers. The public's safety, and the economy's health will be impaired if utilities avoid their obligation to serve. We will take all action necessary to enforce this obligation, while regulating and controlling utilities in a manner consistent with state law, and make the following orders:

II. Background

In Decision (D.) 01-01-018, we adopted an immediate, interim surcharge for PG&E and SCE, subject to refund and adjustment.[1] This surcharge is in effect for 90 days from the effective date of D.01-01-018. As stated in that decision, the increase is a temporary surcharge to improve the ability of the applicants to cover the costs of procuring future energy in wholesale markets that they cannot produce themselves to serve their loads. We determined that this expedited action was necessary to fulfill our statutory obligations to ensure that the utilities can provide adequate service at just and reasonable rates. Emergency hearings were held in late December 2000 and additional hearings are planned for February.

In D.01-01-018, we state that we do not yet have the facts to evaluate the utilities' claims of their dire circumstances. We have called for an audit and must await the independent auditors' report. Moreover, we do not have all of the facts

[1] Those customers eligible for the California Alternative Rates for Energy (CARE) program are exempt from this surcharge. The surcharge applies to all other customers, including direct access customers.

related to the parent companies, the utilities, the affiliates, and the flow of funds among these entities. The independent auditors will also consider these questions in their reports. We must consider the overall financial position of the utilities and will do so expeditiously.

Further, in D.01-01-018 we state:

> We are very troubled by the utilities' assumption that ratepayers must bear the burden of significant rate increases without the shareholders sharing in the pain. The utilities and their shareholders have received significant financial benefit from restructuring thus far. For example, PG&E and Edison have each received the benefit of over $2 billion in cash proceeds from rate reduction bonds. As reported in the monthly TCBA reports, PG&E has received over $9 billion in headroom and other transition cost revenues and Edison has received over $7 billion in such revenues. As revealed in cross-examination of PG&E witness Campbell, disbursements from PG&E to the parent company, PG&E Corporation (PG&E Corp.) during the transition period were approximately $9.6 billion. Out of this total, PG&E Corp. issued dividends (both common and preferred stock) of approximately $1.5 billion. PG&E also repurchased stock in the amount of approximately $2.8 billion and retired approximately $2.8 billion of debt. PG&E recognized that market problems were beginning to occur in June of this year, but decided to declare a third-quarter dividend. PG&E did not consider establishing a contingency fund or retaining cash to cushion its risk, because it believed that "its generally conservative financial profile and financing practices would adequately provide cushion against . . . a reasonable range of contingencies." (TR: 409.)
>
> Now that such contingencies are outside the reasonable range, the utilities turn to the ratepayers for relief. It is decidedly not business as usual and the utilities need to realize that ratepayers are not the only answer to their dilemma. For example, parties have only just begun to explore the ability of the utilities' holding companies to participate in the solution. While the cash on hand in the holding companies may be insufficient when compared with the going-

forward costs of procuring power, we are convinced that other potential solutions should be explored. (*Id.* mimeo. at pp. 15-16.)

III. Discussion

Since mid-June, we have seen prices in the wholesale electricity market skyrocket to staggering levels as a result of the severe dysfunction of the California wholesale electricity market. As a result, several deleterious consequences have occurred. Ratepayers in San Diego Gas & Electric Company's (SDG&E) service territory saw their electric bills double and triple over the summer. PG&E and Edison have defaulted on payments. Stage 1, 2, and 3 emergencies have occurred with alarming regularity, and indeed, rolling blackouts occurred in Northern California on January 17 and 18, 2001. The Governor, Legislature, and this agency are actively seeking solutions to the energy crisis confronting us. The Federal Energy Regulatory Commission (FERC), despite finding that wholesale electric rates are not just and reasonable, chose to lift price caps, and to refrain from devising a remedy under Section 206(a) of the Federal Power Act (16 USC Section 824e(a)),[2] while making a number of other changes that add to the complexity and uncertainty of the commercial relationships. As we explained in D.01-01-018, these actions have left California's utilities and ratepayers prey to wholesale electricity sellers who

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[2] This statute provides in pertinent part:

Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

immediately quadrupled and quintupled their prices above already unprecedented levels.

In the hearings we held on financial issues in December and early January, a representative of Edison indicated that in the event that Edison could not purchase power in excess of the 7 cents per kilowatt-hour available in retail revenues to pay for power, Edison would request to be relieved of its obligation to serve. (TR: 755)

On January 18, we received a declaration from Gary Heath, Executive Director of the Electricity Oversight Board (EOB) regarding PG&E's assertion to the Deputy Director Raymond Hart of the California Department of Water Resources (CDWR). Mr. Hart informed Mr. Heath that PG&E stated that beginning January 20, 2001, PG&E would schedule only its own generation and would not purchase additional needed generation to serve remaining customer load. Mr. Heath verified this assertion with PG&E Vice President Dan Richard at 2:15 p.m. on January 18. Mr. Richard confirmed that PG&E would only serve its customers through its own generation, and therefore would not schedule the resources secured by the CDWR for PG&E's remaining load. Mr. Heath states that PG&E cannot rely on its own generation to meet its obligations to serve all the customers in its service territory. If PG&E does not obtain additional generation, reliability of service to PG&E customers will be "seriously jeopardized." (Declaration of Gary Heath, Attachment 1.)

Also on January 18, we received affidavits from Terry Winter, the President and Chief Executive of the California Independent System Operator (ISO) and Ziad Alaywan, Managing Director of the ISO. Mr. Winter declares that Harold Ray, a senior vice president of Edison, stated in a 4:15 p.m. telephone call that Edison plans to continue to act a scheduling coordinator for all of Edison's non-direct access customers. Mr. Ray stated that there is not an intent to

abandon any of its customers. At 4:20 p.m., Mr. Winter had a telephone conversation with Mr. Richard of PG&E and Bruce Worthington, General Counsel of PG&E. Mr. Richard stated that PG&E would not change its scheduling responsibilities at this time and that there was a misunderstanding of the scheduling coordination responsibilities regarding the CDWR's role as a conduit to serve some of PG&E's customers. Mr. Winter then declares that: "Mr. Richards [sic] advised me that while the company does not intend to change its scheduling coordination role for all its non-direct access customers at this time, the company will continue to review its scheduling coordination responsibilities to its non-direct access customers as the situation unfolds." (Affidavit of Terry Winter, Attachment 2.)

Mr. Alaywan declares that he participated in two conference calls with personnel from PG&E, Edison, and CDWR, which took place at approximately 8:00 a.m. and 2:00 p.m. on January 18, 2001. During the morning call, all participants agreed that PG&E and Edison would continue to act as scheduling coordinators for all their non-direct access customers, even though some customers would be served by generation provided by CDWR. PG&E and Edison agreed to undertake an inter-scheduling coordinator trade with CDWR in accordance with prescribed ISO processes. During the afternoon call, a PG&E director indicated that it no longer wished to act a scheduling coordinator for non-direct access customers served by generation provided by CDWR. The PG&E director stated that "PG&E does not wish to shirk its responsibilities, but stated again that another entity should serve as scheduling coordinator for customers served by CDWR generation." (Affidavit of Ziad Alaywan, Attachment 3.)

We also received a declaration, dated January 18, 2001, from Peter Garris, employed by the CDWR as Chief Water and Power Dispatcher. Mr. Garris

confirms the 2:00 p.m. January 18 conference call described by Mr. Alaywan. Mr. Garris specifically states that Claudia Grief, Director of PG&E Scheduling, informed the participants that PG&E would not be the scheduling coordinator for load that could not be served by its own resources. Mr. Garris also participated in a 4:45 p.m. conference call with Ms. Grief, PG&E Vice President Roy Kuga, other CDWR staff, and individuals from the ISO and Power Exchange. Mr. Garris confirms that during this call, Mr. Kuga indicated that PG&E would not take scheduling coordinator trades from CDWR after Saturday, January 20, 2001, for energy acquired by CDWR for PG&E's load that is not served by PG&E's own generation. Mr. Garris states that PG&E lacks sufficient resources to meet its native load without securing energy from other sources; if this is left unresolved, PG&E's customers will experience adverse reliability problems.

IV. Obligation to Serve

State law clearly requires utilities to serve their customers, and a threatened bankruptcy filing or threat of insolvency does not change that obligation. Similarly, the financial distress of one utility cannot be used as an excuse by another utility to avoid its obligation to serve. As we stated in D.01-01-018, we have a duty to assure that the utilities are able to continue to procure and deliver power for their customers. This duty applies even if the utilities under our jurisdiction have filed for bankruptcy or are on the brink of petitioning for such relief. Our basic obligation under the Public Utilities Act is to assure the people of California adequate service at reasonable rates. Section 451[3] provides, in relevant part:

---

[3] All statutory references are to the Public Utilities Code, unless otherwise noted.

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful. Every public utility shall furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment and facilities as are necessary to promote the safety, health, comfort and convenience of its patrons, employees, and the public.

We therefore issue this decision to affirm that PG&E and Edison must continue to provide reliable, safe, and adequate service to all Californians at just and reasonable rates, including continuing to enter into and maintain any current and future low-cost contracts to procure power. Our actions are consistent with the Legislature's intent, as stated in §§ 330(g), 330(h) and 391(a), part of Assembly Bill (AB) 1890 (Stats. 1996, Ch. 854), which provide in relevant part:

> 330(g): Reliable electric service of utmost importance to the safety, health, and welfare of the state's citizenry and economy.
>
> 330(h): It is important that sufficient supplies of electric generation will be available to maintain the reliable service to the citizens and business of the state.
>
> 391(a): Electricity is essential to the health, safety, and economic well-being of all California consumers.

In addition, §§ 761-788 give the Commission broad authority to issue orders controlling the equipment, practices and facilities of regulated utilities. For example, § 761 gives the Commission authority to order the "service, or methods to be observed, [or] furnished" by California Utilities. Section 761 also provides that utilities must furnish their commodities, or render their services

according to the rules and orders of the Commission, so long as a customer makes "proper demand and tender of rates."

In relevant part, § 762 requires that:

> Whenever the commission, after a hearing, finds that additions, extensions, repairs, or improvements to, or changes in, the existing plant, equipment, apparatus, facilities, or other physical property of any public utility or of any two or more public utilities ought reasonably to be made, or that new structures should be erected, to promote the security or convenience of its employees or the public, or in any other way to secure adequate service or facilities, the commission shall make and serve an order directing that such additions, extensions, repairs, improvements, or changes be made or such structures be erected in the manner and within the time specified in the order.

Furthermore, § 768 provides, in relevant part:

> The commission may, after a hearing, require every public utility to construct, maintain, and operate its line, plant, system, equipment, apparatus, tracks, and premises in a manner so as to promote and safeguard the health and safety of its employees, passengers, customers, and the public.

Section 770 provides, in relevant part:

> The commission may, after a hearing:
>
> Ascertain and fix just and reasonable standards, classifications, regulations, practices, measurements, or service to be furnished, imposed, observed, and followed by all electrical, gas, water, and heat corporations.

Section 701 gives the Commission power to undertake all necessary actions to properly regulate and supervise California utilities. In Consumers Lobby Against Monopolies v. Public Utilities Commission (1979) 25 Cal.3d 891, 905, the California Supreme Court declared:

> The commission is a state agency of constitutional origin with far-reaching duties, functions and powers. (Cal. Const., Art. XII §§ 1-6.) The Constitution confers broad authority on the commission to regulate utilities, including the power to fix rtes, establish rules, hold various types of hearings, award reparation, and establish its own procedures (*Id.*, §§ 2, 4, 6.) ...
>
> Pursuant to this grant of power, the Legislature enacted Public Utilities Code section 701, conferring on the commission expansive authority to '*do all things*, whether specifically designated in [the Public Utilities Act] *or addition thereto*, which are necessary and convenient' in the supervision and regulation of every public utility in California. (Italics added.) the commission's authority has been liberally construed. (Consumers Lobby Against Monopolies at 905.)

The California Supreme Court has further found that "the commission often exercises equitable jurisdiction as an incident to its express duties and authority. For example, the commission may issue injunctions in aid of jurisdiction specifically conferred upon it." (*Id.* at 907.)

Therefore, under our plenary powers and until this crisis is resolved, we intend to closely monitor and supervise the actions and expenditures of the investor-owned utilities under our regulation to ensure that service is provided. While we are dismayed that the energy crisis has escalated to the point that such tight control by the State is required, we intend to exercise the required control. We recognize that hearings are required and will provide for these, as we discuss below. Today we issue a temporary restraining order in order to avoid irreparable harm to public health and safety, to maintain the status quo, and to ensure that PG&E and Edison continue to schedule generation through the ISO to serve all customers with adequate, reliable service, consistent with their obligation to serve.

A TRO serves the purpose of preventing the actions of a party from causing irreparable harm to another party, pending a hearing on the need for a

preliminary injunction. We are issuing this TRO on our motion and on an ex parte basis because we are convinced that if adequate service were not maintained, great or irreparable harm would result before the matter could proceed to a hearing. A TRO has the same force and effect as a preliminary injunction and remains in effect until an order can be issued granting or denying a preliminary injunction.

We therefore order PG&E and Edison to appear at an evidentiary hearing scheduled for January 29, 2001 at 10:00 a.m. to show cause as to why a preliminary injunction should not be issued.

We expect the utilities to fully comply with our orders. We have previously stated that nothing in AB 1890 relieves the existing utilities of their obligation to serve all customers in their service territories under their respective tariffs (D.97-09-047, mimeo. at p. 44.). In PG&E's holding company decision, D.98-04-068, the Commission specifically found that: "The capital requirements of PG&E, as determined to be necessary and prudent to meet the obligation to serve or to operate the utility in a prudent and efficient manner, shall be given first priority by PG&E Corporation's Board of Directors." (*Id.*, at 98.) The Commissions' holding company decision clearly affirms the continuing obligation to serve.

V. Unforeseen Emergency Situation

Government Code § 11125.5 and Rule 81 of our Rules of Practice and Procedure allow the Commission to take action more quickly than would be permitted if advance publication were made on the regular meeting agenda. An example of such an unforeseen emergency situation are those activities that severely impair or threaten to severely impair public health or safety.

As underscored by Governor Gray Davis, who declared a state of emergency, this is such a situation. If PG&E and Edison were to rely only on

their own generation to meet their obligations to serve all customers in their service territory, reliability of service would be severely undermined.

Draft decisions are generally subject to a 30-day review and comment period (§ 311(g)(1)). However, § 311(g)(2) provides that this 30-day period may be reduced or waived in an unforeseen emergency situation. We have determined that this situation exists and therefore waive the public review and comment period on this draft decision. (See also Rules 77.7(f)(1), 77.7(f)(9) and 81.)

Findings of Fact

1. On January 3, 2001, in final oral argument before the Commission on the proposed decision of ALJ Minkin in this proceeding, attorney Henry Weissmann, representing Edison, stated that if the Commission's decision prevented Edison from obtaining additional financing, it would not be able to buy power to meet its customers needs. He requested the Commission relieve Edison of the obligation to serve to the extent it cannot purchase power in excess of the 7 cents per kilowatt hour available in retail revenues to pay for power.

2. In D.01-01-018, we state that the interim surcharge of 1 cent per kilowatt hour, subject to refund and adjustment, is adopted to improve the ability of PG&E and Edison to cover the costs of procuring future energy in wholesale markets that they cannot produce themselves to serve their loads.

3. In D.01-01-018, we find that the utilities understood the risks AB 1890 and electric restructuring imposed. In addition, while the cash on hand in the holding companies may be insufficient when compared with the going-forward costs of procuring power, we are convinced that other potential solutions should be and are currently being explored.

4. The evidence obtained at hearing in this proceeding does not support a finding that PG&E or Edison cannot continue to provide service unless there are

substantial rate increases. Instead, we called for an audit and must await the independent auditors' report. Moreover, we do not have all of the facts related to the parent companies, the utilities, the affiliates, and the flow of funds among these entities. The independent auditors will also consider these questions in their reports.

5. On January 18, we received a declaration from Gary Heath, Executive Director of the EOB regarding PG&E's assertion to the Deputy Director Raymond Hart of the CDWR.

6. Mr. Hart informed Mr. Heath that PG&E stated that beginning January 20, 2001, PG&E would schedule only its own generation and would not purchase additional needed generation to serve remaining customer load. Mr. Heath verified this assertion with PG&E Vice President Dan Richard at 2:15 p.m. on January 18, 2001.

7. Mr. Heath states that PG&E cannot rely on its own generation to meet its obligations to serve all the customers in its service territory. If PG&E does not obtain additional generation, reliability of service to PG&E customers will be jeopardized.

8. We also received affidavits on January 18, 2001 from Terry Winter, the President and Chief Executive of the ISO and Ziad Alaywan, Managing Director of the ISO.

9. Mr. Winter declares that Harold Ray, a senior vice president of Edison, stated in a 4:15 p.m. telephone call on January 18, 2001, that Edison plans to continue to act as scheduling coordinator for all of Edison's non-direct access customers. Mr. Ray stated that there is not an intent to abandon any of its customers.

10. At 4:20 p.m. on January 18, 2001, Mr. Winter had a telephone conversation with Mr. Richard of PG&E and Bruce Worthington, General Counsel of PG&E.

Mr. Richard stated that PG&E would not change its scheduling responsibilities at this time and that there was a misunderstanding of the scheduling coordination responsibilities regarding the CDWR's role as a conduit to serve some of PG&E's customers.

11. Mr. Winter declares that Mr. Richards then advised the ISO that PG&E "will continue to review its scheduling coordination responsibilities to its non-direct access customers as the situation unfolds."

12. Mr. Alaywan declares that he participated in two conference calls with personnel from PG&E, Edison, and CDWR, which took place at approximately 8:00 a.m. and 2:00 p.m.

13. During the morning call, all participants agreed that PG&E and Edison would continue to act as scheduling coordinators for all their non-direct access customers, even though some customers would be served by generation provided by CDWR. PG&E and Edison agreed to undertake an inter-scheduling coordinator trade with CDWR in accordance with prescribed ISO processes.

14. During the afternoon call, Mr. Alaywan states that a PG&E director indicated that PG&E no longer wished to act as a Scheduling Coordinator for non-direct access customers served by generation provided by CDWR.

15. The same participants took part in a 3:00 p.m. conference call on January 18, 2001, in which Edison now indicated that it was taking the same position as PG&E as to scheduling coordinator responsibilities. Mr. Ziad understands from conversations with Mr. Winter that PG&E and Edison have currently indicated that they will serve as scheduling coordinators for all their non-direct access customers in accordance with the process agreed to during the January 18, 2001 morning call.

16. The January 18, 2001 declaration of Peter Garris of the CDWR confirms the 2:00 p.m. phone call described by Mr. Alaywan. Mr. Garris also participated in a

4:45 p.m. conference call with Ms. Grief Director of PG&E Scheduling, PG&E Vice President Roy Kuga, other CDWR staff, and individuals from the ISO and Power Exchange.

17. During this call, Mr. Garris confirms that Mr. Kuga indicated that PG&E would not take scheduling coordinator trades from CDWR after Saturday, January 20, 2001, for energy acquired by CDWR for PG&E's load that is not served by PG&E's own generation.

18. Mr. Garris states that PG&E lacks sufficient resources to meet its native load without securing energy from other sources; if this is left unresolved, PG&E's customers will experience adverse reliability problems.

Conclusions of Law

1. State law clearly requires utilities to serve their customers, and a threatened bankruptcy filing or threat of insolvency does not change that obligation.

2. As we stated in D.01-01-018, we have a duty to assure that the utilities are able to continue to procure and deliver power for their customers. This duty applies even if the utilities under our jurisdiction have filed for bankruptcy or appear to be threatened with insolvency. Our basic duty under the Public Utilities Act is to assure the people of California adequate electric service at just and reasonable rates.

3. Under Public Utilities Code sections 451, 761, 762, 768, and 770, PG&E and Edison have an obligation to provide full and adequate service to all of their customers, including continuing to enter into and maintain any current and future low-cost contracts to procure power.

4. Electricity is essential to the health, safety, and economic well-being of all California consumers.

5. Customers of PG&E and Edison would suffer irreparable harm if the utilities did not maintain adequate service to all customers.

6. In order to ensure full and adequate service to all customers of PG&E and Edison, the Commission should issue a Temporary Restraining Order preventing the utilities from refusing to provide adequate service to all of their customers. This restraining order should specifically prevent the utilities from refusing to act as scheduling coordinator with the California Independent System Operator to serve all of their non-direct access customers.

7. A TRO serves the purpose of preventing the actions of a party from causing irreparable harm to another party, pending a hearing on the need for a preliminary injunction.

8. We are issuing this TRO on our own motion and an ex parte basis because we are convinced that if adequate service were not maintained, great or irreparable harm would result before the matter could proceed to a hearing.

9. A TRO has the same force and effect as a preliminary injunction and remains in effect until an order can be issued granting or denying a request for a preliminary injunction.

10. A hearing should be held expeditiously to require PG&E and Edison to show cause as to why a preliminary injunction should not be granted.

11. Nothing in AB 1890 relieves the existing utilities of their obligation to serve all customers in their service territories under their respective tariffs.

12. Consistent with Government Code § 11125.5 and Rule 81, immediate action is required because PG&E and Edison's potential failure to serve all non-direct access customers is an unforeseen emergency situation that threatens to severely impair public heath and safety.

13. Because this is an unforeseen emergency situation, the 30-day public review and comment period is waived, consistent with § 311(g)(2).

14. This order should be effective today, so that a temporary restraining order may be issued expeditiously.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison) shall continue to provide full and adequate service to all their customers.

2. PG&E and Edison are temporarily restrained from refusing to provide adequate service to all customers, including refusing to act as scheduling coordinators to serve all their non-direct access customers with the California Independent System Operator.

3. PG&E and Edison shall appear for an evidentiary hearing on January 29, 2001 at 10:00 AM at the Commission's San Francisco Courtrooms to show cause why the Commission should not proceed to issue a preliminary injunction and to take legal action against PG&E and Edison for their actions.

This order is effective today.

Dated January 19, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
CARL W. WOOD
Commissioner

Commissioner Richard A. Bilas is necessarily absent.

I will file a dissent.

/s/ HENRY M. DUQUE
Commissioner

ATTACHMENT 1
DECLARATION

I, GARY HEATH, declare:

1. I am employed by the Electricity Oversight Board as the Executive Director. I have personal knowledge of the facts stated herein except as to matters stated upon information and belief, and as to those matters, I believe them to be true. If called upon to testify, I could and would competently do so.

2. Today, I received a telephone at about approximately 2:00 p.m. from Deputy Director Raymond Hart of the California Department of Water Resources.

3. Mr. Hart informed me that starting Saturday, January 20, 2001, Pacific Gas and Electric Company ("PG&E") told him that it would only schedule its own generation, and would not purchase additional needed generation to serve remaining customer load.

4. I verified this information from Mr. Hart by contacting PG&E Vice President Dan Richard, at approximately 2:15 p.m. today. Mr. Richard confirmed that PG&E would only serve its customers through its own generation, and therefore would not schedule the resources secured by the California Department of Water Resources for PG&E's remaining load.

5. PG&E cannot rely on its own generation to meet its obligations to serve all the customers in its service territory. PG&E must obtain additional generation; otherwise, reliability of service to PG&E customers will be seriously jeopardized.

I declare under penalty of perjury that the foregoing is true and correct. Executed this 18th day of January, 2001, at Sacramento, California.

/S/ GARY HEATH
Gary Heath

(END OF ATTACHMENT 1)

ATTACHMENT 2

AFFIDAVIT OF TERRY WINTER

I, Terry Winter, declare as follows:

1. I am the President and Chief Executive of the California Independent System Operator. I have personal knowledge of the matters set forth below and can testify thereto if called as a witness.

2. At approximately 4:15 on January 18, 2001, I had a telephone conversation with Harold Ray, a senior vice president of Southern California Edison Company (SCE) concerning that company's plans for acting as scheduling coordinator for all SCE non-direct access customers. Mr. Ray advised me that SCE is planning to continue to act as scheduling coordinator for all SCE non-direct access customers. Mr. Ray further advised me that any confusion on this point was due to some uncertainty as to how responsibilities for acting as scheduling coordinator would be allocated between the California Department of Water Resources and SCE. He advised me that there was no intent on the part of SCE to "abandon" any of its customers.

3. At approximately 4:20 on January 18, 2001, I had a conversation with Dan Richards, a senior executive of Pacific Gas and Electric Company (PG&E) and Bruce Worthington, General Counsel of PG&E, concerning that company's plans for acting as scheduling coordinator for all PG&E non-direct access customers. Mr. Richards advised me that PG&E would not change its scheduling coordinator responsibilities at this time. Mr. Richards further advised me that any confusion on this point was due to a misunderstanding of the scheduling coordination responsibilities of PG&E in light of the Governor's statement regarding the role of the California Department of Water Resources as a conduit to serve some of PG&E customers. Mr. Richards advised me that while the company does not intend to change its scheduling coordination role for all its non-direct access customers at this time, the company will continue to review its scheduling coordination responsibilities to its non-direct access customers as the situation unfolds.

Declared under penalty of perjury by:

/S/ TERRY WINTER
Terry Winter

(END OF ATTACHMENT 2)

ATTACHMENT 3

AFFIDAVIT OF ZIAD ALAYWAN

I, Ziad Alaywan, declare as follows:

1. I am a Managing Director at the California Independent System Operator. I have personal knowledge of the matters set forth below and can testify thereto if called as a witness.
2. On January 18, 2001, I participated in two conference calls with personnel from Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and the California Department of Water Resources (CDWR), which took place at approximately 8:00 AM and 2:00 PM. These conference calls related to the mechanics for scheduling of non-direct access customers of PG&E and SCE.
3. During the morning call it was agreed that PG&E and SCE would act as scheduling coordinators for all their non-direct access customers, although some such customers would be served by generation provided by CDWR. PG&E and SCE would undertake an inter scheduling coordinator trade with CDWR to account for the generation to be provided by CDWR, in accordance with the ISO process for inter scheduling coordinator trades, which requires confirmation from both scheduling coordinators entering into a transaction.
4. During the 2:00 PM call, a PG&E director indicated that PG&E did not wish to act as scheduling coordinator for non-direct access customers served by generation provided by CDWR. This director stated that another entity should be used to act as scheduling coordinator for these customers. The CDWR representative asked whether PG&E was shirking its responsibilities as a utility. The PG&E director stated that PG&E does not wish to shirk its responsibilities, but stated again that another entity should serve as scheduling coordinator for customers served by CDWR generation. Since it appeared that the entities on the phone had reached an impasse, we agreed to try speaking again at 3:00 PM.
5. After the 2:00 PM call, I called another PG&E representative to get confirmation of the PG&E position. I was told that this person could not help me. I therefore informed the ISO President and Chief Executive Officer, Terry Winter, of the development.
6. The group (representatives from PG&E, SCE, CDWR and myself) reconvened for a call at 3:00 PM. During this call, the SCE representative indicated that it was taking the same position as PG&E as to scheduling coordination responsibilities, in light of issues that needed to be resolved, including for example the $100 penalty for underscheduling.
7. I understand from conversations with Mr. Winter that at this time PG&E and SCE have indicated that they will serve as scheduling coordinators for all their non-direct access customers in accordance with the process agreed to during the 8:00 AM call this morning.

Declared under penalty of perjury by:

/s/ ZIAD ALAYWAN

Ziad Alaywan

(END OF ATTACHMENT 3)

ATTACHMENT 4
DECLARATION

I, PETER GARRIS, declare:

1. I am employed by the California Department of Water Resources ("CDWR") as Chief Water and Power Dispatcher. I have personal knowledge of the facts stated herein except as to matters stated upon information and belief, and as to those matters, I believe them to be true. If called upon to testify, I could and would competently do so.

2. At approximately 2:00 p.m. today, I participated in a teleconference meeting with representatives from Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company, the California Independent System Operator ("ISO") and the California Power Exchange ("PX"). During this meeting, Claudia Grief, Director of PG&E Scheduling, informed us that PG&E would not be taking "scheduling coordinator to scheduling coordinator trades" from CDWR to PG&E, as of Friday, January 19, 2001, for energy that would flow on Saturday, January 20, 2001. She also informed us that PG&E would not be the scheduling coordinator for load that could not be served by its own resources.

3. At approximately 4:45 p.m., I participated in a teleconference meeting with PG&E Vice President Roy Kuga and Ms. Grief. The meeting was attended by other CDWR staff, and individuals from the ISO and the PX. During this meeting, Mr. Kuga indicated that PG&E would not take "scheduling coordinator to scheduling coordinator trades" from CDWR after Saturday, January 20, 2001, for energy acquired by CDWR for PG&E's load that is not being served by PG&E's own generation.

4. PG&E lacks sufficient generating resources to meet its native load without securing energy from other sources, including CDWR. If the resource deficiency is unresolved, this will result in adverse reliability problems for PG&E customers.

I declare under penalty of perjury that the foregoing is true and correct. Executed this 18th day of January, 2001, at Sacramento, California.

/s/ PETER GARRIS
Peter Garris

(END OF ATTACHMENT 4)

Commissioner Duque, dissenting:

These are clearly stressful times. The Commission, and each Commissioner, wishes to do whatever we can to reduce the rolling blackouts that Californians are now facing. Nevertheless, I cannot support today's decision of the majority that adopts a Temporary Restraining Order (TRO) against SCE and PG&E.

A careful review of each of the affidavits attached to today's order of the majority belies the need for the issuance of a TRO. The affidavits document an understandable confusion on the part of SCE and PG&E concerning the new role of the California Department of Water Resources in buying power. More importantly, the affidavits show an underlying commitment by SCE and PG&E to honor their obligation-to-serve Californians. In particular, consider attachment 2, point 2 "there is no intent on the part of SCE to 'abandon' any of its customers." Furthermore, consider attachment 3, point 7 ". . . at this time, PG&E and SCE have indicated that they will serve as scheduling coordinators for all their non-direct access customers. . ." The affidavits demonstrate that there is no threat by either utility to deny their obligation-to-serve Californians. If there were such a threat by utilities to abrogate their obligation to serve, I would support the order of the majority. The evidence before the Commission, however, does not justify the issuance of a TRO.

It is also wise to ask what the adoption of this order will accomplish. The obligation-to-serve is already clear in California law, and the TRO adds nothing to that obligation. Moreover, the order may simply poison the atmosphere between government and the utilities, thereby making communications even more difficult in this time of crisis. Thus, the order of the majority is unwise, with potential risks and costs exceeding any benefits.

Finally, in the few minutes before this meeting, I called Gordon Smith, the CEO of PG&E. He stated that PG&E has no intention to abrogate its obligation-to-serve. I also called John Bryson, the Chairman of SCE, who said the same thing. These verbal commitments only confirm my reading of the affidavits and my conclusion that there is no need for today's order.

For these reasons, I respectfully dissent from today's order of the majority.

___/s/ HENRY M. DUQUE_____

Henry M. Duque

January 19, 2001

San Francisco, California

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 28

CPUC Decision 01-04-005

COM/LYN/sid

Mailed 4/4/2001

Decision 01-04-005 April 3, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (E 3338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000) **AB 1X**

INTERIM OPINION

I. Summary

This order adopts the method the Commission will use to calculate the "CPA," the California Procurement Adjustment established by Public Utilities Code Section 360.5. This order then applies that method, and calculates—for each utility—a company-wide average CPA rate. Using that rate, this order determines the CPA revenue amount, which can be used by the Department of Water Resources (DWR) to begin the process of issuing bonds. This decision does not allocate any utility revenue to DWR. Although this Commission has authority to order a portion of CPA revenue to be paid as the "Fixed DWR Set-Aside," (FDWRSA) it does not take that action at this time.

II. Background

On February 1, 2001, Assembly Bill (AB) 1 from the First Extraordinary Session (AB 1X) was signed into law. A detailed description of the statute is set out in D.01-03-

081. AB 1X sets out a number of mechanisms to ensure DWR is paid for electricity it sells to customers of Southern California Edison Company's (Edison), Pacific Gas & Electric Company's (PG&E), and San Diego Gas and Electric Company (SDG&E).[1] This decision addresses the issuance of revenue bonds, which depends upon the calculation of the CPA.

AB 1X establishes the DWR Electric Power Fund (the "Fund") in the State Treasury, and authorizes DWR to issue bonds, notes, and other evidences of indebtedness (collectively, "Bonds") for certain limited purposes, including:

- paying the costs of electric power and transmission, scheduling, and other related expenses, or to reimburse expenditures from the Fund for those purposes.

- repaying to the General Fund certain advances made to DWR for the power purchase program; and

- establishing or maintaining reserves in connection with the Bonds and paying certain costs incidental to the issuance, payment and security of the Bonds.

Water Code Section 80130, enacted as part of AB 1X, addresses the issuance of bonds by DWR to finance electricity purchases. That statute provides in relevant part:

[1] In this decision, we use the term "utilities" interchangeably with "electrical corporations."

> "In no event shall the [DWR] authorize the issuance of bonds ... in an aggregate amount greater than the amount calculated by multiplying by a factor of four the annual revenues generated by the California Procurement Adjustment, as determined by the commission pursuant to Section 360.5."

Section 360.5 contains detailed requirements for the calculation of a rate known as the "CPA." That statute provides:

> "The commission shall determine that portion of each existing electrical corporation's retail rate effective on January 5, 2001, that is equal to the difference between the generation related component of the retail rate and the sum of the costs of the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services. That portion of the retail rate shall be known as the California Procurement Adjustment. The commission shall further determine the amount of the California Procurement Adjustment that is allocable to the power sold by the department. That amount shall be payable, by each electrical corporation, upon receipt by the electrical corporation of the revenues from its retail end use customers, to the department for deposit in the Department of Water Resources Electric Power Fund, established by Section 80200 of the Water Code. The amount determined pursuant to this subdivision shall be known as the Fixed Department of Water Resources Set-Aside."

III. Procedural History

On February 5, 2001, Administrative Law Judge (ALJ) Joseph DeUlloa issued a ruling setting a prehearing conference on February 6, 2001, to discuss the requirements of the Department of Finance for implementing AB 1X. The ALJ ruling also set workshops[2] on February 6 and 7 for the implementation of AB 1X and a second prehearing conference on February 7 to discuss workshop progress.

[2] The following attended these workshops: PG&E, Edison, San Diego Gas & Electric Company (SDG&E), Office of Ratepayers Advocates, Department of Water Resources (present only on the first day of workshop), The Utility Reform Network, ENRON Energy Services, AES New Energy, Inc., CLECA, Calpine Corporation, Federal Executive Agencies, Aglet Consumer Alliance, CMTA, Turlock Irrigation District, Watson Cogeneration Company, IEP, California

Footnote continued on next page

Initially, the utilities proposed to submit advice letters that would take effect on the day submitted to the Commission. The ALJ rejected this approach and issued a ruling directing the utilities to serve their proposals for determining CPA. The ruling also provided parties an opportunity to comment on the proposals for determining CPA.

On February 23, 2001, Edison, PG&E, and SDG&E each served a proposal to calculate the CPA on a monthly basis by subtracting generation-related costs from generation-related revenues. Each proposed to calculate generation-related revenue residually from the total retail rate and also adjust revenues for certain costs. Each utility's proposal for calculating CPA differs in the inputs used in its calculation. Further, all three, in effect, propose to create balancing accounts for tracking CPA on a monthly basis.

In a letter dated March 14, 2001, DWR set forth its views on how the Commission should determine CPA. The ALJ also issued a ruling seeking comments from parties on DWR's letter. Parties filed separate comments on both the utilities' proposals for CPA and DWR's letter.

We reviewed the parties' comments and on March 27, 2001, issued Decision (D.) 01-03-081 which among other things contained a proposed methodology for calculating CPA and also sought comment on the proposal, including the proposed calculation. On March 29, 2001, parties tendered comments on the CPA methodology proposed in D.01-03-081.

IV. Discussion

We remind the parties that the scope of this decision is narrowly focused to calculate the maximum amount of bonds that DWR may issue. Many of the parties'

Farm Bureau Federation, New West Energy, Cal-Pine CAL-SLA, Pacificorp, Dynergy, CAC/ EPUC, and JDRP.

comments address concerns or speculate about matters outside of the scope of this decision.

In order to determine the amount of bonds that DWR may issue, the Commission must first determine the CPA. Water Code Section 80130 governs the amount of bonds DWR may issue. Water Code Section 80130 states that:

> "In no event shall [DWR] authorize the issuance of bonds ... in an aggregate amount greater than the amount calculated by multiplying by a factor of four the annual revenues generated by the California Procurement Adjustment ..." (Emphasis added.)

Thus, absent the Commission determining the CPA, DWR may not issue bonds.

Some parties address issues outside the scope of this decision such as DWR's revenue requirement. The maximum bonding authority is not determined by DWR's revenue requirement. In D.01-03-081, we determined that utilities must pay amount they have collected in their role as billing agent for DWR but did not address the revenue requirement. However, Water Code Section 80134 provides that DWR's revenue requirement should provide, among other things, for the amounts necessary to pay the principal and interest on all bonds. We anticipate that once DWR issues bonds and determines the amounts needed to repay such bonds that DWR will determine its revenue requirement. In D.01-03-081, we determined that utilities must pay amounts they have collected in their role as billing agent for DWR but did not address the revenue requirement. Regardless, under the Water Code the determination of the maximum amount of bonds that DWR may issue is an independent determination from the determination of DWR's revenue requirement.[3] Moreover, we may not engage in any reasonableness review of DWR's revenue requirement, whereas the Commission is statutorily required to determine the CPA.

[3] DWR's revenue requirement includes both sums to pay ongoing power costs as well as bond costs.

A substantial amount of comment is also devoted to the FSWRSA. Public Utilities Code Section 360.5 delegates to the Commission the responsibility of determining the amount of the CPA that is allocable to the power sold by DWR. In D.01-03-081, we expressly stated we are not deciding this issue now. However, a substantial amount of comments allege that financial harm will result to qualifying facilities (QFs) or utilities if an inflated amount is established as the FDWRSA. These parties assert that the use of "underestimated" costs will set the CPA artificially high and thus inflate the portion of the CPA, the FDWRSA, that is ultimately allocated to DWR. Parties claim this hypothetical result will be a "taking." These arguments are at best speculative and ignore the fact that this Commission has discretion to allocate CPA as appropriate. Parties may raise such concerns when the Commission takes comments on determining the FDWRSA. Until such time, the parties "taking" concerns are premature. Similarly, requests that the Commission make findings or clarifications unrelated to the determination of the CPA are outside the scope of this decision.

Rather than financially harm QFs or utilities, we believe that the QFs' and utilities' financial concerns are partially alleviated to the extent that DWR is able to borrow money to purchase power through the issuance of bonds. DWR's purchases of power should relieve financial pressure on utilities.

Another matter outside the scope of this decision that we briefly address given the substantial amount of comments are concerns that DWR should not receive any of the monies collected by the utilities for power DWR sells to retail end use customers. Such concerns are inconsistent with Water Code Section 80104 which makes payment for such sales a direct obligation of the retail end use customer to DWR. Further, DWR could collect such payment directly from the retail end use customer.[4] Given Water Code Section 80104, we fail to follow the logic of how the utilities could deprive DWR of its

[4] However, Water Code Section 80106 provides that DWR <u>may</u> contract with the utilities to provide billing.

right of ownership to such monies. Such conversion is not authorized by any provision of law or Commission order or rule. In any event, the proper place to voice such concerns is in a pleading responsive to D.01-03-081.

A. Generation-Related Component of the Retail Rate

In D.01-03-081, for each utility we adopted a company-wide average generation-related rate component (except that for SDG&E, we adopted separate numbers for capped and uncapped customers). In D.01-03-081, we also stated that the generation-related rate component of retail sales is derived from the rates in effect as of January 5, 2001. Further, we included in the calculation of the generation-related component of the retail rates, the 1-cent/kWh surcharge for PG&E and Edison, adopted by the Commission in January 2001.

In D.01-03-081, for Edison and PG&E (whose rates are still frozen), we calculated the generation-related component of retail rates as follows:

Total bundled electric rate (which includes one cent per/kWh surcharge and reflects the legislated 10% rate reduction for those customers to whom it is applicable);

Less non-generation-related rates or charges:

Transmission;[5]

Distribution;

Public Purpose Programs;

Nuclear Decommissioning;

Fixed Transition Amount.[6]

The remainder is the generation-related rate component of retail rates.

[5] For PG&E this includes the charge called "Reliability Services."

[6] This charge is sometimes referred to as the Trust Transfer Amount.

In D.01-03-081, we observed that SDG&E's rate freeze under AB 1890 has ended and it has no 1 cent/kWh surcharge. Further, D.01-03-081 noted that SDG&E has an "energy" rate ceiling of 6.5 cents/kWh for residential, small commercial, and street lighting customers, pursuant to AB 265. For these "capped" customers, D.01-03-081 adopted a generation-related rate component equal to the 6.5 cent/kWh ceiling. The amount that "uncapped" customers pay for generation varies depending on wholesale market prices. Thus, for SDG&E's uncapped customers, D.01-03-081 stated that the generation-related rate component is necessarily based on an estimate of wholesale prices.

D.01-03-081adopted the following company-wide average generation-related rate components:

7.277 cents/kWh for Edison;

6.471 cents/kWh for PG&E;

6.5 cents/kWh for SDG&E capped customers;

12.539 cents/kWh for SDG&E uncapped customers.

B. CPA is a Set Rate Component

In D.01-03-081, we solicited comment on whether CPA is a set rate component, calculated using utility rate components. After careful consideration of the parties' comments, we conclude that CPA is a set rate component as opposed to a periodically changing revenue amount as advocated by the utilities.

Our interpretation that CPA is a "rate" is consistent with language in Section 360.5 which states:

> "The commission shall determine that portion of each existing electrical corporation's retail rate effective on January 5, 2001, that is equal to the difference between the generation related component of the retail rate and the sum of the costs of the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services. That portion of the retail rate shall be known as the California Procurement Adjustment. ...." (Emphasis added.)

Our interpretation that CPA is "set" and a "rate" is also consistent with Water Code Section 80130 which determines the amount of indebtedness that DWR may incur.

> "... In no event shall [DWR] authorize the issuance of bonds ... in an aggregate amount greater than the amount calculated by multiplying by a factor of four the annual revenues generated by the California Procurement Adjustment ..." (Emphasis added.)

The issuance of bonds is dependent on the CPA. If CPA fluctuated monthly, little certainty would exist concerning the amount of bonds that DWR could issue.[7] An interpretation of Section 360.5 that concludes that the CPA is a set rate is more consistent with Water Code Section 80130. Thus, we reject the utilities' proposals that CPA is an amount that fluctuates monthly. Those proposals focus more on the role of the CPA as a factor in determining the fixed DWR Set-Aside.

The use of the verb "generated" in Water Code Section 80130 also supports our interpretation that CPA is a rate. Amounts do not "generate" revenues, whereas a "rate" would generate revenues.

C. Calculation of the CPA

The primary purpose for which we are calculating the CPA today is to enable DWR to proceed with the process of issuing bonds in a timely fashion.

Each of the utilities proposes to calculate the CPA using essentially the following model:

1. The generation-related component of retail rates is multiplied by the company's total annual kWh sales to produce total generation-related revenues.

2. The four statutorily authorized costs are then subtracted from the revenues calculated above.

[7] Some of the utilities' proposals conclude that CPA may sometimes be a negative number. Determining CPA in a manner that yields a negative number is also inconsistent with Water Code Section 80130.

As explained above, the CPA is a set rate. However, because the statute requires costs to be deducted from rates, we agree with the utilities that it is appropriate to multiply the generation-related rate-component by total kWh sales[8] to arrive at generation-related revenues. It is then possible to deduct generation-related costs from these revenues. The result of this calculation, however, is not the CPA (which is a rate), but rather it is the revenue produced by the CPA over a given time period (namely the time period over which the kWhs were delivered to customers). These CPA-generated revenues can then be divided by the company's total kWh sales in the same time period to calculate the CPA rate.

After calculating the revenues produced by the generation-related rate component, therefore, we must next determine the sum of the costs of the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services. Section 360.5 expressly refers to those identifiable costs, and no others. Thus, we conclude that the only costs to be utilized in calculating the CPA are those specifically enumerated in Section 360.5.

At the workshops, the utilities presented estimates of generation-related costs and of kWh sales, which they used to develop CPA revenues under several different scenarios. Their workpapers and proposals show a number of adjustments to the total generation-related revenues, as well as a number of categories of costs they believe fall within the four statutorily authorized categories.[9] We do not agree with the utilities that all of these adjustments and costs are appropriate. Section 360.5 clearly refers to those

[8] For the purpose of this proposed calculation of the CPA, we use total sales to refer to sales by the company and DWR to the utility's bundled service customers, which excludes sales to direct access customers.

[9] The utilities' workshop workpapers were submitted to the service list in A.00-11-038 et al. on February 9, 2001.

specific identifiable costs. Thus, we shall exclude from the utilities' submission those costs not specifically provided for in Section 360.5.

For example, we agree with Aglet that franchise fees attach to all retail revenues, not generation costs, and that, uncollectibles are not costs at all, but instead are revenue requirement allowances related to nonpayment of customer bills. Aglet correctly contends that these items are not included in the four categories in Section 360.5. Aglet also correctly argues that while other items such as direct access credits, restructuring implementation costs, employee-related transition costs, losses on sale and QF shareholder incentives conceptually are generation-related costs, they are not encompassed by any of the four categories in Section 360.5. Indeed, since direct access customers are sold electricity by neither the utility nor DWR, direct access revenues and credits both should be excluded from these calculations.[10] We also agree with Aglet that rate reduction bond revenues are not included in any of the four items in Section 360.5. Nuclear incentive amounts--for example, Diablo Canyon ICIP payments--in excess of actual costs are not strictly generation costs but are settled revenue requirement amounts. These incentive amounts have been excluded from our revised calculations pursuant to information the utilities provided in response to Ordering Paragraph 10 of D.01-03-081, as explained in greater detail below. Customer Service and Informational expenses and "indirect" administrative and general (A&G) costs are not generation costs and do not fall within the scope of the four items in Section 360.5.

In order to calculate the CPA, we will look to the scenarios the utilities provided at the workshops. For Edison and PG&E we have used their scenarios which reflect QFs priced at $80/MWh. This figure reflects ongoing efforts to restructure QF

[10] The attached workpapers from SDG&E properly exclude these direct access figures. The scenarios originally submitted by Edison and PG&E included direct access sales in their total sales figures. The Commission has relied on other workpapers from these utilities to make the necessary corrections.

pricing. SDG&E provided only one scenario in which it forecasted QF payments in 2001 according to actual contract terms. We have corrected the selected scenarios to eliminate the adjustments and costs we have found inappropriate (as discussed above). Using these corrected spreadsheets, we have calculated the annual revenues generated by the CPA. As shown in Attachment E, the annual revenues generated by CPA would be: for PG&E $1,793,173,000 for Edison $856,430,000, for SDG&E capped $303,291,000, and for SDG&E uncapped, $402,929,000. The CPA rate itself is then calculated by dividing the annual CPA revenues by the company's total annual kWh sales for both utility and DWR supplied energy, excluding Direct Access. The figures produce the following company-wide average CPA rates. For PG&E, 2.413 cents per kWh, for Edison, 1.120 cents per kWh, for SDG&E capped, 2.717 per kWh, or SDG&E uncapped, 8.748 cents per kWh. These calculations will enable DWR to determine the maximum amount of bonds it can issue under Water Code Section 80130.

In using these selected scenarios to calculate the CPA, we are not accepting the utilities' cost figures as a basis for calculating future rates or revenue requirements for the utilities. These cost figures have not been subject to the kind of analysis and scrutiny by the Commission and the parties that would be necessary before we could accept them for such purposes. We accept them here solely for purposes of calculating the CPA, which we do primarily in order to permit DWR to determine the maximum amount of bonds it may issue.

Some of the comments criticized the determination of generation-related costs. Our original calculations, based on utility workpapers, reflected QFs priced at $80/MWh. A number of parties—including the utilities who developed this estimate—then argued that this figure is too low. After careful consideration of the parties' comments, we retain our original figure of QFs priced at $80/MWh. We do so based on D.01-03-067 which established a reasonableness benchmark (called the "Consumer Transition Price") for payments to QFs of $79/MWh. The $80/MWH QF scenarios we use here for the CPA calculation is consistent with the D.01-03-067 benchmark established for QFs. Although

some of the details of the QF calculations and indices need to be settled, D.01-03-067 ties its benchmark to that of the FERC. The "Consumer Transition Price" benchmark of $79/MWH is also tied to the average price of the portfolio of electricity supply developed by DWR for the next five years. Therefore, it is reasonable to develop the CPA using the "benchmark" reference of $79/MWH from D.01-03-067 for the purpose of financing the bonds.

We also believe that any effect on utility finances due to an underestimate of QF prices and resultant overstated CPA may be mitigated or avoided when the Commission allocates CPA. When the Commission takes comments on how to allocate the CPA, parties may advocate that the Commission allocate the CPA in a manner that fully avoids the results of any understated costs used to calculate CPA. Today's decision does not allocate the CPA as between the DWR and the utilities, thus the financial effects the utilities are concerned about in terms of a possible understatement of QF costs are premature.

Consequently, we believe this decision accomplishes our stated goal of allowing determination of the maximum amount of bonds that DWR may issue. Our action has no negative impact on the financial well being of utilities. To the contrary, our decision takes positive steps in ensuring that DWR may move forward to issue bonds.

V. Financing Order

DWR requests that we determine the CPA for each utility as part of an order, and that we acknowledge that the Department may rely upon this determination for purposes of Section 80130 of the Water Code. DWR further proposes that upon its written acceptance thereof, our order would constitute an agreement between DWR and the Commission within the meaning of Water Code Section 80110. That statute provides in relevant part that:

> "The commission may enter into an agreement with the department with respect to charges under Section 451 for purposes of this division, and that agreement shall have the force and effect of a financing order adopted in accordance with Article 5.5 (commencing

> with Section 840) of Chapter 4 of Part 1 of Division 1 of the Public Utilities Code, as determined by the commission."

This provision must be read in conjunction with Water Code Section 80130, which provides in relevant part that:

> "In addition, before the issuance of bonds, the department shall establish a mechanism to ensure that the bonds will be sold at investment grade ratings and repaid on a timely basis from pledged revenues. This mechanism may include, but is not limited to, an agreement between the department and the commission as described in Section 80110."

The Legislature clearly anticipated that the Commission and DWR would enter into necessary agreements to ensure the marketability of the bonds. Determination of both the CPA and the annual revenues produced by the CPA are key steps in determining the maximum amount of bonds that may be issued. DWR should be able to rely upon these determinations. Accordingly, with respect to our determination of the CPA rate and the annual revenues generated by the CPA, we agree that DWR's request should be approved. Upon their written acceptance by the department, the determinations of both the CPA and the annual revenues produced by the CPA made herein shall constitute a rate agreement between DWR and the Commission within the meaning of Section 80110 of the Water Code, and such agreement shall have the full force and effect of a financing order.

VI. Comments on Decision

Under Public Utilities Code Section 311(g)(3) and Rule 77.7(f)(9) of the Rules of Practice and Procedure, the Commission may determine on its own motion that public necessity requires reduction or waiver of the 30-day public review and comment period set by Public Utilities Code Section 311(g)(1). We have weighed the interest in allowing the full comment period against the need to provide DWR with certainty about the revenues that will be generated by the CPAs of the three utilities so that DWR can proceed to issue bonds. We conclude that the public interest in providing certainty at an

early date, especially in the current energy crisis, outweighs the interest in allowing a full comment period. Therefore, this period has been reduced. The following parties filed comments.

PG&E's comments raise concerns about the accuracy of assumptions used to calculate the CPA. PG&E contests the accuracy of power costs for QFs, ISO, retained generation, distribution costs and ICIP costs. PG&E also challenges the calculation of generation-related revenues. In essence these claims assert that different assumptions should be used to calculate the CPA amount. However, we are not persuaded that the Commission's assumptions are inappropriate for the purpose of calculating a CPA to be used to size bonds. Since we will subsequently allocate CPA amounts, we can make adjustments that are necessary to reflect a proper revenue allocation at that time.

In addition, PG&E contends that the Commission has excluded statutorily required costs from the calculation of CPA. However, PG&E's comments do not specifically identify what these costs are that PG&E believes the Commission's CPA methodology has excluded. Additionally, PG&E's comments appear to assert that the Commission does not use a residual method for determining CPA. PG&E's comments on this latter point are difficult to discern. For instance, in discussing a financing order, PG&E states that "[t]hese recitations do not relieve the Commission from its statutory duty of calculating the CPA on a residual basis." Despite such esoteric comments, it appears that PG&E does not challenge the residual method the Commission used to determine CPA. Instead, it appears that PG&E's real concern is that the Commission interprets CPA as being a "set" rate as opposed to an amount that fluctuates.

PG&E asserts that its proposal for a CPA that fluctuates on a monthly basis more accurately reflects the statutory mandate of AB 1X. However, in deference to "brevity," PG&E's comments do not cite the statutes it alleges are consistent with its proposal. The Commission (in D.01-03-081), in arriving at the conclusion

that CPA is a set rate, considered Water Code Section 80130[11] which PG&E's comments do not address. Despite the Commission's explicit proposed conclusion that CPA will not be used for determining PG&E's cost recovery and that the Commission is not determining the FDWRSA, PG&E speculates that the creation of a financing order with DWR based on a CPA "may require PG&E to send revenues to DWR at the expense of [PG&E's] own costs and creditors."[12] Lastly, PG&E asserts that remittance of CPA revenues to DWR would be an unlawful taking if the CPA overstates the amounts residually available. We address PG&E's fear in our discussion and find that such concerns are outside the scope of this decision.

In response to Ordering Paragraph 10 of D.01-03-081 has information about its actual nuclear cost, excluding nuclear incentive amounts in excess of actual costs. PG&E states in its notes to its attached CPA calculation that actual 2001 nuclear costs are $353 MM for an 11-month period. We have prorated the 11-month period to an annual amount of $385 MM (excluding ICIP). Subtracting $385 MM from the $558.581 MM nuclear costs included for PG&E in Attachment E of D.01-03-081, results in an adjustment to utility related costs of $173.581 MM for PG&E.

According to PG&E, ancillary services should include additional ISO costs, not included in Attachment E. Chief among these are imbalance energy and out-of-market purchases made by the ISO. These additional costs are not ancillary services, nor are they "existing bilateral contracts." Thus, like other generation-related costs that may be incurred by PG&E, these simply do not fall within the four kinds of generation costs specified in Section 360.5.

[11] Water Code Section 80130 which sets a cap on the amount of bonds DWR may issue. The cap is tied to the CPA.

[12] Comments of PG&E at p.11.

Edison, similar to PG&E, raises concerns that CPA may be overstated and argues that Edison will suffer deleterious financial affects. In this decision, we do not allocate the alleged overstated CPA. At such time as the Commission takes comment on the allocation of the CPA, Edison may raise its concerns by proposing that Edison receive a disproportionately higher allocation or all of the CPA. Edison also argues for inclusion of costs not listed in Section 360.5 on the ground that the Commission should excuse the legislature for not knowing what costs to properly include. The Commission has no authority to second-guess clear and unambiguous language contained in statute. Edison also points to Commission decisions prior in time to passage of Section 360.5 as support for including costs in the calculation of CPA not listed in Section 360.5. Contrary to Edison's suggestion, the Commission lacks authority to undo statutory directives.[13] Edison also raises extraneous matters such as the allegation that DWR must buy all of Edison's net short. We do not address, because they are non-responsive to our proposal, this and other extraneous issues contained in Edison's comments.

In Attachment A of its comments, Edison also recalculates the CPA. The only adjustment shown by Edison that is necessary is to subtract $55.4 MM from utility related costs to account for SONGS ICIP revenues in excess of operating costs.

SDG&E disagrees that the CPA is a "set" rate. SDG&E believes that no provision in law states that CPA is a set rate. Instead, SDG&E argues that the CPA should vary monthly. We have reviewed Section 360.5 and AB 1X and conclude that no provision in law states that CPA should vary monthly. If the legislature had meant to say that CPA should vary monthly it knew how to say so yet it did not. Absent explicit direction from the legislature, we believe our interpretation is most consistent with AB 1X for the reasons already discussed. Similar to Edison and PG&E, SDG&E is concerned that the

[13] Edison also claims that the proposed calculation of the CPA ignores reliability must run (RMR) costs. This assertion is incorrect. RMR costs have been subtracted from the generation revenues as shown in the notes for column D of Attachment E.

CPA may be overstated. As already discussed, SDG&E should raise such concerns when the Commission takes comments on how to allocate the CPA. SDG&E also states that its SONGS related costs are generally 25% of Edison's. Based on SDG&E's representation we subtract from SDG&E's generation costs 25% of the adjustment that Edison suggests for ICIP revenues in excess of operating costs (i.e., $55.4 x 25% = $13.85 million) in calculating a CPA for SDG&E. Lastly, SDG&E also asserts that the Commission's methodology is unreliable because the data relied upon to calculate the CPA is unreliable. However, the CPA must be calculated now, in order to allow DWR to proceed to issue bonds. If we were to wait, as the utilities suggest, until after we have actual data, the bonds could not be issued when they are needed. Accordingly, we are calculating the CPA now, using estimates provided by the utilities that may reasonably be relied on for the purpose of calculating the maximum amount of bonds that DWR can issue.

The comments of the Cogeneration Association of California (CAC) state that the general proposed methodology for calculating the CPA is consistent with state and federal law. However, CAC appears concerned about allocating a portion of the CPA[14] to DWR for the power DWR procures. The basis for this concern is its belief that the input used for QFs is artificially low. Hence, CAC seeks clarification that DWR shall not receive payment inconsistent with Section 360.5 or in the alternative an assurance that utilities shall pay QFs consistent with state and federal law. As previously stated, this decision does not address the allocation of the CPA. Thus, CAC's concerns are premature.

The comments of CE Generation provide a short history lesson of the Public Utilities Regulatory Policy Act of 1978 (PURPA). CE Generation is primarily concerned that CPA is overstated and thus monies that should be used to pay utility expenses, such as QF costs, are instead being allocated to DWR via the FDWRSA. The concern of CE

[14] The portion of the CPA that DWR receives is defined in Section 360.5 as the FDWRSA.

Generation is premature, in this proceeding we do not allocate the CPA. CE Generation may raise the argument that PURPA requires the Commission to allocate the CPA to CE Generation or similarly situated entities at such time when the Commission takes comment on how to allocate the CPA. In the interim, we see no harm to CE Generation from DWR raising funds, through the issuance of bonds, to purchase power.

The Utility Reform Network (TURN) states that the Commission correctly interprets the Section 360.5 when it proposes to exclude from utilities' proposals the costs not specifically provided for in Section 360.5. However, TURN provides some clarifications three areas of cost exclusion.

TURN recommends that exclusion of A&G costs should be clarified to create a very limited exception for such expenses directly attributable to the operation of utility-related generation plants. Consistent with TURN's recommendation we have already, based on the information (AB 1X worksheets) provided by the utilities, excluded "indirect" A&G costs. We also correct a minor mistake in Attachment E of D.01-03-081 relating to Edison's Customer Information and Service Costs and A&G costs -- $35,681 should be subtracted rather than $36,521 (see notes for Column G).

The Office of Ratepayer Advocates (ORA) generally agrees with the methodology for calculating CPA. However, ORA is uncomfortable with the limited scrutiny the numerical inputs to the calculation have received. ORA supports the omission of the various costs items and the proposed QF cost assumption. ORA recommends recalculating the CPA in Attachment E, by excluding QF buyout costs for Edison ($112.1 MM), and excluding $140 MM, $68 MM, and $30 MM of nuclear costs for PG&E, Edison, and SDG&E, respectively. QF buyout costs may be considered QF-related costs and thus we do not exclude such costs. We also decline to adopt ORA's recommendations to adjust the nuclear costs in Attachment E. Instead, we have updated nuclear costs based on information provided by the utilities. We are using such information

only for calculating the maximum amount of bonds that DWR may issue. ORA may challenge the utilities' nuclear costs in other forums.

In its comments ORA states that "a financing order would essentially securitize that portion of the utilities' revenue stream associated with the CPA for use in repayment of the bonds." We do not agree. Pursuant to Water Code Section 80110, certain agreements between this Commission and the DWR "shall have the force and effect of a financing order adopted in accordance with Article 5.5 (commencing with Section 840) . . . of the Public Utilities Code." By making certain provisions of today's order a financing order, we do not dedicate any particular stream of revenues to DWR. Rather, we are simply allowing DWR to rely on the irrevocable nature of a financing order, as generally referenced in Public Utilities Code Section 841(c), when using the figures contained in today's order to make the calculations required under Water Code Section 80130.

Aglet does not oppose the execution of a rate agreement between the Commission and DWR. Aglet also recommends several revisions to the Commission's proposed findings of fact. We adopt Aglet's revision to Finding of Fact 2 which makes clear that making CPA a rate is a necessary interpretation, not an absolute fact created by the legislation. Finding of Fact 6 is also added to reflect the decision's discussion concerning QF pricing.

Williams Communications filed comments in support of the Commission's proposal that CPA should be determined as a set rate component. Further, Williams seeks clarification concerning generation-related costs that should be included in the calculation of CPA and instruction to Utilities to make timely payments to all vendors and suppliers of energy, capacity and ancillary services, on a pro-rata basis if necessary, in the same manner as the Commission directed payment to DWR. We do not find it necessary to make further changes to our discussion concerning generation-related costs. With respect to ordering utilities to make payments, such matter is outside the scope of this decision. We have taken steps to ensure payment to DWR based on statutory direction contained in AB 1X.

Findings of Fact

1. CPA is a set rate.

2. It is reasonable to calculate a utility's CPA by dividing CPA-generated revenues by the company's total kWh sales.

3. Franchise fees, uncollectibles, direct access credits, restructuring implementation costs, employee-related transition costs, losses on sale and QF shareholder incentives, rate reduction bond revenues, nuclear incentive amounts, customer service and informational expenses and "indirect" administrative and general (A&G) costs should be excluded from utility costs for the purpose of calculating the sum of the costs of the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services pursuant to Public Utilities Code Section 360.5.

4. The cost figures the utilities included in their workpapers are useful for the sole purpose of calculating CPA to permit DWR to determine the maximum amount of bonds it may issue.

5. Determination of both the CPA and the annual revenues produced by the CPA are key steps in determining the maximum amount of bonds that may be issued.

6. Based on the Consumer Transition Price established in D.01-03-067, it is reasonable to assume a qualifying facility price of $80 per megawatt-hour for purposes of calculating the CPA for each utility.

7. We have weighed the interest in allowing the full comment period against the need to provide DWR with certainty about the revenues that will be generated by the CPAs of the three utilities and concluded that the public interest in providing certainty at an early date outweighs the interest in allowing a full comment period.

Conclusions of Law

1. In using selected scenarios from the utilities' workpapers to calculate the CPA, we are not accepting the utilities' cost figures as a basis for calculating future rates or revenue requirements for the utilities; we accept them here solely for purposes of

calculating the CPA, which we do today in order to permit DWR to determine the maximum amount of bonds it may issue.

2. The determination of the CPA rate and the annual revenues generated by the CPA should, upon acceptance in writing by the California Department of Water Resources (DWR), constitute an agreement between this Commission and DWR within the meaning of Water Code Section 80110, and as such should have the full force and effect of a financing order adopted in accordance with Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the Public Utilities Code.

