Assessment of California Natural Gas and Electricity Markets

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EXECUTIVE SUMMARY

In May of 2001 Water and Energy Consulting was retained by Valley Center Municipal Water District to, among other things, prepare a summary of the electricity and natural gas markets in California and to make recommendations on options that were available to Valley Center to stabilize and reduce their energy cost exposure.

Virtually every characteristic of the electricity and natural gas markets in May of 2000 has been completely reversed. In May of 2002 California was facing very high wholesale electricity costs and natural gas costs as well as experiencing electrical blackouts due to insufficient generating capacity. Retail electric rates, on the other hand, were stabilized in the San Diego Gas Electric area by legislative fiat. Consumers were faced with retail rates that were considerably lower than the wholesale costs of electricity. Large generation facilities that could sell power into the wholesale market were being actively promoted, in part due to the high wholesale price of electricity and in part due to numerous incentives that the state offered – such as expedited permitting and siting and performance bonuses for rapid construction.

Since May 2002 wholesale electricity prices have plummeted from an average of over 22 cents/kWh to the 2-3 cents/kWh range. Natural gas prices have dropped from $60.00 in December of 2000 to the $2-3/MMBTU range. Retail electricity rates, on the other hand, have risen considerably as we try and pay off the state electricity purchasing binge. Ten of thousands of MW of new generation is under construction or being permitted. The state has signed thousands of MW of contracts for new generation for up to 20 years from power producers, which will give consumers in California a considerable and long-lasting economic headache as we continue to purchase electricity from these high price contract.

Numerous official reports have assessed the electricity market – adequate and likely to remain that way, and natural gas – plentiful and likely to remain cheap. However, there are a number of significant caveats. First , that a significant amount of the approved new generation will actually be constructed. Second, that there will be no natural gas “hiccups” that will significantly decrease the supply of or increase the price of natural gas. Third, that the unprecedented conservation of electricity that California experienced this last summer will continue.

Currently Valley Center is facing high retail electricity prices for the foreseeable future, adequate and reasonably priced natural gas availability, and low wholesale prices for electricity. Large generation facilities which sell electricity into the wholesale market are not a viable option at this time, due to the low wholesale price of electricity and the expiration of the performance and construction bonuses. However, on site generation that displaces retail electricity is a viable option and warrants further economic analysis. It is recommended that Valley Center suspend evaluation of any large generation facilities and concentrate analysis on self generation and energy efficiency improvements. It is further recommended as a necessary security measure that Valley Center develop a written Operations Manual.

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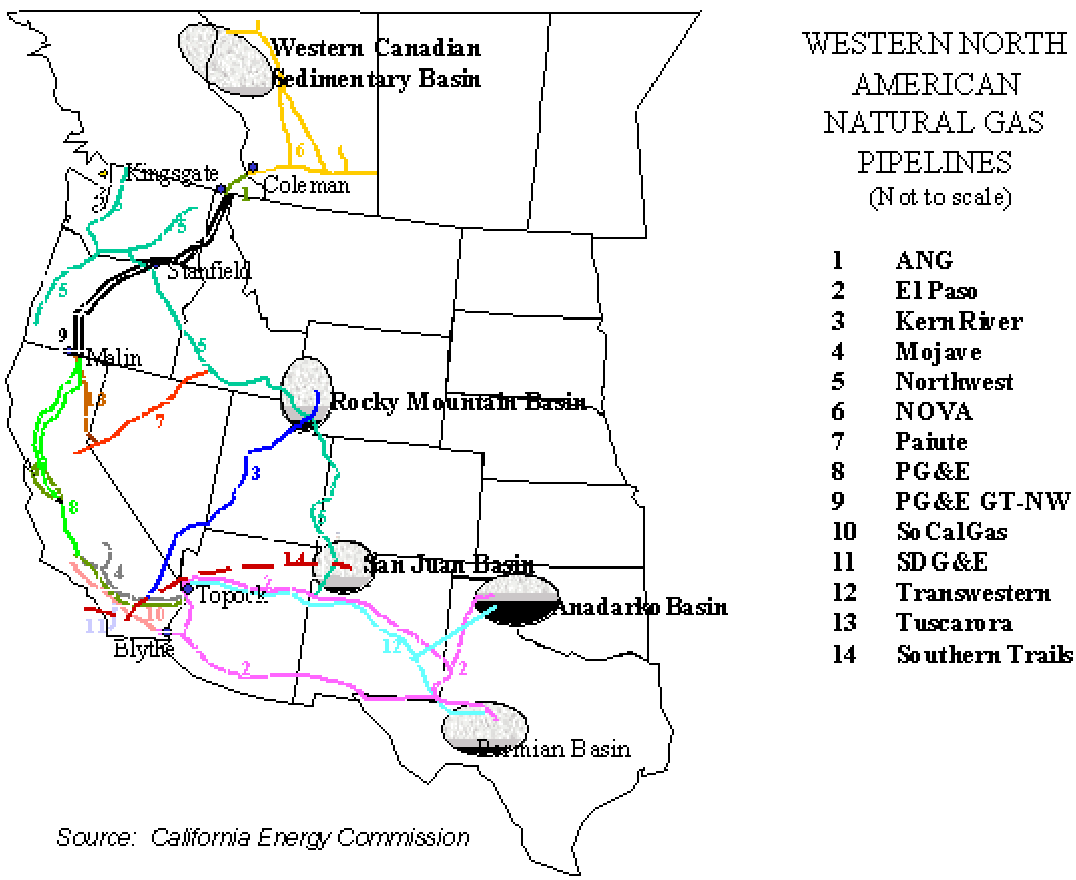
I NATURAL GAS MARKET OVERVIEW

Californians consume between five and six billion cubic feet of natural gas per day (Bcf/d). California can only physically take supplies from four producing regions—the Southwest, the Rocky Mountains, Canada, and California. In-state production satisfies approximately 15 percent of this demand. The remaining 85 percent comes from the San Juan Basin, the U.S. Rocky Mountain region, and the Western Sedimentary Basin of Alberta and British Columbia. Figure 1-1 shows the pipeline locations.

Figure 1-1: California's Interconnected Pipeline Network



As the following Table 1-1 shows, the transfer capacity of the El Paso pipeline is over one-half of the transfer capacity of all the interstate pipelines into California.

