Memorandum

To: RCI Policy Working Group

From: Kenji Takahashi, Jennifer Kallay

Date: 8/15/07

Re: Results Based on Alternative Scenarios and Minor Adjustments

RCI-1

Alternative Scenario: 5-year Ramp In

The fact that the record on sustained DSM savings of 1% per year is thin does not mean that it is not attainable. States have only begun to push the limits on energy efficiency beyond past experience. See the Table 1 for energy conservation plans by a number of utilities or states.

Table 1. Plans for Cumulative Energy Reductions through DSM

Jurisdiction or Entity	Savings Target	Source
New Jersey	20 percent by 2020	Governor's *Economic Growth Strategy* 2007
California	16 percent by 2013	CPUC 2004 Goals Order (calculated)
New York	15 percent by 2015	Governor's *Clean Energy Plan* 2007
Sacramento Municipal Utility District (CA)	15 percent by 2017	Data provided by SMUD
Austin Energy (TX)	15 percent by 2020	*2003 Strategic Plan*
SDG&E	13 percent by 2013	*2004 Long-Term Resource Plan*[1]
Puget Sound Energy (WA)	12 percent by 2013	*2005 Least Cost Plan*[1]
Pacific Gas & Electric Co. (CA)	12 percent by 2013	*2004 Long Term Procurement Plan*[1]

While there is no doubt that we cannot solve climate change problems without aggressive efficiency programs, we note that projections based on limited experience with over 1% annual savings attainment over the mid to long term (>3 years) have additional uncertainty associated with them. Also, the utilities that have achieved 1% per year have long-term experience with DSM program administration and significant budget levels. Colorado utilities may need more

[1]As reported in LBNL 2006, *Energy Efficiency in Western Utility Resource Plans.*

time and experience to attain 1% per year energy savings. This is especially likely to be the case for rural cooperatives or municipal utilities with no existing DSM programs. Moreover, consumers are more likely to accept higher rates and/or charges to fund aggressive DSM programs if the level of DSM and the associated increase in rates/charges are ramped in over a number of years.

In response to these concerns, a different scenario was created, and the emission and cost impacts of that scenario were estimated. The alternative scenario assumes a 5 year ramp-in period to reach 1% (0.1% in 2008, 0.2% in 2009, 0.4% in 2010, 0.6% in 2011, and 0.8% in 2012) for both electric and gas utilities. The scenario, shown in Table 2, yields about 41 MMT CO2e savings (about 9 MMT CO2e less than the original scenario), $1320 million economic benefits (instead of $1620 million benefits), and -$31.9/tCO2 saved cost-effectiveness (instead of -$32.29/tCO2 saved). The original scenario is shown in Table 3.

Table 2. RCI-1, Summary Results from the 5 Year Ramp-in Scenario

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI – 1 Total	1.43	7.53	41.4	$711		($2,030)	($1,320)	($32)
Electric DSM	1.03	5.41	29.8	$526	$16 /MWh	($1,177)	($651)	($22)
Gas DSM	0.40	2.12	11.6	$185	$0.84 /MMBtu	($853)	($668)	($58)

Table 3. RCI-1, Summary Results from the Original Scenario (3 Year Ramp-in)

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI – 1 Total	2.23	8.33	50.1	$871		($2,489)	($1,617)	($32)
Electric DSM	1.61	5.98	36.1	$645	$16 /MWh	($1,444)	($799)	($22)
Gas DSM	0.62	2.34	13.9	$226	$0.86 /MMBtu	($1,044)	($818)	($59)

RCI-5

Adjustments

The original result was based on energy savings using avoided electricity at the customer level and assuming increasing price elasticity. The summary result originally presented at the CAP meeting on August 1 is presented in Table 4.

Table 4. RCI-5 Results, As Presented on August 1

	GHG Reductions ($MMtCO_2e$)			Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020		
RCI - 5	4.9	17.1	102.5	($2,916)	($28)

We have corrected the original assumptions by (1) accounting for energy savings based on avoided electricity at the generation level and (2) calculating the decrease in energy consumption due to the surcharge based on short-term price elasticity only.