INTERIM ORDER

IT IS ORDERED that:

1. The California Procurement Adjustment (CPA) rates for Southern California Edison Company (Edison), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) and the annual revenues generated by these CPA rates are as follows:

	CPA Rate (¢/kWh)	Annual Revenues (000)
a. Edison	1.120	$856,430
b. PG&E	2.413	$1,793,173
c. SDG&E – capped	2.717	$303,291
d. SDG&E – uncapped	8.748	$402,929

2. Our determination in this order of the CPA rates for each utility and the annual revenues generated by the CPA shall, upon acceptance in writing by the California Department of Water Resources (DWR), constitute an agreement between this Commission and DWR within the meaning of Water Code Section 80110, and as such shall have the full force and effect of a financing order adopted in accordance with Article 5.5. (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the Public Utilities Code. This ordering paragraph applies solely to our determination of the company-wide average CPA rates and the annual revenues generated by the CPA, and to

no other provisions of this decision. This ordering paragraph will allow DWR to rely on the provisions of Ordering Paragraph 1 for purposes of Water Code Section 80130, but does not dedicate any particular revenue stream to DWR.

This order is effective today.

Dated April 3, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
CARL W. WOOD
GEOFFREY F. BROWN
Commissioners

Commissioner Richard A. Bilas, being necessarily absent, did not participate.

ATTACHMENT A

DEPARTMENT OF WATER RESOURCES (Letterhead)

March 14, 2001

Commissioners Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

Dear Commissioners:

This letter is submitted by the Department of Water Resources (the "Department") for your consideration in connection with the determination by the Commission of the "California Procurement Adjustment" mentioned below. The Department respectfully requests that the Commission determine the California Procurement Adjustment consistent with what the Department believes to be the clear meaning of Assembly Bill No. 1 from the First Extraordinary Session ("ABX1-1"), Chapter 4, Statutes of 2001, as described below.

Governor Davis signed ABX1-1 on January 31, 2001. Section 2 of ABX1-1 adds Section 360.5 to the Public Utilities Code, which reads as follows:

> 360.5 The commission shall determine that portion of each electrical corporation's retail rate effective on January 5, 2001, that is equal to the difference between the generation related component of the retail rate and the sum of the costs of the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services. That portion of the retail rate shall be known as the California Procurement Adjustment. The commission shall further determine the amount of the California Procurement Adjustment that is allocable to the power sold by the [D]epartment. That amount shall be payable, by each electrical corporation, upon receipt by the electrical corporation of the revenues from its retail end use customers, to the [D]epartment for deposit in the Department of Water Resources Electric Power Fund, established by Section 80200 of the Water Code. The amount determined pursuant to this subdivision shall be known as the Fixed Department of Water Resources Set-Aside.

For compelling and practical reasons, the Commission's determination of the California Procurement Adjustment (the "CPA") is a critical element in the implementation of ABX1-1. It is the initial step in establishing an important revenue source for the Department in meeting its power purchase responsibilities. It is also important to any long-term or short-term financing by the Department.

In their filings in this proceeding, the electrical corporations make the unwarranted assertion that, in enacting ABX1-1, the Legislature not only afforded relief to the utilities with respect to procurement of the so-called "net short," but that the Legislature also granted them, in effect, a rate increase on the portion of the power which they continue to supply. The clear meaning of ABX1-1 is very different. Section 360.5 was intended to address important changes in circumstances that arose from the enactment of ABX1-1. Through the enactment of Section 360.5, the Legislature recognized that a significant portion of the electrical corporation's costs intended to be recovered in established generation rates were no longer being borne by the electrical corporations to the extent that the Department purchased the "net short" and that an appropriate adjustment in generation rates was therefore required. Section 360.5 was also clearly intended to provide financial assurance to the Department for its power purchases pursuant to ABX1-1 by making available to the Department (to the extent of the Commission-determined "Fixed Department of Water Resources Set-Aside") the portion of the rate applicable to each corporation that was intended to be applied by the corporation to pay for the "net short" being purchased by the Department.

In order to address these changes in circumstances, ABX1-1 envisions that for the Department's sale of "net short" energy to the customers of each electrical corporation, the Department will initially receive (i) a per-kWh price equal to the applicable generation-related retail rate per kilowatt-hour established for each electrical corporation as in effect on January 5, 2001 plus (ii) a Commission-determined portion of the January 5, 2001 rate for power the electrical corporation continues to sell. Consequently, ABX1-1 provides that each electrical corporation will continue to receive—on a per-kWh basis—only (i) the components of the January 5, 2001 rate attributed at the time of original rate-making to power that the corporation will continue to sell to its retail end use customers, (*i.e.*, native generation, qualifying facility contracts, existing bilateral contracts and ancillary services) plus (ii) a Commission-determined portion of the January 5, 2001 rate for power the electrical corporation continues to sell, (*i.e.*, the portion of such rate which is not determined to be part of the Fixed Department of Water Resources Set-Aside. Nothing in ABX1-1 suggests that the electrical corporations are to retain any revenues attributable to power furnished by the Department and to allow them to do so was certainly not the intent of ABX1-1.

As Section 360.5 states, the CPA is a portion of a "retail rate effective on January 5, 2001." Therefore the CPA itself is a rate, to be expressed in terms of cents per

kilowatt-hour (as Section 80130 of the Water Code also requires, as discussed below). Section 360.5 calls for the following determinations and calculations with regard to each electrical corporation:

First: Identify the generation related component of the corporation's retail rate that was in effect on January 5, 2001, expressed in terms of cents per kilowatt-hour (the "Total Generation Related Rate").

Second: Determine the "sum of the costs" (also expressed as a rate, *i.e.*, in terms of cents per kilowatt-hour) imputed at the time of rate-making by the Commission in connection with the establishment of the January 5, 2001 rate, to the corporation's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services (the "Utility Retained Rate").

Third: Determine "the difference between" the Total Generation Related Rate and the Utility Retained Rate. That is, subtract the Utility Retained Rate from the Total Generation Related Rate to determine the CPA applicable to the electrical corporation. (Note that, under the language of Section 360.5, since the CPA is "a portion of the Total Generation Related Rate, it cannot be negative.)

Section 360.5 requires that each electrical corporation pay to the Department, upon receipt of payment by each of its end use customers for power sold by the electrical corporation (as opposed to power deemed sold to such user by the Department), all or a portion of an amount equal to the product of (i) the number of such kilowatt-hours purchased by the user from the electrical corporation, multiplied by (ii) the electrical corporation's CPA. That portion of the CPA to be paid to the Department is the Fixed Department of Water Resources Set-Aside. Please note that the Department is <u>not</u> requesting that the Commission determine the Fixed Department of Water Resources Set-Aside at this time.

Following is an example which illustrates the CPA calculation methodology required by ABX1-1. Assume that (i) a hypothetical utility delivers to its retail end use customers 100 kWh annually, half of which is power derived from the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services, and the other half of which is "net short" power. Further assume that the hypothetical utility's Total Generation Related Rate is 5¢ per kWh, which took into account and consisted of an imputed cost of the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services of 2¢ per kWh at the time the Total Generation Related Rate was determined and the cost of the "net short"

power of 8¢ per kWh at the time the Total Generation Related Rate was determined. (The 2¢ per kWh imputed cost of 50 kWh ($1.00) and the 8¢ per kWh imputed cost of the other 50 kWh ($4.00) result in an average blended cost of 5¢ per kWh for all 100 kWh. In other words, the "Total Generation Related Rate" for the hypothetical utility is 5¢ per kWh.) In the example, the difference between the 5¢ per kWh Total Generation Related Rate and the 2¢ imputed cost of the power which the utility will continue to sell from the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services equals a CPA of 3¢ per kWh. In this example, the CPA of 3¢ per kWh would be subject to further allocation by the Commission to determine the Fixed Department of Water Resources Set-Aside.

Confirmation that the Legislature's intended construction of Section 360.5 is consistent with the CPA calculation methodology described above can be found in Section 80114 of the Water Code, enacted as part of ABX1-1, which provides as follows:

> 80114. The commission shall take those actions necessary to ensure that all, or a portion of, the component rates that are available to electrical corporations for the purchase of their net short position of electricity are used to recover the revenue requirements established pursuant to this division.

Consistent with the language of ABX1-1, since the January 5, 2001 retail rate—and, therefore, the components of the CPA—took into account historical costs, the CPA is fixed and immutable. It is not affected by any change in the costs of any generation resource of any electrical corporation that was not reflected in the January 5, 2001 rate at the time such rate was originally determined. On the other hand, the calculation of the CPA, in and of itself, does not alter the right of the Department to recover any portion of its revenue requirements which is not fully recovered through the application of the portion of the CPA equal to the Fixed Department of Water Resources Set-Aside (nor does it affect any right of the Commission to allow additional cost recovery to the utilities for the portion of the power for which they remain responsible, subject, to applicable law and Commission proceedings). Further, the calculation of the CPA does not quantify the division of the CPA as between the Department and any electrical corporation (*i.e.*, the determination of the Fixed Department of Water Resources Set Aside). The Department requests that Commission effectuate that division through a later determination and requests that the Commission's determination at this time be limited to the determination of the California Procurement Adjustment.

ABX1-1 also enacted Division 27 (commencing with Section 80000) of the Water Code. Division 27 established in the State Treasure the Department of Water Resources Electric Power Fund (the "Fund") and authorized the Department to issue bonds, notes,

and other evidences of indebtedness (collectively, "Bonds") for certain limited purposes, including:

- paying the costs of electric power and transmission, scheduling, and other related expenses, or to reimburse expenditures from the Fund for those purposes.
- repaying to the General Fund certain advances made to the Department for the power purchase program; and
- establishing or maintaining reserves in connection with the Bonds and paying certain costs incidental to the issuance, payment and security of the Bonds.

Section 80130 of the Water Code (the "Bond Cap"), enacted as part of ABX1-1, provides in relevant part as follows (emphasis added):

> In no event shall the [D]epartment authorize the issuance of bonds ... in an aggregate amount greater than the amount calculated by multiplying by a factor of four the annual revenues generated by the California Procurement Adjustment, as determined by the [C]ommission pursuant to Section 360.5.

During the Legislature's consideration of ABX1-1, the bill's author communicated to the Legislature his expectation that the amount of the Bond Cap that would result from the application of Section 80130 would approximate $10 billion. Many Legislators cited the $10 billion figure during the floor debate of ABX1-1. The phrase "generated by" – used in Section 80130—is further evidence that the CPA is a rate to be expressed in terms of cents per kilowatt-hour and not a dollar amount of revenues. Consistent with Section 80130 of ABX1-1, the Department will determine the Bond Cap by calculating the dollar amount of the annual revenues which would be generated by the applicable CPA (as determined by the Commission) in each electrical corporation's service area, adding such dollar amounts and multiplying the resulting sum by four.

The Department requests that the Commission (i) determine, as part of an order, the CPA of each electrical corporation pursuant to Section 360.5 and in accordance with the methodology discussed above, and (ii) acknowledge that the Department may rely upon such determination for the purposes of Section 80130 of the Water Code.

In addition, we request that the order provide that, upon its acceptance by the Department in writing, the order will constitute an agreement between the Department and the Commission within the meaning of Section 80110 of the Water Code and that,

pursuant to Section 80110, the order will have the full force and effect of a financing order.

Thank you for your assistance and attention to this important matter. We will be submitting additional information and requests to the Commission relating to the Department's power purchase program and financing plans and appreciate your continuing cooperation.

Sincerely,

/s/ THOMAS M. HANNIGAN

Thomas M. Hannigan
Director

(END OF ATTACHMENT A)

(FOR ATTACHMENTS B, C, D AND E, SEE THE ACROBAT VERSION.)

Attachment B

1. QF Payment @ $80/MWh
2. Includes Imputed RRB Credits

Southern California Edison Company
Calculation of California Procurement Adjustment
(As Set Forth in ABX1)
(Unless Denoted Otherwise, Amounts are In Thousands)

Line No.	Component	2001 Estimate February	March	April	May	June	July	August	September	October	November	December	Total
1.	Total Delivered Sales (Metered GWh)	6,290	6,715	6,419	6,722	7,029	7,491	8,275	7,573	7,619	6,663	6,665	77,461
2.	Generation Rate As of 1-05-01 ($/MWh)	56.85	56.85	56.85	56.85	63.46	73.37	73.37	73.37	66.76	56.85	56.85	63.40
3.	Emergency Procurement Surcharge ($/MWh)	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
4.	Generation Rate + EPS ($/MWh)	66.85	66.85	66.85	66.85	73.46	83.37	83.37	83.37	76.76	66.85	66.85	73.40
5.	Gross Generation Revenue	(420,491)	(448,867)	(429,135)	(449,338)	(516,369)	(624,491)	(689,869)	(631,351)	(584,874)	(445,435)	(445,551)	(5,685,772)
Adjustments:													
6.	Franchise Fees and Uncollectibles	4,717	5,035	4,814	5,040	5,792	7,005	7,738	7,082	6,561	4,996	4,998	63,777
7.	Direct Access Credit	39,083	41,720	39,886	41,764	47,994	58,044	64,120	58,681	54,362	41,401	41,412	528,467
8.	RMR	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	36,255
9.	Restructuring Implementation	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	30,805
10.	Other Authorized Costs/Credits	7,236	7,205	7,174	7,143	7,112	7,081	7,050	7,019	6,988	6,957	6,926	77,891
11.	Imputed 10% Rate Reduction	(27,814)	(31,663)	(27,926)	(29,852)	(32,524)	(36,685)	(42,554)	(36,322)	(33,843)	(31,268)	(31,130)	(361,582)
12.	Imputed TTA	(22,637)	(26,571)	(21,369)	(24,313)	(29,005)	(29,254)	(37,448)	(30,544)	(26,960)	(23,893)	(22,897)	(294,891)
13.	**Generation-Related Component**	**(413,809)**	**(447,044)**	**(420,460)**	**(443,458)**	**(510,904)**	**(612,204)**	**(684,866)**	**(619,339)**	**(571,671)**	**(441,145)**	**(440,146)**	**(5,605,048)**
14.	Generation-Related Rate ($/MWh)	72.61	73.49	72.29	72.82	80.22	90.21	91.35	90.27	82.81	73.08	72.89	79.87
Less:													
15.	A. SCE Owned Generation Rev Rqmt:												
16.	Capital Related	24,612	24,612	24,612	24,612	24,612	24,610	24,608	24,608	24,605	24,603	24,605	270,694
17.	SONGS ICIP	32,282	49,393	47,798	49,393	47,798	49,393	49,393	47,798	49,393	47,798	49,393	519,829
18.	Other On-Going (PV, Coal, and Hydro)	32,546	33,210	28,083	32,442	32,818	34,851	35,879	34,629	33,767	35,808	35,996	370,027
19.	Subtotal	89,439	107,214	100,492	106,446	105,228	108,853	109,879	107,035	107,764	108,208	109,993	1,160,551
20.	B. QF Payments:												
21.	QF Energy and Capacity Costs ($80)	174,400	158,240	176,080	171,600	179,440	174,640	178,480	176,560	168,400	174,000	166,800	1,898,640
22.	QF Buyouts	3,587	6,712	20,395	3,587	6,712	20,395	3,587	6,712	20,395	3,587	7,024	102,693
23.	Shareholder Incentives	-	-	-	-	-	-	-	-	-	-	-	-
24.	Scheduling, Dispatch & Admin	70	70	70	70	70	70	70	70	70	70	70	770
25.	Subtotal	178,057	165,022	196,545	175,257	186,222	195,105	182,137	183,342	188,865	177,657	173,894	2,002,103
26.	C. Bilateral Contract Costs:												
27.	Interutility Net Contract Costs	9,836	10,372	10,712	9,239	10,420	11,760	11,775	12,082	12,433	10,352	10,568	119,549
28.	Interutility Buyouts	-	-	-	-	-	-	-	-	-	-	-	-
29.	Scheduling, Dispatch & Admin	262	262	262	262	262	262	262	262	262	262	262	2,877
30.	BFM Contracts Costs	-	-	-	-	-	-	-	-	-	-	-	-
31.	Bilateral Contract Costs	11,752	13,032	12,557	12,984	12,605	17,679	17,775	17,099	15,624	14,957	15,336	161,400
32.	Subtotal	21,850	23,666	23,531	22,485	23,287	29,701	29,812	29,443	28,319	25,571	26,166	283,826
33.	D. Ancillary Services (including GMC)	74,960	82,590	81,755	89,206	90,159	103,498	107,246	96,762	91,246	79,300	81,102	977,824
34.	Subtotal (A + B + C + D)	364,305	378,492	402,323	393,393	404,895	437,157	429,073	416,581	416,194	390,735	391,155	4,424,304
35.	Current Month (Over)/UnderCollection	(49,504)	(68,552)	(18,137)	(50,065)	(106,009)	(175,047)	(255,792)	(202,758)	(155,478)	(50,410)	(48,992)	(1,180,744)
36.	Accumulated UnderCollections	-	-	-	-	-	-	-	-	-	-	-	-
37.	Interest (6.5% Short-Term)	-	-	-	-	-	-	-	-	-	-	-	-
38.	**California Procurement Adjustment**	**(49,504)**	**(68,552)**	**(18,137)**	**(50,065)**	**(106,009)**	**(175,047)**	**(255,792)**	**(202,758)**	**(155,478)**	**(50,410)**	**(48,992)**	**(1,180,744)**

Est. Net Short GWh (Feb through Dec)	21,171
CPA/Est. Net Short (GWh)	$55.77

NOTE: All assumptions are listed on the attached sheet.

Attachment C

Pacific Gas and Electric Company
Calculation of California Procurement Adjustment
(As Set Forth In AB1X)
($000s)

Scenario 1: QF at $80/MwH

Line No.	Component	February	March	April	May	June	July	August	September	October	November	December	Total
		Estimated											
1.	Sales (Metered)	6,454	6,538	6,354	6,420	6,846	7,272	7,572	7,670	6,936	6,405	6,770	75,238
2.	Generation Rate As of 1-05-01 /1	50.03	48.70	47.80	53.85	60.51	60.51	60.42	60.40	60.92	54.22	49.58	55.44
3.	Emergency Procurement Surcharge	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75
4.	Generation Rate + EPS	59.78	58.45	57.55	63.60	70.26	70.26	70.17	70.15	70.67	63.97	59.33	65.19
5.	Gross Generation Revenue	(385,828)	(382,130)	(365,689)	(408,329)	(480,986)	(510,900)	(531,344)	(538,068)	(490,191)	(409,732)	(401,668)	(4,904,865)
Adjustments:													
6.	Franchise Fees and Uncollectibles	3,731	3,695	3,536	3,948	4,651	4,940	5,138	5,203	4,740	3,962	3,884	47,425
7.	Direct Access Credit /2	36,266	35,919	34,372	38,382	45,210	48,022	49,945	50,580	46,078	38,514	37,754	461,042
8.	RMR /3	0	0	0	0	0	0	0	0	0	0	0	0
9.	Restructuring Implementation	0	0	0	0	0	0	0	0	0	0	0	0
10.	Remaining Transition Costs/Credits	9,366	10,447	10,724	25,312	30,903	16,099	13,197	14,298	14,403	15,011	2,821	162,581
11.	Imputed 10% Rate Reduction	(36,309)	(34,717)	(32,148)	(33,063)	(37,508)	(40,553)	(42,451)	(42,315)	(38,664)	(34,703)	0	(372,431)
12.	Imputed FTA	(32,575)	(31,349)	(29,259)	(28,462)	(30,511)	(32,896)	(34,378)	(34,246)	(31,443)	(29,875)	0	(314,995)
13.	**Generation-Related Component**	**(405,349)**	**(398,135)**	**(378,464)**	**(402,213)**	**(468,242)**	**(515,288)**	**(539,893)**	**(544,549)**	**(495,077)**	**(416,823)**	**(357,209)**	**(4,921,243)**
Less:													
14.	A. PG&E Owned Generation Rev Rqmt:												
15.	A1. Hydro												
16.	2001 Revenue Requirement /4	33,351	33,386	33,351	33,295	33,045	33,661	33,352	33,067	33,021	33,021	33,021	365,571
17.	A2. Fossil												
18.	2001 Revenue Requirement /4	18,198	30,354	15,734	16,827	19,020	20,161	19,900	19,685	18,296	17,745	17,244	213,165
19.	A3. Nuclear												
20.	Diablo ICIP	48,678	53,862	50,332	27,049	50,404	53,862	53,862	52,134	53,934	52,134	53,862	550,115
21.	CCFT Credit	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(41,613)
22.	Subtotal	44,895	50,079	46,549	23,266	46,621	50,079	50,079	48,351	50,151	48,351	50,079	508,502
23.	Subtotal (A1 + A2 + A3)	96,443	113,819	95,634	73,389	98,686	103,901	103,331	101,104	101,469	99,118	100,345	1,087,239
24.	B. QF Payments												
25.	QF Expenses	124,218	128,629	127,371	144,072	152,047	155,793	153,613	144,032	140,423	128,515	141,331	1,540,043
26.	QF Admin & Legal Costs	759	759	759	759	759	759	759	759	759	759	759	8,349
27.	Subtotal	124,977	129,388	128,130	144,831	152,806	156,552	154,372	144,791	141,182	129,274	142,090	1,548,392
28.	C. Bilateral Contract Costs:												
29.	Irrigation District Contracts and Other /5	(12,202)	(10,681)	(7,140)	1,112	7,360	280	(5,639)	(9,151)	(10,572)	(4,272)	1,544	(49,362)
30.	BFM Contracts Costs /6	0	0	0	0	0	0	0	0	0	0	0	0
31.	Bilateral Contract Costs	8,904	8,349	6,503	6,763	6,763	23,129	23,753	22,321	22,349	21,335	21,829	171,998
32.	Subtotal	(3,298)	(2,332)	(637)	7,875	14,123	23,409	18,114	13,170	11,777	17,063	23,373	122,636
33.	D. ISO Ancillary Services and Related Charges /7	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	220,000
34.	Subtotal (A + B + C + D)	238,121	260,876	243,127	246,095	285,614	303,861	295,817	279,065	274,427	265,455	285,808	2,978,267
35.	Current Month (Over)/UnderCollection	(167,228)	(137,259)	(135,337)	(156,118)	(182,628)	(211,427)	(244,076)	(265,484)	(220,650)	(151,369)	(71,401)	(1,942,976)
36.	Accumulated UnderCollections	0	0	0	0	0	0	0	0	0	0	0	0
37.	Interest (6.5% Short-Term) if Undercollection	0	0	0	0	0	0	0	0	0	0	0	0
38.	**California Procurement Adjustment**	**(167,228)**	**(137,259)**	**(135,337)**	**(156,118)**	**(182,628)**	**(211,427)**	**(244,076)**	**(265,484)**	**(220,650)**	**(151,369)**	**(71,401)**	**(1,942,976)**

Net Short GWh (Feb through Dec)	32,927
Contribution to Net Short ($/MWh)	$59.01

Attachment D

San Diego Gas & Electric Company
Calculation of California Procurement Adjustment for Uncapped Customers
(As Set Forth in ABX1)

Line No.	Component ($000)	2002 Estimate January	February	March	April	May	June	July	August	September	October	November	December	Total
1.	Delivered Sales (GWH)	355	353	353	361	369	398	425	423	448	412	390	374	4,662
2.	Projected Uncapped Generation Rate ($/MWH)	87.19	74.83	73.12	73.03	73.32	83.98	98.43	120.70	110.25	91.94	72.07	65.91	74.83
3.	Gross Generation Revenue	(30,995)	(26,444)	(25,831)	(26,330)	(27,032)	(33,457)	(41,863)	(51,005)	(49,378)	(37,891)	(28,095)	(24,662)	(402,982)
Adjustments:														
4.	Franchise Fees and Uncollectibles	255	240	238	243	249	282	319	345	352	301	262	244	3,330
5.	**Generation-Related Component**	**(30,740)**	**(26,204)**	**(25,593)**	**(26,087)**	**(26,783)**	**(33,175)**	**(41,543)**	**(50,660)**	**(49,026)**	**(37,589)**	**(27,833)**	**(24,418)**	**(399,652)**
Less:														
6.	A. SDG&E Owned Generation Rev Rqmt:													
7.	SONGS ICIP	3,635	3,443	3,880	3,886	3,730	1,991	3,468	3,947	3,754	2,330	3,745	3,812	41,620
8.	B. QF Payments:													
9.	QF Energy and Capacity Costs	2,297	2,409	2,451	2,537	3,917	3,969	3,853	3,738	3,673	2,571	2,571	2,409	36,396
10.	C. Bilateral Contract Costs:													
11.	Interutility Net Contract Costs (PNM & PGE)	1,032	1,065	1,102	1,134	1,068	1,090	1,157	1,122	1,097	1,157	1,151	1,083	13,259
12.	Bilateral Contracts	1,274	1,209	1,359	1,366	1,450	1,420	1,426	1,389	1,309	1,432	1,379	1,330	16,344
13.	Subtotal	2,306	2,275	2,461	2,501	2,518	2,510	2,583	2,511	2,406	2,589	2,530	2,413	29,603
14.	D. Ancillary Services (Including GMC)	2,222	1,969	2,181	1,986	2,161	2,872	3,784	4,686	3,525	2,377	1,972	1,999	31,734
15.	Subtotal (A + B + C + D)	10,460.90	10,095.27	10,973.17	10,909.83	12,326.57	11,341.96	13,687.60	14,881.79	13,358.85	9,866.62	10,817.40	10,632.71	139,353
16.	Current Month (Over)/UnderCollection	(20,279)	(16,109)	(14,620)	(15,178)	(14,456)	(21,833)	(27,856)	(35,778)	(35,667)	(27,723)	(17,016)	(13,785)	(260,300)
17.	Accumulated UnderCollections	(20,279)	(16,109)	(14,620)	(15,178)	(14,456)	(21,833)	(27,856)	(35,778)	(35,667)	(27,723)	(17,016)	(13,785)	(260,300)
18.	Interest (6.5% Short-Term)	-	-	-	-	-	-	-	-	-	-	-	-	-
19.	**California Procurement Adjustment**	**(20,279)**	**(16,109)**	**(14,620)**	**(15,178)**	**(14,456)**	**(21,833)**	**(27,856)**	**(35,778)**	**(35,667)**	**(27,723)**	**(17,016)**	**(13,785)**	**(260,300)**

Est. Net Short GWH (Feb. through Dec.)	2,986
CPA / Est. Net Short ($/MWH)	87.18

FOOTNOTES 1/ Represents Utility Bundled Sales. The approximate split between AB265 Capped and Non-AB265 Customers is 70 / 30. Direct Access is not included because the CPUC has not yet approved cap plementation for them.

2/ The California Procurement Adjustment amount calculated above reflects the monthly amount available to the DWR for procuring power for utility customers, including the cost of imbalance energy and imbalance penalties.

Attachment E - Revised
Based on Utility Provided Scenarios, 12 month Projections for 2001

	A	B	C	D	E	F	G	H	I
	Total Generation Related Rate (¢/kWh)	Sales Reported in Utilities' ABX1 Data (GWh)	Bundled Service Sales (GWh)	Gross Gen. - Related Revs Reported in Utilities' ABX1 Data ($000s)	Gen. - Related Revenues Based on Bundled Service Sales ($000s)	Utility Related Costs ($000s)	Utility Related Costs less CSI and A&G ($000s)	CPA Revenues ($000s)	CPA Rate (¢/kWh)
	A=D/B/10				E=A*C*10			H=E-G	I=H/C
PG&E	6.471	82,008	74,299	$5,306,533	$4,807,719	$3,090,494	$3,014,546	$1,793,173	2.413
SCE	7.277	84,400	76,466	$6,141,557	$5,564,251	$4,743,502	$4,707,821	$856,430	1.120
SDGE Capped	6.500	11,163	11,163	$725,570	$725,570	$422,279	$422,279	$303,291	2.717
SDGE Uncapped	12.539	4,606	4,606	$577,565	$577,565	$174,636	$174,636	$402,929	8.748
Totals				$12,751,225	$11,675,105	$8,430,911	$8,319,282	$3,355,823	

Notes

Column A: Calculated based on gross generation-related revenues shown in column D and sales shown in column B.

Column B: Based on Utilities' sales data provided in ABX1 implementation worksheets emailed to parties in A.00-11-038, et.al, on 2-9-01.
PG&E: Scenario 1: (QFs at $80/MWh); Total metered sales for 2/'01 thru 12/'01 (75,238 GWh), plus 12/'01 sales (6,770 GWh) for 12th month.
SCE: Scenario with QFs at $80/MWh: Total metered sales for 2/'01 thru 12/'01 (77,461 GWh), plus 1/'02 sales (6,939 GWh) for 12th mo.
SDG&E: Total delivered sales for 2/'01 thru 12/'01 (10,192 GWH for capped; 4,251 GWh for uncapped), plus 1/'02 sales (971 GWh for capped; 355 GWh for uncapped) for 12th mo.

Column C: PG&E & SCE: Column B x 0.906 to remove sales to direct access customers.

Column D: Based on Utilities' sales data provided in ABX1 implementation worksheets emailed to parties in A.00-11-038, et.al, on 2-9-01.
PG&E: Scenario 1: (QFs at $80/MWh); Gross generation revenue for 2/'01 thru 12/'01 ($4,904,865), plus 12/'01 revenue ($401,668) for 12th month.
SCE: Scenario with QFs at $80/MWh: Gross generation revenue for 2/'01 thru 12/'01 ($5,685,772), plus 1/'02 revenue ($495,336) for 12th mo. less RMR ($36,255 for Feb. '01 thru Dec. '02, plus $3,296 for Jan. '02).
SDG&E: Total delivered sales for 2/'01 thru 12/'01 ($662,458 for capped; $546,470 for uncapped), plus 1/'02 revenues ($63,112 for capped; $30,995 for uncapped) for 12th mo.

Column E: Calculated based on total generation rate shown in Column A and bundled service sales shown in column C.

Column F: Based on Utilities' sales data provided in ABX1 implementation worksheets emailed to parties in A.00-11-038, et.al, on 2-9-01.
PG&E: Scenario 1: (QFs at $80/MWh); Costs for PG&E-owned gen., QFs, Bilaterals, and Ancillary Services for 2/'01 thru 12/'01 ($2,978,267), plus 12/'01 costs ($285,808) for 12th month, minus $173,581 to reflect actual nuclear operating costs.
SCE: Scenario with QFs at $80/MWh: Costs for SCE-owned gen., QFs, Bilaterals, and Ancillary Services for 2/'01 thru 12/'01 ($4,424,304), plus 1/'02 costs ($374,598) for 12th mo, minus $55,400 to reflect actual SONGS operating costs.
SDG&E: Cost for SDG&E-owned gen., QFs, Bilaterals, and Ancillary Services, excluding PECA amoritzation for 2/'01 thru 12/'01 ($403,402 for capped; $168,330 for uncapped) plus 1/'02 costs ($28,572 for capped; $10,461 for capped) for 12th mo, minus $13,850 ($9,695 for capped, $4,155 for uncapped) to reflect actual nuclear operating costs.

Column G: Column F less Customer Service and Information, and A&G costs identified in utilities data supporting ABX1 implementation worksheets.
PG&E: Column F minus $75,948; SCE: Column F minus $35,681.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 29

Request for Bids for Energy Purchases #1

The California Department of Water Resources

Request for Bids for Energy Purchase (CDWR RFB E2001-01)

January 23, 2001

Introduction: This Request for Bids (RFB) solicits proposals for several types of energy purchase options. The California Department of Water Resources (CDWR) encourages responses to all of the options. Bidders may provide as many bids as desired.

Product: CDWR is soliciting bids for firm energy to be delivered to SP15 and/or NP15 in aggregate for approximately 69,000 gigawatt-hours (GWH) to 100,000 GWH annually On-Peak, including Super Peak, and for approximately 26,000 GWH to 40,000 GWH annually Off-Peak to meet the needs of the State of California. This request is for delivery of firm energy for a period up to 10 years, as specified below, and may be submitted from any entity in the Western Systems Coordinating Council. Each Bidder shall offer to provide firm (100 percent capacity factor) energy at a fixed price for one or more of the delivery periods listed in the bid templates in Attachment A. These delivery periods vary in length from six months to ten years. Each Bidder may offer to provide firm energy for one or more of the delivery periods, but must specify whether the firm energy to be provided is from the same capacity used to provide the firm energy in another bid. In addition, each Bidder may offer to provide firm energy for one or more of the products, but must specify whether the firm energy to be provided is from the same capacity used to provide the firm energy in another bid. CDWR requests that each Bidder offer to deliver one or more of the following products:

Products

1) Base Load - All Day, Every Day - Hours Ending 0-24 (7 x 24)
2) Peak - Hours Ending 7-22, Monday through Saturday (6 x 16)
3) Off-Peak - Hours Ending 0-6, 23, and 24, all day Sunday and holidays
4) Summer Super Peak - Hours Ending 12-20, Monday through Friday from June 1 through October 31
5) Winter Super Peak – Hours Ending 17 – 21, Monday through Friday from November 1 through May 31.

If the energy is from within California, please state the applicable generating unit that will be supplying the generation. If the energy is from a portfolio of resources, please provide the amount of generation in each of the California Independent System Operator's (CAISO) congestion zones that will be supplying the generation. If the energy is from outside California, please state the transmission path that will be used and whether the Bidder has FTRs, or other transmission mechanisms in place to ensure that the energy can be delivered to SP 15 and/or NP 15.

Delivery Point: Bidder has the responsibility to deliver the firm energy to the CAISO congestion zones SP15 and/or NP15.

Bidding Quantities and Location: Bidding quantities should be in minimum 10 MW blocks and specify the congestion zone delivery point. Each product bid should be bid separately. Bidder should specify specific blocks and delivery periods in its proposal.

Price: Price for each product shall be fixed for the delivery period. CDWR will not accept prices that are tied to indices and consequently subject to change through the term.

Initial Delivery Date: The period for bids is established to reflect CDWR's initial energy delivery date of February 1, 2001. Bidders may bid for delivery beginning after the initial day of a delivery period in the event the Bidder can demonstrate one of the following:

- An initial commercial operating date after the initial day of the delivery period, but no later than December 31, 2001.
- Expiration of an existing agreement for sale (in effect as of January 24, 2001) for the generation resource required to meet the bid after the initial day of the delivery period, but no later than December 31, 2001.

Scheduling and Dispatching: All firm energy deliveries will be received by CDWR as a Scheduling Coordinator to Scheduling Coordinator trade in accordance with the CAISO tariff. The Bidder shall meet all CAISO tariff requirements including scheduling and dispatch requirements.

Enabling Agreement: CDWR contemplates that the energy purchase agreements shall be in accordance with and subject to the terms and conditions of the Western System Power Pool Agreement or such other generally accepted standard industry agreements as may be selected and modified by CDWR for purposes of this solicitation.

Bid Contents: Bidder shall respond to this RFB by completing the Bid Template in Attachment A and faxing it to any of the following three fax numbers: (916) 574-2569, (916) 574-2791 or (916) 574-2785.

Response Date: Responses must be received by 12:00 p.m. PST (noon) on January 24, 2001.

Direct responses to the attention of Raymond D. Hart and make reference to California Department of Water Resources Request for Bids for Energy Purchases (CDWR RFB E2001-01).

Validity of Price and Quantity: The Bidder's price and quantity shall be held until 12:00 p.m. PST (noon), January 31, 2001.

Disclaimer and CDWR Rights: This RFB shall not be construed as an offer, and CDWR is not bound, to purchase energy from any Bidder pursuant to this RFB. No rights shall be vested in any Bidder, individual or entity by virtue of its preparation to participate in, or its participation in, such process. No binding commitment shall arise on the part of CDWR to any Bidder under this Request for Bids until and unless the parties sign documents of agreement that become effective in accordance with their terms. This RFB does not commit CDWR to pay any costs incurred by Bidders in the preparation of their proposal. The bids received will be evaluated and selected based on the supplied information, including any supplemental information, submitted pursuant to this RFB. CDWR expressly reserves the right to modify, or withdraw from, the process initiated and described herein, or modify the schedule and any provision contained herein, for any reason. CDWR reserves to itself the selection of winning Bidders, if any, in the exercise of its sole discretion; the right to reject any and all bids, and any portion of a specific bid for any reason, as well as the right to waive any informality or irregularity in any bid received by it. CDWR also reserves the right to award an agreement to a Bidder based on factors other than price. CDWR assumes no obligation to provide a reason for rejection of a Bidder's bid.

Credit: Bidders should assume a transaction credit rating for CDWR of "A" from Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) (S&P) or Moody's Investor Services, Inc. (Moody's).

Neither the full faith and credit nor the taxing power of the State of California are or may be pledged for any payment under any agreement resulting from this solicitation. Revenue and assets of the State Water Resources Development System shall not be available to make payments under any agreement resulting from this solicitation.

Bidder's unsecured long-term debt must have an investment grade rating from either S&P or Moody's. If the Bidder does not meet this ratings requirement, the Bidder must provide some form of additional security acceptable to CDWR.

Additional Information: CDWR reserves the right to obtain additional information from Bidders including, but not limited to, affiliated entities and joint ventures, Bidder's financial strength, litigation and penalties.

CDWR RFB P2001-01

Date: _____

Company Name: _____

Contact Name: _____

E-Mail Address: _____

Address: _____

_____

City: _____

State: _____

Zip Code: _____

Telephone: _____

Fax Number: _____

SP 15 Zone	February 1, 2001 to September 30, 2001		February 1, 2001 to March 31, 2002		February 1, 2001 to March 31, 2004		February 1, 2001 to March 31, 2006		February 1, 2001 to March 31, 2011	
	MW	Price	MW	Price	MW	Price	MW	Price	MW	Price
Base Load										
Peak Load										
Off-Peak Load										

NP 15 Zone	February 1, 2001 to September 30, 2001		February 1, 2001 to March 31, 2002		February 1, 2001 to March 31, 2004		February 1, 2001 to March 31, 2006		February 1, 2001 to March 31, 2011	
	MW	Price	MW	Price	MW	Price	MW	Price	MW	Price
Base Load										
Peak Load										
Off-Peak Load										

CDWR RFB P2001-01

Date: _____

Company Name: _____

Contact Name: _____

E-Mail Address: _____

Address: _____

_____

City: _____

State: _____

Zip Code: _____

Telephone: _____

Fax Number: _____

SP 15 Zone	Super Peak Period Summer 2001		Super Peak Period Summer 2001-2003		Super Peak Period Summer 2001-2005		Super Peak Period Summer 2001-2010	
	MW	Price	MW	Price	MW	Price	MW	Price
Summer Super Peak								

NP 15 Zone	Super Peak Period Summer 2001		Super Peak Period Summer 2001-2003		Super Peak Period Summer 2001-2005		Super Peak Period Summer 2001-2010	
	MW	Price	MW	Price	MW	Price	MW	Price
Summer Super Peak								

CDWR RFB P2001-01

Date: _____

Company Name: _____

Contact Name: _____

E-Mail Address: _____

Address: _____

_____

City: _____

State: _____

Zip Code: _____

Telephone: _____

Fax Number: _____

SP 15 Zone	Super Peak Period Winter 2001		Super Peak Period Winter 2001-2003		Super Peak Period Winter 2001-2005		Super Peak Period Winter 2001-2010	
	MW	Price	MW	Price	MW	Price	MW	Price
Winter Super Peak								

NP 15 Zone	Super Peak Period Winter 2001		Super Peak Period Winter 2001-2003		Super Peak Period Winter 2001-2005		Super Peak Period Winter 2001-2010	
	MW	Price	MW	Price	MW	Price	MW	Price
Winter Super Peak								

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 30

Request for Bids for Energy Purchases #2

NOTICE AND INVITATION TO BID

On February 1, 2001 California Assembly Bill 1,First Extraordinary Session, was signed into law by Governor Gray Davis providing the necessary funding for California Department of Water Resources to enter into contracts for the purchase of energy for electric customers in the State of California.

This is to notify you that effective no later than February 15, 2001, the California Department of Water Resources intends to limit purchasing of electricity in the hour-ahead and day-ahead markets to a maximum of five percent of the load as was originally contemplated by the restructuring initiative. Accordingly, the Department of Water Resources shall be purchasing all of its "net short" capacity and energy through a portfolio of longer-term contracts.

Toward that end, we are inviting bids for shorter-term purchases of 30 days, 60 days, 180 days, one-year, two-year, or three-year duration, as well as longer-term contracts. These bids must be your final and best offer and we will be making awards promptly based on bids submitted and bilateral negotiations. All bids must be received no later than close of business on February 6, 2001 and we will be making awards as early as February 9.

Please state the quantity, the price and the term commencing at the earliest feasible date, and the point of delivery and source of power. Bids may be made by non-generators as well as generators and by both in-state and out of state entities.

The restructured California market can only be successful if there is a portfolio of long-term contracts. We expect your vigorous and competitive response to this solicitation. You can be assured we will act promptly in accepting the low bids.

Please send your bids to the California Department of Water Resources via fax at the numbers noted in the enclosed Request for Bids.

S. David Freeman

Vikram Budhraja

The California Department of Water Resources
Request for Bids for Energy Purchase (CDWR RFB E2001-02)
February 2, 2001

Introduction: This Request for Bids (RFB) solicits proposals for several types of energy purchase options. The California Department of Water Resources (CDWR) encourages responses to all of the options. Bidders may provide as many bids as desired.

Product: CDWR is soliciting bids for firm energy to meet the needs of the State of California. This Request for Bids is specifically targeting delivery of firm energy. Bids may be submitted from or on behalf of any entity in the Western Systems Coordinating Council, including generators, marketers, traders, and financial entities, whether located in-State or out-of-State.

CDWR requests that each Bidder offer to deliver one or more of the following products:

Products

1) Base Load - All Day, Every Day - Hours Ending 01-24 (7 x 24)
2) Peak - Hours Ending 07-22, Monday through Saturday (6 x 16)
3) Off-Peak - Hours Ending 01-06 and Hours Ending 23-24, including Sundays and holidays
4) Summer Super Peak – Hours Ending 12 –20, Monday through Friday for the period beginning June 1 through October 31.

Energy Source

If the energy source is within California and is to be supplied from a specific generating source, please specify the applicable generating unit that will be supplying the energy. If the energy is from a portfolio of resources, please specify the applicable generating units in each of the California Independent System Operator's (CAISO) congestion zones that will be supplying the energy. If the energy is from outside California, please state the transmission path that will be used and whether the Bidder has FTRs, or other

transmission mechanisms in place to ensure that the energy can be delivered to the delivery point specified in the bid. If no specific energy source is supporting the bid, please describe the supply acquisition plan to meet the proposed supply and delivery of the bid amounts.

Delivery Point: Bidder has the responsibility to deliver the firm energy to a CAISO congestion zone and to specify the congestion zone in its bid.

Bidding Quantities and Location: Bidding quantities should be a minimum 25 MW. Each product bid should be bid separately. The Bidder should specify specific blocks and delivery periods in its proposal.

Price: CDWR will accept products under a fixed price structure ($/MWh).

Initial Delivery Date: Bidders may bid for delivery beginning on or after February 9, 2001.

Scheduling and Dispatching: All firm energy deliveries will be received by CDWR as a Scheduling Coordinator to Scheduling Coordinator trade in accordance with the CAISO tariff. The Bidder shall meet all CAISO tariff requirements including scheduling and dispatch requirements.

Enabling Agreement: CDWR contemplates that the energy purchase agreements shall be in accordance with and subject to the terms and conditions of the attached Agreement which may be modified by CDWR for purposes of this solicitation.

Bids shall be submitted via fax to any of the following two fax numbers: (916) 574-1732 and (916) 574-2569.

Response Date: Responses must be received by close of business, 5:00 p.m. PST on February 6, 2001.

Direct responses to the attention of Raymond D. Hart and make reference to California Department of Water Resources Request for Bids for Energy Purchases (CDWR RFB E2001-02).

Validity of Price and Quantity: The Bidder's price and quantity shall be held for 7 days from the closing date of this RFB.

Disclaimer and CDWR Rights: This RFB shall not be construed as an offer, and CDWR is not bound, to purchase energy from any Bidder pursuant to this RFB. No rights shall be vested in any Bidder, individual or entity by virtue of its preparation to participate in, or its participation in, such process. No binding commitment shall arise on the part of CDWR to any Bidder under this Request for Bids until and unless the parties sign documents of agreement that become effective in accordance with their terms. This RFB does not commit CDWR to pay any costs incurred by Bidders in the preparation of their proposal. The bids received will be evaluated and selected based on the supplied information, including any supplemental information, submitted pursuant to this RFB. CDWR expressly reserves the right to modify, or withdraw from, the process initiated and described herein, or modify the schedule and any provision contained herein, for any reason. CDWR reserves to itself the selection of winning Bidders, if any, in the exercise of its sole discretion; the right to reject any and all bids, and any portion of a specific bid for any reason, as well as the right to waive any informality or irregularity in any bid received by it. CDWR also reserves the right to award an agreement to a Bidder based on factors other than price. CDWR assumes no obligation to provide a reason for rejection of a Bidder's bid.

Credit: Bidders should assume a transaction credit rating for CDWR of "A" from Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) (S&P) or Moody's Investor Services, Inc. (Moody's).

Neither the full faith and credit nor the taxing power of the State of California are or may be pledged for any payment under any agreement resulting from this solicitation.

Revenue and assets of the State Water Resources Development System shall not be available to make payments under any agreement resulting from this solicitation. The financing supporting the contracts is described in Assembly Bill 1, which was signed into law on February 1, 2001.

Bidder's unsecured long-term debt must have an investment grade rating from either S&P or Moody's. If the Bidder does not meet this ratings requirement, the Bidder must provide some form of additional security acceptable to CDWR.

Additional Information: CDWR reserves the right to obtain additional information from Bidders including, but not limited to, affiliated entities and joint ventures, Bidder's financial strength, litigation and penalties.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 31

Summary of Compliant Energy Bids

CONFIDENTIAL - PROPRIETARY INFORMATION

Date of Preparation 1/24/01 0:00

CALIFORNIA DEPARTMENT OF WATER RESOURCES
SUMMARY OF COMPLIANT ENERGY BIDS
EXCLUDES "SUPER PEAK" BIDS

NAME	ID	PRODUCT	PRODUCT DELIVERY PERIOD	PRICE $/MWH	MW	ENERGY MWH	DELIVERY POINT
name redacted (1)	001	Base Load	3 years	110.00	39.6	776,873	SP 15
name redacted (1)	001	Base Load	5 years	90.00	39.6	1,468,764	SP 15
name redacted (1)	001	Base Load	10 years	75.00	39.6	3,198,492	SP 15
name redacted	002	Base Load	5 Years	101.00	10.0	451,200	NP 15
name redacted	007	Base Load	10 years	82.50	100.0	8,880,000	SP 15
name redacted (2)	009	Base Load	10 years	85.00	50.0	4,077,600	SP 15
name redacted	013	Base Load	10 years	59.85	180.0	15,984,000	NP 15
name redacted	013	Base Load	10 years	59.85	88.0	7,814,400	NP 15
name redacted	013	Base Load	10 years	59.85	180.0	15,984,000	NP 15
name redacted	015	Peak	5 Years	119.00	20.0	515,520	NP 15
name redacted	015	Off-Peak	5 Years	74.00	10.0	193,200	NP 15
name redacted	020	Base Load	10 years	58.60	200.0	17,322,000	NP 15
name redacted (3)	023	Base Load	1 Year	170.00	44.0	385,440	NP 15
name redacted	018	Base Load	10 years	71.00	45.0	3,996,000	NP 15
name redacted	018	Base Load	10 years	79.50	45.0	3,996,000	NP 15
name redacted (4)	016	Base Load	10 years	75.50	50.0	4,294,000	NP 15
name redacted	028	Base Load	10 years	85.00	50.0	4,038,500	SP 15
name redacted	031	Base Load	3 years	130.10	20.0	552,960	SP 15
name redacted	031	Peak	3 years	144.53	20.0	552,960	SP 15
name redacted	031	Off-Peak	3 years	154.15	20.0	552,960	SP 15
name redacted	030	Base Load	5 Years	85.11	100.0	3,855,000	NP 15
name redacted	030	Base Load	5 Years	65.32	100.0	3,855,000	SP 15
name redacted	030	Peak	5 Years	77.09	100.0	1,996,800	SP 15
name redacted	034	Base Load	10 years	63.95	88.0	7,814,400	NP 15
name redacted	034	Base Load	10 years	63.96	180.0	15,984,000	NP 15
			Weighted Average:	69.09	1818.8	128,540,069	

Notes:

(1) Online Date December 31, 2001
(2) Online Date December 1, 2001
(3) Subject to termination of agreement with PG&E
(4) Clarification on start date delivery point.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 32

Tracking Sheets Showing Annual Capacity Levels

Long Term Sheet (2)

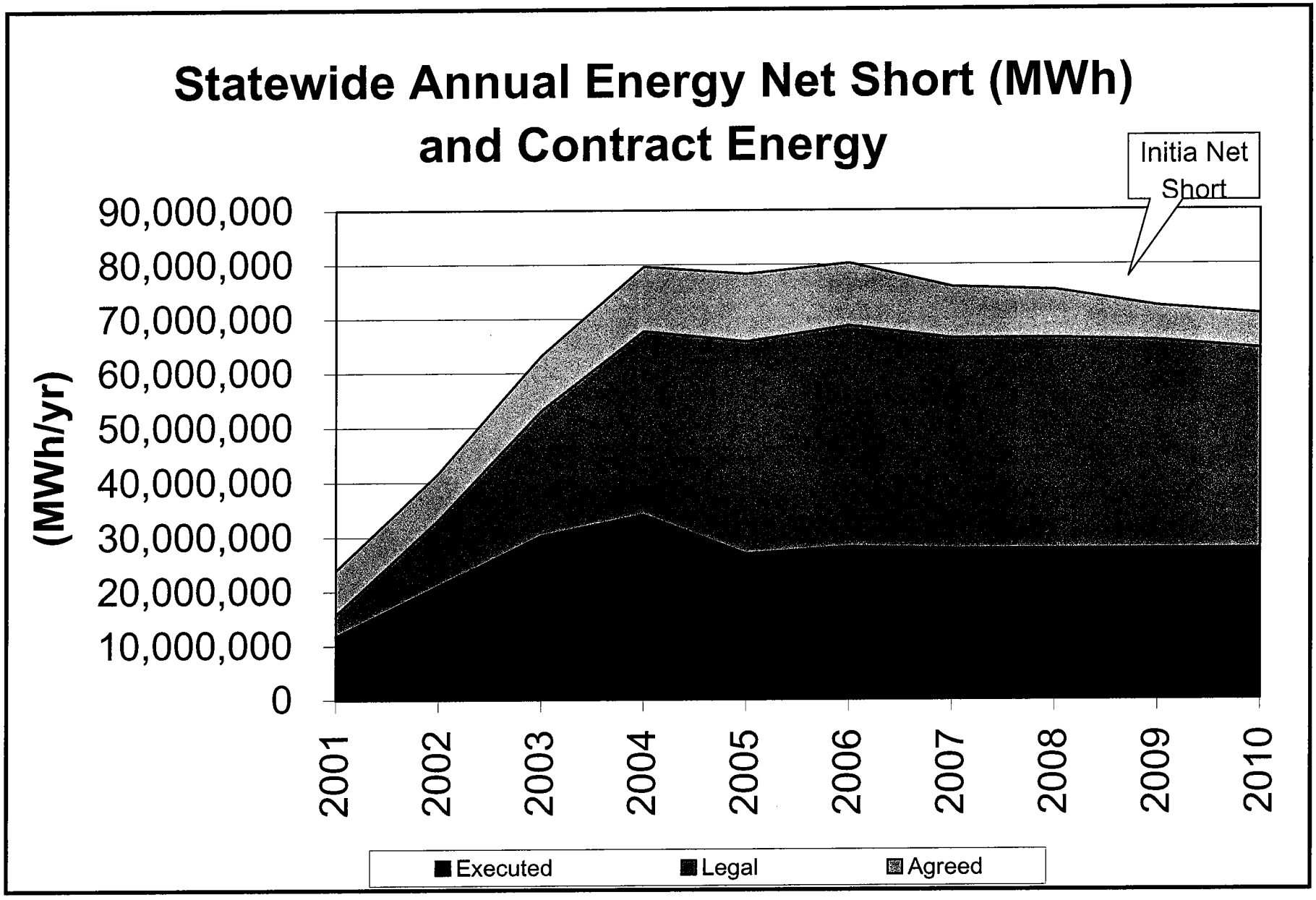
CONFIDENTIAL

CDWR POWER BIDS STATUS
AS OF March 8

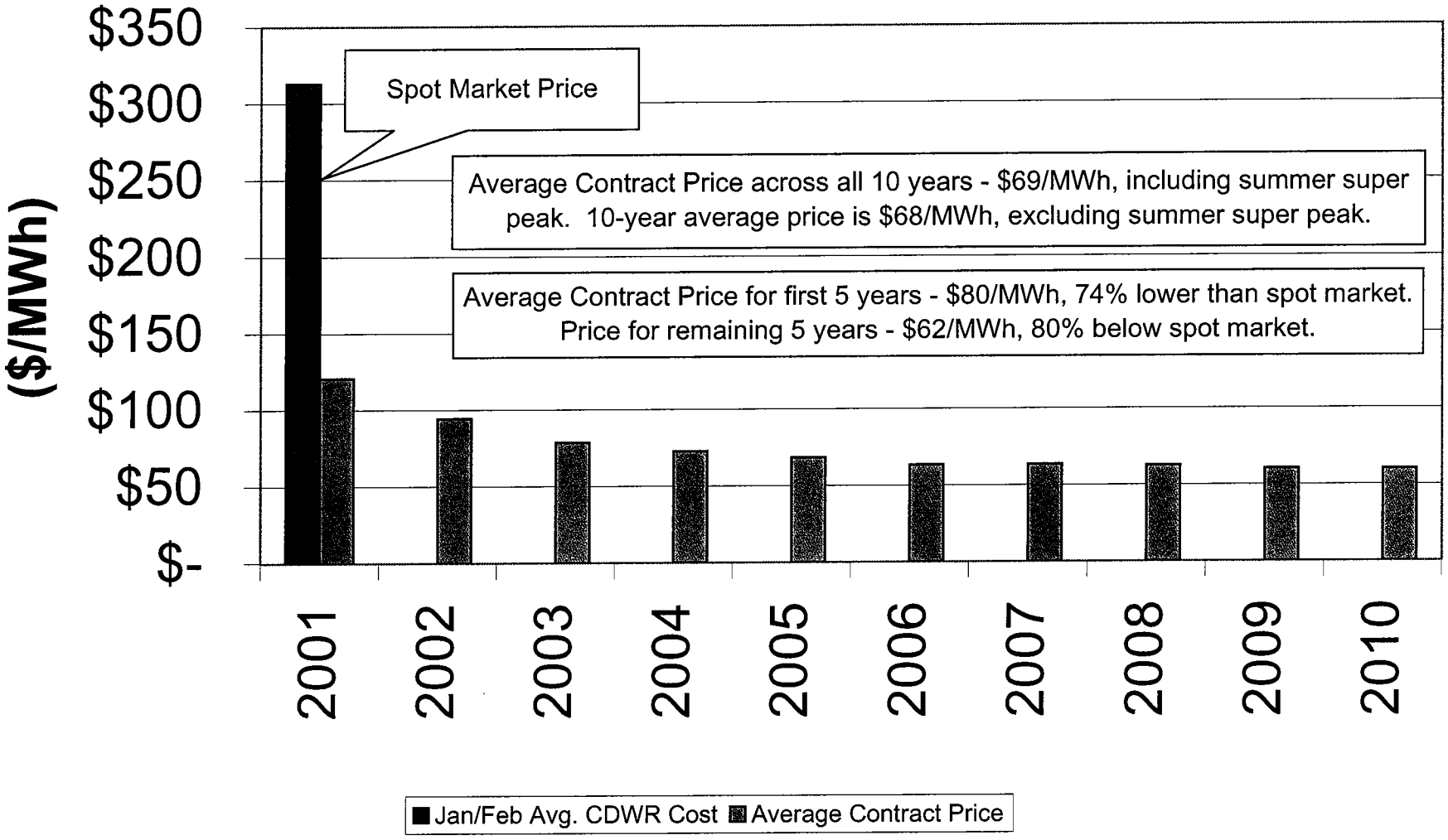
DRAFT

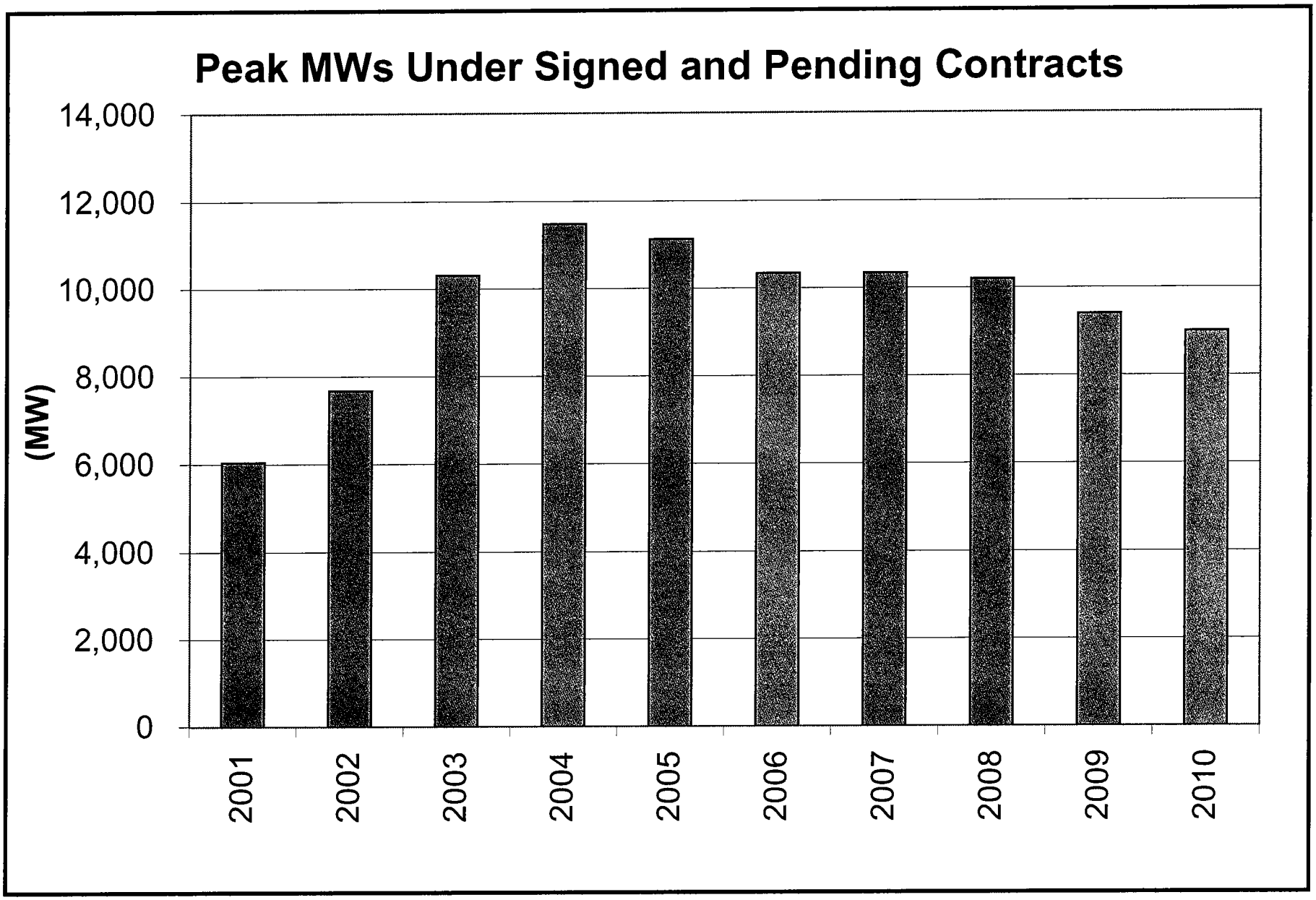
	GENERAL TERMS										STATUS		
Bidder	Start	Term	Product	Price ($/MWh)	MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10	Submitted	Agreement in Principle	Signed Contract
Executed Contracts													
El Paso	2/9/01	5 yr	Peak	$115.00	50	50	50	50	50		2/6/01	2/7/01	2/13/01
El Paso	2/9/01	5 yr	Peak	$127.00	50	50	50	50	50		2/6/01	2/7/01	2/13/01
BPA	2/13/01	14 mos	Base	$55.00	12	18							2/1/01
Morgan Stanley	2/15/01	5 yr	Base	$95.50	50	50	50	50	50		2/6/01	2/7/01	2/20/01
BPA	2/20/01	Bal. '01	Op. Res.	TBD	Unspec.						2/9/01	2/14/01	2/20/01
Enron	2/23/01	3/30/06	Peak	$127.00	200	200	200	200	200		2/6/01	2/7/01	2/22/01
Dynegy	3/1/01	Bal '01	Peak	$96.50	1000						2/22/01	2/23/01	3/2/01
Dynegy	3/1/01	Bal. '01	OffPeak	$96.50	*						2/22/01	2/23/01	3/2/01
Williams 1-Prod B1	4/1/01	10 yr	Peak	$87.00	175	200	250	250	300	300	2/5/01	2/6/01	2/21/01
Williams 2-Prod B2	6/1/01	4.5 yr	Peak	$62.50	140	160	240	320	400		2/9/01	2/9/01	2/21/01
Williams 3-Prod A,C	6/1/01	9.5 yr	Base	$62.50	35	40	60	80	100	600	2/9/01	2/9/01	2/21/01
Calpine 2	7/1/01	9.5 yr	Base	$61.00	200	1000	1000	1000	1000	1000		2/21/01	2/27/01
Calpine 3	8/1/01	20 yr	Peak	$164-$154	90	495	495	495	495	495		2/21/01	2/27/01
Calpine 1	10/1/01	10 yr	Base	$58.60	200	350	600	1,000	1,000	1,000	1/24/01	2/6/01	2/6/01
Dynegy	1/1/02	3 yr	Base	$119.50		200	200	200			2/22/01	2/23/01	3/2/01
Dynegy	1/1/02	3 yr	Peak	$119.50		600	600	600			2/22/01	2/23/01	3/2/01
Dynegy	1/1/02	3 yr	Peak	$96.50		1,500	1,500	1,500			2/22/01	2/23/01	3/2/01
Dynegy	1/1/02	3 yr	OffPeak	$96.50		*	*	*			2/22/01	2/23/01	3/2/01
Williams Prod B3	1/1/03	8 yr	Peak	$62.50			500	500	500	500			2/21/01
MW-Subtotal					**2,202**	**4,913**	**5,795**	**6,295**	**4,145**	**3,895**			
# Contracts-Subtotal				**8**							(some multi-product contracts)		
Legal Dept.													
name redacted	3/1/01	10 yr	Pk/Base	$61.00	250	250	250	500	1,000	1,000	2/12/01	2/26/01	
name redacted	3/1/01	4 mos	Base	85% COB	41						2/9/01	2/12/01	
name redacted	4/1/01	2.25 yr	Peak	$148	200	200	200				2/27/01	2/28/01	
name redacted	4/1/01	3 yr	Base	$80-$85	13	13	13				2/6/01	2/15/01	
name redacted	6/1/01	2.5 yr	Base	$100-$90	16	16	16				2/6/01	2/7/01	
name redacted	6/1/01	10.3 yr	Peak	$150-$75	300	255	350	400	400	400		2/28/01	
name redacted	7/1/01	10 yr	Base	$95-$60	100	200	200	400	400	400	2/9/01	2/12/01	
name redacted	1/1/02	9 yr	Base	$65.75-$35		300	300	300	300	300	1/24/01	2/28/01	
name redacted	1/1/02	9 yr	Base	$74.25-$35		250	500	500	500	500	1/24/01	2/28/01	
name redacted	4/1/02	9.5 yr	Base	$110-$59		220	1,000	1,200	1,200	1,200		2/28/01	
name redacted	7/1/03	8.25 yr	Base	$58.00			745	745	745	745	2/27/01	2/28/01	
MW-Subtotal					**920**	**1,704**	**3,574**	**4,045**	**4,545**	**4,545**			
# Contracts-Subtotal				**7**							(some multi-product contracts)		
TOTAL MWs (signed/legal)					**3,122**	**6617**	**9,369**	**10,340**	**8,690**	**8,440**			
TOTAL # CONTRACTS (signed/legal)				**15**									
Agreement in Principle (credit and other terms under in negotiation)													
name redacted	3/1/01	4 mos	Base	$185.32	100						2/12/01	2/15/01	
name redacted	3/1/01	Bal. '01	Peak	est $100	525							Jan	
name redacted	4/1/01	Bal. '01	Peak	est $100	925							Jan	
name redacted	4/1/01	1.5 yr	Peak	Exchange	400	400					2/23/01	2/26/01	
name redacted	7/1/01	5 yr	Pk/Base	$180-$60	450	450	450	450	450		2/16/01	3/2/01	
name redacted	7/1/01	7.5 yr	Peak	$86-$135	100	300	500	500	800	800	3/2/01	3/2/01	
name redacted	7/15/01	17 mos	SSPeak	$141.30	325	325					2/15/01	3/2/01	
name redacted	8/1/01	10 yr	Sum. Peak	$270.00	80	80	80	80	80	80		2/26/01	
name redacted	9/1/01	6 yr	Peak	$171-$118	142	142	142	142	142	142		2/27/01	
name redacted	9/1/01	10 yr	SSPeak	$200-$152	48	96	96	96	96	96		2/28/01	
name redacted	9/1/01	10 yr	SSPeak	$200-$152	96	144	144	144	144	144		2/28/01	
name redacted	1/2/02	9 yr	Base	$99-$50		50	100	100	100	100	2/6/01	2/7/01	
name redacted	11/1/01	10 yr	Peak	$118-$113	48	96	96	96	96	96		2/28/01	
name redacted	11/1/01	10 yr	Peak	$118-$113	96	144	144	144	144	144		2/28/01	
name redacted	6/1/03	8 yr	Base	$58.50			542	542	542	542	2/15/01	3/2/01	
MW-Subtotal					**3,335**	**2,227**	**2,294**	**2,294**	**2,594**	**2,144**			
# Contracts-Subtotal				**9**							(no BFM contract)		
TOTAL MW (signed/legal/agreed)					**6,457**	**8,844**	**11,663**	**12,634**	**11,284**	**10,584**			
TOTAL # CONTRACTS (s/l/a)				**24**									

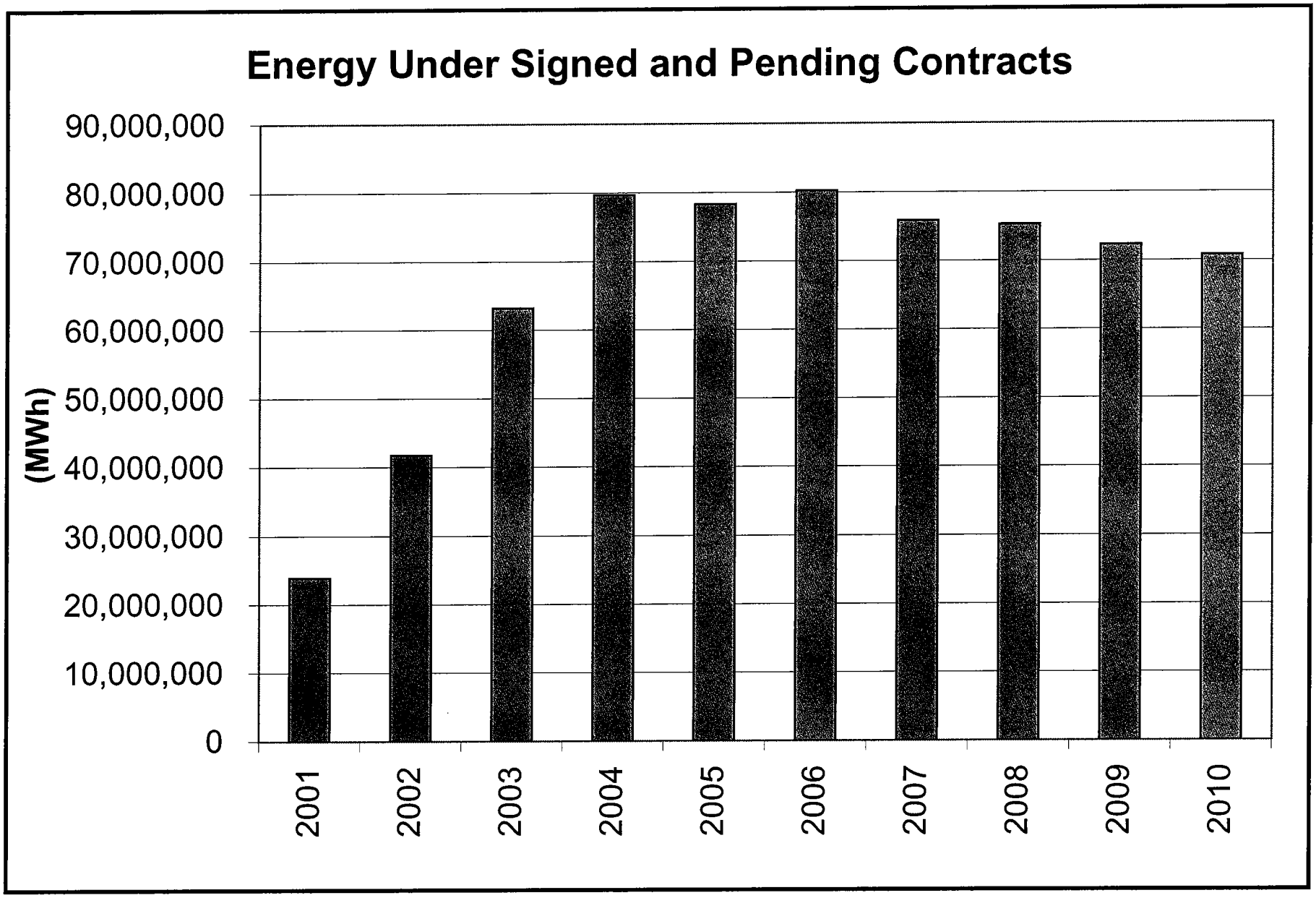
Additional details are available on the Detail Sheet.