Table 1-1

Interstate Pipeline Capacity And Utility Takeaway Capacity (MMcf/d)

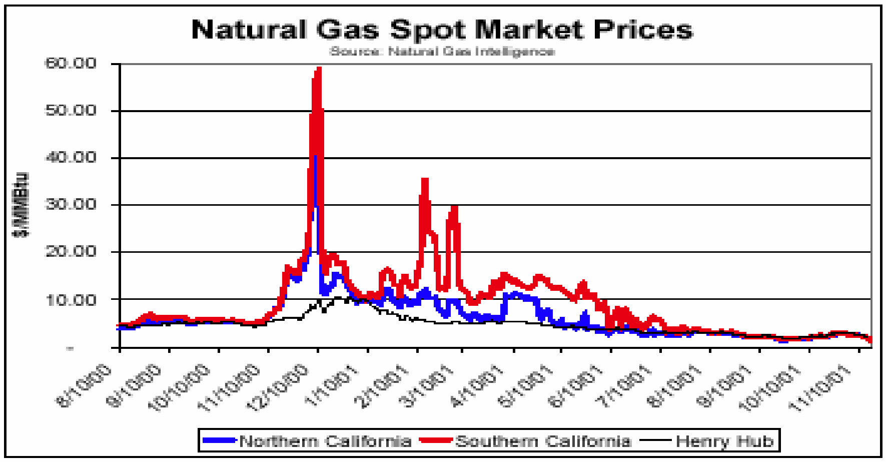
Interstate Pipelines and Delivery Capacity to California		Takeaway Capacity at California Border		
Pipeline	**Delivery Capacity**	**Mojave**	**PG&E**	**SoCalGas**
PG&E GT – NW	1,833			
El Paso	3,530		1,855	1,990
Transwestern	1,065	400	1,140	750
Kern River	700			
Wheeler Ridge Receipt Point				600
Total	7,128	400	2,995	3,340

Notes:

- PG&E GT - NW delivery capacity to California is impacted by its gas flow into the Tuscarora system. Tuscarora can take deliveries up to 112 MMcf/d from PG&E GT - NW at Malin, reducing California deliveries by up to the same amount.
- PG&E may receive up to 1,140 MMcf/d from a combination of El Paso, Transwestern, Kern River, and Mojave deliveries.
- Mojave receives its supply from El Paso and Transwestern.
- Through Wheeler Ridge SoCal Gas receives gas from California production, Kern River, Mojave and PG&E.
- Not listed, but direct deliveries are made by Kern River, Mojave, and from California production to industrial, electricity generation and EOR facilities

The following graph (Figure 1-2) shows the natural gas prices in Northern California and Southern California throughout 2000 and 2001. An explosion on the El Paso pipeline, along with alleged market manipulations, resulted in severely curtailed natural gas transfer capacity into California during the winter of 2000 and the first half of 2001. Combine reduced delivery capacity with increased demand for natural gas to produce electricity in California (due to a drought that severely reduced hydroelectric generation in the Pacific Northwest) and less natural gas in storage than normal and natural gas prices skyrocketed to $60/MMbtu on December 13, 2000 and to the $50/MMbtu range in May of 2001. However, since then natural gas prices have fallen to historic levels and remained there.

Figure 1-2



The high demand and high prices in California have resulted in a number of proposals to improve the ability of California to import natural gas[1]. The proposals include those found on Table 1-2.

Table 1-2: Proposed Interstate Pipeline Additions

(Approved by FERC or Contract Signed)

Name	*Location*	*Capacity (MMcfd)*	*On-line Date*	*Status*
1. Transwestern-Red Rock, *Southwest*	San Juan & Permian Basins to CA/AZ border at North Needles and Topock	150	June 2002	FERC approved July 2001.
2. Questar Southern Trail East Zone, *Southwest*	San Juan Basin to CA/AZ border at North Needles	80	June 2002	FERC approved. Contracts signed.
3. El Paso Plains-All American Pipeline, *Southwest*	Conversion of oil pipeline to gas, San Juan & Permian Basins to CA/AZ border at Blythe	230	Mar 2002	FERC conditionally approved May 2001.
4. Kern River Gas Transmission,	Opal, WY to Wheeler Ridge, other CA delivery points (e.g., Kramer Junction & Daggett),	146	May 2002	FERC approved. Contracts signed.

1 "California Energy Outlook – Electricity and Natural gas Trends Report", California Energy Commission, P200-01-002, September 2001.

Rocky Mountains	Nevada, and Utah			
5. PG&E GTN, *Canada*	Kingsgate to CA/OR border at Malin, 21 miles of loop.	169	July 2002	FERC approved. Contract signed.
6. Otay Mesa Generating Company Pipeline, *Mexico*	From North Baja pipeline to Otay Mesa Power Plant in San Diego County, CA	110	Sep 2002	FERC granted Presidential permit July 2001.
Total 2002[35] Additions		**885**		
7. Kern River Gas Transmission, *Rocky Mountains*	Opal, WY to Wheeler Ridge, other CA delivery points (e.g., Kramer Junction & Daggett), Nevada, and Utah	885	May 2003	FERC application filed Aug 2001. Contracts signed
8. PG&E GTN, *Canada*	Kingsgate to CA/OR border at Malin	80	Nov 2003	FERC application Nov 2001. Contract signed.
Total 2003 Additions		**965**		
Total Expansions[36]		**1,850**		

Additionally, there are a number of additional proposals that are currently only in the preliminary planning stages. These proposed additions still have to go through FERC approval, receive the necessary environmental permits, find customers willing to contract for the new capacity, and get financing from private firms contracting for the new capacity. These projects are shown in Table 1-3

Table 1-3: Expansion Proposals That Are In The Early Stages

Name	Location	Capacity MMcfd	On-line Date	Status
1. Transwestern-Sun Devil, *Southwest*	San Juan Basin to CA/AZ border at North Needles	TBD	TBD	FERC application expected mid-2002. Negotiating contracts.
2. El Paso Southern System Expansion, *Southwest*	Permian Basin to CA/AZ border at Blythe	320	TBD	Not fully committed in open season. Evaluating options.
3. Kinder Morgan-Sonoran Pipeline	New Mexico to North Needles	750	Summer 2004	FERC application Spring 2002. Negotiating contracts.

