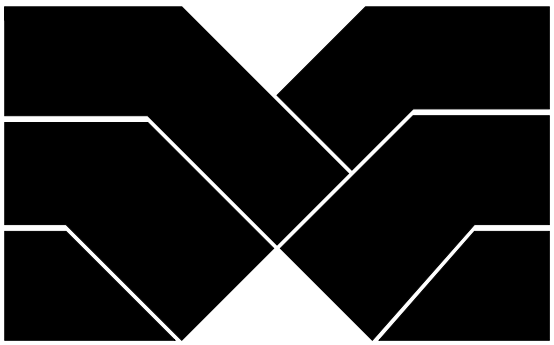

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Memorandum

Date: April 9, 2005

To: McCullough Research Clients

From: Robert McCullough

Subject: Creating Scarcity From Abundance

For the past few weeks the press has treated the west coast to the specter of blackouts in California in the upcoming summer. While many of the reports may be exaggerated, the fact remains that California policy makers have recently issued three reports – one by the California Energy Commission (CEC), one by the California Public Utilities Commission (CPUC), and a third from the California Independent System (CISO) operator that gives this concept some credence.[1] Otherwise, with overall regional capacity margins above 30% for summer 2005, this would seem inconceivable.

While some part of the problem reflects an error in planning – the continued treatment of California as a single region for planning purposes – the largest part of the problem is ideological. California's continued pursuit of a centralized administrative solution to reliability has left it ill-equipped to address everyday operational issues. In this case, a fairly simple exercise in prudent utility practice has been allocated among too many different parties, leaving no one actually in charge of a solution.

One important problem shows up in the CISO study. It appears that the CISO is now forecasting forced outages higher than their 7% operating reserve criterion. If so, either the outages need to be addressed or the criterion increased.

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[1]California Energy Action Plan, CPUC, March 23, 2005; 2005 Summer Operations Assessment, CISO, March 23, 2005; and, Summer 2005 Electricity Supply and Demand Outlook, March 2005, CEC.

A Very Short Primer on Electricity Reliability Planning

Since electricity cannot be stored, we must always have a surplus of available capacity. The planning standards used generally in the industry are simple and robust.

The first step is the load forecast. The capacity forecast is conservative by its very nature – assuming the highest possible requirements. In actual practice this means that the capacity forecast assumes hot weather in the south and cold weather in the north. California has adopted a unique terminology for this practice, the "1-in-10" Forecast standard.[2]

The second source of risk in electric planning is equipment failure. Again, the rule is to use a worst case forecast – drought for hydro, temperature derating for thermal units, and then set an operating reserve margin sufficient to maintain service after unforeseen outages.

These standards have been in place now for forty years. A good reference work on the standards for the Western U.S. and Canada can be found in the November 24, 2004 WECC Power Supply Assessment.[3,4]

In practice, planning reserves are usually in the range of 10 to 15%. This splits into a 7% operational reserve to meet equipment failure and an additional margin to reflect capacity load uncertainty.

For integrated utilities in the rest of the WECC, the determinations are relatively simple. Each utility is tasked with procuring sufficient capacity through construction or contract to meet WECC standards. California is considerably more complex. California has three governmental institutions with responsibility for setting reliability standards, the California Energy Commission, the California Public Utilities Commission, and the California Independent System Operator.[5] Complicating the situation is the fact that the California Independent System Operator only serves a portion of the state and the California PUC only regulates privately owned utilities.

The CPUC has adopted a good solution for 2006 – requiring a reserve margin of 15% to 17% for utilities. This solution has the benefit of being relatively clear, but will not help for the summer of 2005.

The California ISO does not really have a policy. The CISO is deeply committed to a "time-on-target" policy where operational reserves are acquired on a daily basis. In practice, this leaves the CISO in the position of always driving too fast for its headlights. This is an ideological choice based on the peculiar

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[2]California's "1-in-2" forecast is a very odd concept for reliability planning since it describes the average, rather than the worst, case. In everyday terms it represents a level of reliability that could fail half the time.

[3]See particularly, Attachment 1, WECC Power Supply Assessment, November 24, 2004, page 2-35.

