Squeezing Scarcity From Abundance

Illustration by Alex Stephen

California's pursuit of a centralized administrative solution in reliability hinders everyday operational issues.

BY ROBERT MCCULLOUGH

In March and April of this year, three California government agencies, the California Public Utilities Commission (PUC), the California Energy Commission (CEC), and the California Independent System Operator (Cal-ISO), expressed concerns about possible blackouts in Southern California this summer[1]—almost inconceivable by any traditional utility planning standards for a region with capacity margins above 30 percent for summer 2005.[2]

Part of the problem reflects an error in planning—the continued treatment of California as a single region for planning purposes—but the larger issue 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 parties, and no one is actually in charge of a solution. It remains to be seen whether Gov. Schwarzenegger's plan to consolidate some functions of California's agencies within a new state Department of Energy will further complicate reliability planning or make it simpler.

The irony of the belief in better reliability through markets is that Cal-ISO's short-term purchases of system reserves could very well raise prices and reduce reliability.

The cost of substituting ideology for practical solutions often lands on consumers. Emergency declarations by Cal-ISO are costly for both the ISO and the neighboring systems across the Western Electricity Coordinating Council (WECC). Markets for reserves may work best if California would stop "driving ahead of its headlights" in procuring reserves.

When the ISO forecasts forced outages higher than its 7 percent operating-reserve criterion, either the outages must be addressed or the criterion increased. The lesson of the California crisis of 2000/2001 is that bad market design creates an incentive for higher outage rates.

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 generally used in the industry are simple and robust.

The first step is the load forecast. A capacity forecast is conservative by its very nature, assuming the highest possible requirements. In practice it assumes hot weather in the south and cold weather in the north. California's unique terminology for this practice is called the "1-in-10 Forecast" standard.[3] It is standard practice to maintain a planning reserve above the worst-case load forecast. In California, this is equal to using the "1-in-10 Forecast" as a minimum level of capacity and then adding additional reserves to cover other risks.

The second source of risk in electricity planning is equipment failure. Again, the general 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 for 40 years.[4,5] Planning reserves usually fall in the range of 10 to 15 percent. This splits into a 7 percent 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.

However, California is considerably more complex because it has three governmental institutions with responsibility for setting reliability standards: the PUC, the CEC, and the Cal-ISO.[6] Complicating the situation, the ISO serves only a portion of the state, and the PUC regulates only privately owned utilities. (The PUC will require a reserve margin of 15 to 17 percent in 2006 for the utilities under its jurisdiction.)

Although the Cal-ISO is deeply committed to a "time-on-target" policy where operational reserves are acquired on a daily basis, in practice this leaves it in the position of always driving too fast for its headlights. Its choice appears to be based on the assumption that reserves will always be available at the last moment. Despite 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 entirely clear where this concept originated.[7]

Cal-ISO's recent report states:

> 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 (MWh) 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 to 30 percent of average in the Oregon and Washington Cascades, to 70 percent in the upper Snake River area. British Columbia has faired somewhat better so far, reporting near average snow water equivalents.
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> "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 60 to 66 percent of average. By comparison, 2004 runoff at the Dalles was roughly 82 percent of average, while runoff during 2001's drought conditions was around 54 percent of average.[8]

While Cal-ISO was correct that forecasted flows for the summer of 2005 were significantly lower than average, the reality was not terribly bleak. The project capacity margin for the Pacific Northwest for summer 2005 was 54.9 percent—27,722 MW at system peak. As always, these calculations are made assuming drought conditions.[9] Since transmission limitations from Oregon to California reduced the potential supply of capacity to 7,700 MW, the likelihood that capacity availability in the Pacific Northwest would be scarce was slight.[10]

For the summer of 2005 at least, the availability of capacity imports was an institutional problem, not an engineering one. Cal-ISO calculated that assumed capacity would be unavailable on a daily basis.

Three Policy Implications

Three very simple policy implications are suggested from this 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 that can dance on the head of a pin. By anyone's standards, California's current approach to the reliability situation in SP-15 is akin to driving ahead of one's headlights.
2. The Cal-ISO is now forecasting forced outages above the level of its operating reserves. If it believes its own forecasts, then the minimum operating reserve criterion should be changed to preserve loads. At present, the Cal-ISO is like a driver who assumes two flats but only carries one spare tire; it should either buy new tires or add a second spare.
3. If Path 15 is a serious reliability planning problem, California's agencies should divide the state into two sub-regions for the purposes of reliability planning. By any standards, California has too many agencies in charge of reliability and too few regions for reliability to be addressed easily.

Going by the Numbers

The correct place to start is the WECC 10-Year Coordinated Plan, available at *www.wecc.biz*. The annual coordinated plans

Table 1 **WECC Estimated Peak Demands, Resources, and Reserves 2004-2013**

Source: WECC

	Summer Peak							Adverse Hydro Conditions		
Month	**2004** AUG	**2005** JUL	**2006** JUL	**2007** JUL	**2008** JUL	**2009** JUL	**2010** JUL	**2011** JUL	**2012** JUL	**2013** JUL
Loads – Firm	137,600	140,759	144,448	147,845	151,211	154,549	157,887	161,328	164,829	168,528
Int. & Load Mgt.	2,561	2,586	2,592	2,593	2,595	2,597	2,600	2,602	2,603	2,605
Total – MW	140,161	143,345	147,040	150,438	153,806	157,146	160,487	163,930	167,432	171,133
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	185,375	191,373	196,147	203,486	204,309	204,526	206,069	207,102	207,137	207,181
Maint./Inoperable Cap. – MW	3,782	3,741	3,950	3,505	3,490	3,490	3,505	3,492	3,490	3,408
Reserve Capability MW	43,993	46,873	49,749	52,136	49,608	46,677	42,282	38,818	35,245	
Percent or Firm Peak Demand	32.0	33.3	34.4	35.3	32.8	30.1	28.3	26.2	23.6	20.9

Table 2 **California-Mexico Power Area Estimated Peak Demands, Resources, and Reserves 2004-2013**

Source: WECC

Summer Peak **Adverse Hydro Conditions**

Month	**2004** AUG	**2005** AUG	**2006** AUG	**2007** AUG	**2008** AUG	**2009** AUG	**2010** AUG	**2011** AUG	**2012** AUG	**2013** AUG
Loads – Firm	53,121	54,195	55,372	56,537	57,739	58,948	60,182	61,433	62,695	63,982
Int. & Load Mgt.	1,760	1,760	1,760	1,760	1,760	1,760	1,760	1,760	1,760	1,760
Total – MW	54,881	55,955	57,132	58,297	59,499	60,708	61,942	63,193	64,455	65,742
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	61,858	63,870	65,931	66,408	66,396	67,665	69,046	70,446	71,860	73,302
Maint./Inoperable Cap. – MW	900	1,162	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104
Reserve Capability MW	7,777	8,513	9,395	8,707	7,493	7,553	7,700	7,849	8,001	8,156
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

are standard across North America. The basic methodology and structure have been consistent for more than 20 years. The aftermath of the price manipulations from May 2000 through June 2001 was a tremendous supply response, leaving the western United States and Canada with a massive surplus (*see Table 1*).[11]

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)*	17.30%	13.30%	12.20%	14.40%
11	1-in-10 Summer Temperature Demand (Hot)	58,667	61,003	61,885	60,937
12	Projected Resource Margin (1-in-10)*	7.90%	4.90%	3.30%	5.30%
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

Source: California Energy Commission

1 Dependable capacity by station includes 1,080 MW of stations located south of Miguel
2 Values provided by Cal-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 imorts 2,834 MW, IID imports 184 MW** and dynamic resources 1,000 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

According to current forecasts, the 2005 summer peak of the WECC left 33.3 percent of the region's capacity in reserve. This is 46,873 MW—approximately the entire worst case capacity load in the Cal-ISO control area this summer.[12]

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 (*see Table 2*).

The WECC forecasts for California showed a healthy situation for the state as a whole—15.7 percent reserves. However, at the request of the Cal-ISO, the derivation of the ISO's contribution to this forecast has been confidential since 2001.[13]

While the submission to the WECC is secret, both the CEC and the Cal-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 chart from the CEC appears on the bottom of p. 42.*) [14]

Comparing the official WECC tabulations with the tables from California requires care. The WECC began with total resources and then compared them with total load. The CEC complicated 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 MW of capacity resources and contracts. The CEC forecast 54,773 MW of capacity, 129 MW of new resources in August, and 12,921 MW of imports—a total of 67,823 MW—almost 4,000 MW in excess of the CEC forecast. The CEC then removed 3,500 MW of plant outages, which made the WECC and CEC numbers roughly comparable.[15]

Projected loads were 55,955 MW at the WECC and 57,913 MW at the CEC. Removing the forced outages from the planning reserve calculation produced a projected reserve margin of 15.7 percent—the same level as the WECC forecast.

California's forced outages have been quite high since restructuring. During the height of the market manipulation period, merchant plant thermal outages occasionally reached 50 percent. The assumed level of forced outages seemed high by comparison with recent years, but not implausible, given the incentives to withhold generation during periods when Cal-ISO may be forced to pay a premium for emergency purchases. We now 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 MW assumed here still appeared high by industry standards—approximately 6.4 percent of all resources. The reason was that the CEC staff added approximately 1,000 MW to its outage figures to be conservative.[16] Since outages are the reason for operating reserves, this assumption was not out of line with California's operating reserve margin of 7 percent.

Overall, the statewide CEC analysis matched the WECC analysis.

Source: WAPA

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)*	16.50%	13.50%	13.40%	14.80%
11	1-in-10 Summer Temperature Demand (Hot)	48,323	50,384	50,526	50,043
12	Projected Resource Margin (1-in-10)*	7.10%	4.40%	4.30%	5.50%
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 Cal-ISO
3 2004 Cal-ISO estimates **DC imports 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) 2,400 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

Source: California Energy Commission

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)*	18.50%	12.20%	10.50%	8.90%
11	1-in-10 Summer Temperature Demand (Hot)	26,667	28,273	28,721	29,054
12	Projected Resource Margin (1-in-10)*	7.70%	2.10%	0.70%	-0.70%
13	MW needed to meet 7% Reserve	0	1,085	1,435	1,791
14	Surplus MW above 7% Reserve	153	0	0	0

1 Dependable capacity by station includes 1,080 MW of stations located south of Miguel
2 Values provided by Cal-ISO
3 2004 Cal-ISO estimates **DC imports 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) 2,400 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

TABLE 3 — SP26 NON-COINCIDENT PEAK ANALYSIS – SCE AND SDG&E SERVICE TERRITORIES

1	Forecasted Peak Demand (“1-in2” Forecast)	21,133	22,929	25,799	27,080	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** **Estimated SP26 Generation outages and De-Rates**	**24,322**	**24,322**	**24,956**	**24,956**	**25,090**
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)	(375)
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 Requirment (“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)	1,085	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	2,918	(250)	(1,725)	(844)

Source: Cal-ISO SP-15 Analysis

The 15.7 percent planning reserve was sufficient to meet two major contingencies:

(1) a 6.86 percent higher load forecast during hot weather; and

(2) a 6.39 percent forced outage level.

The CEC study also addressed the ISO control area.[17] Over time, the control area effectively has shrunk to serving only 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 (*see the top chart on p. 43*).

The CEC's view of the Cal-ISO actually was more positive than its view for the state as a whole. The CEC predicted that the planning reserve margin for Cal-ISO alone in August was 18.7 percent.[18] As noted before, such a planning reserve should prove adequate for meeting a higher than normal hot weather load contingency—7.2 percent—and forced outages of 6 percent. The forecasts that forced outages would be lower for the ISO than the other areas of California were surprising, given historical experience, but the differential was not so extreme as to be significant.[19]

The problem turned out not to be the level of California reserves, or even the level of reserves at the 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 (*see bottom chart on p. 43*).[20]

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

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

Cal-ISO's own report also addressed the situation in SP-15, but its unique terminology and approaches are inconsistent with those used elsewhere, and made it difficult to interpret the ISO's calculations without careful review. The SP-15 analysis is contained in Attachment A to the report (*see table on p. 43*).[21]

The system peak analysis at the ISO resembled that of the CEC, but was even more idiosyncratic. The ISO listed total generation at 24,956 MW for August. In spite of industry practice that identifies only useful capacity at system peak, the ISO then itemized generation outages and derations from lines 12 through 18. Its analysis mixed planned outages and derates with forced outages. Since derates and scheduled outages are known beforehand, industry practice identifies 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 reserves are determined. Again, although this is a question of accounting, it always makes the comparison of Cal-ISO's calculations with the rest of the electric industry unnecessarily challenging.

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

While the ISO assumed more capacity, it also had higher forced outages and transmission limitations. Its assumed forced outages are troubling. Since time immemorial, thermal systems in the WECC have used 7 percent as an operating reserve to meet the risk of forced outages.[22] The forced outages forecast by the ISO were 1,975 MW across a resource base of 24,956 MW—a forced outage of 7.9 percent. This is higher than the official ISO's operating reserve percentage.

Taken in isolation, this implies that the ISO believed 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. Even so, this assumption makes the minimum operating reserve criterion adopted by the ISO irrelevant 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 by themselves would make their own operating reserve criterion imprudent.

The ISO also assumes a much higher transmission limitation than the CEC. The ISO did not document its assumption, so it was difficult to evaluate the likely importance of these limitations. The CEC report mentioned transmission constraints on contractual deliveries from Mexico. Logically, the ISO may still be viewing constraints on Path 15. Given both 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 were surprisingly close: 18,980 MW for the CEC and 19,168 MW for the ISO.

Table 4 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**

Source: California Energy Commission

The Cal-ISO report does not document imports into SP-15. They so closely approximated the CEC value that it was logical to address the CEC derivation as the basis for both values (*see Table 4*).[23]

	CEC (MWs)	ISO (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%

Source: CEC, Cal-ISO

The final match for the two reports is very close:

Both agencies agreed that operating reserves were tight during the August peak on an operating level. The extremely high forced outages assumed by the ISO indicated a slightly dourer outcome.

SP26 Net Interchange

The basic difference between traditional utility operations and those at Cal-ISO is the timing of reserve purchases. In any other WECC control area, this situation would call for a serious effort to contract for summer capacity. Depending on the various assumptions itemized above, the California ISO needed to raise the committed capacity imports between 500 to 1,000 MW above its current assumptions.

This was not a serious problem when the WECC showed a capacity surplus of 49,749 MW for summer peak in 2005.[24] The Pacific Northwest had 27,722 MW, and the Arizona New Mexico sub region had 7,074 MW.[25]

The constraint was not generation capacity, but it may have concerned transmission capacity. Neither report addressed whether the lines into SP-15 were a limiting factor in meeting the summer peak. The reference to the low hydroelectric conditions in the Pacific Northwest implied that both agencies believed that the problem lay in generation and not transmission.

The ISO report contained a short table that summarized transmission capability for the summer (*see Table 5*).[26]

The CEC import assumptions listed imports along the DC intertie from Oregon as only 2,000 MW—1,100 MW less than capacity. Total imports from the Southwest were only 2,900 MW, compared with 14,500 MW of capacity.[27]

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

The problem, as noted earlier, is ideological. Both reports, rightly, feared that additional capacity might not be available on a day's notice. Such a scenario was quite possible. The ISO control area is unique in the WECC for its determination to provide capacity on a daily basis. Other systems make prudent advance provisions for reliability. As a general rule, reserves must be contracted for—not merely assumed.

Last-minute purchases pose significant problems for neighboring systems. Fuel-limited resources in particular require advanced planning and notice. The hydroelectric resources in the Pacific Northwest 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 MW interties between Oregon and California were 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.

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TABLE 5 — MAJOR ISO PATHS AND OTC LIMITS, SUMMER 2004/2005

Source: Cal-ISO

	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	3,700	3,000	3,400	3,000
Path 15	1,275	5,400	1,275	3,950
Path 45	408	800	408	800
Southern California Import Transmission (SCIT)	14,500		13,700	

Endnotes

1. California Energy Action Plan, CPUC, March 23, 2005; 2005 Summer Operations Assessment, Cal-ISO, March 23, 2005; and Summer 2005 Electricity Supply and Demand Outlook, March 2005, CEC.
2. WECC 10-Year Coordinated Plan Summary, September 2004, Table 7, p. 28.
3. California's "1-in-2" forecast is an 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.
4. A good reference work on the standards for the western U.S. and Canada is in the Nov. 24, 2004, WECC Power Supply Assessment. See in particular Attachment 1, WECC Power Supply Assessment, Nov. 24, 2004, pp. 2-35.
5. The western U.S. and Canada, plus a small portion of northern Mexico, belong to the Western Energy Coordination Council, the body responsible for reliability planning for the region.
6. The California ISO is a unique institution with a board appointed by the governor, but largely exempt from open-meeting and open-document rules.
7. In reality, the California ISO could arrange operational reserves on any basis it deemed practical. While a change in purchasing methodology may require approval from the Federal Energy Regulatory Commission, it is unlikely that the timing of Cal-ISO's purchases is a controversial issue at FERC—or anywhere other than Cal-ISO.
8. 2005 Summer Assessment, Cal-ISO, p. 25.
9. 10-Year Coordinated Plan Summary, WECC, September 2004, p. 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 20 times.
10. Ibid., see p. 54.
11. Ibid., p. 28. Note the phrase, "Adverse Hydro Conditions" in the upper right corner of this table.
12. See Table II-1 of the Cal-ISO 2005 Summer Assessment, p. 5.
13. A continuing planning problem in California is the lack of transparency at Cal-ISO. These numbers, for example, are not normally secret for utilities elsewhere in the WECC.
14. Summer 2005 Electricity Supply and