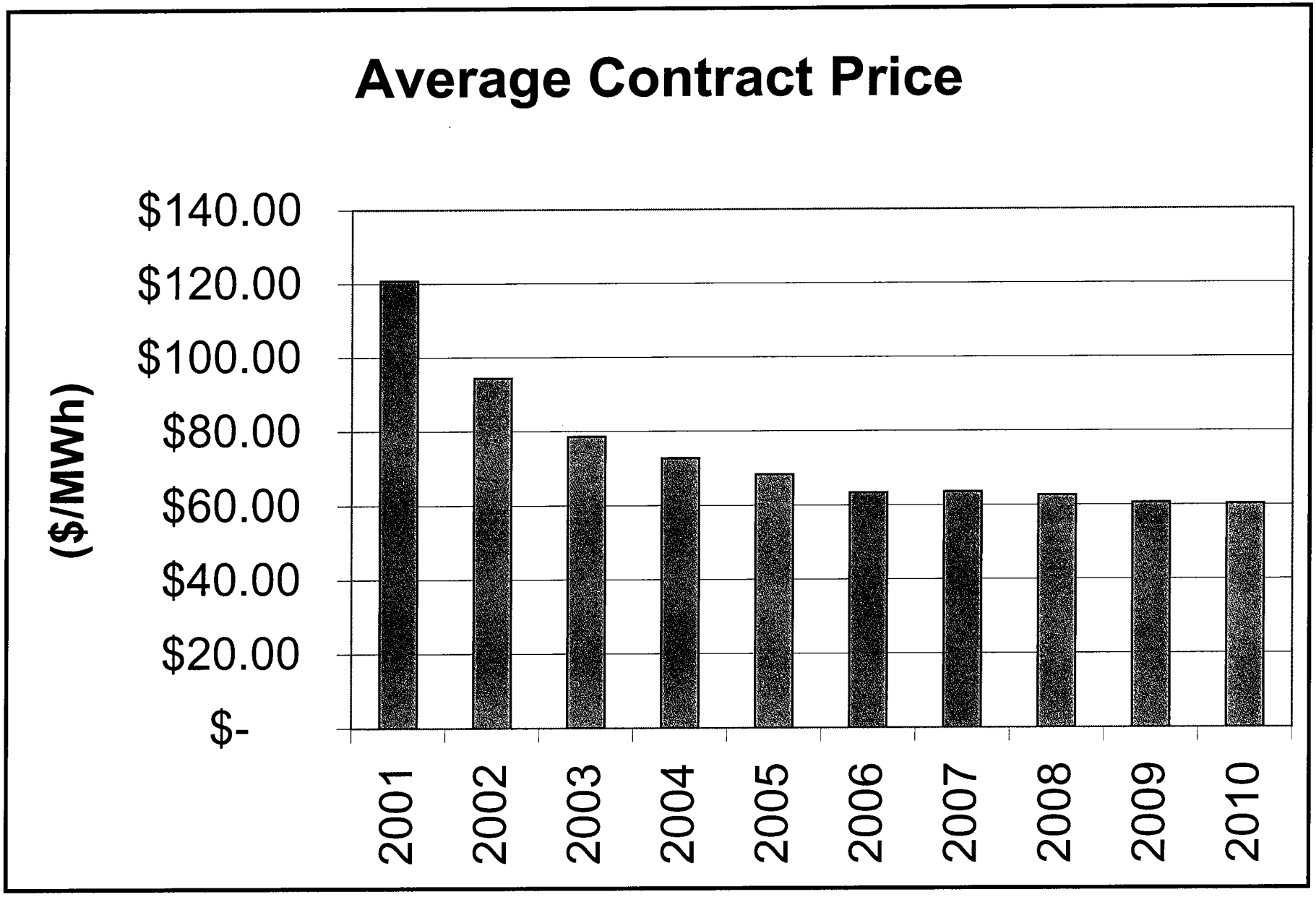

Statewide Annual Energy Net Short (MWh)
and Contract Energy
Initia Net Short
(MWh/yr)
90,000,000
80,000,000
70,000,000
60,000,000
50,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Executed
Legal
Agreed

Contract Price vs. Spot Market Price




Peak MWs Under Signed and Pending Contracts
(MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010


Energy Under Signed and Pending Contracts
(MWh)
90,000,000
80,000,000
70,000,000
60,000,000
50,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010


Average Contract Price
($/MWh)
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 33

Attorney General's Letter

1300 I STREET, SUITE 125
P.O. BOX 944255
SACRAMENTO, CA 94244-2550

Telephone: (916) 445-1939
Facsimile: (916) 323-5317
E-Mail: BentusM@doedojnet.state.ca.us

February 28, 2001

Dave Rosenberg,
Director of Intergovernmental Relations and Senior Adviser to the Governor
Office of the Governor
State Capitol
Sacramento, CA 95814

Dear Mr. Rosenberg:

The Governor's Office has sought the Attorney General's opinion on the following question: Under the terms of AB 1X, can the Department of Water Resources (DWR) enter into contracts to buy natural gas for use by generators with which DWR has contracted to purchase electric power? We conclude that DWR may enter into such contracts.

DISCUSSION

Chapter 2, commencing with new Water Code Section 80100, authorizes the following activities relevant to this question:

> 80012. The department shall do those things *necessary and authorized* under Chapter 2 (commencing with Section 80100) to make power available directly or indirectly to electric consumers in California. . . .
>
> 80100. . . . [T]he department may contract with any person, local publicly owned electric utility, or other entity for the purchase of power. . . .
>
> (a) *The intent of the program described in this division is to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatthour.*
>
> 80102. (a). . . .
>
> (b) Any contract for the purchase or sale of electric power shall contain *any contractual terms* and security provisions *as are determined by the department to be necessary or appropriate and the department may enter into such arrangements as may be necessary or appropriate to implement the foregoing.*
>
> 80116. The department may sell any power acquired by the department pursuant to this division to retail end use customers, and to local publicly owned electric utilities, at not

more than *the department's acquisition costs, including transmission, scheduling, and other related costs*, plus other costs as provided in Section 80200....

80122. The department may do any of the following as may be, in the determination of the department, necessary for the purposes of this division:

(a) Hire and appoint employees as required....

(b) Engage the services of private parties to render professional and technical assistance and advice and other services in carrying out the purposes of this division.

(c) Contract for the services of other public agencies.
****

80132. (a) Bonds may be issued by the department....

(b) ... The department may enter into such contracts or arrangements as it shall deem to be necessary or appropriate for the issuance and further security of the bonds.

80134. (a) The department shall. . . establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:. . . .(2) The amounts necessary to pay for power purchased by it and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and *other related expenses incurred by the department*. . . .

80200. (a) There is hereby established in the State Treasury the Department of Water Resources Electric Power Fund [which]... shall be available for the purposes of this division....

(b) ... Payments from the fund may be made only for the purposes authorized by this division, including, but not limited to, payment for any of the following:

(1) The cost of electric power and transmission, scheduling, and *other related expenses incurred by the department.*

The announced legislative purpose of AB 1X was to give DWR authority to meet the electric energy crisis, and thereby protect the "safety, health, and well-being of the people of California," by purchasing electrical power in a "reliable" and "reasonably priced" way. Section

80000, subd. (a); see also Section 80100, subd. (a) ("reliable service at the lowest possible price per kilowatthour"). The Legislature also expressly directed that AB 1X be "construed in a manner so as to effectuate the purposes and objectives thereof." Section 80003, subd.(3).

AB 1X authorizes DWR to contract for the purpose of purchasing electric power for "retail end use customers being served by electrical corporations." Section 80002.5. The fund and bond financing schemes established under AB 1X allow for payment both of the cost to DWR of electric power and transmission, and of "related expenses incurred" by DWR in fulfilling its duties. See Sections 80200, subd. (a), (b) (1); 80134, subd. (a)(2).

If California citizens are able to secure electric power reliably and reasonably priced through DWR's ability to buy and supply natural gas to electric power generators, then AB 1X authorizes such purchases as expenses related to the purchase of electric power, notwithstanding the absence in AB 1X of reference to natural gas purchasing or other technical details of procuring electric power.

The broad language of the statute is consistent with that conclusion. Section 80012 reads: "The department [DWR] shall do those things *necessary* and authorized under Chapter 2 (commencing with Section 801000) to make power available directly or indirectly to electric consumers in California." (Emphasis added.) Because the ability of DWR to secure natural gas for use by generators in producing electric power allows DWR to obtain reasonably priced electric power for electric consumers, it follows that its purchase is necessary and authorized. In addition, it is noteworthy that any natural gas which DWR purchases would not be for distribution to retail end use consumers, for whom the Legislature intended DWR to acquire only

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electric power. Accordingly, nothing in DWR's purchase of natural gas for use by generators in producing electric power is incompatible with the express intent or language of AB 1X.

Sincerely,

MORRIS BEATUS
Senior Assistant Attorney General

For BILL LOCKYER
Attorney General

BILL LOCKYER
Attorney General

State of California
DEPARTMENT OF JUSTICE

1300 I STREET, SUITE 125
P.O. BOX 944255
SACRAMENTO, CA 94244-2550

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December 4, 2001

William Kissinger
Governor's Legal Affairs Office
Office of the Governor
State Capitol
Sacramento, CA 95814

RE: Attorney General's Opinion Regarding Authorization of Department of Water Resources under AB 1X to Enter into Certain Contractual Arrangements

Dear Mr. Kissinger:

The Governor's Office has requested the Attorney General's opinion on whether the Department of Water Resources ("DWR") is authorized under AB 1X[1] to enter into certain contractual arrangements for procuring natural gas in connection with tolling agreements that permit or require DWR to furnish natural gas to generators for use in generating electricity for sale to DWR. The reasoned expectation is that these agreements will reduce the overall cost of DWR's purchase of electric energy. The contractual arrangements in issue include the purchase, sale, transportation, storage of physical gas for use in electric generation, with its cost of transportation and storage, as well as various financial agreements for hedging by way of gas futures, swaps, and options to manage gas price and associated volumetric risk and volatility.

SUMMARY

It is the opinion of the Attorney General that AB 1X authorizes DWR to enter into and pay the costs of such contractual arrangements in accordance with accepted industry practice for prudently managing a natural gas portfolio directed to securing reliable reasonably priced electric power, provided that any hedge arrangements are for the purpose of managing price, volumetric risk, and volatility, and not for speculative or other purposes unrelated to the purchase of reasonably priced electric power.

[1] Assembly Bill 1 of the 2001-2002 First Extraordinary Session.

DISCUSSION

AB 1X requires DWR to purchase electric power to supply the unmet demand of utility customers throughout California. The purpose of delegating that authority to DWR is to furnish "reliable *reasonably priced* electric service . . . essential for the safety, health, and well-being of the people of California." Water Code, §80000(a) (emphasis added). The rapid and substantial increase in electric wholesale costs and retail rates at the time AB 1X was enacted constituted an immediate "peril" to those essential state interests. *Id.*

The legislative response was to provide DWR with authority to contract for the purchase of power "at such prices the department deems appropriate," Water Code, §80100, taking into account several factors, including achieving an overall portfolio of contracts for energy resulting in "reliable service at the lowest possible price per kilowatthour," subd.(a), the desire to secure as much low-cost power as possible under contract, the duration and timing of contracts made available from sellers, and the desire to secure as much firm and non-firm renewable energy as possible. Subd. (b)-(f).

AB 1X also provides finance mechanisms, enabling DWR both to pay for the power it purchases and delivers to purchasers, and to cover the costs of "other *related expenses* incurred by the department." Water Code, §80134(a)(2)[bonds]; §80200(b)(1)[Electric Power Fund](emphasis added). Although the "related expenses" are not defined, AB 1X expressly directs that the provisions establishing DWR authority to buy electric power "be construed in a manner so as to effectuate the purposes and objectives [of the division]." Water Code, §80003(b). Again, those purposes and objectives are directed to securing "reliable reasonably priced electric service . . . essential for the safety, health, and well-being of the people of California." Water Code, §80000(a).

In addition to expressly authorizing DWR's related expenses for reasonably priced electric power, AB 1X contains legislative reference to the significance of industry practice, and expressly recognizes that "for the department to adequately and expeditiously undertake and administer the critical responsibilities established in this division, it must be able to obtain . . . *personnel with requisite expertise and experience in energy marketing*, energy scheduling, and accounting." Water Code, §80000(b)(emphasis added).

We note at the outset that the law affords deference to a state agency exercising its legislatively imposed responsibilities, as it does to the agency's presumed expertise in executing the duties within the scope of that authority and to the regularity attaching to the agency's actions. *See California Hotel & Motel Assn. v. Industrial Welfare Com.*, 25 Cal.3d 200, 212 (1979). It is appropriate, therefore, to conclude that DWR acts within the authority granted under AB 1X in determining, based on industry practice, that the most prudent way to obtain reliable and reasonably priced electric power, under specific circumstances, is through tolling agreements by which DWR purchases natural gas to supply generators for producing electricity that DWR will then buy. Assuming, as is reasonable, that the cost of natural gas for this purpose

is a related expense authorized under AB 1X for reasonably priced electric power, it follows that AB 1X also authorizes natural gas portfolio management if, by "means of expertise and experience in the energy market," DWR concludes that it is prudent to secure reasonably priced electric power by hedging its price exposure on natural gas in relation to the electric power supply contracts. While the Attorney General cannot render an opinion on prudent industry practice, or the specific application of such practice to the circumstances that confront DWR in managing its natural gas portfolio, it is apparent that DWR is acting consistent with the language and intent of AB 1X by following a recognized market practice of spreading risk by hedging.

CONCLUSION

In summary, nothing in AB 1X appears to preclude natural gas portfolio management, by which DWR enters into a wide range of agreements, with a variety of market or tariff mandated provisions, pertaining to the purchase, sale, transportation, storage or hedging of physical gas for use in electric generation. DWR has the authority under AB 1X to enter into and pay the costs of such contractual arrangements in accordance with accepted industry practice for prudently managing a natural gas portfolio directed to securing reliable reasonably priced electric power, provided that any hedge arrangements are for the purpose of managing price, volumetric risk, and volatility, and not for speculative or other purposes unrelated to the purchase of reasonably priced electric power.

Sincerely,

MORRIS BEATUS
Senior Assistant Attorney General

For BILL LOCKYER
Attorney General

MB:AJ

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 34

Contract Approval Form and Template

(CONFIDENTIAL - INTERNAL USE ONLY)		
Executed Contract Distribution – (Cindy or Support to Distribute upon execution)		
1) Management – Original – Ray Hart	2) Scheduling/Operations – Pete Garris	3) Negotiations – RNichols/DJacinto
4) Finance/Acct/Sttlmts – Jerry Green	5) Risk Mgmnt – Rjohnson, KStevens	6) Legal – Susan Weber

CDWR Contract Summary
Cover Sheet For Ray Hart's Approval

Negotiator Sign-off_____**Date**_____
(Vikram/Nichols) **Print Name**_____

DWR Legal Review/Sign-off_____**Date**____
(O'Brien) **Print Name**_____

DWR Scheduling/Sign-off_____**Date**____**ONLINE DATE**
(Pete Garris) **Print Name**_____ |_____|

Coordination/Sign-off_____**Date**____
(Dick Ferreira) **Print Name**_____

Risk Managment/Sign-off_____**Date**____
(Kim Stevens) **Print Name**_____

LEAD NEGOTIATOR - _____Reachable Phone#_____
Print name only

Recommendation:

Contract Name/Title:

Quantity:

Product
(Base, Peak, Shaped, Dispatchable:

Term:

Issues of Note:

CDWR CERS
General Contract Summary Form

CONFIDENTIAL
INTERNAL USE ONLY

Counterparty	
Date of Execution	
Internal Contract No.	
External Contract No.	
Enabling Agreement (EEI, WSPP, or other)	
Term	
Start Date	
Receipt Point	
Delivery Point	
Generation Development Project ?	
Unit Location	
Site Land Rights Status	
Interconnection Status	
Gas Pipeline Capacity/Transportation Status	
Permitting Strategy/Regime	
Permitting Status	
Emissions Levels Through May 2002	
Emissions Levels Beginning June 2002	
Product	
Description (TOU Blocks, or # of Dispatchable Hours and Start-Ups)	
Volume	
Firmness	
Units	
Resource Type	
Alternate Supply Source	
Exchange? (if yes, see Exchange section)	
Pricing	
Fixed and Flat Price	
Fixed per Schedule Prices	
Floating on Electricity Index (specify)	
Fuel Pass-Through Quantity	
Actual	
Actual with Heat Rate Cap (specify)	
Fixed Heat Rate (specify)	
Fuel Pass-Through Price (actual or specify index)	
Natural Gas Transmission and Handling Costs	
Capacity Charge	
Capacity Penalty/Bonus vs. Comm'l Ops Date	
Emissions Costs	
Variable O&M, specify any escalation rate	
Start-Up Costs	
No Load Costs	
Fuel Procurement	
Initial Responsible Party	
CDWR Planning Option with Counterparty	
CDWR Procurement Option	
Scheduling	
CDWR Minimum Take	
CDWR Optional Take	
CDWR Dispatch Flexibility	
Counterparty's Optional Put	
Contract Availability Factor	
Operational Requirements	
Start-Up Notification Time	
Minimum Run Time	
Maximum Run Time	
Ramp Rate	
Counterparty's Scheduling Coordinator	
Party With Risk for Seller's Imbalances	
Scheduling Time Zone	
Scheduling Notification Time	
Schedule Change Notification Time	
Settlement Terms	
Transmission--General	
Transmission Curtailment Provisions	
Transmission Scheduling Requirements	
Transmission--Import Mechanisms	
Specify Tie	
Party Responsible for Transmission Rights	
Counterparty's Transmission Rights (FTR, as-available, or none)	
Tie Capability (inbound and outbound)	
Exchange Terms	
Exchange Rate (MWh:MWh)	
Minimum Capacity on Exchange Returns	
Maximum Capacity on Exchange Returns	
Return Delivery Point	
Alternate Return Delivery Point	
Term of Exchange Returns	
Time Periods of Exchange Returns	

CDWR CERS
General Contract Summary Form

Counterparty	
Other	
Conditions Precedent	
Governing Law	
Most Favored Nation Provision re: credit	
Billing Schedule	
Remedy Payment Acceleration	
Environmental or Seasonal Resource Constraints	
NOx limits	
Environmental Upgrades	
Governmental Charges	
Additional Potential Charges	
Guarantee Provision	
Performance Bond Provision	
Force Majeure Changes from EEI	
CDWR Credit Issues	
Termination Rights	
Termination Payments	
Covenants	
Other	

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 35

Methods/Assumptions for Estimating Net Short Energy

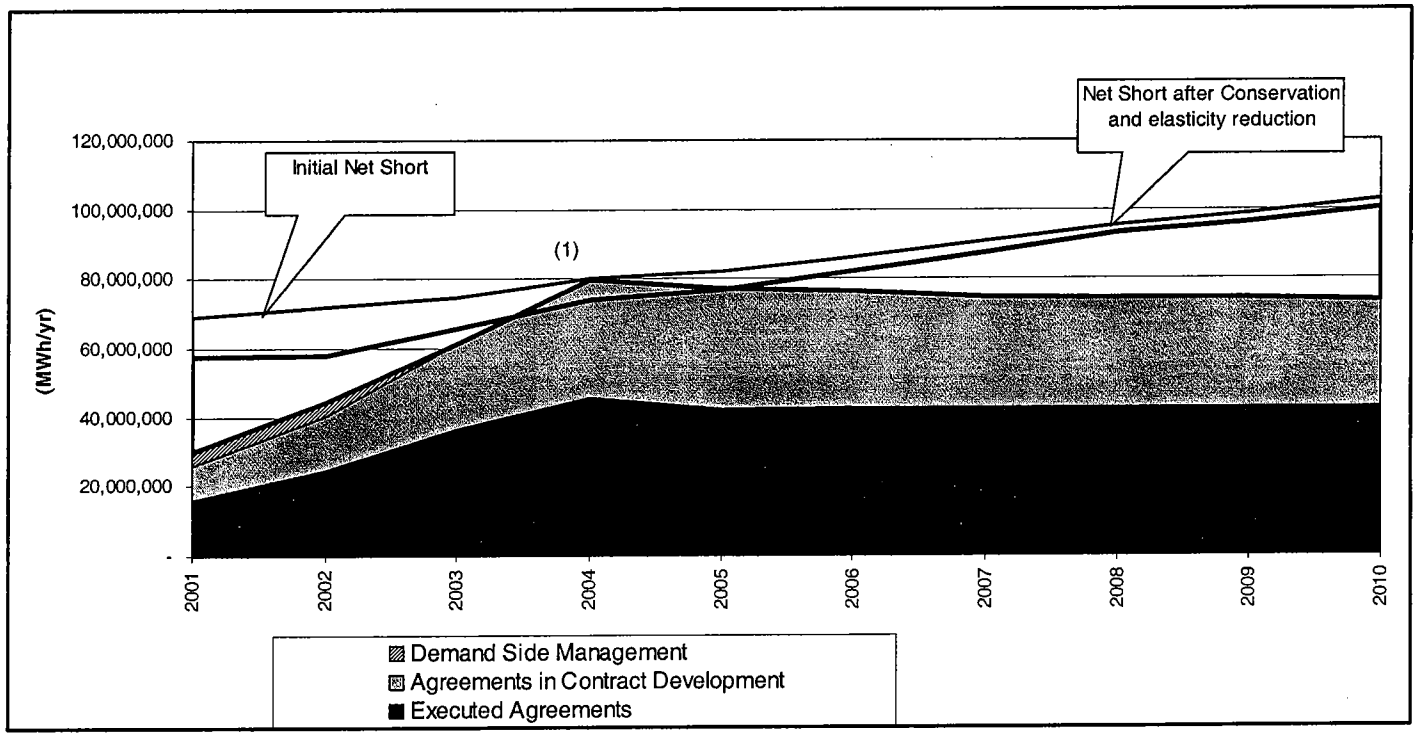
Methods and Assumptions for Estimating the Revenue Requirement for Net Short Energy Purchases

Navigant Consulting/Montague DeRose

Definition of Net Short Energy Requirements

- Net Short is the difference between:
  - Total electrical loads of the three investor-owned utilities ("IOUs"), and
  - The combined energy production of:
    - IOU's remaining owned generation (nuclear, hydro and some fossil fueled)
    - Qualifying Facility ("QF") output
    - Remaining bilateral power purchase agreements between the IOUs and others
- Figure 1 presents the estimated annual quantity of net short energy purchases compared to expected quantities of CDWR's energy purchase under long-term contracts

Figure 1
Statewide Annual Energy Net Short (MWh) and Contract Energy



Note:

- Some portion of the energy presented in this curve is dispatchable and would not be called upon for operation if the net short energy needs are less than available contract delivery quantities.
- 2001 based on March through December data.

Source of Net Short Energy Requirements Estimate

- CDWR retained independent, professional energy consultants (Navigant Consulting) to develop estimate of net short requirements
- Baseline data provided by Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE"), San Diego Gas and Electric ("SDG&E") and California Independent System Operator ("ISO")
- Forecasts were modified to develop consistent estimated hourly and day of the week net short energy needs, for each month from 2001 through 2010
- Net short energy requirements after 2003 extrapolated from adjusted 2001-2003 forecasts
- Forecasts were adjusted for conservation, QF availability on line and hydroelectric generation production assumptions

Adjustments to IOU Load Estimates

- Prior to adjustment, forecasts assumed approximately 2 percent annual growth in demand
- The base level forecasts were reduced based upon an assumed 4 percent conservation in demand in all hours due to observed customer behavior year-to-date 2001
- Based on announced retail electric rate increase of approximately 30 percent, assumed 3 percent incremental reduction in demand as of June 1, 2001 for price elasticity effects
- 4 percent observed conservation and 3 percent reduction in loads due to price elasticity are assumed to decrease after 2002 as shown in Table 1

Impacts of Qualifying Facility Production on Net Short

- Approximately 35 percent of firm QF capacity estimated to be off-line at present
- Based on California Public Utilities Commission ("CPUC") March 27, 2001 change to QF contract pricing, assumes approximately one half of capacity off-line returns to service during May 2001
- Assumes June 2001 through 2010 that 90 percent of QF capacity returns to service (as shown in Table 1)

Table 1
Adjustments to Net Short for Non-Programmatic Conservation and Qualifying Facility Production Variation

	Conservation & Load Curtailments		
	Conservation	Price Demand	Assumed MW of QF Outages
Apr '01	4.0%	0.0%	1,800
May'01	4.0%	0.0%	950
Jun '01	4.0%	3.0%	600
Jul '01	4.0%	3.0%	600
Aug '01	4.0%	3.0%	575
Sep '01	4.0%	3.0%	560
Oct '01	4.0%	3.0%	535
Nov '01	4.0%	3.0%	535
Dec '01	4.0%	3.0%	535
Jan '02	4.0%	3.0%	535
Jan '03	3.0%	1.5%	535
Jan '04	2.0%	1.0%	535
Jan '05	2.0%	0.5%	535
Jan '06	2.0%	0.0%	550
Jan '07	1.5%	0.0%	570
Jan '08	1.0%	0.0%	570
Jan '09	1.0%	0.0%	560
Jan '10	1.0%	0.0%	560

Components of CDWR Purchases to Meet Net Short Requirements

- Long-term contracts (executed and agreement in principle)
- Conversion of California Independent System Operator ("CAISO") Summer Reliability Agreements to CDWR bilateral contracts
- Implementation of the "20/20" and other conservation programs (2001-2002) (See Table 2)
- CAISO, IOU and/or CDWR voluntary economic load curtailment programs to reduce net short energy requirements (2001-2002) (See Table 2)
- Additional long-term energy purchases which could be entered into by CDWR
- Balance of month, day-ahead, and intra-day purchases in the short-term or spot market

Table 2
Total Peak Demand Reduction Impacts-Summer 2001
Assumed as Part of Means to Meet Net Short Energy Requirements

Peak Demand Impact (MW)	Price Rolled-in $/MWh	Program	Comments
1620	$575	CA ISO Discretionary Load Curtailment Programs (DLCP)	ISO pays for energy curtailed only, no capacity payment; designed for load aggregators
596	$500 + monthly fixed fee	CA ISO Demand Relief Program (DRP)	ISO pays for capacity and curtailed energy
268	$708	CA ISO Back Up Generation Program (BUG)	ISO pays for capacity and energy produced
2,200	$100	20/20 Program	Expected maximum available load reduction over peak periods
1,100	No cost	3% reduction due to approx. 30% increase in rates 20/20 Program	Elasticity estimate consistent with SDG&E experience last year (beginning June 2001)
1,450	No cost	4% customer conservation	Portion of observed year-to-date reduction in load relative to last year
7,234			Total

Key Assumptions and Considerations

- First quarter required virtually all spot purchases with additional QFs off line and State required to purchase shortfall
- Actual contracted power increases with each quarter
- Additional power plants come on line with each quarter, increasing supply
- Conservation programs begin and increase in effectiveness between Spring and Summer
- Load management programs implemented Summer 2001 and 2002 to reduce "on-peak" energy purchases
- QFs return to market progressively through the year
- Price elasticity from rate increase begins Summer 2001
- Net short purchase prices assumed to be higher 2nd & 3rd quarters but the net short spot purchases have diminished as a percent of total purchases
- Longer term prices based increasingly upon negotiated prices already in place

Prices for Short-Term Energy Purchases

- Quantities of energy remaining to be met after CDWR's long-term contracts and conservation/load management are quantified
- Prices established for standard full peak 6X16 period (6 days/week, 16 hours/day peak), off-peak period, and "super peak" hours
- Short-term purchases reflect available energy production sources, and estimated gas prices in the California market
- Resultant prices shown in Table 3

Summary of Forecasted Net Short Prices

Table 3 details, for each quarter, the following:

- Estimated statewide net short energy requirements and average price/MWh
- Energy purchases under contract and block forward purchases (quantity and average price based on contract terms)
- Energy purchases in short-term market, not presently under contract (quantity and average price based on a range of hourly spot market prices and block forward purchases)
- 2001 first quarter prices are actual purchases
- Third quarter 2001 lower non-contracted prices reflect reduced on-peak spot market purchases due to conservation, peak load curtailment and greater on-peak, long-term purchases at lower cost in Q3 compared to Q2 and Q4
- Figure 2 provides statewide, all-in average price taking into account both contract and short-term, non-contract power purchases

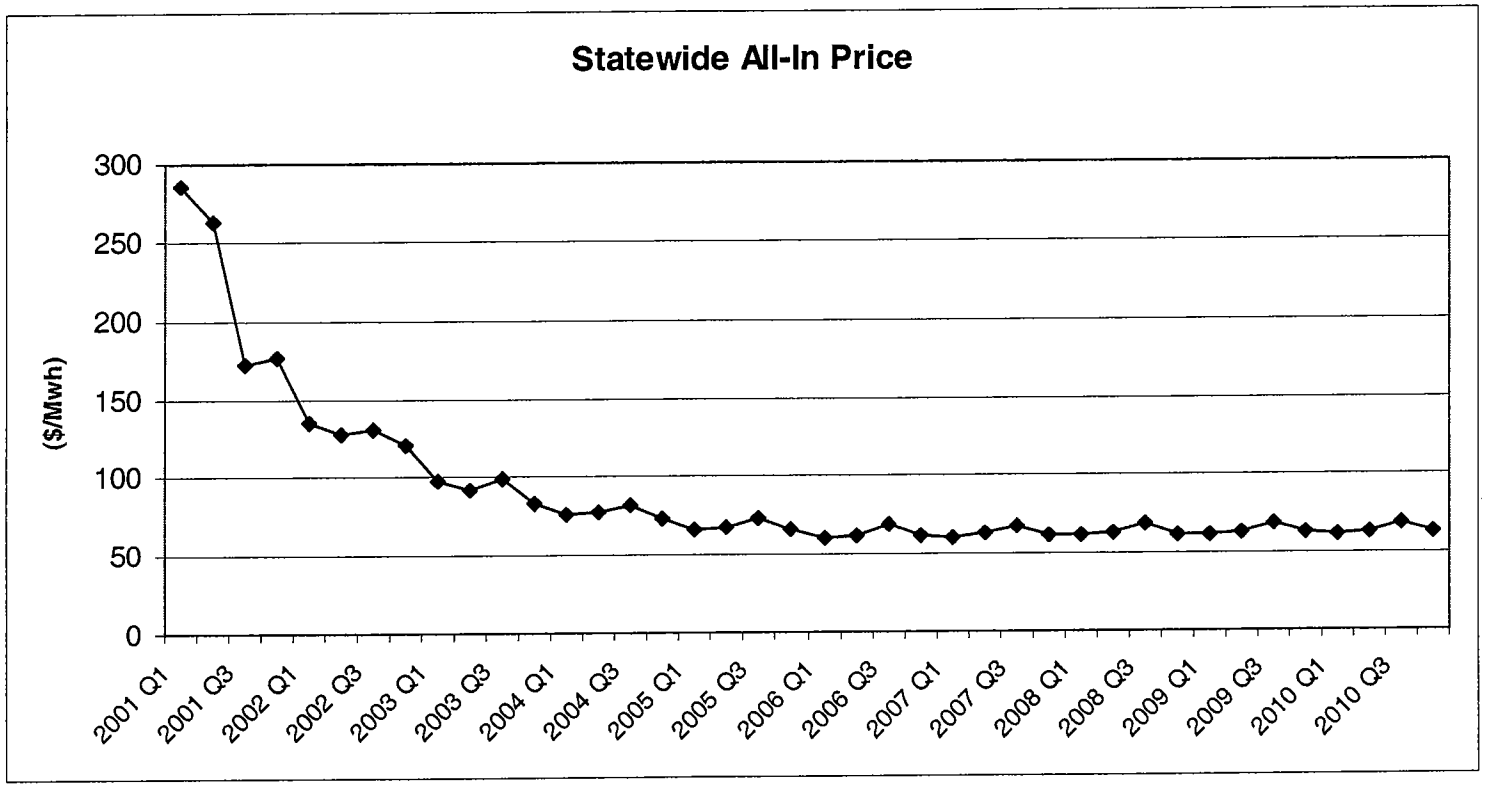
Table 3
Summary of Forecasted Net Short Costs

	Total			Contracted			Non-Contracted		
	Mwh	Total Cost ($1000s)	Avg Price ($/Mwh)	Mwh	Cost ($1000s)	Avg Price ($/Mwh)	Mwh	Cost ($1000s)	Avg Price ($/Mwh)
2001 Q1*	13,308,000	$ 3,798,465	$ 285	N/A	N/A	N/A	N/A	N/A	N/A
Q2**	17,301,661	$ 4,550,488	$ 263	6,835,030	$ 925,468	$ 135	10,466,630	$ 3,625,020	$ 346
Q3**	21,250,889	$ 3,672,830	$ 173	8,241,181	$ 1,139,357	$ 138	13,009,708	$ 2,533,473	$ 195
Q4	17,494,520	$ 3,089,072	$ 177	7,583,534	$ 943,565	$ 124	9,910,986	$ 2,145,508	$ 216
2002 Q1	13,607,508	$ 1,835,879	$ 135	8,874,797	$ 887,776	$ 100	4,732,711	$ 948,103	$ 200
Q2	15,078,598	$ 1,921,541	$ 127	9,736,927	$ 1,036,213	$ 106	5,341,672	$ 885,328	$ 166
Q3	21,547,911	$ 2,822,880	$ 131	12,466,863	$ 1,399,825	$ 112	9,081,049	$ 1,423,056	$ 157
Q4	18,261,734	$ 2,213,642	$ 121	11,408,290	$ 1,059,733	$ 93	6,853,444	$ 1,153,909	$ 168
2003 Q1	16,026,397	$ 1,564,767	$ 98	12,528,699	$ 1,085,280	$ 87	3,497,698	$ 479,487	$ 137
Q2	16,532,781	$ 1,524,643	$ 92	13,862,979	$ 1,211,480	$ 87	2,669,802	$ 313,163	$ 117
Q3	24,085,451	$ 2,371,656	$ 98	18,336,722	$ 1,681,729	$ 92	5,748,729	$ 689,927	$ 120
Q4	22,311,602	$ 1,857,746	$ 83	19,737,558	$ 1,593,041	$ 81	2,574,043	$ 264,705	$ 103
2004 Q1	21,643,805	$ 1,657,445	$ 77	21,398,531	$ 1,635,107	$ 76	245,274	$ 22,338	$ 91
Q2	20,861,843	$ 1,612,648	$ 77	20,019,949	$ 1,536,004	$ 77	841,894	$ 76,644	$ 91
Q3	26,363,885	$ 2,154,408	$ 82	21,412,396	$ 1,732,516	$ 81	4,951,489	$ 421,892	$ 85
Q4	24,659,502	$ 1,803,294	$ 73	23,182,863	$ 1,704,610	$ 74	1,476,640	$ 98,683	$ 67
2005 Q1	21,135,169	$ 1,407,508	$ 67	20,750,188	$ 1,376,546	$ 66	384,980	$ 30,962	$ 80
Q2	20,467,158	$ 1,391,607	$ 68	19,542,403	$ 1,318,901	$ 67	924,755	$ 72,706	$ 79
Q3	27,079,042	$ 1,974,980	$ 73	20,486,838	$ 1,509,107	$ 74	6,592,204	$ 465,873	$ 71
Q4	24,684,859	$ 1,617,324	$ 66	21,060,134	$ 1,371,723	$ 65	3,624,725	$ 245,600	$ 68
2006 Q1	21,949,030	$ 1,317,674	$ 60	21,151,029	$ 1,251,999	$ 59	798,000	$ 65,676	$ 82
Q2	21,490,395	$ 1,324,871	$ 62	19,575,129	$ 1,174,242	$ 60	1,915,266	$ 150,629	$ 79
Q3	28,313,503	$ 1,931,735	$ 68	19,753,088	$ 1,322,665	$ 67	8,560,415	$ 609,070	$ 71
Q4	25,180,516	$ 1,559,486	$ 62	19,795,707	$ 1,176,044	$ 59	5,384,808	$ 383,442	$ 71
2007 Q1	21,684,137	$ 1,315,265	$ 61	19,359,819	$ 1,127,605	$ 58	2,324,318	$ 187,660	$ 81
Q2	22,053,673	$ 1,384,563	$ 63	18,428,604	$ 1,104,039	$ 60	3,625,069	$ 280,524	$ 77
Q3	29,732,503	$ 2,027,133	$ 68	19,684,263	$ 1,319,151	$ 67	10,048,240	$ 707,982	$ 70
Q4	26,183,861	$ 1,630,171	$ 62	19,591,520	$ 1,165,065	$ 59	6,592,341	$ 465,106	$ 71
2008 Q1	22,554,855	$ 1,381,569	$ 61	19,153,515	$ 1,112,987	$ 58	3,401,340	$ 268,581	$ 79
Q2	23,429,388	$ 1,478,193	$ 63	18,763,391	$ 1,121,144	$ 60	4,665,997	$ 357,049	$ 77
Q3	31,332,995	$ 2,145,275	$ 68	19,294,144	$ 1,288,971	$ 67	12,038,851	$ 856,304	$ 71
Q4	27,099,273	$ 1,683,304	$ 62	18,854,008	$ 1,103,942	$ 59	8,245,265	$ 579,362	$ 70
2009 Q1	23,076,526	$ 1,418,465	$ 61	18,797,465	$ 1,091,078	$ 58	4,279,061	$ 327,387	$ 77
Q2	24,316,954	$ 1,540,484	$ 63	18,709,911	$ 1,117,245	$ 60	5,607,044	$ 423,239	$ 75
Q3	32,144,744	$ 2,198,258	$ 68	19,293,801	$ 1,288,045	$ 67	12,850,943	$ 910,213	$ 71
Q4	27,451,467	$ 1,716,305	$ 63	18,779,557	$ 1,110,135	$ 59	8,671,910	$ 606,170	$ 70
2010 Q1	23,781,978	$ 1,474,505	$ 62	18,709,260	$ 1,091,336	$ 58	5,072,718	$ 383,169	$ 76
Q2	24,950,229	$ 1,587,113	$ 64	18,607,505	$ 1,116,706	$ 60	6,342,724	$ 470,407	$ 74
Q3	33,368,529	$ 2,301,222	$ 69	18,922,185	$ 1,272,959	$ 67	14,446,344	$ 1,028,263	$ 71
Q4	28,418,492	$ 1,804,358	$ 63	18,490,208	$ 1,098,810	$ 59	9,928,284	$ 705,548	$ 71

*Q1 is actual cost, virtually all of which was spot market purchases

**Average prices include a mixture of off peak, peak and super peak hours. 2001 Q2 and Q3 avg. super peak costs estimated at $435/MWh.

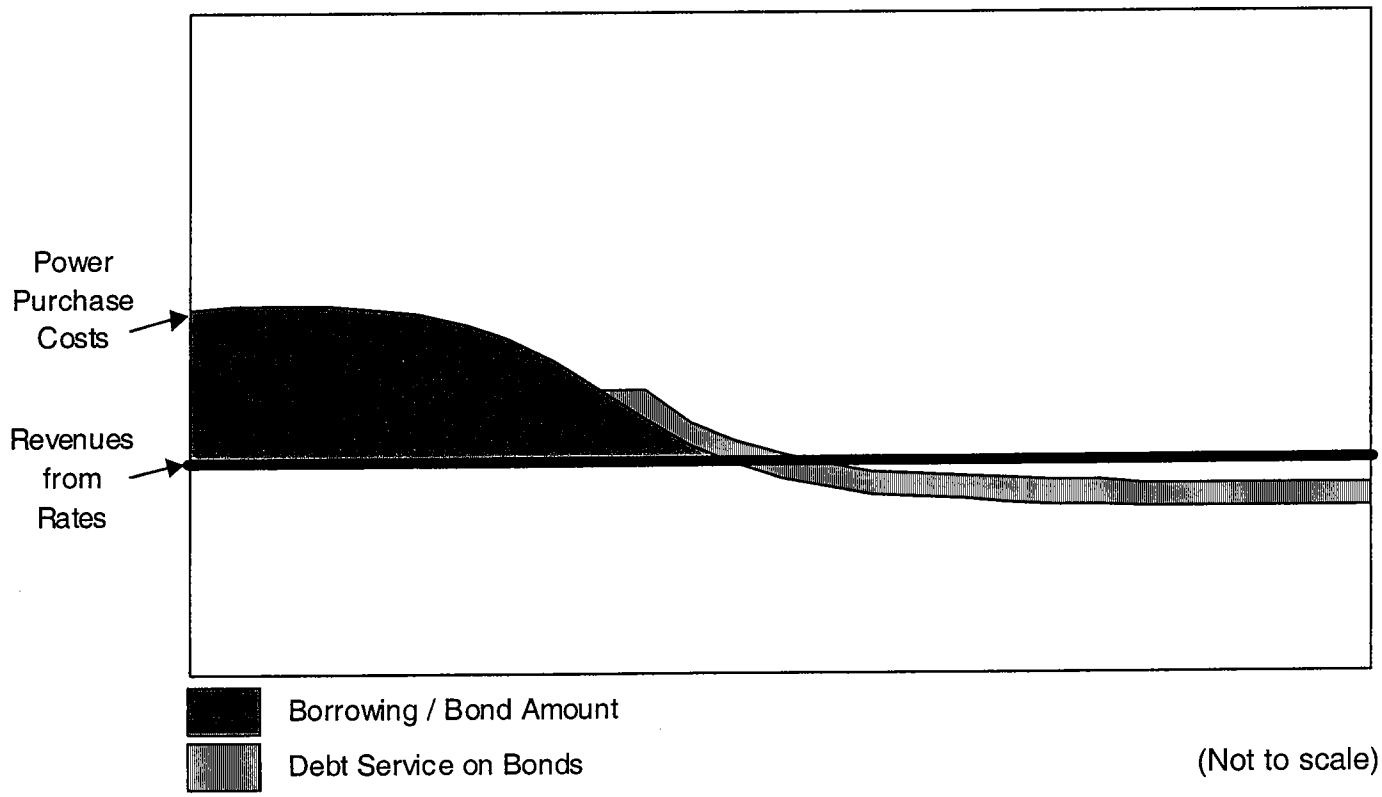
Figure 2
Projected Average Cost of Power



Financing Plan Assumptions and Results

Navigant Consulting/Montague DeRose

Figure 3
Illustration of DWR Energy Bond Financing Program



Energy Cost and Revenue Assumptions

- Assumes rate increases for PG&E and SCE customers are effective March 27, 2001 and begin to be collected in June 2001; assumes PUC implements a corresponding rate increase for SDG&E customers
- Ratepayer revenue collections assume that DWR is entitled to the energy component in the January 5, 2001 rate structure of each IOU for DWR energy provided to each IOU's customers
- Ratepayer revenue collections assume that the PUC allocates to DWR, from rate increases, revenues sufficient (together with bond proceeds) to meet its revenue requirements
- Energy costs financed also include $500 million for payment of prior ISO balancing energy purchases

Table 4
Schedule of DWR Revenue Requirements

DWR Ratepayer Revenue Requirements
($000,000's)

Month	Power Purchase Payments	Administrative Costs	Financing Costs	Total DWR Expenditures	Ratepayer Receipts From Past Power Sales	Other Revenues	Power Fund Interest Earnings	Expenditure of Bond Proceeds (1)	Ratepayer Revenue Requirements	Power Fund Balance
Jan-2001	58.017	2.083	-	60.101	-	-	-	(60.101)	-	738.899
Feb-2001	687.754	2.083	-	689.838	(32.746)	-	(3.079)	(654.013)	-	1,580.642
Mar-2001	1,590.232	2.083	-	1,592.316	(206.859)	-	(6.586)	(1,378.871)	-	2,201.771
Apr-2001	1,983.127	2.083	-	1,985.210	(334.137)	(0.356)	(9.174)	(1,641.543)	-	2,068.522
May-2001	1,954.438	2.083	-	1,956.521	(192.493)	-	(8.619)	(1,441.736)	313.673	808.785
Jun-2001	1,473.687	2.083	-	1,475.770	-	(17.303)	(3.370)	(808.028)	647.069	0.757
Jul-2001	1,214.206	2.083	-	1,216.289	-	90.184	(0.003)	(659.153)	647.317	3,406.899
Aug-2001	1,242.338	2.083	-	1,244.421	-	93.962	(17.140)	(630.401)	690.843	2,776.498
Sep-2001	1,258.421	2.083	-	1,260.505	-	93.676	(14.513)	(569.186)	770.482	2,207.312
Oct-2001	1,303.035	2.083	-	1,305.119	-	102.211	(12.141)	(618.189)	777.000	1,589.124
Nov-2001	1,070.652	2.083	-	1,072.735	-	92.743	(9.566)	(385.983)	769.929	1,203.140
Dec-2001	961.639	2.083	-	963.722	-	92.308	(7.957)	(329.149)	718.924	873.991
Jan-2002	891.624	2.083	-	893.707	-	(34.413)	(6.586)	(207.252)	645.456	708.728
Feb-2002	698.654	2.083	-	700.738	-	(33.574)	(5.897)	(21.460)	639.807	746.697
Mar-2002	541.788	2.083	-	543.871	-	(41.524)	(6.055)	-	496.291	894.105
Apr-2002	490.282	2.083	-	492.365	-	(39.101)	(6.670)	(4.814)	441.781	1,040.249
May-2002	619.146	2.083	-	621.229	-	(28.760)	(7.279)	(13.986)	571.205	1,054.627
Jun-2002	626.156	2.083	-	628.239	-	(43.679)	(7.338)	(10.298)	566.924	1,133.166
	18,665.197	37.500	-	18,702.697	(766.235)	326.374	(131.973)	(9,434.163)	8,696.701	

(1) Expenditures of bond proceeds shown in January through June represent reimbursement for State General Fund expenditures prior to the issuance of bonds. Total expenditures of bond proceeds above are net of Cal ISO balancing cost payments, debt service reserve fund deposit, interest on bonds funded through July 1, 2002, bonding costs of issuance and do not include $616 million of bond proceeds to be spent after June 2002.

Bridge Loan and Bond Assumptions

• Bridge Loan Amount:	$4.125 Billion
• Blended Interest Rate on Tax-Exempt and Taxable Portions of Bridge Loan:	6.00% (1)
• Long-Term Tax-Exempt Energy Bond Issuance Date:	June 29, 2001
• Long-Term Taxable Energy Bond Issuance Date:	June 29, 2001
• Final Maturity of Long-Term Energy Bonds:	July 1, 2016
• Average Long-Term Tax-Exempt Interest Rate:	5.35%
• Average Long-Term Taxable Interest Rate:	7.25%
• Capitalized Interest Period:	12 Months
• Debt Service Reserve Requirement:	10% of Par
• Energy Bond Debt Service Coverage Requirement:	1.35 times
• Energy Bond Insurance Capacity:	$5 Billion
• Costs of Issuance:	1% of Par

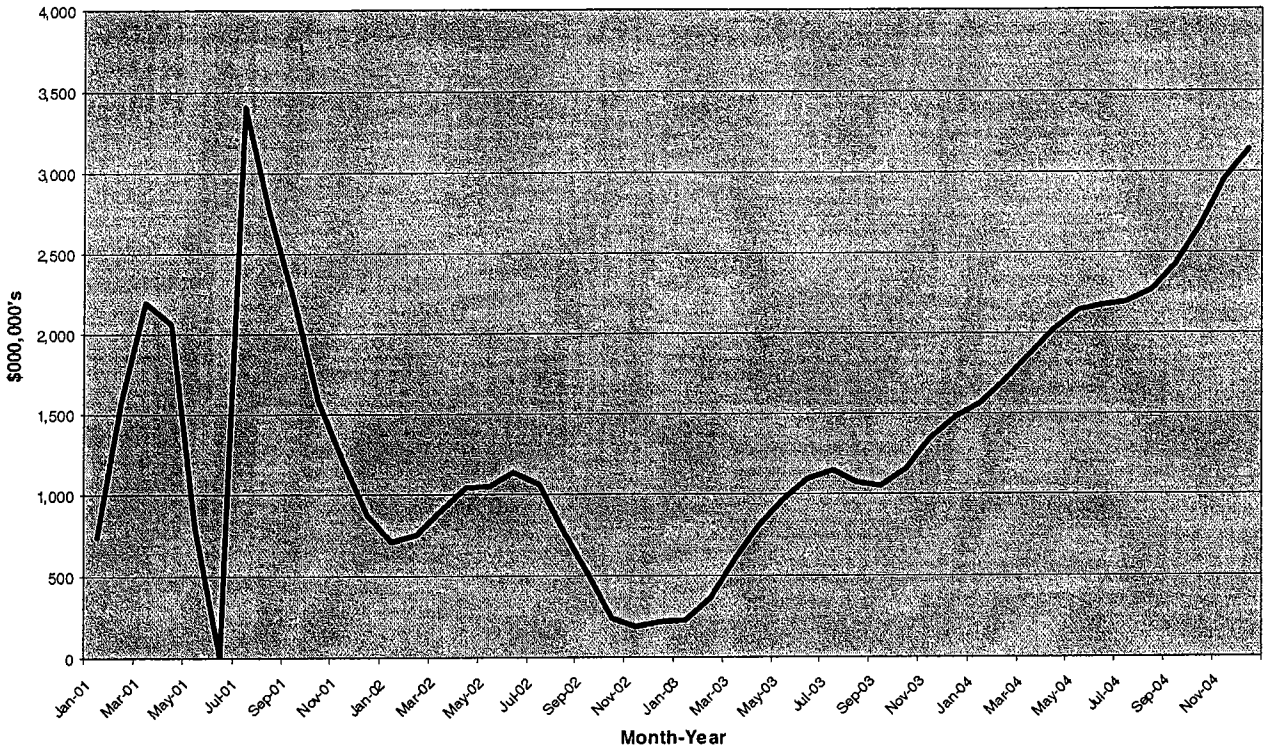
(1) 6.00% used for modeling purposes. Commitments to date estimated at average cost of 5.38%

Energy Program Bonding Requirements and Results

• PG&E Energy Component Rate Increase:	44.0%
• SCE Energy Component Rate Increase:	32.0%
• SDG&E Energy Component Rate Increase:	44.0%
• Tax-Exempt Bond Issuance:	$8.0 Billion
• Taxable Bond Issuance:	$4.5 Billion
• Total Bond Issuance:	$12.5 Billion
• Date of Minimum Electric Power Fund Balance:	November 2002
• Minimum Electric Power Fund Balance:	$188 Million
• Projected 2001 Total Net Short Power Cost:	$15.11 Billion
• Projected 2002 Total Net Short Power Cost:	$8.79 Billion
• Projected 2003 Total Net Short Power Cost:	$7.32 Billion

Figure 4
DWR Electric Power Fund Balance

CDWR Fund Balance



Note: Fund balance includes General Fund contributions, bridge loan proceeds and bond proceeds. Peaks in 2001 are attributable to the inflow of bridge loan and long-term bond proceeds.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 36

Representative News Articles Concerning Summer 2001 Energy Needs

ity $400-million, a provision that is also in Davis' MOU. The plan, which would probably be offered as an amendment to Polanco's bill, would also ask generators to write off about 25% of the amount SoCal Ed owes them, an aide said.

"It should come as no surprise the current MOU will not pass the Legislature without some modifications," Nation said. "What we have been trying to do for the past few weeks is offer alternatives within the governor's plan. That way we can get the necessary votes in the Legislature."

"More importantly," Nation added, "we will achieve the objective of making Edison creditworthy and getting the state of California out of the electricity-buying business."

COURT LETS PG&E PAY PROPERTY TAXES, HONOR 'PUBLIC PURPOSE' OBLIGATIONS

The U.S. Bankruptcy Court in San Francisco last week granted Pacific Gas and Electric's request that it be allowed to pay property taxes and provide its customers with financial incentives to encourage energy efficiency and renewable generation.

The court said that funds collected by the utility for its "public purpose programs," which include renewable generation, energy efficiency and low-income assistance, are not part of the bankruptcy estate and can be used to honor its pre-bankruptcy petition obligations. The utility owes about $37-million to consumers in energy efficiency rebates. The ruling also protects the $260-million currently set aside for future payments.

The court also authorized PG&E to pay the pre-petition portion of its property taxes. The company pays property taxes in 49 counties. As a result of the ruling, PG&E will be able to pay up to $41.2-million, its portion of property taxes prior to April 6, the date of its Chapter 11 filing. The company's total property tax payment was $78.5-million. It paid the post-petition portion of $37.3-million April 10.

Bankruptcy Judge Dennis Montali also last week promised to rule soon on whether PG&E's $4-billion in recovered stranded costs should be considered utility assets, allowing the court to void a March 27 Public Utilities Commission ruling that required the company to offset its losses in the wholesale power market with money it made from its own generation.

In arguments Monday, PG&E lawyers said the decision—which also extended the utility's rate freeze—illegally committed the utility's property to repay purchased-power costs. PG&E's bankruptcy filing was necessitated, it said, when its costs for wholesale power had far outstripped what it was able to collect from ratepayers under capped retail rates.

In its motion, PG&E asked the court to stay the PUC's March 27 decision, which changed the accounting procedures for tracking all utilities' stranded costs. The state's restructuring law allows utilities to end their state-imposed retail rate freeze once stranded costs have been recovered. PG&E unsuccessfully asked the PUC last year to lift its rate freeze because, it said, it had recovered those costs.

In its March order, the PUC required PG&E to net its generating revenue against its operating costs back to Jan. 1, 1998. PG&E told the bankruptcy court the commission's so-called "true-up" accounting change would interfere with the rights of its creditors and shareholders to recover about $9-billion in undercollected wholesale power procurement costs that the utility has amassed since last summer. Bankruptcy law requires Montali to approve any valuation of PG&E's assets without interference from the PUC, the utility argued in earlier bankruptcy proceedings.

"We want the court to enjoin the commission from implementing the order," a PG&E spokesman said. "We believe it interferes with the rights of our creditors."

PG&E attorney Gary Falk told the court that the PUC's action violates federal law and, rather than permitting the company to reorganize and pay off its debt, it would force the utility to liquidate its assets.

But Walter Rieman, a PUC attorney, disputed PG&E's argument, saying that in its March order, the commission was only exercising its statutory authority to determine the length of the utilities' rate freeze.

Montali, however, said the PUC order was inconsistent in that it declined to lift PG&E's rate freeze it at the same time it approved a 3-cents/kWh rate increase for PG&E and SoCal Ed. He also rigorously questioned PG&E's argument that the recovered stranded costs represent property assets.

Also last week, PG&E filed reply comments with the bankruptcy court reiterating its belief that formation of a ratepayers' committee is not part of the process established by the Bankruptcy Code. The utility said that although it does not object to ratepayers having a voice in the process, when issues arise where the court determines they have standing, it believes creation of the committee not allowed.

The company identified "several inaccuracies" in the U.S. Trustee's comments on the need for a ratepayers' committee, saying that ratepayers are not official creditors of the company and under the Bankruptcy Code, only creditors are represented in the proceedings.

In addition, PG&E said the state attorney general or some other official could represent ratepayers in the proce
Arguments by the trustee that a ratepayers' committ
needed because the state had decided not to partici
process to preserve its sovereign immunity, should
used by the trustee to skirt the bankruptcy code, th
said in a statement.

ISO PREDICTS TOUGH SUMMER IN CALIF., AS HOT, DRY WEATHER REIGNS IN REGION

California is likely to experience a tough summer, officials with the state Independent System Operator said last week.

In a briefing to the ISO board of governors, the staff presented three scenarios for the coming summer. Under the one considered most likely, the state will experience a peak summer load of 45,300 MW, which is slightly below a projected peak generating capacity of 46,600 MW.

The mid-range scenario assumes qualifying facilities in the state will provide 5,800 MW this summer, well below the 10,300 MW of maximum QF capacity. The ISO's numbers appeared to be at odds with Gov. Gray Davis' recent claims that 90% of the state's QFs are now on-line. While that may be true, industry sources said, looking merely at the number of

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QFs is misleading because many are operating only long enough each day to meet their contractual obligations to utilities.

The ISO's estimate also assumes 2,600 MW of new generation will go into operation over the summer and that there will be about 3,500 MW of capacity out of service because of forced outages.

An average of about 3,500 MW of capacity is expected to be imported from out-of-state generators, the staff said, warning, however, that California has already seen reduced imports of hydropower from the Pacific Northwest and that a unusually dry winter and spring has lowered in-state hydro production. In addition, the staff cautioned that unspecified financial uncertainties could keep some generators from being on-line this summer.