[4]The western U.S. and Canada, plus a small portion of northern Mexico belong to a reliability council named the Western Energy Coordination Council. This body is tasked with reliability planning for the region.

[5]The California ISO is a unique institution with a board appointed by the governor, but exemption from open meeting and open document rules.

assumption that reserves will always be available at the last moment. In spite of the substantial rhetoric to the contrary, there is no a priori reason why a regional transmission organization needs to purchase reserves at the last moment, nor is it very clear where this rigidly held ideology originated.[6]

In the CISO's recent report, they state:

> Snow-pack/hydro conditions in neighboring regions is one factor that can affect ISO imports. Typically, hydro conditions have more effect on the amount of energy (MWhrs) imported into the ISO Control Area throughout the season, rather than affecting the amount of import capacity (MW) available at peak. However, in severe drought conditions, neighboring regions' water levels may be too low to offer this spare "peaking" capacity during periods of high ISO demand. For 2005, various trade journals and other sources have reflected concern, and have debated over hydro conditions in the Pacific Northwest (Oregon, Washington, and British Columbia). Currently northwestern 2005 snow equivalents range from 20-30% of average in the Oregon and Washington Cascades, to 70% in the upper Snake River area. British Columbia has faired somewhat better so far, reporting near average snow water equivalents.
>
> "Runoff at the Dalles" (Columbia River flow-through at the Dalles) is another common indicator of northwest hydroelectric availability. Recent reports have forecasted the 2005 Dalles runoff at of 60-66% of average.19 By comparison, 2004 runoff at the Dalles was roughly 82% of average, while runoff during 2001's drought conditions was around 54% of average.[7]

While the CISO is correct that forecasted flows for the summer of 2005 are significantly lower than average, the real situation is not terribly bleak. The project capacity margin for the Pacific Northwest for summer 2005 is 54.9% – 27,722 megawatts at system peak. As always, these calculations are made assuming drought conditions.[8] Since transmission limitations from Oregon to California reduce the potential supply of capacity to 7,700 megawatts, the likelihood that capacity availability in the Pacific Northwest will be scarce is slight.[9]

At least for the summer of 2005, the availability of capacity imports is an institutional problem, not one of engineering. The CISO calculations fear that capacity will not be available on a daily basis. If the CISO was in charge of supermarkets, they would have equal problems assuring the supply of food, since they would be unwilling to engage in negotiations for guaranteed supplies beyond the next day.

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[6]In reality, the California ISO could arrange operational reserves on any basis they found practical. While a change in their purchasing methodology may require approval from the Federal Energy Regulatory Commission, it is unlikely that the timing of their purchases is a controversial issue at FERC – or anywhere other than the California ISO.

[7]2005 Summer Assessment, CISO, Page 25.

[8]10-Year Coordinated Plan Summary, WECC, September 2004, page 36. The conservative nature of reliability planning is often overlooked in California which is one of the reasons that every WECC reliability planning table includes "Adverse Hydro Conditions" in the upper right corner. This single study, for example, contains the phrase twenty times.

[9]Ibid., see page 54.

Going By the Numbers

The correct place to start is the WECC 10-Year Coordinated Plan. This document is freely available at www.wecc.biz. The annual coordinated plans are standard across North America. Their basic methodology and structure has been the same for over twenty years. The aftermath of the price manipulations from May 2000 through June 2001 was a tremendous supply response, leaving the Western U.S. and Canada massively surplus.[10]

Table 7 - WECC Estimated Peak Demands, Resources, and Reserves 2004 - 2013

	SUMMER PEAK							Adverse Hydro Conditions		
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Month	AUG	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL
Loads - Firm	137600	140759	144448	147845	151211	154549	157887	161328	164829	168528
Int. & Load Mgt	2561	2586	2592	2593	2595	2597	2600	2602	2603	2605
Total - MW	140161	143345	147040	150438	153806	157146	160487	163930	167432	171133
Growth from Previous Yr. - %	0.2	2.3	2.6	2.3	2.2	2.2	2.1	2.1	2.1	2.2
Generation ± Transfers - MW	185375	191373	198147	203486	204309	204526	206069	207102	207137	207181
Maint./Inoperable Cap. - MW	3782	3741	3950	3505	3490	3490	3505	3492	3490	3408
Reserve Capability MW	43993	46873	49749	52136	49608	46487	44677	42282	38818	35245
Percent of Firm Peak Demand	32.0	33.3	34.4	35.3	32.8	30.1	28.3	26.2	23.6	20.9