(Cont. on p. 54)

TABLE 6 COMPARISON OF WEATHER FORECAST SERVICES FOR SUMMER 2003 AT CAL-ISO

Weather Service Average Absolute MW Error

Forecaster (11 a.m. DA Unless Marked)	July 10-Sept. 22	Aug. 15-Sept.22
NWS– AVN MOS	616	600
Commercial Forecaster A	730	671
Commercial Forecaster B	750	659
Commercial Forecaster B (7 a.m.)	784	745
Commercial Forecaster C	845	735
Commercial Forecaster D 7 a.m.	846	832
NWS – MRF MOS	846	857
Commercial Forecaster E	922	895
NWS – ETA MOS	922	955
Commercial Forecaster F	971	875
Commercial Forecaster G	1,135	1,187
Commercial Forecaster H	2,535	2,289
Commercial Forecaster I	3,397	3,497

costs over a year. In addition, extreme weather events can occur, as they do in most regions of the United States, and this often occurs during very high cost periods. Managing weather and load forecast error both of a small nature and for those larger events is very cost-effective. How cost-effective depends on the individual power system, weather phenomena, the load, and modeling tools used.

Given that load imbalances and congestion accumulate significant costs in competitive power markets, more and more attention will be devoted to benchmarking the errors and finding more advanced solutions to reduce their magnitude. Clearly, more accurate weather forecasting can make a significant improvement in load forecasting, as well as reduction of costs.

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Endnote

1. NOAA, The Northeast Energy Network Performance Analysis Report: Final Report (August 2003); NOAA, The Use of 30 Year Climate Forecasts To Improve Regional Long-Range Energy Infrastructure Planning for San Diego County); NOAA, The Economic Benefits of Incorporating Weather and Climate Forecasts into Western Energy Production Management.

* The work by Dennis Gaushell (*www.consultingforenergy.com*) was performed for the California ISO. The authors acknowledge the contribution of L. Heitkemper of EarthSat, Jan Dutton of AWS, and Alexander Gershanov of the Scripps Institution of Oceanography.

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Demand Outlook, March 2005, p. 4.

15. Since the ISO submission is unavailable, 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.
16. Summer 2005 Electricity Supply and Demand Outlook, CEC, March 2005, pp. 10-11.
17. Summer 2005 Electricity Supply and Demand Outlook, CEC, March 2005, p. 5.
18. 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.
19. As noted above, the complex structure of the Cal-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.
20. Summer 2005 Electricity Supply and Demand Outlook, CEC, March 2005, p. 7.
21. 2005 Summer Operations Assessment, California Independent System Operator, March 23, 2005, p. 35.
22. Like many rules of thumb in the electric industry, this was selected on the basis of experience and has proven 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, p. 5.
23. The CEC's report assumed 9,903 MW while the ISO assumed 9,700 MW. Documentation for the 9,903 MW assumed by the CEC is on p. 12.
24. 10-Year Coordinated Plan Summary, WECC, September 2004, p. 28. Again, these estimates are made for "Adverse Hydro Conditions" as noted twice on this page.
25. Ibid., pp. 36 and 44. Again, these estimates are made for "Adverse Hydro Conditions" as noted four times on these two pages.
26. 2005 Summer Operations Assessment, California ISO, March 23, 2005, p. 26.
27. 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.

Correction: On p. 60 of the June 2005 issue, in Table 3 accompanying the article *"CEO Pay Reflects Strong Stock Performance in 2004"* by Edward Metz of SNL Energy, Otter Tail Corp. CEO John D. Erickson's total compensation was overstated. Erickson would not have appeared in this table had John D. Erickson's compensation been correctly stated. Additionally, Entergy CEO J. Wayne Leonard did not exercise any stock options in 2004 and should not have appeared in Table 1. SNL Energy regrets the error and any confusion this may have caused.