Phase 1, *Southwest*				
4. Ruby Pipeline, *Rocky Mountains*	New pipeline from Southwestern WY to Sacramento, Stockton, and Antioch	750	Dec 2004	FERC application in mid 2002. Negotiating contracts.
5. Questar Southern Trail West Zone, *In-State*	North Needles to Long Beach	TBD	TBD	FERC approved.
6. El Paso Bi-directional Lateral, *In-State*	Blythe to Daggett	TBD	TBD	Not fully committed in open season. Evaluating options.
7. Kinder Morgan-Sonoran Pipeline Phase II, *In-State*	North Needles to Bay Area	1,000	TBD	FERC application Spring 2002. Negotiating contracts.
8. Mojave Sacramento Valley, *In-State*	Topock to Sacramento Valley	TBD	TBD	Project on hold.

I.a SDG&E's Gas Transmission System

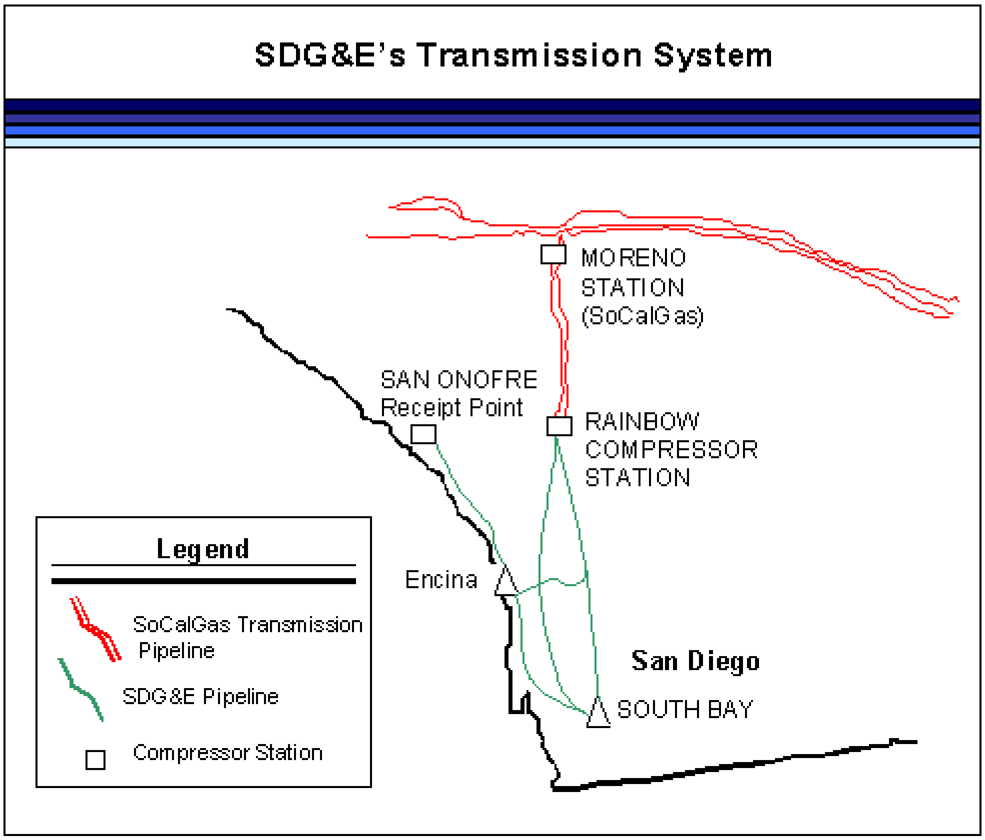
SDG&E receives all of its natural gas from SoCalGas on two pipelines, at the San Diego County line at the San Onofre and Rainbow metering stations. Maximum capacity at the Rainbow Station is 635 MMcfd in the winter and 615 MMcfd in the summer. The San Onofre Station capacity is about 30 MMcfd.

SDG&E has a small storage contract with SoCalGas, but the storage fields are not in the SDG&E area. Consequently, SDG&E's peak system demand must be met entirely via the natural gas transmission capacity of the San Onofre and Rainbow lines.

SDG&E experienced significant gas curtailments on its system during the winter of 2000-2001, because natural gas demand by large electric generation customers was much higher than in previous years. A significant portion of this increased power-plant demand was due to the large new gas-fired power plant that came online in Rosarito, Mexico in the summer of 2000.

In May 2000, SoCalGas reduced the likelihood of future curtailments in its territory by adding 70 MMcfd of capacity to the pipeline that supplies most of the gas to the SDG&E system.

SDG&E currently delivers natural gas to Mexico for electric generation facilities at the Presidente Juarez Power Plant in Rosarito, Mexico. SDG&E may reduce deliveries to the Rosarito facility in September 2002, if the North Baja pipeline is operational. This new interstate pipeline would deliver Southwest gas from the California/Arizona border to the Mexico border at Yuma, Arizona.



The CPUC has identified two local gas transmission points on the SoCalGas system with potential constraints[2]. These constraints are located on the transmission pipelines located in the San Joaquin and Imperial Valleys. Expansions of these lines may be necessary to minimize bottlenecks and reduce the possibility of curtailments. The CPUC is reviewing these local transmission constraint points in Investigation (I.) 00-11-002.

SoCalGas will file a General Rate Case application toward the end of 2002 for a 2004 Test Year. In addition, SoCalGas will likely file another Biennial Cost Allocation Proceeding application in late 2003 or in 2004. These proceedings will give the California Public Utilities Commission ("CPUC") opportunities to review again the adequacy of SoCalGas' infrastructure, and require SoCalGas to expand its system further,

2 "California Natural Gas Infrastructure Outlook" , California Public Utilities Commission, November 2001.

if necessary, with adequate lead-time to assure a high level of reliability. The CPUC will also address policy regarding SoCalGas' natural gas transmission capacity in I. 00-11-002.

Under most scenarios, the CPUC expects the existing transmission capacity into the SDG&E system to be more than adequate to serve all average monthly demand in the SDG&E territory. Similarly, the latest CEC annual forecasts of gas demand indicate ample natural gas transmission capacity on the SDG&E system. The CEC forecasts indicate slack capacity of about 50% during the forecast period.

The major uncertainties related to SDG&E's ability to serve its customers are: 1) whether the North Baja pipeline will actually be completed, 2) how much SDG&E gas load that project will serve, 3) how much new electric generation facilities will impact the operation of electric generators in the SDG&E area, and 4) whether adverse weather conditions will occur, such as dry hydro conditions or very cold weather. Curtailments could still occur on the SDG&E system in the winter of 2001-2002 on very cold days. After the winter of 2001-2002, assuming that the North Baja pipeline is constructed and completed by November 2002, the probability of noncore customer curtailments falls to about once in twenty to 35 years.