According to current forecasts, the 2005 summer peak of the WECC will leave 33.3% of the region's capacity in reserve. This is 46,873 megawatts – approximately the entire worst case capacity load in the CISO control area this summer.[11]

Because transmission links are weak between different areas in the vast expanse covered by the WECC, the 10-Year Coordinated Plan is split into four sub-regions: Pacific Northwest, California, Rockies, and the Southwest.

Each sub-region also has a detailed analysis of future capacity loads and available resources. The section on California and Northern Mexico starts on page 46.

[10]Ibid., page 28. Please note the "Adverse Hydro Conditions" entry in the upper right corner of this table.

[11]See Table II-1 of the CISO 2005 Summer Assessment, page 5.

Table 28 - California-Mexico Power Area Estimated Peak Demands, Resources, and Reserves 2004 - 2013

	SUMMER PEAK							Adverse Hydro Conditions		
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Month	AUG	AUG	AUG	AUG	AUG	AUG	AUG	AUG	AUG	AUG
Loads - Firm	53121	54195	55372	56537	57739	58948	60182	61433	62695	63982
Int. & Load Mgt	1760	1760	1760	1760	1760	1760	1760	1760	1760	1760
Total - MW	54881	55955	57132	58297	59499	60708	61942	63193	64455	65742
Growth from Previous Yr. - %	3.4	2.0	2.1	2.0	2.1	2.0	2.0	2.0	2.0	2.0
Generation ± Transfers - MW	61858	63870	65931	66408	66396	67665	69046	70446	71860	73302
Maint./Inoperable Cap. - MW	960	1162	1164	1164	1164	1164	1164	1164	1164	1164
Reserve Capability MW	7777	8513	9395	8707	7493	7553	7700	7849	8001	8156
Percent of Firm Peak Demand	14.6	15.7	17.0	15.4	13.0	12.8	12.8	12.8	12.8	12.7

The WECC forecasts for California, as a whole, show a healthy situation for the state as a whole – 15.7% reserves.

Unfortunately, at the request of the California ISO, the derivation of the ISO's contribution to this forecast has been confidential since 2001.[12]

While the submission to the WECC is secret, both the California Energy Commission and the California ISO publish their own slightly idiosyncratic versions of the WECC tabulation. Of the two, the CEC approach provides the closest match to traditional reliability planning standards.

The corresponding table from the CEC is:[13]

[12] A continuing planning problem in California is the lack of transparency at the California ISO. These numbers, for example, are not normally secret for utilities elsewhere in the WECC.

[13] Summer 2005 Electricity Supply and Demand Outlook, March 2005, page 4.

Line		June	July	August	September
1	Existing Generation[1]	53,808	53,718	54,773	54,902
2	Retirements (Known)	-850			
3	Retirements (High Risk)	-1,192			
4	High Probability CA Additions	1,952	1,055	129	1
5	Forced Outages	-3,500	-3,500	-3,500	-3,500
6	Zonal Transmission Limitation[2]	-800	-800	-800	-800
7	Net Interchange [3]	12,921	12,921	12,921	12,921
8	Total Supply (MW)	62,339	63,394	63,523	63,524
9	1-in-2 Summer Temperature Demand (Normal)	54,900	57,365	57,913	57,015
10	Projected Resource Margin (1-in-2)*	17.3%	13.3%	12.2%	14.4%
11	1-in-10 Summer Temperature Demand (Hot)	58,667	61,003	61,885	60,937
12	Projected Resource Margin (1-in-10)*	7.9%	4.9%	3.3%	5.3%
13	MW needed to meet 7.0% Reserve	0	1,045	1,860	844
14	Surplus MW above 7.0% Reserve	400	0	0	0

[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel

[2] Values provided by CA ISO.

[3] 2005 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 2,500 MW, NW imports (COI) 4,000 MW, North of Miguel 400 MW, LADWP Control Area imports 2,834 MW, IID imports 184 MW** and Dynamic Resources 1,003 MW. **Imports supplying own reserves are in bold text.**

* Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Resource Margin. Calculated as ((Supply - **imports with own reserves**)/(Demand - **imports with own reserves**))-1

Comparing the official WECC tabulations with the tables from California requires some care.

The WECC starts with total resources and then compares them with total load. The CEC complicates the problem by assuming a substantial amount of forced outages halfway through the table. This tends to obscure the conclusion by confusing planning reserve with operational reserves.

The WECC forecast 63,870 megawatts of capacity resources and contracts. The CEC forecasts 54, 773 megawatts of capacity, 129 megawatts of new resources in August, and 12,921 megawatts of imports – a total of 67,823 megawatts – almost 4,000 megawatts in excess of the CEC forecast. The CEC then removes 3,500 megawatts of plant outages, which makes the WECC and CEC numbers roughly comparable.[14]

Projected loads are 55,955 megawatts at the WECC and 57,913 megawatts at the CEC. Removing the forced outages from the planning reserve calculation produces a projected reserve margin of 15.7% – the same level as the WECC forecast.

Since restructuring, California's forced outages have been quite high. During the height of the market manipulation period, merchant plant thermal outages reached 50% on occasion. The assumed level of

[14]Since the ISO submission is not available, it is logical to assume that the forced outages were incorrectly included in the WECC tabulation. If so, this is simply a problem in the ISO's approach to the question, and not an actual adding error.

forced outages seem high by comparison with recent years, but not implausible given the incentives to withhold generation during periods when the California ISO may be forced to pay a premium for emergency purchases. We know that Enron and Reliant provided fraudulent outage information as a means to raise prices, so the high levels of outages during the crisis are not surprising. However, the 3,500 megawatts assumed her seem high by industry standards ~ approximately 6.4% of all resources. The reason for the high assumption is that the CEC staff added approximately 1,000 megawatts to their outage figures in order to be conservative.[15] Since outages are the reason for operating reserves, this assumption is not out of line with California's operating reserve margin – 7%.

Overall, the statewide CEC analysis matches the WECC analysis:

> the 15.7% planning reserve

is sufficient to meet two major contingencies:

(1) a 6.86% higher load forecast during hot weather
(2) a 6.39% forced outage level.

The CEC study also addresses the ISO control area.[16] Over time, the ISO control area has effectively shrunk to serving just the sum of the control areas of the three investor owned utilities, excluding the municipals – especially L.A. and Sacramento – and the Western Area Power Administration.

[15]Summer 2005 Electricity Supply and Demand Outlook, CEC, March 2005, pages 10-11.

[16]Summer 2005 Electricity Supply and Demand Outlook, CEC, March 2005, page 5.

Line		June	July	August	September
1	Existing Generation[1]	45,969	45,457	46,512	46,641
2	Retirements (Known)	-530			
3	Retirements (High Risk)	-1,192			
4	High Probability CA Additions	1,210	1,055	129	1
5	Forced Outages	-2,800	-2,800	-2,800	-2,800
6	Zonal Transmission Limitation[2]	-800	-800	-800	-800
7	Net Interchange [3]	9,303	9,303	9,303	9,303
8	Total Supply (MW)	51,160	52,215	52,344	52,345
9	1-in-2 Summer Temperature Demand (Normal)	45,085	47,004	47,134	46,679
10	Projected Resource Margin (1-in-2)*	16.5%	13.5%	13.4%	14.8%
11	1-in-10 Summer Temperature Demand (Hot)	48,323	50,384	50,526	50,043
12	Projected Resource Margin (1-in-10)*	7.1%	4.4%	4.3%	5.5%
13	MW needed to meet 7.0% Reserve	0	1,115	1,138	621
14	Surplus MW above 7.0% Reserve	35	0	0	0

[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel
[2] Values provided by CA ISO.
[3] 2004 CA ISO estimates **DC imports of 1,500 MW,** Path 26 2,700 MW, **SW imports 2,500 MW,** Dynamic 1,003 MW and **CEC estimate of LADWP imports of 1,000 MW.** 2005 estimate increases **DC transfer capability by 500 MW,** Path 26 by 300 MW, **North of Miguel by 400 MW** and **Northwest (minus SMUD) 2400 MW.** Imports supplying own reserves are in bold text.
* Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Resource Margin. Calculated as ((Supply - **Imports with own reserves**)/(Demand - **Imports with own reserves**))-1

The CEC's view of the ISO is actually more positive than its view for the state as a whole. The CEC predicts that the planning reserve margin for the ISO alone in August will be 18.7%.[17] As before, this planning reserve should prove adequate to meeting a higher than normal hot weather load contingency – 7.2% – and forced outages of 6%. The forecasts that forced outages will be lower for the ISO than the other areas of California is surprising, given historical experience, but the differential is not so extreme as to be significant.[18]

The problem turns out not to be the level of California reserves, or even the level of reserves at the California ISO, but the reserves for southern California. In the language of the ISO, SP-15 is the trouble area. The next CEC table addresses the southern part of the state:[19]

[17] Again, this is sorting the table back into the traditional reliability planning format – adding all resources and imports and then comparing that total to the 1-in-2 load forecast.

[18] As noted above, the complex structure of the California ISO has rewarded fraudulent outage reports in the past. Since the incentives for plant maintenance outside of the ISO are relatively simple – if the plant isn't running its owner bears the costs – and complex within the ISO – if the plant isn't running, its owner may actually be able to negotiate higher payments – most analysts would forecast lower outage rates at LADWP rather than higher outage rates.

[19] Summer 2005 Electricity Supply and Demand Outlook, CEC, March 2005, page 7.

Line		June	July	August	September
1	Existing Generation[1]	20,086	20,371	20,851	20,980
2	Retirements (Known)	-530			
3	Retirements (High Risk)	-146			
4	High Probability CA Additions	961	480	129	1
5	Forced Outages	-1,200	-1,200	-1,200	-1,200
6	Zonal Transmission Limitation[2]	-800	-800	-800	-800
7	Net Interchange [3]	9,903	9,903	9,903	9,903
8	Total Supply (MW)	28,274	28,754	28,883	28,884
9	1-in-2 Summer Temperature Demand (Normal)	24,782	26,275	26,691	27,001
10	Projected Resource Margin (1-in-2)*	18.5%	12.2%	10.5%	8.9%
11	1-in-10 Summer Temperature Demand (Hot)	26,667	28,273	28,721	29,054
12	Projected Resource Margin (1-in-10)*	7.7%	2.1%	0.7%	-0.7%
13	MW needed/(Excess) to meet 7.0% Reserve in SP26	0	1,085	1,435	1,791
14	Surplus MW above 7.0% Reserve in SP26	153	0	0	0

[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel
[2] Values provided by CA ISO.
[3] 2004 CA ISO estimates **DC imports of 1,500 MW,** Path 26 2,700 MW, **SW imports 2,500 MW,** Dynamic 1,003 MW and CEC estimate of **LADWP imports of 1,000 MW**. 2005 estimate increases **DC transfer capability by 500 MW,** Path 26 by 300 MW and **North of Miguel by 400 MW.** Imports supplying own reserves are in bold text.
* Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Resource Margin. Calculated as ((Supply - **Imports with own reserves**)/(Demand - **Imports with own reserves**))-1

While the overall level of reserves would appear rosy, line 6, the "Zonal Transmission Limitation", is a significant problem. The level of planning reserves falls to 12.7% with this restriction included. Obviously, 12.7% is not an appropriate level of reserves with the assumption of a 7.6% hot weather load increase and possible forced outages of 6%.

The "Zonal Transmission Limitation" reflects transmission problems for power in NP-15 and Mexico entering SP-15. As such, normal planning standards would be to identify the level of imports and not to derate the total resources. As noted in footnote 2, this assumption has been taken from the California ISO.