At the same time, the National Oceanic and Atmospheric Administration forecasted continued drought conditions for the Pacific Northwest and "seasonal warmth and dryness" for California. Historically, the Northwest ships low-cost hydropower to California during the peak summer period, but lower water levels in the Northwest have severely curtailed power exports to California from the north.

The ISO also appeared to be worried that utility load curtailment programs will offer little relief over the summer. Large users participating in Pacific Gas & Electric's interruptible program have already reached or are close to their maximum number of curtailments, and Southern California Edison can call on its participating customers only eight more times, the staff said.

Heavy calls on interruptible customers early this year has left the ISO without an important load-shedding tool going into the summer peak period, raising the prospect of blackouts. Staff said the ISO is now debating whether it should simply use up the remaining curtailable load as conditions demand or hold onto it, even if that caused blackouts now, to help avoid problems this summer.

In addition, staff told the board that the ISO is feeling increased pressure from state lawmakers to schedule blackouts. Partly in response, the system operator is beefing up the information available on its Website and intends to publish load-forecast information hourly to give businesses and residential users a better sense of whether blackouts are likely.

Blackouts the ISO ordered May 7 and 8 were caused by a high number of power plants that were off-line due to maintenance and repair because of extended use, Mark Willis, operations engineer said. The ISO is hoping all of the units will be back in service by the end of June, he added.

Staff offered the board one piece of good news—PG&E is upgrading its Path 15 transmission corridor, the main north-south transmission line in the state, by 500 MW. The work, which could be completed by early next month, will allow the ISO to move more power north if Pacific Northwest imports fall short, Willis said. The line currently has a capacity of 3,750 MW, and the utility hopes to increase the capacity to 5,500 MW by October 2004.

Other transmission upgrades should lower the chance of voltage problems in the San Francisco and San Jose areas this summer, Willis said.

NERC FEARS WORST SUMMER YET IN WEST, WORRIES ABOUT CONGESTION IN THE EAST

With at least 260 hours worth of rotating blackouts projected for California, the second-lowest hydro supply year in the Northwest ever, and an extremely tight supply picture for New York City, this summer could be the worst one yet for electric system reliability, the North American Electric Reliability Council said last week.

"That's an unqualified 'Yes,'" said NERC President and CEO Michehl Gent when asked if that description would fit.

Releasing its summer assessment, NERC said California could experience 260 hours of rolling blackouts, which would translate to about 15 hours a week, a much bleaker projection than the California Independent System Operator's view published in March.

The state could see up to 700 hours of blackouts if interruptible customer relief is not available, if customers do not respond to rate hikes and if conservation does not accomplish as much demand reduction as hoped for, according to NERC.

Pacific Northwestern states, which are experiencing its second-lowest water year ever will not be able to export power to California, NERC officials said. In fact, the Pacific Northwest could face rotating blackouts during its peak demand period next winter if the hydro supply picture does not improve, they said.

Except for California, generation supply should be adequate to meet demand in other areas this summer, NERC said, but New England, New York City and Texas "should be closely watched" for power problems.

"New England and New York City are particularly sensitive to long-term heat waves and higher-than-expected generating unit forced outages," the assessment said. New York City is adding 600 MW of capacity this summer, but if local opposition stalls the construction there could be shortages in the city this summer, Gent said.

While Texas is expected to have enough capacity to meet load, the council will be watching the transition from multiple control areas to a single control area in ERCOT in June.

NERC also pointed to concerns it has about north-to-south transmission transfer capability east of the Mississippi if the South experiences extreme heat and the North a cooler summer. Last summer, north-to-south transfers resulted in numerous transmission loading relief calls (TLRs), including five that cut power transactions, NERC officials said.

"Early indications are that key transmission interfaces used to transfer electricity from north to south are already fully subscribed going into this summer, and that transmission congestion will again be prevalent in this area throughout the summer," the assessment said.

Gent described last summer's overloaded lines as "scary" because security coordinators could not monitor the extremely heavy north-to-south flows.

Under current scheduling practices, transmission capacity tends to get oversold, leading to the need to call TLRs, which range from a warning to security coordinators, holds on transactions, or actual curtailments, he said.

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Power Cut to Parts of State; Electricity: First blackouts since March may be the beginning of warm-weather outages, industry officials warn.

The Los Angeles Times; Los Angeles, Calif.; May 8, 2001; MITCHELL LANDSBERG;KAREN ROBINSON-JACOBS;

DC_ABS

The blackouts, the first since March, were triggered at 4:45 p.m. after a day in which the California Independent System Operator struggled to patch together enough electricity to keep the grid running without outages. That worked for most of the day, but finally a combination of warm weather and power plant outages proved to be too much for the grid jockeys, and they were forced to order the hourlong blackouts, which affected about 100,000 residential, industrial and commercial customers.

[Dick Rosenblum] said about 34,000 Edison customers lost power during the blackouts. They were scattered across Edison's 50,000-square-mile territory, and included such communities as Irvine, Barstow, Santa Monica, Long Beach and Inglewood, he said.

Also Monday, [Gray Davis] said he anticipates that a deal to purchase the transmission system of San Diego Gas & Electric "will be resolved before the week is out." He has offered more than $7 billion to buy the transmission systems of SDG&E, Edison and PG&E. So far, only Edison has accepted the deal. PG&E's ability to sell its grid has been complicated, if not thwarted, by the company's decision to file for protection in federal Bankruptcy Court.

DC_FULLTEXT

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The dreaded summer of 2001 cast its shadow over California on Monday as an early spate of hot weather forced an hour of scattered, statewide electrical blackouts--a precursor of what could be a difficult season ahead.

With more warm weather expected today and tomorrow, state power officials warned that more blackouts might be necessary before an expected cooling trend later in the week. And they acknowledged that this could be the start of a long, dark summer.

"I hate to be the bearer of bad news," said Ed Riley, a spokesman for the agency that operates the statewide electrical grid, "but yeah, this is the start."

The blackouts, the first since March, were triggered at 4:45 p.m. after a day in which the California Independent System Operator struggled to patch together enough electricity to keep the grid running without outages. That worked for most of the day, but finally a combination of warm weather and power plant outages proved to be too much for the grid jockeys, and they were forced to order the hourlong blackouts, which affected about 100,000 residential, industrial and commercial customers.

The customers hit by the outage were those served by the state's three largest private utilities--Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric--plus a number of people served by municipal utilities in Pasadena and Vernon.

As has been the case throughout the power crisis, which began last summer, customers of the municipally owned Los Angeles Department of Water and Power were spared. The DWP operates independently of the statewide grid.

State officials have been warning for months that this summer would probably bring frequent blackouts.

Demand for electricity in California has far outstripped the supply, and the state's ability to import power from elsewhere in the West has been limited by a drought in the Pacific Northwest, which relies heavily on hydroelectricity, and by prices that have soared beyond the reach of the private utilities.

The heat that triggered Monday's blackouts was far from the hottest that can be expected this summer. Temperatures ranged from the 70s along the Southern California coast to 80 degrees in downtown Los Angeles, 95 degrees in Northridge and Sacramento, and a statewide high of 104 degrees in Palm Springs.

However, there also were more power plants out of service than officials hope will be the case this summer. In all, about 12,500 megawatts of power were unavailable, mostly because of planned outages for maintenance. That amounts to about one-quarter of the state's peak summer demand for power.

California uses more electricity in the summer because air conditioners require vast amounts of power. Power officials said the latest blackouts were an ominous sign.

"This is probably typical of what we'll see this summer, but I would say this was a less than full experience," said Dick Rosenblum, Edison senior vice president for distribution and transmission.

"Here we go," said Michael Zenker, California director of Cambridge Energy Research Associates, a Massachusetts energy consulting firm. "This is a bad omen for how bad the situation is."

Rosenblum said about 34,000 Edison customers lost power during the blackouts. They were scattered across Edison's 50,000-square-mile territory, and included such communities as Irvine, Barstow, Santa Monica, Long Beach and Inglewood, he said.

The blackouts also affected about 54,000 PG&E customers scattered through Northern and Central California, and about 8,600 customers of SDG&E in parts of San Diego and Orange counties.

As is typical in such blackouts, the utilities received only a few minutes' warning from Cal-ISO before they had to pull the plug.

No serious incidents were reported. "People are starting to get the hang of this," observed Tustin Police Lt. Mike Shanahan, who said he was pleasantly surprised at the ease with which drivers in his Orange County community began treating blacked-out signals as four- way stops.

The blackouts came slightly more than two hours after Cal-ISO officials expressed cautious optimism that they might squeak through the day. Worries in the morning had eased when the state received 1,000 megawatts from a Canadian supplier, and when "interruptible" customers--those who agree to occasionally shut off power in exchange for lower rates--came through when asked.

Riley guessed that the late-afternoon shortage occurred when the interruptible customers turned their power back on. In the past, he said, such customers--usually large businesses and institutions-- typically quit work for the day rather than wait around to turn the power back on.

"For some reason today, some of that load came back," Riley said.

He said it was difficult to immediately determine the extent to which Californians were conserving electricity, and whether poor conservation efforts could be blamed for the blackouts.

Gov. Gray Davis has been exhorting Californians to conserve energy as part of a multi-pronged--and hotly contested--state strategy to cope with power shortages and exorbitant prices.

On Monday, speaking at a news conference in Los Angeles, Davis thanked President Bush "for what he has done to date"--a rare bouquet- -but was clearly critical of recent comments made by Vice President Dick Cheney that energy prices should not be capped or regulated under any circumstances, even if the problem threatens the nation's economy.

"By far the most important thing that the federal government could do for us is to moderate prices, which are staggering," Davis said. He said it would be a "grave mistake" for the Bush administration to "rigidly adhere to ideology even if it meant hardship for California."

Also Monday, Davis said he anticipates that a deal to purchase the transmission system of San Diego Gas & Electric "will be resolved before the week is out." He has offered more than $7 billion to buy the transmission systems of SDG&E, Edison and PG&E. So far, only Edison has accepted the deal. PG&E's ability to sell its grid has been complicated, if not thwarted, by the company's decision to file for protection in federal Bankruptcy Court.

Davis has faced difficulty at every turn attempting to rescue the state's electrical system while staying afloat in a political tar pit.

The latest setback took shape over the past few days as chief executives of several independent power companies turned down the governor's invitation to a meeting in his office on Wednesday. Davis had sent out the invitations to a dozen chief executives last week. Most responded by offering to send lower-ranking officers.

Davis has relentlessly attacked independent generators, refusing to let up even as he invited them.

"I'm going ask these generators, who have made more money than God sucking money out of California and taking it back to Texas and other Southwest states, to reduce the cost of power for this summer, and to reduce the claims they have on us for money the utilities owe," he said.

In declining the invitation, Stephen Bergstrom, president and chief operating officer of Dynegy Inc. of Houston, wrote: "We are greatly disturbed by the increasingly virulent rhetoric that is coming from Sacramento."

Also Monday:

* Democratic lawmakers announced in Sacramento that they are suing the Federal Energy Regulatory Commission to compel the agency to cap wholesale electricity prices. The agency recently ordered a limited cap, but the legislators said it was not enough.

* The state Senate voted to impose a special tax on the "windfall" profits of energy producers whose earnings have soared astronomically during the last year. The resulting revenue would be returned to income taxpayers in the form of a credit.

* Frustrated by a Republican roadblock, Democratic legislators pushed forward with a parliamentary maneuver to reimburse the state budget for billions in electricity purchases--a last-gasp move that will effectively delay repayment until August.

*

Times staff writers Miguel Bustillo, Carl Ingram, Dan Moran and Julie Tamaki in Sacramento, Robin Fields, Geoff Mohan, Nancy Rivera Brooks in Los Angeles, John Glionna in San Francisco, Tony Perry in San Diego, Scott Gold in San Bernardino and Deanne Brandon in Orange County contributed to this story.

[Illustration]
Caption: PHOTO: Randy Nunnink, a dispatcher at Cal-ISO, works to counter hourlong blackouts that affected 100,000 customers statewide.; PHOTOGRAPHER: Associated Press

Credit: TIMES STAFF WRITERS

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*DC_SIC*221122*DC_SIC*561210
DC_SUBTITLE: [Home Edition]
DC_EDITION: Record edition
DC_STPAGE: A.1
ISSN: 04583035
DC_SUBJTERM: Power supply
Electric utilities
Weather
Blackouts
Energy shortages
DC_GEONAME: California
DC_COMP: **Independent System Operator-California***DC_SIC*221122*DC_SIC*561210

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The State; Blackouts Mean More Than Inconvenience for Disabled; Energy: They say life-saving equipment could fail. Advocates will urge state officials and utilities to provide a stronger safety net.

The Los Angeles Times; Los Angeles, Calif.; May 8, 2001; JOHN M. GLIONNA;

DC_ABS

Activists are calling for a statewide early-warning system; the creation of charging stations on exempt circuits for recharging equipment during blackouts; funds to buy backup batteries and generators and a toll-free emergency hotline for the disabled.

PUC Commissioner Carl Wood said Monday he would be open to any suggestions to assist the sick, elderly and disabled in the event of continued blackouts. "The energy crisis has put a huge burden on the most vulnerable people in our society--people just trying to survive," he said.

Disability Rights Advocates has recently heard from dozens of disabled residents from across the state, including a woman who uses a respirator to breathe at night--who says she must stay awake during blackouts because she cannot afford a generator.

DC_FULLTEXT

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As she monitored the news of possibly more rolling blackouts Monday, Lori Gray braced for another tense day in the projected summer-long fallout from the state's worsening energy crisis.

For the 39-year-old Berkeley woman--who is blind and suffers from epilepsy, asthma and chronic pain from aching joints that restrict movement--losing electricity is more than just an inconvenience.

It could kill her, she says.

Gray relies on electricity to run several life-saving machines that do everything from dispensing her asthma medication and opening her door by remote control to relaying her emergency telephone numbers in a computerized voice.

Today, disability activists are calling on state officials and California's utilities to do more to assist residents like Gray-- disabled people who are perilously vulnerable to any loss of electrical power.

In letters to Gov. Gray Davis, the California Public Utilities Commission and Judge Dennis Montali, who is presiding over Pacific Gas & Electric's recent bankruptcy filing, an Oakland-based disability watchdog is calling for a comprehensive statewide system to ensure that disabled people do not fall through the energy crisis safety net.

Lawyers from Disability Rights Advocates want a state-mandated emergency plan that responds to the "disproportionate and life- threatening impact of the energy crisis on people with disabilities."

Activists are calling for a statewide early-warning system; the creation of charging stations on exempt circuits for recharging equipment during blackouts; funds to buy backup batteries and generators and a toll-free emergency hotline for the disabled.

They also seek a state investigation into remedies for the long- term impacts--including rate increases.

Gray says the prospect of losing power and relying on unreliable generators pervades even her dreams.

"I spend my days worrying," she says. "I worry over when the next blackout will come. I worry about my friends who are in similar, if not worse, predicaments than me--who rely on their respirators. Let me tell you, this is no way to live."

At least two utilities said Monday they already employ an early- warning system for many customers on life support, but were open to other suggestions on how to improve services for the disabled. They added that the burden also rests with state officials.

Activists, who called the letters a first attempt to open discussions of the issues, say they have not ruled out a class- action lawsuit on behalf of what they say are 3 million people with disabilities in California.

"The response should not be an ad hoc process--one utility doing this and another that," said Shawna Parks, an attorney for the Oakland nonprofit. "We want an organized system that addresses some very serious needs. And as for any lawsuit if this doesn't happen, we're not closing any doors."

Disability Rights Advocates recently won major concessions in settling a lawsuit it filed against health care giant Kaiser Permanente for failing to address the needs of its wheelchair patients.

PUC Commissioner Carl Wood said Monday he would be open to any suggestions to assist the sick, elderly and disabled in the event of continued blackouts. "The energy crisis has put a huge burden on the most vulnerable people in our society--people just trying to survive," he said.

But funding new programs presents problems.

"One utility faces bankruptcy and others could be close, so some might question the wisdom of giving them new mandates when there may be no money to fund them," Wood said. "The goals are reasonable. The question is where the money comes from."

Dan Quigley, director of emergency communications for PG&E, said the company contacts about 22,000 life-support customers before anticipated blackouts. Another 48,000 are part of a medical baseline program in which they receive reduced electrical rates.

"We didn't design the system to shut people off and cause them inconvenience," he said. "We're eager to work with the PUC and disabled advocates to figure out a system that reduces the disruption."

Quigley added, however, that some of the activists' suggestions-- such as community battery charging stations--would be better served by state emergency response groups.

Anita Gore, a spokesperson for the state's massive health and human services agency, said the suggestions will be considered. "This is all relatively new," she said of the blackouts, "so we're gearing up to address concerns of the disabled and everyone else."

Ed Van Herik, a spokesman for San Diego Gas & Electric, said the company notifies 3,500 life-support customers of impending blackouts and "calls those customers back later to make sure the power has come back on."

He echoed concerns about the suggestion of an emergency hotline. "Some of those calls might be better handled by 911," he said.

Disability Rights Advocates has recently heard from dozens of disabled residents from across the state,

including a woman who uses a respirator to breathe at night--who says she must stay awake during blackouts because she cannot afford a generator.

A deaf man who uses visual alarms for the phone, doorbell, smoke detector and baby monitor has lost them during blackouts and fears going without power at night--saying his family will have difficulty communicating because they use sign language.

Another disabled woman who uses a wheelchair told advocates she was stranded in her apartment during a blackout because the elevator did not work and she could not use the stairs.

Parks said activists want the utilities to expand services for the disabled.

"There are situations faced by the disabled that aren't defined as critical by the utilities," she said. "There are many more definitions of being disabled than to be on a respirator or life support."

Lori Gray knows how the system can fail the disabled.

She was expelled from PG&E's medical baseline program last summer after failing to respond to a company letter requiring her to recertify.

"They sent a printed letter, but I'm blind and can't see," she said. "But they bounced me anyway."

Now Gray must acquire new letters from her doctors to get readmitted into the program. And when she asked utility officials to attach a staple to the return address of future letters so she could distinguish them as important mail, they refused--until she complained to PUC officials.

Gray says she would do anything to be included in the early warning programs because notification could be a lifesaver.

"It would relieve the stress of worrying when the next blackout is coming," she said. "I think the disabled deserve that much."

[Illustration]
Caption: PHOTO: Lori Gray of Berkeley, who is blind and has epilepsy and asthma, relies on electricity to run several life-saving machines.; PHOTOGRAPHER: RANDI LYNN BEACH / For The Times

Credit: TIMES STAFF WRITER

DC_SUBTITLE: [Home Edition]
DC_EDITION: Record edition
DC_STPAGE: B.8
ISSN: 04583035
DC_DATELINE: SAN FRANCISCO

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THE ENERGY CRISIS; A Delicately Guided Dance With Darkness; Electricity: Reluctantly, engineers set off rolling blackouts to keep the entire grid from failing.

The Los Angeles Times; Los Angeles, Calif.; May 9, 2001; NANCY RIVERA BROOKS;

DC_ABS

It is a delicate balancing act, coordinated with other Edison operations centers in Fontana, Ventura and Dominguez Hills, to pull the plug on thousands of electricity customers when power supplies dip perilously low. At the same time, Edison must keep the juice flowing to users considered essential--hospitals, fire stations, police stations, air traffic controllers and prisons, among them.

Edison limits customer outages to about an hour before moving on. PG&E and SDG&E's blackouts last 60 to 90 minutes. Once a group has been blacked out, it moves to the bottom of the list.

PG&E customers have a jump on those of Edison and SDG&E. They are told in their monthly bills which outage block they are in and they can visit the PG&E Web site to see which is next for blackouts.

DC_FULLTEXT

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The heart of darkness for Southern California is in Santa Ana.

That's where engineers in Southern California Edison's Distribution Operations Center execute orders for rolling blackouts across the utility's 50,000-square-mile territory when the word comes down from Folsom, home of California's electricity grid operator.

It is a delicate balancing act, coordinated with other Edison operations centers in Fontana, Ventura and Dominguez Hills, to pull the plug on thousands of electricity customers when power supplies dip perilously low. At the same time, Edison must keep the juice flowing to users considered essential--hospitals, fire stations, police stations, air traffic controllers and prisons, among them.

The dance is replicated at Pacific Gas & Electric and San Diego Gas & Electric when commanded by the California Independent System Operator, which balances supply and demand on the grid for about 75% of the state.

"This is no fun," Edison spokesman Steve Conroy said. "We are in the business of keeping the lights on, not taking them down."

California goes dark by stages according to an emergency plan maintained by Cal-ISO, the state's top electron traffic cop:

* Stage 1 means operating reserves have dropped below 7%. "Operating reserves" means generation that is not yet being used but could be, a kind of standby power. The utilities issue appeals for conservation.

* Stage 2 means electricity reserves are less than 5%; conservation pleas grow louder; large customers that get discount rates are asked to cut usage.

* Stage 3 means the state is within 1.5% of running out of available power; rotating power outages become likely to keep the electricity system from failing.

The industry calls these blackouts "firm load interruptions." Cal- ISO coined a new term this week:

"involuntary conservation."

Unlike an earthquake, which spreads out from an epicenter to wreak its damage, blackouts are scattered in clusters of circuits across each utility's service area.

Edison bundles customers into groups of about 100 megawatts, with 1 megawatt providing enough power for 500 to 1,000 homes. Each of the roughly 110 groups contains business and residential, wealthy and poor, city and rural customers.

The power is cut automatically to most customers, but some crews must be sent out to open circuits manually to turn off the electricity. PG&E and SDG&E work similar blackout plans, grouping at least 40% of their total customers into such outage blocks.

In a 500-megawatt outage, Edison would cut power to five groups for an hour. Electricity would then be restored to those customers, and another five groups would be blacked out if Cal-ISO said the need remained.

Edison limits customer outages to about an hour before moving on. PG&E and SDG&E's blackouts last 60 to 90 minutes. Once a group has been blacked out, it moves to the bottom of the list.

PG&E customers have a jump on those of Edison and SDG&E. They are told in their monthly bills which outage block they are in and they can visit the PG&E Web site to see which is next for blackouts.

Edison and SDG&E were ordered last month by the California Public Utilities Commission to provide the same service.

Without blackouts, the state's entire system would be at risk, repeating the 1996 outages that swept across Western states.

"When we can control the situation and control where the outages are, you avoid a catastrophic collapse," Conroy said. "In an uncontrolled outage situation, blackouts last well beyond an hour and all customers are subject to them."

Credit: TIMES STAFF WRITER

DC_SUBTITLE: [Home Edition]
DC_EDITION: Record edition
DC_STPAGE: A.25
ISSN: 04583035

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Officials Warn Power Outages Could Cause Major Sewage Spills; Utilities: Regional water authorities say cutoff at pumping stations and in underground pipes could loose millions of gallons.

The Los Angeles Times; Los Angeles, Calif.; Jun 22, 2001; SEEMA MEHTA;

DC_ABS

The problem may be in getting the sewage to the plants. Most sewer agencies take advantage of gravity to move sewage from homes and businesses to centralized treatment facilities. But in hilly areas, especially in coastal Orange County, cities rely on lift or pump stations to move the waste to higher ground. Each of these units is connected to the electrical grid, and subject to rolling blackouts.

"Sewage lift stations not equipped with functional emergency backup supplies, such as generators, may be extremely vulnerable to rolling blackouts," wrote Gerard Thibeault, executive officer of the Santa Ana Regional Water Quality Control Board, in a June 15 letter to local sewer agencies.

"We've already got a system breaking down and falling apart now. Rolling blackouts are going to do nothing but make it more complicated," said Roger von Butow, chairman of the Clean Water Now! Coalition in Laguna Beach. "I can not conceive of having rolling blackouts for any substantial amount of time without having sewer spills."

DC_FULLTEXT

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Regional water officials are warning sewer agencies throughout Southern California and elsewhere to prepare for rolling blackouts this summer, fearing that small cities that lack adequate backup power supplies could experience major sewage spills.

While some agencies are making special preparations--buying emergency generators and testing critical power systems--others insist their existing facilities can withstand the outages and pose no threat to public health and the region's waterways.

Critics are weary, however, saying the labyrinth of pump stations and underground pipes that move billions of gallons of sewage a day in Southern California is, in general, not well maintained and susceptible to mechanical failure.

"They're not prepared for the unexpected," said Wayne Baglin of the San Diego Regional Water Quality Control Board, which enforces federal and state water laws in San Diego County and south Orange County. "Mechanical and electrical systems often come with surprises."

There have been no reported spills in the smattering of rolling blackouts earlier this year, according to regional water officials.

However, a massive blackout in 1996 caused a failure at the Hyperion treatment plant near Los Angeles International Airport, causing 6 million gallons of partially treated sewage to flow into Santa Monica Bay. A 10-mile stretch of beach was closed.

The same outages caused a pump station failure in south Orange County, causing a spill that sent up to 100,000 gallons of sewage into the Pacific Ocean off Doheny State Beach.

One planned outage even caused a major spill. As part of a Y2K readiness test in 1999, the Los Angeles

Sanitation Bureau shut off power to a Van Nuys treatment plant--causing 3 million gallons of sewage to spill into a nearby park.

The state's power grid operators have predicted that if California uses the same amount of electricity this summer as it did last summer, residents face 34 days of rotating blackouts.

While critical operations such as hospitals and police agencies are exempt from power outages, sewer systems are not. Though their work does not involve life-and-death consequences, a failing sewer system can have severe impacts, such as fouling beaches with raw waste or causing sewage to back up into homes.

While treatment plants run on electricity, the large ones in Orange, Los Angeles and San Diego counties can produce enough internal power to be self-sufficient in times of crises, using methane and other biogases created during the treatment process. Some agencies also can burn trash or use waste water to create hydroelectric power.

However, the problem may be in getting the sewage to the plants. Most sewer agencies take advantage of gravity to move sewage from homes and businesses to centralized treatment facilities. But in hilly areas, especially in coastal Orange County, cities rely on lift or pump stations to move the waste to higher ground. Each of these units is connected to the electrical grid, and subject to rolling blackouts.

In Southern California, executive officers from regional water boards covering Orange, Los Angeles, San Diego, Riverside, San Bernardino, Ventura and Santa Barbara counties have either sent out, or plan to send out by month's end, letters warning local agencies to prepare for rolling blackouts this summer.

"Sewage lift stations not equipped with functional emergency backup supplies, such as generators, may be extremely vulnerable to rolling blackouts," wrote Gerard Thibeault, executive officer of the Santa Ana Regional Water Quality Control Board, in a June 15 letter to local sewer agencies.

Roger Briggs, executive officer of the Central Coast Regional Water Quality Control Board, was more pointed in a June 11 letter to sewer agencies in parts of Santa Barbara, San Luis Obispo, Monterey and other central coastal counties.

"An interruption of power that causes a [spill] will not likely shield a discharger from mandatory penalties," such as fines, he wrote.

Officials say the duration and geographic range of the blackouts will shape what happens this summer. Some agencies have begun preparing for the worst.

Huntington Beach, which has 27 lift stations, is now equipped to deal with a citywide blackout that would last several hours. The city council voted Monday to spend $175,000 to buy six backup diesel-powered generators to add to the existing five generators.

"Plan for the worst and hope for the best," said city spokesman Rich Barnard.

The city of Santa Barbara recently installed a large backup generator at its sewage treatment plant in anticipation of rolling blackouts.

Despite these measures, environmental activists remain skeptical.

Last year, there were 377 sewer spills in Orange County, 40 of which contaminated the county's coast and forced beach closures. This year, 25 beach closures were caused by sewer spills.

"We've already got a system breaking down and falling apart now. Rolling blackouts are going to do nothing but make it more complicated," said Roger von Butow, chairman of the Clean Water Now! Coalition in Laguna Beach. "I can not conceive of having rolling blackouts for any substantial amount of time without having sewer spills."

But other agencies, including Los Angeles and Orange counties, and the cities of San Diego, Newport Beach and Laguna Beach, say they are already well prepared.

Don Avila, spokesman for the Sanitation Districts of Los Angeles County, said its treatment facilities generate 117 megawatts of power, making it about the 20th-largest power generator in the state.

Credit: TIMES STAFF WRITER

DC_SUBTITLE: [Ventura County Edition]
DC_EDITION: Record edition
DC_STPAGE: B.6
ISSN: 04583035

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COLUMN ONE; Blackout Forecasts' Dark Side; * If optimists are wrong and the power runs out, California's energy crisis could quickly cost lives and cripple the economy.

The Los Angeles Times; Los Angeles, Calif.; Jun 20, 2001; JENIFER WARREN;

DC_ABS

At best, they say, Californians can expect some gridlocked intersections, an occasionally overloaded 911 system, perhaps some business bankruptcies, certainly inconvenience. At worst, the Western power grid could crash, causing uncontrolled blackouts that might lead to looting, contaminated water supplies, even civil unrest.

Dr. J. Michael Leary dreads blackouts--not personally, but professionally. Leary is an emergency room physician in the desert city of Rancho Mirage. When air conditioners go on the blink there, the victims--scores of them, mostly old folks--wind up in his ER.

Dr. J. Michael Leary, an emergency room physician in Rancho Mirage, fears "a great toll in human suffering" during power outages.; PHOTOGRAPHER: BRYAN CHAN / Los Angeles Times; GRAPHIC: Heat- Related Deaths in the U.S., Los Angeles Times

DC_FULLTEXT

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It's here. Summer 2001, the blackout season, is only a day away.

Already Californians anticipate power outages when temperatures rise. By August, the occasional annoyances endured so far-- stoplights gone dark, computers, air conditioners and elevators idled- - could seem almost quaint.

Gov. Gray Davis insists we needn't worry. Four large new power plants are firing up soon, he said, and government's best and brightest are locking up still more megawatts to help meet our peak summer need. Californians, Davis predicts, will valiantly heed his call to conserve, helping the state survive the hot months, no sweat.

With luck, he'll be right. Power prices have stabilized, and some energy analysts are wondering whether California may have tamed the blackout beast.

But what if those plants don't get built in time, people don't trim their electricity use 7% and energy imports are more meager than expected?

And what if the state gets hit by a summer that is not moderately hot, as Davis bets, but blistering, record-setting hot?

Government experts who ponder such questions don't expect disaster in the coming months. But they are planning for it nonetheless.

At best, they say, Californians can expect some gridlocked intersections, an occasionally overloaded 911 system, perhaps some business bankruptcies, certainly inconvenience. At worst, the Western power grid could crash, causing uncontrolled blackouts that might lead to looting, contaminated water supplies, even civil unrest.

"How bad could this summer get?" said state Sen. Joe Dunn (D- Santa Ana). "This summer could be the

worst disaster to ever hit the state of California."

Imagine it's a Thursday morning in the third week of July. Relentless heat grips California, the curse of a stubborn high- pressure ridge that just won't budge.

As air conditioners from Redding to Chula Vista lumber to life, managers of the state's power grid in Folsom gulp their third and fourth cups of coffee, stare at a bank of computers and begin to fret.

Demand is jumping. Supply is static, Canada and Arizona have nothing to sell. It's looking tight.

Thirty minutes later, the picture is gloomier. A brush fire shuts down transmission lines near Fresno, squeezing supply in the Central Valley. In the Bay Area, the unusual heat drives demand well past projections.

By noon things look bleak. Operators of the Diablo Canyon nuclear power plant near San Luis Obispo have cut output by 80%. The trouble? Chunks of kelp have lodged in one of the plant's seawater intake valves, creating a clog like one that plagued the facility in January.

With a chorus of groans, the grid's keepers scour the market for power to offset the Diablo loss. No luck. As the mercury climbs and the Golden State economy roars into full swing, electricity consumption upward, minute by minute. And when managers of a power plant near Long Beach cut output because of a cracked turbine, everyone knows what it means.

Alert the utilities. It's lights out, California, for the fourth day in a row.

Dr. J. Michael Leary dreads blackouts--not personally, but professionally. Leary is an emergency room physician in the desert city of Rancho Mirage. When air conditioners go on the blink there, the victims--scores of them, mostly old folks--wind up in his ER.

In a normal year, 75% of his emergency patients are geriatrics. Like infants, the elderly are unusually vulnerable to the heat. When blackouts hit, they are most at risk.

"It's as if you lived in Maine and they turned the heat off in January," Leary said. "This is an extreme environment we live in. The effects can be devastating."

Many desert seniors are on fixed incomes and live in mobile homes, some of them poorly insulated boxes that turn into ovens under the brutal summer sun. Take away the air conditioning and the humans inside start baking, quick.

For Leary, the specter of continual, back-to-back blackouts in July--and, some predict, in June and August too--conjures images of an 82-year-old man, living alone in one of those mobile homes, taking medication for heart disease. The cardiovascular drugs plague the man with numerous side effects; one inhibits his body's ability to cool itself.

When a person gets overheated, body temperature eventually rises uncontrollably. Then comes a nasty spiral of effects, and pretty soon "you go into shock," Leary said. "Everything just shuts down."

On average each year, 371 Americans die from heat-related causes, more than the number killed by earthquakes, tornadoes, hurricanes, lightning and floods combined. In 1995, a record hot spell in Chicago killed 465 people. Eleven Californians died from the heat in 1998.

A new report by the United Seniors Assn. predicts that more than half a million elderly Californians could need hospitalization for heat-related ailments this summer.

Some communities have laid plans for cooling shelters, wading pools and other measures to provide relief. But will all who need help get it? Or get it in time?

Out in the desert, paramedics expect a crush of 911 calls when the power goes out and the ill, frail and frightened seek help. Leary and others at Eisenhower Medical Center will be waiting, armed with ice packs, cooled IVs and ventilators.

"I am very, very worried," the doctor said. "I think we'll see a great toll in human suffering, even mortality."

California's tomato processors are no less anxious. They wash, cook, peel, chop, mash and can about 1 million tons of tomatoes a week from July to October--enough to account for half the world's supply. For them, a string of unexpected power losses could mean economic ruin in a matter of days.

The reason lies in the peculiar nature of food processing--a sterile system instantly contaminated if the power fails and the plant's precise temperature is disturbed.

Once a batch of tomatoes is tainted, it must be thrown out--all 50,000 pounds. The plant must then be sanitized, a painstaking process that takes about 36 hours.

"If you get hit by blackouts every third day for, say, two weeks, you're starting, stopping, cleaning, restarting--it's a nightmare," said Jeff Boese, president of the California League of Food Processors. "You could lose three batches and be out $40 million before you knew what hit you."

Meanwhile, farmers with still more truckloads of tomatoes line up outside the plant, waiting to be paid for their crop: "If we can't process them, the farmers have spent an entire season growing them for nothing," Boese said.

In Sonoma County, the object in peril is the chicken. Egg producers equip their laying houses with fans and swamp coolers to keep the hens comfortable. Power is also needed to run giant refrigerators filled with eggs.

"In a blackout, those hens can overheat in no time," said Rich Matteis of the Pacific Egg and Poultry Assn. "In 20 or 30 minutes, you could have 100,000 birds die."

Many large producers have backup generators, but they are not designed for ongoing, intensive use. Will they hold up? Small-scale egg producers often have no backup power at all.

Hundreds of other California businesses could suffer if summer shapes up as bad as some predict.

The Valero Refining Co. of California, northeast of San Francisco, produces 115,000 barrels of gasoline a day. Because restarting a refinery is a complicated task, two or three blackouts close together could prompt officials to shutter it until electricity supplies stabilize--costing California about 10% of its gasoline supply.

At a Berkeley medical laboratory, doctors say power losses to their freezers could destroy bone marrow needed to give young leukemia patients lifesaving transplants. The state's 400 dialysis centers, where

patients without kidney function go to have their blood cleansed every other day, are in the same fix. Few have backup generators, so when an outage hits, technicians must crank the machines by hand.

Most Californians, of course, face far more ordinary consequences. The scoreboards will fizzle at summer softball games, joggers on treadmills will be stopped in their tracks, electric organs will go silent, leaving choirs to sing without accompaniment.

Parents will be asked to retrieve children from day-care centers when the lights and cooling systems conk out. Anniversary lunches may be ruined when restaurants cannot grill salmon or blend margaritas.

Most people will tolerate occasional disturbances, psychologists say, doing their part in a time of crisis. But what if such irritations become an everyday fact of life?

Hundreds of "essential" energy users--including prisons, fire departments and airports--are protected from blackouts, and hundreds more have applied for exemptions. That means the pool of people bearing the blackout burden is shrinking, so more frequent outages are likely.

Blackout predictions vary widely, but at least one forecaster, a consultant for California water districts, anticipates an outage almost every afternoon of every workday this summer if temperatures are unusually warm.

Californians are accustomed to trash compactors, giant-screen TVs and having the Internet at their fingertips. How much deprivation will they tolerate?

"So far, the version of blackouts we've experienced hasn't looked too scary to people--it happens on a workday, in the afternoon, and you basically have to come home and reset your VCR," said Dan Kammen, a professor of energy and society at UC Berkeley.

But if outages become daily events, and start to invade the evening hours, the public mood could change abruptly.

"When there's a disaster or crisis or trauma, people tend to act heroically and work together," said Robert Butterworth, a Los Angeles psychologist and trauma specialist. "But the civilized behavior only lasts a short period. Then people start acting in unpredictable ways."

That tendency may be exacerbated, Butterworth said, by the nature of the energy crisis--not a natural disaster, but a man-made one.

"People start to look for a scapegoat," he said. "People will look for a target, and there's a tendency to strike out at whoever is closest to you."

One place that tendency may surface, Butterworth said, is on traffic-clogged roads. Blackouts already have led to scores of accidents. Add summer heat to the mix, and repeat the pattern day after day at rush hour, and motorists' patience could wear thin, law enforcement officials say.

"We're bracing for . . . possible acts of violence and road rage," said Sacramento County Sheriff's Lt. Larry Saunders.

Lon House is the water consultant who predicts California could see blackouts almost every summer weekday. Among the worries for the 440 water agencies he represents: losing the ability to pump water

during wildfire season.

"I'm telling them to be ready for a major earthquake every day this summer--meaning all your power is out throughout your district for multiple hours," House said.

House insists he isn't an alarmist. But on top of the fire fears, he warns that blackouts of more than a few hours would allow air into water pipes, contaminating supplies. If that happens, Californians would be urged to boil their water until the system can be disinfected from one end of the pipe to the other.

Though rolling blackouts are risky, they remain essentially a controlled phenomenon, occurring when and where the grid managers and utilities decide. Far more frightening--and devastating--are unexpected, cascading outages that could shut down the entire Western power grid. It happened in August 1996, leaving 4 million people without power during a triple-digit heat wave.

The problem began when power lines in Oregon sagged into trees and shut themselves off. That triggered a chain reaction of automatic switch-offs and oscillating surges of energy that ultimately shut down all four of the main power arteries between California and the Pacific Northwest.

That robbed the system of thousands of megawatts--enough to power four cities the size of Seattle for four days--and scattered outages across California and six other Western states. Thousands of customers were without power for more than a day.

Though such an episode is rare, California grid managers say it is more likely today because the system is taxed by the ever-increasing load of electricity it bears.

"The system is very dynamic, and when it's heavily loaded and highly stressed, like it is now, the smallest little thing could cause big trouble," said Kevin Bakker, who oversees California's connection to the greater Western power grid.

If a massive, uncontrolled outage should hit, the ramifications could be dizzying, said Mike Guerin, chief of law enforcement for the state Office of Emergency Services. Police departments would probably go to tactical alert, guarding against looting by criminals who might take advantage of disabled alarm systems and darkened street lights.

In hot areas, cities might convert municipal buses--parked with air conditioners running--into cooling shelters, Guerin said. The state would provide emergency generators to nursing homes and others in need, while the California National Guard might be called into action.

"With this kind of blackout scenario, you're not worried about the bologna going bad in the refrigerator," Guerin said. "We're talking about doctors doing surgeries on backup generators for three days. We're talking about a lot of things we don't like to think about."

*

Times staff writers Nancy Vogel and Alexander Gronke and researcher Patti Williams contributed to this story.

(BEGIN TEXT OF INFOBOX / INFOGRAPHIC)

Heat-Related Deaths in the U.S.

371 Average number of heat-related deaths annually

*

1,700 Most heat-related deaths in a single year (1980)

*

465 Number of people in the Chicago area who died during a July 1995 heatwave

*

11 Number of Californians who died of heat-related causes in summer 1998.

*

62% Percentage of heat-related fatalities 55 and older

*

Sources: U.S. Centers for Disease Control and Prevention, United Seniors Assn.

*

Large Power Plants Coming Online This Summer

Plant Megawatts Online Sutter
Power Project 500 Aug. 1 Los Medanos Energy
Center 500 July 1 Sunrise Power Project
320 Aug. 1 Huntington Beach Power Station 450 Aug. 1
*

Another 827 megawatts of power are expected to be available by Sept. 30 from 10 smaller "peaker" plants, designed to run at times of peak demand, usually late afternoon.

*

Note: One megawatt is enough to serve between 750 and 1,000 homes.

Source: California Energy Commission

[Illustration]
Caption: PHOTO: Dr. J. Michael Leary, an emergency room physician in Rancho Mirage, fears "a great toll in human suffering" during power outages.; PHOTOGRAPHER: BRYAN CHAN / Los Angeles Times; GRAPHIC: Heat- Related Deaths in the U.S., Los Angeles Times

Credit: TIMES STAFF WRITER

DC_SUBTITLE: [Home Edition]
DC_EDITION: Record edition

Water Districts Seek Exemption on Blackouts; Power: Some requests have been denied. Officials fear water surges can burst mains if pumps stop. Fire crews may also be hampered.

The Los Angeles Times; Los Angeles, Calif.; Apr 13, 2001; DAVID KELLY;

DC_ABS

"We knew the PUC was granting exemptions for fire departments, and we felt if you didn't have water for firefighters to fight fires, those exemptions were meaningless," said John Johnson, general manager of the 55,000-customer district. "We never got a letter saying 'no' but we heard the general statement that the PUC is not granting exemptions to water districts."

The commission has crafted a list of those exempt from outages. Hospitals, police and fire departments, commercial airports, some military bases such as those at Point Mugu and Port Hueneme, 911 dispatch centers, jails and anything vital to national security are exempt.

"There is really not a lot of wiggle room," said Nancy Williams, spokeswoman for Southern California Edison. "The PUC develops the criteria and we have to implement it. Keep in mind that [the outages] are only for a one-hour duration, so the PUC is thinking what are the odds that something draconian will happen."

DC_FULLTEXT

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When brush fires flare this summer, Casitas Municipal Water District officials hope they will be able to supply firefighters in the Ojai Valley with all the water they need without worrying about power outages.

District officials recently asked the state Public Utilities Commission for an exemption from rolling blackouts at the height of the summer season, when energy use is expected to skyrocket. Electric water pumps would be rendered useless in a blackout.

The commission's return letter said only that it would consider Casitas' request, but provided no firm answer.

"We knew the PUC was granting exemptions for fire departments, and we felt if you didn't have water for firefighters to fight fires, those exemptions were meaningless," said John Johnson, general manager of the 55,000-customer district. "We never got a letter saying 'no' but we heard the general statement that the PUC is not granting exemptions to water districts."

Not being exempt means taking an unnecessary risk, Johnson said.

"You will get no fire flow if the pumps are off," he said. "We have some backup generators, but the pumps are way too big for generators on everything."

The Calleguas Municipal Water District, which supplies 500,000 residents throughout the county, also filed a request for an exemption. Officials told the commission that outages at peak hours could cause water surges, ruptured pipes and even damaged roadways.

"We were denied right away," said Donald Kendall, general manager of the district. "They said it was physically impossible to isolate the water district like that."

Power failures in the past have caused major water surges that have burst pipes and broken apart streets, Kendall said. An outage increases pressure on the district's water main because purveyors cannot pump water out.

"Our biggest concern is that we'll be pumping away and then they will shut down," he said. "If that happens it will send a pressure surge through the water line. Pressure surges can blow up pipes."

That is what happened in 1997 when a 66-inch water main running under Madera Road in Simi Valley burst, blowing apart a huge chunk of the street and spewing about 8 million gallons of water into the surrounding neighborhood.

Meanwhile, officials with the United Water Conservation District said they never requested an exemption because they thought it would be denied.

"If we have to go more than six hours without power, I don't know what we'll do," said Dana Wisehart, general manager.

Wisehart said United, which pumps water for 300,000 residents, has backup plans and gas generators to use in a pinch. During a blackout, she said, there would be no pressure in the pipeline and none in the fire hydrant.

"We have a backup system," she said, "but it would be cheaper and easier if we were exempt."

A PUC spokeswoman said there had been no firm decision on the fate of water districts.

Sheryl Inouye, an information officer with the PUC, said the commission has asked all agencies seeking exemptions to file applications for consideration by the five-member panel.

The commission has crafted a list of those exempt from outages. Hospitals, police and fire departments, commercial airports, some military bases such as those at Point Mugu and Port Hueneme, 911 dispatch centers, jails and anything vital to national security are exempt.

Though water districts and treatment facilities are considered essential, they are not automatically exempt. If they suffer a serious problem during a blackout, officials can call an 800 number to restore power.

"There is really not a lot of wiggle room," said Nancy Williams, spokeswoman for Southern California Edison. "The PUC develops the criteria and we have to implement it. Keep in mind that [the outages] are only for a one-hour duration, so the PUC is thinking what are the odds that something draconian will happen."

Local agriculture is also bracing for impending blackouts, though there has been no effort to ask for exemptions yet.

"It will be a tremendous cost factor," said Rob Roy, president of the Ventura County Agricultural Assn. "Processors of avocados and onions are having to resort to buying expensive generator equipment costing one-quarter to a half-million dollars."

His group of more than 100 growers and shippers of agricultural commodities is backing legislation that would, among other things, fund the purchase and development of energy-efficient farming machinery.

THE CALIFORNIA ENERGY CRISIS; Elevator Anxiety Is Riding High; Emergencies: Workers in skyscrapers worry about blackouts trapping them in their buildings. Some take the risk in stride; others make plans to take the stairs.

The Los Angeles Times; Los Angeles, Calif.; Mar 21, 2001; JOHN M. GLIONNA;JOE MOZINGO;

DC_ABS

"I think about it all the time," said [Susan Clifton], a 21-year-old receptionist at Deutsche Bank's offices on the 48th floor of a tower in the city's financial district who recently moved from rural Virginia. "The way I see it, Californians take a lot of things on faith, working atop tall buildings with all these earthquakes and power outages."

Fire Department spokesman Pete House said the city has 19 trucks with experts trained to extricate people trapped in elevators. Firefighters handling blackout-related emergencies rescued a person trapped in a downtown building Tuesday and handled five elevator mishaps Monday.

"Hey, I'm young and I'm healthy. I can always walk down the stairs," said the 29-year-old receptionist. "I've done the Statue of Liberty. It can't be any worse than that. And walking down 42 flights is a lot easier than walking up all those stairs."

DC_FULLTEXT

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In Susan Clifton's highly placed opinion, sunny Tuesday would have been a picture-perfect day to work atop one of the tallest buildings in San Francisco, a scenic city littered with soaring skyscrapers.

But Clifton--like many other high-rise office dwellers in blackout- prone parts of California--couldn't help but feel some high anxiety at the prospect of being stranded by electrical outages that were sweeping across the state for a second day.

"I think about it all the time," said Clifton, a 21-year-old receptionist at Deutsche Bank's offices on the 48th floor of a tower in the city's financial district who recently moved from rural Virginia. "The way I see it, Californians take a lot of things on faith, working atop tall buildings with all these earthquakes and power outages."

For Long Beach office worker Dave Suhada, the anxiety has taken the form of elevator phobia: a fear of getting stuck on an 80-degree day crammed in a pod of sweating, heavy-breathing humans, with no way out.

"I'm just eyeing the buttons to see which one I could push as fast as I can if the power goes out," he said.

For 20-year-old Lisa Riley, it means entering the elevator each day in her Long Beach office building with a prayer. "I just could not get stuck for an hour and a half," she said, nodding nervously. Often she now opts for the stairs.

In San Francisco, emergency services officials say that most of the city's office buildings are equipped with backup generators to run elevators and security equipment in the event of a blackout.

Fire Department spokesman Pete House said the city has 19 trucks with experts trained to extricate people trapped in elevators. Firefighters handling blackout-related emergencies rescued a person trapped in a downtown building Tuesday and handled five elevator mishaps Monday.

Christopher Stafford didn't get caught inside an elevator Monday, but suffered the next-worst thing: being stranded in his 15th-floor apartment after the power failed when he went home for lunch.

So the 41-year-old real estate worker trooped down the stairs to the lobby and even made some new friends along the way, helping a few elderly women who were struggling down the stairs.

"It was a pain," he acknowledged. "But I have to tell you: I really like my panoramic view, so it's worth the hassle."

Nowadays, Sherrie Tellier makes sure her cellular phone is in hand when she gets in the elevator. She got trapped once before, and the emergency phone didn't work. It's amazing, she said, how small an elevator seems when you can't get out. "It's like a broom closet.Now there's a sigh of relief every time the door opens."

Some high-rise office workers said Tuesday that they preferred not to think about the perils of going without power and being vulnerable and isolated so high up.

But on the 42nd floor of San Francisco's Transamerica Tower, Sasha Monpere wasn't fazed by the chance that during a blackout, her building's backup generators wouldn't kick in.

"Hey, I'm young and I'm healthy. I can always walk down the stairs," said the 29-year-old receptionist. "I've done the Statue of Liberty. It can't be any worse than that. And walking down 42 flights is a lot easier than walking up all those stairs."

Likewise with Phil Ip, who works on the 52nd--and top--floor of San Francisco's tallest skyscraper. The 25-year restaurant veteran says he has the utmost faith in modern technology.

"We're safe, even up here," said Ip, assistant general manager of the Carnelian Room, a restaurant atop the Bank of America building. "You should see the engineer's room in this building. It's like a big steamship. They're equipped for anything that could happen."

One floor below, Cheryl Martin hears every day about people's fear of heights. In the year since she began answering phones in a law office, she has often escorted clients afraid of express elevators that shudder and rise so fast that passengers' ears pop from the altitude gain.

"Everybody, and I mean everybody, asks, 'So, what happens during a power outage?' " she said.

Rory Thompson said he believes in karma and is sure that if the rolling blackouts come calling, his office will be spared. In July 1993, Thompson's building was the site of an incident known as the 101 California St. massacre, in which gunman Gian Luigi Ferri killed eight people and wounded six before killing himself.

"This building has already had its bad day," he said. "They say that the day after a crash is the safest day to ride an airline. So I'll take my chances with the rolling blackouts."

[Illustration]
Caption: PHOTO: Susan Clifton, whose office is on the 48th floor in San Francisco, says her fellow high-rise workers "take a lot of things on faith."; PHOTOGRAPHER: ROBERT DURELL / Los Angeles Times

Credit: TIMES STAFF WRITERS

So Far, More Angst Than Grief in O.C. Blackouts; Power: Rolling outages interrupt business, slow traffic, then move on. You know it's coming, says one anxious businessman. 'The problem is when.'

The Los Angeles Times; Los Angeles, Calif.; Mar 21, 2001; SCOTT MARTELLE;MAI TRAN;

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2 photos Above, [Calvin Qui Ngo], manager of a mall in Westminster, says his tenants are experiencing "a lot of anxiety" over blackouts. Below, a sign posted at Shurgard Self Storage in Mission Viejo.; PHOTOGRAPHER: AL SCHABEN / Los Angeles Times; 2 photos Above, Calvin Qui Ngo, manager of a mall in Westminster, says his tenants are experiencing "a lot of anxiety" over blackouts. Below, a sign posted at Shurgard Self Storage in Mission Viejo.; credit line only; PHOTOGRAPHER: DON TORMEY / Los Angeles Times; Traffic crawls along Crown Valley Parkway in Mission Viejo after a blackout shut down traffic signals.; PHOTOGRAPHER: DON TORMEY / Los Angeles Times; GRAPHIC: Blackouts Hit O.C. Again, PAUL DUGINSKI / Los Angeles Times

DC_FULLTEXT

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How do you plan for the unplannable?

If you're the manager of the high-end Stuart Moore jewelry shop in Newport Beach's tony Fashion Island, you print up little paper signs to tape to the door in case the power dies and you have to lock the customers out and the gems in.

Then you wait.

"It's been in the corner of my mind this morning," Lee Duren, the store director, said Tuesday, adding that a Wolfgang Puck restaurant a couple hundred feet away was darkened for nearly an hour the day before. "It's really interesting to see how electrical lines can be drawn."

For all our reliance on electricity to power our daily lives, the disruptions Monday and Tuesday haven't been that disruptive, primarily because they have been short. An hour here, an hour there. Kitchens close and cash registers won't open, but in the end, it all amounts to a long coffee break and a few lost sales.

It does, however, make for some anxiety.

Police departments in several cities scrambled Tuesday to direct traffic at darkened intersections. In Huntington Beach and Buena Park, plainclothes detectives were back in uniform for the day after those cities were warned of imminent outages.

But the lights stayed on in Buena Park, where nine detectives, five motorcycle officers and 20 police volunteers had hit the streets.

"It was all for nothing, but it was a good drill," Buena Park Police Lt. Ken Coovert said.

Power did go out earlier near South Coast Plaza in Costa Mesa, contributing to a collision about 10:45 a.m. Police said a car driven by a motorist identified as Jane Clark struck another car driven by Christopher Cruz as Cruz was exiting the San Diego Freeway at South Coast Drive, where the signal lights were out.

"She didn't realize the lights were blacked out," Costa Mesa Police Officer Chris Bates said. Both

drivers were treated for hand and wrist injuries at Coastal Communities Hospital in Santa Ana.

Fears over food poisoning led the Orange County Health Care Agency to print special handbooks for food workers that include tips on preserving foods should an outage last two hours or more.

In Westminster, the anticipation kept businessman Calvin Qui Ngo on edge.

"There is a lot of anxiety," said Ngo, 56, property manager for the Mall of Fortune on Westminster Avenue near Little Saigon. "We know we're going to lose power. The problem is when."

Ngo spent Monday morning cruising the complex of shops asking merchants to set their refrigerators to cool a little less, and to dim whatever lights they could.

"I see them using all this power, just letting all their lights go," Ngo said. "I'm here to tell them to conserve. That's all I can do."

For emergency planners, there wasn't much to be done either. An earthquake calls for one set of responses, massive El Nino-style storms another. A series of short blackouts, though, amounts to a mass of mosquitoes that won't go away.

The Orange County Public Facilities and Resources Department, for example, has a stockpile of as many as 300 portable stop signs at its Anaheim maintenance yard. You would think they could drop them at intersections where the traffic lights have gone out. But they don't.

Primarily because they haven't been asked, said Ken R. Smith, deputy director of the public facilities department. But also because an hour is hardly enough time to mobilize, judging by their experience in putting out signs where signals have malfunctioned.

"Typically, what happens is by the time we get the stop sign out there, the signal's been repaired," Smith said, adding that state traffic laws already cover the issue. "The motor vehicle code says that when lights aren't working at an intersection, it automatically reverts to a four-way stop."

Restaurateur Alan Zemek, 43, approached the day with a mix of dread and deja vu. His Split Rock Tavern in Laguna Hills went dark at lunchtime Sunday when an underground cable failed. On Monday, Southern California Edison pulled the plug on purpose--again, at lunch time.

On Tuesday, he was mulling buying 2,000 pounds of ice to keep his meat stocks cooled should the plug be pulled again.

"This power crisis is no longer in the abstract. It is very real," Zemek said. "There's a lot of anxiety to that. It is not so much from losing power, but it is the anxiety about when the power is going to come back on."

Darkness descended up and down the economic scale, striking working-class neighborhoods in northeast Santa Ana and, to the south, areas of South Coast Plaza in Costa Mesa.

At a Santa Ana Food 4 Less, workers were forced to restock goods when the power died Tuesday morning and rendered scanners and cash registers useless. At South Coast Plaza, the lights went out for less than a minute--long enough to jolt the computers at Diesel, an upscale jeans shop.

"Our computers went blank," manager Laura Fesperman said. "We had to call New York to have them help us."

Managers of amusement parks found nothing amusing about what the summer might be like, with power outages already cropping up in the dawning days of spring.

"I hear this summer's going to be kind of tricky when it comes to power, and I think that's going to be our biggest challenge," said Allan Ansdell, president of Adventure City in Stanton.

Ansdell said the park does not have a backup power supply, but that all rides are equipped with fail-safe devices that will stop them and allow for their manual operation.

"Fortunately, they've been turning the power off for just an hour," Ansdell said. "If the power goes out for three or four hours though, that will be a problem."

Disneyland also escaped outages, but was ready with a mix of backup generators, manual overrides and other emergency procedures, said spokeswoman Chela Castano-Lenahan.

An outage would cause more trouble at that refuge for the modern adolescent, the video arcade. At Fullerton's The Reagan Years, co- owner Sean Francis kept an eye on news reports of where the outages were occurring. One struck just a quarter-mile away on Monday.

If a blackout hits, all 44 of his vintage 1980s machines would shut down, forcing him to refund game players' quarters. Francis considered buying a generator but rejected it as too expensive for, in essence, an hour's worth of power insurance.

"I feel like somebody is liable for this," he said. "And how fair is that? You pay your bills and they're supposed to provide service, and then they can cut you off without any warning."

Mohammed Shamsi, owner of Discount Mart near Wilshire and Raymond in Fullerton, has already been working under his own self-imposed outage, this one driven by the bills he's been receiving. Bills that once ran $250 a month have reached $385 a month.

So he has shut off the air-conditioner in his discount goods shop and sits in the dark. When a customer comes in he springs up from behind the counter and turns on a large floor fan and the lights. When the customer leaves, he turns them off again.

Tuesday morning, he was busy moving merchandise back into the darkened shop after doing some renovations.

"It only makes me hotter, but what choice do I have now?" he said. "I never thought I'd be paying $385, and I can't afford [it]."

Workers at Norm's family restaurant in Huntington Beach were preparing for the unthinkable: an outage that would make a lie of the big neon sign on the side of the building bragging that "We Never Close."

If the power goes out, said general manager Betsy Fisher, they'd serve customers already in the restaurant but lock the door to others.

Which would put at least that moment down in Norm's history.

"The only time Norm's actually closed was when Kennedy died and Norm died," she said. "And that was it."

*

Times staff writers Stanley Allison, Matthew Ebnet, Dennis McLellan, Monte Morin, Jason Song and Nancy Wride contributed to this report.

(BEGIN TEXT OF INFOBOX / INFOGRAPHIC)

Blackouts Hit O.C. Again

From 9:30 a.m. to 2:30 p.m. Tuesday, parts of these 14 cities were affected by rolling blackouts that once again swept Orange County.

Buena Park

Yorba Linda

Placentia

Garden Grove

Westminster

Santa Ana

Huntington Beach

Costa Mesa

Irvine

Dana Point

Mission Viejo

Laguna Hills

Aliso Viejo

Laguna Niguel

*

Source: Times reports

Researched by BRADY MacDONALD / Los Angeles Times

Use of Diesel Generators Proposed to Bolster Grid; Energy: State says small backup systems, which lack pollution controls, could avert blackouts. Activists and air quality officials protest.

The Los Angeles Times; Los Angeles, Calif.; May 24, 2001; GARY POLAKOVIC;

DC_ABS

Gov. Gray Davis' administration is considering pressing into service thousands of diesel-powered generators, a move that would eke out a little more electricity but pump massive quantities of pollutants into the air.

"If backup generators were to be used, it would only be as a last resort to avoid blackouts," said Davis spokesman Roger Salazar. "Unfortunately, we are in an emergency situation. Everything is on the table."

Under a worst-case scenario prepared by the California Air Pollution Control Officers Assn., generators could produce nearly 17,000 tons of pollutants if they all ran 40 days during blackouts and Stage 3 emergencies. Half of the pollution would be concentrated in the air quality region that includes Los Angeles, Orange and parts of Riverside and San Bernardino counties. That is the smog equivalent to the nitrogen dioxide all the cars in California produce in 13 days, according to the Air Resources Board. Nitrogen dioxide contributes to ozone and microscopic airborne particles, two abundant air pollutants.

DC_FULLTEXT

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Gov. Gray Davis' administration is considering pressing into service thousands of diesel-powered generators, a move that would eke out a little more electricity but pump massive quantities of pollutants into the air.

The proposal, part of an emerging strategy to avert blackouts this summer, is one of several options being advanced by Richard Sklar, whom Gov. Davis appointed last month to bring more electricity online with less red tape.

"If backup generators were to be used, it would only be as a last resort to avoid blackouts," said Davis spokesman Roger Salazar. "Unfortunately, we are in an emergency situation. Everything is on the table."

But environmentalists and air quality officials are outraged, calling the plan a recipe for unhealthy air during the smoggiest months in the nation's most polluted state. The legions of small backup generators typically burn diesel fuel and have no pollution controls.

"They could have a huge negative effect on air quality," said Ellen Garvey, executive officer for the Bay Area Air Quality Management Agency. "It's one thing to run these generators during blackouts and emergency conditions, but using them for other purposes could be devastating."

The plan is one of several options being developed by the governor. One approach would pay operators to run the generators when supplies are stretched to alleviate demand on the state's power grid.

California has about 17,200 backup generators, most in hospitals, office buildings, sewage treatment plants and university labs, although some are portable rentals.

Each generator spews 500 times more nitrogen dioxide for each megawatt of electricity than a natural-

gas fired power plant, according to the state Air Resources Board. The generators also release soot.

Under a worst-case scenario prepared by the California Air Pollution Control Officers Assn., generators could produce nearly 17,000 tons of pollutants if they all ran 40 days during blackouts and Stage 3 emergencies. Half of the pollution would be concentrated in the air quality region that includes Los Angeles, Orange and parts of Riverside and San Bernardino counties. That is the smog equivalent to the nitrogen dioxide all the cars in California produce in 13 days, according to the Air Resources Board. Nitrogen dioxide contributes to ozone and microscopic airborne particles, two abundant air pollutants.

Backup generators are so small that collectively they do not produce much power. Only about 550 megawatts could be generated each day, officials say, in a state that requires nearly 100 times as much to function.

Nevertheless, business groups are lobbying for the change, including the League of Food Processors, the California Manufacturers and Technology Assn. and San Diego Gas & Electric Co.

"These generators could go a long way to taking some demand off the electric grid and putting some supply back into the power system," said Gino DiCaro, spokesman for the manufacturers association.

*

MORE INSIDE

Official visit: President Bush agrees to meet with Gov. Gray Davis during his California trip. B8

Credit: TIMES STAFF WRITER

DC_SUBTITLE: [Home Edition]
DC_EDITION: Record edition
DC_STPAGE: B.1
ISSN: 04583035
DC_SUBJTERM: Air pollution
Energy shortages
Diesel engines
Nonutility generators
DC_GEONAME: California
DC_PNAME: **Davis, Gray**

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History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 37

Representative News Articles – Reactions on Summer 2001 Estimated Prices

Conservation Financing Authority to boost generation supplies that would be sold at cost-based rates to consumers. Under the legislation, which was sponsored by state treasurer Phil Angelides, the authority could issue up to $5 billion in bonds, part of which would fund cleaner energy sources and the retrofitting of old, dirty power plants (see CEM No. 615 [16.1]).

"This measure recognizes that the state of California, as a matter of public policy, cannot stand by and hope that the private markets, in and of themselves, will solve California's energy problems and protect consumers and businesses," Angelides said.