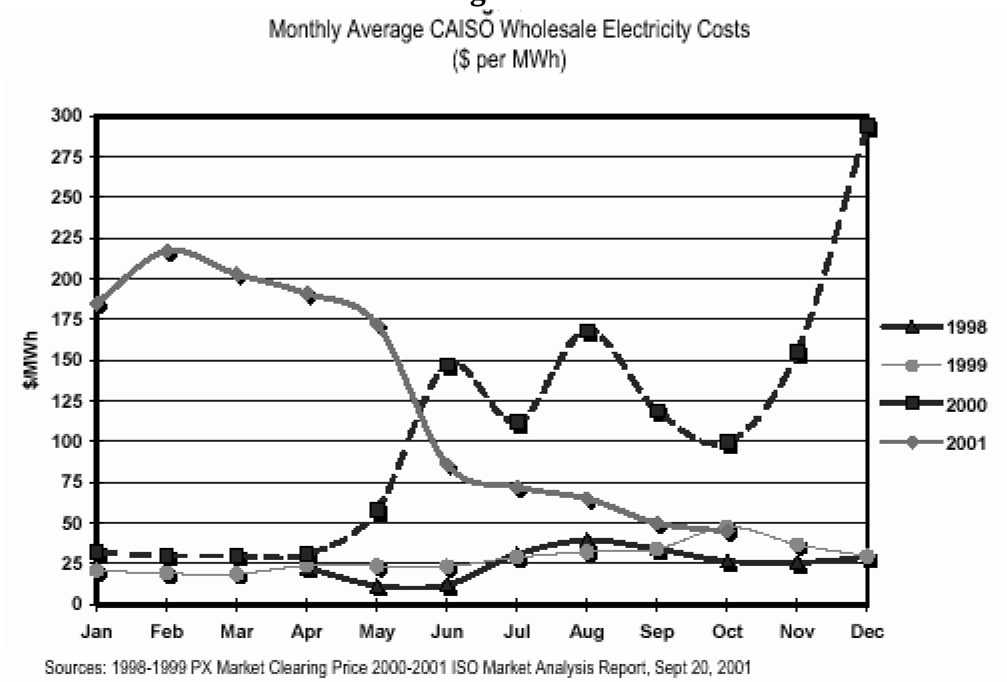
In Investigation (I.) 00-11-002, the CPUC is reviewing the SDG&E system to determine if any additions are needed. This evaluation of potential SDG&E transmission capacity additions will take into account the timetable for proposed additions, the costs, and future natural gas demand. Based on the evidence, the CPUC will direct SDG&E to take reasonable measures to enhance its transmission infrastructure. If hydro conditions return to normal, and the North Baja pipeline is built and serves some of the demand in the SDG&E area, the likelihood of system-wide gas curtailments will be further reduced or eliminated.

At this time, the North Baja project construction schedule is on track. On January 16, 2002, the Federal Energy Regulatory Commission ("FERC") gave final approval to the U.S. segment of the North Baja Pipeline project that will bring natural gas from Mexico to fuel electric generating plants in southern California and northern Mexico. The $230 million pipeline will be operated by an international subsidiary of Sempra Energy , PG&E Corp. and Mexico-based Proxima Gas S.A. de C.V. The 215-mile pipeline (346-km) would carry up to 500 million cubic feet of natural gas per day. FERC gave final approval for the project after determining the pipeline would not harm the environment.

II. ELECTRICITY MARKET OVERVIEW

Figure 2-1 shows average California electricity prices from 1998 through present. Spot market energy costs increased dramatically beginning June 2000. This trend first occurred when there were system stability problems in the San Francisco Bay Area and reached unprecedented levels during the winter of 200/2001.Wholesale price increases were based in part on high natural gas prices and increased demand in adjoining states that likely resulted in higher priced energy imports. Natural gas prices in the summer of 2000 were 80 percent higher than in the summer of 1999, and over 100 percent higher in the winter of 2001.

Figure 2-1



Wholesale electricity prices have stabilized in the 2-3 cents/kWh range, at the levels we experienced in 1998 and 1999. This stabilization of electricity prices is due to a number of actions.

II.a Conservation

The summer of 2001 saw an extraordinary reduction in peak demand[3]. Even though the summer of 2000 and 2001 were both about the 25 hottest years, actual peak demand in 2001 was substantially lower than the summer 2000 peak demand. There were 29 days during the summer of 2000 when demand exceeded 40,000 MW. There were only 6 of these high demand days during the summer of 2001.

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3 "Emergency Conservation and Supply Response 2001", California Energy Commission, P700-001-005F, December 2001.

As the following table shows, Californians used about 10 percent less electricity during the summer of 2001 than in previous years (about 5,000 MW less, or more than the entire demand of SDG&E area). The primary cause of the demand reduction is the subject of rigorous debate, with advocates of the cause of the reductions being due to higher prices for electricity, or the economic slowdown, or responses to conservation and incentive programs, or investments in new energy saving technologies.

Table 2-1

Historic Peak Demand (MW)

Year	Statewide Peak Demand
1998	53,119
1999	53,163
2000	52,588
2001	47,820

Regardless of whatever the primary cause of the conservation is, the principle concern is its permanence. If the Summer of 2001 demand was primarily behavioral or due to the economic slowdown, that demand could come back very rapidly, and start to cause reliability problems.

II.b State Purchases

In mid-January, 2001, the major California utilities were no longer credit worthy and the State of California (through the Department of Water Resources) stepped in and started purchasing electricity. The state racked up tremendous bills purchasing electricity during the first nine months of 2001 (over $12 billion), and locked customers in the state into a crushing burden of long run contracts to purchase electricity from generators.

From January through October 2001 the state spent approximately $13 billion purchasing electricity. The need to repay the state resulted in significant retail rate increases, a 1 cent/kWh increase in January, and a 40 percent rate increase for PG&E and Edison on June 1 and a 12 percent rate increase for SDG&E customers in October. This year (2002) the state is anticipating issuing approximately $14 billion in 15 year bonds that will be repaid by electric customers through their electric rates.