The California ISO's own report also addresses the situation in SP-15. As is the practice with the ISO, it uses unique terminology and approaches not consistent with those used elsewhere, so it is difficult to interpret their calculations without careful review. The SP-15 analysis is contained in Attachment A to their report:[20]

[20] 2005 Summer Operations Assessment, California Independent System Operator, March 23, 2005, page 35.

SP26 Non-Coincident Peak Analysis - SCE and SDG&E Service Territories

		May-05 (MW)	Jun-05 (MW)	Jul-05 (MW)	Aug-05 (MW)	Sep-05 (MW)
1	Forecasted Peak Demand ("1-in-2" Forecast)	21,133	22,929	25,799	27,060	25,764
2	Minimum Operating Reserve Requirement ("1-in-2" Forecast)	980	1,101	1,293	1,379	1,291
3	SP26 Capacity Requirement ("1-in-2" Forecast)	22,113	24,030	27,092	28,459	27,055
	SP26 Generation Resources					
4	Maximum Net Dependable Capacity of Participating Thermal Units	16,889	16,889	16,889	16,889	16,889
5	Maximum Capacity of Non-Participating Thermal Units	3,924	3,924	3,924	3,924	3,924
6	Maximum Net Dependable Capacity of IOU Hydro	1,624	1,624	1,624	1,624	1,624
7	Maximum Net Dependable Capacity of MUNI	86	86	86	86	86
8	Maximum Capacity of Wind Resources	1,341	1,341	1,341	1,341	1,341
9	Accumulative Planned New Generation Capacity	458	458	1,092	1,092	1,226
10	Accumulative Retirements*	-	-	-	-	-
11	**Total SP26 Generation Resources**	**24,322**	**24,322**	**24,956**	**24,956**	**25,090**
	Estimated SP26 Generation Outages and De-Rates					
12	Participating Thermal Outages Scheduled	(2,209)	(36)	(51)	(58)	(16)
13	Participating Thermal Outages Forced	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)
14	Non-Participating Thermal Limitations	(442)	(442)	(942)	(942)	(1,424)
15	IOU Hydro Outages Scheduled	(26)	(26)	(26)	(26)	(346)
16	IOU Hydro Outages Forced	(375)	(375)	(375)	(375)	(375)
17	Muni De-rates	-	-	-	-	-
18	Estimated Wind De-rates	(1,287)	(1,287)	(1,287)	(1,287)	(1,287)
19	Estimated Transmission Limitations/Environmental Constraints (Stranded Generation)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)
20	**Total SP26 Outages and De-Rates**	**(7,439)**	**(5,266)**	**(5,781)**	**(5,788)**	**(6,548)**
21	**Estimated SP26 Resource Capacity (at time of peak)**	**16,883**	**19,056**	**19,175**	**19,168**	**18,542**
	SP26 Imports					
22	Estimated Net Dynamic	1,200	1,200	1,200	1,200	1,200
23	Estimated Unit Contingent	2,000	2,000	2,000	2,000	2,000
24	Other Expected Net Imports	6,500	6,500	6,500	6,500	6,500
25	**Net SP26 Area Interchange**	**9,700**	**9,700**	**9,700**	**9,700**	**9,700**
26	**Estimated SP26 Available Capacity**	**26,583**	**28,756**	**28,875**	**28,868**	**28,242**
27	Minimum Operating Reserve Requirement ("1-in-2" Forecast)	980	1,101	1,293	1,379	1,291
28	**Projected Reserve Margin ("1-in-2" Forecast) %**	**25.8%**	**25.4%**	**11.9%**	**6.6%**	**9.6%**
29	**Surplus/(Deficiency) after Imports ("1-in-2" Forecast)**	**4,469**	**4,726**	**1,783**	**409**	**1,187**
	"1-in-10" Forecast Scenario					
30	Forecasted Peak Demand ("1-in-10" Forecast)	22,694	24,623	27,704	29,080	27,667
31	Minimum Operating Reserve Requirement ("1-in-10" Forecast)	1,065	1,214	1,421	1,513	1,418
32	**Projected Reserve Margin ("1-in-10" Forecast) %**	**17.1%**	**16.8%**	**4.2%**	**-0.7%**	**2.1%**
33	**Surplus/(Deficiency) after Imports ("1-in-10" Forecast)**	**2,804**	**2,819**	**(260)**	**(1,725)**	**(644)**