Passage of the bill is seen as a significant victory for consumers. "The people of California would benefit, and not the [investor-owned utilities'] corporate officers and shareholders," Burton said. Lenny Goldberg, lobbyist for The Utility Reform Network, said, "It is the only way to take back some control over our energy fate." He added that it undercuts the oft-heard cry that state involvement in the electricity market will scare away needed investment in power plants, because the state itself would build and finance plants.

Under SBx1-6, the authority would be managed by a five-member committee, appointed by the governor and headed by Angelides.

Mark Seetin, vice president of the New York Mercantile Exchange, said the passage of the bill was a positive step and one that would bring more power into the system, particularly because "the state does not have a very good record of helping itself" ***[Elizabeth McCarthy].***

[17.2] Bowen Backs Bond Bill

Although legislation establishing a state power agency passed the Legislature, the bill authorizing the sale of bonds to finance state power purchases has been held up, largely by Republicans who want to reduce the bond amount by using $5 billion of general fund money to cover purchased power. Earlier, Assembly Republicans told Governor Gray Davis they would not budge unless he released specifics on the state's past, present and future power.

Davis is seeking $12.5 billion in bonds funding, but state treasurer Phil Angelides said he would settle for $10 billion in purchases (see story at [17]).

The vehicle for a bond authorization is expected to be SBx1-31 by Senator Debra Bowen (D-Redondo Beach), and legislative approval is needed by May 8 to allow Angelides to secure more than $4 billion in bridge financing. Bowen, however, said she would not put her name on the bill unless it includes provisions ensuring that the investor-owned utilities will pay the Department of Water Resources for the energy it has purchased on behalf of the IOU ratepayers. Pacific Gas & Electric and Southern California Edison have challenged the payment formula, known as the California Procurement Adjustment under ABx1-1, that gave DWR the authority to buy the IOUs' net-short positions.

The larger bone of contention is the size of the bond authorization and how to pay for the state's power purchases.

The Assembly Republican Caucus sent Speaker Bob Hertzberg (D-Van Nuys) a letter May 2 that rejected securing a bridge loan, insisting $5 billion from the state surplus should be used to reduce the state's power debt. "[T]here is absolutely no need for the taxpayers of California to sweeten the deal of a pending energy revenue bond issue by entering into the proposed bridge loan," wrote Assembly Republican leader Dave Cox (R-Fair Oaks).

Cox said his caucus would agree to back an $8 billion bond measure to cover further sales and urged that public power agency customers' utility bills be reduced because their tax money would be used to cover the $5 billion spent on energy purchases.

The Republican agenda also included knocking out environmental safeguards to expedite bringing more power plants on line, providing direct access to residential customers, limiting the California Energy Commission licensing authority to power projects 125 MW and greater and ensuring that qualified facilities get paid for their energy sales. The QF unpaid invoices were not addressed.

> 'There is absolutely no need for the taxpayers of California to sweeten the deal of a pending energy revenue bond.'

The impact of eliminating environmental safeguards, particularly regarding air quality, on new generation plants was acknowledged by caucus spokesperson Jaime Fisfis. "Environmental standards are compromised for the sake of building more power," he told CALIFORNIA ENERGY MARKETS.

But whether much more can be done to increase the number of new power plants is questionable. "Power doesn't grow on trees," noted Mike Florio, attorney with The Utility Reform Network, adding that the most promising source of immediate energy "is all the hot air coming out of the Capitol" ***[E. McC.].***

[17.3] Power Sales to Reach $18 Billion by Next Summer, Governor Says

Governor Gray Davis handed the Assembly Republican Caucus a 70-page document that listed the amount of the power the state purchased and the projected costs of unsecured power, in hopes caucus members would sign on to legislation needing a two-thirds vote to authorize the issuance of revenue bonds.

But Republicans were not biting. "He wooed and courted us all day, but the plan was greeted with skepticism," said Jaime Fisfis, Republican Caucus spokesperson. Davis said he needed $12.5 billion in bond financing to cover the Department of Water Resources' energy sales.

Under Davis' scenario, viewed as overly optimistic by members of the opposing party, DWR is expected to burn through $18.7 billion by June 2002. The amount is based on a spot-market price from

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April to June estimated at $346/MWh, which would drop to $195/MWh the following quarter, and assumes a 7 percent conservation and load-curtailment rate from June through the end of the year.

Ratepayer advocates agreed with Republicans that Davis was low-balling the spot-market purchases.

The total purchase price also assumes that many of the qualifying facilities forced off line because of being grossly shortchanged by the investor-owned utilities would go back on line. The document estimated that 90 percent of the QFs will be producing by June, up from 66 percent in April.

The analysis is set out in the *Benefit-Cost Analysis of the MOU with Southern California Edison* by the Blackstone Group and Saber Partners released April 30. That it was not referred to as a cost-benefit analysis was another indication that the figures were rose tinted ***[E. McC.]***.

[18] Bill Easing Way for MUDs Passes

After its third round of review, a controversial bill that would increase energy options for local governments passed the Senate Energy, Utilities and Communications Committee on May 1 by an 8-2 vote. The bill, SBx1-23 by Senator Nell Soto (D-Pomona), was stalled by opposition from the cable and telecommunications industry, which was threatened by the removal of hurdles to the formation of municipal utility districts.

SBx1-23 specifically would prohibit a local agency formation commission from interfering with a development of a proposed public power agency; undercut the ability of private utilities to drag proposed MUDs into court to litigate a distribution system takeover; and lower the voter approval requirement to a majority vote.

Soto amended her bill to specify it was not intended to boost local agencies' competitiveness in the cable and telecommunications arena, but industry lobbyists continued to insist that the bill should prohibit cities from entering the business. City representatives strenuously objected because that would take away existing rights. The bill continues to face an uphill battle, particularly over the provision reestablishing a conclusive presumption in place of a rebuttable presumption on the issue of whether takeover is in the public interest.

A bill facilitating aggregation for public agencies, which would also allow aggregators to sell excess power, failed. The main objections to ABx1-8 by Senator Richard Alarcon (D-Sylmar) were over allowing public aggregators to profit from power sales and sell their excess juice into investor-owned-utility territory.

A low-income oversight board would be created to implement low-income electricity and gas assistance programs under another Alarcon bill. Under SBx1-2, which passed on an 8-3 vote, the new board would replace the California Public Utilities Commission's low-income advisory board and freeze rates for California Alternative Rates for Energy (CARE) customers at January 1, 2000, levels until 2005.

Assemblymember Rod Wright's (D-Los Angeles) ABx1-3 would expand the reach of the CARE program and require the CPUC to adjust the income eligibility to factor in inflation. The bill, which won on an 8-3 vote, also includes a one-time retroactive rate reduction for natural gas charges.

'It is part of an effort to get the federal government to take some responsibility.'

Legislation that would require the California Energy Commission to monitor building energy-efficiency standards and develop a plan to decrease wasteful energy consumption in buildings, SBx1-37 by Senator Jim Brulte (R-Cucamonga), passed on a 10-0 vote.

A resolution by Assemblymember Dennis Cardoza (D-Merced) urging the Federal Energy Regulatory Commission to propose cost-based natural gas regulation at the California border, prohibiting the withholding of capacity and asking the president to meet with California delegates to discuss the energy mess was also approved. "It is part of an effort to get the federal government to take some responsibility," Cardoza said.

Another bill authored by Soto, SBx1-1, would impose a windfall tax on generators' and traders' energy sales priced above $80/MWh, or above an industrywide average price determined by the California Public Utilities Commission plus a "reasonable' profit. That bill passed the Senate Appropriations Committee on a 7-3 vote April 30. Renewables suppliers were exempted from the bill, as were existing power sales contracts.

Brulte's SBx1-17, which would provide a 50 percent tax rebate on the purchase and installation of solar equipment, passed the Appropriations Committee on a 9-0 vote ***[Elizabeth McCarthy]***.

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May 11, 2001

platts Global Power Report

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CALIF. SENATE SETS IN MOTION PLAN TO SET UP STATE POWER AUTHORITY

The California state Senate on May 4 set the stage for the state to enter the power generation business and build as much as 5,000 MW of new power plants.

In a 24-to-14 vote, the state's democratic party-dominated Senate approved creation of a public power authority and sent its bill to Gov. Gray Davis (D) for his signature. The bill, SB6x, was co-sponsored by Democratic state Senators Debora Bowen and John Burton.

The proposed new power authority, modeled in part along the lines of the New York Power Authority, will, it is argued, give the state more control over its wholesale electricity market by building and operating its own power plants. State-owned plants could charge lower prices, and

(continued on page 3)

CALIFORNIA PASSES POWER BOND BILL, BUT IT COULD BE TOO LITTLE, TOO LATE

The California legislature passed a bill authorizing issuance of up to $13.4-billion in revenue bonds needed to keep the state's lights on, but the funds may prove to be too little and too late.

Voting along party lines—49 to 29, with the Democrats in the lead and two abstentions—the California State Assembly May 8 passed SB31x authorizing the state to issue bonds that will allow the California Dept. of Water Resources to pay for future power purchases. The Senate passed its version of the bill May 9 in a 23-to-15 vote. The governor was expected to sign the bill into law on May 10, after press time.

The passage of the measure was not without its complications, however. It fell just shy of the two-thirds majority needed for the bill to take effect immediately. Instead, it will not take effect for 90 days. The three-month lag has several effects. It leaves a large gap in the state's budget. It jeopardizes some long-term power contracts between generators and the DWR. Some suppliers were given the option to back out of their contracts if the revenue bonds were not issued by July 1, but it was unclear at press time which suppliers had the option of backing out of the deals. One supplier said that it intended to fulfill its long-term contract regardless of the

(continued on page 2)

AES, BLAMING ANEEL, BNDES, SUSPENDS $2.5-BIL. PLANNED INVESTMENT IN BRAZIL

Saying that "Brazil has not been a good experience" for the company, AES Corp. president Dennis Bakke announced May 7 in Porto Alegre, Brazil, that the power firm was suspending indefinitely its plans to invest $2.5-billion in at least 10 new thermal generation plants in the country.

The projects affected include a 700-MW plant in Rio Grande do Sul known as TermoSul, and a 2,000-MW facility in Santa Branca, in Sao Paulo.

Coming from the largest private investor in Brazil's power sector, the remarks are intended to force the Cardoso administration to push for more investor-friendly policies from national electricity regulator ANEEL and national development bank BNDES.

AES last week filed a suit against ANEEL in federal court, seeking an extraordinary 7.7% tariff increase for its Rio Grande do Sul distributor, AES Sul, on the grounds that the gap between its costs and its tariff revenues had widened to 18% over the last three months.

The company also cancelled the official inauguration ceremony, scheduled for May 21 and to which President Fernan-

(continued on page 3)

CALIFORNIA PASSES BILL FOR POWER BONDS: TOO LITTLE, TOO LATE...begins on page one

timing of the bond issuance.

The delay also throws plans for a $4.1-billion bridge loan into disarray. State Treasurer Philip Angelides had hoped to have the bridge loan in place by the May 8 deadline, but the timing of the loan was contingent on having the bond offering in place by July 1 because the proceeds from the bonds would be used to repay the loan. Late on May 8, Angelides, in a terse statement, said "we will be reviewing our options to assess what, if any, steps, can be taken to stabilize the state's fiscal condition in the short term."

And finally, to add insult to possible self-inflicted injury, the Senate version of the bond bill specifically precludes spending more than $500-million from the state's general fund to purchase power after Nov. 15.

The larger question, however, is whether or not the proceeds from the proposed bond issue will be sufficient to cover the state's power bill for the next year or year and a half.

The state's controller, Kathleen Connell, has already expressed concern that the amount of money the state will need to pay for power over the next 15 months is far greater than Gov. Gray Davis' team of financial advisers has estimated and greater than the expected proceeds from the bond issue. Connell takes issue with the $195/MWh estimate for average electricity prices that the governor's team uses for this summer and with their projections that conservation will lower demand by 7%. She estimates that the state will need to spend considerably more than the $20.1-billion the governor's advisors project through year-end 2002.

Other officials have also questioned the state's own estimates. Just last week, Ray Hart, deputy director of DWR, said that the agency is finding that it is paying a premium for the power because suppliers are questioning the state's ability to pay its bills. Since Jan. 18, DWR has spent $8.3-billion to buy power, less than half of which is expected to be recouped through current rates, Hart noted.

The widely quoted $195/MWh estimate of average spot prices for power purchases this summer comes from a report prepared for the governor by Navigant Consulting. Rich Nichols, a Navigant vice president, argued that DWR, the power purchasing agent for the state since mid-January, is actually buying most of its non-contract power at lower, off-peak prices, rather than at the higher, peak prices on the spot market.

In addition to the Navigant estimates, the governor's financial advisory team, led by investment banker Joseph Fichera from the Saber Group, assumes that there will be a 4% conservation in demand "in all hours due to observed customer behavior year-to-date 2001," plus a "3% incremental reduction in demand as of June 1, 2001, for price elasticity effects" resulting from the earlier announced 3 cents/kWh increase in retail rates.

Fichera's team established estimates of how much power the DWR would have to buy for the state's three main investor-owned utilities through year-end 2010, and how much cash they will need to make those purchases. It based its estimates on data DWR has begun releasing on the amount of power the purchasing agent now has under long-term contract.

For the remaining three quarters of this year, Fichera estimates DWR will spend $11.3-billion, of which $3-billion will be spent on contract power with an average price of $138/MWh, and $8.3-billion will be needed to buy some 33.3 million MWh over the remaining three quarters of the year, at a weighted average price of $251/MWh.

In 2002, Fichera's report argues, DWR will need a total of $8.8-billion, with $4.4-billion spent for contract supplies and $4.4-billion spent on the spot market, where the average price for the year will be, according the report, $172/MWh.

Fichera's report assumes that wholesale prices will remain above retail rates during 2002. However, a turn-around will begin in 2003 as power plants now under construction in California begin to come on-line. The report projects an average spot price for 2003 of $119/MWh and argues that the DWR will need to spend $7.3-billion that year, comprised of $5.6-billion for contract power, and $1.7-billion for spot purchases.

Whether or not the funds raised by the bonds will be sufficient for the state's needs, the fact that they will not be issued for another three months could play havoc with the state's near-term finances.

Treasurer Angelides had hoped to use the $4.1-billion bridge loan to be supplied by a syndicate of bankers to replenish the state's general fund, which has been drawn down to cover DWR purchases of power.

The state, which entered this fiscal year with a $6-billion surplus, will likely end the year with a net loss of perhaps as much as $9-billion. In June, the legislature must reconvene and rewrite the state's budget for the fiscal year beginning July 1.

The bankers' concern now, which is shared by credit rating agencies, is that the state's general fund will be further depleted by payments it will have to make over the next couple of months to fund power purchases by the DWR.

On April 24, Standard & Poor's cut its rating on California's general obligation debt by two notches, from AA to A+. In explaining its action, the rating agency cited the planned bond offering as a positive factor because it would stem the flow of cash being siphoned from the general fund by the DWR.

Meanwhile, the state senate May 7 passed SB1x, a "windfall profits" tax, that would force power suppliers to return 100% of all revenues above an $80/MWh sale price to the state's taxpayers. The measure brought howls from company executives who called it "illegal" and "confiscatory." The assembly, which had not approved the measure by press time, was considering establishing the threshold price for the tax at $60/MWh.

While such a measure could prove to be an effective "cap" on power prices in California, and generate significant revenue, it also could be the final straw that drives generators from the state.

California Gov. Gray Davis was set to meet with representatives of five key power suppliers May 9, after press time, in an attempt to lower both the cost of power this summer and the amount the state owes power suppliers. The suppliers are Duke Energy, Dynegy, Mirant Corp., Reliant and Williams.

A Reliant spokesman said that John Stout, senior vice president for asset commercialization in the company's wholesale division, and Stephanie Newell, vice president for state government relations, would attend the meeting for Reliant.

The spokesman said the company had a four-part message to deliver: First, "there is a very real, severe supply shortage in California, and the political rhetoric must stop now;" second, "this [crisis] applies to the entire Western economy;" third, "California must immediately work with power providers to encourage investment in power production and infrastructure;" and fourth, "the overriding message we intend to deliver to-

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History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 38

Presentation to CPUC/CEC
(Update on Energy Procurement Program)

CONFIDENTIAL

Revenue Requirement & Consultant's Report Briefing to the Staff of CEC and CPUC on DWR Energy Procurement Program

May 18, 2001

Draft--Results Subject to Change

Navigant Consulting, Inc.

CEC & CPUC Staff Briefing

Objectives:

- Overview of requirements and purpose of consultant's report for financing.
- Update on status of DWR contracting
- Preliminary disclosure of key data and assumptions.
- Discussion of key policy issues
- Review of key DWR, CPUC, CEC, CAISO areas of interest.
- Determine desire and method for CEC and CPUC staff input to DWR.

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Navigant Consulting, Inc.

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- DWR Revenue Requirements
- IOU Revenue Requirements
- Impact of DWR Revenue Requirements on Retail Rates
- Sensitivity Analyses
- Principal Assumptions and Considerations
- Findings and Conclusions

Navigant™
CONSULTING, INC.

Load Forecast

Key Assumptions

- IOU sales projected to grow 2.0 percent p.a. through 2010 before adjustments.
- Sales reduced by following factors:
  - Customer responses to electricity crisis and appeals to conserve
  - Impact of rate increases (elasticity)
  - New conservation spending (SB 5x, AB 29x, AB 970)
  - Increased self-generation (CPUC Decision 01-03-073)
- Adjusted for these factors, total IOU Energy Requirements are 179,600 GWh in 2001
  - Total is 10 percent lower than in 2000
  - Excludes direct access (5,150 GWh, 2.9 percent of requirements)
  - Direct access is mainly a result of actual figures for Q1 2001
- Non-coincidental peak demand is adjusted for customer responses, conservation, curtailment programs
  - Combined supply- and demand-side reduction is 6,666 MW in 2001
- Adjusted non-coincidental peak demand is 34,472 MW

Navigant
CONSULTING, INC.

Conservation and Load Curtailment Assumptions

IMPACT OF NEW CONSERVATION AND LOAD MANAGEMENT INITIATIVES ON SUMMER 2001 DEMAND

Program or Initiative	Demand Impact (MW)			
	June	July	August	September
AB 970	281	320	335	335
SB 5X and AB 29X	925	1,871	2,222	2,691
20/20 Program	3,100	3,100	3,100	3,100
Government Initiatives	658	658	658	658
Utility Interruptible Programs[1]	1,500	1,500	1,500	1,500
CAISO DRP[2]	596	596	596	596
CAISO DLCP[3]	--	--	--	--
Backup Generation[4]	--	--	--	--
Total	**7,060**	**8,045**	**8,411**	**8,880**
Total Used for This Assessment[5]	**5,850**	**6,050**	**6,150**	**6,150**

[1] Assumes no increase in participation relative to year 2000.
[2] Does not include additions from second round of requests.
[3] Program rolled out in mid-April.
[4] Program under development; 296 MW bid on a CAISO solicitation.
[5] Discounted for overlapping effects, non-coincidence with system peak, and reduced implementation success. These values do not include the effect of savings in line losses.

Load Forecast Table

ESTIMATED ENERGY REQUIREMENTS
(GWh)

	Calendar Year									
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
PG&E[1]										
Energy Requirements[2]	89,370	91,158	92,981	94,840	96,737	98,672	100,645	102,658	104,711	106,806
Less: Self Generation	152	707	1,259	1,850	2,474	3,067	3,623	4,177	4,730	5,283
Direct Access	2,219	779	822	833	847	3,517	5,426	5,853	6,279	6,360
Energy Requirements Before Demand Side Effects	86,999	89,672	90,900	92,157	93,416	92,088	91,596	92,628	93,702	95,163
Less: Non-Programmatic Customer Reductions[3]	3,933	3,698	1,421	1,115	654	667	681	694	708	722
Conservation & Curtailment Programs[4]	2,671	4,080	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630
Energy Requirements After Demand Side Effects[5]	80,395	81,894	86,849	88,412	90,132	88,791	88,285	89,304	90,364	91,811
SCE										
Energy Requirements[2]	90,482	92,292	94,138	96,021	97,941	99,900	101,898	103,936	106,015	108,135
Less: Self Generation	154	716	1,275	1,874	2,506	3,106	3,669	4,231	4,790	5,351
Direct Access	2,263	901	950	963	980	4,389	6,665	7,075	7,472	7,575
Energy Requirements Before Demand Side Effects	88,065	90,675	91,913	93,184	94,455	92,405	91,564	92,630	93,753	95,209
Less: Non-Programmatic Customer Reductions[3]	3,845	3,592	1,361	1,103	635	648	661	674	688	701
Conservation & Curtailment Programs[4]	2,727	4,157	2,683	2,683	2,683	2,683	2,683	2,683	2,683	2,683
Energy Requirements After Demand Side Effects[5]	81,493	82,926	87,869	89,398	91,137	89,074	88,220	89,273	90,382	91,825
SDG&E										
Energy Requirements[2]	19,802	20,198	20,602	21,014	21,435	21,863	22,301	22,747	23,201	23,665
Less: Self Generation	30	138	246	362	483	599	708	816	924	1,032
Direct Access	669	144	153	155	158	528	942	1,006	1,098	1,113
Energy Requirements Before Demand Side Effects	19,103	19,916	20,203	20,497	20,794	20,736	20,651	20,925	21,179	21,520
Less: Non-Programmatic Customer Reductions[3]	867	818	314	247	145	148	151	154	157	160
Conservation & Curtailment Programs[4]	524	801	510	510	510	510	510	510	510	510
TOTAL IOUS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Energy Requirements (2)	199,655	203,648	207,721	211,875	216,113	220,435	224,844	229,341	233,927	238,606
Less: Self Generation	337	1,561	2,780	4,085	5,463	6,773	8,000	9,225	10,444	11,666
Direct Access	5,151	1,825	1,925	1,951	1,985	8,434	13,033	13,934	14,850	15,048
Energy Requirements Before Demand Side Effects	194,167	200,262	203,016	205,839	208,665	205,228	203,810	206,182	208,633	211,892
Less										
: Non-Programmatic Customer Reductions	8,646	8,108	3,097	2,465	1,434	1,463	1,492	1,522	1,552	1,583
Conservation & Curtailment Programs	5,922	9,037	5,822	5,822	5,822	5,822	5,822	5,822	5,822	5,822
Energy Requirements After Demand Side Effects (3)	179,600	183,116	194,098	197,551	201,409	197,944	196,496	198,838	201,259	204,486

1 All values adjusted for distribution and transmission system losses. Amounts shown for self-generation and conservation programs are increases above the levels experienced historically.
2 Annual peak demands before the effects of supply side and demand side programs and price elasticity.
3 Includes demand reduction effects resulting from price elasticity and public awareness.
4 Includes 20/20 Program, load management programs, AB 970, and new programmatic conversion.
5 Peak demand to be met through electric generating resources or power purchases.

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Load Forecast Table (cont'd)

ESTIMATED PEAK DEMANDS
(MW)

	Calendar Year									
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
PG&E[1]										
Peak Demand[2]	19,439	19,821	20,210	20,614	21,026	21,447	21,876	22,313	22,759	23,215
Less: Self-Generation	62	156	272	400	536	667	789	911	1,032	1,153
Direct Access	147	157	172	174	177	744	1,167	1,289	1,379	1,397
Peak Demand Before Demand Side Effects	19,230	19,508	19,766	20,040	20,313	20,036	19,920	20,113	20,348	20,665
Less: Non-Programmatic Customer Reductions[3]	1,033	795	304	241	141	143	146	149	152	155
Conservation & Curtailment Programs[4]	2,230	2,425	858	858	858	858	858	858	858	858
Peak Demand After Demand Side Effects[5]	15,967	16,288	18,604	18,941	18,314	19,035	18,916	19,106	19,338	19,652
SCE										
Peak Demand[2]	18,927	19,308	19,838	20,370	20,817	21,298	21,827	22,304	22,732	22,991
Less: Self-Generation	60	157	256	363	477	581	684	790	895	1,000
Direct Access	164	178	196	201	205	913	1,407	1,509	1,596	1,608
Peak Demand Before Demand Side Effects	18,703	18,973	19,386	19,806	20,135	19,804	19,736	20,005	20,241	20,383
Less: Non-Programmatic Customer Reductions[3]	1,022	759	289	235	136	139	142	145	148	150
Conservation & Curtailment Programs[4]	1,977	2,107	766	766	766	766	766	766	766	766
Peak Demand After Demand Side Effects[5]	15,704	16,107	18,331	18,805	19,233	18,899	18,828	19,094	19,327	19,467
SDG&E										
Peak Demand[2]	3,239	3,321	3,384	3,435	3,510	3,576	3,644	3,700	3,807	3,879
Less: Self-Generation	11	27	42	60	78	94	110	126	142	158
Direct Access	23	23	25	25	26	87	155	165	182	185
Peak Demand Before Demand Side Effects	3,205	3,271	3,317	3,350	3,406	3,395	3,379	3,409	3,483	3,536
Less: Non-Programmatic Customer Reductions[3]	184	135	52	40	24	24	25	25	26	26
Conservation & Curtailment Programs[4]	219	310	329	125	125	125	125	125	125	125
Peak Demand After Demand Side Effects[5]	2,802	2,826	2,936	3,185	3,257	3,246	3,229	3,259	3,332	3,385

Peak Demand (MW)										
TOTAL IOUS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demand	41,605	42,450	43,432	44,419	45,353	46,321	47,347	48,317	49,298	50,085
Less: Self Generation	133	340	570	823	1,091	1,342	1,583	1,827	2,069	2,311
Direct Access	334	358	393	400	408	1,744	2,729	2,963	3,157	3,190
Peak Demand Before Demand Side Effects	41,138	41,752	42,469	43,196	43,854	43,235	43,035	43,527	44,072	44,584
Less: Non Programmatic Customer Reductions	2,239	1,689	645	516	301	306	313	319	326	331
Conservation & Curtailment Programs	4,427	4,843	1,954	1,750	1,750	1,750	1,750	1,750	1,750	1,750
Peak Demand After Demand Side Effects	34,472	35,220	39,870	40,9830	41,803	41,179	40,972	41,458	41,996	42,503

1 All values adjusted for distribution and transmission system losses. Amounts shown for self-generation and conservation programs are increases above the levels experienced historically.
2 Annual peak demands before the effects of supply side and demand side programs.
3 Includes demand reduction effects resulting from price elasticity and public awareness.
4 Includes 20/20 Program, load management programs, AB 970, and new programmatic conversion.
5 Peak demand to be met through electric generating resources or power purchases.

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Comparison of Load Management Reductions to Total Load

	Load Managem (Mwh)	Total Load* (Mwh)			Load Management Cost ($)
May-01	19,440	14,539,660	0.1%		$ 11,178,000
Jun-01	998,272	15,274,708	6.5%		$ 155,594,656
Jul-01	998,272	16,668,975	6.0%		$ 155,594,656
Aug-01	1,033,632	17,406,438	5.9%		$ 159,130,656
Sep-01	962,912	16,803,123	5.7%		$ 152,058,656
Oct-01	19,440	15,589,479	0.1%		$ 11,178,000
Nov-01	19,440	14,470,047	0.1%	Total Effect for May-Dec 2001	$ 11,178,000
Dec-01	19,440	14,988,992	0.1%	3%	$ 11,178,000
Jan-02	19,440	15,137,217	0.1%		$ 11,178,000
Feb-02	19,440	14,063,446	0.1%		$ 11,178,000
Mar-02	19,440	14,804,321	0.1%		$ 11,178,000
Apr-02	19,440	14,402,007	0.1%		$ 11,178,000
May-02	19,440	14,811,245	0.1%		$ 11,178,000
Jun-02	962,912	15,512,766	6.2%		$ 152,058,656
Jul-02	1,033,632	17,059,348	6.1%		$ 159,130,656
Aug-02	1,033,632	17,681,427	5.8%		$ 159,130,656
Sep-02	962,912	17,097,475	5.6%		$ 152,058,656
Oct-02	19,440	15,868,822	0.1%		$ 11,178,000
Nov-02	19,440	14,786,729	0.1%	Total Effect for 2001	$ 11,178,000
Dec-02	19,440	15,262,708	0.1%	2%	$ 11,178,000

* Total Load is after conservation and price demand elasticity

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New Generation Additions--2001

STEAM (COMBINED CYCLE)

DEVELOPER	NAME	MW	START DATE	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
Wisvest	Blythe Energy Power Project	520	Mar-03							
Calpine Bechtel	Delta Energy Center	880	Jul-02							
Calpine	Sutter Project	500	Jul-01		500	500	500	500	500	500
Calpine	Los Medanos	559	Jul-01		559	559	559	559	559	559
Sempra	Elk Hills Power Project	500	3/1/02 & 3/1/03							
Inland Constellation	High Desert Power Plant	720	Jul-03							
AES	Huntington Beach Modem.	450	Aug-01			450	450	450	450	450
Duke	Moss Landing Expansion	1,060	Jun-02							
Enron	Pastoria Power Project	750	Jan-03							
ARCO Western	Midway Sunset Power	500	Mar-03							
Thermo Ecotek	Mountain View	1,056	Dec-02							
Edison Msn/Txco Global	Sunrise Phase 2	540	Jun-03							
PG&E NEG	La Paloma	1,048	12/01 & 3/02							524
PG&E NEG	Otay Mesa	510	Apr-03							
	TOTAL	**9,593**		**-**	**1,059**	**1,509**	**1,509**	**1,509**	**1,509**	**2,033**

COMBUSTION TURBINE

	NAME	MW	START DATE	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
Alliance Colton LLC	Alliance Century	40	Aug-01			40	40	40	40	40
Alliance Colton LLC	Alliance Drews	40	Aug-01			40	40	40	40	40
Calpine	Calpine King City	50	Aug-01			50	50	50	50	50
SMUD	SMUD McClellan Upgrade	22	Jul-01		22	22	22	22	22	22
LADWP	LADWP CT Projects	300	Aug-01			300	300	300	300	300
El Paso Mchnt Enrgy	United Golden Gate Peaking	51	Aug-01			51	51	51	51	51
Wildflower Energy LLC	Wildflower Larkspur	90	Sep-01		90	90	90	90	90	90
Wildflower Energy LLC	Wildflower Indigo	135	Sep-01		135	135	135	135	135	135
EdisonMsn/Txco Glbal	Sunrise Power Phase I	320	Aug-01			320	320	320	320	320
GWF Power	Hanford Peaker	95	Aug-01			88	88	88	88	88
Excelon	McClellan AFB	50	Jun-02							
CalPeak Power LLC	Cal Peak 1-7	350	Jun-01		50	150	200	300	350	350
Wellhead LLC	Wellhead - 1-4	155	Jul-01		21	150	150	150	150	150
Power Inovators	Statewide	500	Aug-01			250	500	500	500	500
Mega Energy	Tulare/Visalia	92	Sep-01				92	92	92	92
KMS Energy, Inc.	Units 1-5	50	Sep-01				50	50	50	50
Soledad	Soledad 1	13	Jun-01		13	13	13	13	13	13
Whitewater	Cabozon	43	Jan-02							
City of Colton	New CT Units	189	Jul-02							
Panda	Suisun 1&2	95	Nov-01						95	95
Neo	RedBluff	47	Jul-01		47	47	47	47	47	47
Ramco	Escondido	44	Jun-01	44	44	44	44	44	44	44
	TOTAL	**1,628**		**44**	**422**	**1,790**	**2,232**	**2,332**	**2,477**	**2,477**
	GRAND TOTAL	**11,221**		**44**	**1,481**	**3,299**	**3,741**	**3,841**	**3,986**	**4,510**

Navigant CONSULTING, INC.

New Generation Additions--2002

STEAM (COMBINED CYCLE)

DEVELOPER	NAME	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Wisvest	Blythe Energy Power Project									
Calpine Bechtel	Delta Energy Center							880	880	880
Calpine	Sutter Project	500	500	500	500	500	500	500	500	500
Calpine	Los Medanos	559	559	559	559	559	559	559	559	559
Sempra	Elk Hills Power Project			300	300	300	300	300	300	300
Inland Constellation	High Desert Power Plant									
AES	Huntington Beach Modern.	450	450	450	450	450	450	450	450	450
Duke	Moss Landing Expansion						1,060	1,060	1,060	1,060
Enron	Pastoria Power Project									
ARCO Western	Midway Sunset Power									
Thermo Ecotek	Mountain View									
Edison Msn/Txco Global	Sunrise Phase 2									
PG&E NEG	La Paloma	524	524	1,048	1,048	1,048	1,048	1,048	1,048	1,048
PG&E NEG	Otay Mesa									
	TOTAL	**2,033**	**2,033**	**2,857**	**2,857**	**2,857**	**3,917**	**4,797**	**4,797**	**4,797**

COMBUSTION TURBINE

	NAME	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Alliance Colton LLC	Alliance Century	40	40	40	40	40	40	40	40	40
Alliance Colton LLC	Alliance Drews	40	40	40	40	40	40	40	40	40
Calpine	Calpine King City	50	50	50	50	50	50	50	50	50
SMUD	SMUD McClellan Upgrade	22	22	22	22	22	22	22	22	22
LADWP	LADWP CT Projects	300	300	300	300	300	300	300	300	300
El Paso Mchnt Enrgy	United Golden Gate Peaking	51	51	51	51	51	51	51	51	51
Wildflower Energy LLC	Wildflower Larkspur	90	90	90	90	90	90	90	90	90
Wildflower Energy LLC	Wildflower Indigo	135	135	135	135	135	135	135	135	135
EdisonMsn/Txco Glbal	Sunrise Power Phase I	320	320	320	320	320	320	320	320	320
GWF Power	Hanford Peaker	88	88	88	88	88	176	340	340	340
Excelon	McClellan AFB						50	50	50	50
CalPeak Power LLC	Cal Peak - El Cajon	350	350	350	350	350	350	350	350	350
Wellhead LLC	Wellhead - 1-4	150	150	150	150	150	150	150	150	150
Power Inovators	Statewide	500	500	500	500	500	500	500	500	500
Mega Energy	Tulare/Visalia	92	92	92	92	92	92	92	92	92
KMS Energy, Inc.	Units 1-5	50	50	50	50	50	50	50	50	50
Soledad	Soledad 1	13	13	13	13	13	13	13	13	13
Whitewater	Cabozon	43	43	43	43	43	43	43	43	43
City of Colton	New CT Units							189	189	189
Panda	Suisun 1&2	95	95	95	95	95	95	95	95	95
Neo	RedBluff	47	47	47	47	47	47	47	47	47
Ramco	Escondido	44	44	44	44	44	44	44	44	44
	TOTAL	**2,520**	**2,520**	**2,520**	**2,520**	**2,520**	**2,658**	**3,011**	**3,011**	**3,011**
	GRAND TOTAL	**4,553**	**4,553**	**5,377**	**5,377**	**5,377**	**6,575**	**7,808**	**7,808**	**7,808**

Navigant CONSULTING, INC.

New Generation Additions--2003

STEAM (COMBINED CYCLE)

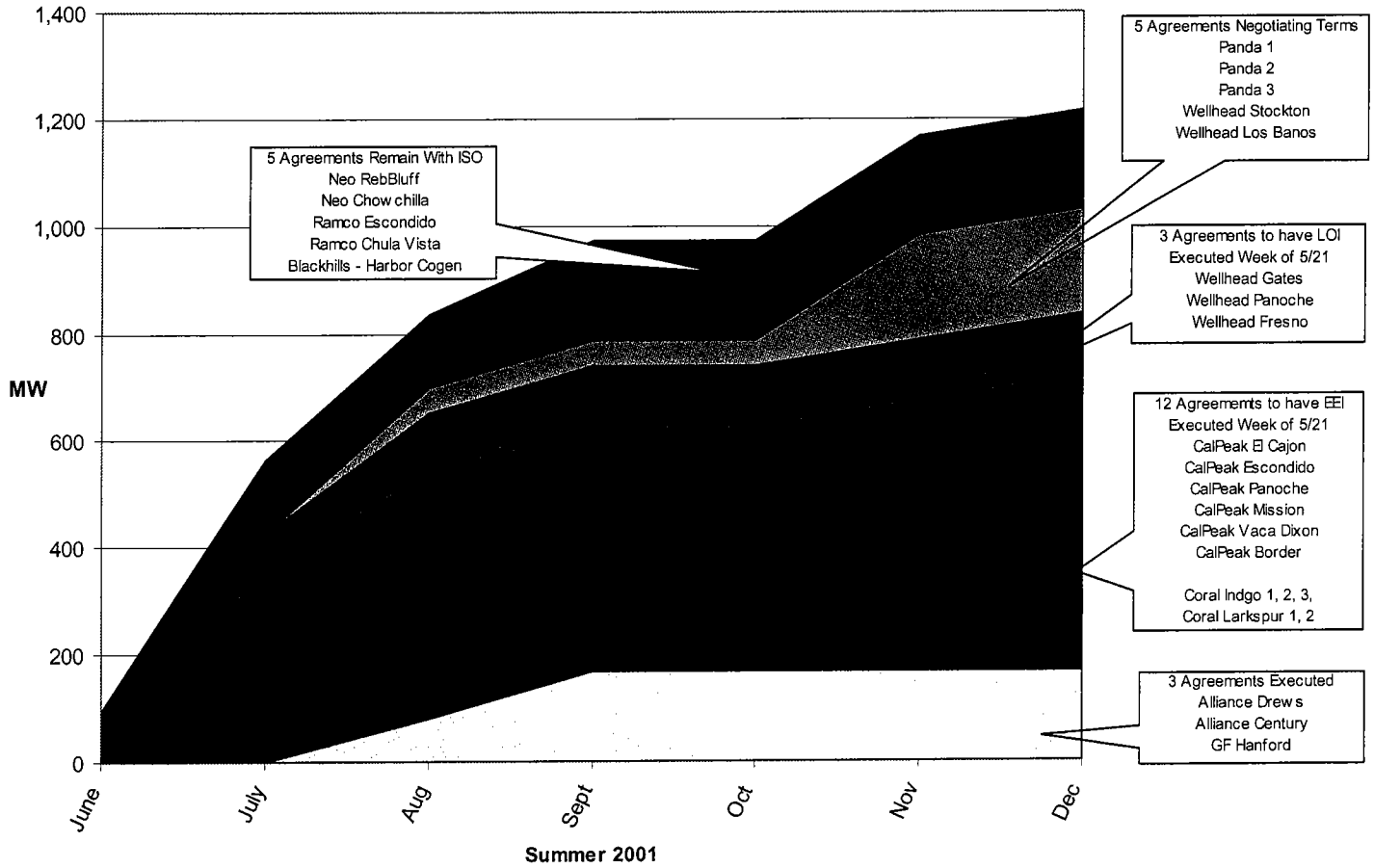
DEVELOPER	NAME	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03
Wisvest	Blythe Energy Power Project			520	520	520	520	520	520	520
Calpine Bechtel	Delta Energy Center	880	880	880	880	880	880	880	880	880
Calpine	Sutter Project	500	500	500	500	500	500	500	500	500
Calpine	Los Medanos	559	559	559	559	559	559	559	559	559
Sempra	Elk Hills Power Project	300	300	500	500	500	500	500	500	500
Inland Constellation	High Desert Power Plant							720	720	720
AES	Huntington Beach Modern.	450	450	450	450	450	450	450	450	450
Duke	Moss Landing Expansion	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
Enron	Pastoria Power Project	750	750	750	750	750	750	750	750	750
ARCO Western	Midway Sunset Power			500	500	500	500	500	500	500
Thermo Ecotek	Mountain View	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056
Edison Msn/Txco Global	Sunrise Phase 2						540	540	540	540
PG&E NEG	La Paloma	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048
PG&E NEG	Otay Mesa				510	510	510	510	510	510
	TOTAL	**6,603**	**6,603**	**7,823**	**8,333**	**8,333**	**8,873**	**9,593**	**9,593**	**9,593**

COMBUSTION TURBINE

	NAME	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03
Alliance Colton LLC	Alliance Century	40	40	40	40	40	40	40	40	40
Alliance Colton LLC	Alliance Drews	40	40	40	40	40	40	40	40	40
Calpine	Calpine King City	50	50	50	50	50	50	50	50	50
SMUD	SMUD McClellan Upgrade	22	22	22	22	22	22	22	22	22
LADWP	LADWP CT Projects	300	300	300	300	300	300	300	300	300
El Paso Mchnt Enrgy	United Golden Gate Peaking	51	51	51	51	51	51	51	51	51
Wildflower Energy LLC	Wildflower Larkspur	90	90	90	90	90	90	90	90	90
Wildflower Energy LLC	Wildflower Indigo	135	135	135	135	135	135	135	135	135
EdisonMsn/Txco Glbal	Sunrise Power Phase I	320	320	320	320	320	-	-	-	-
GWF Power	Hanford Peaker	340	340	340	340	340	340	340	340	340
Excelon	McClellan AFB	50	50	50	50	50	50	50	50	50
CalPeak Power LLC	Cal Peak - El Cajon	350	350	350	350	350	350	350	350	350
Wellhead LLC	Wellhead - 1-4	150	150	150	150	150	150	150	150	150
Power Innovators	Statewide	500	500	500	500	500	500	500	500	500
Mega Energy	Tulare/Visalia	92	92	92	92	92	92	92	92	92
KMS Energy, Inc.	Units 1-5	50	50	50	50	50	50	50	50	50
Soledad	Soledad 1	13	13	13	13	13	13	13	13	13
Whitewater	Cabozon	43	43	43	43	43	43	43	43	43
City of Colton	New CT Units	189	189	189	189	189	189	189	189	189
Panda	Suisun 1&2	95	95	95	95	95	95	95	95	95
Neo	RedBluff	47	47	47	47	47	47	47	47	47
Ramco	Escondido	44	44	44	44	44	44	44	44	44
	TOTAL	**3,011**	**3,011**	**3,011**	**3,011**	**3,011**	**2,691**	**2,691**	**2,691**	**2,691**
	GRAND TOTAL	**9,614**	**9,614**	**10,834**	**11,344**	**11,344**	**11,564**	**12,284**	**12,284**	**12,284**

Navigant CONSULTING, INC.

Statewide CAISO Summer Reliability Generation and New Summer Peakers Contract Energy



Navigant CONSULTING, INC.

CAISO Summer Reliability & New Summer Peaker Agreements

GENERAL TERMS

Contact No.		Unit MW	Term	Product	Zone	Start	June	July	Aug	Sept	Oct	Nov	Dec	Contract Status	Signed Contract	Status/Comments
ISO Summer Reliability Generation																
1	Alliance	40	10 yr	Sum. Peak	SP15	8/1/2001			40	40	40	40	40	PPA Executed	4/25/2001	
2	Alliance	40	10 yr	Sum. Peak	SP15	8/1/2001			40	40	40	40	40	PPA Executed	4/25/2001	
3	GWF	88	11yr	Sum. Peak	NP15	9/1/2001				88	88	88	88	PPA Executed	5/11/2001	
In Contract Development																
4	CalPeak	49.3	10 yr	SSPeak	SP15	7/15/2001		48	48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA
5	CalPeak	49.3	10 yr	SSPeak	SP15	7/15/2001		48	48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA
6	CalPeak	49.3	10 yr	Sum. Peak	SP15	8/15/2001			48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA
7	CalPeak	49.3	10 yr	Sum. Peak	NP15	12/1/2001							48	LOI Signed	5/7/2001	Negotiating Final PPA
8	CalPeak	49.3	10 yr	Sum. Peak	NP15	7/15/2001		48	48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA
9	CalPeak	49.3	10 yr	Sum. Peak	NP15	8/15/2001			48	48	48	48	48	LOI Signed	5/7/2001	Negotiating Final PPA
10	CalPeak	49.3	10 yr	Sum. Peak	NP15	11/15/2001						48	48	LOI Signed	5/7/2001	Negotiating Final PPA
11	Coral Larkspur 2	43	11.25 yr	Sum. Peak	SP15	7/1/2001		43	43	43	43	43	43	LOI Signed	4/3/2001	Negotiating Final PPA - Energy Portfolio, SRA Units and Market Resources
12	Coral Larkspur 1	43	11.25 yr	Sum. Peak	SP15	7/1/2001		43	43	43	43	43	43	LOI Signed	4/3/2001	Negotiating Final PPA - Energy Portfolio, SRA Units and Market Resources
13	Coral Indigo 1	43	11.25 yr	Sum. Peak	SP15	7/1/2001		43	43	43	43	43	43	LOI Signed	4/3/2001	Negotiating Final PPA - Energy Portfolio, SRA Units and Market Resources
14	Coral Indigo 1	43	11.25 yr	Sum. Peak	SP15	7/1/2001		43	43	43	43	43	43	LOI Signed	4/3/2001	Negotiating Final PPA - Energy Portfolio, SRA Units and Market Resources
15	Coral Indigo 1	43	11.25 yr	Sum. Peak	SP15	7/1/2001		43	43	43	43	43	43	LOI Signed	4/3/2001	Negotiating Final PPA - Energy Portfolio, SRA Units and Market Resources
16	Wellhead Fresno	21.3	10 yr	Sum. Peak	NP15	7/1/2001		18	18	18	18	18	18	LOI	Est. 5/24/01	Drafting LOI
17	Wellhead - Gates	49	10 yr	Sum. Peak	NP15	8/1/2001			49	49	49	49	49	LOI	Est. 5/24/01	Drafting LOI
18	Wellhead - Panoche	49	10 yr	Sum. Peak	NP15	7/15/2001		49	49	49	49	49	49	LOI	Est. 5/24/01	Drafting LOI
19	Wellhead Los Banos	49	10 yr	Sum. Peak	NP15	8/15/2001			49	49	49	49	49			Negotiating Terms
20	Wellhead Stocton	24	10 yr			-										Negotiating Terms
21	Panda	49	6 yr	Sum. Peak	NP15	11/1/2001						49	49			Lost Original Equipment - Re-Negotiating Term Sheet
22	Panda	49	6 yr	Sum. Peak	NP15	11/1/2001						49	49			Lost Original Equipment - Re-Negotiating Term Sheet
23	Panda	49	6 yr	Sum. Peak	NP15	11/1/2001						49	49			Lost Original Equipment - Re-Negotiating Term Sheet
Will Stay with ISO																
24	Neo	48.6	10 yr	Sum. Peak	NP15	6/1/2001	48.6	48.6	48.6	48.6	48.6	48.6	48.6			Indicated intent to stay with ISO Contract
25	Neo	48.6	10 yr	Sum. Peak	NP15	9/1/2001				48.6	48.6	48.6	48.6			Indicated intent to stay with ISO Contract
26	Ram	44		Sum. Peak	SP15	6/15/2001	44	44	44	44	44	44	44			Indicated intent to stay with ISO Contract
27	Ram	44		Sum. Peak	SP15	7/15/2001		44	44	44	44	44	44			Indicated intent to stay with ISO Contract
28	Blck	30		Sum. Peak	SP15											Indicated intent to stay with ISO Contract

	June	July	Aug	Sept	Oct	Nov	Dec
NP15	0	115	261	349	349	544	592
SP15	0	311	439	439	439	439	439
Total	0	426	700	788	788	983	1031

	June	July	Aug	Sept	Oct	Nov	Dec
Indicated intent to stay with ISO Contract	93	137	137	185	185	185	185
In Negotiations	0	0	49	49	49	196	196
LOI to be Executed	0	67	116	116	116	116	116

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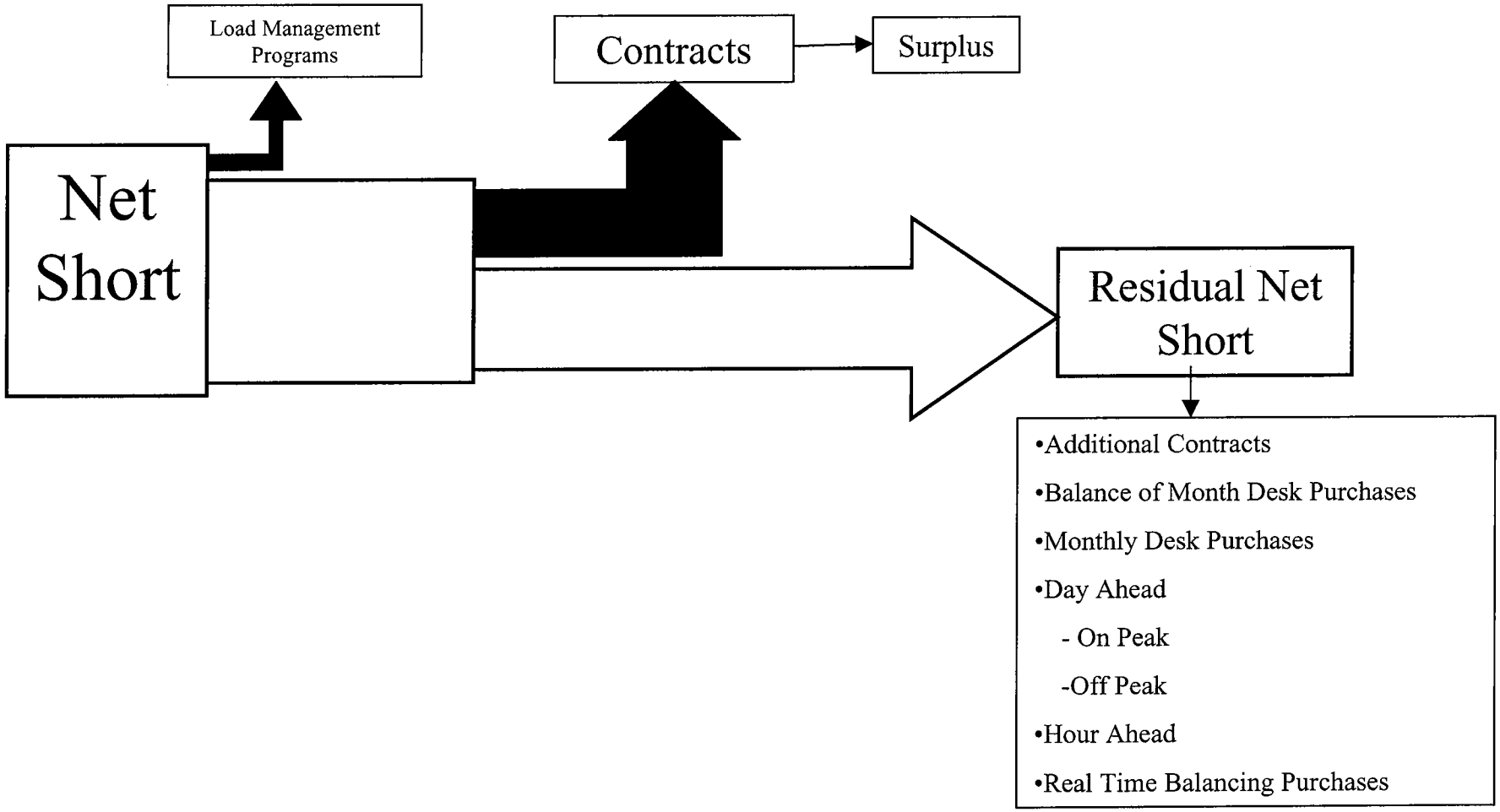
Components of Department of Water Resources Purchases of Net Short Energy



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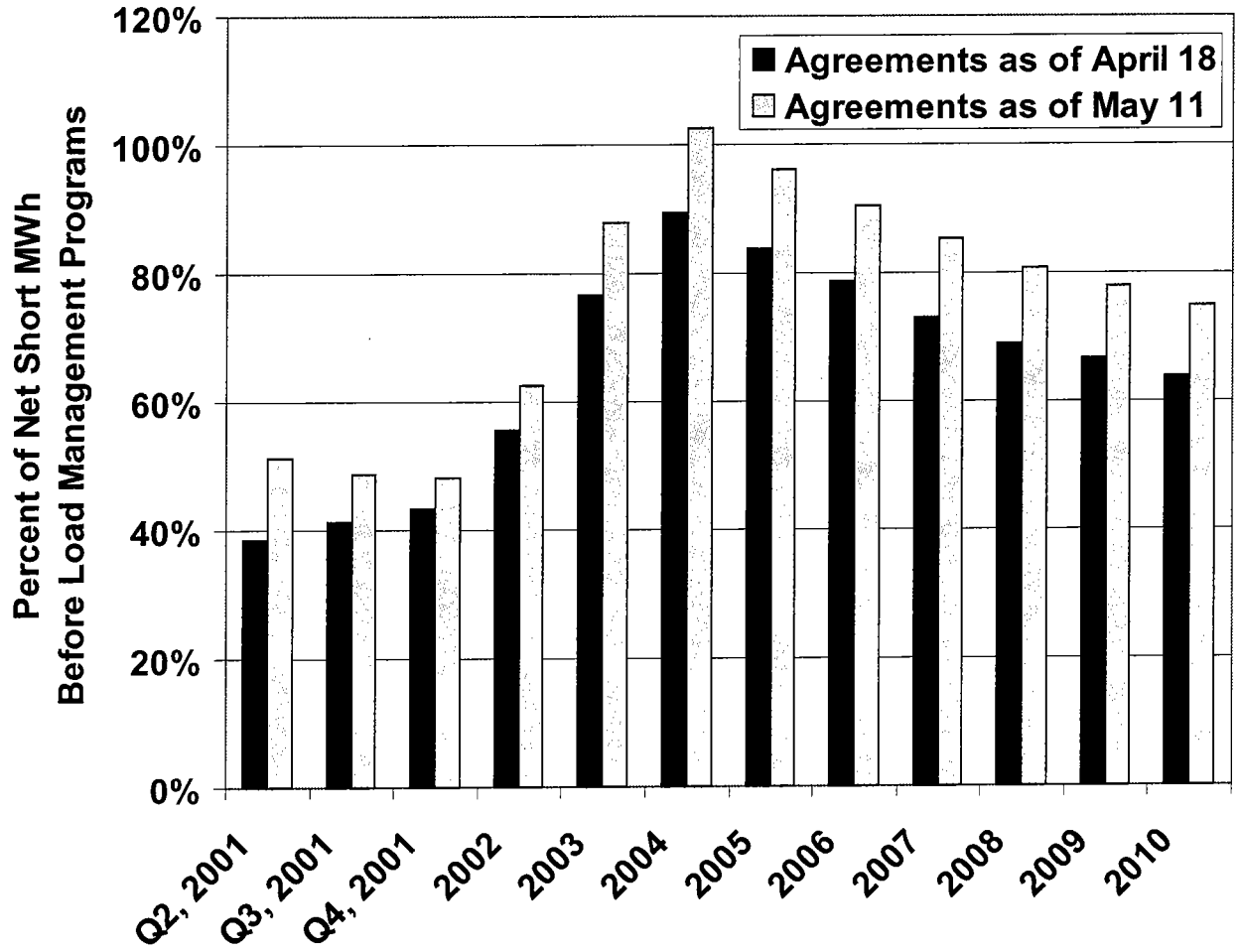
DWR Procurement Process Improves Energy Price Certainty

- First quarter 2001 required virtually all spot purchases with additional QFs off line and State required to purchase shortfall.
- Actual contracted power increases with each quarter.
- Additional power plants come on line with each quarter, increasing supply.
- Conservation programs begin and increase in effectiveness between Spring and Summer.
- Load management programs implemented Summer 2001 and 2002 to reduce "on-peak" energy purchases.
- QFs return to market progressively through the year.
- Price elasticity from rate increase begins Summer 2001.
- Net short purchase prices assumed to be higher 2nd & 3rd quarters but the net short spot purchases have diminished as a percent of total purchases.
- Longer-term prices based increasingly upon negotiated prices already in place.

DWR is Making Gains in Contract Security for Energy Pricing



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Contract and Load Management to Meet Net Short (000 MWh)

	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jul-02	Jul-03
Total Net Short	4,939	5,729	6,552	7,013	5,698	5,442	5,512	6,959	7,700
On Peak NS Mwh	3,658	3,882	4,507	4,735	4,032	3,847	3,702	4,790	5,210
Off Peak NS Mwh	1,280	1,847	2,045	2,278	1,666	1,596	1,810	2,169	2,490
Total Contracts	2,740	3,074	3,278	3,220	2,848	2,721	2,798	4,828	7,178
On Peak Contracts Mwh	2,102	2,428	2,677	2,583	2,290	2,177	2,189	3,587	5,035
Off Peak Contracts Mwh	637	646	602	637	558	544	609	1,242	2,144
Peak Net Short met by Load Management	998	998	1,034	963	19	19	19	1,034	-
Residual Net Short	1,201	1,657	2,240	2,831	2,831	2,702	2,695	1,097	521
Total Contracts and Load Management as a % of Net Short	76%	71%	66%	60%	50%	50%	51%	84%	93%
On Peak Contracts and Load Management as a % of Peak Net Short	85%	88%	82%	75%	57%	57%	60%	96%	97%
Off Peak Contracts as % of Peak Net Short	50%	35%	29%	28%	33%	34%	34%	57%	86%

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Contracts and Load Management to Meet Net Short (000 MW)

	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jul-02	Jul-03	Jul-04	Jul-05
Peak Net Short Mw (1)	10,118	10,241	11,993	13,221	10,771	9,774	9,564	11,617	13,304	15,135	15,669
Peak Contracted Mw	5,054	5,860	6,405	6,712	5,541	5,277	5,324	8,666	11,915	13,851	12,827
Peak Net Short met by Load Management	4,952	4,952	4,952	4,952	1,620	1,620	1,620	4,952	2,752	-	-
Residual Net Short	112	(572)	636	1,557	3,610	2,877	2,620	(2,002)	(1,363)	1,284	2,842
Total Contracts as a % of Net Short	50%	57%	53%	51%	51%	54%	56%	75%	90%	92%	82%
Total Contracts and Load Management as a % of Net Short	99%	106%	95%	88%	66%	71%	73%	117%	110%	92%	82%

(1) Maximum Peak of the Average Week

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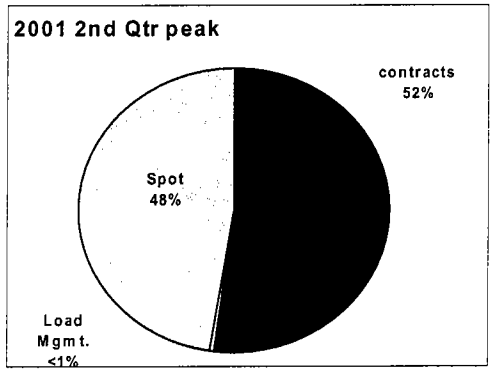
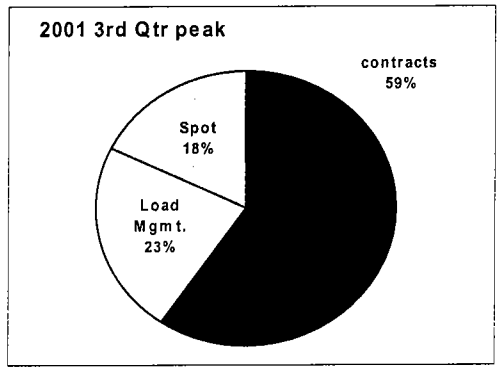
DWR has Focused its Purchases for Summer 2001 on Peak Energy Needs - Limiting Exposure to Peak Spot Prices

2001 Typical 2nd Qtr vs 3rd Qtr Monthly Energy Sources to Meet Net Short Energy Requirements

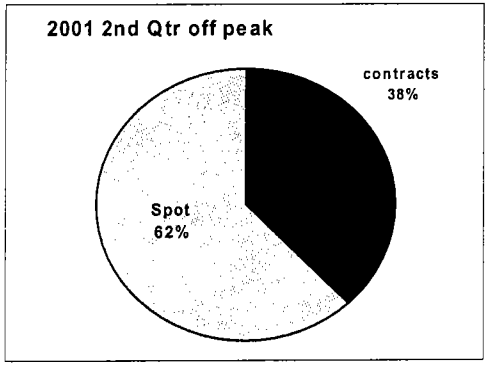
(Comparison of On-Peak and Off-Peak)



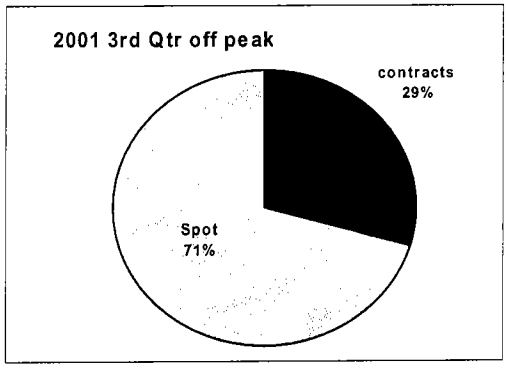
Net short



Net short



Net short



Net short

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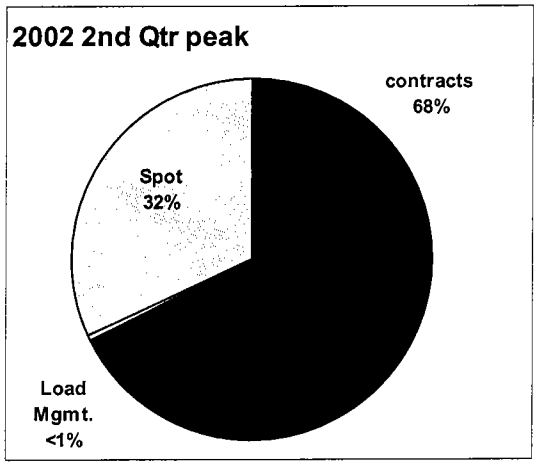
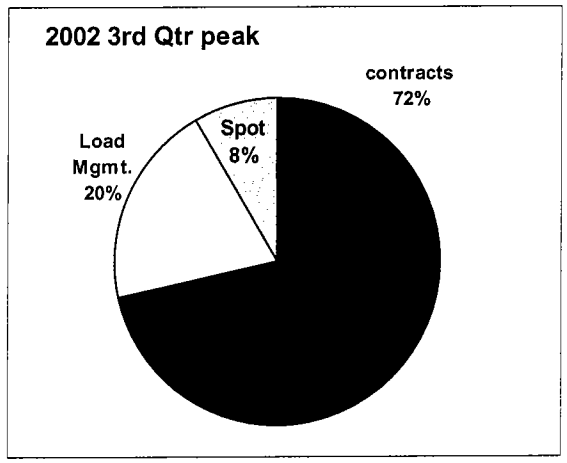
2002 Summer Peak Spot Price Exposure is Less Than 2001

2002 Typical 2nd Qtr vs 3rd Qtr Monthly Energy Sources to Meet Net Short Energy Requirements

(Comparison of On-Peak to Off-Peak)



Net short



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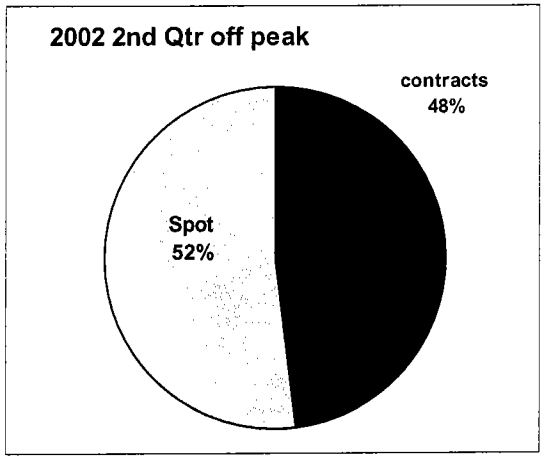
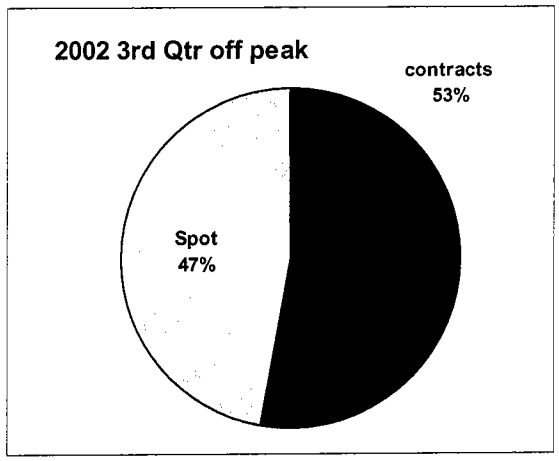


Net short



Net short

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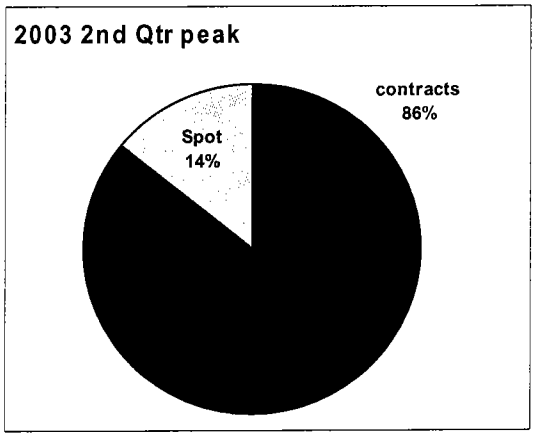
By 2003, without Load Management Programs, Spot Market Exposure is Eliminated

2003 Typical 2nd Qtr vs 3rd Qtr Monthly Energy Sources to Meet Net Short Energy Requirements

(Comparison of On-Peak to Off-Peak)



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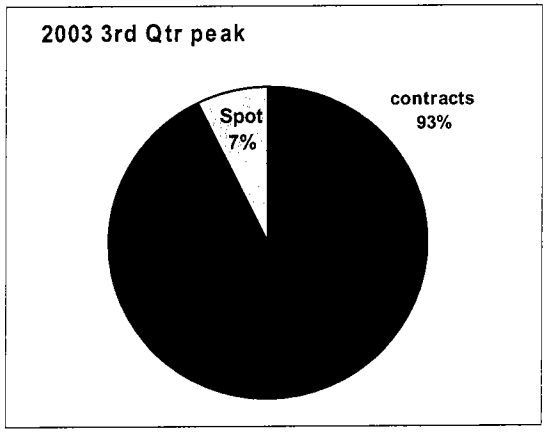
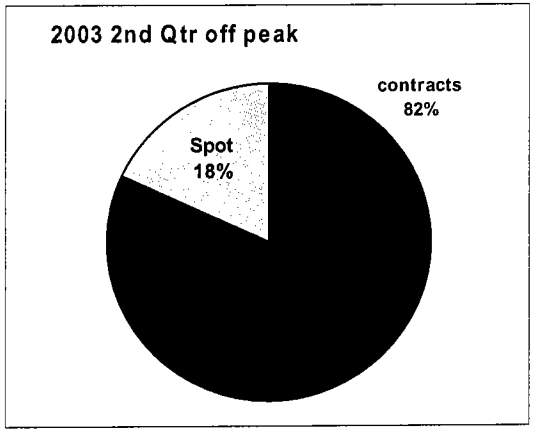
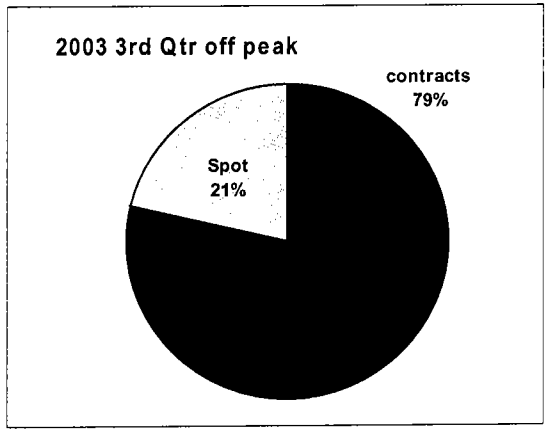


Net short



Net short



Net short

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Rights to Terminate Agreements

- Various agreements provide for right (but not obligation) of termination by one party or the other prior to the full term of the agreement, which could result in changes in the energy supply portfolio from that presented in this summary.
- Seller Termination Rights --Termination rights by the seller in some of the agreements include, but are not limited to:
  - Lack of maintenance of investment grade credit.
  - Failure by CDWR to issue the bonds contemplated by AB1X prior to a set date (such as July 1, 2001).
    - Bond-related termination rights could affect contracts providing peak capacity in the range of approximately 2,100 MW (2001 impact) to approximately 6,700 MW (2004 impact).
  - Failure to make energy payments within specified days after CDWR's receipt of an invoice.

Rights to Terminate Agreements (Cont'd)

- Buyer's Termination Rights:-- Termination rights by the buyer (CDWR) in some of the agreements include, but are not limited to:
  - Failure of a new generation unit to meet commercial operating date deadlines within a specified window.
  - Failure to achieve certain operating standards (primarily unit availability) at specified levels for specified periods.
  - Failure to operate a generating unit within "prudent industry practice" after notice and opportunity to cure such failure.

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Potential for Termination/ Renegotiation

Contracts subject to termination due to failure of CDWR to issue investment rated bonds by July 1, 2001

Agreement/Bidder	Start	Term	Product	Zone	MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10
Executed Contracts										
A	2/15/2001	5 yr	Base	SP15	50	50	50	50	50	
B1	3/1/2001	Bal '01	Peak	SP15	1000					
B2	3/1/2001	Bal. '01	OffPeak	SP15	**					
B3	1/1/2002	3 yr	Base	SP15		200	200	200		
B4	1/1/2002	3 yr	Peak	SP15		600	600	600		
B5***	1/1/2002	3 yr	Peak	SP15		500	500	500		
B6***	1/1/2002	3 yr	OffPeak	SP15		**	**	**		
C1	4/1/2001	10 yr	Peak	SP15	175	200	250	250	300	300
C2	6/1/2001	4.5 yr	Peak	SP15	140	160	240	320	400	
C3	6/1/2001	9.5 yr	Base	SP15	35	40	60	80	100	600
C4	1/1/2003	8 yr	Peak	SP15			500	500	500	500
D1	10/1/2001	10 yr	Base	NP15	*	350	600	1,000	1,000	1,000
D2	7/1/2001	9.5 yr	Base		200	1000	1000	1000	1000	1000
D3	8/1/2001	20 yr	Peak		*	450	495	495	495	495
E1	4/1/01	2.25 yr	Peak	SP15	200	200	*			
E2	7/1/03	8.25 yr	Base	SP15			745	745	745	745
F1	3/1/01	6 mos	Peak	SP15	250					
F2	1/1/03	1 yr	Peak	NP15			150			
F3	10/1/01	10.25 yr	Base	SP15	*	250	250	500	1,000	1,000
G****	9/1/01	10 yr	Peak	NP15	*	340	340	430	430	430
MW-Total					**2,050**	**4,340**	**5,980**	**6,670**	**6,020**	**6,070**

* Capacity provided during year, but not in July (month of maximum statewide net short)
** Off-peak capacity is not part of peak MW tabulation
*** Range of Peaking 500 to 1500, range of off-peak 200 to 1500
**** Bond contingency date is September 1, 2001

Bidder	Start	Termination Date	Reason for Termination
Executed Contracts			
A	2/15/2001	7/1/2001	Failure to issue bonds rated at least BBB- or Baa3, by S&P or Moody's respectively by 7/1/01
B	3/1/2001	7/1/2001	Same
C	4/1/2001	7/1/2001	Same
D	10/1/2001	7/1/2001	Same plus other more subjective measures
E	4/1/01	7/1/2001	Failure to issue bonds rated at least BBB- or Baa3, by S&P or Moody's respectively by 7/1/01
F	3/1/01	3/23/2002	Failure to incure indebtedness and issue at least $3 billion in bonds rated at least BBB- or Baa2
G	9/1/2001	9/1/2001	Failure to issue bonds rated at least BBB- or Baa3, by S&P or Moody's respectively by 9/1/01

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Rights to Terminate Agreements--Assessment

- No contracting entities have announced intent to terminate based on SB 31X effective bond issue date of August 14.
- SB 31X, while possibly delaying the bond issue, eliminated controversy of California Procurement Adjustment, established the $13.424 billion issue amount.
- DWR's progress in contracting raises questions about divested utility generation to compete beyond 2002/2003 absent a long-term contract.
- DWR is in negotiation with other parties for capacity/energy not reflected in contract total (not yet agreement in principle) which could replace some contracts, if terminated by seller.

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QF Effective Capacity Status -- Shutdown or Offline for Maintenance (or Forced Outage)

Service Territory	As of Monday, 5/07/01 Shutdown (Financial) (MW)	Maintenance (or Forced Outage) (MW)	Total (MW)	As of Monday, 4/30/01 Shutdown (Financial) (MW)	Maintenance or Forced Outage (MW)	Total (MW)	As of Monday, 4/23/01 Shutdown (Financial) (MW)	Maintenance or Forced Outage (MW)	Total (MW)
PG&E	109 (8 QFs)	82 (13 QFs)	191	637 (27 QFs)	103 (5 QFs)	740	618 (25 QFs)	193 (8 QFs)	811
SCE	225 (11 QFs)	274 (8 QFs)	499	225 (11 QFs)	292 (8 QFs)	517	225 (11 QFs)	473 (7 QFs)	698
SDG&E	0 (0 QFs)	0 (0 QFs)	0	151 (4 QFs)	0 (0 QFs)	151	151 (4 QFs)	0 (0 QFs)	151
Total	334	356	690	1013	395	1,408	994	666	1,660
N.Cal.	109	82	191	637	103	740	618	193	811
S.Cal.	225	274	499	376	292	668	376	473	849

Source: CPUC

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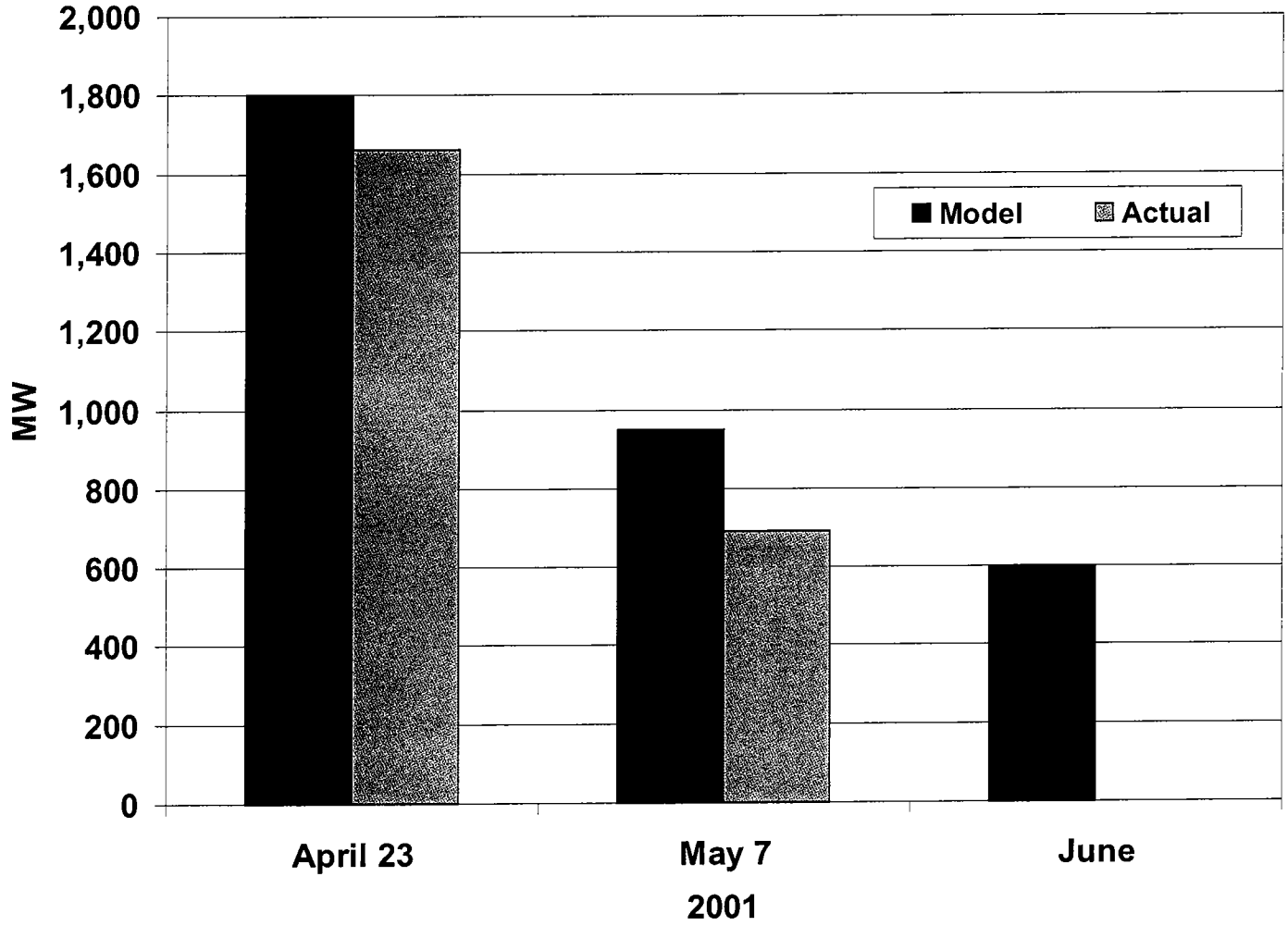
QF Capacity is Back on Line, More Quickly Than Expected

QF capacity offline



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Potential Expansion to 2001 Power Supply--Enhanced Run Hours

- Much of divested IOU generation has limited run hours due to emission limits.
- Some of DWR contracts are for emission--limited generation.
- Some owners of divested generation claim they change extreme prices to avoid dispatch and retain summer operating hours.
- DWR could increase summer peak capacity at reasonable prices if air quality districts would allow DWR to fund emission credit pool and allow scheduled hours of operation.
- Requires policy decision and generator cooperation.

Path 15 Transmission Capability

- The operating transfer capability (OTC) of Path 15 is based upon the system's ability to withstand the simultaneous loss of 2 parallel transmission lines (so called "N-2" failure).
- The south-to-north transfer capability across Path 15 is influenced by:
  - East to west flows across a path known as "West of Borah - WOB" (located between central Idaho and the Pacific Northwest)
  - The amounts of remedial actions (RAS) available in northern California
  - Ambient temperatures in the area
- The Path 15 OTC can range from 4,000 MW (with WOB transfers of 2000 MW or less, low ambient temperatures, and high RAS availability) to less than 1,500 MW (with WOB transfers of 2,300 MW, high temperatures, and low RAS availability).

Path 15 Transmission Capability

- Path 15 limitations have impacted the ability to deliver resources from the Midway area and southern California to northern California.
- Unless they are remedied, these limitations will likely impact the ability of DWR to use resources located in the Midway area and southern California to serve load in northern California or for sales of excess energy to the Pacific Northwest.
- For example, it would not be possible to schedule power from southern to northern California if:
  - Diablo Canyon generation is operating at 2,200 MW
  - Morro Bay generation is operating at 900 MW
  - The approved and proposed IPPs in the Midway area were operating at about 1,700 MW

DWR's SP-15 Purchase Obligations Focus Attention on Path 15 Constraints

- DWR has entered into contracts for delivery into the SP-15 zone which exceed SP-15 needs during certain periods
- In the 2003-2005 period SP-15 contract supply can exceed projected net short needs by 1500 W to 4600 MW with the larger excess occurring in off-peak months.
- The initial proposed upgrade to Path 15 (Los Banos-Gates and Gates-Midway 230 kV line) would enable and additional approximately 1000 MW of this excess to be transferred into NP-15 to meet net short energy requirements.
- Further Path 15 upgrades such as Midway-Adelanto (or equivalent) would increase SP-15 to NP-15 flows by another 1000 MW.

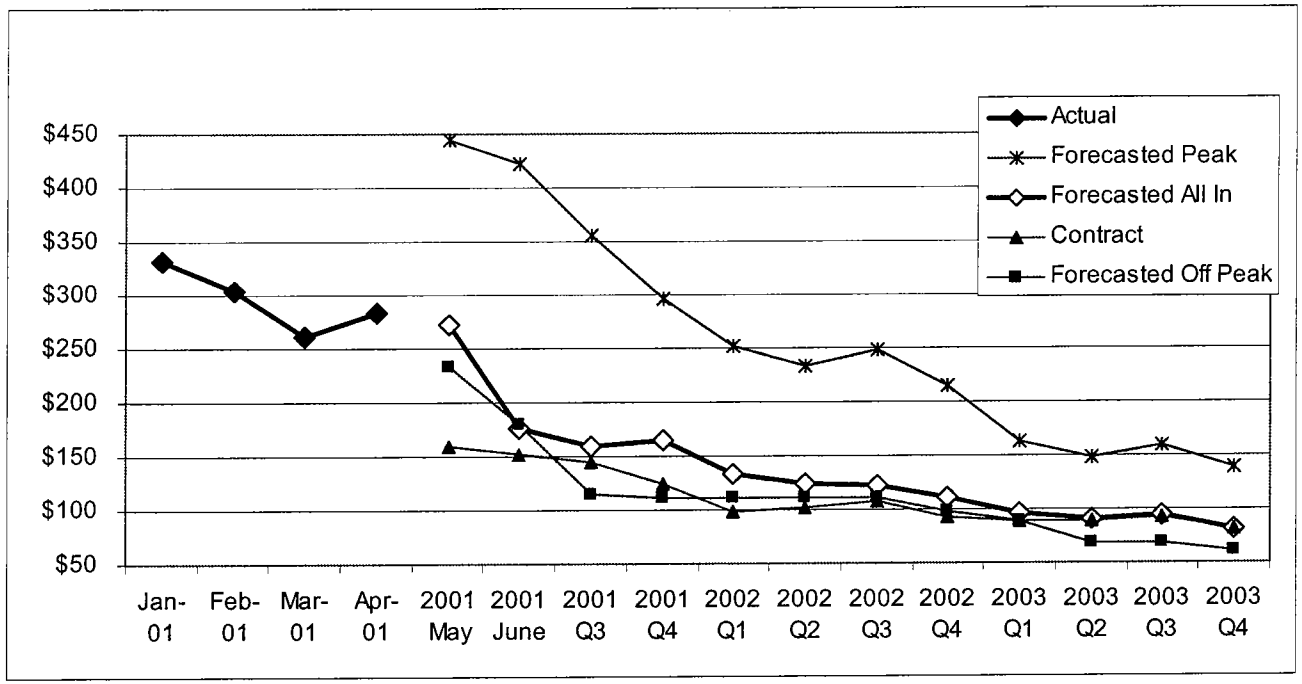
Path 15 Upgrade Timing Implications

- DWR's contracting assumed late 2002 to early 2003 upgrade completion with 2003-2004 "Midway-South" expansion.
- Delay in completion leaves NP-15 further exposed and creates challenges to delivery and use of SP-15 contract purchases during certain load conditions.
- Average prices to retail customers of all three IOUs will be impacted by timing of Path 15 upgrade.
- More detailed studies underway to better quantify impact.

Why Will Summer Prices Not be the Same as Spring?

- During Spring 2001 over 12,500 MW of capacity was off-line, including over 3,100 MW of base load nuclear.
- No load management programs were in effect during Spring months.
- Result was high off-peak pricing, similar to on-peak.
- With nuclear and base-load QF capacity on-line in Summer and with other gas-fired steam plants on-line to meet peak sales in spot or contract market, substantial additional generation will be on-line off-peak, lowering off-peak prices.
- With load management, about 20% of peak energy needs would face the spot market, on average, limiting peak prices.

Forecasted and Actual Market Prices for Energy (2001-2003)



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Detail of DWR Net Short Energy and Total Purchases

		Load Management Programs			Contracted Energy			Remaining Net Short										Total Purchases		
	Net Short Before Load Management Programs (GMwh)	Volume (GMwh)	% of Net Short (%)	Avg. Price ($/Mwh)	Volume (GMwh)	% of Net Short (%)	Avg. Price ($/Mwh)	Volume (GMwh)	Peak Volume (GMwh)	% to be purchased on peak (%)	Peak Avg. Price ($/Mwh)	Off Peak Volume (GMwh)	% to be purchased off peak (%)	Off Peak Avg. Price ($/Mwh)	Average Price of Remaining Net Short and Load Management ($/Mwh)	Total Purchased Energy (1) (GMwh)	Total Cost of Purchased Energy ($1000s)	Avg Price of Purchased Energy ($/Mwh)
2001 Q1																13,300	$ 3,792,565	$ 285
2001 April																6,582	$ 1,859,537	$ 283
2001 May,June	10,598	1,018	10%	$ 164	5,819	55%	$ 155	4,077	2,238	30%	$ 460	1,839	57%	$ 216	$ 313	10,914	$ 2,496,719	$ 229
2001 Q3	18,635	2,995	16%	$ 156	10,078	54%	$ 145	6,222	1,936	16%	$ 338	4,286	69%	$ 114	$ 175	19,294	$ 3,069,011	$ 159
2001 Q4	15,549	58	0%	$ 575	9,224	59%	$ 124	7,370	4,013	38%	$ 297	3,358	66%	$ 111	$ 216	16,653	$ 2,743,288	$ 165
2002 Q1	15,161	58	0%	$ 575	10,580	70%	$ 98	5,570	3,369	32%	$ 253	2,201	47%	$ 111	$ 201	16,208	$ 2,169,529	$ 134
2002 Q2	15,820	1,002	6%	$ 174	11,139	70%	$ 102	4,422	2,184	20%	$ 222	2,239	46%	$ 111	$ 167	16,563	$ 2,043,655	$ 123
2002 Q3	21,038	3,030	14%	$ 155	14,412	69%	$ 108	4,435	1,157	8%	$ 245	3,277	47%	$ 111	$ 150	21,877	$ 2,676,174	$ 122
2002 Q4	18,040	58	0%	$ 575	13,884	77%	$ 93	4,613	2,401	20%	$ 217	2,211	37%	$ 98	$ 165	18,555	$ 2,059,939	$ 111
2003 Q1	17,356	-	0%	$ -	15,149	87%	$ 90	3,123	1,716	14%	$ 166	1,407	26%	$ 88	$ 131	18,272	$ 1,767,745	$ 97
2003 Q2	16,930	-	0%	$ -	16,567	98%	$ 89	1,496	704	6%	$ 141	793	15%	$ 68	$ 102	18,063	$ 1,622,422	$ 90
2003 Q3	23,698	-	0%	$ -	21,811	92%	$ 92	2,678	1,189	8%	$ 156	1,489	19%	$ 68	$ 107	24,489	$ 2,300,777	$ 94
2003 Q4	19,450	-	0%	$ -	22,848	117%	$ 81	490	57	0%	$ 139	433	7%	$ 56	$ 66	$ 23,338	$ 1,880,946	$ 81

(1) Total Energy and Load Management Reductions

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DWR's Two Simulation Models

- Static, spreadsheet model (used for data provided to PUC to date)
  - Simple to understand
  - Fast
  - Best for firm contract blocks at firm prices
  - Uses price forecasts, loads, and resources to calculate costs
  - Accurately tracks costs through to revenue requirements
- Dynamic, chronological model: Prosym (Henwood)
  - Complex
  - Slower but comprehensive
  - Extensive database of generators, hourly loads, transmission limits
  - Best for hourly, chronological dispatch, random outages, load flows
  - Generates California market price forecasts
  - Planned for use in NCI's consultant's report for DWR bond financing
  - Projected prices will change with this model

Gas Price Forecast Methodology

- Econometric -- relates weather and well completions to price.
- Calculate Henry Price --
  - set initial year using January 2001 futures
  - normal weather
  - well completions sufficient to reach 31 Tcf
- Add assumed basis to reach California border.
- Basis to other regions uses old relationship.

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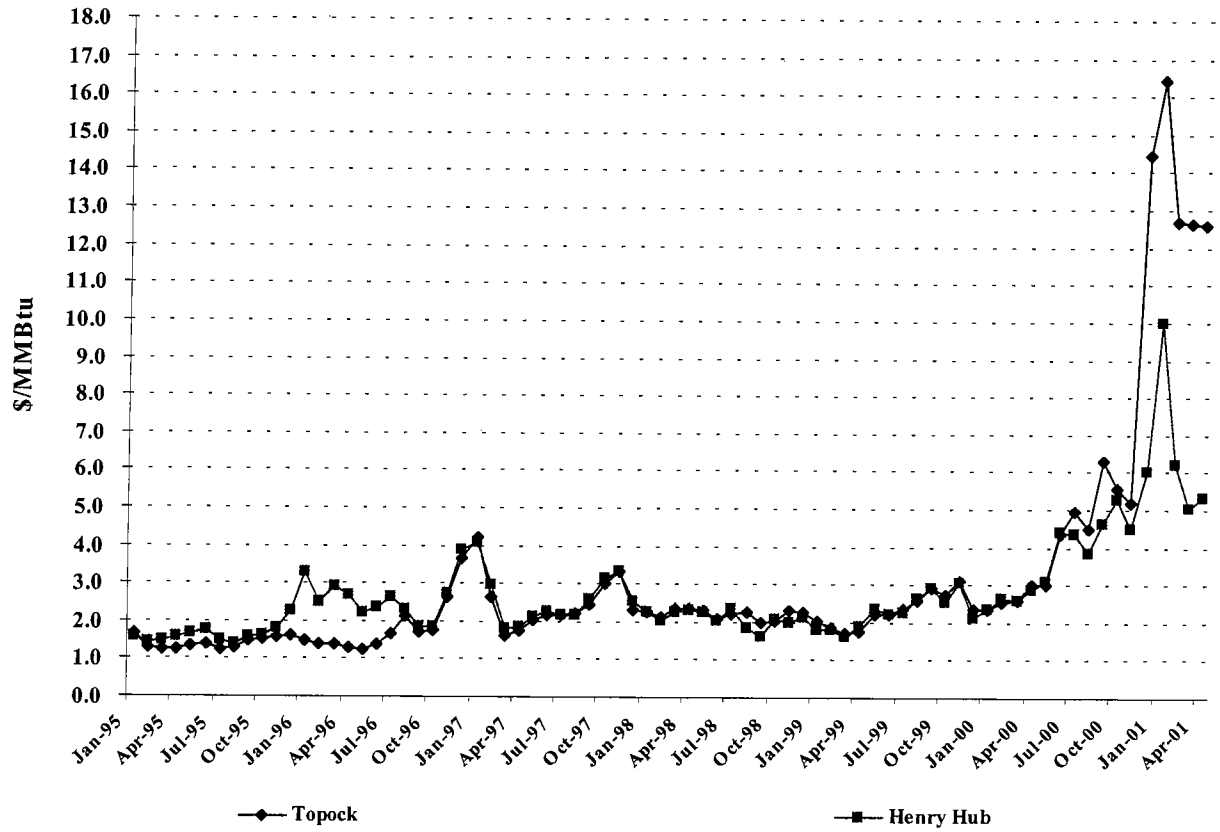
Gas Prices
Topock vs. Henry Hub -- Actual



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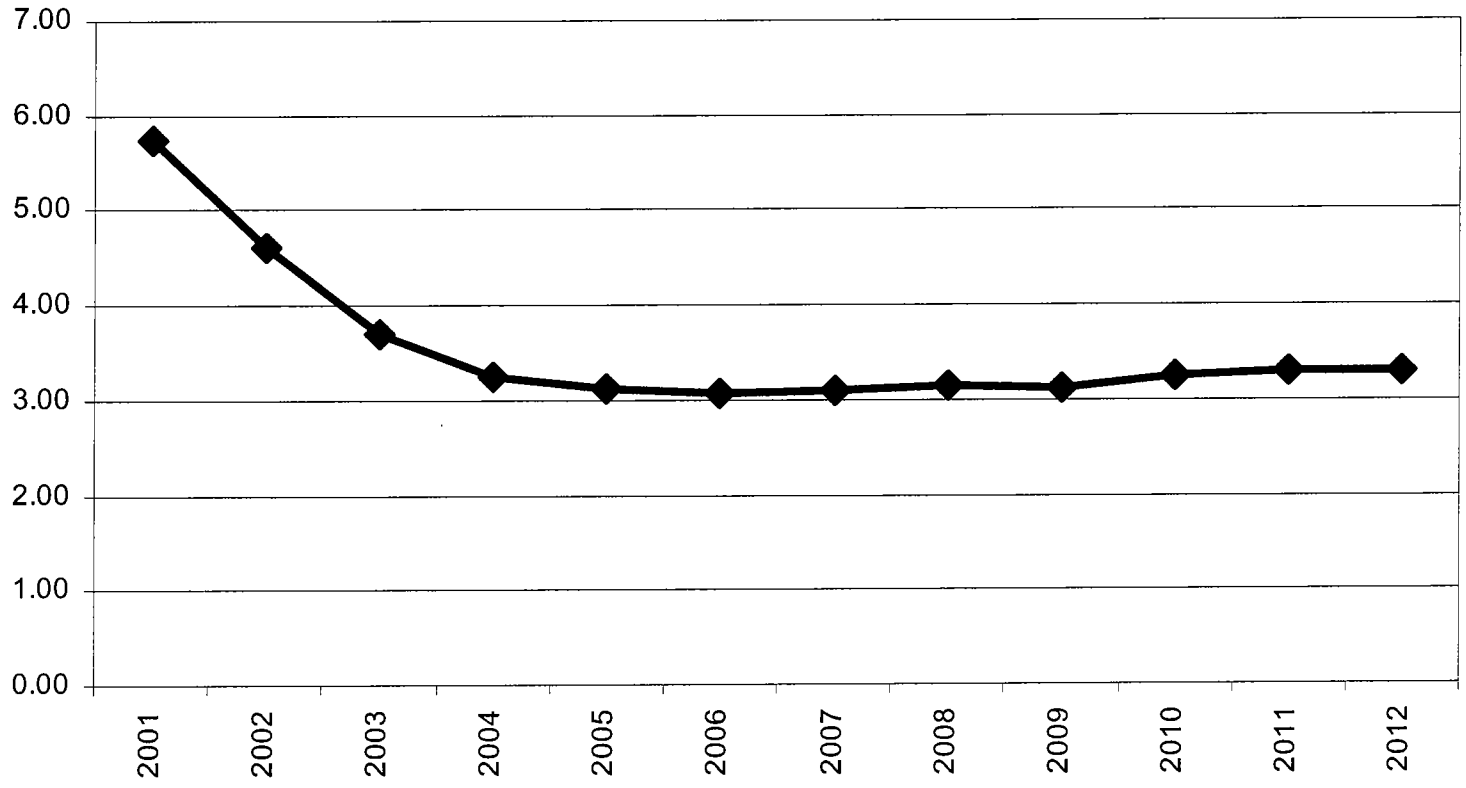
Henry Hub Forecast



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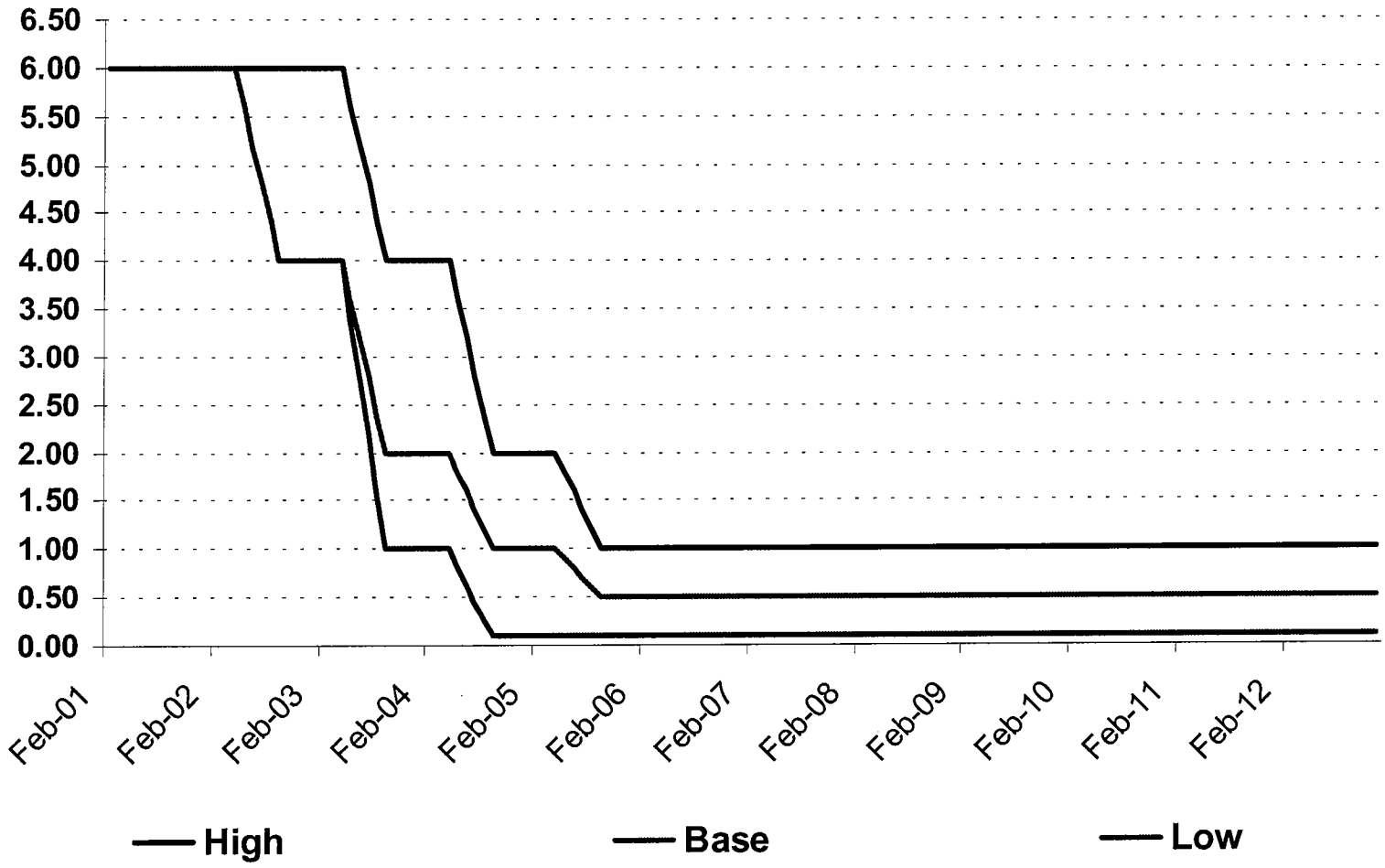
Assumed Basis Differentials

$/MMBtu



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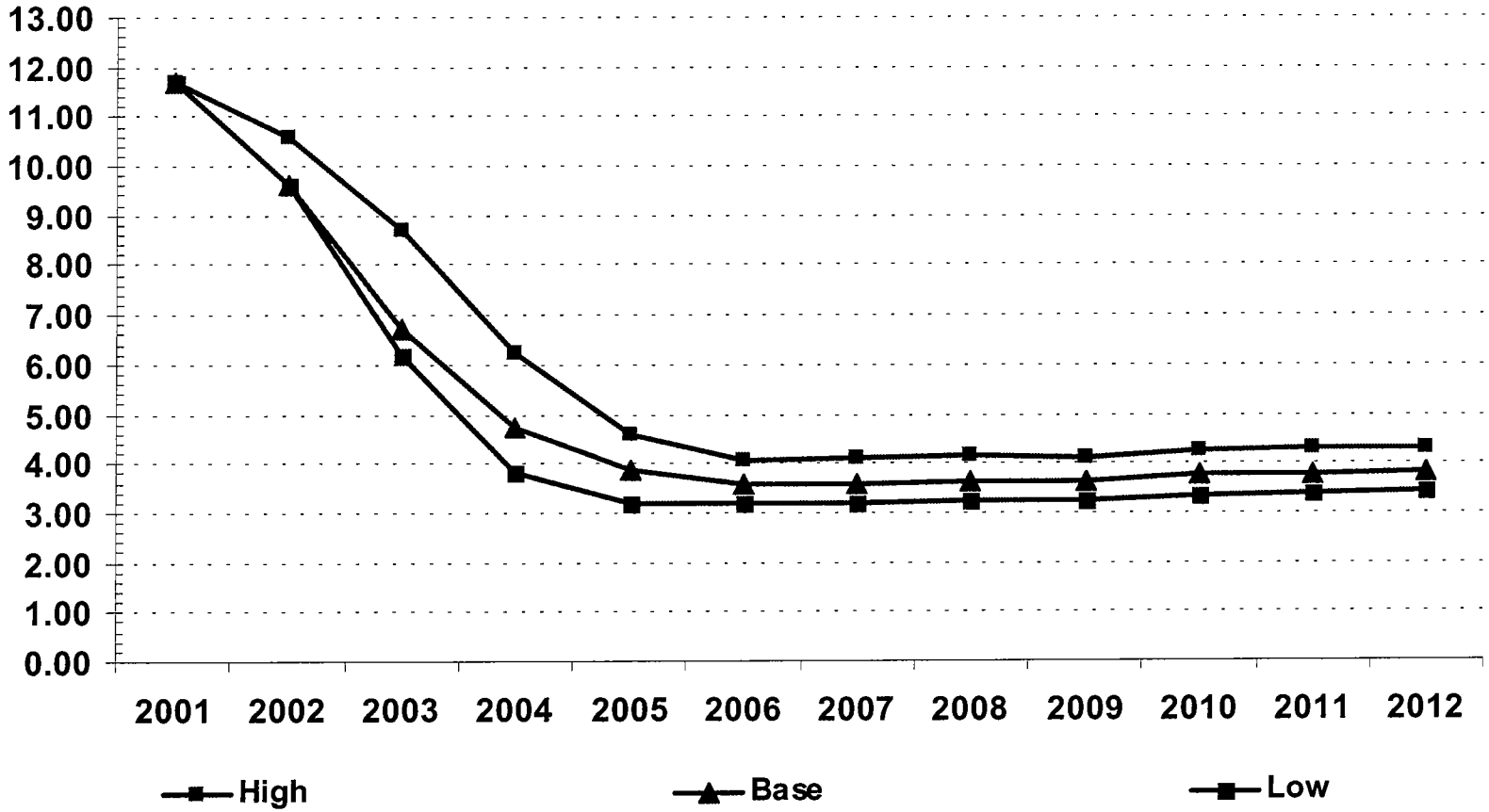
California Border Gas Prices

$/MMBtu



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California Border Gas Prices

$/MMBtu

Year	High	Base	Low
2001	11.67	11.67	11.67
2002	10.61	9.61	9.61
2003	8.71	6.71	6.21
2004	6.25	4.75	3.80
2005	4.61	3.86	3.21
2006	4.07	3.57	3.17
2007	4.09	3.59	3.19
2008	4.14	3.64	3.24
2009	4.12	3.62	3.22
2010	4.25	3.75	3.35
2011	4.29	3.79	3.39
2012	4.31	3.81	3.41

Basis Differential to Other WSCC Markets

- Basis reflects "old"/"normal" relationship before current market disruption.

PacNW ($/mmBtu)	RockyMT ($/mmBtu)	AZ_NV ($/mmBtu)
($0.70)	($0.43)	($0.28)

- Model tends to locate resources where gas costs are lower.

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Consultant's Report for Financing Will Include Five-Year IOU Total Revenue Requirement Projections

- Need to show ability to meet DWR and IOU costs within retail rate range.
- Need comparison of IOU rates to other utilities.
- Expect to show sensitivity cases with range of revenue requirements.
- Rating agencies and investors require total rate evaluations for assessment of consumer willingness to pay.

Sensitivity Cases Will Be Evaluated

Cases Could Include

- Changes in demand
- Ranges of short-term outages
- Fuel price ranges
- Changes in timing of new capacity additions
- Different hydroelectric production conditions
- Timing of Path 15
- Changes in completion of contracts

DWR, CAISO, CPUC and CEC Coordination Needs

- CAISO and DWR need to coordinate on resource planning, scheduling and purchase decisions.
- DWR needs CAISO scheduled outage information.
- CAISO dispatch needs to recognize DWR contract pricing and obligation.
- DWR plans to fund programmatic conservation and load curtailment implemented by IOUs.
- DWR will monitor prices and loads to periodically update its revenue requirement.
- DWR and CEC should coordinate on conservation, renewable and distributed generation programs.
- DWR and CEC need regular coordination on new project permitting.
- Schedule for and means to accelerate Path 15 upgrade is critical.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 39

FERC Price Mitigation Order

95 FERC ¶ 61,418

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Curt Hébert, Jr., Chairman;
William L. Massey, Linda Breathitt,
Pat Wood III, and Nora Mead Brownell.

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	Docket No. EL00-95-031
Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-030 EL00-98-033
California Independent System Operator Corporation	Docket Nos. RT01-85-000 RT01-85-001
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	Docket Nos. EL01-68-000 EL01-68-001

ORDER ON REHEARING OF MONITORING AND MITIGATION PLAN FOR THE CALIFORNIA WHOLESALE ELECTRIC MARKETS, ESTABLISHING WEST-WIDE MITIGATION, AND ESTABLISHING SETTLEMENT CONFERENCE

(Issued June 19, 2001)

Introduction and Summary

On April 26, 2001, the Commission issued an order (April 26 Order) [1] establishing new price mitigation for sales in the California Independent System Operator's (ISO) ancillary services and imbalance energy markets (spot markets). [2] The April 26 Order also instituted an investigation under section 206 of the Federal Power Act (FPA) into the reasonableness of the rates for wholesale sales in the spot markets [3] in the Western Systems Coordinating Council (WSCC). [4] In so doing, we were mindful that the West is a single market which is at once inextricably interrelated, yet characterized by important differences. Fundamental in this regard is that the California spot markets are presently administered largely through the ISO's centralized clearinghouse, which operates a single price auction, while sales in the rest of the West are consummated on an individual bilateral contract basis and not through a centralized clearinghouse.

We have received and carefully considered many comments on how to change or improve our price mitigation in California and on whether and how to initiate price mitigation in the rest of the WSCC. Today, we will prescribe price mitigation for spot markets throughout the West which will guide the WSCC's energy markets through the difficult process of self-correction. In so doing, we seek to intervene in markets in as limited a manner as possible consistent with our responsibilities to ensure just and reasonable rates under the FPA, to rely on market principles wherever we can, and to balance carefully the need for price relief against the need for price signals to attract critical supply entry.

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[1]San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,115 (2001). On May 25, 2001, the Commission issued an order providing clarification and preliminary guidance on the implementation of the mitigation plan. 95 FERC ¶ 61,275 (2001).

[2]The price mitigation established in the April 26 Order replaced the price mitigation previously in effect for such sales, and is an outgrowth of a Commission investigation under section 206 of the Federal Power Act (FPA) of the reasonableness of rates for public utility sales through the markets operated by the ISO and the California Power Exchange (PX).

[3]As used throughout this document, the terms "spot markets" or "spot market sales" means sales that are 24 hours or less and that are entered into the day of or day prior to delivery.

[4]References throughout this document to the WSCC are intended to refer only to the United States portion of the WSCC.

Today's order is one of a series of mitigation directives that began with our underlying order, issued December 15, 2000, [5] to correct dysfunctions in the wholesale power markets operated by the ISO and PX. Specifically, the elimination of the mandatory buy-sell requirement and the elimination of the PX rate schedule have helped to turn the tide in eliminating California investor-owned utilities' chronic reliance on spot markets. The effects of the price mitigation directed by our December 15 Order and the actions of the State of California in moving to longer-term contracts and conservation efforts have had a significant dampening effect on prices. As a result, California investor-owned utilities no longer rely on spot markets for meeting the entirety of the needs of the electric customers they serve. California now forecasts that it will only rely on the spot markets this summer for about 20% of its on-peak energy requirements, as compared to 100% prior to the December 15 Order. [6] In fact, in certain hours, the ISO data show no purchases whatsoever in its imbalance energy market. Because this market is the closest in time to when load must be met, it can exhibit the highest prices in times of shortage.

The reduction of the size of the ISO's spot market to levels more reflective of appropriate risk management was, and remains, the cornerstone of our price mitigation. The reduction of the size of California's spot market in conjunction with the mitigation plan adopted in our April 26 Order, as well as a dramatic reduction in gas prices and fewer generation outages in California, are among the factors that have had the effect of lowering energy prices in the West. Western power prices have fallen recently, with reports by the ISO citing peak daytime purchase costs of less than $100/MWh and off-peak power purchases of less than $20/MWh. During the week ending June 9, prices for last-minute peak power at Western trading hubs fell to less than $55/MWh from a high of about $170/MWh earlier in the week.[7] This trend continued into the week ending June 16 with prices hovering between $50/MWh and $65/MWh at most of the Western power indexes.[8] In addition, prices for Western forward contracts are also down

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[5]San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000) (December 15 Order).

[6]Update of California Department of Water Resources Power Purchase Contract Efforts, California Department of Water Resources (May 31, 2001).

[7]Platts Power Markets Week, June 11, 2001. Prices of Spot Electricity, Week Ending June 9 - Daily On-Peak Indexes for Calif-Ore Border, Mid-Columbia, Palo Verde, Four Corners, North Path 15, and South Path 15 (Six Western Indexes).

[8]Megawatt Daily's Market Report, June 11 through June 14, 2001, for Six Western

(continued...)

dramatically, with year 2002 forward transactions dropping from $127 to $68/MWh, and 2003 forward contracts from $60 to $41 in the past month.[9]

While progress has been made in correcting market dysfunctions, the dysfunctions will not be fully corrected until additional load is moved from the spot market to longer-term contracts (a mixed portfolio of supply contracts) and the basic structural defect of inadequate supply in the West is corrected. The Commission therefore has determined that in order to ensure that rates for sales for resale in spot markets in California and the rest of the WSCC continue to fall within a zone of reasonableness, we will provide for price mitigation in California and throughout the remainder of the WSCC during reserve deficiency hours, i.e., when reserves in California fall below 7 percent (in California, Stage 1 is called when reserves fall below this level).[10] As we found in our April 26 Order, this is when the level of demand approaches the amount of available supply and suppliers have the greatest opportunity to exercise market power. In addition, based on the comments received and based on prices that we recently have observed in California in hours where there is no reserve deficiency, we conclude that as an added measure in protecting customers, at this time it is also appropriate to provide for a type of price mitigation for spot market sales during other hours.

As noted, we find it appropriate to provide for price mitigation in the spot markets in California and throughout the West in reserve deficiency hours, i.e., when reserves fall below 7 percent in California. As we found in our April 26 Order, at these times supply is scarce relative to demand and sellers have the greatest ability to dictate price. The price mitigation we will adopt for these hours will be based on market principles and will apply to California and the remainder of the West. Because there is no centralized clearinghouse for spot market sales in the WSCC other than in the ISO, and therefore no ability to develop a separate market clearing price for sales outside the ISO, we will apply the ISO market clearing price as the maximum price to all sales in the WSCC spot markets during reserve deficiency hours (Stage 1 or above) called by the ISO. We expect prices to be below this level to reflect the degree to which supply exceeds demand. Thus,

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[8](...continued)
Indexes.

[9]Platt's Power Markets Week, June 11, 2001, pp. 1, 16. As used throughout this document, "forward contracts" or "forward transactions" means any transactions with a future delivery that are entered into more than 24 hours before commencement of service.

[10]Our April 26 Order referred to Stage 1 being called by the ISO when reserves in California fall below 7.5%. The correct number is 7%.

our mitigation will apply to all sellers in the WSCC, including marketers and non-public utilities. It is critical to treat all sellers alike to remove the incentive to sell in one area versus another when a reserve deficiency is called by the ISO. We also will allow sellers other than marketers the opportunity to justify prices above the market clearing price during reserve deficiency hours and we will provide guidance on the specific showing that a seller must make.

In non-reserve deficiency hours, when supply is not scarce, prices should be disciplined sufficiently and should reflect an accurate measure of the shortage confronting the West and provide a clear price signal to induce new supply. However, commenters are concerned that prices may remain high in hours when reserves are adequate. There is little doubt that regulators are ill-equipped to replicate the premiums which a functioning market assigns to a diminishing supply. It is precisely for this reason that, in our April 26 Order, we did not attempt to develop an administratively determined component for shortage and chose instead to rely on prices in non-reserve deficiency hours to send the correct price signal. Nevertheless, at this time, we will implement price mitigation in non-reserve deficiency hours as well. However, we will use a modified form of our present mitigation during non-reserve deficiency hours -- to ensure that prices will continue to induce new supply. We do so as a discretionary matter to provide an added measure to protect customers and the economies of the Western states, even though we view prices above the marginal cost of generation in these hours as a necessary reflection of the supply shortage at hand. Instituting mitigation in these hours will protect customers so that all energies and attention can be harnessed on the tasks of adding new supply and upgrading energy infrastructure and of completing California's transformation from 100% reliance on the spot market to a balanced portfolio of short, medium and long-term supply arrangements, as well as protecting neighboring states from undue harm. Later in this order, we direct the State of California and parties in the San Diego Gas & Electric Company complaint proceeding to settlement proceedings to complete the task of settling past accounts and structuring the new arrangements for California's energy future. We will monitor our price mitigation in non-reserve deficiency hours to ensure that it is providing the incentives needed to correct the present market dysfunctions. We will adjust the mitigation, as needed, to induce long-term supply entry and the forward contracts required to support that entry.

The price mitigation we are adopting again relies on market solutions and mechanisms to the maximum extent possible. We will continue to use a single market clearing price derived from must offer and marginal cost bidding requirements for hours of reserve deficiency in California's organized spot market. We also will adapt these market clearing prices for use in all other hours, both in California's spot markets and the West's spot markets. Before describing in general the price mitigation that will be required in the ISO's markets and in the bilateral spot markets in California as well as the

rest of the West, we believe it is important to enumerate the major considerations we have balanced in developing appropriate price mitigation.

- There is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot markets in California and the rest of the West, and the prices in forward markets.

- Uniform price mitigation for California and the balance of the West should reflect the same essential competitive market principles, while recognizing the significant differences in the structure of those markets. It also should eliminate incentives for so-called "megawatt laundering". [11]

- In exercising our statutory responsibility to ensure just and reasonable rates, i.e., rates that fall within a zone of reasonableness, we must balance the need for immediate price relief for customers against the need for price signals to attract new supply and demand-side investments.

- As mentioned in our prior orders, the cornerstone of remedying the dysfunctions in the energy markets in the West and in bringing both spot and forward prices down over the last few months is eliminating California's excessive reliance on spot markets. While significant progress has been made, some 20 percent of California's load remains in the ISO's spot markets at peak periods. [12]

- Buyers and sellers need certainty and closure. To the extent possible, our price mitigation should have clear rules, should set prices before they are charged and should not subject prices to change or adjustment after financial settlement of the day's transactions. Similarly, it should not rely on costly and time consuming administrative processes to set, adjust or justify prices.

- Abuse of market power cannot and will not be tolerated. Sellers will be subject to losing their market based rates for engaging in anticompetitive conduct. Further, as a condition of continued authorization of market-based rates, public utility sellers in the WSCC must agree to refunds, with interest pursuant to 18 C.F.R. § 35.19a, of any overcharges resulting from anticompetitive bidding or behavior.

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[11] The term "megawatt laundering" describes behavior where a supplier schedules supply out of state and then re-imports that power to avoid a mitigated price.

[12] Recent data indicates that the reliance on the spot market is higher during off-peak periods.

To satisfy these principles, the mitigation plan will consist of the following measures:

- We will retain the use of a single market clearing price with must offer and marginal cost bidding requirements for sales in the ISO's spot markets in reserve deficiency hours, i.e., Stage 1 when reserves are below 7 percent in California. Sellers in the ISO's single price auctions will receive the hourly market clearing price. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC) we will apply this clearing price as a maximum price. Sellers outside the ISO's single price auction will receive the prices they negotiate up to this maximum price. There are, however, three adjustments to the clearing price methodology we have previously used.

  First, marketers will be required to bid as price takers. This means that marketers cannot bid higher than the market clearing price.

  Second, we will require sellers that own generation to submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas used for generation (i.e., what the seller would pay to procure gas at the last minute) plus variable O&M costs.

  Third, we instruct bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs and direct the ISO to file a rate mechanism to bill those costs over the entire load on the ISO system. These cost inputs have proven too varied to standardize in a single market clearing price.

Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will provide guidance later in this order on what sellers that seek to do so must demonstrate.

- For spot market sales, both in the WSCC and in California, in all non-reserve deficiency hours (i.e., when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can be no higher than $119/MWh (i.e. 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market

clearing price, but that clearing price will not exceed $119/MWh.[13] For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward as the new maximum price. Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will later in this order provide guidance on what sellers that seek to do so must demonstrate.

- The mitigation plan will become effective beginning on the day following the date this order is issued. [14]

- We will continue to apply all price mitigation to non-public utilities as a condition of selling into the spot markets which are the subject of this order and as a condition of using the interstate transmission grid under our jurisdiction.

- We will reaffirm that all public and non-public utilities who own or control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled (or committed for minimum operating reserves) for delivery in the hour. We will also require all public and non-public utilities in the remainder of the WSCC to offer in the spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is also not scheduled (or committed for minimum operating reserves) for delivery in the hour.

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[13] As we explain later, the ISO is required to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. This adder will not be reflected in the market price for the rest of the WSCC.

[14] We will grant waiver of notice for the ISO's approved rate mechanism to recover the cost of emission requirements to be effective on the day following the date this order is issued. Absent a new reserve deficiency on the ISO's system declared before the effective date of the price mitigation outlined in this order, the market clearing price carried forward for non-reserve deficiency hours is $108.49/MWh (i.e. 85 percent of $127.64/MWh) (May 31, 2001, clock hour ending 1400).

- The price mitigation will terminate on September 30, 2002.

- We will establish settlement proceedings at this Commission to address any and all issues to ensure that California completes the transformation of its load to long-term contracts. The Parties in the San Diego Gas & Electric Company complaint proceeding and the State of California are directed to participate in good faith in these proceedings.

We emphasize that the rate mitigation prescribed in this order is part of a series of steps the Commission has taken to remedy dysfunctions in California wholesale power markets. However, as we recognized in our first remedial order on December 15, 2000, many of the critical remedies that need to be taken fall either wholly or in part within the jurisdiction of the State of California. In particular, the consummation of additional long-term wholesale contracts, the development of demand side response signals, the siting of new generation and transmission, and the construction of intrastate natural gas delivery infrastructure are critical to remedying the current market dysfunctions and are dependent on State action. We recognize the significant progress that California has made thus far and urge further implementation of these critical measures. We stand ready to assist in these efforts to the extent possible within our authority.

Finally, in taking action in today's order as well as in prior orders in these dockets, beginning on December 15, 2000, the Commission has taken careful, reasoned steps to fulfill its statutory responsibilities under the FPA. The Commission's statutory responsibility to set just and reasonable rates gives it broad authority to adapt its ratemaking policies to the practical realities facing it. The Supreme Court ruled very early on that individual company cost-of-service rates were not the sine qua non of rate regulation, and that no single method of ratemaking is sacrosanct as the only means to reach the statutory goals. Rather, the value of any ratemaking policy is to be judged by its ability to meet the statutory goal of assuring that rates remain within a zone of reasonableness consistent with the maintenance of adequate service.

The ratemaking power granted the Commission under the FPA includes the authority to set the rules, regulations, practices, and contracts affecting rates, as well as the rates themselves. The Commission's orders related to the California markets have sought to establish a structure within which market forces will operate to achieve the statutory goal. In this order, the Commission continues the efforts of its earlier orders to modify the existing market structure throughout the West to minimize the potential for market power abuse, and thus to protect against possible unjust and unreasonable rates, while, at the same time, maximizing the incentive for increased supply in the entire western region.

I. Background

In an order issued August 23, 2000, [15] the Commission instituted formal hearing proceedings under section 206 of the FPA to investigate the justness and reasonableness of the rates for energy and ancillary services of public utility sellers into the ISO and PX spot markets, and also to investigate whether the tariffs, contracts, institutional structures, and bylaws of the ISO and PX were adversely affecting the wholesale power markets in California. These proceedings were intended to investigate the significant increases in the prices for energy and ancillary services in the California market.

In the December 15 Order, the Commission found that the market structures and rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy under certain conditions. The Commission, therefore, established a variety of remedies for the California wholesale electric markets, which included, in part, elimination of the mandatory PX Buy-Sell requirement, establishment of penalties for underscheduling load, a requirement for an independent governing board for the ISO, and a requirement for the filing of generation interconnection procedures.

As an interim measure, the Commission also established a $150/MWh breakpoint under which public utility sellers bidding above the breakpoint receive their actual bids, but are subject to monitoring and reporting requirements to ensure that rates remain just and reasonable, including the potential for having to pay refunds for prices charged above the breakpoint. [16] The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology by May 1, 2001.

On January 23, 2001, the Director of the Division of Energy Markets in the Office of Markets, Tariffs and Rates convened a technical conference to develop a plan to

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[15] San Diego Gas & Electric Company, et al., 92 FERC ¶ 61,172 at 61,606 (2000) (August 23 Order).

[16] On March 9, 2001, the Commission issued an order directing public utility sellers to provide refunds (or offsets to amounts owed) or to provide cost or other justification for prices that exceeded the breakpoint. 94 FERC ¶ 61,245 (2001), reh'g pending.

replace the interim breakpoint price. [17] Comments and reply comments on how to replace the interim break-point were filed with the Commission. In March 2001, Commission Staff issued a recommendation for prospective market monitoring and mitigation for the real-time electric market, and comments were filed on this proposal. The comments focused in particular on the method used for price mitigation and the periods when mitigation would be applied.

On April 26, 2001, the Commission issued its order adopting a prospective monitoring and mitigation plan for real-time California wholesale electric markets. The Commission's plan included the following elements:

It enhanced the ISO's ability to coordinate and control planned outages during all hours.

It required sellers with Participating Generator Agreements (PGAs), as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours.

It required public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours.

It established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours.

It required the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue to monitor generating unit outages and real-time prices.

It established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert, which is defined as having reserves of 7 percent or less. Under this mechanism, the Commission established a formula (based on gas-fired generation) that the ISO can use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

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[17] 93 FERC ¶ 61,294 at 61,983, 61,996-97.

In the April 26 Order, the Commission also established an inquiry into whether a price mitigation plan similar to the one for California should be implemented in the WSCC. The order invited comment on how such a plan should be structured.

The parties listed on Appendix A have filed for rehearing of the April 26 Order. A number of parties have filed motions for late intervention. While the Commission ordinarily does not permit late interventions after an order has been issued solely to file for rehearing, the Commission will grant the late interventions in this instance because of extensive overlap of the issues between the California-oriented parts of the April 26 Order and the West-wide investigation instituted in that order, and the fact that the April 26 Order authorized additional comments and interventions for purposes of the latter. Appendix B lists those filing comments in the section 206 proceeding with respect to the WSCC.

II. Discussion

As described earlier, the Commission is adopting a mitigation plan covering both California and the remainder of the WSCC during all hours for spot market sales. In the following sections, the Commission will address the rehearing requests and the West-Wide comments relating to this mitigation plan.

A. Outage Coordination

The April 26 Order found that in order to maintain sufficient generation capacity to meet market needs, the ISO must work with California generators to coordinate generating unit maintenance and outages, so that sufficient energy will be available when needed while also providing for reliable plant operation. The order required the ISO to make a tariff filing proposing a mechanism for outage coordination. The ISO made its compliance filing on May 11, 2001.

Most parties are in favor of such outage coordination. The CPUC, however, states that procedures relating to outage control and coordination are within the state's jurisdiction. CAC/EPUC contends that outage coordination may unreasonably burden QF facilities, because their outages are affected by their thermal host. DWR contends the outage controls should not be applied to hydroelectric generators. Duke, on the other hand, protests the ISO's proposal and asks the Commission to clarify the need for truly cooperative standards and procedures.

The ISO has the authority to coordinate and control generation outage schedules for resources under PGAs. The Commission clarifies that only the ISO's outage coordination role will be extended to all other in-state generating facilities insofar as

these generators must submit to the ISO maintenance schedules for their generating units. This will provide the ISO with the information necessary to maximize the efficient use of all in-state resources. For example, with this information, the ISO will be able to determine whether to schedule generation under its control based on when other generation resources will be out-of-service. The ISO, however, will not be authorized to schedule maintenance for units not under a PGA.

B. Selling Obligations

The mitigation plan requires those generators with PGAs, as well as non-public utility generators in California selling through the ISO markets or using the ISO's transmission lines, to offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run. This must-offer obligation does not apply to power scheduled to run under bilateral agreements. The must-offer obligation does not apply to hydroelectric power because of its multi-purpose limitations (e.g., irrigation, recreation, and power production). The must-offer obligation is designed to prevent withholding and thereby to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. The basis for this requirement is that, under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time. The rehearing requests raise a number of issues that will be addressed below.

1. Applicability to Non-Public Utility Generators

A number of non-public utility entities request rehearing of the requirement that, because they make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), they must offer all their available power in real time during all hours. They primarily argue that the Commission is overstepping its jurisdictional bounds by asserting jurisdiction over them in violation of section 205 of the FPA.

CMUA, SMUD, and others contend that the Commission lacks jurisdiction over municipalities and other state agencies. CMUA maintains that "as far back as 1998, CMUA members have voluntarily made units available to the ISO, have sold the ISO energy on a regular basis in response to reliability calls, and continue to sell to creditworthy buyers." CMUA at 8. CMUA contends that there is no evidence that such facilities are refusing unreasonably to sell in the ISO's markets.

The Commission denies the requests for rehearing. The Commission is not asserting jurisdiction over non-public utilities. Rather, as the Commission explained in

the April 26 Order, it is exercising its conditioning authority to assure that all generators located in California, including non-public utility generators, that voluntarily sell into the ISO's spot market or that use the ISO's interstate transmission grid, offer their available power in California. [18] As we stated in the April 26 Order, if a non-public utility makes sales into the ISO's markets over which the Commission has exclusive jurisdiction or uses the ISO-controlled interstate transmission facilities, it must abide by the same conditions that are applicable to public utilities. [19] On rehearing, parties have raised no arguments that warrant a different result. We cannot meet our statutory responsibilities under the FPA to ensure just and reasonable rates in the Western spot markets if we allow non-public utilities to participate in the ISO's markets and use interstate transmission facilities, while refusing to comply with the measures necessary to ensure the justness and reasonableness of the ISO's rates and terms and conditions of service. In short, the Commission cannot ensure just and reasonable rates under the FPA unless non-public utilities, which sell power into the ISO's market or use the ISO's transmission lines, are subject to the same market rules as public utilities.

CAC/EPUC contends that imposing the must-offer obligation and the mitigation plan on QF facilities conflicts with the regulatory scheme established under the Public Utility Regulatory Policies Act of 1978 (PURPA). QFs that engage in sales for resale in interstate commerce and/or the transmission of electric energy in interstate commerce are public utilities and are therefore subject to the Commission's jurisdiction, although the Commission has exempted them from many provisions of the FPA. [20] However, because of the need for uniformity among all sellers, the Commission will not exempt QFs from the must-offer obligation and mitigation plan to the extent that QFs use the ISO's

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[18]San Diego Gas and Electric Company, et al., 95 FERC ¶ 61,115 at 61,356 (2001).