Not only have customers not paid off the past debts of the state, the state has signed contracts for up to 20 years that obligate the state to purchase some $40-80 billion worth of electricity at considerably higher than current market rates. Appendix A-4 provides a summary of the contracts the state has entered into.

Finally, the utilities have accrued debts for the difference between retail electricity prices and the cost of wholesale power during the 2000/2001 run-up in electricity prices. SDG&E customers do not owe as much as the other utilities, but will continue to be repaying these utility debts for years to come.

II.c New Generation

Expedited state siting and permitting, as well as performance incentives, resulted a rush to build new generation in California. As Table 2-2 shows, almost 2,300 MW of new generation was added in 2002. Table 2-3 shows that another 3,700 MW will come on line during 2002[4].

However, this 5,000 MW of new generation is just a portion of the almost 30,000 MW of projects have been identified and undergoing permitting, as Table 2-4 shows.

How much of this new capacity will actually be built is a matter of some concern. The Enron bankruptcy has had serious ramifications throughout the energy world, with tightened credit requirements resulting in the bond ratings of the major generation builders (Mirant, Dynergy, Calpine, Reliant) being reduced to junk bond status. This economic reversal, combined with low wholesale prices, has caused these generation providers to modify or suspend construction plans. For example, on January 17th Calpine Corporation, the largest constructor of new generation in California, announced it would suspend 4,800 MW of new construction in California but would finish the projects that it has currently under construction.

[4] "California Summer Electricity Outlook: 2004-2004", California Energy Commission, P700-01-003, November 2001.

New Additions Online (MW)

Online as of 10/31/01			
Approved CEC Projects	**Capacity**	**Derate**	**Online**
Proctor & Gamble	44	44	4/1/01
Sunrise	320	285	6/27/01
Sutter	540	504	7/2/01
Los Medanos	555	532	7/9/01
		1365	
ISO Peaker			
Harbor Cogen	19.00	19.00	6/14/01
NEO/Chowchilla II	48.60	48.60	6/15/01
Wildflower Larkspur (Tejas- Border)	90.00	90.00	7/13/01
Wildflower Indigo (Tejas- Palm Springs)	90.00	90.00	7/26/01
NEO/Red Bluff	46.80	46.80	8/2/01
Alliance/Drews	40.00	40.00	8/15/01
Wellhead/Fresno Cogen	23.00	23.00	8/16/01
Wildflower Indigo (Tejas- Palm Springs)	45.00	45.00	9/10/01
Alliance/Century	40.00	40.00	9/15/01
CalPeak Enterprise #7	49.50	49.50	9/30/01
CalPeak San Diego Border /Otay Mesa	49.50	49.50	10/27/01
		541.40	
Renewables			
Riverside County Waste Resources, Badlands (LFG)	2.00	2.00	2/15/01
Wheelabrator Shasta Energy Co., Inc., (BIOMASS)	3.80	3.80	2/15/01
Sierra Pacific, Sonora (BIOMASS)	7.50	7.50	2/16/01
Metropolitan Water Dist of Southern California, (SMALL HYDRO)	9.90	9.90	5/23/01
San Diego, Point Loma Wastewater Treatment Power Plant (SM HYDRO)	1.35	1.35	5/24/01
Energy 2001, (LFG)	1.20	1.20	5/30/01
SeaWest WindPower, Inc., Alexander 4 (WIND)	3.60	1.08	9/30/01
SeaWest WindPower, Inc., Alexander 1, 2, and 3 (WIND)	4.90	1.47	9/30/01
SeaWest WindPower, Inc., Phoenix 2, 3, 4, 5 (WIND)	7.70	2.31	9/30/01
SeaWest WindPower, Inc., 16 West – 1 & 2 (WIND)	3.50	1.05	9/30/01
SeaWest WindPower, Inc., Catellus 1, 2, 3, 4, 5 (WIND)	35.00	10.5	9/30/01
SeaWest WindPower, Inc., Catellus 6 (WIND)	1.80	0.54	9/30/01
		42.70	
CEC Peakers			
GWF Power Systems - Hanford Energy Park Peaker	95	85	9/1/01
		85	
Other Summer Projects			
Union Sanitary District (Union City)	1.25	1.25	06/01/01
LADWP- Sun Valley	47	47.0	09/06/01
		48.25	
Restart Biomass			
Sierra Forest Products	7	7	3/6/01
Dinuba	12	12	3/27/01
Primary Power	18	18	4/26/01
Honey Lake	30	30	5/17/01
Madera	25	25	6/1/01
Soledad	13	13	7/19/01
		105	
Rerate Energy Commission Projects			
Proctor & Gamble	9	9	5/30/01
El Segundo	10	10	10/8/01
		19	
Rerate Other Projects			
McClellan (SMUD)	22.00	22.00	3/30/01
Mt. Poso Cogen (Millennium Energy)	2.50	2.50	4/30/01
Rio Bravo Jasmin	3.00	3.00	5/1/01
Rio Bravo Poso Unit 1	3.00	3.00	5/1/01
		30.50	
2001 Generation Online as of 10/31/01		**2236**	

Table 2-3

New Additions Expected Online by September 1, 2002 (MW)

Online in 2002				
Project		**Capacity**	**Derate**	**Online**
Misc. Renewable Projects		78.55	27.41	1/1/02
Calpine King City		50	45	12/28/01
Huntington Beach		450	450	12/30/01
Energy Transfer/Hanover		23	23	12/31/01
El Segundo		10	10	1/1/02
	Online By 1/1/02		**555**	
Misc. Renewable Projects		30	22.5	1/31/02
	Online By 2/1/02		**22.5**	
CalPeak/El Cajon		49.50	49.50	2/15/02
El Segundo		8	8	3/1/02
Misc. Renewable Projects		13.85	8.68	3/1/02
	Online By 3/1/02		**66**	
Delta - Calpine		880	844	4/1/02
COSO Navy 2		12	12	4/1/02
Redding		54	54	4/1/02
Misc. Renewable Projects		48.55	11	4/1/02
	Online By 4/1/02		**921**	
Valero Refining - Valero Cogeneration I		51	45	4/30/02
Misc. Renewable Projects		126.97	30	4/15/02
	Online By 5/1/02		**75**	
La Paloma I		262	251	5/13/01
Moss Landing - Duke		1,060	1,017	6/1/02
Misc. Renewable Projects		79.85	29.49	6/1/02
	Online By 6/1/02		**1,297**	
La Paloma II		262	251	6/9/01
CalPeak/Vaca-Dixon		49.00	49	6/30/02
La Paloma III		262	251	7/1/01
Misc. Renewable Projects		48.00	10.75	7/1/01
	Online By 7/1/02		**562**	
La Paloma IV		262	251	7/22/01
	Online By 8/1/02		**251**	
	Online By 9/1/02		**0**	
Online By September 2002			**3,749**	

Table 2-4

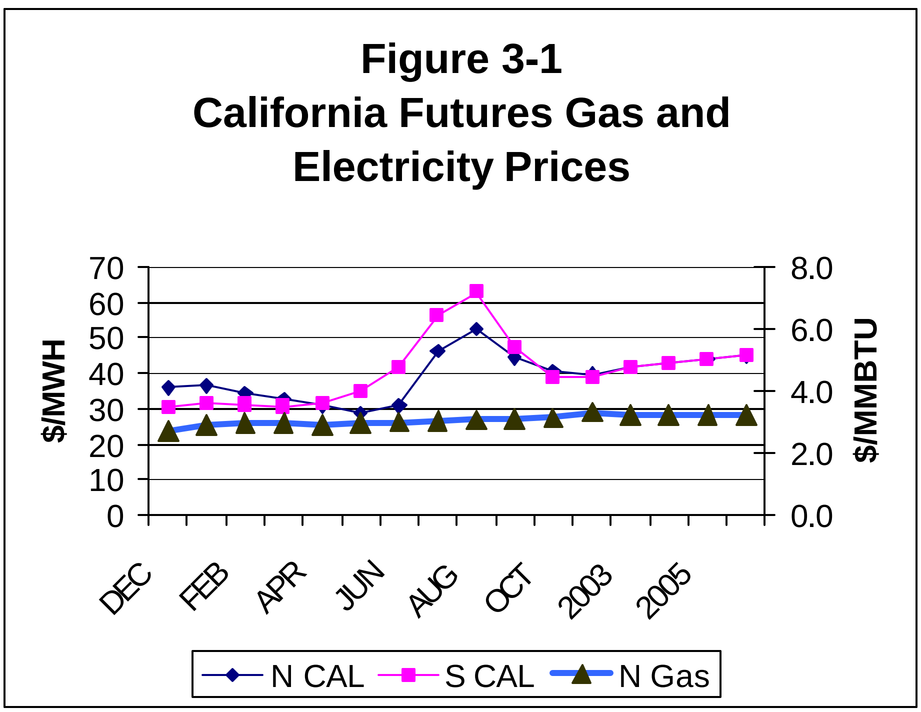
Capacity Additions by County

Location	Operational	Construction	Finance	Data Adequacy Review	Under Review	Announced	Total
Alameda				1,120	1,700		2,820
Colusa County					500		500
Contra Costa	555	1,410				134	2,099
Fresno						1,100	1,100
Kern	320	2,298	500		200	716	4,034
Kings	95			600	91		786
Los Angeles					880	395	1,275
Merced						420	420
Monterey		1,110					1,110
Orange		450					450
Placer				900			900
Riverside	135	520		670		1,531	2,856
Sacramento				1,000		260	1,260
San Bernardino	80	1,776	180			450	2,486
San Diego	139	559				500	1,198
San Francisco					540		540
San Joaquin				169			169
San Luis Obispo					1,200		1,200
San Mateo				570		114	684
Santa Clara		135	600	96	315	782	1,928
Shasta			500				500
Solano			102				102
Stanislaus			80				80
Sutter	540						540
Yolo						200	200
Total	1,864	8,258	1,962	5,125	5,426	6,602	29,237

III. FUTURE PRICES FOR ELECTRICITY AND NATURAL GAS

Current wisdom is that wholesale prices will remain low for the foreseeable future, that Californians will continue to conserve, that there will not be a run-up in demand due to a rebounding economy, that natural gas will continue to be abundant and relatively stable in price, and that generation will be built sufficient to maintain a competitive wholesale market.

Convention wisdom is reflected in current futures prices for electricity and natural gas. Figure 3-1 shows that currently one can purchase electricity for up to 5 years into the future in the 3-4 cents/kWh range, and natural gas in the $3-4/MMbtu range.



Retail prices for electricity, however, will increase slightly and then plateau at historically high levels, due to the need to repay long term state commitments for electricity purchases, paying off state debt for past purchases of electricity, and paying off utility past due bills.

The California Energy Commission states: "Under the current circumstances, retail rates for IOU customers will most likely increase in the 2002-2003 period[5]". A rate decrease is unlikely, unless the Federal Energy Regulatory Commission (FERC) orders merchant generators and energy traders to refund for overcharges incurred during the fall and winter of 2000-2001.

Future retail electricity rates for the IOUs depend to a certain extent on the regulatory decisions of the FERC, State Legislature, the Governor, and the CPUC, rather than the spot market prices (which are likely to remain low). If regulators decide that ratepayers should bear the utilities debt, rates would likely increase gradually up to an average of 13.0 cents/kWh in the 2002-2005 period. The rates will stabilize at this level for most of the next decade. Most of the IOU electricity rate components are relatively set for the next ten years. Therefore, major rate fluctuations in retail rates are unlikely.

Table 3-1 provides the California Energy Commission forecast of future electricity prices. Appendix A-1 provides this forecast by customer class. Appendix A-2 provides the CEC forecast of natural gas prices.

Table 3-1

System Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	10.5	13.8	13.2	9.6	8.9	11.8	11.7	11.8	103.0
2003	12.4	14.0	13.5	9.4	8.7	11.6	11.4	11.5	105.5
2004	11.8	14.5	12.9	9.6	8.3	11.9	11.7	11.8	108.3
2005	11.9	13.7	12.6	9.9	8.5	12.3	12.0	12.2	111.2
2006	12.0	13.6	12.9	10.2	8.8	12.6	12.4	12.5	114.0
2007	11.8	13.3	12.6	10.5	9.1	12.8	12.8	12.9	116.9
2008	11.2	12.7	11.9	10.8	9.3	13.0	13.1	13.2	119.6
2009	10.9	12.4	11.7	11.2	9.7	13.2	13.6	13.7	123.7
2010	10.7	12.1	11.4	11.6	10.0	13.4	14.0	14.1	127.4
2011	10.6	11.9	11.3	12.9	10.4	13.6	13.9	14.6	131.5
2012	10.4	11.6	11.0	12.4	10.9	13.7	13.7	15.1	135.7

5 "2002-2012 Electricity Outlook Report", California Electricity Commission, P700-01-004, November 2001.