The system peak analysis at the ISO resembles that of the CEC, but the organization is even more idiosyncratic. For August, the ISO lists 24,956 megawatts. In spite of industry practice to identify only useful capacity at system peak, the ISO then itemizes generation outages and derations from lines 12 through 18. The tricky part of this analysis is that they mix planned outages and derates with forced outages. Since derates and scheduled outages are known beforehand, it is industry practice to identify

these separately. The actual operating reserve is designed to protect the system against forced outages, so this would be treated as an issue to be addressed after the planning reserve had been determined. Although this is a question of accounting, it makes California ISO calculations unnecessarily challenging to compare with the rest of the electric industry.

The first step – determination of capacity – should have already have taken into consideration standard issues such as thermal constraints. The ISO's determination yields 22,643 megawatts of capacity available on a planning basis. The CEC lists 20,980 megawatts available within SP-15.

While the ISO assumes more capacity, they also have higher forced outages and transmission limitations. The forced outages assumed by the ISO are troubling. Since time immemorial, thermal systems in the WECC have used 7% as an operating reserve to meet the risk of forced outages.[21] The forced outages forecasted by the ISO are 1,975 megawatts across a resource base of 24, 956 megawatts – a forced outage of 7.9%. This is higher than the ISO's operating reserve percentage.

Taken in isolation, this implies that the ISO believes that the WECC standard for thermal system reserves is too low. As mentioned above, there are good reasons why the ISO has experienced apparent forced outages much higher than any other control area. However, even so, this assumption makes irrelevant the minimum operating reserve criterion adopted by the ISO and brings into question the ISO's filings with the WECC on reliability standards. Simply said, the ISO has assumed a level of forced outages that, in itself, would make their operating reserve criterion imprudent.

The ISO also assumes a much higher transmission limitation than the CEC. The ISO has not documented this assumption, so it is difficult to evaluate how important these limitations are likely to be. The CEC report mentions transmission constraints on contractual deliveries from Mexico. Logically, the ISO may still be viewing constraints on Path 15. Given both the CEC and ISO reports, it is clear that SP-15 should be viewed as an independent reliability sub-region and reported as such to the WECC.

After considering outages and transmission limitations, the ISO and CEC estimates are surprisingly close 18,980 megawatts for the CEC opposed to 19,168 megawatts for the ISO.

Imports into SP-15 are also undocumented in the ISO report. They so closely approximate the CEC value that it seems logical to address the CEC derivation as the basis for both values.[22]

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[21]Like many rules of thumb in the electric industry, this was selected on the basis of experience and has proved acceptable since it was adopted in the 1960s. For an "oral history" of this value, see Merrill Schultz's comments to the WECC as reported in California Energy Markets, March 11, 2005, page 5.

[22]The CEC assumes 9,903 megawatts while the ISO assumes 9,700 megawatts. Documentation for the 9,903 megawatts assumed by the CEC is found on page 12 of their report.

Table 7: SP26 Net Interchange

Path 26	3,000
Net of DC Line	2,000
Net SW Imports	2,900
Net Dynamics	1,003
Net LADWP Imports	1,000
Total	**9,903**

The final match for the two reports is very close:

	CEC	ISO
	(MWs)	(MWs)
Forecasted Peak Demand ("1-in-10" Forecast)	28,721	29,080
Planned Resources (Before Forced Outages)	30,083	30,843
Planning Reserve Margin	4.74%	6.06%
Operating Reserve Criterion	7.00%	7.00%

In sum, both agencies agree that operating reserves will be tight during the August peak on an operating level. The extremely high forced outages assumed by the ISO indicate a slightly more dour outcome.

SP-26 Net Interchange

The basic difference between traditional utility operations and those at the California ISO concerns the timing of the purchase of reserves. In any other control area in the WECC, this situation would call for a serious effort to contract for summer capacity. Depending on the various assumptions itemized above, the California ISO needs to raise the committed capacity imports between 500 to 1,000 megawatts above their current assumptions.

This is not a serious problem when the WECC is currently showing a capacity surplus of 49,749 megawatts for summer peak in 2005.[23] The Pacific Northwest has 27,722 megawatts and the Arizona New Mexico subregion has 7,074 megawatts.[24]

The constraint is not generation capacity, but it could possibly concern transmission capacity. Neither report addresses whether the lines into SP-15 will be a limiting factor in meeting the summer peak. The reference to the low hydroelectric conditions in the Pacific Northwest implies that both agencies feel that

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[23] 10-Year Coordinated Plan Summary, WECC, September 2004, page 28. Again, these estimates are made for "Adverse Hydro Conditions" as noted twice on this page.

[24] Ibid., pages 36 and 44. Again, these estimates are made for "Adverse Hydro Conditions" as noted four times on these two pages.

the problem lies in generation and not transmission.

The ISO report does contain a short table that summarizes transmission capability for the upcoming summer:[25]

Table VI-1
Major ISO Paths and OTC Limits, Summer 2004/2005

	2005 Summer OTC (MW)		*2004 Summer OTC (MW)*	
	North-to-South (MW)	South-to-North (MW)	North-to-South (MW)	South-to-North (MW)
Path 66 - California-Oregon Intertie (COI)	4,800	3,675	4,800	3,675
Pacific Direct Current Intertie (PDCI)	3,100	2,200	2,000	2,000
Path 26[21]	3,700	3,000	3,400	3,000
Path 15[22]	1,275	5,400	1,275	3,950
Path 45[23]	408	800	408	800
Southern California Import Transmission (SCIT)	14,500		13,700	

The CEC import assumptions list imports along the DC intertie from Oregon as only 2,000 megawatts – 1,100 megawatts less than the increased capacity. Total imports from the southwest are only 2,900 megawatts as compared to 14,500 megawatts of capacity.[26]

Nothing in either report indicates an engineering impediment to additional capacity imports.

The problem, as noted in the preface tot his review, is ideological. Both reports, rightly, fear that additional capacity might not be available on a one day notice.

This is highly possible. The ISO control area is unique in the WECC for its determination to provide capacity on a daily basis. Other systems make prudent advanced provisions for reliability. As a general rule, reserves must be contracted for elsewhere – not merely assumed.

Last minute purchases pose significant problems for neighboring systems. Fuel limited resources, in

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[25]2005 Summer Operations Assessment, California ISO, March 23, 2005, page 26.

[26]The ISO's SCIT estimate would also be required to accommodate "dynamic" resources to some degree. In either case, it seems unlikely that southwest imports would be blocked by transmission limitations.

particular, require advanced planning and notice. The hydroelectric resources in the Pacific Northwest will need to allocate scarce water to the highest value tasks – only one of which is energy production.

The engineering studies behind the construction of the nearly 8,000 megawatt interties between Oregon and California was based on the principle of harnessing regional diversity – the ability of the dams to store energy by reducing releases by the import of thermal energy in the spring and winter and the release of water during the summer. While not costless, this is a very efficient arrangement to optimize operations across regions with different peaking seasons and generation technologies.

Unfortunately, this level of optimization is not easily accomplished on the basis of a daily capacity market – and even less on the basis of emergency "out of market" purchases from the larger regional markets.

Policy Implications

There are three very simple policy implications from the review of recent California estimates of SP-15 capacity reserves for summer 2005:

1. When the lights go out, the ideology of restricting capacity import negotiations to daily sales may seem remarkably similar to a debate concerning the number of angels who can dance on the head of a pin. By anyone's standards the reliability situation in SP-15 is akin to driving ahead of one's headlights.

2. The ISO is now forecasting forced outages above the level of their operating reserves. If they believe their forecasts – which I suspect they do – they should change the minimum operating reserve criterion to preserve loads. At the moment the ISO is assuming two flats and only carrying one spare tire. They need to buy new tires or add a second spare.

3. If Path 15 is a serious reliability planning problem, the state of California should be reflected as two sub-regions, not one, in regional reliability planning. If the state quacks like two ducks, walks like two ducks, and looks like two ducks, it should be counted as two ducks.