[19]Id. Since CMUA members already sell power on a regular basis to the ISO, and are assured of recovering their marginal costs when they run pursuant to the must-offer obligation, CMUA has not demonstrated that the Commission's actions would have an adverse effect on them.

[20]Section 210(e) of PURPA states the Commission shall prescribe rules under which QFs are exempt, in whole or in part, from the FPA, PUHCA, and from state laws and regulations respecting rates or financial or organizational regulation. 16 U.S.C. § 824a-3 (1994). The Commission exempted most QFs from portions of the FPA, 18 C.F.R. § 292.601 (2000), PUHCA, 18 C.F.R. § 292.601 (b) (2000), and from state laws and regulations respecting rates and financial and organizational regulation, 18 C.F.R. § 297.601 (c) (2000).

interstate transmission lines and make sales through the ISO's markets. [21] The exemptions from regulation granted pursuant to PURPA to QFs do not mean QFs must or should be exempted from the must-offer obligation.

2. Extent of the Must-Offer Obligation

The predominant issue raised on rehearing is how to apply the must-offer obligation to thermal generators with environmental limitations on their operations. The April 26 Order stated that generators would not have to run if doing so would violate their certificate or applicable law. But it required those units to run if it involved only the paying of additional amounts to obtain emission credits to permit them to run outside their emission limitations.

A number of rehearings request clarification that generators do not have to run if doing so would violate certificates or subject them to possible criminal penalties or fines.[22] Sellers further maintain that units with maximum run limitations have legitimate opportunity costs that the Commission has failed to recognize. [23] They recognize that the issue of energy limited units is complex, [24] but that the Commission's proposed emission credit adder does not fully take into account the costs imposed by forcing these plants to run whenever the ISO determines. They argue that they have traditionally managed these units to ensure that they run only during the times of the year when they are most valuable and that they should not be required to run at other times without adequate compensation for the revenues they forgo. [25] Mirant maintains that exempting hydroelectric power from the must-run requirement while not exempting environmentally-limited gas units is discriminatory. Sellers maintain that the Commission should either eliminate the must-offer requirement or permit generators to include in their bids an amount to capture the economic value of losing the ability to

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[21]CAC/EPUC filed a request to stay the application of the mitigation plan as applied to QFs. Given the resolution of the rehearing request, the request for stay is denied.

[22]Rehearing Requests by MID, M-S-R, NCPA, TANC.

[23]Rehearing Requests by Dynegy, Mirant, Reliant.

[24]See Rehearing Request by Reliant.

[25]For example, Dynegy maintains that forcing its units to run today will require it to use up emission credits allocated for the year 2003, and that it should be reimbursed for the lost opportunity of being unable to run that unit in the year 2003.

generate in later years. Reliant maintains that application of the must-offer obligation to energy limited units should be conditioned on expansion of California Executive Order D-24-01 to sales into the ISO, so that run-time limits would not apply to such sales.

Municipals [26] similarly argue the Commission needs to make allowances for the possibility that imposing a must run obligation on a generator may impose additional price or cost risk at later periods of time. NCPA maintains that it is required to make use of its thermal plants to meet its member-customer needs and is concerned that if it is forced to run during particular periods, it may not be able to meet the power needs of its members in later periods, if it is unable to obtain additional emission credits. It therefore requests clarification that it not be required to honor the must offer obligation unless it is able to obtain additional air pollution credits and that it be permitted to include those credits in any bid it makes into the ISO. Municipal generators request clarification that they do not have to make power available to the ISO when that power is being used to serve their own retail load or is required as reserves under interconnection agreements. [27] They contend that the April 26 Order was not clear whether the requirement to serve retail loads would be considered the equivalent of bilateral contracts. CAC/EPUC contends the must-offer obligation should not be applied to QF facilities, because it interferes with the QF's obligation to its thermal host, which is governed by a contract or operational protocol. Calpine similarly argues that QF units with capacity committed to a utility are not subject to the must-offer even if it chooses not to operate at maximum capacity.

The Commission clarifies that generators should not be exempt from the must-offer requirement absent a showing that running the unit violates a certificate, would result in criminal violations or penalties, or would result in QF units violating their contracts or losing their QF status. Many of these issues are within the domain of the State of California, and we strongly urge California to modify current policies to enable generators to run during this period of scarce supply. For municipal generators the must-offer obligation applies only to available power remaining after the municipality satisfies its own retail load and contractual obligations. Given the shortage of power in California, all generators in California, including municipals, should not hold energy in reserve (over minimum acceptable levels) when the energy is needed to meet demand.

For QF facilities, like other generators, the must-offer obligation applies to energy that is available from generation that is not already contractually committed or would not

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[26] Rehearing requests by NCPA, NRECA.

[27] MID, M-S-R, TANC.

violate its contractual obligation to its thermal host. With respect to Calpine's argument, a QF with capacity committed to a utility is, therefore, subject to the must-offer obligation if it chooses not to sell its maximum output to the utility. With respect to CAC/EPUC's contention, the Commission has granted waivers of the operating and efficiency standards so that QFs, without jeopardizing their QF status, can generate power regardless of whether the host needs thermal energy. [28] Therefore, QF facilities will be expected to produce available energy regardless of whether the host requires thermal energy.

Due to the severity of the power shortage in the WSCC in general, and in California specifically, the Commission finds that the incurrence of expenses for obtaining additional emission allowances is not a valid reason to withhold available energy from the ISO's market. As discussed later in this order, the Commission is providing a mechanism for generators that incur emission related expenses to recover those costs through the ISO. Moreover, the Governor of California signed an Executive Order, D-40-01, allowing generators to exceed their emission runtimes without losing valuable future emission allowances, provided the energy is sold to DWR (or another California buyer) or dispatched by the ISO. Therefore, exceeding today's emission limits will not affect future limits. Thus, Executive Order D-40-01 moots all arguments on this issue insofar as California generators are concerned, including those of the municipal generators.

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[28] See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,238 at 61,772 & n.3 (2000) (December 8 Order)(granting temporary waiver of QF regulations); San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 at 62,018 (December 15 Order)(extending waivers); Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,970-71 (March 14 Order)(extending QF waivers); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 at 61,767-68 (2001) (May 16 Order)(waivers extended to entire WSCC and through April 30, 2002). In a second order issued on May 16, the Commission required California Utilities to provide interconnection and transmission service to QFs pursuant to existing agreements to permit certain sales of QF power to third-party purchasers. San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,226 (2001).

3. Withholding Generation for Operational Reasons

Mirant, Reliant, and Williams maintain that the must-offer obligation fails to recognize the need to withhold generation to cover the possibility that a unit will unexpectedly go offline. They take issue with the statement in the April 26 Order that a generator cannot be financially harmed from offering all of its units because the generator will only have to pay for the cost of replacement power, which is the same amount the generator would earn if the unit ran. They argue that, while this statement is true in theory, it does not apply to the ISO's markets because due to penalties in the ISO's tariff and the manner in which the ISO computes the cost of replacement energy, the generator would have to pay more for replacement energy than it would receive for the unit's bid in the market.

The must-offer obligation is crucial to ensuring that all capacity is in the market when needed and tariff provisions should not inhibit the fulfillment of this obligation. The Commission finds that during the periods mitigation is in effect, the current ISO tariff provisions in this regard are unjust and unreasonable, and, therefore, we will require the ISO to modify its tariff, to be effective the day after the date of this order, so that the only penalty for having a unit forced out of service is the cost of replacement energy. The must-offer obligation modifies various market rules that existed when the current penalty provision was accepted for filing.

4. Other Issues

Several rehearing requests are concerned about generators avoiding the must-offer requirement through so-called "megawatt laundering" where a generator sells power to an out-of-state marketer, who then reimports that power to avoid a mitigated price. [29] The Commission clarifies that the must offer obligation applies to all sellers who own or control generation by contract. Moreover, the mere fact that a generator has a contract to provide power to a marketer does not exempt the generator from the must-offer obligation for energy that the marketer is not scheduling. As long as the generator has available energy, the generator has the obligation to offer that power into the ISO's auction market. Moreover, as described later, all marketers in the ISO's markets must now be price takers and cannot justify a bid higher than the mitigated price.

Dynegy maintains the must-offer obligation should be limited to emergency hours only. It argues that had this obligation been imposed at the time it purchased the plants, it

[29] Rehearing Requests by ISO, CMUA, Metropolitan, NCPA, SMUD, San Diego, Edison.

would have paid a lower amount. It therefore contends the must-offer obligation unfairly changes the contractual conditions under which it purchased the plants. The Commission rejects Dynegy's argument. The must-offer obligation must be applied in all hours in order to ensure that all available capacity is in the market and that none is being withheld, except for the reasons previously discussed. Moreover, mitigation is now being applied in all hours, so the must-offer obligation must also be applied to all hours.

LADWP requests clarification that the must-offer and price mitigation aspects of the order do not apply to its sales of energy under bilateral contracts or to sales or purchases that are scheduled to run in real-time pursuant to a bilateral contract. All public and non-public utilities which control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract only to the extent its output is not scheduled for delivery (or committed for minimum operating reserves) in the hour. All public and non-public utilities in the remainder of the WSCC must offer in a spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled for delivery (or committed for minimum operating reserves). All sales in these spot markets are subject to the price mitigation established in this order.

The rehearing requests raise issues with respect to the effect of the must-offer obligation on the ISO's authority to curtail exports of power to other markets. Reliant and Mirant maintain the must-offer requirement should supplant the ISO's curtailment authority under its tariff. Reliant contends the curtailment authority is unnecessary now that California generators will be bidding all available supply into the real-time market. Williams maintains the ISO should compensate generators for curtailments. SDG&E, on the other hand, contends the Commission should permit the ISO to curtail in-state generation destined for other states.

The Commission is not persuaded to change the ISO's curtailment authority at this time. Since Reliant maintains that this authority is no longer needed as a result of the must-offer obligation, it has not demonstrated how it is harmed by leaving the current authority intact. The price mitigation adopted in this order establishes the same price throughout the WSCC as in California, and therefore does not provide a financial incentive for generators to sell energy outside of California. Parties may renew objections to this authority in future proceedings if they can establish discernible harm.

C. Demand Response

The April 26 Order provided that beginning on June 1, 2001, each public utility purchasing electricity in the ISO's real-time market is required to submit demand-side

bids that will indicate the price at which load will be curtailed and will identify the load to be curtailed.

The ISO requests clarification as to whether the demand response mechanism is voluntary or mandatory. If voluntary, the ISO maintains that it is already implementing a number of demand response mechanisms. If the requirement is mandatory, a number of rehearing requests contend that it is insufficient to solve the problem, [30] and is technically infeasible, in the short-run, because there is no mechanism for obtaining accurate demand response signals from all customers. In addition, the ISO cannot currently curtail power to individual loads. [31] Parties assert that load serving entities should not be required to simply guess at the prices its customers are willing to pay. SDG&E, for example, contends that the CPUC did not permit it to act as an aggregator for demand responses, and accordingly it would simply be guessing at what price its customers are willing to pay. San Francisco maintains that curtailing retail customers is anathema to the Load Serving Entities' (LSEs') duty to serve. A number of requests contend that demand response is a state concern, and the Commission has no authority to indirectly regulate retail customers. Others contend that since the DWR is not a public utility, it would not be covered by the demand response mechanism in any event.

On the other hand, generators maintain that a demand response mechanism is crucial to establishing a viable market and is needed to provide generators with appropriate scarcity rents.

The Commission continues to believe that establishing a demand response mechanism is crucial to establishing a robust market. [32] Without a demand response mechanism, the ISO is forced to work under the assumption that all customers have an inelastic demand for energy and will pay any price for power. There is ample evidence that this is not true. Many customers, given the right tools, can and will manage their demand. Such an assumption inevitably leads to higher prices during times of shortage, since high supply bids do not lead to a reduction in power purchased. A working demand response program puts downward pressure on price, because suppliers have additional

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[30] See Rehearing Request by CMUA,

[31] Rehearing Requests by ISO, DWR, San Francisco.

[32] See Chandley, Harvey, & Hogan, Electricity Market Reform in California, at 25 ("The least controversial reform of market design would be to implement all the changes needed to allow for demand side response in the face of higher prices." (Attached to November 22, 2000 Comments of SDG&E).

incentives to keep bids close to their marginal production costs and high supply bids are more likely to reduce the bidder's energy sales.[33] Appropriate price signals to customers thus helps to mitigate market power as high supply bids are more likely to reduce the bidders' energy sales. Suppliers thus have additional incentive to keep bids close to their marginal production costs. Demand-side price-responsive bids will also help to allocate scarce supplies efficiently.

Indeed, without demand-side price responsiveness, there can be no market mechanism for ensuring that scarce supplies are allocated to the highest valued uses during shortages. However, based on the technical impracticalities raised in the rehearing comments, the Commission does not find that the demand response requirement should be implemented at this time. Because the development of demand response is so critical, we expect that buyers in the ISO's market will submit demand bids as soon as demand bidding becomes technologically feasible. Meanwhile, the Commission will continue to monitor developments in California to determine whether additional Commission action is needed. The ISO must include in its quarterly reports a discussion of all demand response changes that have been implemented. If state programs for demand response do not develop, the Commission expects the ISO to enhance its own programs.[34]

Public utilities along with California officials also must actively pursue such approaches to achieving a viable demand response program. As SDG&E points out, LSEs can effectively act as aggregators for retail demand response. SDG&E and other public utilities should continue to pursue demand response initiatives and are required to file with the Commission by September 14, 2001 a report of the progress that is being made in establishing these mechanisms and any difficulties they have encountered.

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[33]Already conservation has helped to reduce demand. See Peter Behr, "Fears of an Energy Crisis Begin to Dim, Consumption Cuts Help Lower Prices for Gasoline, Natural Gas and Electricity," Washington Post, April 8, 2001, at E1 (California has reduced demand 8%). A properly designed demand side response program could improve this performance even more markedly by providing price incentives for reduction.

[34]Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,972-73(March 14 Order) (DSM programs); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 (2001) (May 16 Order).

To help facilitate these initiatives, the Commission intends to conduct a staff technical conference to explore how demand response can be increased. The first purpose of the conference will be for the Commission to familiarize itself with the status and availability of conservation, demand-side management, and other innovations to help communicate real-time price signals to consumers, including the software and metering necessary to support such programs. The second purpose will be to explore how these programs can be implemented. At the conclusion of the conference, the Commission will reconsider the feasibility and schedule for a demand bidding requirement and its use in establishing prices in the ISO's market.

D. Price Mitigation for California and the WSCC

The April 26 Order applied price mitigation to periods of reserve deficiency, defined as those periods beginning with Stage 1. Under the approach set forth in the April 26 Order, the ISO would conduct a market clearing auction for its real-time markets. During periods of reserve deficiency, however, the ISO would calculate a marginal cost bid for each generator by using a proxy for the gas costs, emission cost, and operation and maintenance (O&M) expenses. The ISO would then use the bid of the last unit dispatched to establish the market clearing price. The justification for this approach is that as reserves are reduced, all sellers are aware of how tight supplies are relative to the amount they have to offer. Thus, sellers have an incentive to offer supply at prices above that which they would ordinarily bid. Because of the imbalance of supply and demand, these prices may not be just and reasonable. The Commission, however, did not impose mitigation during periods of reserve sufficiency because there is less risk that prices would exceed those charged in a competitive market. During reserve sufficiency conditions a supplier has less of an incentive to bid a high price, because it cannot be sure it will be dispatched, since other generators may offer lower bids.

Many rehearing requests, as well as comments in the West-Wide proceeding, contend the Commission should have extended mitigation to cover all hours. They contend that evidence from a number of studies shows that sellers have been able to exercise market power during all hours. They contend that the Commission has the obligation under the FPA to assure just and reasonable rates in all hours. [35] Duke Energy and other generators insist that the record does not show that market power has been exercised.

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[35]Rehearing Requests by ISO, CEOB, CMUA, Assembly, City of Anaheim, et al., CFA, Metropolitan, PG&E, NCPA, SDG&E, San Diego, San Francisco, Seattle, Edison, SCWC.

As described earlier, the Commission here is instituting a two-part approach to price mitigation for spot markets to cover all hours for California and the WSCC. Because these markets are integrated, the mitigation proposal must establish the same prices for all markets in order to prevent arbitrage where power is diverted from the lower priced market to the higher priced. The mitigation plan further has to recognize the differences between the California market, which has an organized auction, and the remainder of the WSCC, which does not have a similar centrally organized market. The plan adopted by the Commission is tailored to provide a uniform scheme of mitigation that at the same time recognizes the differences between these markets. During non-reserve deficiency hours in California, the Commission will adapt the ISO's market clearing price for spot market use West-wide.

The purpose of instituting this dual plan is to stabilize the market in the short-term and permit California time to repair its market mechanisms. The shortage of hydroelectric power together with the failure to build efficient generation is clearly a major part of the problem. This has been exacerbated by the imbalance between high wholesale prices and low retail prices, which do nothing to dampen demand. What is clear, however, is that a major contributor to the high prices was the deficient market mechanisms initially established by California, and approved by the Commission, that have resulted in a dysfunctional marketplace both in California and the remainder of the West. The mitigation plan established in this order, in effect, provides breathing room for the markets to right themselves.

The ISO, CPUC, and PG&E further contend that mitigation should apply outside of the ISO's Imbalance Energy market and should include its Day-Ahead and Hour-Ahead markets for ancillary services and its congestion management market. The Commission's order providing clarification and preliminary guidance addressed these issues. [36]

Several rehearing requests contend the mitigation should apply to all bilateral contracts. [37] The section 206 proceeding involving the ISO was limited to the ISO's and PX's real-time markets and did not extend to bilateral markets.[38] As discussed, however, in the Commission's section 206 investigation of the non-ISO spot markets in the WSCC,

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[36]San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,275 (2001).

[37]Rehearing Requests by CPUC, City of Anaheim, et al., PG&E.

[38]San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,121, at 61,349 (2000) (limited proceeding to real-time markets).

we have determined it appropriate to also apply mitigation to the bilateral spot markets in the WSCC, including California. Parties have not provided justification for extending the scope of our investigation or the mitigation to bilateral transactions other than spot markets. Moreover, any mitigation applied to the ISO's real-time markets will, over time, impact bilateral and forward markets as well.

A number of parties argue that the Commission's market monitoring and mitigation plan will not result in just and reasonable rates as required by the Federal Power Act, and the Commission should either return to individual cost-of-service rates or condition the continued use of market-based rates on effective mitigation measures. [39] The CPUC maintains that because the Commission found rates to be unjust and unreasonable, the Commission is required to fix by order just and reasonable rates. It declares that "[w]here, as here, market power is pervasive through the industry in the west, FERC must impose cost of service pricing." [40] PG&E asserts that the Commission should immediately suspend the existing market-based rates of all sellers in the West and that the Commission should require immediate cost of service filings. [41] CEOB maintains that "[t]he Commission has no choice but to engage in cost-based ratemaking, or to adopt a sweeping mitigation scheme throughout the WSCC to ensure just and reasonable rates...." [42]

Since determining that the market structure and rules for wholesale sales of electric energy in California had caused, and continued to have the potential to cause, unjust and unreasonable rates for short-term energy during certain times and under certain conditions, the Commission has ordered changes to the market structure and rules to assure that future rates would be just and reasonable. [43]

After carefully considering the record, the Commission reaffirmed its general finding that, as a result of the seriously flawed electric market structure and rules for

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[39] See, e.g., ISO, CEOB, CPUC, Assembly, CFA, PG&E, San Francisco, Seattle, and Edison.

[40] CPUC Request for Rehearing at 7.

[41] PG&E Request for Rehearing at 13-15.

[42] CEOB Request for Rehearing at 4.

[43] FERC's remedial measures "must be construed as a whole in assessing FERC's compliance with FPA § 206". In re California Power Exchange Corp., 245 F.3d 1110, 1120 (9th Cir. 2001).

wholesale sales of electric energy in California, unjust and unreasonable rates were charged, and could continue to be charged during certain times and under certain conditions , unless certain targeted remedies were implemented. San Diego Gas & Electric Co., et al. 93 FERC ¶ 61,294 (2000)("December 15 Order"). [44]

The following remedies were adopted by the Commission in order to correct the specific flaws identified through the investigatory and hearing process: (1) because "the mandatory participation requirement . . . [was] producing rates that [were] not just and reasonable during certain periods," the Commission eliminated the requirement that the IOUs sell all of their generation into and buy all their energy needs from, the PX; (2) recognizing that it could assure the justness and reasonableness of California wholesale markets prices only by eliminating the PX's exclusive mandatory exchange, the Commission terminated the PX's wholesale tariffs; (3) to eliminate market participants' chronic underscheduling with the ISO, which jeopardized ISO system operations and created a strong sellers' market and higher prices in the most volatile spot market (real-time imbalance), the Commission required market participants to preschedule 95 percent of their load, with penalties for scheduling deviations in excess of five percent of an entity's hourly load requirements and disbursements of penalty revenues to all loads scheduled accurately; (4) mindful that eliminating the mandatory buy/sell requirement would move a considerable amount of load into the forward long-term markets all at once, the Commission established, effective for one year, an advisory benchmark for pricing five-year contracts; (5) because of concerns about the independence and effectiveness of the ISO governing board, the Commission ordered that the current stakeholder governing board be replaced by a non-stakeholder board composed of members independent of market participants; and (6) the Commission required the ISO and the IOUs to file generation interconnection procedures to facilitate the interconnection of new generators or existing, upgraded generators, thereby enhancing system reliability and reducing price volatility.

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[44] The Commission has freedom, "within the ambit of [its] statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. "FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942); In re California Power Exchange Corp., 245 F.3d at 1120 . FPA § 309, 16 U.S.C. § 825h, gives the Commission the necessary flexibility to take unusual remedial action in appropriate circumstances. See Permian Basin Area Rate Cases, 390 U.S. 747, 776 (1968) (applying NGA § 16, the counterpart of FPA § 309, the Court held that "the Commission's broad responsibilities . . . demand a generous construction of its statutory authority."); FPC v. Louisiana Power & Light Co., 406 U.S. 621, 642 (1972)(same).

To further assure that prices in the ISO's and PX's spot markets are just and reasonable, the Commission directed that a technical conference be held to develop a comprehensive and systematic monitoring and mitigation program to be submitted to the Commission by March 1, 2001. Until that date, the Commission established an interim $150/MWh breakpoint for spot market sales. On an interim basis, all public utility sellers bidding at or below $150/MWh would receive the market clearing price up to $150/MWh, and only those sellers bidding above $150/MWh would receive their actual bid price. However, all accepted bids above $150/MWh were required to be reported to permit proper monitoring and review by the Commission.

On April 26, 2001, the Commission adopted a prospective monitoring and mitigation plan for real-time California wholesale electric markets which replaced that previously in effect. The Commission's plan: (1) enhanced the ISO's ability to coordinate and control planned outages; (2) required sellers with PGAs, as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours; (3) required public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours; (4) established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours; (5) required the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue to monitor generating unit outages and real-time prices; (6) established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert (i.e., when reserves are below 7 percent). This mechanism provided a formula (based on gas-fired generation) for the ISO to use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

In this order, the Commission is expanding the market monitoring and mitigation plan to produce spot market prices in all hours that are just and reasonable and emulate those that would be produced in a competitive market. We find that a return to individual cost-of-service ratemaking is unwarranted. As addressed above, the market changes and monitoring procedures already implemented by the Commission have improved the wholesale power markets in California. This order continues that effective course. In contrast, cost-of-service ratemaking tends to penalize more efficient generators and not provide proper incentives for generators to become more efficient, since each generator's

price is dependent on its costs. [45] Moreover, individual cost-of-service rates may not provide generators with appropriate scarcity rents. Establishing individual cost-of-service rates is also difficult with respect to spot markets. For peaking units, decisions would need to be made about the number of projected MWhs over which to spread costs. Generators also would have to make filings establishing their rate base, acceptable rate of return, and cost-of-service, possibly including trackers for volatile costs such as gas and emissions fees. Resolving the issues involved in such filings would be protracted and would not provide price certainty to the market. We do provide for any generator unable to work within the revised mitigation framework the opportunity to apply for cost-based rates for the duration of the plan.

The monitoring and mitigation plan adopted by the Commission in this order satisfies the requirements of the FPA. In particular, FPA Section 206 allows the Commission to determine whether "any rate, charges, or classification . . . or any rule, regulation, practice, or contract affecting such rate, regulation or classification" is unjust or unreasonable, and to fix "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force." 16 U.S.C. § 824e(a)(1994). In this order, as in our earlier orders related to this matter, the Commission has examined the rules, regulations, practices and contracts that are currently being used, and made changes that are necessary to prevent possible abuses that could lead to unjust and unreasonable rates.

The focus on changes to the existing market structure, rather than on setting cost-of-service rates for individual sellers, is consistent with the case law. As the Supreme Court made clear, it "has never held that the individual company cost-of-service method is a sine qua non of natural gas [or electric] rate regulation." [46] Nor has the Court limited ratemaking agencies "to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.'" [47] The success of a particular ratemaking approach is judged by "the result reached not the method employed." [48] The end result of any ratemaking order must be to provide rates within a zone of reasonableness that "take fully into account the probable consequences of a given

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[45] See National Rural Telecom Association v. FCC, 988 F.2d 174, 178 (D.C. Cir. 1993).

[46] Wisconsin v. FPC, 373 U.S.294, 309 (1963).

[47] Permian Basin Area Rate Cases, 390 U.S. 747, 776-77 (1968).

[48] FPC v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944).

price level for future programs of exploration and development".[49] As that language makes clear, a cost-based inquiry alone would not be sufficient in these circumstances to fulfill the statutory duty. Rather, the Commission must consider the broader public interest, and, in particular, the interest in setting rates that will assure adequate supply.[50]

The Commission is free to adopt market-based rates.[51] In adopting market-based rates, the Commission must: (1) provide a clear and reasoned analysis of the need for market-based pricing to promote the statutory objectives of the FPA; (2) support its decision with substantial evidence; and (3) assure that the resultant market-based rate falls within a "zone of reasonableness."[52] Having adopted a market-based approach for the California market, nothing requires the Commission to revert to a cost-of-service ratemaking approach whenever it finds flaws in the market structure. See Environmental Action v. FERC, 996 F.2d 401, 411(D.C. Cir. 1993) (finding that the Commission "has

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[49] Permian Basin, 390 U.S. at 797; see Atlantic Refining Co. v. Pub. Service Comm., 360 U.S. 378, 388 (1959) (same).

[50] Permian Basin, 390 U.S. at 796-97; Mobil Oil Corp. v. FPC, 417 U.S. 283, 317-18 (1974); Consumers Union v. FPC 510 F.2d 656, 660 (D.C.Cir. 1974); see also Central Iowa Power Coop v. FERC, 606 F.2d 1156, 1165 n. 28 (D.C.Cir. 1979) (affirming rate based on "need to stimulate short-term purchases of excess capacity in lieu of adding new capacity and to discourage reliance on emergency energy when units are less than efficient").

[51] E.g., Louisiana Energy and Power Authority v. FERC, 141 F.3d 364 (D.C. Cir. 1998); Elizabethtown Gas Company v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993); see also Midcoast Interstate Transmission, Inc. v. FERC, 198 F.3d 960, 968 (D.C.Cir. 2000). Other agencies subject to ratemaking regimes similar to that of the FPA have been upheld in adopting a market-based, rather than a cost-of-service, approach to setting rates. See Nat'l Ass'n of Regulatory Util. Comm'rs v. FCC, 737 F.2d 1095, 1137 (D.C. Cir. 1984); Nat'l Rural Tel. Ass'n v. FCC, 988 F.2d 174 (D.C. Cir. 1993); Consolidated Rail Corp. v. U.S., 812 F.2d 1444 (3d Cir. 1987); Potomac Elec. Power Co. v. ICC, 744 F.2d 185 (D.C.Cir. 1984).

[52] In Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), cert. denied sub nom. Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984), the court explained that it may not invalidate "rate orders that fall within a 'zone of reasonableness,' where rates are neither 'less than compensatory' nor 'excessive.'" It added that "when FERC chooses to refer to non-cost factors in ratesetting, it must specify the nature of the relevant non-cost factor and offer a reasoned explanation of how the factor justifies the resulting rates."

never bound itself to a rule requiring either rigid regulation or textbook markets"). The courts have also approved the use of marginal cost pricing as an appropriate regulatory tool. Town of Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992) (stating "one of the best-established precepts of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equivalent to the marginal cost of producing it.") See Electricity Consumers Resources Council v. FERC, 747 F.2d 1511 (D.C. Cir. 1984) (same).

Rather, in such circumstances, the presence of a monitoring program under which the Commission can take appropriate action to restructure the market is key. For example, in Elizabethtown, the court found that the continued "exercise of the Commission's NGA] § 5 authority . . . to assure that a market (i.e., negotiated) rate is just and reasonable" sufficiently safeguards against abuses under a market pricing approach. 10 F.3d at 870. Similarly, in Environmental Action, the court approved the combination of price ceilings and complaint procedures as sufficient safeguards because that would allow "competitive forces, not market power, [to] determine most transaction prices . . . and serve to extend competitive pricing to situations where market power might otherwise prevail." 996 F.2d at 413. [53]

Through the remedies ordered in earlier orders and herein, the Commission determined and is continuing to determine pursuant to FPA Section 206 "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract" to replace flawed structure and rules, and to "fix the same by order." The Commission was not obliged to set seller-specific cost-based rates to resolve the perceived problems, given its continuing monitoring and review of the situation which offers adequate safeguards against potential market abuse. The mitigation plan adopted in this order relies on market solutions and mechanisms to the maximum extent possible, consistent with the Commission's statutory responsibilities to maintain just and reasonable rates. The revisions made in this order are designed to provide a structure that will minimize potential market power abuses, thus lowering customer rates, while also encouraging adequate supply in the market for the immediate future.

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[53]The courts have approved market pricing for other agencies if available remedies assure that market power will not be abused. E.g., Ford Motor Co. v. ICC, 714 F.2d 1157, 1158-59 (D.C. Cir. 1983); Arkansas Power & Light v. ICC, 725 F.3d 716, 718 (D.C. Cir. 1984); Coal Exporters Ass'n v. U.S., 745 F.2d 76, 80 and 90 n. 18 (D.C. Cir. 1984); Arizona Public Service Co. v. U.S., 742 F. 2d 644, 647 (D.C. Cir 1984).

E. ISO Market Clearing Auction During Periods of Reserve Deficiency

Under the April 26, 2001 mitigation plan, each gas-fired generator in California (both those signing PGAs and covered non-public utility gas-fired generators) will file with the Commission and the ISO (on a confidential basis) the heat rate and emission rate for each generating unit. The ISO would use these heat rates to calculate a marginal cost for each generator by using a proxy for the gas costs, emission cost, and a $2.00/MWh adder for O&M expenses. The gas cost proxy was based on an average of the daily prices published in Gas Daily for all California delivery points. The emission cost was to be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit. All generators would be paid a single market clearing price reflecting the last unit dispatched calculated using the proxy prices.

Rehearing requests addressed a number of elements of this plan. Based on those rehearing requests, the Commission, as discussed in detail below, is modifying the method of determining the cost for gas, the treatment of emission costs, and the O&M adder. The Commission will address below the rehearing requests with respect to the ISO auction mitigation plan.

1. Use of the Marginal Cost of the Last Unit Dispatched

PG&E maintains the Commission should not determine price using the marginal cost of the last unit dispatched. Instead, it maintains the Commission should use the heat rate of the average cost unit. PG&E maintains that in a competitive market, each unit of generation would recover only its own marginal costs.

In a competitive market, however, each generator would not receive only its own marginal cost, as PG&E asserts. Competitive markets clear at a single price, which is effectively set by the marginal cost of the last unit produced. All more efficient units will receive the same price, which creates an incentive for firms to increase their efficiency. Therefore, using the marginal cost of the least efficient generating unit dispatched best replicates prices in a competitive market. In 1998 and 1999, when the California spot markets were producing average annual wholesale prices of $29 and $31 per MWh, respectively, the marginal cost of the last unit dispatched set these prices. The mitigation plan simply returns the market to the competitive principles that existed in 1998-99.

The ISO contends that inflexible units such as combustion turbines should not set the proxy price, because they do not have the flexibility to be dispatched on a 10-minute basis. The Commission's mitigation plan is based on the payment of the marginal cost of the last generator dispatched to serve the last increment of load. Therefore, if a

combustion turbine is the last generator dispatched, its bid should establish the market clearing price.

2. Calculation of Market Clearing Price

Rehearing requests raise a number of issues with respect to the calculation of the mitigated price, particularly with respect to the gas prices and emission prices used.

a. Gas Costs

Under the Commission's April 26, 2001 approach, gas costs used in the formula are determined by an average of reported daily spot gas prices at California delivery points. The requests for rehearing raise a number of issues regarding the use of gas costs to determine the market clearing price. Several rehearing requests contend that the Commission should not use proxy prices, but should use actual gas (and emissions) costs for generators.[54] Others contend that using the reported gas prices overstates gas costs, because generators have a portfolio of gas supplies and are not buying all their gas at spot prices.[55] The ISO and CEOB contend that to better reflect supply portfolios, the Commission should use monthly bid-week gas prices, rather than daily spot prices. The ISO recommends the Commission use bid-week monthly prices from Gas Daily, but for only three points in California, Malin, SoCal Gas (large packages), and PG&E city-gate (excluding PG&E large packages). Others contend that using the average gas price does not accurately reflect the marginal costs of generators, because gas prices are higher at the Southern California points than Northern California points.[56] They suggest that the gas proxy price should be revised to more accurately reflect the marginal costs of each generator.

The Commission's mitigation plan is designed to establish generators' bids and market prices up-front. Using actual costs to determine marginal cost, as some suggest, would not establish generator bids, but would require an after-the-fact review of whether a generator's bid actually reflected its marginal cost. Using actual costs, therefore, would not provide price transparency, and would be administratively infeasible because it would require a constant reevaluation of every generator's bids.

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[54]Rehearing Requests by NCPA, Seattle, Edison.

[55]Rehearing Requests by ISO, CPUC, Assembly, Metropolitan, PG&E, SDG&E, San Diego, San Francisco, Edison.

[56]Rehearing Requests by CEOB, Dynegy, Reliant, Williams.

The Commission will revise the spot gas prices to be used in the formula to accord with the requests by the ISO to establish the proxy gas cost for determining marginal costs.[57] The ISO will be required to average the mid-point of the monthly bid-week prices reported by Gas Daily for three spot market prices reported for California.[58] This price represents a reasonable proxy for the marginal cost that generators will incur, since they can pre-buy their gas requirements for the month at this price.[59]

The Commission recognizes that, as Reliant and Dynegy point out, spot gas prices in southern California off of SoCal Gas's system exceed other spot prices in California. The staff of the California Energy Commission has recognized that a chief contributor to the high natural gas prices in southern California is the deficit of intrastate capacity on the SoCal Gas system.[60] It reports that the interstate delivery capability exceeds the ability of SoCal Gas to receive that gas by 300 MMcf/d. It concludes that:

> this deficit in receipt capacity contributes to the high natural gas prices in California and the tight supplies to meet natural gas demand by electric generators.[61]

Another contributing factor to the high gas prices is the inability of generators and other shippers to acquire firm transportation rights on SoCal Gas's backbone system and SoCal Gas's system of allocating transportation on its backbone system, which leads to great uncertainty in scheduling gas supplies from interconnecting pipelines. This Commission recently has taken action to help improve the certainty of nominations on

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[57]See Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992) (one of the best established principles of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equal to the marginal cost of producing it); Electricity Consumers Resources Council v. FERC, 747 F.2d 1511 (D.C. Cir. 1984).

[58]The three points are SoCal Gas (large packages), Malin, and PG&E city-gate.

[59]The average for June as reported in the Gas Daily Price Guide is $9.10. The bid-week monthly index prices are SoCal Gas (large packages) $11.71, Malin $5.98, PG&E Citygate $9.61.

[60]California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

[61]California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

interstate pipelines into southern California,[62] but in the absence of scheduling changes on SoCal Gas, the Commission's changes to interstate scheduling practices cannot remove this uncertainty altogether. The Commission staff held a technical conference on May 24, 2001 to examine the problems in California gas infrastructure in which many participants continued to express concern about the lack of intrastate capacity on SoCal Gas and the difficulty in achieving certainty in scheduling gas supplies due to SoCal Gas's allocation procedures.[63] The Commission also is continuing to pursue efforts to try to dampen these higher prices into southern California. For example, the Commission recently issued orders requesting comment on whether to establish reporting requirements to create greater transparency in the gas market for southern California and whether imposing a price ceiling on capacity release transactions would have an effect on dampening prices.[64] The Commission will continue to monitor the situation in California to see whether further efforts are needed.

In addition to the dysfunction in southern California gas markets, the Commission cannot be certain that the daily SoCal Gas (large packages) spot price represents the actual cost of southern California generators. Gas Daily and the other reporting services do not indicate what volume moves at these prices, how much volume may be sold at lower prices in non-spot markets, and whether generators may be able to use other options to protect themselves against such higher prices.

Because of these concerns about the supplies coming into California from SoCal Gas, the Commission does not find it reasonable to base the market clearing energy price for California and the remainder of the WSCC solely on the southern California spot price for gas. Instead, the most equitable way of handling this issue is to use the approach described above. Under the mitigation plan adopted in this order, individual southern California generators are permitted to justify bids above the market clearing price so long as they can show their entire gas portfolio justifies such a bid.

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[62]Amoco Energy Trading Corp. v. El Paso Natural Gas Company, 93 FERC ¶ 61,060 (2000), aff'd 94 FERC ¶ 61,225 (2001).

[63]California Natural Gas Transportation Infrastructure, Docket No. PL01-4-000.

[64]Order Proposing Reporting Requirement on Natural Gas Sales to California Market and Requesting Comments, 95 FERC ¶ 61,262 (2001); San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,264 (2001).

b. Emission Costs

The April 26 Order stated that the emission cost would be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for each unit. Many rehearing requests point out that the method of paying for exceeding emission allowances has been changed, so generators no longer can buy NOx emissions when they run out of emission allowances. Instead, local air districts now require generators to pay mitigation fees when they exceed their emission allowances.

Several rehearing requests contend that the emissions cost should not be included as part of the proxy price, but should instead be collected in an up-lift charge when actually incurred. [65] Several also argue that not all generators pay emission costs and those that do incur such costs pay them only when they have used up their emission allotments. [66] They contend, therefore, that emissions costs should not be included until they have to be paid. ARB maintains that mitigation fees are not variable costs and should not be included in the marginal cost calculation because it will increase prices to all customers. It also argues that including mitigation fees as part of marginal costs will result in increased pollution as air districts may decide to reduce the emissions fees as a result of the higher consumer costs for power.

Sellers, on the other hand, contend that emissions costs are legitimately included as marginal costs. [67] They maintain that in running beyond their allotment of emission costs today, they not only are required to pay mitigation fees, but their emission allotments in subsequent years are reduced. [68] Sellers claim they need reimbursement for the opportunity costs of losing the ability to run their units in later years.

We will eliminate NOx costs from the calculation of the mitigated market clearing price. Since the Commission issued the April 26 Order, the SCAQMD's RTC program for electric generators larger than 50 MW (which was publicly traded by Cantor Fitzgerald Environmental Brokerage Services) has been eliminated by the SCAQMD's governing board and the rules governing generator run-times have been altered by the

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[65] Rehearing Requests by ISO, ARB, CEOB, CPUC, Assembly, PG&E, San Diego, SCAQMD, Edison, SCWC.

[66] Rehearing Requests by Assembly, PG&E, Edison, SCWC.

[67] Rehearing Request by Williams.

[68] Rehearing Requests by Dynegy, Mirant, Reliant.

Governor of California.[69] There are 35 air quality districts within California and many of these districts treat NOx emissions differently from other air quality districts within California. Moreover, the ability of these districts and the state to change the rules governing NOx emissions renders a one size fits all approach for emission costs impractical.

However, mitigation fees associated with NOx emissions are a legitimate cost of producing energy. Therefore, generators should be permitted to recover the cost of these mitigation fees. We direct the ISO to develop a specific emission allowance administrative charge assessed against all in-state load served on the ISO's transmission system in order to recover NOx emission mitigation costs assessed against generators that are required to run in accordance with ISO dispatch instructions and the must offer provisions of this order. Monies collected through this administrative charge will be placed in an interest bearing escrow account by the ISO. When a generator actually incurs mitigation costs, the generator will submit an invoice to the ISO for recovery of these costs and the ISO must pay these invoices. Because all customers within California benefit from cleaner air as a result of application of these mitigation fees, the administrative charge should be assessed against all in-state load served on the ISO's system. We direct the ISO to submit tariff modifications incorporating an emission allowance administrative charge within fifteen days of the date of the order.

c. O&M Adder

The April 26 Order added $2.00 to the marginal cost price for each generator to represent operations and maintenance (O&M) expense. MID and the Assembly claim the Commission has not justified the $2.00 adder for O&M expenses. MID maintains the Commission should permit generators to include actual O&M costs.

Variable O&M costs are legitimate marginal costs that are incurred as a result of the physical production of energy. Therefore, an adder to the marginal price of energy is appropriate in order for the generating unit to recover its variable O&M costs associated with each MWh produced and bid into the ISO's imbalance energy market. The Commission found in San Diego Gas & Electric Company, et al., 94 FERC ¶ 61,245 (March 9 Order), that a $2/MWh adder for variable O&M expense was reasonable. Furthermore, in the March 9 Order, we noted that the California Energy Commission also

[69] See Executive Order D-40-01 by the Governor of the State of California.

estimates variable O&M expenses of $2 to $3/MWh in a recent report titled "Market Clearing Prices Under Alternative Resources Scenarios 2000 to 2010." [70]

We are cognizant of the concerns raised by MID that the O&M adder may be lower than actual O&M expenses; therefore, we will increase the O&M adder from $2/MWh to $6/MWh. The O&M forecasts made by the California Energy Commission are for new, efficient combined cycle units that are not the units on the margin in the California market. An O&M adder of $6/MWh is based upon a seventeen year average of actual non-fuel O&M expenses for oil and gas-fired steam plants. [71] The California market primarily consists of older oil and gas-fired steam plants. Thus, using a long-term average of actual O&M expenses for the same kind of units currently in the California market should permit generators in the California market full recovery of all non-fuel expenses.

d. Heat Rate

The April 26 Order provided that the heat rate should be based on operational heat rates and should not include start-up and minimum fuel load costs. This requirement was justified because the market clearing price should reflect the costs needed to operate at or near maximum output. Williams maintains that the bid for each generator should include minimum fuel and start-up costs. It also maintains the price should be calculated each hour based on the heat rate and NOx curves for the point at which the unit is dispatched.

On May 18, 2001, the ISO submitted a status report informing the Commission that the ISO had issued two market notices to market participants providing a format for submission of the requested heat and emissions data. The ISO requested heat and emission rates for eleven different operating points with the first and last operating points representing the unit's minimum and maximum operating level, respectively. As noted by the ISO, by collecting eleven different operating points, the ISO will be able to approximate the actual incremental cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range.

The ISO's proposal to include the minimum and maximum operating levels for each unit and nine points in between is reasonable. The ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams. In addition, because the ISO

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[70] 94 FERC at 61,863, n. 8.

[71] See http:/www.eia.doe.gov/oiaf/issues/opctbl3.html. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997.

will have the approximate heat rate curve for each unit, the ISO is directed to calculate the proxy market clearing price based upon the approximate point on the heat rate curve at which the last unit is dispatched. [72] However, we will allow sellers to recover their actual start-up fuel costs. Sellers will invoice the ISO their actual start-up fuel costs for recovery by the ISO in the same manner that emissions costs are recovered, and the ISO must pay these invoices. We direct the ISO to submit tariff modifications incorporating these costs within 15 days of the date of this order. This change adequately reflects the concerns raised by Williams, and, therefore, its rehearing request is moot.

e. Opportunity Cost, Scarcity Rents, Recovery of Fixed Costs, and Justification of Higher Prices

Generators maintain that the Commission's methodology for calculating marginal costs excludes legitimate opportunity costs related to energy-limited plants as well as scarcity rents.[73] They further maintain that paying only marginal cost of the last unit dispatched will not provide them with a reasonable opportunity to recover the fixed costs of peaking units. They further maintain that they will be unable to recover legitimate scarcity rents.

As discussed previously, the Commission is permitting generators to fully recover their emissions costs. As the Commission explained in the April 26 Order, in the real-time market, generators do not have opportunities to sell in higher-price markets because the real-time market consists only of energy that has not been previously sold in bilateral transactions. Since the Commission is imposing similar mitigation over the United States western markets in this order, sellers would no longer have any incentive to offer energy at a higher price to any other buyers in other states. Further, by using the marginal cost of the last unit dispatched to establish the market clearing price during periods of reserve deficiency, the Commission is permitting all more efficient generators a fair opportunity to recover capital costs.

The generators maintain that, while the market clearing price will enable generators more efficient than the last generator dispatched to recover capital costs, it will not permit recovery of the capital costs for that generator. Sellers such as Avista, Duke Energy, Dynegy, Reliant, and PPL have a portfolio of generating capacity, with units that will be more efficient than the unit setting the market clearing price. Therefore, the

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[72]The emissions data is no longer relevant based upon our aforementioned removal of NOx costs from the proxy market clearing price.

[73]Rehearing Requests by Avista, Duke Energy, Dynegy, Reliant, PPL.

amounts earned on the more efficient plants will cover the investment in the marginal plant. Furthermore, we note that California no longer relies exclusively on the spot market. Negotiated bilateral agreements have, in large part, replaced this market and provide opportunity for any seller to structure the arrangements necessary to recover its costs. Finally, under the FPA and our authorization for market-based rates, sellers are not guaranteed to recover all costs but are provided the opportunity to do so.

The Commission, in this order, has sought to provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs. Sellers have not suggested a reasonable method of measuring the magnitude of such costs. The Commission's mitigation plan uses available data to develop a reasonable marginal cost for each generator and to permit reasonable recovery of legitimate costs. If sellers do not believe that these prices sufficiently cover their costs, they can file for cost-of-service rates covering all of their generating units in the WSCC for the duration of the mitigation plan.

Reliant and PPL contend that generators are entitled to a premium to cover the real risk of non-payment in California. We recognize that the risk of nonpayment in California continues to be greater than that in the larger West-Wide market. We also note that there is a longer payment lag in the ISO spot markets of approximately 75 days that does not generally exist in the Western bilateral spot markets. We instruct the ISO to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. [74] The adder is not instituted to compensate generators for past unpaid bills. The ISO must incorporate this provision in its compliance filing. This adder may be lifted by the Commission depending on the outcome of the settlement proceeding. However, the Commission believes that questionable business practices have sent negative signals to future supplies, credit rating agencies and investors and therefore an adder for credit risk is justified and necessary.

As described above, our order today prescribes a market-driven price mitigation mechanism in all hours. Sellers dissatisfied with these prices have two options. They may propose cost-based rates for their entire portfolio of generating facilities in the WSCC in a section 205 filing with cost support including a reasonable rate of return on investment that reflects the unique conditions in California. Alternatively, although we believe the mitigated price to be adequate, sellers can seek to justify each transaction above the mitigated price. Any such justifications, however, cannot include premiums to compensate for credit risk, since our market-clearing price for the ISO's markets already reflects an adder for this risk. Similarly, a seller's emission costs cannot be used to justify

[74] This adder will not be reflected in the market price for the rest of the WSCC.

exceeding the market-clearing price because our order allows each seller to recover its emission costs directly from the ISO. Claims of opportunity costs will not be considered because energy that is available in real-time cannot be sold elsewhere. Also, as explained elsewhere, marketers will not be allowed to justify prices higher than the mitigated prices because they must be price takers. Finally, while our approach allows recovery of gas costs, we will consider justifications based on higher actual gas costs if conditions in natural gas markets change significantly (assuming, of course, that suppliers can document and support their gas purchasing portfolio and allocation among all generating units at the relevant time). [75]

3. Applicability to Marketers And Out-of-State Generators

A number of rehearing requests contend that generators can circumvent price mitigation by selling energy to marketers. [76] They argue the generator could sell energy to a marketer at a high price and then the marketer could bid a high price into the ISO market, which it justified on the basis of its acquisition cost. In order to ensure compliance with the price mitigation, the Commission will not permit marketers to bid a price higher than the market clearing price. This will still provide marketers with an opportunity to earn a reasonable return on purchased energy, since the mitigated price is established by the marginal costs of the last unit dispatched and this price will be above the costs of the generators from which the marketers obtain their portfolio of energy. In this case, the marketer is no different than the last generator dispatched; it can recover the marginal costs of the last unit of energy produced.

The ISO maintains that out-of-state generators should be covered by the mitigation requirement so that any bids they submit above the market clearing price will be subject to refund. Out-of-state generators that want to have their marginal costs included in calculating the market clearing price can submit the required heat rate and gas source to the ISO for use in calculating the market clearing price. In the April 26 Order, the Commission did not require out-of-state generators to justify their price if they bid into the ISO market, because the Commission did not want to discourage out-of-state generators from bidding into the ISO market. However, now that the Commission is

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[75]Currently, emission costs outside of California are de minimis. However, we recognize that this may change, and that sellers could be subject to entirely new costs resulting from changes in circumstances. We will consider such costs on a case-by-case basis.

[76]Rehearing Requests by ISO, CEOB CMUA, Metropolitan, NCPA, SMUD, San Diego, Edison.

implementing mitigation for the entire WSCC, out-of-state generators will be treated like in-state generators.

F. Conditions on Market-Based Rate Authority

The April 26 Order conditioned public utility sellers' market-based rates to ensure that they do not engage in certain anticompetitive behavior. Sellers violating these conditions would have their market-based rates subject to refund and possible revocation.

Several generators have requested rehearing of this aspect of the April 26 Order.[77] Mirant and Williams, for example, urge the Commission to realize that sellers save certain units for when they can get the best price. Mirant contends that the bidding practices proscribed by the April 26 Order are legitimate, justifiable strategies in a competitive market and requests the Commission to eliminate the conditions or at a minimum, to limit the imposition of the conditions to certain hours.

Dynegy opposes the prohibition on the first category of bids, so-called "hockey stick" bidding. Dynegy submits that the risk of outage goes up substantially as the unit is pressed into operating longer than is advisable. The generator, therefore, faces new risks, such as a forced outage, and must be able to place premiums on the price per unit. EPSA, meanwhile, opposes the prohibition on bids that rise as the unit's output drops. EPSA states that the Commission should not revoke market-based rate authority based on a legitimate effort to recover total costs, but rather only if it finds that market power has been abused.

We will not tolerate abuse of market power or anticompetitive bidding or behavior. Emblematic of these practices is the now well-publicized bid of $3,880/MWh by Duke Energy. This bid resulted in total revenues for Duke Energy of $11 million. Exacerbating the problem was the fact that, while this transaction was identified in the March 9 Order as exceeding the proxy price, Duke Energy failed to even report this transaction in its quarterly report. The March 9 Order gave Duke Energy the choice of refunding all revenues in excess of those that would have occurred using the proxy price, or justifying the higher bid. Duke Energy chose the latter. Duke Energy argued that the payments for the energy it had supplied were in arrears, and therefore, it added a credit premium. The data show that Duke Energy's risk premium exceeds its variable cost by an

[77] Rehearing Requests by Dynegy, Mirant, Reliant, EPSA, Duke, PPL.

order of magnitude. [78] Duke Energy's bidding at multiples of its marginal costs in an attempt to recover past due amounts can in no way be found to be just and reasonable. Accordingly, Duke Energy is directed to refund with interest pursuant to 18 C.F.R. § 35.19a, or offset, down to the level of the proxy price, $273/MWh for January, during the relevant hours. As the proxy price is well above Duke Energy's claimed running costs, it will be sufficient to cover any credit risk that Duke Energy may face. [79]

Public utility sellers' market based rate authority will be subject to potential revocation if they are found to have engaged in inappropriate behavior. Further, WSCC public utility sellers' market-based rate authorizations are hereby conditioned on agreeing to potential refunds for overcharges resulting from anticompetitive behavior.

The Commission denies Dynegy's request asking the Commission to clarify that the prohibition on bidding practices will expire on April 30, 2002, along with the rest of the April 26 Order.

G. Refunds

In the April 26 Order, the Commission established that all charges below the market clearing price would not be subject to refund. Refunds would be required only for sellers that fail to justify bids above the market clearing price. The Commission further stated that generators would not be liable for refunds if the Commission did not act within 60 days of the filing of the justification report.

PG&E and Edison maintain that the Commission cannot erase statutory refund obligations by stating that certain prices are deemed just and reasonable. Edison argues that the Commission must order refunds for all amounts above a just and reasonable rate and should not be able to limit refunds to emergency situations. Edison maintains that the Commission cannot establish that refund authority will expire within 60 days. It

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[78]Duke Energy unequivocally states that it is using the $3,880/MWh bid as a negotiating tool to recover payment for prior transactions. Duke Energy states that it will settle for the proxy price if and when it is paid in full for its prior, unpaid transactions. March 23, 2001 compliance filing in Docket Nos. ER01-1448-003 and ER01-1448-004 at pp. 10-12.

[79]The Commission notes that there are a number of submittals dealing with sellers' market-based rate authorizations as well as bid justifications. We will address them in separate orders, if not resolved as part of the settlement process established elsewhere in this order.

further contends that the Commission cannot shield generators from refunds, because the Commission has the authority to correct its legal errors. The CPUC maintains that refunds should exceed unlawful gains to act as a deterrent and suggests that the Commission impose treble damages, as provided for in antitrust law.

The Commission is establishing price mitigation in all hours of reserve deficiency and, as a discretionary matter, is also extending a form of that mitigation to hours of non-reserve deficiency. This price mitigation establishes the maximum just and reasonable rates in spot markets, absent cost justification. Moreover, the 60 day period for review of cost justifications was a self-imposed requirement to ensure that there is price certainty. The Commission has the authority to extend the period if necessary to finish processing the justifications.

With respect to the CPUC's arguments, the CPUC cites no provision of the FPA authorizing the Commission to impose penalties. Finally, the Commission has no authority to impose treble damages.

H. Underscheduling Penalty

On December 15, 2000, the Commission issued an order which established, among other things, as part of a comprehensive price mitigation plan, a maximum penalty of $100/MWh if energy buyers had over 5 percent of their load served in the real-time market. [80] Several parties request that the Commission suspend the penalty for underscheduling in this proceeding. [81] Due to the Commission's decision in the April 26 Order to defer action on suspending the penalty for underscheduling, we will address this issue in a future order.

I. Confidentiality of Data

The Commission stated in the April 26 Order that it would continue the previous practice of keeping bid data confidential for six months, because disclosure of such information may lead to a reduction in competition because it will allow competitors to learn what their competitors are bidding and could lead to price collusion or coordination. The Commission also found that generator's heat rates and emission cost information was also confidential business information that should not be disclosed.

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[80] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,294 (2000), reh'g pending.

[81] See Comments by CPUC, DWR, PG&E.

Several parties contend that the Commission should not keep the heat rate and other cost information used to justify bids confidential, but should make the data publicly available, under section 205 of the FPA, on a next-day basis. [82] They also assert that due process requires that all data used to determine the proxy price is an essential part of a rate schedule and must be made available so it can be challenged by other parties, particularly ratepayers. SCWC and Assembly contend that the solution to collusion or gaming is not confidentiality, but rather regulation of seller conduct. As an alternative, San Francisco and Assembly maintain that the Commission can keep the data confidential, but that the filing of the data should be publicly noticed pursuant to the FPA, and the data should be available for review by those parties who enter into a protective order.

As the Commission found in the April 26 Order, the information on heat rates and emission costs is highly confidential business information. The disclosure of such information can cause competitive harm by allowing competitors to learn of the behavior and costs of their competitors. The Commission regulations provide for granting confidential treatment of business sensitive information. [83] These issues are raised in other pleadings before the Commission, and we will address these matters in a later order.

EPSA's concerns relate to the independence of the ISO Board and the apprehension of disclosing confidential data to a non-independent body. EPSA suggests replacing the ISO Board or alternatively, requiring the reporting of such data to an independent entity so it can perform the marginal cost calculations. The concerns related to the independence of the ISO Board are beyond the scope of this rehearing and will be addressed in a later order.

M-S-R and TANC state that the April 26 Order is silent with respect to ordering the ISO to keep the bid and cost data confidential. While the Commission finds that the order was sufficiently clear in the first instance, out of an abundance of caution, the Commission clarifies that the ISO is ordered to treat all cost data in a confidential manner.

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[82] Rehearing Requests by NCPA, Assembly, SCWC, Edison, San Francisco, PG&E.

[83] See 18 C.F.R. §§ 388.112 (2000), 385.206(e), 385.213(c)(5), 385.410(c) (providing for confidential treatment for business sensitive information).

J. Review and Duration of the Mitigation Plan

In the April 26 Order, the Commission established a maximum one-year time period for the duration of the mitigation plan. In addition, the Commission instituted a process for reviewing the operations of the plan and the conditions in the California market on a quarterly basis.

Several parties request rehearing on the duration of the mitigation plan, stating that the Commission's decision to establish a pre-determined time period for applying mitigation is arbitrary and capricious.[84] Anaheim asserts that there is no rational basis for ending the mitigation after one year while SCWC states that the only criterion for terminating mitigation is whether markets are competitive or not. Metropolitan states that the Commission's assumptions about planned demand reduction and market development within one year should not be the basis for terminating mitigation. Metropolitan, Assembly, and others urge the Commission to monitor the progress of market entry by new generation and other market developments before termination.

The Commission is requiring the ISO to file on or before March 26, 2002, a report on market conditions that addresses among other things: (1) a list of all new generating resources (including the nameplate capacity) that the State of California has announced this year would be on line by summer 2002 and which of those facilities actually are on line (see Attachment to this order); [85] and (2) the continued progress in executing long-term contracts and reducing the reliance on the spot market. We will extend the mitigation through September 30, 2002. Our requirement for quarterly reports will continue.

K. RTO Proposal

In the April 26 Order, the Commission conditioned the implementation of the market monitoring and mitigation plan on the ISO and the three investor-owned utilities (IOUs) (SDG&E, Edison, and PG&E) filing an RTO proposal by June 1, 2001, consistent with the characteristics and functions in Order No. 2000.

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[84]Rehearing Requests by Edison, CPUC, CMUA, Anaheim, SCWC, Metropolitan.

[85]As pointed out in the April 26 Order, California has committed itself to increasing in-state generation and projects that new generation totaling 4,168 MW will be on line by the end of August 2001 and that there could be as much as 6,879 MW on line for the summer of 2002.

Several parties have requested rehearing challenging the Commission's conditioning mitigation on the filing of an RTO. [86] While requesting rehearing on the lawfulness of the condition, City of Seattle and others assert that filing an RTO proposal by June 1, 2001 is highly unrealistic, and therefore request that the RTO condition be removed from the April 26 Order on rehearing.

As noted in the April 26 Order, the RTO condition recognizes that the only real solution to supply problems that affect the Western United States is to create a regional response. The Commission intended to create such a response, and to improve and enhance supply and deliverability infrastructure so as to make the deliverability of supply possible and more reliable by imposing this condition as a necessary component to a solution for California and the Western United States. The ISO and two IOUs, SDG&E and Edison, filed an RTO proposal on June 1, 2001. PG&E also made a separate filing. Since the RTO filings have been made, the monitoring and mitigation plan will remain in effect. The Commission will address the adequacy of these filings in future orders. Since the ISO and utilities made the requisite filings, the requests for rehearing on this issue are moot.

L. West-Wide 206 Implementation

In the April 26 Order, the Commission instituted an investigation under section 206 of the FPA into the rates, terms and conditions of sales for resale of electric energy in interstate commerce in the WSCC other than sales through the ISO's markets, to the extent that such sales for resale involve: (1) electric energy sold in real-time spot markets (i.e., up to 24 hours in advance) and (2) take place during conditions when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent. These proceedings were instituted to investigate whether and the extent to which significant increases in the prices for energy and ancillary services in the California market are affecting prices for such services in the WSCC outside of California.

In the April 26 Order, the Commission recognized that the California market is integrated with those of other states in the WSCC. Therefore, the Commission stated its intention that, to the extent possible, its proposed changes would mirror the measures to be applied to California markets. [87] The April 26 Order proposed the following three measures for the WSCC:

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[86] Rehearing Requests by Seattle, Anaheim, SCWC, San Diego, CPUC, PG&E, CMUA, Metropolitan, CEOB.

[87] 95 FERC ¶ 61,115, at 61,356.

(1) A requirement that all public and non-public utility sellers, with energy operationally and contractually available in real-time, offer that energy for sale;

(2) Price mitigation during periods when reserves fall below 7 percent; and

(3) A condition on the market based rate authority of public utility sellers selling in the WSCC region to ensure that they do not engage in anti-competitive behavior.

On April 27, 2001, the Commission issued a notice establishing a refund effective date 60 days from the date on which notice of initiation of the investigation was published in the Federal Register. The notice was published in the Federal Register, 66 Fed. Reg. 22223, on May 3, 2001. Thus, the refund effective date is July 2, 2001.

1. WSCC Mitigation Plan Overview

Based upon the need for uniform pricing throughout the Western region, we now find it necessary to adopt a market monitoring and mitigation plan for the WSCC spot markets. This plan will consist of several primary elements, each of which is intended to closely mirror the monitoring and mitigation plan we have adopted for California while also taking into account the various disparities between the California and WSCC markets.

Effective on the day following the date of this order, the plan we adopt below applies in all hours to all spot market transactions throughout the WSCC. In the hours when California experiences reserve deficiencies, prices for WSCC spot market sales cannot exceed the ISO's hourly market clearing price, absent justification.

Under our current and revised mitigation plan, the price in the ISO's Imbalance Market during times of insufficient operating reserves will consistently reflect the marginal cost of energy. Recent data show that during hours of sufficient operating reserves, the average hourly Imbalance Energy price has been zero and at times a negative value. These prices indicate that either there were no transactions in this market or that generation actually exceeded load during these hours. While there may be a number of factors that contribute to these anomalous results (e.g. changes in buying strategies), we are convinced that we must use a modified mitigation approach during hours of non-reserve deficiencies.

For spot market sales, both in the WSCC and in California, in all non- reserve deficiency hours (i.e., when reserve levels in the ISO exceed 7%), we will adapt the use

of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can be no higher than $119/MWh (i.e. 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market clearing price, but that clearing price will not exceed $119/MWh. For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward.

Third, the plan imposes a must-offer requirement for all hours upon sellers with the exception of hydroelectric resources and capacity needed to meet WSCC minimum operating reserve criteria for control areas. Fourth, the plan applies to all public utilities (including marketers) and non-public utilities who sell into Commission-regulated spot markets or use the interstate transmission grid subject to our jurisdiction. Market-based rate authorizations for public utilities are hereby conditioned upon adherence to this plan.

2. Interventions and Comments

In the April 26 Order, the Commission provided that comments should be submitted within ten days of the date of that order. Timely notices of intervention, motions to intervene and comments in the WSCC proceeding were filed by the entities listed in Appendix B.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, notices of intervention and timely, unopposed motions to intervene serve to make the intervenors listed in Appendix B parties to this proceeding. Given the early stage of the proceedings, we will accept the late-filed comments.

3. Megawatt Laundering

In the April 26 Order, the Commission noted that several commenters complained that generators may avoid the Commission's mitigation requirements through "megawatt laundering." In that order, the Commission recognized that the California market is integrated with other states and instituted the instant investigation. In addition, the Commission extended the must-offer obligation to include non-public utility generators in California which currently make use of the ISO's interstate transmission grid. In their comments, CPUC, DWR, TURN/UCAN, and CEOB request that the Commission also address megawatt laundering in this proceeding.

As discussed above, megawatt laundering will no longer be a concern due to our revised mitigation plan. First, the mitigation plan will be for all hours and will be applicable uniformly throughout the WSCC. Second, both sales within and outside California will be treated uniformly including sales by marketers. As a result of these modifications, this strategy cannot be used to avoid potential mitigation.

4. The Proposed 7 Percent Reserve Deficiency Trigger

The April 26 Order established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, and proposed that mitigation in the WSCC would be triggered when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent.

Numerous commenters raise issues regarding how the reserve deficiency mechanism would be implemented for the WSCC. Based on the numerous concerns raised by the comments, we will simplify the West-wide mitigation so that it will trigger only when the ISO declares a reserve deficiency.

5. The Proposed Must-Offer Requirement

In the April 26 Order, the Commission included a requirement that all generators in California (with the exception of hydroelectric power), including non-public utility generators that make sales through the ISO's markets or that use the ISO's interstate transmission grid, must offer any power that they have available in real time to the ISO. This includes power not already scheduled to run through bilateral agreements.[88] With respect to the WSCC investigation, the Commission stated that it intends to mirror the approach used in California.

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[88] 95 FERC ¶ 61,115, at 61,355-57.

A number of parties oppose the requirement for the WSCC. For example, the Oregon Office of Energy believes that a requirement to offer energy for sale is difficult to police because a generator must be allowed to decide when its equipment must be taken out of service and at what levels of output it can run.

We clarify that the must offer requirement throughout the WSCC will not apply to hydroelectric resources or to generation that is necessary for control area operators to meet the applicable WSCC Minimum Operating Reserve Criteria. We recognize that outside of California there is currently no operational ISO or RTO in place in the WSCC and therefore, no centralized location to post this information. The lack of an operational regional structure will make implementation of this feature of the mitigation plan difficult.

In order to implement this feature of the mitigation plan immediately, we will require all public utilities that are control area operators to have their wholesale merchant function calculate on a daily basis the amount of capacity that will be available after load and operating reserve forecasts have been calculated. The wholesale merchant function will post this information on its company web site and on the Western System Power Pool (WSPP) web site, and will maintain in its daily log the amount of non-hydro resources that will be available. Actual arrangements for energy sales from such resources should be made with the wholesale merchant function and not with the control area operator.

To implement this requirement, we will require each marketer and independent power producing entity to post available capacity on a daily basis on its own web site and the WSPP web site.

6. Applicability to Non-public Utilities

The April 26 Order extended the must-offer requirement and the price mitigation plan to non-public utility generators in California which currently make use of the ISO's interstate transmission grid or sell in the ISO's markets. The Commission found that extending these requirements to non-public utilities is necessary to ensure that the mitigation and monitoring proposal is applied equally to all generators in California. [89]

[89] Id. at 61,356 .

Similarly, the April 26 Order proposes to extend these requirements to non-public utility generators in the WSCC. [90]

Non-public utilities oppose applying these requirements to them. On the other hand, Avista Energy requests that the Commission suspend price mitigation measures established for public utilities in the WSCC if the Commission does not extend the mitigation measures to non-public utility sellers.

For the same reasons the April 26 Order applied mitigation to all generators within California, we will extend the mitigation plan adopted herein to include all public and non-public utilities throughout the WSCC. Moreover, the percentage of non-public utility generation in the WSCC outside of California is significantly larger than that inside of California.[91] We believe that all entities must assist with solving the problems in the WSCC. Accordingly, the Commission will require that, as a condition of selling into the markets which are subject to this Commission's exclusive jurisdiction, and as a condition of using Commission jurisdictional interstate transmission facilities, all sellers located in the WSCC, including non-public utility sellers in the WSCC, must abide by the WSCC price mitigation plan and by the must-offer obligation (if applicable) described in this order.

While the Commission does not directly regulate the non-public utility sales for resale throughout the WSCC, we have the authority, and, indeed, the responsibility, to ensure that rates, terms and conditions for jurisdictional service are just and reasonable. However, the Commission cannot ensure such just and reasonable rates in the current circumstances in the WSCC unless all entities that sell energy in the relevant spot markets or use the interstate transmission grid subject to our jurisdiction abide by the same conditions. Finally, by applying the plan discussed in this order to non-public utilities, we eliminate the incentive, and the means, for public utilities to avoid mitigation (i.e., by making wholesale sales to non-public utilities for resale in the spot market).

7. Refund Issues

As noted above, the refund effective date established in this proceeding is July 2, 2001. Some parties contend that it is premature to establish a refund effective date for the WSCC, or that the prospect of refunds could cloud supplier decision-making, while others are concerned that if a transaction is executed in the day-ahead market prior to a

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[90] Id. at 61,365.

[91] See Powerdat database, Resource Data International, Inc., April 2001 data set.

declared reserve deficiency, the transaction should be honored without mitigation or refund obligation. [92]

We will not rescind the refund effective date because we are legally obligated to establish a refund effective date when an investigation is instituted under section 206 of the FPA. We have established the earliest possible refund effective date permitted by the FPA Section 206, to provide maximum protection to customers. We expect that sellers will observe the requirements of this order and that the need for refunds will be rare. The commenters have not justified providing less protection. Moreover, the mitigation plan is taking effect prior to the refund effective date and this should obviate the need for refunds.

8. Mitigation Beyond Summer 2001

Although we are confident of the efficacy of our West-wide mitigation plan throughout the Summer of 2001, we nonetheless wish to obtain comment for the purpose of revising the mitigation methodology for future periods, if necessary. [93] Accordingly, we invite interested partes to file with the Commission comments and proposals concerning: (1) any developments, either beneficial or adverse, which have occurred in the Western region spot markets as a result of this order; (2) any difficulties with implementation of the mitigation plan detailed in the order, and the relevant solutions thereto; and, most importantly (3) any alternative market mitigation approaches. In order to provide for timely review and analysis, we will require that parties' comments and proposals be submitted to the Commission within 60 days of the date of issuance of this order.

M. Settlement Conference

We will require that all public utility sellers and buyers in the ISO's markets participate in settlement discussions to complete the task of settling past accounts and structuring the new arrangements for California's energy future. To achieve this goal, it is imperative that the parties reach agreement on (1) the additional load that is to be moved from the spot market to longer-term contracts, (2) refund (offset) issues related to past periods, and (3) creditworthiness matters. In highlighting these specific issues, we are not suggesting that the settlement discussions are limited to these matters, but emphasize that

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[92] See Comments of Avista Energy, Duke and Powerex.

[93] In particular, we seek comments on whether our approach is appropriate given regional differences between California and other regions.

all issues that remain outstanding to resolve past accounts and ensure California's energy future are on the table for the parties to address. Finally, we stress that it will be critical to the success of these discussions that the State of California designate one or more representatives, authorized to act on behalf of all affected state interests, to participate fully in the settlement discussions. We will appoint the Chief Administrative Law Judge or his designee to serve as a settlement judge to assist the parties in reaching a settlement and require the judge to convene an initial settlement conference no later than June 25, 2001, and to complete the settlement discussions no later than 15 days after the commencement of the settlement conference. The settlement judge shall make a recommendation to the Commission within 7 days after the close of the settlement discussions if the issues are not resolved by the parties.

N. ISO Compliance Filing

In the April 26 Order, the Commission directed the ISO to submit a compliance filing no later than fifteen days from the date of that order. The ISO made its compliance filing in Docket Nos. EL00-95-034 and EL00-98-033 on May 11, 2001. Due to the significant modifications to the mitigation plan we are adopting today, we will require a new compliance filing within 15 days of the date of this order.

The Commission orders:

(A) The ISO shall submit tariff changes to comply with this order within 15 days of the date of this order.

(B) Sellers of energy in the WSCC are subject to the mitigation plan as discussed in the body of this order. The mitigation plan will become effective on the day following the date of this order.

(C) Rehearing is granted in part, and denied in part, as discussed in the body of this order.

(D) The requests for stays of the April 26 Order are denied as discussed in the body of the order.

(E) No later than 7 days after the completion of settlement discussions, the settlement judge shall make a recommendation to the Commission with respect to the settlement negotiations in the captioned dockets.

(F) Duke Energy must file a report quantifying refunds or offsets within 15 days of the date of this order, as discussed in the body of this order.

(G) Interested parties are hereby invited to file comments and proposals regarding the market mitigation plan, as discussed in the body of this order.

By the Commission. Commissioner Massey concurred in part with a separate statement attached.

(S E A L) Commissioner Breathitt concurred with a separate statement attached.

Linwood A. Watson, Jr.,
Acting Secretary.

Appendix A
Requests for Rehearing of April 26 Order
(* - denotes request for late intervention)

Party	Abbreviation
American Public Power Association	APPA
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
California Air Resources Board *	ARB
California Department of Water Resources	DWR
California Electricity Oversight Board	CEOB
California Independent System Operator Corporation	ISO
California Municipal Utility Association	CMUA
California State Assembly	Assembly
Calpine Corporation	Calpine
Cities of Anaheim, et al.	Anaheim
City and County of San Francisco	San Francisco
City of Burbank *	Burbank
City of San Diego	San Diego
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition[94]	CAC/EPUC
Consumer Federation of America *	CFA
Duke Energy North America, et al., LLC	Duke Energy

[94]Request for stay.

Party	Abbreviation
Dynegy Power Marketing, Inc. et al.	Dynegy
Electric Power Supply Association	EPSA
Imperial Irrigation District *	IID
Los Angeles Department of Water and Power	LADWP
M-S-R Public Power Agency, et al.	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, et al.	Mirant
Modesto Irrigation District	MID
National Rural Electric Cooperative Association *	NRECA
Northern California Power Agency	NCPA
Pacific Gas and Electric Company	PG&E
PPL EnergyPlus, LLC, et al.	PPL
Public Utilities Commission of State of California	CPUC
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
San Diego Gas & Electric Co.	SDG&E
South Coast Air Quality Management District *	SCAQMD
Southern California Edison Company	Edison
Southern California Water Company	SCWC
Transmission Agency of Northern California	TANC

Party	Abbreviation
Turlock Irrigation District *	TID
Williams Energy Marketing & Trading Company	Williams

Appendix B
WSCC Comments
(* - denotes Motions to Intervene)
(** - denotes Notice of Intervention)
(*** - denotes late filed comments)

Party	Abbreviation
AES Southland, Inc. ***	AES
American Public Power Association *	APPA
Attorney General of Washington *	Washington Attorney General
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
Avista Utilities	Avista Utilities
California Air Resources Board *	ARB
California Department of Water Resources *	DWR
California Electricity Oversight Board ***	CEOB
California Independent System Operator Corporation	ISO
California Municipal Utility Association	CMUA
California State Assembly	Assembly
Cities of Anaheim, et al. *	Anaheim
County of San Diego *	San Diego
City and County of San Francisco *	San Francisco
City of Burbank *	Burbank
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition *	CAC/EPUC

Party	Abbreviation
Cogeneration Coalition of Washington *	CCW
Colorado Association of Municipal Utilities *	Colorado AMPS
Duke Energy North America, et al., LLC *	Duke Energy
Electric Power Supply Association	EPSA
Enron Power Marketing , Inc. and Coral Power, L.L.C.	Enron
Idaho Public Utilities Commission **	Idaho Commission
Imperial Irrigation District *	IID
Los Angeles Department of Water and Power ***	LADWP
M-S-R Public Power Agency, et al.	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, et al. *	Mirant
Modesto Irrigation District *	MID
Morgan Stanley Capital Group Inc.	Morgan Stanley
National Rural Electric Cooperative Association*	NRECA
Nevada Attorney General's Bureau of Consumer Protection *	Nevada BCP
Nevada Independent Energy Coalition*	NIEC
Nevada Public Utilities Commission *	Nevada Commission
Northern California Power Agency	NCPA
NRG Power Marketing Inc.	NRG

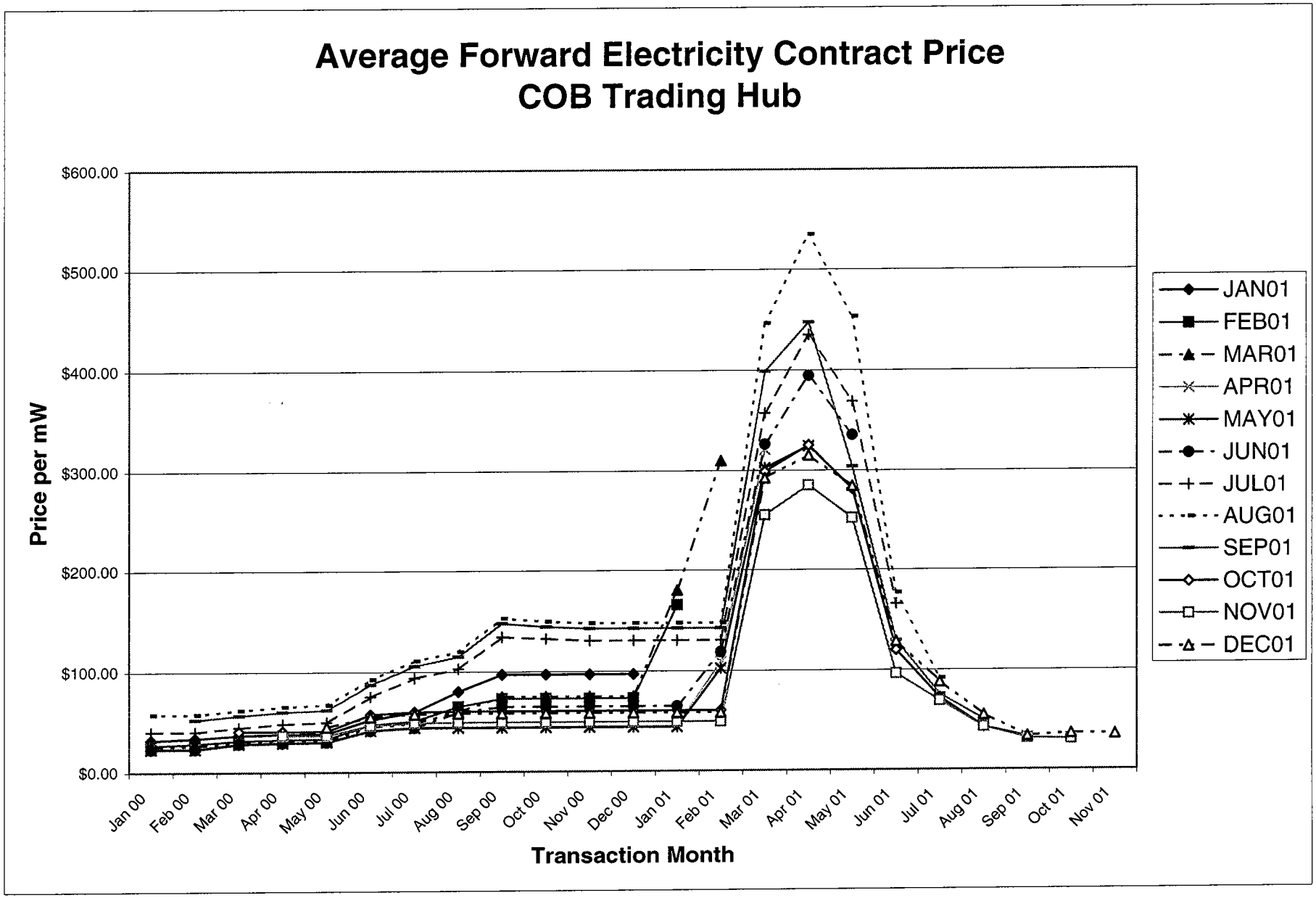
Party	Abbreviation
Official Committee of Unsecured Creditors of PG&E *	OSC
Oregon Office of Energy	Oregon Office of Energy
Pacific Gas and Electric Company *	PG&E
Pinnacle West Capital Corporation, Arizona Public Service Company, Pinnacle West Energy Corporation and APS Energy Services, Inc.	Pinnacle West Companies
Portland General Electric Company	PGE
Powerex Corporation *	Powerex
PPL EnergyPlus, LLC, et al. *	PPL
Public Utilities Commission of State of California **	CPUC
Puget Sound Energy, Inc.*	Puget Sound
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
Salt River Project Agricultural Improvement and Power District *	SRP
San Diego Gas & Electric Co. * ***	SDG&E
South Coast Air Quality Management District *	SCAQMD
Southern California Edison Company *	Edison
Tri-State Generation and Transmission Association, Inc. *	Tri-State
Turlock Irrigation District *	Turlock
Utah Municipal Power Agency *	UMPA
Utility Reform Network and the Utility Consumers' Action Network	TURN/UCAN

Party	Abbreviation
Washington Utilities and Transportation Commission **	Washington Commission
Williams Energy Marketing &Trading Company	Williams
Wyoming Public Service Commission ***	Wyoming Commission

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 40

Average Forward Electricity Contract Price (COB and Palo Verde)


Average Forward Electricity Contract Price
COB Trading Hub
Price per mW
$600.00
$500.00
$400.00
$300.00
$200.00
$100.00
$0.00
Jan 00
Feb 00
Mar 00
Apr 00
May 00
Jun 00
Jul 00
Aug 00
Sep 00
Oct 00
Nov 00
Dec 00
Jan 01
Feb 01
Mar 01
Apr 01
May 01
Jun 01
Jul 01
Aug 01
Sep 01
Oct 01
Nov 01
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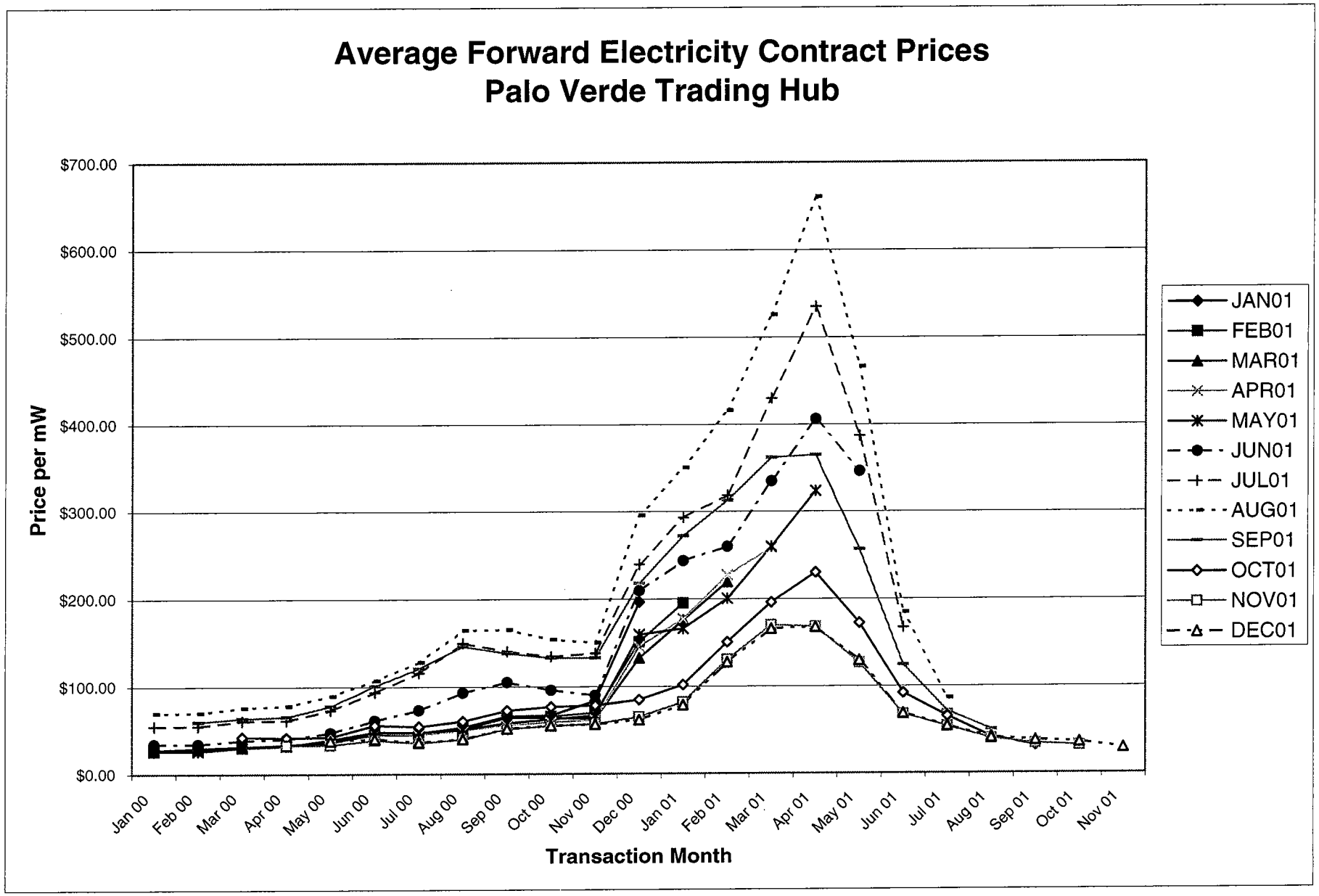
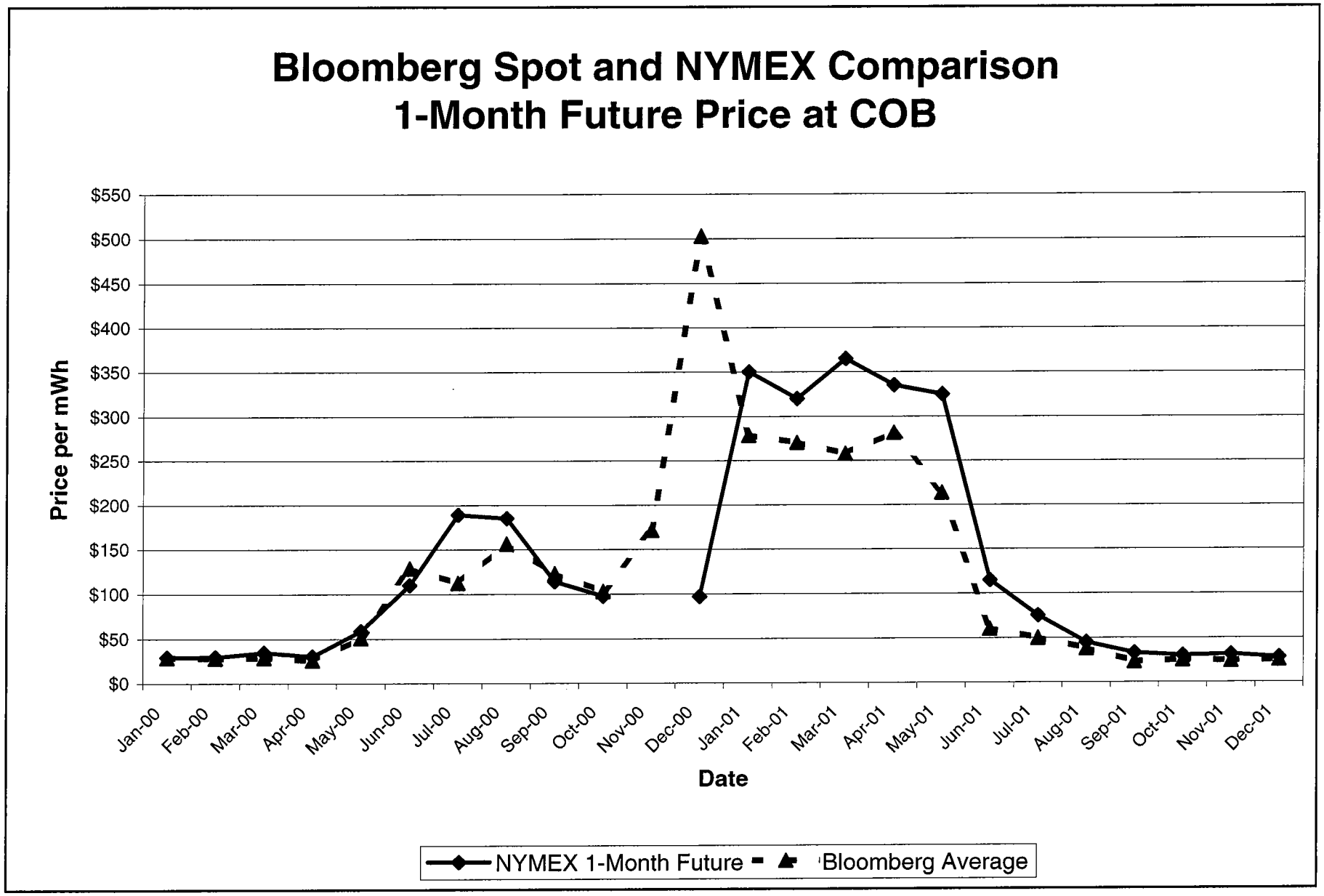
JUL01
AUG01
SEP01
OCT01
NOV01
DEC01

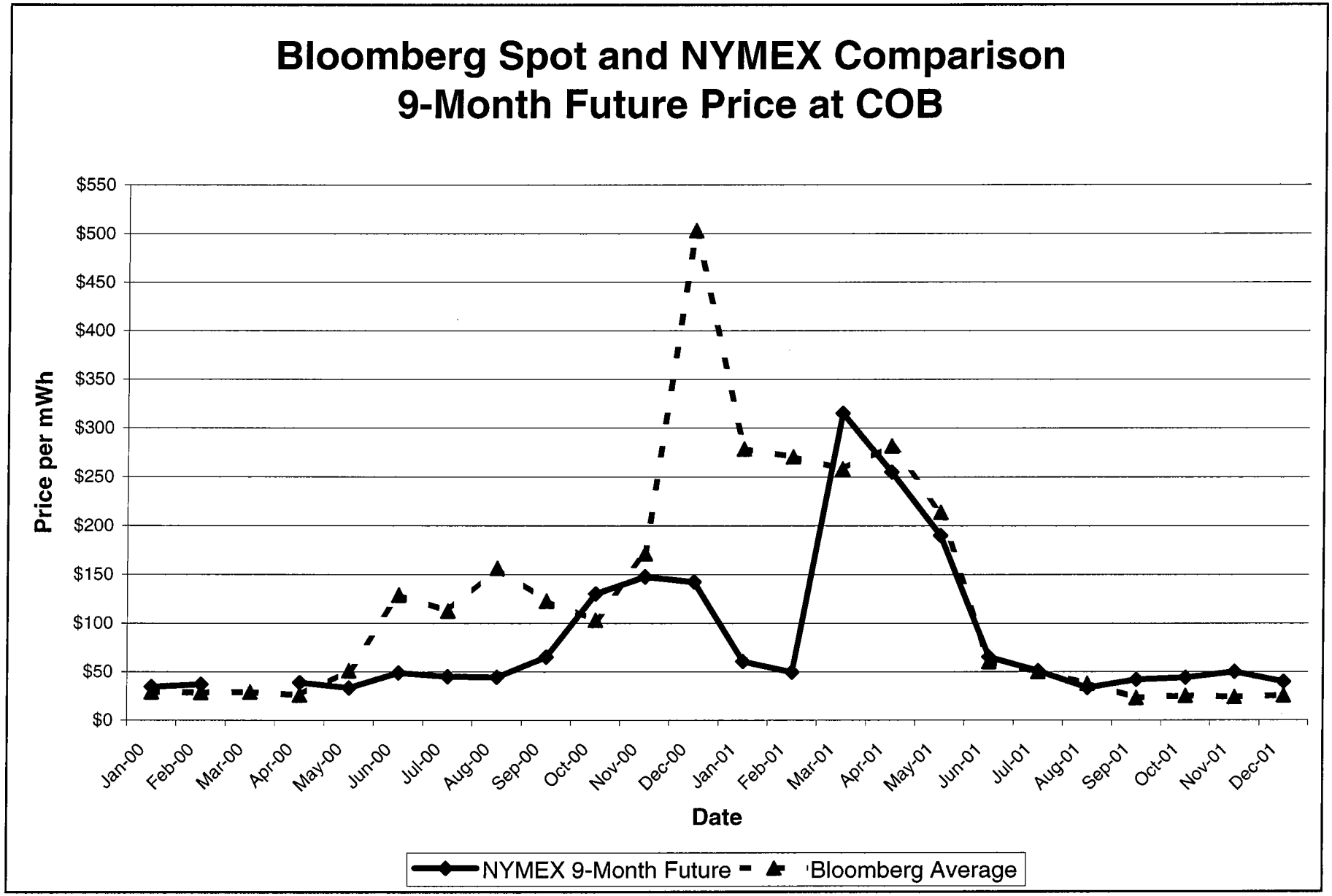

Average Forward Electricity Contract Prices
Palo Verde Trading Hub
Price per mW
$700.00
$600.00
$500.00
$400.00
$300.00
$200.00
$100.00
$0.00
Jan 00
Feb 00
Mar 00
Apr 00
May 00
Jun 00
Jul 00
Aug 00
Sep 00
Oct 00
Nov 00
Dec 00
Jan 01
Feb 01
Mar 01
Apr 01
May 01
Jun 01
Jul 01
Aug 01
Sep 01
Oct 01
Nov 01
Transaction Month
JAN01
FEB01
MAR01
APR01
MAY01
JUN01
JUL01
AUG01
SEP01
OCT01
NOV01
DEC01

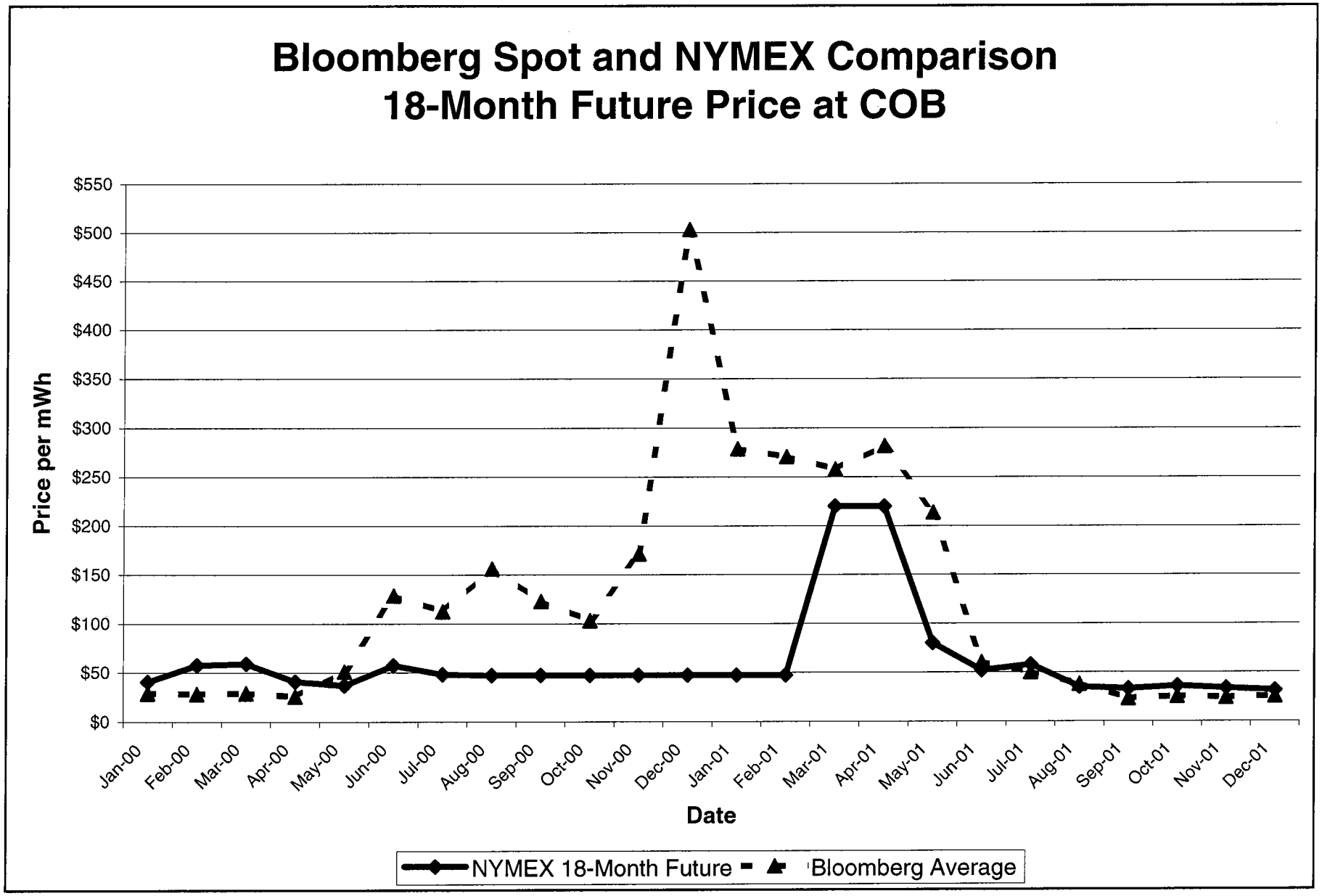
History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 41

Correlation between Bloomberg Spot and Nymex Futures Prices at COB


Bloomberg Spot and NYMEX Comparison
1-Month Future Price at COB
Price per mWh
$550
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Jun-01
Jul-01
Aug-01
Sep-01
Oct-01
Nov-01
Dec-01
Date
NYMEX 1-Month Future
Bloomberg Average

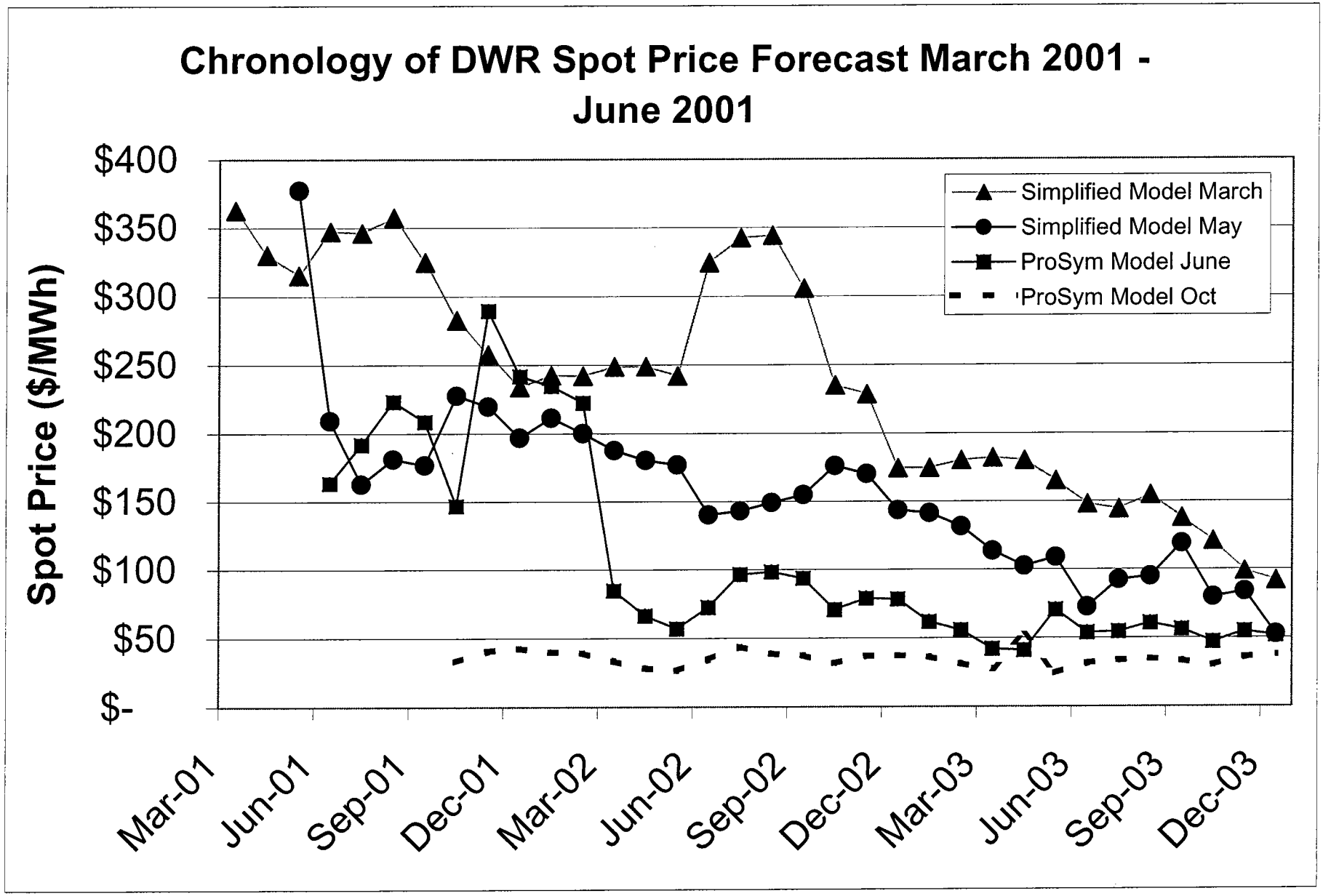

Bloomberg Spot and NYMEX Comparison
9-Month Future Price at COB
Price per mWh
$550
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Jun-01
Jul-01
Aug-01
Sep-01
Oct-01
Nov-01
Dec-01
Date
NYMEX 9-Month Future
Bloomberg Average


Bloomberg Spot and NYMEX Comparison
18-Month Future Price at COB
Price per mWh
$550
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Jun-01
Jul-01
Aug-01
Sep-01
Oct-01
Nov-01
Dec-01
Date
NYMEX 18-Month Future
Bloomberg Average

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 42

Evolution of Spot Market Price Projections


Chronology of DWR Spot Price Forecast March 2001 - June 2001
Spot Price ($/MWh)
$400
$350
$300
$250
$200
$150
$100
$50
$-
Mar-01
Jun-01
Sep-01
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Simplified Model March
Simplified Model May
ProSym Model June
ProSym Model Oct

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 43

Agreements in Principle/Letters of Intent which DWR Entered but did not get Converted into L-T Contracts

CDWR POWER BI' 'NTRACT TRACKING

CONFIDE TIAL

	Bidder	Start	Term	Product	Zone	Price ($/MWh)	MW 2001	MW 2002	MW 2003	MW 2004	MW 2005	MW 2006-10	Lead	Contract Manager	Comp. Date	Fuel Risk	Comments
1	name redacted	12/31/01	12 yrs	As-Avail	SP15	$60		16.9	16.9	16.9	16.9	16.9	LRowe	Skowronski	Nd Fnl Copy	NA	PPA suspended. Developer informed that Project should proceed with Power Authority.
2	name redacted	6/30/02	12 yrs	As-Avail	SP15	$60		36	36	36	36	36	LRowe	Skowronski	Nd Fnl Copy	NA	PPA suspended. Developer informed that Project should proceed with Power Authority.
3	name redacted	7/2/02	15 yrs	Peak	SP15	$84		189	288	288	288	288	Skowronski	Skowronski	Nd Fnl Copy	FR	Party can't make summer 02 date; discussions with developers started
4	name redacted	11/15/01	10.1yr	Peak	NP15	$94.00	*	30	30	30	30	30	Buzz White	T.Haines	5/23/01	FR	Second extension executed
5	name redacted	9/1/01	10 yrs	Peak	SP15	$120	10	10	10	10	10	10	JJudge	Skowronski	6/21/01		LOI Signed 6/21, Legal Preparing PPA
6	name redacted	4/1/02	10	Disp	NP15	$68		150	150	150	150	150	JJudge	Skowronski			LOI executed 7/15/01, Legal preparing PPA
7	name redacted	9/30/01	10yr	Peak	NP15	$147	*	165	165	165	165	165	Buzz White	T.Haines			Revised prices from _____ still too high
8	name redacted	6/1/02	10 yrs	Peaking	NP15	$110	370	370	370	370	370	370	TSkupnjak	T.Haines	5/21/01	FR	Pricing Agreed, Developing PPA
9	name redacted	7/1/01	10yrs	Biomass	NP15	$68-$79	12	12	12	12	12	12	LRowe	Skowronski	4/23/01	NA	EEI Draft Contract sent to Developer on 5/10.
10	name redacted	7/1/01	3.25 yr	Peak Dis	SP15	$165.00	525	745	1450	1450			Skowronski	Skowronski	Nd Fnl Copy	FR	In process of developing PPA; on fast track; commercial issues remain
11	name redacted	7/23/01	3Yr	Peak	NP15	$250.00	4	100	100	100			BWhite	T.Haines	5/10/01	no	Biodiesel; Distributed Load Shedding; Capacity Only; continuing to have problems getting air permits
12	name redacted	9/30/01	2 yrs		SP15	$248	*	92	92				Skowronski	Skowronski	Nd Fnl Copy	FR	Legal issue on gas credit; termination clause contested;
13	name redacted	7/1/01	3.5	Base	SP15	$102-$57	150	300	300	300			D.Herdocia	T.Haines		FR	Additional up front service being proposed by [party]. Credit still an issue. Continuing negotiations.
14	name redacted	1/1/05	6 yrs	Peak	SP15	$102-$57					300	300	D.Herdocia	T.Haines		FR	Additional up front service being proposed by [party]. Credit still an issue. Continuing negotiations.
15	name redacted	1/1/02	3 yrs	Base	NP15	$94-$54		250	500	500			D.Herdocia	T.Haines		FR	Additional up front service being proposed by [party]. Credit still an issue. Continuing negotiations.
16	name redacted	1/1/05	6 yrs	Peak	NP15	$94-$54					500	500	D.Herdocia	T.Haines		FR	Additional up front service being proposed by [party]. Credit still an issue. Continuing negotiations.
17	name redacted	5/15/01	2yrs	Peak	SP15	$68	150	150					JJudge	Skowronski	Nd Fnl Copy		In Legal Review - Interim Power WSPP Interim Contract Signed 5/
18	name redacted	5/15/01	2yrs	Off Peak	SP15	$68	**	**					JJudge	Skowronski	Nd Fnl Copy		LOI Approved by Contracts Committee on 4/26. Stuggling with credit issues.
19	name redacted	5/15/01	7yrs	Base	SP15	$65	40			40	190	360	JJudge	Skowronski	Nd Fnl Copy		LOI Approved by Contracts Committee on 4/26. Stuggling with credit issues.
20	name redacted	5/15/01	1 yr	Off Peak	NP15	$68	**						JJudge	Skowronski	Nd Fnl Copy		LOI Approved by Contracts Committee on 4/26. Stuggling with credit issues.
21	name redacted	1/1/02	10 yrs	Base	NP15	$68		47	47	487	487	487	JJudge	Skowronski	Nd Fnl Copy	FR	LOI Approved by Contracts Committee on 4/26. Stuggling with credit issues.
22	name redacted	7/1/01	5 yr	Peak	SP15	$180-$60	450	450	450	450	450				3/2/01		Figures from Jeff Van Horne Tracking Sheet of 3/23
23	name redacted	7/1/01	5 yr	Base	SP15	$180-$60	90	90	90	90	90				3/2/01		Figures from Jeff Van Horne Tracking Sheet of 3/23
24	name redacted	8/1/01	6.25 yr	Disp	NP15	$158.00		98	98	98	98	98	T. Nolan	T.Haines	3/22/01		
25	name redacted	6/1/01	10 yrs	Disp	NP15		48	94	94	94	94	94	T.Skupnak	T.Haines			
26	name redacted	1/1/02	9 yr	Base	SP15	$99-$50		50	100	100	100	100			2/7/01		
27	name redacted	6/1/02	15 yr	Disp	NP15	$136-$76		43	43	43	21	21			8/14/01		
28	name redacted	6/1/02	15 yr	Base	NP15	$50.00		25	25	25	25	25			8/14/01		
29	name redacted	6/1/02	15 yr	Base	NP15	Est. $50				105	105	105			8/14/01		
						Total MW	1849	3513	4466.9	4959.9	3537.9	3167.9					*Lines 1-25 from 8/9/01 tracking sheet*
						NP Total	434	1384	1634	2179	2057	2057					*Lines 26-32 from 3/23 tracking sheet*
						SP Total	1415	2129	2832.9	2780.9	1480.9	1110.9					

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 44

September 20 Direct Access Suspension Order's Impact on Net Short Forecast

Comparison of Department 2002-04 Net Short Forecast with Alternate Direct Access Suspension Dates of July 1 and September 20, 2001

	2002		2003		2004
NS assuming July 1 cutoff (GWh)					
PG&E	26,307		30,957		39,646
SCE	23,890		30,011		33,848
SDGE	11,241		12,251		15,125
TOTAL	61,438		73,219		88,619
NS assuming Sep 20 cutoff (GWh)					
PG&E	21,906		23,461		28,213
SCE	14,839		15,734		17,797
SDGE	8,300		9,083		11,017
TOTAL	45,045		48,278		57,027
% Difference					
PG&E	-17%		-24%		-29%
SCE	-38%		-48%		-47%
SDGE	-26%		-26%		-27%
TOTAL	-27%		-34%		-36%

Notes

1. Net short forecast assuming Jul 1 cutoff from data supporting proposed 2001-02 revenue requirement filing of August 7, 2001. Assumes 2% direct access statewide.

2. Net short forecast assuming Sep 20 cutoff from data supporting proposed 2003 revenue requirement filing (ProSym Run 36), current as of August 5, 2002. Assumes 14% direct access statewide.

3. Energy quantities 'at the generator' and include T&D line losses

4. Changes in net short between cutoff dates forecasts reflect not only the sales differences from direct access, but modifications to assumptions for bundled sales and URG dispatch from August 7, 2001 to August 5, 2002.

Prepared by Navigant Consulting, Inc.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 45

Summary of Renegotiated Contract – Press Release by Governor's Office

Please click here to return to the previous page.

Press Release

Governo Seal

OFFICE OF THE GOVERNOR

PR02:229
FOR IMMEDIATE RELEASE
04/22/2002

STATE RESTRUCTURES EIGHT POWER PACTS 04/22/2002

SAN FRANCISCO

State officials today announced that they have restructured eight of California's long-term energy contracts, reducing costs by approximately $3.5 billion (from approximately $15 billion to $11.4 billion, or 23 percent) and providing the state with stronger commitments for needed new power plants, greater flexibility in utilizing the power, and competitively-priced electricity that will be delivered during summer peak periods.

Governor Gray Davis, the Public Utilities Commission, Department of Water Resources, and the Electricity Oversight Board said the new deals for four contracts with San Jose-based Calpine Corporation and one with High Desert Power Plant LLC, a subsidiary of Baltimore, Md.-based Constellation Energy Corporation, along with three contracts with renewable energy providers - Capitol Power, Cabazon, and Whitewater Hill - were the result of negotiations that began in late Fall. In separate action, Calpine and Constellation agreed to settlements of all claims with Attorney General Bill Lockyer for alleged electricity- pricing violations.

The new contracts represent the first successful renegotiations of power pacts originally signed by the State in the Winter and Spring of 2001. The long-term contracts, along with record conservation, the construction of 11 new power plants approved by the Davis Administration, and long-overdue action by the Federal Energy Regulatory Commission (FERC) to cap wholesale prices, were largely responsible for breaking the back of the spot market, which led to lower electricity prices and eased the state's power crisis last summer.

"This was a team effort by all parties and I congratulate our negotiating team," said Gov. Davis in announcing the agreements. "They brought back a better product for less money. The State has gotten the power it needs, where it needs it, when it needs it and at a more competitive rate.

"We had three goals in restructuring these contracts: to reduce costs, to insure reliable sources of new power, and tailor the delivery of power to meet the state's needs," continued Gov. Davis "The State has achieved each of these goals and kept renewable energy as a key part of its power portfolio."

"But these new contracts do not mean that the Federal Energy Regulatory Commission should shirk its responsibility to California. Californians are still owed billions of dollars in refunds. Allegations of market manipulation need to be thoroughly investigated in a timely fashion. And for the remaining

generators that refuse to renegotiate contracts signed when the markets were dysfunctional, we'll see them in court and at FERC."

With Calpine, state negotiators sliced the state's longest contract from 20 years to 10 years with at least $800 million in savings. Two other 10-year baseload energy contracts were reduced by two years, with savings of nearly $1.03 and $1.16 billion, respectively.

The agreement with Constellation Energy will result in savings of at least $560 million off the original $3.28 billion contract. The agreement also reduces the eight-year, three-month contract by six months.

State officials explained that aside from cost savings for ratepayers, the new contracts provide stronger provisions to bring new power plants online as well as more favorable terms for delivering the power. Many of the State Auditor's recommendations were also incorporated in the new pacts.

For example, the new contracts provide incentives to complete plans for new power plants, provide the state with the right to inspect those plants, give DWR more flexibility and reliability in obtaining power, allow it greater freedom to tailor its power supply to meet demand, and require the companies to pay DWR the costs of purchasing replacement energy if contract power cannot be delivered. They also require the delivery of power to Northern California (north of Path-15) to alleviate power shortages in the Bay Area. The new contracts also improve DWR's ability to assign contracts to the state's investor-owned utilities when they achieve investment-grade credit ratings.

In the enforcement settlements with the Attorney General, Calpine agreed to pay $6 million and Constellation $2.5 million to the state. The settlements end the Attorney General's claims against the two power companies regarding improper electricity pricing practices and the seeking of refunds from FERC for the allegedly illegal electricity rates charged in California. Calpine will put $1.5 million of the settlement proceeds into a fund established by the Attorney General for retrofitting public facilities with solar power. Constellation's payment to the solar power fund will be $1.25 million.

In addition, because of the benefit to California ratepayers, the California Public Utilities Commission has also agreed to drop its FERC proceeding against Calpine and Constellation.

CALPINE RESTRUCTURING HIGHLIGHTS

Reliability

- DWR has four contracts with Calpine. Two provide baseload power (#1 and #2). Two others (#3 and #4) provide peaking power that can be tailored to meet hourly and daily changes in consumer demand.
- Contracts #2, #3, and #4 have new provisions to insure new power plants are built. Calpine will suffer penalties if they are not constructed.
- Contract #2 requires Calpine to build four plants: Metcalf, Otay Mesa, East Altamont, and one other (to be chosen by DWR among Teayawa, Inland Empire, and San Joaquin Valley Energy Center). If Calpine does not meet certain requirements, the State may takeover the site and permit from Calpine and complete the plant itself.
- Powerful incentives to build new plants have been added in Contract #3. This contract requires Calpine to build 11 peakers; four are already built. If it does not build the other seven by June 1, 2003, the capacity payments it can charge for those units over the life of the contract will be reduced by approximately 30 percent. If it fails to build a unit by December 31, 2003, it loses the right to sell power from that unit to DWR, and it may not substitute power.
- Contract #4 requires Calpine to build a plant in San Jose. If it does not do so, DWR may terminate the contract.

- Capacity payments are tied to the actual availability of capacity in Contracts #3 and #4. Calpine will guarantee an availability factor of 98 percent in summer and 92 percent in winter, with pro rate reductions of the capacity payment if those targets are missed and with incentives for Calpine to exceed those targets. Payments also will be reduced if annual performance tests show lower than expected capacity, and if the plant's ability to deliver is limited by permit restrictions.
- DWR will be paid damages (the cost to DWR to purchase replacement energy in the market) for an unexcused failure to deliver power.
- DWR will receive better utilization of power as part of the new contracts as part of a new provision that says Calpine may not supply from ISO's imbalance energy market unless DWR or ISO directs the company do to so.
- Contract #2 will require power to be delivered into Northern California, north of NP-15. The original contract allowed Calpine to deliver power from its own plants into either SP-15 or NP-15.
- Contract #2 will limit Calpine's ability to substitute power by requiring it to provide power into NP-15 when its energy suppliers are tight.
- New provisions in Contracts #3 and #4 limit Calpine's right to substitute energy.
- New provisions redefine "Force Majeure," limiting the company's ability to failure to delivery energy.
- New "anti-gaming" provisions in Contracts #3 and #4 include new, stronger penalties (including rights to terminate the contract) for certain inappropriate uses of the imbalance market.

Flexibility

- All four contracts have been tailored to provide DWR with flexibility in utilizing power. Under the old contracts, DWR had limited ability to tailor when the energy was needed.
- Contracts #1 and #2 have new provisions that allow DWR to acquire additional dispatchable power for 2002 and 2003 at better prices and allow for day-ahead scheduling of power, with up to 30 percent scheduled intra-day.
- Contract #3 is reduced from the fixed price of $73/MWh to a tolling agreement based on an indexed gas price and a guaranteed heat rate of 10.5 MMBTU/MWh. (At today's gas prices, the price falls from $73 to $45 MWh.)
- Contract #3 gives DWR enhanced dispatchability rights (30-minute dispatch for all contract hours).
- Contract #4 gets additional flexibility to tailor its power. It now can schedule 4,000 hours of energy on a day-ahead or hour-ahead basis. Up to 2,000 hours can be scheduled on less than an hour-ahead
basis. Under certain circumstances, up to 1,000 hours can be scheduled on as little as 15 minutes notice.

Affordability

- Both Contracts #1 and #2 are cut from 10 to 8 years. Payments in the two canceled years would have totaled over $1 billion in each contract.
- Contract #2 is cut from $61/MWh to $59.60 MWh, saving approximately $80 million.
- Contract #3 is cut from 20 years to 10 years, saving $800 million in capacity payments. It also saves energy payments that would have been made in years 11 through 20. (The amount of this saving depends on how much energy would have been purchased in years 11-20.)
- Contract #3 is reduced from a fixed energy price of $73/MWh to a tolling agreement, based on an indexed gas price and guaranteed heat rate. Based on the allowed hours of dispatch under the contract, this change could save up to $280 million during the shortened life of the contract.
- Under Contract #3, Calpine must complete construction of the peaking units by June 1, 2003. If it doesn't, capacity payments are reduced. Units that do not come on line by December 31, 2003

are eliminated from the contract. Each unit eliminated reduces DWR costs by $65 million.
- Contract #4 reduces costs by denying Calpine the right to sell substitute energy prior to the time it brings the plant online, saving DWR approximately $12 million this year.

CONSTELLATION RESTRUCTING HIGHLIGHTS

The California Department of Water Resources (DWR) has an eight-year, three-month contract with Constellation subsidiary High Desert Power Plant, LLC, which has been reduced by six months.

Reliability

- Under the old contract, High Desert could provide substitute energy to the State before completing construction. There is now a strong incentive for High Desert to complete construction by the July 1, 2003 estimated completion date because the State will not make any capacity payments until the plant has been brought on line and its capacity established. Further, High Desert is not allowed to provide substitute energy until the plant has been completed, and then only if the plant is unable to operate.
- If High Desert ceases construction efforts by October 2004, DWR may terminate the contract and collect a $50 million payment from High Desert, guaranteed by Constellation.
- The revised contract gives DWR the exclusive right to all the output from the High Desert plant. High Desert may not sell to any third parties once the contract begins. In addition, High Desert must deliver all energy requested by DWR from the plant, unless the plant is unable to generate the energy because of an outage, repairs, permit or plant limitations, or other similar events.
- If High Desert fails to deliver energy without a proper excuse, the contract can be terminated. DWR can also impose a $7.5 million liquidated damages penalty if High Desert fails to deliver from the plant for economic reasons (for example, if it decides it would be cheaper not to run the plant).
- There will also be annual capacity testing to ensure that the plant is running at optimum output. To the extent it is not, the monthly capacity payment is reduced.
- There is also a 95 percent availability guarantee - to the extent High Desert does not provide DWR with scheduled energy 95 percent of the time, the monthly capacity payment is reduced by a proportional percentage (i.e., if High Desert provides only 90 percent of the energy DWR schedules, the capacity payment is reduced by five percent).
- High Desert may not supply from ISO's imbalance energy market unless DWR or CAISO directs it to do so. Use of the imbalance energy market is restricted to hourly variations and daily curtailments of plant output. This insures that DWR is getting better utilization of the State's energy resources.
- DWR also obtains an additional 400 MW of power during May to October 2002 and 2003 (prior to the time the plant is brought on line).

Flexibility

- Under the old contract, DWR had no ability to shape the energy and was obligated to pay $58/MWW. DWR can now tailor the way it dispatches the unit within the unit's reasonable operational capabilities. This will allow DWR to utilize the resource to follow load over the course of each day.
- DWR must schedule on a day ahead basis but may on an intraday basis adjust the schedule as circumstances require. Because the High Desert plant is now reserved exclusively for DWR's needs, only the plant's actual physical limitations will narrow this flexibility.

Affordability

- The High Desert contract has been shortened by six months, resulting in savings of roughly $155 million in energy purchases DWR would otherwise be obliged to make.
- The contract price has changed from a fixed energy price of $58/MWH to a fixed capacity payment and an energy price based on actual fuel costs and the plant's heat rate. This should decrease the average price by more than 15 percent.
- Because DWR will no longer by required to take energy around the clock in amounts unrelated to its needs, it will realize savings of roughly $405 million, making the total savings from the original $3.28 million contract approximately $560 million.
- DWR's ability to bid the High Desert facility into the CAISO ancillary services markets may result in net revenues to DWR.

CAPITOL POWER

- The original contract value was $52,625,000 over five years. ($89/MWh) from a 15 MW biomass plant in Amador County.
- The new contract value is $46,298,000 - a 12 percent reduction. The renegotiated contract reduces the term by six months, lowers the price by $2/MWh and caps the total net income the generator will receive.
- The amended contract contains many of the terms recommended by the State Auditor.
- If the costs of running the plant are lower than projected, then the cost to DWR will be reduced. The amended contract contains many of the terms recommended by the State Auditor.
- In addition to helping insure DWR's portfolio has renewable power, Capitol now has additional time to bring the plant on-line; extending the operating date from December 15, 2001 to July 15, 2002.

CABAZON

- This 42.9 MW wind contract for 12 years was originally priced at $60/MWh for 12 years. The amended contract reduces that price to either $54/MWh if the units are operating by August 31, 2002 or $40/MWh if the units are operating after August 31, 2002. It also shortens the contract by six months.
- Based on price and length, DWR estimates the renegotiated contract will save between $11.2 million and $29.3 million - a savings of between 14 and 36 percent. The amended contract includes many of the terms recommended by the State Auditor.
- To help insure that DWR's portfolio has renewable power, Cabazon is given additional time to bring its power online. It extends the Commercial Operation Date from a target date of December 31, 2001 to a firm date of December 31, 2002.

WHITEWATER HILL

- This 12-year, 65.1 MW wind contract was originally priced at $60/MWh. The amended contract reduces that price to either $54/MWh if the units are online by August 31, 2002 or $40/MWh if the units aren't running by then. It also shortens the contract by six months.
- The renegotiated contract will save between $17 million and $44.5 million. That's a savings of between 14 and 36 percent.
- To broaden DWR's portfolio of renewable power, Whitewater Hill is given additional time to bring its power on-line. It extends the Commercial Operation Date from a target date of December 31, 2001 to a firm date of December 1, 2002.

Click on the link below for copies of the renegotiated contracts.

Department of Water Resources

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California Department of Water Resources

[x] News Release

May 2, 2002

CONTACTS:

- Oscar Hidalgo, California Energy Resources Scheduling Division, DWR, (916) 574-1292

DWR Successfully Restructures CalPeak Power Contract

Sacramento - The California Department of Water Resources (DWR) today announced that it has successfully restructured its contract with CalPeak Power, reducing costs by a total of $71 million (or 17 percent).

The new contract with CalPeak calls for the termination of one of seven peaker projects, shortening the term of another and reducing the cost of the remaining projects. In addition, the new contracts have improved the operational flexibility and include provisions that meet concerns expressed in an audit report by the California State Auditor.

"We were able to reduce cost while increasing reliability in power delivery to Californians," said Pete Garris, Deputy Director of DWR. "The greater flexibility also brings additional cost savings by allowing DWR to better match supplies with fluctuations in demand."

Today's announcement comes just 10-days after state officials announced the restructuring of eight power agreements at a cost savings of $3.5 billion. Those included agreements with Calpine Corporation, High Desert Power LLC - a subsidiary of Constellation Energy Corporation, Capitol Power, Whitewater Energy Corporation (Whitewater Hill and Cabazon). There are a total of nine long-term agreements that have now been restructured.

The CalPeak agreements originally consisted of the construction of seven separate 50 megawatt plants at a cost of $403 million over 10 years. The new agreements now call for six, 48 megawatt facilities at a cost of $332 million over 10 years.

Summary of Restructured Terms

- Reduce overall cost by $70.9 million from the original cost of $403 million to $332 million over 10 years;
- Terminates CalPeak's Mission Bay project, one of seven originally planned peaker facilities;
- Relocates the Midway Project, which was located in a transmission- congested area of Kern County, to a Northern California location free from transmission constraints. Location for the new site has yet to be determined;
- Shortens Midway project by one year, from 10 years to nine years;
- Commercial operation date for Midway plant has been extended from Dec. 31, 2001 to June 1, 2003;
- Reduced capacity payments of remaining plants - Border, Enterprise, Vaca-Dixon, El Cajon and

Panoche - by $750,000 per year for 10-years;
- Strengthens performance guarantees, and improves termination and inspection rights;
- Adds reliability and cost control by increasing dispatch rights, allowing DWR to better match resources to varying loads.

CalPeak currently has three of the six peaker facilities on-line. Two more plants are expected on-line by June 1, 2002 and a sixth (and final) on-line by June 1, 2003.

The CalPeak contract, including the restructured contracts announced on April 22, 2002, are now available on DWR's web site.

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The Department of Water Resources operates and maintains the State Water Project, provides dam safety and flood control and inspection services, assists local water districts in water management and water conservation planning, and plans for future statewide water needs.

Visit Archived News Releases or return to the DWR California Water Page

Write or phone the DWR Office of Water Education for more information about DWR's water activities.

History of DWR's Net Short Energy Procurement Process Under Long Term Contracts

Exhibit 46

Off-System Sales Forecast

Off-System Sales/Forecasted MCP Summary

	Actual - Off-System Total Revenue[1]	Actual - Off-System Total Volume[1]	Actual - Off-System Average Price - $/MWh[1]	Nov. 5 Rev Req - Average Spot Purchase Price - $/MWh	Nov 5 Revenue Req Average Spot Purchase Price as a % of Actual Price
Jan-02	$ 2,414	158	$ 15.25	$ 38.21	40%
Feb-02	$ 2,436	136	$ 17.93	$ 37.26	48%
Mar-02	$ 2,722	108	$ 25.09	$ 31.51	80%
Apr-02	$ 5,477	298	$ 18.40	$ 27.90	66%
May-02	$ 9,701	446	$ 21.73	$ 26.45	82%
Jun-02	$ 6,263	375	$ 16.72	$ 34.91	48%
Jul-02	$ 9,575	508	$ 18.85	$ 39.13	48%

[1]Historical off-system energy sales prices have been entered from CERS' ALTRA scheduling database for the period of January 2002 through June 2002. Sales volumes include Short-Term, Day-Ahead, Hour-Ahead, and Real-Time transactions. Due to informational