IV CONCLUSIONS AND RECOMMENDATIONS

1. The Market

Valley Center MWD is currently likely to face low wholesale prices for electricity, low natural gas prices, but high retail rates for electricity for most of the next decade as we struggle to pay off the utility debt, the state debt for electricity purchase during the first half of 2001, and the high priced state contracts.

2. Generation Options

This scenario means that large generators selling into the wholesale market are not currently a viable option. It is recommended that all analysis/evaluation of generation options in excess of current electricity usage be suspended. Natural gas-fired self generation (meeting Valley Center's electrical demands) are likely candidates for cost effective investments and it is recommended that Valley Center pursue/or continue evaluation of self generation options, with one caveat. As we have seen during the last 12 months, things in the energy market can change with stunning rapidity. It is recommended that analysis of any capital intensive investments be limited to a relatively short pay-back period, to reduce Valley Center's exposure in case the market turns again.

3. Energy Efficiency

The ability to displace retail electricity is going to remain an attractive investment throughout most of this decade due to high retail electricity costs. Valley Center should continue analysis of means to improve it's energy efficiency through conservation investments and other system improvements.

4. Energy Market Monitoring

The current market status quo could change rapidly, if insufficient new generation is not built, demand increases rapidly, natural gas pipelines are not constructed, or if the current rate structure changes dramatically. It is recommend that Valley Center continue to monitor the market carefully, and receive periodic updates on the California electricity and natural gas market, so that it can change its cost minimization strategy accordingly.

5. System Operations

In the review of Valley Center Operations, it became apparent that most of the operating protocols and decision-making was done by two very competent system operators, but that Valley Center does not have an operations manual per se. This is an unnecessary risk for Valley Center, for if something happened to the two senior operators there is no documentation on how to operate the Valley Center system.

It is recommended that some of the money that was allocated to the contract for Water and Energy Consulting's review that will not be used to evaluate large generation options be used to develop a written operations manual for Valley Center. A recommended approach to developing this information and database can be found in Attachment A-3.

APPENDIX A-1

CALIFORNIA ENERGY COMMISSION FORECASTED RETAIL ELECTRICITY PRICES

Small Commercial Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	13.56	18.69	16.95	10.52	9.95	12.19	13.07	15.58	103.02
2003	16.51	19.54	17.55	10.28	9.72	11.90	12.77	15.21	105.46
2004	15.62	18.11	16.57	10.57	9.24	12.36	13.12	15.64	108.28
2005	15.79	17.15	16.15	10.90	9.48	12.72	13.51	16.10	111.22
2006	15.94	17.03	16.51	11.23	9.79	13.02	13.89	16.55	113.99
2007	15.57	16.58	16.00	11.56	10.13	13.22	14.28	17.02	116.91
2008	14.60	15.48	14.89	11.88	10.43	13.43	14.65	17.47	119.62
2009	14.29	15.14	14.55	12.31	10.81	13.65	15.16	18.08	123.65
2010	13.96	14.80	14.23	12.72	11.24	13.88	15.66	18.67	127.44
2011	13.83	14.59	14.05	13.16	11.68	14.05	15.51	19.29	131.45
2012	13.56	14.29	13.76	13.63	12.16	14.21	15.35	19.95	135.70

Medium Commercial Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	11.25	14.79	12.47	9.29	9.00	12.78	12.55	13.43	103.02
2003	12.77	14.57	13.11	9.08	8.79	12.48	12.26	13.12	105.46
2004	12.03	15.69	12.33	9.34	8.33	12.96	12.59	13.49	108.28
2005	12.24	14.82	12.05	9.63	8.56	13.34	12.97	13.89	111.22
2006	12.43	14.71	12.46	9.91	8.83	13.65	13.33	14.28	113.99
2007	12.16	14.27	12.11	10.21	9.14	13.87	13.71	14.68	116.91
2008	11.87	13.92	11.82	10.49	9.42	14.08	14.07	15.07	119.62
2009	11.60	13.58	11.54	10.87	9.75	14.32	14.56	15.59	123.65
2010	11.32	13.23	11.27	11.24	10.15	14.56	15.03	16.10	127.44
2011	11.20	13.01	11.13	11.62	10.54	14.73	14.89	16.64	131.45
2012	10.97	12.71	10.90	12.04	10.98	14.91	14.74	17.21	135.70

Medium Industrial Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	7.65	11.93	10.13	7.20	7.64	11.19	11.05	7.92	103.02
2003	8.97	11.75	10.79	7.04	7.46	10.93	10.80	7.73	105.46
2004	8.28	11.72	9.95	7.24	7.03	11.35	11.10	7.95	108.28
2005	8.45	10.98	9.67	7.46	7.22	11.68	11.43	8.18	111.22
2006	8.62	10.92	10.08	7.68	7.45	11.96	11.75	8.41	113.99
2007	8.39	10.61	9.73	7.91	7.72	12.15	12.08	8.65	116.91
2008	8.14	10.30	9.44	8.13	7.95	12.33	12.39	8.88	119.62
2009	7.91	10.00	9.16	8.42	8.23	12.54	12.82	9.19	123.65
2010	7.67	9.70	8.90	8.71	8.56	12.75	13.24	9.49	127.44
2011	7.57	9.50	8.76	9.01	8.90	12.90	13.12	9.80	131.45
2012	7.37	9.24	8.53	9.33	9.26	13.06	12.98	10.14	135.70

Agricultural Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	12.92	13.00	12.41	N/A	9.03	N/A	N/A	N/A	103.02
2003	14.48	12.80	12.87	N/A	8.82	N/A	N/A	N/A	105.46
2004	13.75	12.99	12.34	N/A	8.59	N/A	N/A	N/A	108.28
2005	13.96	12.29	12.12	N/A	8.82	N/A	N/A	N/A	111.22
2006	14.17	12.24	12.44	N/A	9.10	N/A	N/A	N/A	113.99
2007	13.88	11.96	12.16	N/A	9.42	N/A	N/A	N/A	116.91
2008	13.58	11.67	11.94	N/A	9.70	N/A	N/A	N/A	119.62
2009	13.30	11.40	11.72	N/A	10.05	N/A	N/A	N/A	123.65
2010	13.01	11.13	11.51	N/A	10.46	N/A	N/A	N/A	127.44
2011	12.89	10.95	11.40	N/A	10.86	N/A	N/A	N/A	131.45
2012	12.65	10.71	11.22	N/A	11.31	N/A	N/A	N/A	135.70