Table 5 presents results with an adjustment made to the avoided cost electricity cost (Adjustment 1).

Table 5. RCI-5, Summary Results based on Adjustments on Avoided Generation Cost

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI-5 total	5.47	18.96	113.9	$1,777	$12.40 /MWh	($5,501)	($3,724)	($33)
Inverted Block Rate	1.33	3.94	23.8	$0	$0 /MWh	($1,179)	($1,179)	($50)
EE Program	4.15	15.03	90.1	$1,777	$15.63 /MWh	($4,322)	($2,546)	($28)

With respect to adjustment (2), the long-term price elasticity accounts for customers' investment in infrastructure (including efficient appliances and building envelope). Because RCI-5 also involves funding efficiency program(s), part of which would be customers' long-term response to higher electric prices, we modeled the short term impact of the surcharge using the short-term elasticity, separately from the long-term impact, which is accounted for by the energy efficiency measures.

The following table shows the results from both adjustments. The major difference is the level of savings in energy and GHG emissions by the inverted block rate and energy efficiency programs. Adjustment 2 (Table 6) resulted in much less savings from the inverted block rate than the results of Adjustment 1 (Table 5), because lower elasticity means higher electric consumption, which in turn results in more funding for new energy efficiency programs.

Table 6. RCI-5, Summary Results based on Adjustments on Price Elasticity and Avoided Generation Cost

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI-5 total	4.95	18.34	109.5	$1,979	$14.36 /MWh	($5,255)	($3,276)	($30)
Inverted Block Rate	0.74	1.10	8.6	$0	$0 /MWh	($441)	($441)	($51)
EE Program	4.21	17.24	100.8	$1,979	$15.55 /MWh	($4,814)	($2,835)	($28)

The original elasticity numbers are shown in the following table. The new elasticity is only based on the first year price elasticity.

Table 7. RCI-5, Price Elasticity Assumptions

	First Year	Second Year	Third Year	Long Term
Residential	-0.29	-0.34	-0.49	-0.49
Commercial	-0.17	-0.2	-0.45	-0.45

Alternative Scenario: Higher Thresholds

Finally we would like to present results for RCI-5 based on an alternative scenario that changes the baseline energy consumption (i.e., the threshold) above which electric rates are raised. The original scenario is based on Architecture 2030 targets as follows:

Table 8. RCI-5, Original Scenario Based on Architecture 2030

Year	Architecture 2030 Target
2010	60%
2015	70%
2020	80%

Architecture 2030 calls for energy reduction in new and renovated commercial buildings according to these targets. As discussed at the August 1 CAP meeting, RCI-5 currently uses these targets in a different context, i.e., setting the threshold or baseline energy consumption for electric residential and commercial customers using these targets. For example, 60% means that the threshold is set at 40% of the average energy consumption for residential or commercial customers.

The alternative scenario is set at higher threshold as follows:

Table 9. RCI-5, Alternative Scenario

Year	Target
2010	30%
2015	35%
2020	40%

These thresholds are based on recent investor owned utility (IOU) experience with inverted block rates in California. The California Public Utilities Commission requires IOUs to establish inverted block rates for residential customers. In this rate structure, the baseline consumption or the threshold that covers basic needs of residential customers are set higher than those originally set for RCI-5 (based on Architecture 2030). The baseline consumption allocation typically covers 60-70% of the average residential energy use in each region.[2]

Using the new threshold assumptions resulted in significantly lower energy and emission savings, as shown in the two tables.

Table 10. RCI-5, Summary Results based on the Alternative Baseline Consumption

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI-5 total	1.57	6.67	38.2	$690	$14.34 /MWh	($1,825)	($1,135)	($30)
Inverted Block Rate	0.24	0.31	2.9	$0	$0 /MWh	($146)	($146)	($51)
EE Program	1.33	6.37	35.4	$690	$15.47 /MWh	($1,680)	($989)	($28)

[2] SCE. Residential Baseline Allocation, available at http://www.sce.com/NR/rdonlyres/DF137120-E263-459E-96F4-0B4F4BA60520/0/597R0906ResidentialBaseline.pdf

Table 11. RCI-5 Summary Results based on Original Thresholds, with Adjustments on Price Elasticity and Avoided Generation Cost (same as Table 6)

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI-5 total	4.95	18.34	109.5	$1,979	$14.36 /MWh	($5,255)	($3,276)	($30)
Inverted Block Rate	0.74	1.10	8.6	$0	$0 /MWh	($441)	($441)	($51)
EE Program	4.21	17.24	100.8	$1,979	$15.55 /MWh	($4,814)	($2,835)	($28)

RCI – 6

The analysis was presented at the last meeting using a capital recovery factor based on an interest rate of 8% assumed for the commercial and industrial sectors. However, after further consideration, an interest rate of 4.5% is more reasonable for state loans. The table below provides the changes in the results that would occur if this recommendation was implemented.

Table 12. RCI-6, Summary Results based on Adjustment to Interest Rate

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/t$CO_2$e)
	2012	2020	Total 2007-2020					
RCI – 6 w/ 8% Interest Rate	0.5	1.8	11.7	$218	$2.87/MMBtu	($518)	($300)	($26)
RCI – 6 w/ 4.5% Interest Rate	0.5	1.8	11.7	$184	$2.42/MMBtu	($518)	($334)	($28)

RCI-7

Some adjustments were made to the analysis of RCI-7 to (1) account for energy savings based on avoided electricity at the generation level instead of at the customer level and (2) correct the double counting of the program cost. The original analysis assumed both the cost of metering and the $25/MWh cost of saved energy that is assumed for most of DSM programs.

Below are the original results before the adjustments.

Table 14. RCI-7 Results, As Presented on August 1

	GHG Reductions ($MMtCO_2e$)			Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020		
RCI - 7	1.8	2.3	23.3	($256)	($11)

The new results are shown in the following table.

Table 13. RCI-7, Summary Results based on Adjustments

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI-7 total	2.02	2.58	25.4	$347	$10.95 /MWh	($1,191)	($844)	($33)

RCI-9

Some minor adjustments were made to the analysis of RCI-9 to (1) account for energy savings based on avoided electricity at the generation level instead of at the customer level, (2) replace the avoided fuel oil cost assumption from $11.2/mmBtu (a placeholder) to $12.5/mmBtu, and (3) use a smoother ramp-in of annual CHP installation. $11.2/mmBtu was based on the cost of fuel oil for electric generator taken from AEO 2007 forecast for the Mountain region. $12.5/mmBtu is the simple average of commercial and industrial fuel oil prices taken from AEO 2007 forecast for the Mountain region.

Table 15. RCI-9 Results, As Presented on August 1

	GHG Reductions ($MMtCO_2e$)			Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020		
RCI - 9	0.9	2.7	18.2	$67	$4

Table 16. RCI-9, Summary Results based on Adjustments

	GHG Reductions ($MMtCO_2e$)			Gross Cost (Million $)	Gross Cost per Unit of Energy Saved	Gross Benefits (Million $)	Net Present Value 2007–2020 (Million $)	Cost-Effectiveness ($/tCO2e)
	2012	2020	Total 2007-2020					
RCI-9 total	0.68	2.74	16.6	$1,458	$30.46 mmBtu	($1,507)	($49)	($3)

In response to concerns by some working group members, we are presenting some additional information on economic potential. The analysis of RCI-9 assumes that 30 percent of the technical potential identified by the Western Governors' Association (WGA)[3] is the achievable economic potential of CHP in Colorado, adjusted upward for electric consumption growth in the commercial and industrial sectors. This 30 percent assumption draws on the findings of a number of CHP economic potential studies. For example, thirty percent is consistent with the ratios of