APPENDIX A-2

CALIFORNIA ENERGY COMMISSION FORECASTED RETAIL NATURAL GAS PRICES

Annual Average Natural Gas Prices
2000 $ per Mcf

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
PG&E	3.09	3.16	3.22	3.28	3.34	3.40	3.47	3.54	3.61	3.69	3.76
SoCal Gas/ San Diego	2.94	3.00	3.06	3.16	3.25	3.33	3.41	3.48	3.56	3.63	3.70
So. Calif Prod.	2.85	2.946	3.042	3.138	3.234	3.33	3.406	3.482	3.558	3.634	3.71
TEOR/Coolwater	3.05	3.128	3.206	3.284	3.362	3.44	3.514	3.588	3.662	3.736	3.81
Alberta	2.55	2.596	2.642	2.688	2.734	2.78	2.828	2.876	2.924	2.972	3.02
British Columbia	2.72	2.782	2.844	2.906	2.968	3.03	3.094	3.158	3.222	3.286	3.35
Colorado	2.99	3.03	3.06	3.10	3.13	3.17	3.21	3.26	3.30	3.35	3.39
El Paso N & S AZ/NM	2.78	2.88	2.98	3.07	3.17	3.27	3.36	3.45	3.53	3.62	3.71
Kern River	2.90	2.96	3.02	3.09	3.15	3.21	3.30	3.39	3.48	3.57	3.66
Mojave	2.97	3.04	3.12	3.19	3.27	3.34	3.42	3.51	3.59	3.68	3.76
Montana	2.93	2.98	3.03	3.07	3.12	3.17	3.21	3.26	3.30	3.35	3.39
Nev-No	3.08	3.14	3.20	3.25	3.31	3.37	3.44	3.50	3.57	3.63	3.70
Nev-So	3.22	3.30	3.38	3.47	3.55	3.63	3.71	3.78	3.86	3.93	4.01
PGT-Kingsgate	2.28	2.33	2.38	2.42	2.47	2.52	2.57	2.62	2.66	2.71	2.76
PGT-Malin	2.66	2.72	2.78	2.84	2.90	2.96	3.03	3.10	3.17	3.24	3.31
PGT-Stansfield	2.47	2.52	2.57	2.61	2.66	2.71	2.77	2.83	2.88	2.94	3.00
PNW	3.52	3.58	3.64	3.71	3.77	3.83	3.88	3.93	3.99	4.04	4.09
PNW-Coastal	2.76	2.83	2.90	2.96	3.03	3.10	3.16	3.23	3.29	3.36	3.42
Utah	2.99	3.03	3.06	3.10	3.13	3.17	3.21	3.25	3.30	3.34	3.38
Rosarito	2.91	2.99	3.06	3.14	3.21	3.29	3.37	3.45	3.53	3.61	3.69
Otay Mesa	2.92	3.00	3.08	3.16	3.23	3.31	3.39	3.47	3.54	3.62	3.70

Monthly Natural Gas Price Multpliers

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PG&E	1.06	1.06	0.99	0.97	0.99	0.96	0.96	0.96	0.96	0.96	1.05	1.09
Southern California*	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
SDG&E/ Rosarito/ Otay Mesa	1.09	1.04	0.96	0.94	1.00	0.97	0.92	0.97	0.98	0.98	1.09	1.22
Coolwater	1.08	1.05	1.02	0.97	0.96	0.94	0.93	0.94	0.97	0.99	1.08	1.19
Alberta	0.99	1.08	1.00	1.04	0.99	0.93	0.94	0.87	0.91	1.00	1.08	0.97
British Columbia	1.23	0.97	0.88	0.93	0.87	0.83	0.82	0.83	0.87	1.00	1.21	1.36
Colorado	1.05	0.94	0.85	0.88	1.12	0.88	1.07	1.03	0.89	0.92	1.09	1.20
El Paso N & S - AZ	1.07	0.99	1.07	1.28	1.07	0.93	0.90	1.04	0.93	1.10	1.11	1.17
El Paso N & S - NM	1.18	1.02	0.97	0.96	0.97	0.94	0.97	0.96	0.94	1.00	1.11	1.14
Montana	1.38	1.67	1.45	1.28	1.07	1.20	0.83	0.72	0.78	0.81	0.97	1.20
NV - N & S	1.03	1.01	0.95	1.01	0.97	1.02	0.93	0.98	0.99	1.09	1.13	0.98
PGT-Malin/ PGT-Stansfield	1.15	1.12	1.06	0.94	0.84	0.95	0.92	0.90	0.87	0.99	1.13	1.16
PNW/ PNW Coastal/ PGT - Kinsgate	0.68	0.83	1.00	1.27	1.35	0.76	1.01	1.00	1.11	0.90	0.96	1.09
Utah	1.38	1.67	1.45	1.28	1.07	1.20	0.83	0.72	0.78	0.81	0.97	1.20

APPENDIX A-3

RECOMMENDED APPROACH TO DEVELOP OPERATING MANUAL FOR VALLEY CENTER MUNICIPAL WATER DISTRICT

Schematic Summary of the Development of a Valley Center Operations Manual

1) Have Valley Center operators establish a diary that describes the procedure, rule curves and decision making that they use in the operation of the Valley Center system.
2) After sufficient time has elapsed (usually a month), have an outside person take the diary and use it to develop the first draft operations manual.
3) Armed with the draft operations manual, have the outside person shadow the operators for several 24 periods – weekday and weekend during the winter and summer periods at a minimum. Determine if the drafted operations manual is sufficient to duplicate the operations of the Valley Center system and make any modifications and enhancements necessary. Develop a second draft operation manual.
4) Have the second draft reviewed by the Valley Center operators. Make any edits/modification necessary.
5) Finalize a Draft Operations Manual. This should be a living document, available in loose leaf form so it can be constantly be adapted and enhanced as operations, system configuration, and other parameters that affect decision making change.

APPENDIX A-4

LIST OF STATE CONTRACTS FOR POWER