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[3] WGA 2006. Combined Heat and Power White Paper to the Clean and Diversified Energy Initiative of the Western Governors Association, January 2006, available at www.westgov.org/wga/initiatives/cdeac/CHP-full.pdf

economic to technical potential for the Pacific Northwest under an accelerated case, and well below the ratio identified for Alaska (93 percent) (See Table 17).[4]

Table 17. Economic Potential of CHP in Pacific Northwest under Two Scenarios

	AK	ID	OR	WA
Economic Potential Business as Usual				
50-500 kW	101	9	6	11
500 -1000 kW	117	0	36	90
1 - 5 MW	139	0	23	61
5 -20 MW	149	0	120	110
20 -50 MW	0	5	147	270
> 50 MW	410	63	53	189
Total	916	76	384	731
Economic Potential as a Fraction of Technical Potential	82%	5%	8%	9%
Economic Potential Accelerated Case				
50-500 kW	144	43	212	399
500 -1000 kW	160	53	417	678
1 - 5 MW	167	92	320	539
5 -20 MW	166	96	524	358
20 -50 MW	0	16	233	429
> 50 MW	410	127	124	444
Total	1,046	427	1,831	2,847
Economic Potential as a Fraction of Technical Potential	93%	26%	36%	37%

Economic potential is often estimated for different scenarios, based on numerous factors including, but not limited to:

- Economic payback period,
- Electric and fuel (natural gas) prices,
- CHP incentive (e.g., state and federal incentives including investment and production tax credit),
- CHP related policies (e.g., net metering law)
- Standby charge (e.g., accelerated cases tend to have lower standby charges),
- Current or advanced CHP technology, and
- Market response (e.g., development of capacity market)
- Market acceptance, which is often adjusted for other external factors such as ability to retrofit, owner interest and awareness in CHP, capital availability, natural gas availability, and interconnection standards.

[4] EEA 2004. Combined Heat and Power in the Pacific Northwest: Market Assessment: Task 1 - Final Report, submitted to Oak Ridge National Laboratory, August 2004

Some factors affect the relevance of historical economic potential studies to future projections of potential. These include:

- Economic potential studies rarely estimate the potential for mechanical drive applications or for uses of thermal energy other than steam or hot water (e.g., the use of absorption chillers and desiccant dehumidification systems) due to difficulties with analyzing application of these technologies. Therefore, most studies tend to underestimate the potential in this regard.
- Increased natural gas prices have a significant negative effect on economic potential. CHP studies that are even a couple of years old might not take into account recent increases in the price of natural gas. However, at the same time, electric prices are increasing due to price increases in natural gas fuels and power plant equipment. Therefore, the spark spread (e.g. electricity price vs. natural gas price) may not have changed.
- The advanced scenario in the economic studies assume widespread use of only those advanced technologies that currently exist or will be developed in the near future. However, we may develop more efficient technologies in a decade.
- A new era of policymaking may provide clean energy with higher incentives than before. For example, the creation of a nation-wide Renewable or Energy Efficiency Portfolio Standard that includes CHP, or the development of a carbon cap & trade system or carbon tax, will increase the economics of CHP and therefore the economic potential of CHP.[5] These new policies are not likely to have been modeled in recent CHP economic potential studies.

[5] H.R. 3221: New Direction for Energy Independence, National Security, and Consumer Protection Act, passed the House on August 4 this year, would establish a national RPS (15% by 2020) which allows for 4% of the requirement to be satisfied with electricity efficiency measures, including CHP. See http://www.rules.house.gov/amendment_details.aspx?NewsID=2840 Also, the bill would establish a Waste Energy Recovery Incentive Grant Program within EPA that provides incentive payments of $10 per MWh for CHP. See http://thomas.loc.gov/cgi-bin/query/F?c110:2:./temp/~c110bC27he:e893603: