

Decision 07-09-043 September 20, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine
the Commission's post-2005 Energy
Efficiency Policies, Programs, Evaluation,
Measurement and Verification, and
Related Issues.

Rulemaking 06-04-010
(Filed April 13, 2006)

**INTERIM OPINION ON PHASE 1 ISSUES:
SHAREHOLDER RISK/REWARD INCENTIVE MECHANISM
FOR ENERGY EFFICIENCY PROGRAMS**

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**INTERIM OPINION ON PHASE 1 ISSUES:
SHAREHOLDER RISK/REWARD INCENTIVE MECHANISM
FOR ENERGY EFFICIENCY PROGRAMS**

1. Introduction and Summary¹

Energy efficiency is the best choice for meeting the energy needs of California's citizens and its economy, while protecting the environment. Producing "nega-watts," "nega-watt hours" and "nega-therms" of energy by using limited energy supplies more efficiently is smart business, smart for California's ratepayers and the least-cost way to address climate change. Today we adopt a risk/reward incentive mechanism designed to extend California's commitment to making energy efficiency the highest energy resource priority. This action builds upon Assembly Bill 32, the Low Carbon Fuel Standard and other initiatives that California has taken to aggressively reduce greenhouse gases (GHG).² It also reinforces our commitment to ensuring that overall per capita electricity consumption in California holds steady, and declines in the future for the investor-owned utilities we regulate.

By aligning shareholder and consumer interests through today's adopted incentive mechanism, we create a "win-win" regulatory framework for energy efficiency – one that provides both a meaningful level of shareholder earnings and an estimated return *of over 100%* on ratepayers' investment in energy

¹ Attachment 1 describes the abbreviations and acronyms used in this decision.

² Assembly Bill 32 (Stats. 2006, ch. 488) requires that statewide GHG emissions be reduced to 1990 emission levels by 2020. On January 18, 2007, Governor Schwarzenegger established the Low Carbon Fuel Standard by Executive Order S-01-07. This standard will be implemented as an "early action measure" under Assembly Bill 32 to reduce the carbon intensity of all transportation fuels in California.

efficiency as the utilities reach towards and exceed our 2006-2008 energy savings goals.³ This return represents the substantial cost savings created by displacing more expensive supply-side alternatives with energy efficiency, resulting in lower utility revenue requirements and lower customer bills.

If our savings goals for 2006-2008 are met, we estimate that energy efficiency will create \$2.7 billion in *net ratepayer benefits* (resource savings minus investment costs), enabling California to avoid the equivalent of three giant (500 megawatt) power plants over the current three-year program cycle. In addition, the cumulative energy savings will reduce global warming pollution by an estimated 3.4 million tons of carbon dioxide in 2008, equivalent to taking about 650,000 cars off the road.⁴

Success in achieving the benefits of energy efficiency requires a sustained, long-term commitment to energy efficiency on the part of the utilities we regulate. To achieve this commitment, we recognize what the Energy Action Plan⁵ and past Commission decisions have duly noted: There is an inherent utility bias towards supply-side procurement under cost-of-service regulation, namely, that investor-owned utilities can generate earnings for shareholders

³ We use the term “the utilities” to refer collectively to the utility respondents in this rulemaking: Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company and Southern California Gas Company.

⁴ D.05-09-043, *mimeo.*, p. 3.

⁵ California’s principal energy agencies, including this Commission, joined to create the Energy Action Plan in 2003. This plan identifies specific goals and actions to ensure that adequate, reliable and reasonably-priced electrical power and natural gas supplies are achieved and provided through cost-effective and environmentally sound strategies. A copy of the Energy Action Plan is posted on the Commission’s website at <http://www.cpuc.ca.gov/static/energy/electric/energy+action+plan/index.htm>.

when they invest in “steel-in-the-ground” supply-side resources, but not when the utilities are successful in procuring cost-effective energy efficiency.

Ensuring sustained and successful commitment to energy efficiency is best accomplished by moving away from a cost-of-service compliance regulatory framework, to one that will create a “win-win” alignment of shareholder and ratepayer interests. Today’s decision creates incentives of sufficient level to ensure that utility investors and managers view energy efficiency as a core part of the utility’s regulated operations that can generate meaningful earnings for its shareholders. At the same time our adopted incentive mechanism protects ratepayers’ financial investment, ensures that program savings are real and verified, and imposes penalties for substandard performance.

We achieve this alignment of shareholder and ratepayer interests, in the following ways:

- The level of potential earnings under the adopted incentive mechanism represents a meaningful opportunity to earn for utility shareholders based on consideration of supply-side comparability and other factors.
- However, earnings to shareholders accrue only when utility portfolio managers produce positive net benefits (savings minus costs) for ratepayers.
- These earnings begin to accrue only as the utilities reach to meet and surpass the Commission’s kWh, kW and therm savings goals.
- Earnings are greatest when savings performance is superior, not just “expected.”
- All calculations of the net benefits and kW, kWh and therm achievements are independently verified by the Commission’s Energy Division and its evaluation, measurement and verification (EM&V) contractors, based on adopted EM&V protocols.

- Ratepayers receive the vast majority of economic benefits, since they pay for all the energy efficiency portfolio costs.
- The shareholder “reward” side of the incentive mechanism is balanced by the risk of financial penalties for substandard performance in achieving the Commission’s per kW, kWh and therm savings goals.
- Ratepayers are protected against financial losses on their investment in energy efficiency. If portfolio costs exceed the verified savings from that portfolio, shareholders are obligated to pay ratepayers back dollar-for-dollar for those negative net benefits.
- The overall level of potential earnings and penalties is capped in a manner that symmetrically limits both ratepayers’ and shareholders’ exposure to risks, while still encouraging superior performance.

Figure 1 illustrates the risk/reward incentive mechanism we adopt today. As this figure shows, earnings begin to accrue at a 9% sharing rate if the utility meets 85% of the Commission’s savings goals. If portfolio performance achieves 100% of the goals, the earnings rate increases from 9% to 12%. Each earnings rate is a “shared-savings” percentage. This means, for example, if the combined utilities achieve 100% of the 2006-2008 savings goals and the verified net benefits (resource savings minus total portfolio costs) at that level of performance is \$2.7 billion, then \$2.4 billion (88%) of those net benefits goes to ratepayers and \$323 million (12%) goes to utility shareholders.⁶

⁶ We fund energy efficiency programs over a three-year funding cycle, also referred to as a three-year “program cycle.” We also establish annual and cumulative savings goals for each program cycle. Earnings and penalties are based on cumulative achievements.

If utility portfolio performance falls to 65% of the savings goals or lower, then financial penalties begin to accrue. There are two penalty provisions, and the greater of the two applies when savings fall to (or below) the 65% threshold. The “per unit” penalties are 5¢ per kilowatt-hour (kWh), 45¢ per therm and \$25 per kilowatt (kW) for each unit below the savings goal.⁷ The “cost-effectiveness guarantee” obligates shareholders to pay ratepayers back dollar-for-dollar for negative net benefits.

Applying these penalty provisions to the current 2006-2008 utility portfolios results in estimated penalties on the order of \$144 million for all utilities combined, if performance falls to 65% of the goals. Estimated penalties increase to \$238.5 million when performance falls to 50% of the goals. Below 50% of goals, penalties associated with the cost-effectiveness guarantee are expected to become larger than the per-unit penalties. At that point, ratepayers will receive dollar-for-dollar reimbursement for negative net benefits under the cost-effectiveness guarantee.

As shown in Figure 1, there are no earnings or penalties within the “deadband” range of performance, i.e., greater than 65% and less than 85% of goal achievement. In order to provide reasonable limits to the risks and rewards under the incentive mechanism, penalties and earnings are capped at \$450 million (all four utilities combined) for each three-year program cycle.

⁷ As discussed in Section 5.2, we adopt this level of per-unit penalties for energy efficiency to be consistent with the penalty levels we have established under the Renewables Portfolio Standard program.

Table 1 presents the potential shareholder earnings and penalties at various levels of portfolio performance for all four utilities combined, based on the 2006-2008 savings goals and portfolio costs.⁸ Table 1 also presents the level of net benefits that accrue to ratepayers (their “return on investment”) at each level of performance, after accounting for shareholder earnings or penalties. All amounts are in pre-tax dollars.

⁸ See Attachment 8 for a breakdown of potential earnings and penalties (and caps) by utility.

Figure 1: Adopted Incentive Mechanism Earnings/Penalty Curve

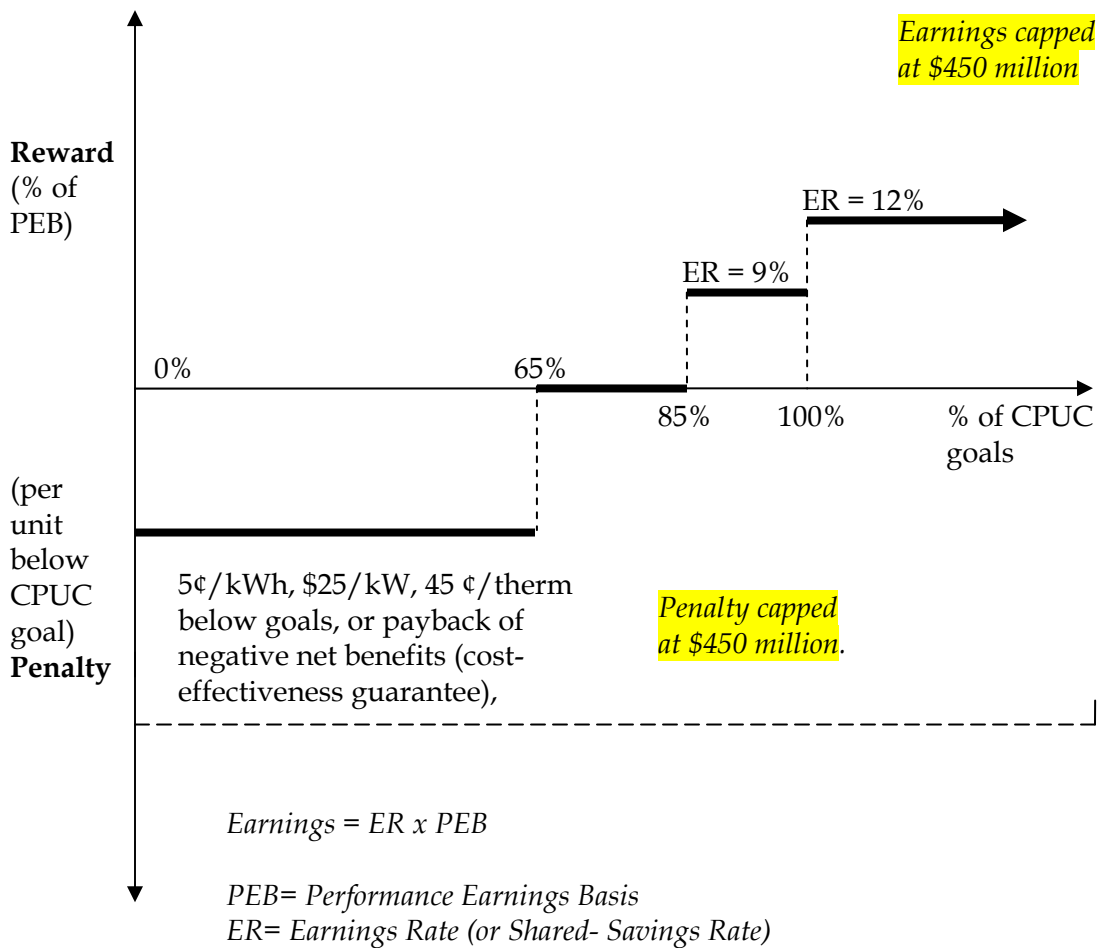


TABLE 1

**Ratepayer and Shareholder “Share” of Verified Net Benefits
Under Adopted Shareholder Risk/Reward Incentive Mechanism
(Based on 2006-2008 Portfolio Costs and Savings Goals)**

Verified Savings % of Goals	Total Verified Net Benefits	Shareholder Earnings	Ratepayers' Savings
125%	\$3,919	\$450 cap	\$3,469
120%	\$3,673	\$441	\$3,232
115%	\$3,427	\$411	\$3,016
110%	\$3,181	\$382	\$2,799
105%	\$2,935	\$352	\$2,583
100%	\$2,689	\$323	\$2,366
95%	\$2,443	\$220	\$2,223
90%	\$2,197	\$198	\$1,999
85%	\$1,951	\$176	\$1,775
80%	\$1,705	\$0	\$1,705
75%	\$1,459	\$0	\$1,459
70%	\$1,213	\$0	\$1,213
65%	\$967	(\$144)	\$1,111
60%	\$721	(\$168)	\$889
55%	\$475	(\$199)	\$674
50%	\$228	(\$239)	\$467
45%	(\$18)	(\$276)	\$258
40%	(\$264)	(\$378)	\$114
35%	(\$510)	(\$450) cap	(\$60)

As indicated above, potential earnings for the 2006-2008 program cycle start at \$176 million if all four utilities achieve the minimum performance threshold of 85%, which in turn would deliver approximately \$1.9 billion in net benefits. That is, if the utilities *actually produce net benefits of \$1.9 billion* (based on verified costs and resource savings) when they reach 85% of the savings goals, then their shareholders will receive \$175 million of those net benefits under the shared-savings structure we adopt today. The vast majority of the net benefits--\$1.775 billion--goes to ratepayers.

The level of potential earnings to shareholders increases to \$323 million (for all utilities combined) at 100% achievement of the Commission's 2006-2008 savings goals, if and only if the corresponding net benefits of \$2.7 billion are actually realized. If the utilities' performance is superior, whereby they exceed the goals by a significant margin, the earnings for their shareholders increase up to a maximum of \$450 million, provided that the utilities produce the corresponding \$3.9 billion in net benefits at that maximum.

As described in today's decision, the sizable net benefits produced by energy efficiency – even after earnings are paid out – will more than offset the short-term rate and bill impacts associated with recovering those earnings in rates.

Some parties to this proceeding argue that because shareholders do not put up their capital to finance energy efficiency, and therefore do not incur the associated financial risks, it would not be “fair” to ratepayers to award more than minimal shareholder earnings under the risk/reward incentive mechanism. This perspective ignores the performance risks imposed by the penalty provisions of the incentive mechanism, which are far from minimal, as well as

the inherent biases that exist in favor of supply-side resources to the detriment of achieving our energy efficiency objectives.

More importantly, in considering what is fair to ratepayers, we observe that ratepayers “invest” in both supply-side and energy efficiency resources, irrespective of who puts up the initial capital. The only difference is that for steel-in-the-ground investments (generation, transmission, distribution) ratepayers have to pay not only the cost of the facilities, but also the financing costs (debt service, return-on-equity, and associated taxes) to compensate those that put up the initial capital. In contrast, since energy efficiency expenditures are expensed and reflected in rates immediately, energy efficiency saves ratepayers substantial financing costs. Those cost savings are magnified because a dollar of energy efficiency can displace far more than a dollar of supply-side investment to meet the same amount of kWh, kW and therm energy needs.

The magnitude of these cost savings produces a staggering potential return on investment for ratepayers. As discussed in today’s decision, for the 2006-2008 program cycle alone, the \$2.2 billion in energy efficiency investments is projected to produce over *\$2.7 billion in net benefits* (resource benefits minus portfolio costs). This benefit is only a “potential” return on ratepayers’ investment because realizing it requires portfolio management that must be more innovative, aggressive and motivated to “mine deeper” for cost-effective energy savings than ever before in California’s history.

What is fair to ratepayers? We believe that it is to make sure that this large return on their investment, the kW, kWh and therm savings goals and the large reductions in GHG emissions, are actually realized with the funds authorized. By aligning shareholder and ratepayer interests, today’s adopted incentive mechanism serves to ensure this result. In doing so, this mechanism *produces a*

*return in excess of 100% on ratepayers' investment in energy efficiency as the utilities achieve and surpass our 2006-2008 savings goals.*⁹

By today's decision, we also establish the earnings claim and recovery process: There will be two interim claims during each three-year program cycle that are "progress payments" towards total expected earnings, and one final true-up claim after the program cycle is completed. We hold back 30% of the expected earnings in each interim claim to provide a margin for error in expected earnings.¹⁰ Authorized earnings will continue to be recovered in electric distribution and gas transportation rates, pursuant to D.98-03-063.¹¹

Each earnings claim will be based on the savings and net benefits verified in Energy Division's interim and final EM&V reports, and each claim will be submitted via compliance Advice Letter by the utilities. We establish procedures that provide numerous opportunities for the utilities and interested parties to participate, both procedurally and substantively, in the development of the draft and final EM&V reports prepared by Energy Division and its EM&V contractors. We do not restrict the final true-up process, as some parties propose. Ratepayers

⁹ See Table 1 above: If 100% of the goals are achieved, the ratepayer share of net benefits is \$2.366 billion, which is 107.5% of the \$2.2 billion in ratepayer investment. At higher levels of performance, the return (net benefits) associated with the same level of portfolio investment will increase.

¹⁰ As discussed in this decision, we also permit the utilities to book any amounts of the progress payments that might need to be paid back to ratepayers at the final true-up claim, despite this hold-back amount, against a claim for positive earnings in the next program cycle.

¹¹ Changes to Commission rate recovery and cost allocation procedures are beyond the scope of Phase 1, as we discuss in Section 12 below. However, we encourage the Assigned Commissioner, in consultation with Energy Division staff, to consider how

Footnote continued on next page

will only be required to share net benefits with shareholders to the extent that those net benefits actually materialize, based on Energy Division's EM&V results.

In addition, today we resolve two issues related to how energy efficiency cost-effectiveness calculations will be performed. First, we direct that the costs of shareholder incentives be included both when evaluating the cost-effectiveness of program plans submitted during the program planning cycle, as well as when conducting a cost-effectiveness review of portfolio performance in hindsight. Second, we clarify how the "free rider" adjustment should be applied to the cost side of the equation in conducting cost-effectiveness evaluations or in calculating the net benefits to be shared under the adopted incentive mechanism.¹²

Finally, we establish a schedule for revisiting today's adopted risk/reward incentive mechanism, after we have gained experience with implementation. We direct Energy Division to prepare an evaluation report for Commission consideration by February 1, 2011. This will enable us to consider any recommended modifications to the incentive mechanism in time for the 2012-2014 program cycle. More generally, in a concurrent phase of this proceeding we have embarked on a state-wide, strategic planning effort for our

cost allocation issues may be raised for Commission consideration in the future, in the appropriate procedural forum and with proper notice to all interested parties.

¹² In the context of energy efficiency, "free riders" are those program participants who would have undertaken the energy efficiency activity in the absence of the program. We adjust program savings to remove the effect of free riders because their participation would have happened anyway, and therefore the savings associated with their actions cannot be considered a benefit of the program. Today we clarify that participant costs should also be adjusted to account for free riders, unless those costs represent program expenditures (utility revenue requirements).

utility energy efficiency programs. This effort focuses on developing long-term programs and saving goals that extend beyond our three-year planning cycles. Today's decision, combined with our long-term planning efforts, lays a strong foundation for making energy efficiency an integral part of "business as usual" in California.

2. Procedural Background

On April 13, 2006, we opened this rulemaking to further develop the regulatory framework for energy efficiency activities administered by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas). Today's decision marks the final step in implementing our post-2005 regulatory framework for the procurement of energy efficiency by investor-owned utilities. Less than ten years ago, when utilities were removed from the role of energy portfolio managers during electric industry restructuring, energy procurement and rates became vulnerable to market abuses and factors beyond California's control. Since 2002, with the support of state legislation, we restored the utilities to their traditional energy procurement responsibilities: To procure least-cost, environmentally sensitive energy resources on behalf of their customers.

Those actions were coupled with a renewed commitment to energy efficiency, placing it "first in the loading order" for utility energy procurement.¹³

¹³ *Energy Action Plan* (2003), page 4: "The Action Plan envisions a "loading order" of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases electricity and natural gas demand." See also D.04-01-050 in R.01-10-024, *mimeo.* at p. 9, referencing the Energy Action Plan and

Footnote continued on next page

We have already taken several steps to ensure that this policy becomes a reality in California. In our predecessor energy efficiency Rulemaking (R.) 01-08-028, we established the savings goals, policy rules, evaluation, measurement and verification protocols and administrative structure to guide the post-2005 energy efficiency programs funded by the ratepayers of these utilities.¹⁴ In D.05-09-043, we committed \$2.2 billion in ratepayer funds to procure energy efficiency savings during 2006-2008. In doing so, we identified the development of a shareholder risk/reward incentive mechanism as the next priority for energy efficiency.¹⁵

Assigned Commissioner Dian M. Grueneich and assigned Administrative Law Judge (ALJ) Meg Gottstein held a prehearing conference in this rulemaking on May 9, 2006 in San Francisco. On May 24, Commissioner Grueneich issued a detailed scoping ruling for the multiple phases of this rulemaking, identifying Phase 1 as the forum for addressing the design and implementation of a shareholder risk/reward incentive mechanism.¹⁶ Parties were directed to meet and confer informally on Phase 1 issues prior to workshops, and to submit

stating the Commission's policy preference that "resource adequacy be met first through cost-effective energy efficiency programs, other cost-effective demand reduction programs, and cost-effective renewable resources." See also pp. 53-54, 96 and 100-101 in that decision.

¹⁴ See D.04-09-060, D.05-01-055 and D.05-04-051 in R.01-08-028.

¹⁵ D. 05-09-043, *mimeo.* p. 153; See also Conclusion of Law 163 and Ordering Paragraph 22. We use the terms "risk/reward incentive mechanism," "risk/return incentive mechanism," "shareholder incentive mechanism" and "incentive mechanism" interchangeably in today's decision.

¹⁶ See *Assigned Commissioner's Ruling and Scoping Memo and Notice of Phase 1 Workshops*, May 24, 2006.

pre-workshop written comments by June 16, 2006 with preliminary proposals for an incentive mechanism. With respect to the need for evidentiary hearings, Commissioner Grueneich made a preliminary determination that hearings would not be required to resolve disputed issues in Phase 1. However, she indicated that she would make a final determination on this matter at the completion of the workshop process.¹⁷

Pre-workshop comments were filed by the utilities, the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), the Natural Resources Defense Council (NRDC) and the Community Environmental Council (CE Council).

Four days of workshops on Phase 1 issues were held on June 26-28 and July 18, 2006 in San Francisco, California, facilitated by the assigned ALJ with assistance from the Commission's Division of Strategic Planning. Other than Commission staff, approximately 35 individuals representing 12 different organizations participated at one or more days of the workshop. At the final workshop session, Commissioner Grueneich indicated to the workshop participants that evidentiary hearings would not be held on Phase 1 issues. This determination was memorialized in a July 20, 2006 Assigned Commissioner's ruling.¹⁸ The ruling provided direction to the parties for the preparation of their written post-workshop comments and the development of joint summary documents of final recommendations.

¹⁷ *Ibid.*, p. 23.

¹⁸ *Assigned Commissioner's Ruling Determining No Need for Evidentiary Hearings and Establishing Procedural Schedule for Phase 1 Issues*, July 20, 2006, p. 1.

Post-workshop comments and final proposals were filed on September 8, 2006 by the utilities, DRA, TURN, NRDC and CE Council. The joint summary documents were filed on September 15, 2006. The utilities, DRA, TURN and NRDC filed reply comments on September 29, 2006. On November 22, 2006, TURN filed a correction to its reply comments. On February 23, 2007, the assigned ALJ requested further comment on TURN's correction as well as additional scenarios from the utilities for their calculations of supply-side comparable earnings. The utilities, TURN, NRDC and DRA filed comments on these issues during March 2007. PG&E and SDG&E/SoCalGas filed corrections to their submitted calculations on March 28, 2007 and April 20, 2007, respectively.

On March 13, 2007, TURN, NRDC and DRA jointly supplemented their post-workshop comments on their proposed penalty rates, at the direction of the assigned ALJ. The utilities filed responses on March 21, 2007.¹⁹ On April 23, 2007, the utilities, TURN, NRDC and DRA provided further comment on proposed procedures for the review and approval of interim and final earnings claims, as requested by the Assigned Commissioner.²⁰ Reply comments were filed by NRDC, DRA, TURN, PG&E and jointly by SDG&E and SoCalGas on May 4, 2007.

By ruling dated March 26, 2007, the Assigned Commissioner determined that evidentiary hearings were needed to address disputed factual issues related

¹⁹ See *Administrative Law Judge's Ruling Memorializing Electronic Rulings on Phase 1 Requests for Information and Changes to Submittal Dates*, March 13, 2007.

²⁰ See *Assigned Commissioner's Ruling Soliciting Further Comment on Procedures For Review and Approval of Interim and Final Earnings Claims*, April 3, 2007.

to the establishment of the shared-savings rate(s) under the risk/reward incentive mechanism. Opening and reply testimony was submitted by the utilities, DRA, TURN, NRDC and California Large Energy Consumers Association (CLECA). Four days of evidentiary hearings were held on May 29 through June 1, 2007, with over 70 exhibits received into evidence.

Opening briefs were filed on June 18, 2007 by DRA, TURN, NRDC, CE Council, CLECA, the utilities and Women's Energy Matters (WEM).²¹ Reply briefs were filed on June 27, 2007 by DRA, TURN, NRDC and the utilities.

3. Scope of Phase 1 and Definitions of Incentive Design Parameters

As outlined in the Assigned Commissioner's May 24, 2006 Scoping Ruling, the purpose of Phase 1 is to develop a shareholder risk/reward incentive mechanism for energy efficiency "consistent with the policy rules, performance basis and associated updating/true-up determinations adopted in [R.] 01-08-028

²¹ WEM's filing goes beyond not only the Assigned Commissioner's Ruling dated March 26, 2007, which clearly defined the issues that were to be included in the hearing and addressed in the brief, but also beyond the Assigned Commissioner's Ruling and Scoping Memo, which delineated the issues to be addressed in the risk/reward incentive mechanism. Instead of addressing the factual or methodological issues for establishing a relevant benchmark for shared-savings, WEM argues against adopting any amount of shareholder incentives for energy efficiency in this proceeding. (*WEM Comments on Shareholder Incentives*, June 18, 2007, pp. 1-4.) WEM also argues for third party administrators, a proposal that has been decided in prior decisions and is not the subject of this proceeding. (p. 2.) Instead of referencing any of the extensive record in this Phase of the proceeding, WEM presents excerpts from its questioning of witnesses during evidentiary hearings in R.06-02-013, as well as from a recent newspaper article, in support of its position. (*Ibid.*, pp. 5-7.) We reiterate our previous admonition that "WEM is not new to the complex Commission proceedings and should have been able to present...its views on the issues being address." (D.07-65-012, May 3, 2007 at fn. 7 and D.07-05-012 at fn.7.) For these reasons, we find that WEM's pleading is beyond the scope of this proceeding and do not address it any further in today's decision.

and related proceedings.”²² The ruling recognizes that we have already addressed certain threshold incentive design issues for energy efficiency, and therefore excludes these issues from the scope of this proceeding. In particular, in D.05-04-051 we directed that energy efficiency performance should be evaluated based on overall portfolio achievements, rather than on the performance of each individual program. We also determined what metric will be used to establish a dollar value for energy efficiency performance, which we refer to as the “performance earnings basis” or “PEB.” We adopted a PEB that represents the net benefits to ratepayers (resource benefits minus costs) from their investment in energy efficiency.

More specifically, to calculate the PEB, the energy savings (kW, kWh and therm reductions) are assigned a dollar value that reflects Commission-adopted avoided costs, that is, the supply-side generation, transmission, distribution and environmental costs avoided by those reductions in demand.²³ As discussed in Section 8 below, these savings levels are verified based on EM&V activities undertaken by the Commission staff and their consultants. When valued at

²² *Assigned Commissioner’s Ruling and Scoping Memo and Notice of Phase 1 Workshops*, May 24, 2006, p. 3. We use the term “energy efficiency” to refer to non-low income energy efficiency activities authorized by this Commission, except where otherwise indicated. Low-income energy efficiency programs are funded separately from non-low income energy efficiency programs, and are subject to a separate performance-adder incentive mechanism. As discussed in the ruling referenced above, we do not address that mechanism in today’s decision. For a description of the current performance adder mechanism for these low-income programs, see D.05-10-041, Attachment 3.

²³ The methodology and values established for energy efficiency avoided costs were most recently addressed in the 2006 update of avoided costs, in Rulemaking 04-04-025. See D.06-06-063.

avoided costs, these verified savings become the “resource benefits” used in the PEB calculation.

The costs of implementing the energy efficiency portfolio are then subtracted from the resource benefits to yield the “net benefits” value for the PEB. Positive net benefits accrue only when the portfolio is cost-effective, that is, when resource benefits are greater than costs. Conversely, negative net benefits accrue when the portfolio costs are greater than the resource benefits.²⁴ We refer to “net benefits” and “performance earnings basis” or “PEB” interchangeably in this decision.

By defining the PEB in this manner, we established that shareholder earnings would represent some percentage (“earnings rate” or “shared-savings rate”) of the net benefits achieved by the energy efficiency portfolio. We also directed that before any of these earnings would accrue, the portfolio must achieve a minimum threshold of gigawatt-hour (GWh), megawatt (MW) and million therm (MTherm) savings tied to the achievement of the Commission’s savings goals for energy efficiency. We left it to this phase of the proceeding to establish the level of this threshold, referred to as the “minimum performance standard” or “MPS”.²⁵ These design parameters are incorporated into parties’ proposals, as discussed further below.

²⁴ See Section 10 below for further description of the adopted PEB metric, which is actually a weighted average of two cost-effectiveness tests. For the Commission’s determination on PEB-related issues, see D.05-04-051, *mimeo.*, pp. 38-43, 60-64. See also *Administrative Law Judge’s Ruling on EM&V Protocol Issues*, September 2, 2005 in R.01-08-028, pp. 2-6, 14-15.

²⁵ D.05-04-051, p. 43.

By today's decision, we address the remaining design and implementation issues associated with a risk/reward incentive mechanism for energy efficiency, which primarily involves defining the parameters of the earnings/penalty "curve," as follows:

1. What is the *minimum performance standard or "MPS,"* that is, what *minimum threshold of performance* must the energy efficiency programs achieve before any shareholder earnings will accrue?
2. If the MPS is not achieved, what will trigger penalties and what **penalty rate(s)** will then apply?
3. Once the MPS is achieved, what will be *the earnings rate(s),* that is, *what percentage of the PEB* will accrue to shareholders? The earnings rate(s) are also referred to as the *shared-savings* or *sharing* rate(s).
4. Will there be *caps* on the absolute level of earnings or penalties and, if so, at what level(s)?
5. *What program activities will count* towards the MPS and towards the PEB of the mechanism?
6. What will be *the earnings claim and recovery process,* as well as the precise *linkage of incentive payout to EM&V results?*

These and other design and implementation issues are within the scope of Phase 1, and addressed in today's decision. We also address two issues that were identified in the scoping of Phase 1 to further clarify how cost-effectiveness calculations should be performed. (See Section 10.)

Consistent with the Commission's direction in D.05-04-051, all parties presented proposals for a risk/reward incentive mechanism that result in a sharing of net benefits between shareholders and ratepayers once the portfolio achieves a minimum level of savings relative to the savings goals. Moreover, all parties recommend that the sharing rate (also referred to as the "earnings" or "shared-savings" rate in today's decision) be tiered so that the percentage of net

benefits going to shareholders will increase with higher and higher levels of achievement relative to those savings goals. They also presented proposals for penalty provisions under the incentive mechanism. However, parties strongly disagree on a number of specific design parameters that define the earnings/penalty curve.

Attachments 2 through 4 summarize the positions of the parties on incentive design and implementation issues and the level of potential earnings and penalties under each incentive proposal. In the sections that follow, we refer to these attachments in describing the range of positions on each issue before discussing the reasoning behind our determinations. As usual in such proceedings, the record is voluminous. We concentrate on the chief points of contention, rather than summarizing every nuance in individual positions.

4. Minimum Performance Standard (MPS)

The MPS is the minimum level of savings that utilities must achieve relative to their savings goal before accruing any earnings, and is expressed as a percentage of that savings goal. Graphically, the MPS is illustrated in the figures presented in Attachment 4 as the point along the “x” axis where the earnings/penalty curve becomes positive. For example, in Figure 2 of that attachment under PG&E’s proposal, earnings would not begin to accrue until the portfolio achieves 80% of the savings goal.

Since the Commission establishes individual goals for MW, GWh and MTherm savings, there is more than one option for determining when the MPS is reached. Parties propose for our consideration three different approaches to establishing the MPS, and present recommendations for the MPS level that range from 70% to 100% of the savings goal(s). These differences are described below.

4.1. Proposals for Establishing the MPS

SCE recommends that the MPS be established by averaging the achievements (relative to goals) across the savings goals metrics that are applicable to each utility. For example, if the MTherm savings achieved by the portfolio represent 75% of the MTherm goal, the GWh savings represent 85% of the GWh goal and the MW savings represent 80% of the MW goal, then the simple average of these percentages (75 + 85 + 80 divided by 3 = 80) would meet the 80% MPS proposed by SCE.

DRA, TURN and NRDC propose that the MPS threshold apply to each GWh, MW and MTherm savings metric individually. This means, if the portfolio fails to achieve the MPS level (e.g., 85% of the goal) for any one of these savings metrics, then the utility is not eligible for any earnings on the portfolio achievements. NRDC recommends an MPS of 85%, DRA recommends an MPS of 90% and TURN recommends an MPS of 100% for each savings metric.

PG&E, SDG&E/SoCalGas and CE Council propose a hybrid approach, whereby the MPS would be met by averaging the GWh, MTherm and MW achievements, but each individual savings metric would be subject to a minimum floor. More specifically, PG&E and SDG&E/SoCalGas recommend that the MPS be set at 80% based on an average of the percentage of goal achieved by each savings metric, as long as no single metric falls below 70% of its goal. Under the numerical example presented above, this MPS would be met because each individual savings metric meets the minimum floor of 70% of its goal and the simple average of the percent-of-goal achieved by each metric equals 80%. In addition, SDG&E/SoCalGas recommend a variation for SoCalGas since, by definition, as a gas-only utility it cannot average across two or more savings metric to meet the MPS. Under this variation, the MPS for

SoCalGas alone would be set at the 70% floor established above for each individual savings metric.

CE Council supports the hybrid approach, but recommends that the MPS be set at 100% for the average minimum threshold, with the individual floors set at 90% for each savings metric.

4.2. Discussion

In our view, the MPS approach proposed by DRA, NRDC and TURN sets up an “all-or-nothing” trigger for allowing *any* earnings that relies too heavily on specific numerical values. Under this approach, just missing one of these values by a small amount could mean that the utilities forfeit the potential for any earnings on the portfolio, even if that portfolio produces sizable net benefits to ratepayers and achieves or surpasses the savings goals for one or more of the other metrics. Consider a situation where the utility achieves 110% of both the MW and GWh goals and 84.5% of the MTherm goal. Under NRDC’s proposed MPS of 85%, these results would receive no incentives at all, despite the substantial net dollar benefits to ratepayers, the achievement of electric savings that exceed the portfolio forecast, and therm savings that “just miss” the MPS threshold. This is not a reasonable outcome, in our view.

Moreover, the possibility of missing the MPS by falling short on one metric by a small margin is also likely to motivate utility administrators in ways that do not make sense from the standpoint of optimizing portfolio performance. PG&E points out that the actions of the marketplace may be difficult to predict, especially several years in advance. Under the approach proposed by DRA, TURN and NRDC, if the utility were behind on one savings goal, but well over for the other goal(s) due to unanticipated market interest, the utility would have to focus extensive, and potentially expensive attention on one component while

reducing attention (and probably funding) for the highly successful and probably more cost-effective components that the market desires.²⁶

Incentive design should try to avoid creating such “pressure points” for determining whether the utilities are eligible for any earnings at all. At the same time, we agree with NRDC and others that the simple average approach proposed by SCE would allow a utility to earn rewards even if it is doing a poor job in achieving one or more of the individual savings goals. DRA points out in a numerical example how there are tradeoffs between maximizing the net benefits of the portfolio and achieving each one of the individual savings goals.²⁷ As a result, an MPS based on simple averaging could result in the utility becoming eligible for earnings, even if it has unacceptably under-performed in one or more areas.

The hybrid approach recommended by PG&E, SDG&E/SoCalGas and CE Council presents us with an option that both provides the utility with some flexibility in achieving the MPS (through averaging) and yet ensures that poor performance is not rewarded by establishing individual floors for each savings metric. The result is a framework that motivates superior performance while

²⁶ *PG&E Reply Comments on Energy Efficiency Shareholder Risk/Reward Incentive Mechanism*, September 29, 2006, p. 12.

²⁷ *DRA Proposed Risk/Return Shareholder Incentive Mechanism for Energy Efficiency Portfolios*, September 8, 2006, pp. 16-17. However, we do not concur with DRA’s conclusion that any averaging of goals in establishing the MPS is undesirable because it will encourage the utilities to *not* meet 100% of each goal. DRA reaches this conclusion without considering other aspects of the incentive mechanism, in particular, the tiered earnings rates that would increase potential shareholder earnings as the utility achieves savings at and beyond the goals.

reducing unnecessary pressure points. Therefore, we will adopt this approach in establishing the MPS for the risk/reward incentive mechanism.

This brings us to the issue of the level of the overall MPS, that is, the percentage of the goals (on average) that must be achieved before earnings begin to accrue to shareholders. In addressing the level of the MPS, some parties argue that the utilities will have little difficulty in achieving the Commission-adopted savings goals, and therefore the MPS should be set at 100% of the goals (TURN, CE Council) or relatively close to them, e.g., within 10% (DRA). The utilities, on the other hand, argue there is considerable uncertainty associated with forecasting program participation and associated load impacts, and therefore the MPS should reflect this uncertainty by being set no less than 20% below the savings goals.

The savings goals established by D.04-09-060 are aggressive, yet achievable. As we noted in that decision, the goals reflect the expectation that 55% to 59% of the utilities' incremental electric energy needs between 2004 and 2013 will be met through energy efficiency. Our adopted goals for natural gas energy efficiency represent a 116% increase in expected savings over the next decade, relative to the status quo.

While we concluded in D.04-09-060 that these goals are achievable, we do not agree with CE Council that they "shouldn't be particularly difficult to meet."²⁸ Moreover, we do not agree with the conclusion reached by TURN that because the utility portfolio plans are designed to meet the Commission's cumulative goals, the utilities should not be eligible for financial incentives until

²⁸ *Revised Post-Workshop Comments on a Proposed Risk/Reward Incentive Mechanism by the CE Council, September 14, 2006, p. 10.*

they exceed those goals.²⁹ There are significant unknowns at the time of portfolio and program planning with respect to how the market will respond and the level of load impacts that will be achieved on an *ex post* (post-installation) basis even under this “expected case” of portfolio performance. As a result, as the utilities work with their expanded number of energy efficiency partners and receive market feedback and EM&V evaluation results, they must quickly and efficiently incorporate new information into their program designs and aggressively pursue all potential avenues for cost-effective energy efficiency throughout the program cycle. The challenges that utilities face in achieving the savings goals should be recognized in the adopted MPS threshold.

Therefore, in establishing the MPS, we recognize that the Commission’s aggressive goals for energy efficiency will require utility program managers to be proactive and innovative to meet them, especially in face of the inherent uncertainties discussed above. At the same time, we want to give appropriate weight to the individual goals themselves in establishing a minimum level of performance before any earnings will accrue.

In our judgment, a MPS of 85% coupled with individual floors of 80% for each savings metric will accomplish our objectives. This provides a buffer for uncertainty around the individual goals of 20% and a buffer of 15% around the average of the GWh, MW and MTherm goals. While utilities argue for a wider buffer and some parties argue for less of one, today’s adopted MPS represents a reasonable compromise among the competing positions and meets our

²⁹ *TURN’s Post-Workshop Comments on the Design of an Energy Efficiency Shareholder Incentive Mechanism*, September 8, 2006, p. 15. See also *DRA Proposed Risk/Return Shareholder Incentive Mechanism for Energy Efficiency*, September 8, 2006, p. 6.

objectives. Moreover, it recognizes that the utilities' success in achieving 85% to 100% of the savings goals creates a substantial return on ratepayers' investment, even after shareholder earnings are paid. As discussed in Section 6.3.4, ratepayers will earn an estimated \$1.775 billion over and above their 2006-2008 energy efficiency investment if the utilities achieve 85% of the savings goals under today's adopted incentive mechanism. That return will continue to increase if the utilities reach beyond the MPS to meet and surpass the 2006-2008 savings goals. (See Attachment 8.)

As a gas-only utility, SoCalGas is subject to a single goal (for MTherm savings), and therefore will not be able to average across two or more individual savings goals to demonstrate achievement of the MPS. Therefore, SoCalGas will have less flexibility than the other utilities in meeting an average MPS of 85%. In order to treat all utilities consistently with respect to a minimum threshold of performance, we agree with SDG&E/SoCalGas that the MPS for SoCalGas should be established at the level of the individual floors we have adopted for the other three utilities.

In sum, to be eligible for earnings, PG&E, SDG&E and SCE must (1) achieve a minimum of 85% of the savings goals, based on a simple average of the percentage of each individual GWh, MW and (as applicable) MTherm goal they achieve, *and also* (2) meet a minimum of 80% of the goal for each individual savings metric. SoCalGas will be eligible for earnings if it achieves a minimum of 80% of the savings goal that applies to a gas-only utility, namely the MTherm goal.

PG&E raises the issue of what "numbers" should be used to establish the MPS level, that is, the Commission-adopted savings goals or the compliance filing targets submitted by the utilities at the start of the program cycle. As

discussed in Section 8.3 below, we will use the Commission-adopted goals to evaluate utility performance in our adopted risk/reward incentive mechanism.

5. Penalty Provisions and Deadband Range

The earnings/penalties curve includes a “deadband” where neither earnings nor penalties accrue. The MPS defines one end of this deadband, and the trigger for penalties defines the other end. Parties present two conceptual approaches for establishing the penalty trigger. In the next section we discuss these approaches to establishing the penalty trigger and associated deadband range, before addressing the penalty levels.

5.1. Penalty Trigger

The utilities propose that penalties be triggered when the net benefits from the portfolio become negative ($PEB < 0$).³⁰ This approach is referred to as the “cost-effectiveness guarantee,” and requires that utilities pay back any negative net benefits to ratepayers, dollar-for-dollar, up to the cost of the energy efficiency portfolio.

NRDC, TURN, and DRA recommend that penalties be triggered when achieved savings fall below a certain percentage of the Commissions goals, even if that occurs when portfolio net benefits are positive. Penalties would be

³⁰ There is a difference among the utilities on how the cost-effectiveness guarantee translates into their proposals for the bottom end of the deadband range, however. Under its earnings/penalty curve proposal, PG&E specifies the penalty trigger (bottom of the deadband range) as 40% percentage of savings goals, at which point the cost-effectiveness guarantee takes effect. The other utilities define the bottom of the deadband range as whenever negative net benefits start, irrespective of the percentage of goals achieved. Therefore, under PG&E’s penalty proposal there could be negative net benefits, but no penalty provisions, if the utility achieves 40% or more of the savings goals.

assessed on a per unit (kW, kWh and therm) basis, for each unit below the savings goal. NRDC and DRA would combine this approach with the cost-effectiveness guarantee so that penalties would begin to accrue when *either* $PEB < 0$ *or* the savings achieved fall below a certain percentage of the savings goal. The two types of penalties would be additive under their proposals.³¹

As indicated in Attachment 2, negative net benefits under the cost-effectiveness guarantee are generally expected to start when performance falls to 40%-50% of the savings goals. The utilities argue that as long as net benefits are positive to ratepayers, ratepayers are earning a positive return on their investment in energy efficiency, and therefore it is not reasonable to impose any other type of financial penalties on the utilities. They also point out that the Commission adopted this approach for the penalty provisions under the pre-1998 shared-savings mechanism.

We agree with the utilities, NRDC and DRA that ratepayers should be protected against the risk of portfolio losses in the form of negative net benefits, and therefore adopt a cost-effectiveness guarantee provision under today's adopted incentive mechanism. However, we do not agree with the utilities that paying back negative net benefits to ratepayers is a sufficient penalty mechanism in the context of this Commission's current resource planning and procurement priorities. Today, more than any other time in our history, we are relying on

³¹ CE Council proposes a fixed dollar penalty of \$135 (for all utilities combined) if savings falls to any level below 50% of the Commission's goals. (See Attachment 2). However, CE does not present a basis for establishing this structure to penalty provisions, or even indicate how the \$135 million in penalties should be allocated among the individual utilities. Hence, we cannot evaluate this proposal in any meaningful way, and do not discuss it any further in today's decision.

energy efficiency to produce a significant level of savings through ratepayer-funded energy efficiency programs. Establishing explicit savings goals represents a departure from our development of a shared-savings incentive mechanism prior to electric restructuring and the energy crisis in California. In the early 1990s, as we sought to revitalize energy efficiency in utility resource planning, we focused on maximizing the net resource benefits from ratepayer-funded energy efficiency and tied the MPS, the penalty provisions and the earnings rate to that single parameter. Unlike today, we did not combine the objective of maximizing energy efficiency net benefits with that of achieving and exceeding specific MW, GWh or therm energy efficiency savings levels.

Therefore, in the context of today's dual objectives for energy efficiency, it is reasonable to combine a portfolio cost-effectiveness guarantee with per-unit penalty provisions that start when the utilities miss savings goals at a level of performance below the MPS. This ensures that each end of the deadband, where penalties and rewards are triggered, is structured to reflect the performance objectives discussed above. Moreover, since 2003 we have introduced penalty provisions in other areas of resource procurement that apply if the utility fails to meet specific procurement targets or obligations.

In particular, in our Renewable Portfolio Standard proceeding, we instituted a penalty of 5¢/kWh for a utility failing to meet annual Renewable Portfolio Standard procurement targets.³² We have also adopted penalty provisions in our local and system resource adequacy proceedings tied to the

³² See D.03-06-071, pp. 50-51.

performance objectives for those procurements.³³ Adopting penalty provisions tied to the accomplishment of energy efficiency savings goals is consistent with this direction.

In terms of how far below the MPS these penalties should begin, TURN, NRDC and DRA each propose a 15% deadband range for the individual savings metrics under their recommended earnings/penalty curve.³⁴ Applying a comparable 15% deadband range to our adopted minimum floors for each metric (of 80%) yields a penalty trigger at 65% of the individual savings goals. This trigger level is reasonable for the reasons discussed below.

In designing a risk/reward incentive mechanism, we seek to impose financial penalties when savings performance is substandard. At the same time, there may be significant net benefits created by the energy efficiency portfolio even when it does perform below the MPS. While some parties argue for a per-unit penalty trigger above 65%, and others for one below 65%, in our judgment, a trigger at 65% of the savings goals strikes the appropriate balance among these competing considerations.³⁵

The risk of incurring penalties should be one that the utility can reasonably be expected to manage. The utilities have argued in this proceeding that

³³ See D.06-06-064 at pp. 66-67, and D.05-10-042 at p. 94.

³⁴ TURN: MPS of 100%/Tier 1 penalties start at 85%; DRA: MPS of 90%/Tier 1 penalties start at 75%; NRDC: MPS of 85%/Tier 1 penalties start at 70%. Under these parties' proposals, the deadband applies to the individual metric performance, not an average of two or more.

³⁵ For these reasons we also reject Pacific Energy Policy Center's proposal, introduced in its comments on the proposed decision, i.e., that we eliminate the deadband altogether such that per-unit penalties would start if the utilities fails to meet 85% of their annual savings goals.

establishing a penalty trigger at essentially any level above 40-50% of the savings goal imposes too much risk on utilities, in particular, too much forecasting risk and market risk. However, with over \$2 billion in ratepayer funding, including funding for market penetration studies and process evaluations to assess what is working and what is not in program implementation, the utilities have an unprecedented amount of resources available to manage these risks. In fact, they have the flexibility to use their authorized funding to “dig deeper” to achieve more GWh, MW and MTherm savings (whether to avoid the trigger for penalties or to meet the MPS threshold for financial rewards) even if the ratio of costs to savings increases in the process.³⁶

Moreover, the utilities have access to over ten years of completed studies on energy efficiency load impacts, savings persistence and retention, and implementation “best practices” – many of which were conducted or managed by the utilities – to draw from in managing their portfolios. And finally, the utilities have the ability to manage market and forecasting risks through portfolio diversification, since the penalty trigger is based on the GWh, MW and MTherm savings achieved from a large portfolio comprised of a broad range of energy efficiency activities. In sum, we conclude the utilities have a reasonable opportunity to manage the risk of potential penalties under a risk/reward incentive mechanism that sets the penalty trigger at 65% of the individual savings goals.

³⁶ Under the fund shifting rules adopted in D.05-09-043, utility portfolio managers are able to shift resources among budget categories within programs, as well as across programs to manage these risks, with only a few circumstances where Commission approval is required. (See D.05-09-043, Table 8.)

5.2. Penalty Levels

We now turn to the level of penalties below the deadband, beginning with the cost-effectiveness guarantee. All parties agree that under this guarantee, utilities will reimburse ratepayers dollar-for-dollar for any negative net benefits up to the total ratepayer investment (i.e., the total cost of the energy efficiency portfolio), subject to any penalty limits under parties' proposals. (See Section 7 below.) Except for PG&E, all parties propose that the calculation of negative net benefits be based on the same PEB metric used for calculating positive net benefits. Only PG&E proposes an alternate calculation, which produces a lower rate at which penalties would increase up to the total amount of portfolio costs.³⁷ For example, if the utilities only achieve 35% of the savings goals, using PG&E's calculation produces negative net benefits of \$369 million whereas using the PEB definition produces negative net benefits of \$510 million, for all four utilities combined. (See Attachment 2.)

As discussed above, in D.05-04-051 we established how the net benefits achieved by energy efficiency should be defined for the purpose of this risk/reward incentive mechanism. We see no reason to modify this definition on the penalty side alone, as PG&E suggests. Therefore, both positive and negative net benefits produced by the energy efficiency portfolio will be based on the adopted PEB formula.

The utilities do not propose that any penalties be assessed based on missing the savings goals, and therefore have not proposed any penalty rates for

³⁷ More specifically, PG&E proposes using the results from only one of the two tests of cost-effectiveness that are weighted to produce the PEB net benefit calculations per D.05-04-051, namely, the Program Administrator Cost test. See the description of the PEB formula in Section 10 below.

this purpose. TURN, NRDC and DRA recommend a 2-tiered structure for penalty rates when achievement towards the savings goals falls below the deadband. Tier 1 rates would start right at the lower end of the deadband, and then would be superceded by higher Tier 2 penalty rates as performance falls (as a percentage of savings goals) by another 15% to 25%, depending on the proposal. Tier 1 penalty rates proposed by these parties range from 1- 2 ¢/kWh, 10- 20 ¢/therm and 5-10 dollars/kW. Their proposed Tier 2 penalty rates are exactly double the Tier 2 rates.

In developing their original proposals, DRA, NRDC and TURN used a Tier 1 penalty rate that was generally benchmarked against supply-side costs to reflect 1/8 of the cost of a kWh, kW and therm.³⁸ In constructing their proposed shareholder incentive mechanism, NRDC, DRA and TURN chose these penalty rates in order to balance overall risk with reward in their proposals taken as a whole. Subsequent to workshops, NRDC adjusted its per-unit penalty rates in order to present its entire proposal in pre-tax form. Accordingly, NRDC's penalty rates are double those proposed by DRA and TURN (in both tiers).

On balance, all of the other structural elements of today's adopted incentive mechanism (the MPS, the deadband range and earnings potential above the MPS) are much closer to NRDC's proposal than those recommended by TURN or DRA. Therefore, as a starting point, the per-unit penalty rates corresponding to the higher levels that NRDC proposes will better serve to balance overall risks with the reward side of the incentive mechanism. Since

³⁸ See *Response to ALJ Electronic Ruling Dated March 8, 2007 Regarding Proposed Incentive Mechanism Penalty Rates of the DRA, NRDC and TURN*, March 13, 2007. As explained in

Footnote continued on next page

NRDC's proposed Tier 1 (between 55% and 70% of goals) overlaps with the deadband range under today's adopted mechanism, the Tier 2 rates are more relevant for our consideration. These rates are 4¢/kWh, 40¢/therm and 20 dollars/kW.

While representing a reasonable starting point, NRDC's Tier 2 kWh rate is still significantly lower than the per unit penalty imposed on utilities if they miss their Renewable Portfolio Standard requirement. We see no reason to impose lower per kWh penalties on energy efficiency relative to renewables, particularly since energy efficiency is "first in the loading order" under California's resource procurement priorities. Therefore, we will increase NRDC's Tier 2 kWh penalty rate from 4¢ to 5¢/kWh and adjust the other per unit rates upwards to reflect a comparable increase. Making these adjustments yields the following per unit penalty rates for performance at or below 65% of goals: 5 ¢/kWh, 45 ¢/therm and \$25/kW.

Adding these per unit penalties to the cost-effectiveness guarantee, as NRDC and DRA recommend, results in penalties that would pay ratepayers back more than their full investment in energy efficiency, if left uncapped.³⁹ Instead, we will apply the *larger* of the per unit and cost-effectiveness guarantee penalty provisions at performance below the deadband.

Applying these penalty rates results in estimated penalties on the order of \$144 million for all utilities combined if performance falls to 65% of the goals,

that filing, these parties acknowledge that the \$5/kW Tier 1 rate is lower than what a 1/8 benchmark would produce, but was agreed upon as reasonable for other reasons.

³⁹ This can be observed in Attachment 2, where under the NRDC and DRA proposals the total penalties will ultimately exceed the \$2.2 billion in ratepayer investment, if left uncapped.

increasing to \$238.5 million at 50% of the goals. Below 50% of goals, penalties associated with the cost-effectiveness guarantee are expected to become larger than the per-unit penalties. At that point, ratepayers will receive dollar-for-dollar reimbursement for the negative net benefits. As we discuss in Section 6.3.4, our adopted per unit penalty levels in conjunction with the cost-effectiveness guarantee and the “reward” side of the mechanism produce a reasonable balance of potential earnings and penalties on either side of the deadband.

The total level of potential penalties will be capped at the same dollar level as the cap on earnings, as discussed in Section 7 below. These penalties are intended to compensate ratepayers for their reduced benefits or increased costs on a pre-tax basis as a result of the utilities’ substandard performance.

6. Earnings Curve and Associated Shared-Savings Rate(s)

The earnings curve and associated shared-savings (or “sharing”) rate(s) create the opportunity for earnings under the risk/reward incentive mechanism, once the MPS is achieved. All parties agree that this opportunity should be based on a percentage of the verified net benefits achieved by the portfolio of energy efficiency programs. For example, if verified portfolio net benefits are \$100 million when a utility achieves 100% of the savings goals, and the sharing rate is 10% at that level of performance, then ratepayers would retain \$90 of the \$100 million in net benefits and pay the utility \$10 million in earnings. Parties also agree that the earnings curve should be “tiered” in structure, that is, the shared-savings rate (the percentage of net benefits shareholders receive) should increase at higher levels of portfolio achievement with respect to the savings goals.

However, parties fundamentally disagree on how to establish the shareholder earnings potential under the incentive mechanism, the appropriate level for such earnings and the associated shared-savings rates. The utilities and NRDC argue that supply-side “comparable earnings” is a key benchmark for this purpose. Accordingly, these parties calculate what the utility would otherwise earn on the portfolio of supply-side resources avoided by energy efficiency to establish this benchmark.⁴⁰ DRA, TURN, CE Council and CLECA, on the other hand, argue that using a supply-side return is an excessive benchmark for establishing an energy efficiency incentive where ratepayers, not shareholder, dollars are at risk. They use different approaches to establish their recommended shared-savings rates, which result in substantially lower earnings potential than under the risk/reward incentive mechanisms proposed by the utilities and NRDC.

The parties also disagree on the appropriate methodology for calculating supply-side comparable earnings, should the Commission adopt this approach. In particular, there is disagreement over whether: 1) comparable earnings calculations should impute any earnings associated with purchased power to reflect debt equivalence, 2) supply-side investment returns should be reduced to account for alternative use of capital, and 3) comparable earnings should be evaluated with respect to the same amount of savings, or the same amount of investment.

⁴⁰ As discussed in this decision, the utilities and NRDC rely on this benchmark to varying degrees in establishing the earnings potential under their respective incentive proposals.

Finally, parties disagree on how the tiered shared-savings rates should be structured beyond the MPS, and whether they should include a larger incentive (in the form of a higher earnings rate) for achieving higher levels of kW savings.

In the following sections we address these and other issues related to the level of sharing of net benefits between ratepayers and shareholders. We begin with a description of the utilities' supply-side comparable earnings analysis, which other parties refer to extensively in their filed comments and testimony.

6.1. Utility Supply-Side Comparable Earnings Analysis

In developing proposals for a shared-savings rate, each utility conducted what we refer to as a "supply-side comparable earnings analysis" or simply, a "comparable earnings analysis." This analysis calculates the level of shareholder earnings associated with procuring supply-side resources that are displaced by energy efficiency. As discussed in this decision, there is disagreement among the parties on several key assumptions that go into performing this analysis. Moreover, parties disagree on the relevance and purpose of using supply-side comparability as a benchmark for the shared-savings rate. However, before discussing those disagreements, it is useful to review how the supply-side comparable earnings analysis is performed.

Mechanically, the utilities perform this analysis by estimating the amount and type of supply-side resources avoided if they achieve 100% of the savings goals over the 2006-2008 program cycle with energy efficiency. They then determine the revenue requirement they would need to recover from customers as a result of these avoided supply-side procurements. Some of the procurements would be from "steel-in-the-ground" supply-side resources (e.g., avoided generation, transmission and distribution facilities) and some

would be from avoided power purchases. For their base case analysis, each of the utilities assumed a 50-50 split between these utility-build and utility-buy scenarios.

The utilities' revenue requirement calculations for "steel-in-the-ground" supply-side resources reflect that these costs would be rate-based. That is, the utility finances such infrastructure projects through a combination of debt and equity capital, and then rates are set to recover the original investment plus an authorized cost of capital (interest on debt and return on equity). The revenue requirement calculations, including the return to shareholders for their capital (equity) investment, are also grossed up for all applicable taxes.

For purchase power contracts, the revenue requirement is recovered contemporaneously from ratepayers through balancing accounts. Therefore a cost of capital (debt or equity) is not included in those revenue requirement calculations. However, in producing their revenue requirement calculations, the utilities impute what is referred to as "debt equivalence" for the purchased power assumed in the analysis.

Debt equivalence is a term used by credit rating agencies for treating long-term non-debt obligations, such as power purchase agreements, as if they were debt in assessing a utilities' credit rating.⁴¹ The utilities assume that 30% of the dollar value of the purchase power contracts included in their supply-side comparable analysis is equivalent to additional debt in their capital structure. This increases the proportion of equity capital required in the utility's capital

⁴¹ D.04-12-047, *mimeo.*, p. 5.

structure which, in turn, increases the total return on equity included in calculation of the avoided revenue requirement.

The dollar level return on equity that is included in the revenue requirement calculations described above is what we refer to as “supply-side comparable earnings.” This is the amount of earnings to shareholders that, but for energy efficiency, the utility would be authorized to collect in rates. Dividing this level of earnings by the net benefits (PEB) expected from the energy efficiency portfolio (at 100% goal achievement) yields the “supply-side comparable” shared-savings rate.

Table 2 below summarizes the results of each utility’s supply-side comparable analysis, which incorporate the following base case assumptions: 1) a 50-50 split between the “utility build” and “utility buy” scenario, 2) average energy efficiency measure life of 12-years and 3) debt equivalence for purchased power. The comparable earnings shared-savings rate is calculated by dividing the comparable earnings by the PEB (net benefits).⁴² All numbers are presented on a pre-tax basis.

⁴² The PEB used for this purpose reflects all costs included in the calculation of net benefits. Supply-side comparable earnings numbers are from the base case scenarios presented in Exh. 55; PEB numbers for PG&E are from Exh. 34B (corrected to reflect a July 1, 2006 valuation date and adjusted further to reflect all costs included) and for the other utilities from Table 8A, *Joint Summary Documents*, September 18, 2006.

TABLE 2
UTILITIES' COMPARABLE EARNINGS ANALYSIS
(All Costs Incl. in PEB)

	(1) Supply-Side Comparable Earnings (Million \$)	(2) Performance Earnings Basis at 100% Goals (Million \$)	(3) Comparable Shared-Savings Rate (1)/(2)
PG&E	272	1097	25%
SCE	312	1199	26%
SDG&E	62	297	21%
SoCalGas	38	134.5	28%

6.2. Position of the Parties

Parties' proposals for the earnings curve, i.e., the shared-savings tier structure and associated shared-savings rates, are compared in Attachment 3.⁴³ As indicated in that attachment, DRA, TURN and CE Council propose shared-savings rates in the 1.5% to 3% range beyond the MPS, plus a higher earnings rate of up to 3.5% if kW goals are exceeded by 25-50% (depending on the proposal).⁴⁴ NRDC proposes shared-savings rates in the 6% to 12% range

⁴³ These earnings curve proposals also reflect each party's proposal for the level of MPS, which we have addressed in Section 4 above. As we discuss below, CLECA supports a sharing rate of 3-5%, but did not provide specific design parameters for the risk/reward incentive mechanism (e.g., tiers for earnings rates, or corresponding penalty rates, MPS, etc.). Therefore, while we summarize CLECA's position in our discussion, we do not include CLECA in the Attachments and summary tables.

⁴⁴ Parties to this proceeding refer to this higher incentive for kW savings as the "kW kicker" rate, but we prefer to describe this proposal using different language.

beyond the MPS, and the utilities propose rates in the 10% to 30% range, depending on the tier.

Attachment 2 presents these proposals in terms of the dollar earnings at different levels of savings goal achievement, based on a PEB that includes all portfolio costs.⁴⁵ Some parties to this proceeding suggest that we view proposed dollar earnings relative to portfolio costs, that is, as a ratio of earnings to portfolio funding levels. This perspective fails to recognize that the sharing rate and associated earnings are not tied to the energy efficiency portfolio costs, but rather to the much larger dollar value of avoided supply-side costs. We continue to endorse the yardstick we set in D.03-10-057 that the earnings levels we establish under a shared-savings mechanism should be compared to “how much ratepayers would have had to pay if the program savings had not been realized.”⁴⁶

From this perspective, we present below (1) the shareholder earnings level for all four utilities combined at 100% of savings goals, and (2) the ratepayers’ portion of net benefits under each party’s sharing proposal:

⁴⁵ As discussed in Section 9, there are some differences among the parties on whether the costs associated with “non-resource” programs and certain EM&V costs should be included in the PEB calculation. To put the proposals on an “apples-to-apples” comparison, we present this comparison based on a PEB that includes all portfolio costs.

⁴⁶ D.03-10-057, Finding of Fact 9.

TABLE 3

Shareholder Earnings/Ratepayer Net Benefits by Proposal

<u>Sharing Proposal Of:</u>	<u>Shareholder Earnings at 100% of Goals (all utilities combined) (\$ million)</u>	<u>Ratepayer Net Benefits at 100% of Goals⁴⁷ (\$ million)</u>
PG&E	\$538	\$2,151
SCE	\$538	\$2,151
SDG&E/SoCalGas	\$403	\$2,286
NRDC	\$323	\$2,366
DRA	\$81	\$2,608
TURN	\$54	\$2,635
CE Council	\$54	\$2,635

Before turning to the specific disputed issues on how to establish those levels, we note that the expected ratepayer “return” (net benefits) from the \$2.2 billion ratepayer investment during the 2006-2008 program cycles if the savings goals are met is expected to range from 107% to 132% under the various shared-savings proposals before us. Hence, there is no question that, under any of the parties’ proposals, achievement of the Commission’s 2006-2008 goals for energy efficiency savings is expected to produce an extraordinary monetary return to ratepayers. And in the process, such achievement will create an unprecedented level of net resource benefits to all Californians-- on the order of \$2.7 billion.

⁴⁷ The ratepayer portion of net benefits is calculated as the PEB at 100% of goals from Attachment 2 (\$2,689 million) minus the shareholder earnings under each proposal.

It is within this context that we consider one of the fundamental, and most controversial, issues in this proceeding: *What level of earnings potential under the risk/reward incentive mechanism should be adopted to ensure that this type of return to ratepayers on their investment, and associated net resource benefits to all Californians, are achieved or surpassed?* In the following sections, we summarize parties' positions on the level of earnings potential and associated shared-savings rates for the risk/reward incentive mechanism.

6.2.1. PG&E, SCE, SDG&E and SoCalGas (“The Utilities”)

The utilities argue that supply-side comparability provides a relevant benchmark for establishing the earnings potential and shared-savings rate(s), pointing to the language of the National Action Plan for Energy Efficiency, California's Energy Action Plan, the Energy Policy Act, recent studies and prior Commission decisions as clear and strong policy support for this benchmark. In their view, these policies are based on the common sense understanding of what it takes to ensure the sustained commitment of utility management to meet and exceed the Commission's savings goals with cost-effective energy efficiency. They argue that this takes a potential stream of earnings from energy efficiency that both the investment community and utility management will view as a comparable earnings opportunity relative to the utility's core business of creating and operating reliable energy infrastructure.

In addition to the numerical results of their comparable earnings calculations, the utilities testified that they took other factors into account in developing their proposed shared-savings rate(s). In particular, they considered what dollar level of potential earnings for their company would sustain long-term management commitment to energy efficiency at all management levels

and across all utility departments. They also considered which sharing rates at different levels of performance would produce an equitable allocation of net benefits between shareholders and customers.⁴⁸

PG&E also evaluated its proposed shared-savings rate from the standpoint of incentive regulation theory, exploring the fundamental trade-off between the policy objectives of protecting ratepayers against excessive utility profits and ensuring the delivery of effective results and reduced costs by the utility. In its direct testimony, PG&E describes how “sliding scale” or “shared-savings” regulation represents a hybrid form of regulation used widely by regulators to balance these objectives. PG&E concludes that the magnitude of its proposed shared-savings rate is consistent with hybrid regulatory schemes considered to be reasonable based on a review of the economic literature.⁴⁹

Using these considerations, the utilities propose a multi-tiered earnings rate structure for the risk/reward incentive mechanism. The highest shared-savings rate applies when the utility meets or exceeds the savings goals, ranging from 20% to 30% under the utility proposal. Lower shared-savings rates apply when performance is below the savings goals, but at or above the MPS. Utility proposals for these lower rates range from 10% to 15%. (See Attachments 3 and 4.)

6.2.2. NRDC

NRDC concurs with the utilities that the risk/reward incentive mechanism should consider comparability with returns the utilities are currently allowed on

⁴⁸ Exh. 17, p. 9; RT at 117-119; Exh. 36, p. 4-5; Exh 33 at 1-3.

⁴⁹ Exh. 33, Chapter 2; RT at 222-226.

investments in supply-side resources. In NRDC's view, consideration of supply-side comparability is reasonable because utility portfolio managers have the option of directing resources and personnel to different types of resources. Without energy efficiency incentives, NRDC argues that the utilities may be more inclined to devote those resources to supply-side options, for which their shareholders earn a return. However, as discussed below, NRDC also believes that supply-side comparability should be viewed as only one benchmark that the Commission should consider.

In arriving at its estimate of comparable supply-side earnings, NRDC takes a somewhat different approach than the utilities. NRDC first calculates a comparable supply-side earnings rate, and then applies that rate to the level of ratepayer investment in energy efficiency. The utilities, on the other hand, first establish the level of supply-side resources (e.g., steel-in-the-ground investments/power purchases) needed to achieve the savings produced by the energy efficiency portfolio, and then derive the earnings foregone from that level of supply-side procurement. All other things being equal, NRDC's approach results in a lower level of earnings foregone, since the energy efficiency portfolio (in order to be authorized for funding) produces a comparable level of savings at lower costs than the avoided supply-side resources.

More specifically, NRDC first calculates an average pre-tax return on capital of 14.52% based on the Commission's approved cost of capital in D.05-12-043 and a 40.8% tax rate. NRDC then calculates the net present value of the total earnings on a power plant, assuming straight-line depreciation of the

investment over 12 years. NRDC's calculations produce an effective earnings rate equal to 54% of the original capital investment.⁵⁰

NRDC does not support the utilities' position that additional earnings should be imputed for the "debt equivalence" of power purchases, and therefore assumes an effective earnings rate for power purchases of zero. Weighting the earnings rates for utility-build and utility-buy by their respective proportions of the utility portfolio (assumed to be a 50-50 split), NRDC calculates a 27% comparable earnings rate. To produce illustrative foregone earnings, NRDC multiplies this earnings rate by the total energy efficiency 2006-2008 portfolio costs that NRDC believes should be included in the PEB. This calculation produces a comparable earnings estimate of \$497 million for all four utilities combined.⁵¹

NRDC recommends that the Commission also consider the level of performance (% of goal achievement) for which this level of earnings should be awarded. In NRDC's view, comparable supply-side earnings should only be

⁵⁰ A numerical example illustrates how effective earnings become so much greater than the % authorized return. Suppose \$100 million in plant costs is rate based at an authorized rate of return of 10%. However, assuming a 10-year plant life and straight-line depreciation, earnings on that rate-based facility would actually be \$54. Rate base would decrease by \$10 per year (in depreciation), and the 10% rate would be applied to each year-end balance. Hence the effective earnings rate on a \$100 million plant investment would be 54%, as compared to the 10% authorized rate of return. (See D.94-10-059; 57 CPUC 2d, p. 52.)

⁵¹ As discussed during evidentiary hearings, NRDC's calculations actually result in comparable earnings numbers that are generally higher than the utilities' when debt equivalence is removed from their calculations, contrary to expectations. NRDC attributes this result to its use of very simplified assumptions in deriving the comparable earnings rate, and therefore concludes that its calculations err on the high side. RT at 41-44.

fully awarded at a level of excellent performance well above the forecasted level of performance. Accordingly, NRDC recommends that at 100% of goal achievement, the utilities share 12% of the net benefits, which corresponds to earnings of \$323 million for all four utilities combined. Beyond the MPS and until 100% achievement of goals, NRDC proposes an earnings rate half that large (or 6%). In NRDC's view, these earnings rates will provide a level of reward that is material to the utilities, while also requiring them to stretch significantly to achieve excellent performance beyond the savings goals and forecasted PEB.⁵²

6.2.3. DRA

In DRA's view, past policies of establishing energy efficiency sharing rates based on calculations of foregone supply-side earnings lack any factual predicate.⁵³ DRA argues that such an approach erroneously assumes that shareholders are harmed through the loss of shareholder earnings when energy efficiency programs displace utility supply-side investments. DRA contends that this is not the case, based on fundamentals of financial and economic theory.

More specifically, since utility shareholders do not actually invest in ratepayer-funded energy efficiency programs, DRA argues that shareholders retain the option of investing the money they do not invest in utility supply-side resources elsewhere, i.e., in an alternative investment of comparable risk in the marketplace. And since utility shareholders can earn a return that is "presumptively equal to the utility's authorized cost of capital,"⁵⁴ DRA

⁵² NRDC's *Post-Workshop Comments*, September 8, 2006, p. 15. Exh. 2, p. 2; Exh. 3, pp. 1-4; RT at 15, 28, 47;

⁵³ RT at 375.

⁵⁴ Exh. 48, p. 3.

concludes that the earnings rate for energy efficiency programs that achieves supply-side comparability is effectively zero.⁵⁵

Moreover, DRA contends that establishing the incentive levels proposed by the utilities represents an excessive amount of compensation, based on historic data. In particular, DRA points to the shareholder performance incentive for PY2000 and PY2001 that was capped at 7% of the program budget. DRA claims that because the utilities delivered superior results under this incentive mechanism there is no justification for the higher incentive rates proposed in this proceeding.

For these reasons, DRA rejects the comparable earnings approach and calculations proposed by NRDC and the utilities and recommends a benchmark based on a salary-based bonus system. DRA concludes that a 3% sharing rate (at 100% goal achievement) would be comparable to this benchmark.

More specifically, in its September 8, 2006 filing, DRA presents calculations that it claims shows how a sharing rate of 3% (producing \$81 million in earnings for all utilities combined) is in line with the level of management fees that would be paid to mutual fund managers if they managed a fund equal in value to the 2006-2008 portfolio budget.⁵⁶ For this calculation DRA assumes that salaries for energy efficiency program staff and contractors comprise 25% to 30% of the portfolio budget, and a salary-based bonus scale would range from 3% to 15% for average to exemplary performance. For a three-year portfolio of \$2 million, DRA calculates that the performance-based incentives would then range

⁵⁵ Exh. 48, pp. 9-11; Exh 46; Exh 47, p. 22; RT at 378-379.

⁵⁶ *The DRA Proposed Risk/Return Shareholder Incentive Mechanism for Energy Efficiency Portfolios*, September 8, 2006, pp. 7-8.

between \$15 million to \$90 million for average to exemplary performance (or 0.75% to 4.5% of the \$2 million portfolio budget on a pre-tax basis.)

DRA also presents a Managerial Bonus model in its direct testimony to support its earnings rate proposal. As DRA explains, this model relies on two assumptions to obtain the basic incentive level (3% of PEB) at 100% of goals for the three-year program cycle: labor costs as a percentage of energy efficiency program budget and a salary-based bonus rate that should motivate superior performance.

Using data from 2006-2008 budgets, 2006 actual program costs and additional data on managerial compensation, DRA calculates that if all the utilities reached 100% savings goals and the incentive earnings were returned to energy efficiency program staff, each staff member would a bonus of approximately 35% of their base salary. Using the utility's compensation surveys included as part of each utility's general rate case filing, DRA also compared the results of its proposal to the actual bonus rates (total cash compensation to base salaries) paid in the survey years, which include data on the utilities and comparable companies. DRA concludes that an average incentive rate of 35% is greater than the average bonuses paid to 1) employees in the manager/supervisor category for the utilities and those comparable companies included in the utility surveys and 2) a weighted average of all managers, including executives for the utilities.⁵⁷

Based on these results, DRA concludes that its proposal to establish the shared-savings rate at 3% of PEB when 100% of the goals are met will motivate

⁵⁷ Exh. 45, pp. 6-13.

the utilities towards achieving or exceeding the Commission's energy efficiency goals, and at the lowest cost to ratepayers. This translates to earnings of \$81 million over the 3-year program cycle for all four utilities, assuming that they reach 100% of their savings goals.⁵⁸ DRA recommends that for performance between the MPS and 100% goal achievement, the 3% be reduced by half, to 1.5%. DRA also recommends a higher earnings rate of 3.5% if the utility achieves over 125% of the Commission's kW goals.

Finally, DRA reviewed and compared energy efficiency incentive levels in nine other states with those being proposed in this proceeding, based on a 2006 survey by the American Council for an Energy-Efficient Economy (ACEEE). DRA concludes from this information that the incentives proposed by the utilities exceed every existing incentive program by a substantial margin. While its proposal is on the low end of the spectrum, DRA maintains that the size of California's energy efficiency programs should warrant a lower incentive rate.⁵⁹

6.2.4. TURN

TURN's general position is that supply-side comparability does not work in the context of establishing a shared-savings rate for ratepayer-funded energy efficiency, and that the Commission should establish the level of shared savings based on other considerations, as discussed further below.⁶⁰ However, if the Commission were to adopt a benchmark based on supply-side comparability, a position that TURN strongly opposes, TURN contends that the utilities' calculations would need to be reduced to reflect "alternative uses of funds." That

⁵⁸ Based on a PEB of \$2,689, which includes all portfolio costs.

⁵⁹ Exh. 45, pp. 13-16.

is, TURN argues that the utilities' analysis of comparable supply-side earnings ignores the fact that a utility does not hide the money that it doesn't spend on supply-side resources "under the mattress."⁶¹ Instead, TURN argues that the utility has alternative uses for these funds that create substantial shareholder value.

To illustrate this point, TURN describes what the utility could do with shareholder funds if they are not needed for supply-side investments. If the utility did not have enough cash for these investments in the first place, TURN posits that the utility would raise capital in the markets by selling new shares of stock (in the case of California utilities, through its holding company). TURN concludes that if the utility can avoid the issuance of new stock due to expensed energy efficiency, then its earnings-per-share will be higher, all other things being equal. Therefore, even though earnings per share increase when a utility undertakes a supply-side investment (because the utility earns a return on equity and the numerator increases), the resulting increase in earnings per share is diluted because the utility would have had to issue more shares (increase the denominator) to raise the investment capital for these projects.

Using PG&E's 2006 year-end values for earnings, number of shares, book value and stock price, TURN calculates that this dilution factor would reduce the positive impact of new supply-side investments on earnings-per-share on the order of 57%. Therefore, TURN suggests that PG&E's calculations of foregone earnings should be reduced by 57% to reflect this earnings-per-share dilution,

⁶⁰ RT at 477.

⁶¹ *TURN's Post-Workshop Comments*, September 8, 2006, p. 45; See also Exh 66, pp. 7-8.

assuming that PG&E would have sold additional shares of stock to finance the supply-side resources that are no longer needed.⁶²

Where the utility would have adequate equity to finance such investments, TURN describes the following alternative investments available to it: 1) reducing short-term borrowing or increase short-term investments, 2) paying down debt, 3) accelerating replacements of aging equipment or 4) paying dividends to the holding company. TURN argues that investment alternative #1 represents a relatively unprofitable uses of funds and would only be undertaken over the very short-term. With respect to alternative #2, TURN observes that paying down debt is better than investing in a money-market fund (at about a 4% after-tax rate), but is not an extremely profitable use of cash in terms of quantifiable benefits. With regard to alternative #3, TURN concurs with DRA's assessment that this use of funds would result in zero "lost" equity return, since the investments would receive the same return on equity as the supply-side resources no longer needed.

For investment alternative #4, TURN describes four options available to the holding company for the funds it receives (in the form of dividends) from the regulated utility. The holding company could: 1) pay dividends to shareholders, 2) use the additional dividends from the utility as equity to invest in unregulated projects, 3) use the additional dividends from the utility as equity for the pursuit of mergers and acquisitions either of regulated or unregulated entities, or 4) buy back stock with the money. For the first three of these options, TURN concludes

⁶² Exh. 66, pp. 6-7, 12-14. See RT at 531 where TURN describes how its earnings-per-share analysis would translate into adjustments to PG&E's supply-side comparable earnings calculations.

that, from the point of view of the shareholders, there is no lost equity return. According to TURN, this is because shareholders (under option #1) have the ability to reinvest the money in assets that presumably have the same risk-adjusted cost of capital as the utility (otherwise they would not buy them). Under options #2 and #3, shareholders also have no lost equity return because the holding company invests in projects that provide good if not better risk-adjusted returns than California regulated utility projects (otherwise they would not make them).

With respect to option #4, TURN asserts that stock buybacks benefit the utility and its shareholders in several ways, including by increasing earnings per share (all other things being equal), and by providing money to shareholders who choose voluntarily to sell in order to make alternative investments that earn the same amount or more on a risk-adjusted basis. TURN calculates that if PG&E's holding company took the cash no longer needed for supply-side investments, and instead bought back shares of its stock, the "foregone earnings" from not building those supply-side resources would be 45% less than PG&E's comparable earnings calculations suggest, all other things being equal.⁶³

TURN concludes that the utilities' comparable earnings analysis is flawed because it ignores elementary principles of finance, accounting and economics by not considering potential uses of equity that would not be invested in energy efficiency. TURN also agrees with DRA that the theoretically "right" answer to a calculation of foregone shareholder earnings is "probably zero."⁶⁴ Nonetheless,

⁶³ *Ibid.*

⁶⁴ RT at 520. Exh. 66, p. 18;

to provide some boundaries on the utility's calculations, TURN recalculates PG&E's numbers assuming that the Commission establishes a return on equity that is actually greater than the cost of equity.⁶⁵ Under these circumstances, TURN suggests that foregone earnings would be non-zero because shareholders would not be able to find a return on their equity for comparable risk investments as high as the foregone utility supply-side investments. To quantify this scenario, TURN recalculates PG&E's numbers by subtracting PG&E's authorized return on equity (11.35%) by the 8.5% Standard and Poor (S&P) 500 return.⁶⁶ In addition, TURN argues that the utilities have overstated comparable earnings by imputing debt equivalence for power purchases, a practice that TURN contends the Commission had not approved in establishing the utility's cost of capital. TURN removes the debt equivalence calculation from PG&E's numbers and makes other adjustments and corrections to PG&E's calculations. The result is what TURN characterizes as a maximum comparable pre-tax earnings rate of 3.4%.

In sum, TURN concludes that a supply-side comparability analysis does not justify anything higher than a 3.4% shared savings rate, and is probably zero. Moreover, TURN argues that there is no evidence on the record to demonstrate a correlation between high incentive levels based on supply-side comparability and better utility performance, and in fact asserts that historical data suggests quite the opposite. Therefore, TURN recommends that the Commission evaluate

⁶⁵ In fact, TURN Witness Marcus testified that TURN believes this to be the case. (RT at 520; Exh. 66, p. 1-2.)

⁶⁶ Exh. 66, p. 12.

the appropriate level of sharing of energy efficiency net benefits from a different perspective altogether.⁶⁷

TURN submits that the appropriate perspective is one that views the energy efficiency risk/reward incentive mechanism as analogous to performance-based ratemaking (PBR) mechanisms that the Commission has established in the past to either 1) prevent harmful consequences from cost-cutting measures, or 2) reward shareholders for cutting costs. TURN specifically refers to the following PBR mechanisms adopted by the Commission:⁶⁸

- The nuclear and coal power plant performance incentive mechanisms (“target capacity factor” mechanism) adopted in the early 1980s for SCE;
- The Core Procurement Incentive Mechanism (CPIM) and Gas Cost Incentive Mechanism adopted for PG&E and SoCalGas respectively, beginning in 1994;
- SCE’s base rate PBR revenue sharing mechanism adopted in 1996 until 2003 for sharing profits or losses from transmission and distribution operations; and
- The Employee Safety and Distribution Reliability Performance Incentive Mechanism adopted for SCE beginning in 2003.

Based on its review of the sharing rates and caps for these other targeted incentive mechanisms, TURN developed shared-savings rates of 2-3% in this proceeding.⁶⁹ More specifically, TURN proposes a sharing rate of 2% between the MPS and 100% of goal achievement, 2.5% if the goals are achieved and exceeded, and a higher rate (3%) rate if the utility exceeds 125% of the kW goal.

⁶⁷ RT at 519-520.

⁶⁸ *TURN’s Post-Workshop Comments*, September 8, 2006, pp. 8-11; See also RT at 189-193, Exh. 25.

⁶⁹ Exh. 70; Exh. 71.

6.2.5. CE Council

CE Council attended the Phase 1 workshops, filed a proposal for a specific risk/reward incentive mechanism and an opening brief, but did not participate in evidentiary hearings.⁷⁰ Therefore, CE Council did not present sworn testimony, subject to cross-examination, on the position it has taken with respect to the level of shareholder earnings and earnings rates. In its comments, CE Council argues that there is very limited risk to the utilities under energy efficiency programs, and therefore the earnings should be commensurately limited. In particular, CE Council believes that the savings goals should not be particularly difficult to meet and, based on past experience, the risk of penalties is small.⁷¹ Moreover, CE Council argues that the utilities benefit from energy efficiency in intangible ways, such as the benefits associated with brand labeling. CE Council also supports and reiterates several of the arguments presented by DRA and TURN in their workshop comments. CE Council suggests that a better measure of appropriate earnings potential is what has been effective in other states.

Based on these considerations, CE Council recommends sharing rates increasing from 2% to 3% under a two-tier structure.⁷² Like DRA and TURN,

⁷⁰ CE Council is a non-profit environmental organization working primarily with Santa Barbara, San Luis Obispo and Ventura counties.

⁷¹ *Revised Post-Workshop Comments on a Proposed Risk/Reward Incentive Mechanism of CE Council*, September 14, 2006, pp. 5-6, 10.

⁷² *Ibid.*, pp. 13-14. CE Council's tier structure is somewhat different than other parties' proposals in that the first tier rate of 2% begins when the MPS is reached and extends until 150% of goal achievement. The second tier rate (3%) begins at 150% of the goals.

CE Council also recommends a higher earnings rate tied to achieving more than 125% of the kW goals.

6.2.6. Position of CLECA

CLECA did not participate in the workshop process or present a specific design proposal for the risk/reward mechanism in post-workshop filings. However, CLECA did sponsor a witness and testimony during evidentiary hearings on the overall level of potential earnings.⁷³

In that testimony, CLECA contends that the potential earnings proposed by the utilities and NRDC are much too large. CLECA argues that the only risk to shareholders under the pending proposals is if they fail to successfully pursue cost-effective energy efficiency portfolios, which CLECA asserts would be a low risk given the projected benefit-cost ratios for these programs. In addition, CLECA argues that energy efficiency expenditures are not depriving the utilities of earnings opportunities and, in fact, provide them with significant institutional marketing benefits without the need for any shareholder investment. For these reasons, and based on a review of DRA and TURN's submittals, CLECA supports a shared-savings rate in the 3-5% range.⁷⁴

6.3. Discussion

TURN, DRA, CE Council and CLECA ask that we reject any consideration of a supply-side comparable earnings analysis, unless we dramatically reduce the resulting numbers. For the reasons discussed below, we find their arguments for rejecting this analysis unpersuasive, and discuss the shortcomings

⁷³ CLECA represents about 16-17 customers totaling approximately 500 MW in electric load, mainly in the cement and steel industries. (RT at 361.)

⁷⁴ Exh. 50.

of their proposed alternative benchmarks. We conclude that supply side comparability should be one, among other relevant considerations, in establishing the earnings potential under the incentive mechanism we adopt today.

6.3.1. Supply-Side Comparability: History and Purpose

As discussed further below, some parties contend that the purpose and regulatory context that gave rise to using supply-side earnings comparability as a benchmark for energy efficiency incentives in the past has fundamentally changed. Before turning to those specific arguments, we present a brief overview of that history.⁷⁵

The concept of providing utilities with an opportunity to earn from energy efficiency and other demand-side management (DSM)⁷⁶ efforts was developed in the late 1980s in response to the Commission's stated need to take a fresh look at the role of DSM in utility resource procurement. This was a time prior to electric industry restructuring when California's investor-owned utilities met their customers' energy needs by acquiring and delivering energy resources on their behalf, as they do again today. The Commission embarked on a proceeding to create positive financial incentives that would produce a "win-win" alignment of

⁷⁵ More comprehensive summaries of our experience and history with energy efficiency shareholder incentives can be found in D.03-10-057, Attachment 2 and D.05-10-041, Attachments 2, 3 and 4.

⁷⁶ DSM programs focus on the customer side of the utility meter and have included programs for load management and energy efficiency, among others.

ratepayer and shareholder interests in achieving least-cost, integrated resource planning objectives.⁷⁷

After conducting several years of experimental programs on energy efficiency incentive mechanisms, in 1993 the Commission reviewed the results of the experiments and concluded:

“On balance, there are disincentives to DSM created by both regulation and the private profit-making nature of the firm that limit utility shareholders and management’s interest in pursuing all practicable, cost-effective and reliable DSM.” (D.93-09-078, Conclusion of Law 1.)

“Under the current regulatory framework, DSM shareholder incentives are necessary and appropriate to increase the private value of DSM to a utility by bringing that value more in line with its social value.” (*Ibid.*, Conclusion of Law 3.)

“Regulatory mandates and rate of return penalties do not create potential “win-win” situations for shareholders and ratepayers. Rather they create a “ratepayers win or else shareholders lose” approach to DSM regulation.” (*Ibid.*, Finding of Fact 11.)

More specifically, the Commission identified the following financial and regulatory biases against energy efficiency (or in favor of supply-side resources), and concluded that shareholder incentives were an effective way to address them:⁷⁸

- (1) Utilities only earn on supply-side investments under current regulatory practices absent energy efficiency incentives;
- (2) Cost-effective energy efficiency investments will increase rates in the short-term, even though it will minimize revenue requirements and customer bills over time.

⁷⁷ D.93-09-078, 51 CPUC 2d, 371, pp. 380-381.

⁷⁸ *Ibid.*, p. 382; D.94-10-059, 57 CPUC 2d, 1, p. 51.

The Commission then proceeded to evaluate what level of earnings opportunity would be “sufficient (and not too much) to offset these biases” in a lengthy evidentiary process to which most of the same parties to this proceeding also participated, including TURN and DRA.⁷⁹ To this end, the Commission directed parties to calculate the “effective earnings rate” associated with supply-side resources deferred or avoided by DSM investments. Parties also presented other proposals for the Commission to use instead of or in conjunction with its consideration of supply-side earnings comparability. However, the Commission rejected those proposals for various reasons.

For example, the Commission rejected recommendations to rely on historical evidence of utility management interest in establishing the earnings potential. In doing so, the Commission found that levels of earnings achieved in the past would not be accurate indicators of the level of earnings opportunity that would be needed to overcome disincentives to DSM in the future. The Commission also rejected DRA’s recommendation to reduce the supply-side effective earnings rate by 40-50% based on its assertions that utility management was biased in favor of demand-side resources over supply-side resources, contrary to the Commission’s own findings. In addition, the Commission rejected TURN’s position that instead of supply-side comparability, the utility shareholders were entitled only to a minimal management fee for managing ratepayer-funded energy efficiency.⁸⁰

⁷⁹ *Id.*

⁸⁰ *Ibid.*, pp. 51-52; 56-57.

Instead, the Commission elected to develop calculations of supply-side comparability as a general benchmark, and then assess the appropriate level of target earnings within the context of that benchmark and the incentive mechanism being proposed, taking into consideration the relative risks and rewards associated with supply-and demand-side alternatives. In addition to the differences in risk due to who funds the initial investment, the Commission identified other relative risks to be considered, such as how shareholder earnings vary with project performance and who bears the risk of non-cost-effective investments. The Commission described these different (and changing) risk/reward profiles for demand- and supply-side resources in D.94-10-059. In doing so, the Commission considered the relative risks and rewards to shareholders and ratepayers under traditional cost-of-service and performance-based ratemaking that was in place for supply-side resources, or being contemplated in the near future. Not surprisingly, the Commission found that comparisons between the earnings opportunity from DSM and supply-side resources were difficult to make, given the differing performance, earnings and investment characteristics of demand- and supply-side resources.⁸¹

On balance, taking supply-side comparability and other factors into consideration, the Commission adopted an earnings rate at target performance on the lower end of the supply-side comparability analysis presented in the proceeding. “Target” performance (and the MPS) under that earlier shared-savings mechanism was based on the projected level of net benefits (PEB)

⁸¹ *Ibid.*, pp. 54-56; 72.

for the energy efficiency portfolio, as there were no established goals for kW, kWh or therm savings goals at that time.

More specifically, parties to the proceeding presented a range of 26% to 52% for the effective earnings rate associated with supply-side resources deferred or avoided by DSM investments, based on the capital costs of avoided generation. This corresponded to target earnings levels of \$77 to \$153 million for all four utilities combined. The Commission adopted a shared-savings rate of 30%, which translated into potential shareholder earnings of \$88.7 million out of the expected \$295 million in net benefits at target performance (for all utilities combined).

In this proceeding, DRA argues (and TURN concurs) that a supply-side comparability analysis should produce a comparable return of zero because shareholders do not “lose” any earnings when the utility undertakes energy efficiency. In fact, no party argues that utility shareholders *are* made worse off by energy efficiency, since everyone acknowledges that investors can put their investment dollars elsewhere and earn a return comparable to the one they would have earned on the displaced supply-side investments.⁸² However, the purpose of a supply-side comparability analysis is not, and has never been, to prove or disprove the tautology of zero foregone shareholder earnings posed by DRA and TURN in this proceeding.

Instead, as discussed above, a comparable earnings analysis provides a numerical benchmark for addressing the very heart of the bias that stands in the way of successful implementation of California’s energy policies by the utilities

⁸² RT at 545-546. Exh. 18, p. 5; Exh. 34, p. 1-3.

we regulate: Utility investors are attracted by opportunities to earn returns, and absent energy efficiency incentives, utilities only earn on supply-side investments. Recognition of this disincentive to energy efficiency has been expressed in the federal Energy Policy Act of 1992--a statute that is still in effect--and California's 2003 Energy Action Plan.

More specifically, the Energy Policy Act of 1992 requires state commissions to consider the following standard:

"The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency, and other demand side management measures *are at least as profitable*, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for construction of new generation, transmission and distribution equipment."⁸³

California's 2003 Energy Action Plan identified the following action as one of "critical importance" for optimizing energy conservation and resource efficiency:

"Provide utilities with demand response and energy efficiency investment rewards *comparable to the return on investment in new power and transmission projects*."⁸⁴

⁸³ 16 U.S.C. Sec. 2621(d)(8)[emphasis added]; see also 15 U.S.C. Sec 3203(b)(4) (corresponding to Section 115(b)(4) for natural gas).

⁸⁴ *Energy Action Plan*, 2003, action item #6 under "Optimize Energy Conservation and Resource Efficiency," p. 5 [emphasis added]. DRA suggests that this entire language is superceded (and thereby negated) by the Energy Action Plan II issued in 2005, which states that the Commission should "adopt verifiable performance-based incentives in 2006 for IOU energy efficiency investments, with risks and rewards based on

Footnote continued on next page

In 2006, over the objections of both TURN and DRA, this Commission reiterated the need to address this barrier in the context of its adopted Procurement Incentive Framework:

“...the record in this proceeding persuades us that financial incentives for preferred resources are worthwhile to pursue in conjunction with a [greenhouse gas] cap. Doing so is entirely consistent with the policies articulated in prior Commission decisions, as well as with the action items outlined in the [Energy Action Plan] (I and II). In particular, those policies articulate the need to bring energy efficiency and demand-side resource investments in line with traditional supply-side resources when it comes to the opportunities to earn returns on those investments.”⁸⁵

No party to this proceeding presents evidence to dispute that this fundamental bias exists in today’s regulatory environment, now that investor-owned utilities have been returned to role of managing both supply-and demand-side resource procurement on behalf of their ratepayers. As discussed further below, no party presents convincing evidence to overturn the finding we

performance that will align the utility incentives with customer interests.” (RT at 298-300; 331-332; 337-338.) We disagree with this interpretation of the Energy Action Plan II based on the plain language of its purpose, namely, to serve as an “implementation roadmap” that identifies “further actions necessary” that will “refine and strengthen the foundation” prepared by the Energy Action Plan. (*Energy Action Plan II*, pp. 1-2.) Moreover, there is nothing incompatible between the language in these two documents with respect to what we are addressing here today: In the context of developing appropriate performance-based risks *and rewards* that align shareholder and ratepayer interests, we are considering supply-side comparability as a relevant benchmark, among other considerations.

⁸⁵ D.06-02-032, *mimeo.*, p. 31. In that decision, we specifically rejected the repeated arguments of TURN and DRA for categorical rejection of financial incentives for energy efficiency. *Id.*

made in 1993 concerning the short-term rate impacts associated with energy efficiency that also serve to bias utilities towards supply-side options.

More generally, as NRDC and others point out, a comparable earnings benchmark recognizes that utilities as portfolio managers make day-to-day decisions on how to direct their resources and personnel that regulators cannot directly control or mandate. Without an energy efficiency incentive, given the focus of investors and utility management on increasing shareholder value, utilities will on balance be more inclined to devote scarce resources to procurements on which they will earn a return, and not on meeting or exceeding the Commission's energy efficiency goals, or maximizing ratepayer net benefits in the process. As one witness describes:

“Senior management has the job of assigning limited resources including human capital and senior management attention on doing some things with a great degree of attention and other things kind of as business as usual....By having a payout that's much much less than what we would earn on supply side...sends the message that is, quite frankly, less important, and perhaps you shouldn't invest as much attention and resources in that area as you would in other areas that your...investors are going to be demanding from the business enterprise....What we are attempting to do in the state of California – and I think it's all something we all ought to be very proud of – is to treat energy efficiency not just in terms of words, not just in terms of policy, but hard and fast investment dollars, resources and attention as our primary resource for the state of California...as an alternative to supply-side resources...that satisfies the state energy policy as expressed in California Energy Action Plan...and...is the least cost and quickest way to address the global warming issues that this country faces and that this planet faces.”⁸⁶

⁸⁶ SCE Witness Gene Rodrigues, RT at pp. 123-125, emphasis added.

We agree. Therefore, knowing how much investors would have earned on supply-side procurements, if not for energy efficiency, is useful information: It helps us to consider, among other factors, what level of earnings potential will be sufficient to overcome the biases in favor of supply-side resource procurement and achieve our policy objectives for energy efficiency.

In arguing against supply-side comparability, DRA and TURN generally assert that financial and regulatory biases against energy efficiency are significantly less today than in the past. However, upon close inspection of the record, these parties do not actually refute the fact that utilities continue to earn only on supply-side investments under current regulatory practices, absent energy efficiency incentives. Instead, their comments suggest that this is not really a bias at all, since it is shareholders who put up the initial capital for supply-side investments, whereas ratepayers fund demand-side expenditures without requiring up-front capital from investors.⁸⁷ TURN and DRA made this same argument in the proceedings leading up to D.94-10-059, where we rejected it as a rationale for either discontinuing shareholder incentives altogether or for reducing the earnings potential to minimal levels. As we concluded in D.94-10-059, in addition to who funds the initial investment, there are multiple dimensions to relative risk to consider including: (1) how shareholder earnings vary with project performance and (2) who bears the risk of non cost-effective investments.⁸⁸ Moreover, these considerations do not alter the fact that under

⁸⁷ See, for example, *Reply Comments of DRA*, October 3, 2006, p. 3.

⁸⁸ D.94-10-059, 57 CPUC 2d, p. 54.

cost-of-service regulation utilities earn on “steel-in-the-ground” investments, and not on the successful procurement of energy efficiency.⁸⁹

More importantly, in considering what is fair to ratepayers, we observe that ratepayers “invest” in both supply-side and energy efficiency resources, irrespective of who puts up the initial capital. The only difference is that for steel-in-the-ground investments (generation, transmission, distribution) ratepayers have to pay not only the cost of the facilities, but also the financing costs (debt service and return-on-equity, and associated taxes) to compensate those that put up the initial capital. In contrast, since energy efficiency expenditures are “expensed” and reflected in rates immediately, energy efficiency saves ratepayers substantial financing costs. Those cost savings are magnified because a dollar of energy efficiency can displace far more than a dollar of supply-side investment to meet the same GWh, MW and MTherm energy needs.⁹⁰ Hence, the critical question is not “who puts up the capital” for energy efficiency, but rather, “how can we ensure that the potential return on ratepayers’ investment in energy efficiency is actually realized.”

⁸⁹ DRA poses the following question in its comments: “Should the utilities be allowed to fund energy efficiency programs using shareholder dollars and earn a return on this investment?” (*Pre-Workshop Comments of DRA*, June 16, 2006, p. 16.) The experimental shareholder incentives adopted in the early 1990s included a variation of this approach for SCE, and the Commission’s Advisory and Compliance Division evaluated this and the other experimental approaches. Among other things, a “rate-base” approach to funding energy efficiency does not provide an effective incentive for the utility to reduce energy efficiency costs (since the higher the cost, the greater the potential earnings on rate-based assets), to meet or exceed savings goals, or to maximize net benefits to ratepayers in the process. For these and other reasons, the Commission determined that the post-experimental design of energy efficiency incentives should take on a shared-savings structure.

⁹⁰ Exh. 17, p. 13; Exh. 2, p. 3.

DRA also argues that a major disincentive to energy efficiency has been removed with the “decoupling” of sales from revenue requirements in California.⁹¹ As described in the record, this disincentive arises due to forecasting errors when utility base rates are set to recover the utility’s fixed-cost revenue requirements. The rate charged to customers is derived from the authorized revenue requirement divided by *forecasted* sales. Hence, if actual sales fall lower than the forecasted levels (because of greater than expected energy efficiency installations, for example), then the rates charged do not recover the utility’s fixed costs. Therefore, without any decoupling of revenues from sales or other approaches to address this forecasting risk, the utility faces a strong disincentive to reduce sales through energy efficiency beyond the forecast (and, in fact, a strong incentive to promote sales volumes before the next general rate case.) Decoupling sets up a mechanism to track the difference between actual and forecasted base rate revenues, whereby overcollections are refunded to ratepayers and undercollections are recovered in subsequent rate adjustments.⁹²

However, decoupling merely eliminates a financial *penalty* for pursuing energy efficiency – it does not make it the preferred resource from a shareholder, investment community or utility management perspective.⁹³ Moreover, decoupling in the form of an Electric Revenue Adjustment Mechanism (ERAM) was in effect when we considered and adopted a risk/reward incentive mechanism taking into account supply-side earnings comparability in 1994. In

⁹¹ *DRA Opening Brief*, p. 20.

⁹² Exh. 12, p.5; Exh.14, pp. 2-2 to 2-3; Exh. 16, p. 21.

⁹³ RT at 239.

fact, decoupling and other methods to address this “lost revenue” deterrent to energy efficiency were in place in several other states with energy efficiency programs prior to electric industry restructuring, dismantled in conjunction with industry restructuring, and then resurrected in 2001 in California and in some other states in more recent years.⁹⁴ As DRA itself notes: “The Commission eliminated the ERAM in 1996 with the advent of deregulation, but following the energy crisis of 2000-2001, California returned to its policy of decoupling sales from revenues...”⁹⁵ Our reinstatement of a decoupling mechanism is not a reason to ignore our earlier findings on the existence of significant disincentives to energy efficiency or our policy determinations since the energy crisis to address them.

In fact, the only specific change in regulatory circumstances that TURN and DRA identify relates to the manner in which costs for energy efficiency are funded and recovered through rates. They point out (and no party disputes) that since 1996 energy efficiency has been funded through a “non-bypassable” public goods charge and procurement dollars earmarked for energy efficiency and fully recovered immediately from ratepayers.⁹⁶ TURN concludes that this change has addressed a “critical disincentive” to utility energy spending, referring to the Commission’s finding that DSM expenditures funded in rates “have initial rate impacts that pose competitive risks to the utility in the form of

⁹⁴ See Exh. 12, Appendix B; Exh 49, p. 4.

⁹⁵ *DRA Opening Brief*, p. 20.

⁹⁶ See, for example, *Pre-Workshop Comments of DRA on Proposed Risk/Return Shareholder Incentive Mechanisms for Energy Efficiency Portfolios*, June 16, 2006, pp. 15-16. *DRA Proposed Risk/Return Shareholder Incentive Mechanism*, September 8, 2006, p. 8; RT at 401, 452.

potential bypass.”⁹⁷ DRA’s cross-examination of utility witnesses similarly suggests that it too believes that this disincentive has been addressed by the changes in how energy efficiency is funded, relative to the cost recovery methods in place in 1993 and 1994.⁹⁸

We do not find this conclusion to be logical or supported by the record. Funding of energy efficiency through a non-bypassable charge on distribution rates does not change the fact that there are bypass options available in California, that expenditures on cost-effective energy efficiency results in initial rate increases, and that higher rates increase the risk of bypass. California’s investor-owned utilities face a risk of bypass today through community choice aggregation and municipalization proposals and the Commission is considering issues related to the reinstatement of direct access, another form of bypass, in R.07-05-025. As explained by one of SCE’s witnesses, spending on energy efficiency is different from supply-side resources in terms of short-term rate impacts. This is because energy efficiency (unlike supply-side resource additions) reduces the number of kWh, kW and therms over which fixed costs are spread.⁹⁹ No party has convincingly refuted these facts. Therefore, we stand by the following finding we made in 1993: “Even though energy efficiency may have a higher ratepayer and societal value, other options (e.g., inter-utility power

⁹⁷ D.93-09-078, 51 CPUC 2d 375, quoted at page 17 of *TURN’s Pre-Workshop comments and Preliminary Incentive Mechanism Proposal*, June 16, 2006.

⁹⁸ See DRA’s cross-examination, RT at 390-398.

⁹⁹ RT at 179-180.

purchases) may have a higher private value to utilities because they generally do not initially increase rates.”¹⁰⁰

Our finding that fundamental disincentives to energy efficiency persist today is corroborated by two recent national studies discussed in testimony and submitted into the record. The July 2006 National Action Plan for Energy Efficiency, facilitated by the U.S. Department of Energy and U.S. Environmental Protection Agency, describes the bias against energy efficiency in this way:

“When utilities invest in hard assets, they depreciate these costs over the useful lives of the assets. Consumers pay a return on investment for the un-depreciated balance of costs not yet recovered, which spreads the rate effect of the asset over time. Utilities often do not have any opportunity to earn a return on energy efficiency spending, as they do with hard assets.”¹⁰¹

In March 2007, the United States Department of Energy (DOE) issued its report to the United States Congress pursuant to Section 139 of the Energy Policy Act of 2005. That report identifies “the ability to earn a rate of return on physical assets” as a disincentive facing investor-owned utilities to “implementing energy efficiency programs, rather than investing in physical assets such as power plants and transmission lines.”¹⁰²

¹⁰⁰ D.93-09-078, Finding of Fact 5.

¹⁰¹ Exh. 14, p. 2-9. On June 29, 2007, the Commission adopted a *California Memorandum of Understanding in Support of the National Action Plan for Energy Efficiency*, which we take official notice of today. The National Action Plan for Energy Efficiency and the Memorandum of Understanding are posted at www.cpuc.ca.gov/napee.

¹⁰² Exh. 13, p. 15.

The Lawrence Berkeley National Laboratory report cited by both DRA and PG&E specifically noted--similar to the 2007 DOE Report--that one of the two key “hidden costs” that must be mitigated for a “fair incentive”

“...consists of the *opportunity cost* associated with utility activities foregone by pursuit of DSM programs...includ[ing]...foregone earnings from alternative supply-side investments that would have been made in the absence of a DSM program. We believe that these costs increase with the scale of DSM programs and, therefore will be greatest in the later phases of DSM program implementation. This second type of hidden costs, while still difficult to measure, is more well defined....*The primary analytic issue is determining earnings comparable to those that would have been earned through the acquisition of resources in lieu of DSM.*”¹⁰³

In sum, we conclude that the fundamental regulatory and financial biases we identified in D.93-09-078 also exist under the current regulatory framework, in which utilities have returned to their traditional role as resource portfolio managers. Within the context of this history and purpose for supply-side comparability, we address the various issues raised by the parties to this proceeding on the appropriate level of earnings potential under an energy efficiency incentive mechanism. We start with a discussion of alternative benchmarks presented for our consideration.

6.3.2. Consideration of Alternative Benchmarks

As discussed in Sections 6.2.3 and 6.2.4 above, TURN and DRA developed their shared-savings rates based on considerations or benchmarks other than supply-side comparability. Below, we discuss these alternative approaches (“benchmarks”) and our findings and conclusions.

¹⁰³ Exh. 49, p. 22. [Emphasis added.]

6.3.2.1. Mutual Fund Management Fees

Initially in this proceeding, DRA explained that its proposed 3% sharing rate was based on calculations of the range of management fees earned by mutual fund portfolio managers. DRA asserts that such fees range from \$0.75 to \$4.50 per \$100 dollars, and then notes that its 3% sharing rate falls within that range.¹⁰⁴ DRA provides no references or evidence to support its assertion that this is actually what mutual fund managers charge in the way of fees. Moreover DRA makes an “apples-to-oranges” comparison here, because fund management fees are based on the total portfolio value, not the “profits” or net benefits of the portfolio. In contrast, the shared-savings rate that DRA proffers as being within the range of those fees represents a percentage of net benefits of the energy efficiency portfolio, not its total value.¹⁰⁵ As PG&E showed in its rebuttal testimony, if you assume (as TURN does) that the typical return from a portfolio is 8.5%, then DRA’s calculations when presented as a percentage of net benefits would yield a comparable sharing rate on the order of 35% off the flow of earnings, and not 3%.¹⁰⁶

¹⁰⁴ *DRA Proposed Risk/Return Shareholder Incentive Mechanism*, September 8, 2006, pp. 7-8.

¹⁰⁵ In its reply brief (at page 12), DRA states: “Mutual fund management fees are expressed as a percentage of fund asset value, not income from the assets, as assumed by PG&E.” However, PG&E does not make that assumption – rather, PG&E recognizes that the 3% sharing rate is *not* applied to the fund asset value (i.e., portfolio value) as DRA’s analysis implicitly assumes.

¹⁰⁶ Exh 34, p. 3-3 to 3-4; RT at 458-461. However, as DRA points out in its August 29, 2007 Comments on the Proposed Decision (p. 7), the 35% sharing rate off the flow of earnings on a mutual fund portfolio would cover not only profits to managers, but also compensation for all of the actual costs that the fund managers incur. In any case, DRA’s comparison of mutual fund management fees with its proposed 3% shared-savings rate is based on a flawed calculation, and DRA does not provide any

Footnote continued on next page

As we observed in D.94-10-059, when we rejected a similar proposal, we surmise that mutual fund managers would demand considerably more than the single-digit fees DRA calculates if faced with the risk/reward profile associated with today's adopted incentive mechanism. That is, if they earned only in proportion to portfolio gains, as measured over a multi-year period, and if they were also required to pay financial penalties for missing targets and for losses on their clients' investment.¹⁰⁷ Here too, the record does not support adopting this recommendation.

6.3.2.2. Management Bonus Model

To further support its post-workshop recommendation for a 3% sharing rate, DRA presented a Management Bonus Model in its prepared testimony. Based on the results of this model, DRA claims that a 3% shared-savings rate translates into a 35% managerial bonus equivalent, which DRA concludes would be a sufficient financial incentive to motivate utility behavior under the risk/reward incentive mechanism. (See Section 6.2.3 above.)

However, as the record shows, this claim is premised on a calculation that includes only those employees dedicated exclusively to energy efficiency activities in the denominator. This leaves out employees in other departments that directly and indirectly support the development and implementation of energy efficiency programs, including the executives who made the broad policy decisions related to energy efficiency policy and shareholder returns. In particular, DRA's calculations exclude compensation to members of the Board of

information with which to assess the manager "profits" portion of fund management fees when the basis of that calculation is corrected.

¹⁰⁷ D.94-10-059, 57 CPUC 2d, p. 56.

Directors, officers, senior managers, field personnel and other resource-planning and procurement staff who also have a duty to consider the opportunity to increase earnings in making their decisions about deploying resources. Moreover, the 3% bonus equivalent is calculated using “base” salaries alone, and does not consider other salary and non-salary benefits received by employees.¹⁰⁸ Because of these exclusions, DRA’s model results (i.e., that \$81 million in earnings over three years represents a 35% bonus equivalent) is substantially overstated.

We concur with NRDC, SCE and others that all levels of management and personnel throughout the company, and not just within the energy efficiency division, need to be motivated to view energy efficiency a core business activity in order to achieve the aggressive energy efficiency and environmental goals of the state.¹⁰⁹ DRA Witness Roberts appears to agree with this perspective, based on his testimony that DRA’s proposal would be “large enough to motivate the *entire organization*.”¹¹⁰ However, when DRA’s calculations are corrected to actually reflect this perspective, the numbers that result do not resemble a 35% managerial bonus equivalent.

A simple calculation illustrates how DRA’s model results would differ substantially if the denominator reflected the base pay for the entire company, as opposed to the limited group included in DRA’s model. Using DRA’s 35% figure, PG&E’s incentive at 100% of energy efficiency goals would be \$9.7 million

¹⁰⁸ Exh. 34, pp. 3-2 to 3-3; RT at 319-320, 323-324, 335.

¹⁰⁹ RT at 28-29, 95.

¹¹⁰ RT at 336, emphasis added.

per year.¹¹¹ Based on the data presented in DRA's testimony, PG&E's base pay for all employees in 2004 was \$702.6 million.¹¹² Dividing \$9.7 million by the 2004 base pay yields a company wide "bonus" rate of only 1.4 percent, rather than the 35% presented in DRA's testimony. This calculation does not correct for other salary and non-salary benefits that should appear in the denominator of DRA's calculation, which would lower the bonus equivalent further. However, it serves to generally illustrate that DRA's model substantially overstates the bonus equivalent of \$81 million by limiting its focus on a small subset of the utility's employees.

In addition, DRA bases its model on the premise that the utilities' short-term bonus compensation plans are sufficient to motivate the investor-owned utilities of California to aggressively pursue energy efficiency, a premise that is unsupported in theory and unproven in practice.¹¹³ Moreover, when corrected for the limited scope of employees considered by DRA, the Managerial Bonus Model actually reveals why DRA's proposed 3% shared-savings rate would result in a "bonus" that would be virtually imperceptible. For these reasons, we do not adopt it as a benchmark for shared-savings.

¹¹¹ 35% of 2006-2008 budgeted salary of \$83.2 million divided by 3 years is \$9.7 million per year. See Exh. 45, p. 4, Table 1. *PG&E's Concurrent Opening Brief*, June 18, 2007, pp. 23-24.

¹¹² Exh. 45, Attachment 1, p. 4. Multiplying the number of incumbents time the base pay figures for each job category produces a total base pay figure of \$702,619,960.

¹¹³ Exh. 34, p. 3-1.

6.3.2.3. Energy Efficiency Incentives Offered in Other States

DRA and CE Council argue that the incentives offered by other states present the appropriate measure or range that California's energy efficiency incentives should be compared to for benchmarking purposes.¹¹⁴ TURN also joins this argument in its opening brief.¹¹⁵

However, comparisons of the incentive levels offered in other states fail to address the characteristics of individual states that may make them have greater or lesser relevance for California policy makers.¹¹⁶ CE Council refers to earnings rates found in other venues and merely asserts that the administrative structures are comparable. Differences not supporting its position are neglected.

For example, CE Council fails to discuss that the minimum performance threshold for the incentive mechanism in Massachusetts has been 70% and was only recently changed to 75%. CE Council also does not explore whether the MPS is applied against a savings goal that has been increased relative to Massachusetts's recent performance to the same extent as in California.¹¹⁷

Similarly, in assessing the nine other states' energy efficiency incentives presented in its testimony, DRA did nothing to evaluate numerous important factors that are essential to a valid comparison to California. Specifically, DRA did not consider the level of MW, GWh and MTherm goals (if any) established for the utilities in other states and whether these goals were established by

¹¹⁴ *DRA Proposed Risk/Return Shareholder Incentive Mechanism*, September 8, 2006, p. 8; Exh. 45, pp. 13-16; *Revised Post-Workshop Comments on a Proposed Risk/Return Incentive Mechanism by CE Council*, September 14, 2006, p. 9.

¹¹⁵ *TURN Opening Brief*, June 18, 2006, p. 21.

¹¹⁶ Exh. 18, pp. 16-18.

¹¹⁷ *PG&E Post-Workshop Reply Comments*, September 29, 2006, p. 7.

utilities or regulatory/legislative organizations. DRA also did not consider whether verification efforts, if they were in place, were conducted *ex post* (post installation) and independently of the utility in question. DRA did not consider differences in retail sales, energy efficiency budgets and expenditure levels, or whether the investor-owned utilities in the other states had the option of investing in supply-side resources rather than energy efficiency programs.¹¹⁸ Nor did DRA know or consider whether any of these other states' incentive mechanisms also included financial penalties, as did all the proposals in this proceeding.¹¹⁹

A further important variable that the record shows is difficult to assess is to what degree the current regulatory and institutional structures for other states with energy efficiency incentives are indeed analogous to California's. For example, some of these states have restructured their electric markets, whereas others have not, and utilities in some states are given more responsibility for the delivery of energy efficiency resources than in others.¹²⁰ All this makes comparisons particularly difficult without far more information than DRA or CE Council provided for the record here. In fact, the nine states listed in DRA's testimony represent vastly different utilities, in different service areas, with

¹¹⁸ Exh. 44, pp. 1-2, DRA's response to PGE-DRA-004, response to question 2.

¹¹⁹ RT at 338-339.

¹²⁰ Exh 12, p. 6. Massachusetts, for example, has a restructured utility industry with competitive generation and retail markets. The distribution companies remain regulated and are required to offer energy efficiency. However, these same entities are not in the business of portfolio management – making the trade-offs between supply-side and demand-side resource procurement – as are the California investor-owned utilities today. *Ibid.*, p. 26.

different economic determinants of the power marketplace and the energy efficiency market there, as well as critical institutional differences.¹²¹

Importantly, the ACEEE report that DRA cites reviewed energy efficiency incentives after electric restructuring, during which time incentive rates for those states that still retained energy efficiency incentive mechanisms were observed to decline considerably.¹²² DRA's survey of other states' incentive rates reflects where most of those states have ended up after this decline.¹²³ A survey of other state's energy efficiency incentives would have looked much different if DRA had considered the incentive rates in place prior to electric restructuring, when investor-owned utilities across the country managed resource portfolios as our California investor-owned utilities do again today. In fact, the survey conducted by Lawrence Berkeley National Laboratories prior to restructuring produced much higher range for the incentives in place in 1992 and those anticipated for the 1993-1994 period based on initiatives underway in ten states.

¹²¹ RT at 242-244. Those states are: Arizona, Connecticut, Massachusetts, Minnesota, Nevada, New Hampshire, Rhode Island, Vermont and Wisconsin. Exh. 45, Attachment 2.

¹²² Exh. 47, p. 18; RT at 302-303. Exh. 12, p. 2.

¹²³ In its comments on the Proposed Decision, DRA asserts that three of the nine states compared in the ACEEE study did not undergo restructuring (Vermont, Wisconsin and Minnesota), based on information it obtained from a website reference that is not on the record. However, as the ACEEE study (that is on the record) specifically notes, Wisconsin had performance incentives in place in the early to mid-1990s, but "dropped them as the state began investigating restructuring and deregulation" (Exh. 12 p. 35.) , In any event, DRA's assertion that not every one of the nine states in the ACEEE study actually restructured their electric industry does not alter the fact that DRA's analysis fails to consider the relevance of electric restructuring history on the incentives offered in other states.

That survey shows incentives in the range of 8.2% to 50.3% as a percentage of program costs in 1993-1994, as compared to the ACEEE survey results of 3.3% to 15.3% (also as a percentage of program costs).¹²⁴ To put the results of the two surveys in the context of the earnings rate proposals in this proceeding, DRA's proposal represents incentives of 3.7% of program costs and the highest proposal for shared-savings in this proceeding (PG&E's) represents 24.5% of program costs (at 100% of goal achievement).¹²⁵

In addition to ignoring the relevance of electric restructuring history on the ACEEE survey results, DRA further asks that we ignore the higher end of the range of incentive levels that can be observed from that particular survey for Nevada, Arizona and Wisconsin, arguing that they are less appropriate points of comparison.¹²⁶ However, as PG&E notes, several key variables (including expected rate of population growth) make Nevada and Arizona potentially the most comparable, if indeed any state can be validly compared to California.¹²⁷ Moreover, DRA's assertion that because California's programs are more mature, less financial incentive is needed to improve performance is not founded in basic economic theory or logic. Where energy efficiency has been underway for some time, past achievements have generally pushed the utilities further up on the

¹²⁴ Exh. 49, p. 20.

¹²⁵ See Attachment 2. DRA's proposal results in \$81 million in potential earnings at 100% of goals and PG&E's proposal represents \$538 million (for the 2006-2008 program cycle, all utilities combined.) We divide these figures by \$2.2 billion (for the 2006-2008 program cycle) to calculate the percentage of program costs.

¹²⁶ Exh. 45, pp. 14-15.

¹²⁷ Exh. 34, p. 3-5, Table 1.

supply curve, as in California, thus increasing the level of difficulty of achieving future targets.¹²⁸

In sum, DRA and others ask that we benchmark earnings using the range of incentive levels adopted in other states since industry restructuring, and in doing so, to ignore the upper end of that range. For the reasons discussed above, this benchmarking approach is not reasonable, and we do not adopt it.

6.3.2.4. Non-DSM Performance-Based Incentive Mechanisms

As discussed in Section 6.2.4, TURN argues that non-DSM performance-based ratemaking (PBR) mechanisms adopted in California should be used to benchmark the earnings potential for energy efficiency. In its Opening Brief, TURN presents graphs depicting average and maximum dollar incentive awards received by utilities under various PBR mechanisms. TURN submits that its proposal for shared-savings is reasonable, noting that it produces an earnings level for PG&E that falls within the middle of these ranges.¹²⁹

We find that TURN's analysis is flawed, for several reasons. Most significantly, TURN restricts its analysis to just the absolute dollar amount of these non-DSM mechanisms, and never discusses what each mechanism is designed to achieve or the value of success to ratepayers.¹³⁰ However, each of them was developed in the context of the objectives for the particular

¹²⁸ Exh. 34, pp. 3-10.

¹²⁹ TURN has presented this numerical analysis to support its proposal for the first time in its Opening Brief, depriving other parties from the opportunity to respond in rebuttal testimony or to cross-examine a TURN witness of the validity of the interpretation of this information.

mechanism, and each have very different risk/reward parameters. How can one, for example, compare a mechanism designed to establish penalties and earnings related to the average duration of customer outages (e.g., under SCE's performance PBR) with one that is intended to motivate the procurement of an unprecedented level of energy efficiency savings estimated to produce almost two billion dollars in net benefits to ratepayers?

In addition, TURN's comparison looks at the *achieved* results under the various non-DSM PBR mechanisms, whereas it is the *potential* results for energy efficiency that is established by the shared-savings rates and reflected in parties' proposals.

For example, in the only PG&E mechanism TURN mentions – the CPIM, or Core Procurement Incentive Mechanism – the objective is for PG&E to meet or beat the “market” on core natural gas costs. Outside a tolerance band, PG&E shares in the benefits of lower gas costs or pays for gas costs above that level. This mechanism replaces administrative review of the reasonableness of core gas costs. TURN is implicitly comparing all aspects of this mechanism with the challenge of significantly increasing energy efficiency savings on a sustained basis. However, as PG&E points out, the challenges may not be comparable, and the rewards may not all be in the explicit financial opportunity CPIM provides (e.g., the elimination of after-the-fact reasonableness reviews). In particular, TURN does not mention that if PG&E's purchased gas costs are less than the

¹³⁰ See *TURN Opening Brief*, pp. 15-16; See also *TURN's Pre-Workshop Comments*, June 16, 2006, pp. 13-16 and *TURN's Post-Workshop Comments*, September 8, 2006, Section 3.1.

applicable benchmark, and are less than the tolerance deadband, PG&E gets to keep 25% of the savings, and customers get the other 75%.¹³¹

Similarly, while TURN focuses on what was actually earned under the Coal Plant and Nuclear Unit Incentive Procedures, they each provide for a 50% sharing of net benefits earned from successful plant operations with shareholders, which is well in excess of the sharing rates proposed by any party to this proceeding. Moreover, the “maximum” profit under SCE’s PBR mechanism presented in TURN’s graphs is significantly understated, since SCE could actually have earned under that mechanism almost three times the amount depicted in TURN’s graph.¹³²

Nor is there any discussion about the maximum penalty provisions under these mechanisms, or the thresholds of performance established before penalties are imposed or rewards can be earned. As we discussed in D.94-10-059, and reiterate today, the potential for earnings under the energy efficiency performance incentive mechanism should take these other design factors into consideration. TURN’s focus on the level of dollar rewards previously earned under non-DSM PBR mechanism completely ignores these considerations.¹³³

¹³¹ A description of the Commission-approved CPIM may be found at www.pge.com/tariffs/pdf/GPSC.pdf as part of Commission-approved Preliminary Statement to its natural gas tariffs. (See Section C.14.) *Reply Brief of PG&E*, June 27, 2007, p. 27.

¹³² *Reply Brief of SCE*, June 27, 2007, pp. 17-18; RT at 191.

¹³³ TURN considers it “circular” for us to have concluded in 1994 that the risk/reward profile for DSM in the context of our adopted mechanism was unlike that of any PBR mechanisms in place or under consideration at that time on the supply-side. (See *TURN’s Pre-Workshop Comments*, June 16, 2006, p. 14.) TURN would apparently prefer that we adopt the earnings level awarded under a non-DSM PBR mechanism that has been designed for different purposes, and without any consideration of even the risk

Footnote continued on next page

TURN's analysis is further flawed by the lack of reasonable criteria for deciding what PBR mechanisms to include in its analysis, and the apparent exclusion of ones that could be relevant. When asked what criterion or criteria it used to select the non-DSM PBR mechanisms it relied on in developing its incentive proposal, TURN responded that it "did not develop any specific criteria to include or exclude incentive mechanisms."¹³⁴ Interestingly, TURN did not include the Hazardous Substances Clean-up Mechanism adopted in 1993. A key feature of this mechanism is that insurance recoveries relating to these sites are shared by shareholders and ratepayers at a 30/70 sharing rate to incent the utility to aggressively pursue such upsides that benefit everyone.¹³⁵ Nor did TURN include SDG&E's base revenue PBR earnings in its analysis. Had it done so, TURN's analysis would have revealed that its proposal for potential earnings for SDG&E (approximately \$6 million at 100% of goals) over a three-year period was only about 40% of what SDG&E actually earned under its base case PBR over the same timeframe.¹³⁶

profile of the mechanism we are designing today. For the reasons discussed in this decision, we decline to adopt that approach.

¹³⁴ Exh. 71. p. 2.

¹³⁵ D.94-05-020, *mimeo.*, Appendix A, p. 8.

¹³⁶ SDG&E's actual earnings under the Generation and Dispatch Mechanism was: \$3.7 million (Year 1), \$850,800 (Year 2) and \$9.8 million (Year 3). Year 1 and Year 2 awards were reported in *SDG&E's Electric Generation and Dispatch PBR Mechanism Final Evaluation Report*, April 1998, submitted pursuant to D.97-07-064 in A.92-10-017, of which we take official notice. (See Executive Summary, p. 2.) Year 3 awards were adopted in D.98-12-004 as part of settlement agreement adopted in that decision. See Attachment 1, Section VI.B.

For these reasons, we reject TURN's assessment that non-DSM PBR incentive levels provide a reasonable benchmark for establishing incentive levels in this proceeding.

6.3.2.5. Energy Efficiency Incentive Levels During Electric Restructuring and the Energy Crisis

TURN neglects to consider in any context the performance-based DSM incentive mechanism adopted in 1994 as a relevant PBR benchmark for its purposes, even though it was designed to address energy efficiency and procurement objectives similar (although not identical) to those articulated in this proceeding. TURN and DRA argue (with CE Council concurrence) that such consideration would not be meaningful because the utilities have shown no statistical correlation between the higher incentives offered prior to electric restructuring and improved performance.¹³⁷ Instead, these parties conclude that the lower incentive levels adopted by the Commission during electric industry restructuring and the energy crisis would serve as a more appropriate benchmark for earnings in this proceeding.

TURN and DRA make much of the fact that the utilities did not perform a statistical analysis to correlate incentive levels with performance. In fact, the record indicates that such an analysis would be extremely difficult (if not impossible) to perform due to the numerous variables that have affected portfolio performance--as well as differences in how energy efficiency performance has been defined--over the last 15 years. Still, TURN spends 13 pages of its opening brief presenting figures to support its position that utility

¹³⁷ See, for Example, *DRA Opening Brief*, June 18, 2007, p. 33-34. *CE Council Opening Brief*, p. 5.

spending and utility savings do not correlate to the higher incentive levels provided by D.94-10-059. Because all but one of these figures first appeared in briefs, there was no opportunity for other parties to test their assumptions and bases, or confirm that they accurately represented information supplied in utility data responses that were included in the record.¹³⁸ However, as PG&E and others note, these figures are problematic in many ways, including the fact that they do not reflect many other variables that affect performance.¹³⁹

In particular, DRA, CE Council and TURN attempt to infer from historical data on incentive levels and budgets that there is no correlation between the two, and therefore, no correlation between incentive levels and performance. However, the Commission has established funding levels for energy efficiency over the years taking a variety of factors into consideration. As PG&E points out:

“...from 1990 through 1997, the Commission approved energy efficiency funding in rate cases every two to three years, and annually reviewed and approved program plans and expected savings. Between 1997 and 2004, the Commission approved funding (consistent with legislative requirements) as well as programs and expected savings every year. Thus, every budget, program plan and expected savings *reflected public input and ultimate approval by the CPUC*. Each year’s planned budget and expected savings therefore balanced the interests of all active

¹³⁸ *TURN Opening Brief*, June 18, 2007, pp. 22-34, especially p. 29. The only similar figure TURN provided previously in this proceeding was a graph of spending and earnings for the combined utilities, which was also reproduced in CE Council’s post-workshop comments and opening brief. (*TURN Pre-Workshop Comments and Preliminary Incentive Mechanism Proposal*, June 16, 2006, p. 9.)

¹³⁹ See *PG&E Reply Brief*, June 27, 2007, pp. 26-27.

stakeholders (including DRA and TURN) and the policy goals of the Commission at that time.”¹⁴⁰

Therefore, it is not reasonable to conclude that because budgets and spending levels do not appear to be correlated with incentive levels, then higher incentive levels are no more effective than lower incentive levels, as these parties suggest.

We also rejected this line of thinking in D.03-10-057. In 2003, TURN presented similar graphical depictions of budgets and incentives when it argued that the Commission should reopen and repeal the shared-savings incentive mechanism adopted in D.94-10-059. Pointing to the drop in program spending in 1995 relative to previous years, TURN asserted that the shared-savings mechanism we adopted in 1994 did not provide incentives to the utilities to aggressively pursue cost-effective energy efficiency, despite the continuation of substantial shareholder incentives. In rejecting TURN’s position, we explained:

“...the reasons for the reduction in program spending are certainly debatable. TURN fails to point out one very plausible factor to explain this reduction, namely, that we authorized reductions in DSM expenditures in order to continue an electric rate freeze that eventually became the basis for the electric rate freeze codified in [Assembly Bill] 1890.”¹⁴¹

Moreover, as we noted in D.03-10-057, the lack of correlation between incentives and spending levels, for whatever reason, does not mean that the incentive mechanism has not produced sizable net benefits to ratepayers. Interestingly, none of the graphs presented by TURN even look at net benefits

¹⁴⁰ *Ibid.*, p. 23.

¹⁴¹ See D.03-10-057, *mimeo.*, p.28.

(savings minus costs) to ratepayers as a performance metric to consider. In fact, the only figure presented in this proceeding that does suggest a positive correlation between incentive levels and the production of savings at the highest efficiencies (or lowest total costs) is the one produced by SDG&E in its testimony and subjected to cross-examination.¹⁴²

Nonetheless, as the record indicates, it is difficult to draw definitive conclusions from graphing historical data on incentives and savings or net benefits, even if a more comprehensive graphing of data were available. This is because of fundamental differences in reporting and measurement practices, as well as very different purposes and incentive structures over the 15 year period. During some years “commitments” were counted in reporting savings achievements, while in others they were not.¹⁴³ In addition, in most of the years between 1990 and 2005 savings were not subject to *ex post* verification.¹⁴⁴ Therefore, the MWh achievements (and other metrics based on those achievements) depicted in these graphs are not directly comparable.

¹⁴² Exh. 36, p. MMS-4; Exh. 44, RT at 279-280. . DRA dismisses this figure as lacking substance because it presents an optical graphing of net benefits as the difference between savings and expenditures, rather than a statistical analysis. TURN also dismisses this figure, arguing that SDG&E was an “anomaly” that cannot be generalized to the other utilities. See *Comments of DRA on Proposed Decision*, August 29, 2007, p. 12; *TURN’s Opening Comments on Proposed Decision*, August 29, 2007, p. 9. While this graph may have limitations, we point to it because it at least attempts to present visually the historical relationship between incentive levels and net benefits, and does suggest a positive correlation between the two for SDG&E.

¹⁴³ RT at 282. The record indicates that savings from 1990-1997 were reported by the utilities for installed measures only, and for 1998-2005 for installed and committed installations.

¹⁴⁴ RT at 284-285.

In light of these fundamental differences, it is difficult to determine exactly what the figures in TURN's Opening Brief represent. In particular, TURN's argument appears to rest largely on its Figure 4 and 5, which are captioned "total DSM spending" versus "total DSM incentives" and "total first-year electric savings (MWh)" versus "total DSM incentives," respectively. The utility incentives are those associated with the program for that year, but it is not clear whether the figures chart the original utility incentives claim for a given year, or the actual amounts that were collected after the subsequent years of measurement, or the amount awarded in that year for previous years' activities.

In addition, for years 1998-2000 it is not clear whether TURN included both the current program year expenditures plus the pre-1998 commitments that were paid in subsequent years. TURN does not indicate if the expenditures for 1998 and beyond are "actual" as were reported for pre-1998 years or "recorded" expenditures which included commitment dollars to be paid in future years as projects were completed. Moreover, since it presents only first-year savings, Figure 5 does not indicate how incentive levels relate to lifecycle savings for the measures counted in each year.

DRA and TURN ignore these differences and inconsistencies, as well as others. Observing that the utilities exceeded their savings targets in 2001 with incentives capped at 7% of energy efficiency program budgets, DRA argues that this level should be sufficient incentive to the utilities to achieve the Commission's goals.¹⁴⁵ In its opening brief, TURN makes a similar assertion.¹⁴⁶

¹⁴⁵ Exh. 45, p. 22.

¹⁴⁶ *TURN's Opening Brief*, June 18, 2007, p. 34.

However, this and other inferences made by these parties from historical data ignore the fundamental differences in the role of utilities in energy efficiency and resource procurement as well as the changes in Commission policy on energy efficiency over the past 15 years.

As we described in previous decisions,¹⁴⁷ the history of energy efficiency over the last 15 years can be divided into several different “eras”. From 1990-1997 (the “pre-restructuring era”), the Commission viewed DSM including energy efficiency as a resource, and utilities administered the programs and earned incentives for successful achievement of resource savings and positive net benefits to ratepayers. During the first three years of this period, incentives were at relatively low experimental levels and tied to savings achievements based on *ex ante* estimates of load impacts. Beginning in 1993, the Commission adopted rigorous *ex post* measurement protocols and a shared-savings incentive mechanism designed to encourage the achievement of maximum dollar net benefits for ratepayers, and not tied to specific kWh, MW or therm savings goals.

Then, by the end of 1997, electric restructuring brought significant change. The focus of energy efficiency became market transformation with the emphasis on making energy efficiency a normal part of market transactions, and eventually phasing out ratepayer-funded DSM entirely. Utilities became temporary administrators, under short-term extensions through 2001. Milestone-based incentive mechanisms were adopted in lieu of shared-savings. Milestone incentives were based on spending levels, program activity levels (e.g., the number of audits performed) and on measuring market effects, with only a

¹⁴⁷ See D.03-10-057, Attachment 2 and D.05-10-10-041, Attachments 2, 3 and 4.

small portion of the incentive payments based on *ex ante* energy savings – and none on verified net resource benefits.¹⁴⁸ Overall incentives were capped at 7% of total energy efficiency budgets, and were eventually discontinued as of program year 2002.

The energy crisis year of 2001 brought with it emergency responses, including a “summer 2001” solicitation by the Commission to ramp up energy efficiency spending targeted to addressing energy shortfalls as quickly as possible. Since that crisis, and the reinstatement of the utilities as both supply-side and demand-side portfolio managers, we have entered into a new era of energy efficiency policy heralded in by the Energy Action Plan of 2003 and Commission policy determinations in this rulemaking and its predecessor (R.01-08-028).

Given this history, we find it unreasonable to infer that the energy efficiency incentive levels adopted during restructuring (or during the peak of the energy crisis in 2001) are appropriate for the risk/reward incentive mechanism we are adopting today. Nor is it reasonable to infer correlations between the stability of the pre-1998 industry structure and earnings mechanism and the rapid changes of the following few years. Conclusions drawn by comparing only one or two variables (e.g., energy savings and budgets) across these years fail to address the significance of the other variables in play during those years, such as restructuring, the energy crisis, and subsequent recovery.

¹⁴⁸ RT at 285-286.

For the reasons discussed above, we do not find merit to the inferences and recommendations made by TURN, DRA and CE Council concerning historical energy efficiency incentive levels and performance.

**6.3.3. Supply-Side Comparability Benchmark:
Adopted Range of Values**

As discussed in previous sections, supply-side comparability provides a relevant numerical benchmark for the earnings potential under an energy efficiency incentive mechanism, in the context of other considerations. Most of the base case assumptions used by the utilities in their analysis were not disputed in this proceeding, such as the use of a mid-range value (12 years) for average energy efficiency measure lives, or the 50-50 split between “utility build-utility buy” scenarios. Based on the record in this proceeding and our review of the utilities’ long-term procurement plans, we find these assumptions to be reasonable for our purposes today, namely, to estimate a comparable supply-side earnings benchmark.¹⁴⁹

DRA notes that several of the input assumptions are subject to change over time and may vary by utility, but does not present alternate values for calculating the base case numbers “since DRA recommends against using this model for the current program.”¹⁵⁰ Instead, DRA suggests that specific input assumptions be updated and debated at each earnings claim (i.e., “at such time

¹⁴⁹ In particular, see Exh. 41; Exh. 34, pp. 3-13 to 3-14; *PG&E’s Response to ALJ Ruling*, March 15, 2007, pp. 2-3; we have also reviewed the confidential filings of the utilities (i.e., Energy Balance Accounting Table 2007-2016) for their long-term procurement plans in reaching our determination that a 50-50 split between “build versus buy” is a reasonable base case assumption for today’s analysis of comparable earnings.

¹⁵⁰ Exh. 45, p. 24.

that shareholder funded incentives are proposed.”)¹⁵¹ This recommendation presumes that the supply-side comparable earnings calculations developed in this proceeding represent a “model” where the input and output values directly establish the shared-savings rates. This presumption is not valid: As discussed in this decision, supply-side comparability serves as a general benchmark for a range of values, and is considered along with other factors in establishing the earnings potential and associated shared-savings rates under the adopted incentive mechanism.

DRA’s proposal also suggests that the shared-savings rates would be modified at each earnings claim (through the “update and debate” that would occur). This would introduce an unreasonable level of uncertainty as to the design parameters of the mechanism itself, ongoing litigation and associated delays into the earnings recovery process. For these reasons, we do not adopt DRA’s approach to establishing the input assumptions for supply-side comparable earnings calculations. Instead, for today’s purposes of establishing a benchmark range of values, we use the utilities’ base case assumptions with variability around certain parameters, as discussed below.

There was considerable debate in this proceeding over whether the utilities’ return-on-equity assumptions should be adjusted downwards to reflect alternative use of funds, as proposed by TURN. We conclude that TURN’s alternative-use-of-funds analysis is premised on an assumption that is not supported by the factual record in this proceeding or by a persuasive conceptual

¹⁵¹ *Id.*

rationale, as we explain below. Therefore, we do not adopt this proposed adjustment to supply-side comparability calculations.

More specifically, TURN's analysis is premised on the assumption that the utility would have "in its pocket" the amount of cash that it otherwise would have used to invest in the supply-side resources, if not for energy efficiency.¹⁵² According to TURN's Witness Marcus, the utilities would not leave this large amount of available cash "sitting under their mattress," but would instead invest it in alternative ways.¹⁵³

But where does this large amount of cash come from? For PG&E alone, the equity that TURN assumes the utility would have on hand because it did not need to invest in supply-side infrastructure due to energy efficiency is on the order of \$500 million.¹⁵⁴ TURN suggests that the utility has this amount of cash on hand through the accumulation of "retained earnings" over time, that is, what is left over in cash (customer bill payments less utility expenses) after what the utility spends to meet its capital needs and to pay out dividends.¹⁵⁵ However, as PG&E Witness Patterson testified, the utility does not accumulate large amounts of cash on hand to make investments other than in its own capital infrastructure, which currently costs PG&E approximately 2-1/2 to 3 billion dollars per year.¹⁵⁶ Other utility witnesses corroborated this testimony.¹⁵⁷ Common sense as well as

¹⁵² RT at 529-530.

¹⁵³ RT at 526.

¹⁵⁴ RT at 592.

¹⁵⁵ RT at 533-534, 540.

¹⁵⁶ RT at 540-541. Exh. 34, pp. 1-4 to 1-5.

¹⁵⁷ Exh. 18, pp. 12-13; RT at 149-150.

the factual record refute TURN's premise that the utility would make it a practice to raise money in the capital markets to cover supply-side investments that it does not need to make, in order to retain those funds so that they could be used for alternative investments.¹⁵⁸ In fact, TURN's Witness Marcus acknowledges that the utilities are unlikely to issue new shares of stock to raise capital for the investments that they are actually planning to make over the next 3-5 year timeframe, if not longer.¹⁵⁹

In prepared sworn testimony and under cross-examination, utility witnesses explained how their companies actually plan and manage their cash requirements, based on first-hand experience as corporate planners. As they explained, the utility does not plan to have more cash than is needed for the plant and equipment that it will be building (or for working cash requirements), and carefully manages its cash reserves accordingly. The utility also does not sell shares or issue debt to raise cash for a capital investment it does not need to make, such as the supply-side resources that energy efficiency is planned to defer or displace. Granted, as one utility witness pointed out, there may be instances where the original forecast of cash requirements may overstate the need for capital infrastructure, resulting in more cash than is actually needed. However, that is certainly not something the utility plans for, and when it does occur, the utility generally uses that extra cash to buy back enough equity and debt to maintain its authorized equity/debt structure. It does not follow that the utility has "alternate uses" for equity on a dollar-for-dollar basis that was not

¹⁵⁸ RT at 482.

¹⁵⁹ RT at 515-516.

needed for supply-side resources due to energy efficiency, as TURN's analysis assumes.¹⁶⁰

There is no factual dispute that PG&E, SCE, SDG&E and SoCalGas use profits from the capital investments and utility operations they do undertake for a variety of purposes described in TURN's testimony, including the pay-out of dividends to investors or stock repurchases (via their holding companies).¹⁶¹ However, such practices would be expected for any investor-owned utility company that is profitable based on the investments it does make in infrastructure (for which it is authorized a return) and the prudent management of its operating costs. It does not follow (as suggested by TURN's data requests and cross-examination on what the utility has done with earnings it has accumulated in the past or may accumulate in the future)¹⁶² that these profits originate from cash available to the utility because of supply-side investments displaced through energy efficiency.¹⁶³ Moreover, TURN's assertion that the utility's net income "will increase as a result of lower capital expenditures" defies a basic tenet of cost of service ratemaking: When capital expenditures are

¹⁶⁰ RT at 149-150, 543.

¹⁶¹ Exh. 65, RT at 149.

¹⁶² See Exhs. 23, 65; RT 148-150; 477-479.

¹⁶³ In its comments on the Proposed Decision, TURN acknowledges that the company's financial planning will change if it does not build something for any reason. TURN then introduces a new argument that it is the "financial planning that the utility must engage in to manage its cash" that matters, contending that the rate of return on a supply resource should "consider the impact on shareholders of the other cash management techniques that would be used if the plant were not built." (See *TURN's Opening Comments on Proposed Decision*, August 29, 2007, pp. 6-7.) TURN's suggestion that the analysis somehow changes when one looks at overall cash management techniques is not supported by the record, as SCE points out in its reply.

lower, by definition rate base is lower and so too is net income, all else remaining equal.¹⁶⁴

In addition, TURN's analysis of "alternative uses of funds" presents a fundamental contradiction to the position TURN also takes in this proceeding, namely, that the "right" answer to a calculation of foregone shareholder earnings is probably zero.¹⁶⁵ If shareholders are no worse off when energy efficiency displaces supply-side resources because they can take their investment funds elsewhere to earn a comparable return, how is it possible that the utility can use those funds for the alternative investments that TURN describes in its testimony?

Finally, we observe that TURN's economic and financial theories on basically the same issue have taken very interesting twists and turns over the years. For example, in 1993, observing that the utilities' market to book ratios were greater than 1.0, TURN asserted that the utility's return-on-equity was set too high by the Commission. TURN then postulated that because the utilities could improve earnings per share just by issuing additional shares under these circumstances, they were motivated to promote sales growth (and a corresponding growth in utility plant investment). TURN's recommendation at that time was to get rid of this "growth incentive" by setting the rate-of-return lower, rather than authorizing shareholder incentives for energy efficiency. D.93-09-078 presents a detailed discussion on the lack of factual, logical or policy support for TURN's thesis and rationale for opposing the continuation of energy efficiency shareholder incentives.¹⁶⁶

¹⁶⁴ TURN's *Opening Brief*, June 18, 2007, p. 36.

¹⁶⁵ RT at 520.

¹⁶⁶ See D.93-09-078, 51 CPUC 2d, pp.382-385.

Having its previous theory rejected over ten years ago, TURN is now suggesting that utilities are motivated to raise equity in the market for supply-side investments no longer needed (or keep cash raised for that purpose “in its pocket”), so it can use those funds for *alternative* investments that TURN argues would yield an equal if not greater return to its shareholders.

Interestingly, in this proceeding TURN again observes that the utility’s market-to-book ratios are high, and also expresses the view that the Commission is setting the return-on-equity too high in its cost of capital proceedings. However, TURN draws quite different conclusions from these observations in this instant case. According to TURN’s Witness Marcus, the existence of authorized returns that are higher than the cost of equity, and the high ratio of market-to-book values are precisely the reasons for any *positive* foregone earnings that TURN calculates under its alternative-use-of-funds analysis.¹⁶⁷

In sum, TURN’s theory on utility behavior in this proceeding lacks the support of a factual record and a persuasive conceptual rationale. For the reasons discussed above, we do not make adjustments for alternative-use-of-funds to the calculations of supply-side comparability.

There was also debate in this proceeding over whether comparable earnings should be calculated based on “comparable performance” versus “comparable costs.” As described in Section 6.2.2 above, NRDC argues that the latter approach should be taken, i.e., that comparability should be calculated based on the energy efficiency portfolio costs. We do not agree. The utilities’ approach is consistent with the purpose of the comparable earnings analysis,

¹⁶⁷ Exh. 66, p. 1, 14 and RT at 519, 523-524.

namely, to calculate earnings associated with the supply-side resources avoided by energy efficiency. NRDC recommends an approach based on comparable costs, rather than performance, but does not provide a persuasive conceptual rationale for doing so. Nor has this Commission taken that approach in the past when comparing the earnings potential of supply-side resources in the context of an energy efficiency shared-savings mechanism.¹⁶⁸ In fact, when questioned by the assigned ALJ on this subject, NRDC's witness was unaware of any precedent at this Commission or in other states for the approach to comparable earnings that NRDC advocates in this proceeding.¹⁶⁹ For these reasons, we do not calculate comparable supply-side earnings based on the costs of the energy efficiency investment.

Parties also debated whether debt equivalence should be imputed for power purchases in the utilities' comparable earnings calculations. In addition, TURN disputes the use of only combined-cycle natural gas turbines (CCGT) for the avoided generation capacity, and argues for replacing 24% of that amount with lower-cost combustion turbines (CTs).¹⁷⁰

¹⁶⁸ See D.94-10-059, 57 CPUC 2d, p. 52, where the Commission provides an example illustrating how earnings would need to be higher to reflect equivalent performance under a comparable earnings approach.

¹⁶⁹ RT at 46.

¹⁷⁰ The assumed cost of the CT that TURN proposes is disputed by PG&E as being too low, but this issue appears to make a relatively small impact on the comparable earnings analysis, i.e., on the order of 0.3% increase to the shared-savings rate, all other things being equal. (RT at 601.) DRA also asserts that there is a problem with the manner in which PG&E has implemented a mid-year convention for calculating net-present value of cash flows in its workpapers. However, the impact of DRA's recommended changes would be quite small (an impact on the shared-savings rate on order of 5%) and moreover, based upon the examination of this issue during

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We have carefully reviewed the record on these issues, and conclude that there are persuasive arguments on both sides of these disputes. For example, as NRDC, TURN and DRA point out, the Commission has not adopted a formal debt equivalence policy in cost-of-capital proceedings and has chosen instead to consider the issue of debt equivalence on a case-by-case basis in those proceedings. At the same time, as the utilities note, the Commission has authorized the utilities to impute debt equivalence in assessing the risks of power purchase agreements.¹⁷¹ With regard to the CT substitution issue, SCE raises reasonable resource planning and dispatch issues in response to TURN's arguments for such substitution.¹⁷² These specific issues are more appropriately addressed in cost-of-capital proceedings (for debt equivalence policies and calculations) or resource planning/avoided cost proceedings (for the CCGT versus CT avoided cost question). Rather than attempt to resolve them here, we will acknowledge that they create a range of possible outcomes around the base case assumptions for the purpose of calculating comparable earnings.

Imputing debt equivalence to power purchases and assuming avoided generation capacity based exclusively on CCGT costs produces the upper range of comparable earnings estimates. Based on the scenario analysis presented on the record, this upper range is approximately \$700 million for all utilities

evidentiary hearings by the ALJ, we are not persuaded that DRA's objections have merit. (RT at 616 to 628.)

¹⁷¹ See for example: Exh. 3, p. 4; *Comments on Utility Calculations/Scenarios and Reply Comments of NRDC*, March 26, 2007, p. 3; *DRA Opening Brief*, June 18, 2007, pp. 30-32; Exh. 17, pp. 13-14; *Post-Workshop Reply Comments of SCE*, September 29, 2006, pp. 3-6; *Opening Comments of SCE in Response to the ALJ's Ruling*, March 8, 2007, pp. 6-8; Exh. 34, pp. 1-6 to 1-8.

combined, over the three-year program cycle.¹⁷³ Removing debt equivalence and substituting 24% of avoided CCGT costs with CT capacity costs, as TURN recommends, will produce the lower range of the calculations. Based on the record, we estimate this lower range at \$450 million for all four utilities combined, over the three-year program cycle.¹⁷⁴

Finally, DRA questions the applicability of the utilities' supply-side comparability analysis to natural gas energy efficiency activities, since natural gas companies do not avoid the same type of supply-side investments as assumed in the analysis for electric utilities. We agree with PG&E that the supply-side comparability benchmark should not be separated by fuel or type of program activity, but rather should serve as a general numerical guide for setting the appropriate share of the combined net benefits from electric and natural gas efficiency programs. In fact, by including only the earnings from the electric supply-side resources foregone, and none from any gas supply-side resources foregone, it could be argued that the analysis understates the resulting shared savings rate. As PG&E points out, this approach avoids the need to

¹⁷² Exh. 66, pp. 4-5; Exh. 18, p. 7; RT at 183-185.

¹⁷³ Exh. 73, Scenario E for PG&E; Exh. 55, Base Case for SCE, SDG&E and SoCalGas.

¹⁷⁴ This lower range can only be approximated since the substitution of CTs for CCGTs was performed only for PG&E's calculations by the parties. All other things being equal, it appears that the CT substitution alone reduces comparable earnings anywhere from 6% (Exh. 73, Scenario C) to 14% (Exh. 55) depending on the other scenario assumptions (e.g., debt equivalence, alternative use of funds). We use the average of 10% for the purpose of adjusting the "no debt equivalence" scenarios of the other utilities as follows: SCE's, SDG&E's and SoCalGas' Scenario #1B (Exh. 55) reduce to \$186, \$27.9 and \$17.1 million, respectively. Adding to that PG&E's Scenario #1B (which already substitutes CTs for CCGTs before removing debt equivalence) of \$217, produces a total of \$448.

debate the size of gas supply-side resource investments, about which there is no record.¹⁷⁵

In sum, we conclude that the supply-side comparability analysis in this proceeding yields comparable supply-side pre-tax earnings in the range of \$450 to \$700 million for all four utilities combined, based on the energy efficiency program activities planned for the 2006-2008 program cycle.

6.3.4. Adopted Shared-Savings Rate(s)

As most parties to this proceeding acknowledge, establishing the level of earnings opportunity for a shareholder risk/reward incentive mechanism is ultimately a judgment call that the Commission must make, and not a precise science.¹⁷⁶ Generally speaking, we believe that the earnings potential under such a mechanism should be designed both to balance the potential penalties under the mechanism and to offset existing financial and regulatory biases in favor of supply-side procurement. In this context, consideration should be given to what level of earnings potential will provide a clear signal to utility investors and shareholders that achieving and exceeding the Commission's savings goals (and maximizing ratepayer net benefits in the process) will create meaningful and sustainable shareholder value. At the same time, we should weigh and consider differences in the risk/reward profile of utility resource choices in applying the comparable earnings benchmark to our incentive mechanism. In addition, consideration should be given to the level of performance expected in return for higher and higher earnings potential. Moreover, these considerations should be

¹⁷⁵ RT at 427. *PG&E Reply Brief*, June 27, 2007, p. 46.

¹⁷⁶ See for example, RT at 20, 329-330.

balanced by a sense of what is “fair” to ratepayers in terms of the return on their investment in energy efficiency.

In our judgment, providing the opportunity to earn using supply-side comparable earnings as a benchmark creates the sustainable “clear signal” we are looking for on the earnings side of the incentive mechanism. However, we are also persuaded by the arguments made by DRA and others that this benchmark should be applied very conservatively to our adopted incentive mechanism, given the relative risk/reward profiles of utility resource choices and the additional considerations discussed below.

As we recognized in D.94-10-059, it is challenging to compare the different (and changing) risk/reward profiles among utility resource choices in considering how to apply a supply-side comparable earnings benchmark to the design of an energy efficiency incentive mechanism.¹⁷⁷ Nonetheless, we were able to make certain observations relevant to the different risk/reward profiles that were applicable at that time, and reached conclusions from them as to the appropriate level of earnings potential for energy efficiency relative to that benchmark.¹⁷⁸

Today, we observe that since the energy crisis, utilities must now manage supply-side resources to meet resource adequacy requirements subject to the risk of significant financial penalties.¹⁷⁹ With the passage of Senate Bill 1368, utilities also now face the risk of non-compliance for any long-term supply-side procurement that does not meet the GHG performance standard required by

¹⁷⁷ D.94-10-059, 57 CPUC 2d, p. 54.

¹⁷⁸ *Ibid*, pp. 54-58.

¹⁷⁹ See our references in Section 5.1 to these penalty provisions.

that statute. Moreover, although its implementation is several years out into the future, the statewide GHG emissions cap pursuant to Assembly Bill 32 will further increase the financial risks associated with any supply-side resource procurement that increases GHG emissions.¹⁸⁰ These developments serve to increase the risks associated with procuring at least certain types of supply-side resources and, in turn, reduce the relative risks of energy efficiency in the context of utility resource portfolio management, even if the impact of these changes cannot be quantified.

Working in the other direction, however, are the fundamental disincentives to energy efficiency that we discuss in Section 6.3.1 relative to “steel-in-the-ground” supply-side investments of any type (renewables or non-renewable generation, transmission and distribution), and the short-term rate impacts associated with energy efficiency relative to all supply-side procurements, including power purchase agreements. Moreover, as discussed in Section 4.2, energy efficiency is not as readily “deployed” as supply-side resources, since it involves customer-side appliance changes, arrangements with manufacturers and distributors, etc. Hence even when the portfolio funding is authorized, there is more uncertainty as to the actual deployment results of energy efficiency than for supply-side resources. In addition, energy efficiency requires independent verification of load impacts that extends beyond program implementation. These attributes introduce uncertainty and performance risks to shareholders that are not shared by supply-side choices.

¹⁸⁰ Senate Bill 1368 (Stats. 2006, ch. 598)/Assembly Bill 32 (Stats. 2006, ch. 488).

Although ratepayers put up 100% of the investment capital for energy efficiency programs, shareholders are at risk under the adopted incentive mechanism for losses to that capital and face sizable per-unit penalties for substandard performance of the portfolio. Unlike a rate-based plant, shareholder earnings will vary in direct proportion to performance (i.e., realized net benefits), even when factors entirely beyond the utility's management control affect that performance.

At the same time, the utilities now have over 15 years of experience in implementing energy efficiency and over 10 years of EM&V study results available to them. They also have the authorization and funding to conduct meaningful process and market penetration studies to assist them in managing these uncertainties during the program cycle. In addition, as we noted in D.94-10-059, applying the risk/return incentive mechanism to the entire portfolio of programs, rather than on a program-specific approach, will serve to decrease the absolute level of potential penalties as well as the probability of falling into the penalty range.¹⁸¹

On balance, these observations lead us to conclude that energy efficiency earnings should be no higher than the lower end of the range of comparable earnings for supply-side resources, i.e., no higher than \$450 million for all utilities combined, over the three year funding cycle. We also agree with NRDC that we should also consider the level of goals achievement at which supply-side comparable earnings should be awarded.¹⁸²

¹⁸¹ D.94-10-059, 57 CPUC 2d, p. 57.

¹⁸² See *Post-Workshop Comments of NRDC*, September 8, 2006, p. 15, in reference to this issue of when the comparable earnings benchmark should be applied in the context of

Footnote continued on next page

In our view, earnings that approach comparable supply-side levels should be awarded at a level of *superior* performance, that is, performance that is significantly greater than the forecasted level of savings or net benefits expected from the authorized energy efficiency portfolio. Using the supply-side comparability benchmark in conjunction with achievement of superior performance is consistent with our discussion of the role of financial incentives in D.06-02-032, our decision on a procurement incentive framework. There we referred to “financial rewards to [investor-owned utility] shareholders for *superior achievement* in procurement particularly [greenhouse gas]-friendly resources” based on performance benchmarks that are specific to each resource.¹⁸³

In the case of energy efficiency, we are looking for superior achievement in achieving dual objectives, that is, for achieving GWh, MW and MTherm savings beyond the levels that the utilities have estimated can be achieved with available funding, and maximizing net resource benefits in the process. Recognizing that our savings goals are aggressive (yet achievable), and considering what

“excellent” performance. PG&E’s recommendations for shared-savings rate would essentially establish full supply-side earnings equivalency at 100% achievement of the goals, whereas the other utilities and NRDC would not award full supply-side earnings equivalency until anywhere from approximately 110% to 140% of goal achievement, depending on the proposal. For the utility proposals, these performance levels can be estimated by comparing Exh. 55 supply-side comparable earnings values in Table 7 to Table A values in *Joint Documents*, September 16, 2006; For NRDC’s proposal, compare the supply-side comparable earnings it proposes in Table 7 of Exh. 55 to the Table A values in Exh. 4. NRDC’s proposal represents the higher end of this range, i.e., its comparable earnings estimate of \$498 would not be achieved until 140% of the goals are reached.

¹⁸³ D.06-02-032, *mimeo.*, p. 27. Emphasis added.

percentage of sharing is fair to ratepayers and will reasonably balance the penalty side of the curve, we find that the tiered-rate structure described below strikes a reasonable balance.

As discussed in Section 4.2, earnings will start to accrue only when the utility has met the MPS. To meet the MPS the utility must: (1) achieve 85% of the savings goals, based on a simple average of the percentage of each individual GWh, MW and (as applicable) MTherm goal they achieve, *and also* (2) meet a minimum of 80% of the goal for each individual savings metric. SoCalGas will meet the MPS if it achieves a minimum of 80% of the savings goal that applies to a gas-only utility, namely, the MTherm goal.

Once the utility has met the MPS, a first tier sharing rate of 9% will apply. When the utility has met 100% of the goals, a second tier sharing rate of 12% will apply, up to the earnings cap.

Once the MPS is met, each individual savings metric must be no less than 5% below the second tier threshold to be considered within that tier based on the three-metric average. So, for example, if a utility's MW achievement is at 85% of the MW goal, but its GWh and MTherm achievements are 100% and 115% of the goals, respectively, the utility has met the MPS of 85% but not the 100% threshold for the second tier (12%) savings rate. It is still in the first tier (9%) range until it pulls up the MW level to 95%.

Figure 1 in Attachment 8 illustrates the tiered shared-savings rates and the overall earnings/penalty curve. Table 1 in that attachment presents estimated pre-tax earnings levels if the utility energy efficiency portfolios achieve 85% of the 2006-2008 saving goals and above, based on a PEB calculation that includes all 2006-2008 portfolio costs. The table also shows the financial penalties if

performance over that program cycle drops into the penalty range, which begins at 65% of goals.

As shown in Attachment 8, potential earnings for the 2006-2008 portfolios start at \$176 million if all four utilities achieve the minimum performance threshold of 85%, which in turn would deliver approximately \$1.9 billion in net benefits to ratepayers. That is, if the utilities *actually produce a return on ratepayers' investment of \$1.9 billion* (based on verified costs and resource savings) when they reach 85% of the savings goals, then their shareholders will receive \$175 million of that return under the first-tier rate we adopt today. The vast majority of the net benefits--\$1.775 billion – goes to ratepayers.

This level of earnings potential increases to \$322.6 million (for all utilities combined) at 100% achievement of the Commission's savings goals, if and only if the corresponding net benefits of \$2.7 billion are actually produced by the energy efficiency portfolio ratepayers. If the utilities' performance is truly superior, whereby they exceed the goals by a significant margin, the earnings for their shareholders increase up to a maximum of \$450 million, provided that the utilities produce the corresponding \$3.9 *billion* in net benefits at that maximum level of earnings.

In our judgment, this tiered earnings structure appropriately recognizes that, as the utilities move towards and beyond the goals to a level of superior performance, they are creating substantial ratepayer value in the form of net benefits, as well as GWh, MW and MTherm savings. At the same time, this structure also provides a reasonable balance to the penalty side of risk/reward

incentive curve.¹⁸⁴ Moreover, the earnings rate structure we adopt today is fair to ratepayers, since it both ensures that ratepayers receive the vast majority of the return on their investment *and* creates a meaningful level of shareholder rewards to ensure that the potential return on ratepayer investment will be realized.

As discussed in Section 6.2, some parties to this proceeding recommend that we also adopt a higher earnings rate that would apply if the utility exceeds 125% of the Commission's goals for kW savings. TURN argues that this incentive is required to achieve "more valuable reductions in peak period energy use," and more specifically, to "refocus attention to reducing space conditioning that drives peak demand."¹⁸⁵

TURN's proposal for a higher tier of rewards linked to achieving a high level of kW savings is premised on the assumption that peak demand savings are not properly valued in avoided cost calculations.¹⁸⁶ We do not accept this premise. The PEB should provide adequate incentives for peak energy savings based on the avoided costs we have adopted after careful deliberations in

¹⁸⁴ As indicated in Attachment 8, the earnings levels ramp up slightly faster than the penalty levels, particularly right above the deadband. However, this slight asymmetry is appropriate for an energy efficiency incentive mechanism due to the dual nature of the dual objectives for this resource. That is, it is reasonable to establish penalties just below the deadband that are somewhat lower than the earnings levels just above the deadband because there are still positive net benefits produced when savings performance falls below 65% of the goals.

¹⁸⁵ *TURN's Pre-Workshop Comments and Preliminary Incentive Mechanism Proposals*, June 16, 2006, pp. 28-29. In their post-workshop comments, DRA and CE Council support TURN's proposal for a higher earnings rate linked to higher kW performance, but present no additional discussion or arguments on this topic.

¹⁸⁶ *Ibid*, pp. 29-30.

R.04-04-025. We use a methodology that time differentiates generation and transmission/distribution costs hourly and reflects a much higher valuation of savings occurring in peak hours. In fact, we recently increased avoided costs during those hours in the 2006 Avoided Cost Update, albeit not to the level proposed by TURN in that proceeding.¹⁸⁷ Therefore, we do not find it reasonable to establish a higher savings rate for kW savings than for kWh or therm savings in today's adopted incentive mechanism.

Finally, we recognize that Section 111(a)(8) of the federal Energy Policy Act of 1992 (Act) still applies today, and requires state commissions to consider a comparison of supply-side profitability that is similar to the actions recommended in California's Energy Action Plan. (See Section 6.3.1.) For the reasons discussed above, we have adopted a tiered-structure of shared-savings rates that produces a level of profitability that approaches supply-side comparability at superior performance, and in a manner that we believe reasonably balances the level of penalties under the mechanism, recognizes the different risk/reward profiles of energy efficiency and supply-side options and produces a result that is fair to ratepayers. Our adopted shared-savings mechanism is consistent with the federal standard, but based on a broader set of factors than the profitability guideline articulated in that standard. It is appropriate to consider a broader set of factors in establishing the earnings potential for a shared-savings incentive mechanism, given (1) the complexity and diversity in our ratemaking treatment of both supply-side and demand-side

¹⁸⁷ D.06-06-063 in R.04-04-025, pp. 50-55.

resources and (2) the context for energy efficiency today under our procurement incentive framework and related climate change policies.

7. Caps on Penalties and Earnings

There is general consensus among the parties that penalties and earnings be capped in some way, in order to provide upper limits to both ratepayers' and shareholders' risks under the incentive mechanism.¹⁸⁸ As described in the attachments to this decision, the proposals vary in terms of the trigger for the cap (e.g., a specific dollar level, percentage of program costs or percentage of goal achievement), as well as the resulting dollar levels.

For the reasons discussed in Section 6.3.4, we limit the earnings potential under today's incentive mechanism to \$450 million for all utilities combined, over the three-year program cycle. This level is high enough to encourage superior performance in terms of goal achievement and create a corresponding level of superior net benefits to ratepayers. At the same time it provides a limit to the maximum level of earnings that ratepayers will share, thereby limiting ratepayers' exposure to forecasting uncertainty or unanticipated results associated with the mechanism.¹⁸⁹ Limiting penalties to \$450 million provides a symmetrical boundary to the utilities' risk exposure, but still provides ratepayers with substantial protection in the event of poor portfolio performance.

¹⁸⁸ PG&E is the only party that would not cap penalties but would cap earnings under its proposed incentive mechanism. See Attachment 2.

¹⁸⁹ Even though savings are verified through Energy Division's EM&V activities, not all parameters used to calculate the PEB are subject to *ex post* verification for all programs, which can introduce some forecasting uncertainty in both directions (to the benefit of ratepayers or to the benefit of shareholders).

We will allocate the \$450 million limit on penalties and earnings for each program cycle to individual utilities based on the percentage of net benefits expected by their efforts at 100% of goal achievement, as projected in this proceeding. This allocation results in the following utility-specific caps: PG&E--\$180 million (40%), SCE--\$200 million (44%), SDG&E--\$50 million (11%) and SoCalGas--\$20 million (5%).¹⁹⁰ These caps on earnings and penalties apply to each three-year program cycle (beginning with the 2006-2008 program cycle), unless and until modified by the Commission.

8. Earnings Recovery Schedule and Linkage to EM&V Results

Under our adopted EM&V protocols, there is a generic sequence of EM&V events planned that will update and verify the *ex ante* (pre-installation) estimates of energy efficiency savings as programs are implemented over the three-year program cycle. The first event is the reporting by utilities of the number and type of measures installed and services rendered, along with associated program costs. This occurs during the first quarter of each year (beginning in 2007) for the previous year's accomplishments. Next, Energy Division staff and its contractors verify this information and release Verification Reports of the costs and installations and services completed. Under the EM&V protocols, these reports are scheduled to be released by August following the end of each program year.¹⁹¹

¹⁹⁰ Numbers have been rounded to the closest "even" dollar value.

¹⁹¹ See *ALJ Ruling Adopting Protocols for Process and Review of Post-2005 EM&V activities*, January 11, 2006. As discussed further below, the annual schedule for Energy Division's Verification Report was modified by ALJ ruling on January 2, 2007. For the 2006-2008 program cycle, the verification of 2006 installations and program costs will be

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The Verification Reports are used to true-up the *ex ante* estimates of GWh, MW and MTherm savings and PEB with respect to the number and type of measures installed, and the associated program costs. They do not, however, provide all the updated information on parameters that go into the calculation of GWh, MW and MTherm savings and PEB. Other parameters include:

(1) measure or unit energy and peak demand reductions, (2) expected useful lives for installed measures/equipment and (3) “net-to-gross” ratios.¹⁹² Energy Division and its consultants will be conducting EM&V studies throughout the program cycle to evaluate these parameters on an *ex post* (post- installation) basis. The final EM&V event produces a true-up of portfolio savings and PEB over the program cycle based on all the parameters evaluated by Energy Division or its consultants. More specifically, the final true-up will be presented in Energy Division’s Final Verification and Performance Basis Report for the 2006-2008 program cycle, which is scheduled to be released in March 2010. Interim results of the EM&V studies completed earlier in the program cycle will also be made available in March 2008.

In their proposals for earnings recovery, parties agree on a sequence of four earnings claims that would be linked to the EM&V events discussed above. In particular, parties propose that the utilities submit an interim claim after each

combined with the report on 2007 accomplishments, so that both are now scheduled to be released in August of 2008.

¹⁹² Net-to-gross ratios are used to discount savings associated with program to reflect the existence of “free riders,” that is, customers who would have installed the energy efficiency measure or equipment without the utility’s financial incentive (e.g., rebate). Net-to-gross ratios are estimated at the start of program implementation, and EM&V studies are designed to evaluate those ratios on an *ex post* (post-installation) basis, using control groups and statistical regression analyses, among other approaches.

of the three annual Verification Reports, followed by a fourth true-up claim submitted after the Final Verification and Performance Basis Report. This schedule results in an earnings recovery period of approximately five years from the start of the program cycle. Other aspects of the earnings claim and recovery process differ among the parties. The significant areas of differences are discussed below.¹⁹³

8.1. Timeframe and Treatment of Forecasts for the Interim Claims

Three different approaches to the timeframe and treatment of forecasts for the interim claims have been presented for our consideration: 1) Single-Year Basis, 2) Cumulative-to-Date Basis, and 3) Cumulative-Program-Cycle Basis. For the purpose of describing these approaches, we use the term “verified achievements” to represent the savings and PEB resulting from the Verification Reports discussed above, that is, based on the verified number and type of measures installed and associated program costs. This means that the per-measure savings are still based on expected or estimated (*ex ante*) savings for each of the interim claims. For the final “true-up” claim, the achievements considered at that time reflect the results of the Final Verification and Performance Basis Report, that is, the *ex post* results of all performance parameters evaluated by Energy Division and its consultants for the program cycle.

¹⁹³ TURN’s post-workshop comments are silent on many of the earnings claim and recovery issues discussed below and CE Council’s comments provide only a one-sentence general blanket endorsement of DRA’s position on these issues. In the discussion that follows, we attribute a particular position to a party only if the party

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Under the Single-Year Basis approach, verified achievements for a single program year are compared to the savings goal for that year to determine whether performance is within, below or higher than the deadband. The associated earnings or penalties for each interim claim are also calculated based on the results for that single year. Accordingly, once the interim claim has been made, achievements of that particular program year are not considered in the calculation of the remaining interim claims, although they would count in the fourth true-up claim for the entire program cycle.

Unlike the Single-Year Basis approach, a Cumulative-to-Date Basis counts the verified achievements from the previous program year(s) in determining whether the MPS is met in each subsequent interim claim (and in the resulting calculation of earnings or penalties).

The Cumulative-Program-Cycle Basis differs from both the Single-Year and Cumulative-to-Date Basis in that each interim claim requires a calculation of expected achievements over the full 2006-2008 period, with verified information progressively replacing forecast information at each claim. Using a Cumulative-Program-Cycle Basis will level out the interim payouts relative to the two other approaches. We present simple numerical examples of these three alternate approaches in Attachment 5.

The approach we take for the recovery of earnings should send a message to the utility to continue to pursue cost-effective energy savings as quickly and aggressively as possible throughout the program cycle. It should also provide the utility with an opportunity to learn from market and EM&V feedback so that

explicitly presents a position on that issue, including supporting arguments, in its post-workshop comments.

it can “make up” during the program cycle for lower accomplishments in a single program year. The Single-Year approach does not accomplish either of these objectives. In fact, it could actually encourage a utility to slow down or shut down programs because either the annual goals have been met before the end of the calendar or there is no possibility to achieve the annual goals. This result could occur because whatever is accomplished in a previous program year is not counted when evaluating whether the MPS is reached in the next calendar year, except at the very last true-up claim.

In contrast, by considering the achievements of the previous year as well as the current year, the Cumulative-to-Date approach to evaluating interim earnings claims will encourage continuous effort and improvements in response to feedback throughout the program cycle. Moreover, under this approach only verified installations are considered in each interim earnings claim. This approach greatly reduces the forecasting error that is introduced into calculations of savings achievements and PEB for the earlier claims using a Cumulative-Program-Cycle Basis. The payouts (or penalties) in each earnings claim provide a stronger incentive if they are based on what is known to date about program participation, and not diluted by the forecasts of future program participation that were made at the start of the program cycle.

For the above reasons, we adopt the Cumulative-to-Date Basis for calculating the interim earnings claims under our adopted risk/reward shareholder incentive mechanism. However, as discussed in Section 8.3, we do not pay out 100% of the earnings calculated on this basis in each interim earnings claim. Rather, as some parties propose, we have elected to “hold back” a certain percentage (30%) to reduce the effect of load-impact forecasting errors on the final true-up claim. We also modify the four-claim process and schedule

proposed by the parties (and illustrated in our numerical examples) in order to be mindful of resource limitations and competing priorities for staff time. As described below, we adopt an earnings recovery schedule that includes two interim claims (rather than three) and one final true-up claim.

Before discussing these aspects of the earnings recovery process more fully, we turn to the most controversial issue concerning earnings claims, namely, whether there should be any restrictions on the true-up adjustment in the final earnings claim, and if so, the nature of those restrictions.

8.2. True-Up Adjustments in the Final Claim

As discussed above, it is not until the final true-up claim that we will be able to determine the level of net benefits (PEB) and MW, GWh and MTherm savings produced by the energy efficiency portfolio over the three-year period, based on all the EM&V activities undertaken for that program cycle. While we will certainly have progressively better information over time based on Energy Division's verification of program participation and expenditures, there will still be uncertainty over the actual level of portfolio achievements until the final claim. This introduces the risk that portfolio performance will be found to fall within or below the deadband (meaning that the MPS was not actually met) at the final true-up, even though the interim verification results suggested otherwise and earnings were paid out. The numerical examples in Attachment 5 illustrate how this could happen if *ex post* (post installation) per-unit savings were found to be lower than the *ex ante* (estimated) per-unit values.

8.2.1. Proposals for the True-Up Adjustment

Parties are in general agreement that if net benefits (PEB) at the final true-up are higher than previously calculated, the utility should receive a positive adjustment to earnings at the final claim, assuming that the MPS is met.

Otherwise, the utilities would earn less than the shared-savings rate(s) adopted for the incentive mechanism. However, when the savings level or PEB are lower than previously calculated, the parties differ on what should occur at the final true-up claim.

TURN and DRA argue that fairness to ratepayers dictates that the Commission should apply no restrictions to the true-up claim: If the final EM&V results indicate that the MPS was not achieved, the utility should be required to return all earnings previously paid out in the interim claims. If the MPS was reached but the utilities received a higher proportion of net benefits (PEB) than they were entitled to based on the adopted shared-savings rate(s), that difference should be returned to ratepayers. Finally, if the final EM&V results indicate that the utilities are subject to penalties, the utilities should pay these penalties as well as return any interim earnings installments.

In contrast, SDG&E/SoCalGas argue that the utilities should not be required to return previous payouts of earnings, even if the final EM&V results indicate that the MPS was not met by the portfolio. In their view, the final true-up claim should be restricted to non-negative adjustments in order to make the incentive payments meaningful and valuable to the utilities, thereby providing the desired motivation throughout the program cycle.¹⁹⁴ SCE concurs with this recommendation, except in the instance when the final true-up indicates that the portfolio is not cost-effective (i.e., the PEB is negative). Under this circumstance,

¹⁹⁴ NRDC's post-workshop comments suggested that the claim schedule should not include paybacks to customers, but only in conjunction with the claims process being modified to significantly reduce the chance that a payback would ever be needed. (See NRDC's September 8, 2006 Comments, pp. 19-23 and Opening Comments on Proposed Decision, August 29, 2007, p. 9.)

any earnings paid out in the interim claims would be returned to ratepayers. These parties also recommend various ways to minimize the potential risk of overpaying the utilities under their proposals, such as paying less than 100% of the calculated earnings during each interim claim.

PG&E recommends somewhat of a hybrid approach to the final true-up adjustment. PG&E concurs with SCE's recommendation if the MPS is ultimately not met at the final true-up, that is, to not require the payback of earnings already received except if the PEB is negative. However, like DRA and TURN, PG&E would return earnings to ratepayers if the interim pay outs represent a higher share of PEB than provided for under the adopted shared-savings rate(s). PG&E further proposes that any negative or positive adjustments in the final claim be booked against earnings calculated for the next program cycle.

8.2.2. Discussion

More than any other time in California history, we are counting on investments in energy efficiency to reduce California's reliance on nonrenewable supply-side resources and become "first in the loading order", consistent with the Energy Action Plan. To this end we established savings goals for the portfolio of programs funded by ratepayers, and incorporated those savings projections into the utility's supply-side procurement plans. In today's procurement context, energy efficiency needs to produce more than positive returns (net benefits) to ratepayers on their investment to be considered "successful." Most importantly, it needs to produce sizable GWh, MW and MTherm savings that resource planners can depend upon now and in the future.

Throughout this decision, we have designed the shareholder risk/reward incentive mechanism with this primary purpose in mind. Our adopted MPS reflects our assessment of how sizable these savings must be before any earnings

should be awarded. Our adopted deadband range establishes the level of portfolio energy savings we find to be unacceptably low, thereby triggering the start of penalties. However, these design parameters lose meaning if the true-up adjustment does not fully reflect the final EM&V results. Essentially, under the approach proposed by the utilities, the MPS or deadband range could end up being anywhere, since the utilities could keep the earnings they received in the interim claims even if they actually achieved energy savings within the deadband or in the penalty range. In our opinion, this approach is not compatible with an incentive design that establishes the MPS and deadband range based on GWh, MW and MTherm savings achievements.

In response to the utilities' observation that our pre-1998 shared-savings mechanism did not require a full true-up of earnings at the end of the program cycle, we observe that the earlier incentive mechanism also did not tie the MPS and deadband range to a percentage of savings goal achievement. Instead, these parameters were tied to net benefits, the same as the PEB. In that context, the Commission's decision not to true-up the MPS with the final earnings claim was predicated on a different policy perspective. That perspective focused on creating positive *net benefits* to ratepayers on their investment, and did not consider the achievement of specific levels of GWh, MW or MTherm savings as a paramount objective for utility management of the portfolio.

We also observe that the true-up approach proposed by SCE and SDG&E/SoCalGas would result in a skewed treatment of load impact forecasting errors: If they work to the benefit of shareholders, the earnings are adjusted so that the actual earnings rate is never lower than the adopted rate. However, if forecasting errors work to the detriment of shareholders, those errors would be ignored, and shareholders would actually earn at a shared-

savings rate that is higher than the one adopted. This is because these parties recommend that the Commission not make any negative adjustments to PEB in the final claim that result from lower-than-expected load impacts. At the same time, these parties would permit positive adjustments to PEB based on the final claim. PG&E's proposal eliminates this one-sided adjustment to PEB, but as discussed above, would still insulate earnings from the final true-up with respect to achievement of the MPS. In any event, we see no reason to pay out either a higher or lower percentage of actual net benefits under the mechanism, once the MPS is reached. Ratepayers should "share" the net benefits from their investment with shareholders at precisely the adopted shared-savings rates – no more, no less.

Finally, as DRA points out, an approach that fails to true-up savings and net benefits (PEB) accomplishments based on the results of final load impact studies creates a perverse incentive for utility managers to promote exaggerated savings assumptions during the planning process. This is because the utility knows that it can get progress payments based on these inflated estimates that are not returnable when the final true-up reveals lower load impacts. Since our EM&V protocols solicit input from the utilities throughout the process of developing *ex ante* savings estimates, finalizing study evaluation plans and EM&V study results, we need to make sure that our earnings recovery process does not work at cross purposes with the intent of that process, namely, to obtain unbiased, technical input from program administrators. Requiring a true-up that fully impacts total utility earnings provides the proper incentive for utility managers and staff to support the most accurate *ex ante* estimation process as possible. In contrast, for the reasons pointed out by DRA, the approach proposed by the utilities would work at cross purposes with this intent.

For the reasons stated above, we do not restrict the true-up adjustment in the final claim. We recognize that the possibility of refunding earnings already claimed presents certain problems for the utilities with respect to their financial reporting. However, these problems can be readily addressed by 1) limiting payout of initial claim(s) as NRDC and others have suggested and 2) deducting any over-collections from future earnings claims, as recommended by PG&E. Accordingly, we incorporate both of these design features into today's adopted earnings recovery schedule, as discussed further below.

8.3. Schedule for Claims, Percentage of Payout and Related Issues

We have carefully considered parties' proposals and consulted with Energy Division management and staff in developing a schedule for earnings claims. Our objective is to establish a schedule that will link claims and payments to EM&V results, produce a stream of earnings during and at the end of the program to provide ongoing incentives to the utilities, and at the same time be mindful of resource limitations and competing priorities for staff time.

In our judgment, we have achieved a reasonable balancing of these considerations with the schedule illustrated in Attachment 6. As indicated in that Attachment, there will be two interim claims and a final true-up claim, resulting in one claim per calendar year for the 2006-2008 and each subsequent program cycle, beginning in 2008. The interim claims will be tied to the second and third annual Verification Reports, and the final claim will be tied to the Final Verification and Performance Basis Report. We do not tie any claim to the Interim Performance Basis Reports, since these were originally intended by staff to provide feedback for program improvements and not be a basis for incentive payments.

As discussed further below, we adopt an Advice Letter process for the submittal of claims, and indicate the approximate dates of those submittals in Attachment 6. However, the actual due dates for those claims are tied to the issuance date of Energy Division's reports, as discussed in Section 8.4 below. Our staff is fully committed to meeting the deadlines established by our EM&V protocols for their reports. Nonetheless, no one can guarantee that unforeseen circumstances will never require some delay to that schedule.

Therefore, should circumstances warrant, we permit the assigned ALJ to modify the schedule set forth in Attachment 6, in consultation with Energy Division and the assigned Commissioner

Some parties to this proceeding suggest that we authorize the utilities to submit earnings claims and pay out some portion of the estimated savings if those Energy Division reports are delayed in any way. We do not adopt this suggestion. Ratepayers' interests are best served when the payout of earnings (or imposition of penalties) occurs only after the installations, program costs and (for the final claim) load impacts have been verified by our staff and its contractors.

In its pre-workshop comments, PG&E recommended that shareholder earnings claimed but not yet collected should accrue interest from the end of the program year in which the claim is submitted until earnings recovery.¹⁹⁵ Although we permitted interest accrual on uncollected earnings for the pre-1998 shared-savings incentive mechanism, we do not adopt this treatment today. Under the pre-1998 shared-savings mechanism, earnings recovery extended to

¹⁹⁵ *PG&E Pre-Workshop Comments*, June 16, 2006, pp. 16-17.

up to 10 years after program implementation pending the completion of persistence and retention studies. The EM&V reports managed by the utilities at that time, and resulting earnings claims, were subject to litigation that could result in substantial delays to the earnings recovery schedule. In that context, we allowed for the calculation of interest using the 90-day commercial paper rate.¹⁹⁶ However, EM&V responsibilities for post-2005 programs and the claim review and approval process adopted today for energy efficiency do not share these characteristics. Therefore, we are not persuaded that interest should accrue on delayed payments of either earnings or penalties under today's adopted incentive mechanism.

With respect to the percentage of payout, we agree with NRDC and others that some percentage of the interim payouts should be "held back" until the final true-up claim. Doing so reduces the possibility that the utility may have to return earnings already paid out (or reduce the amount considerably) upon the final true-up claim.¹⁹⁷ In the context of the overall incentive design we adopt today, a 30% hold-back is a reasonable way to mitigate this risk. Accordingly, we will hold back 30% of the authorized earnings or penalties for each of the interim claims. For example, if the MPS is met and shared savings would be \$30 million (based on verified costs and installations) for the interim claim, the payout in that claim would actually be \$20 million ($2/3 \times \30). As discussed in this decision, any pay-back obligations that might still arise in the final true-up claim will be booked against positive earnings in the next program cycle.

¹⁹⁶ See D.94-10-059; 57 CPUC 2d, pp. 62-63.

¹⁹⁷ This is illustrated numerically in Example 3 of Attachment 5, using very simplified assumptions.

This brings us to the recommendation of PG&E and SCE to either adjust the MPS or the goals (equal to compliance targets) for the interim claims. In particular, these utilities note that the Commission has established both three-year cumulative and annual goals for the 2006-2008 period, but pursuant to D.04-09-060 has also allowed utilities to “ramp up” to the three-year cumulative goals with program efforts over time. They also observe that their compliance filings for the 2006-2008 portfolio plans include savings targets that reflect a ramping up to the cumulative goals that are generally lower than the annual goals established in D.04-09-060. Therefore, SCE and PG&E argue that the benchmark for the interim claims should comport with this ramp up, by either (1) adopting lower MPS levels for 2006/2007 period (SCE) or (2) keeping the MPS the same in each year but basing the progress payments on achievement of the compliance targets (PG&E).

We decline to adopt either of these approaches. In particular, PG&E’s recommendation could introduce significant gaming of ramp-up targets in future compliance filings. More importantly, PG&E’s concerns that it will forego earnings associated with 2006 activities because of a “slower start” at the beginning of a program cycle only occurs under the “Single-Year Basis” approach that PG&E has proposed in this proceeding. Under the Cumulative-To-Date Approach we adopt today, those efforts will be fully reflected over the program cycle in subsequent claims. In addition, our decision to move the first progress payment to the second year of the program cycle makes moot any need for a lower first-year MPS or threshold savings requirement. Therefore, the MPS will not change from one interim claim to the next, and the MPS threshold for performance will be based on the Commission-adopted annual and cumulative goals.

8.4. Procedures for Reviewing and Approving Claims

To further develop the record on implementation issues, the Assigned Commissioner issued a ruling (ACR) soliciting comment on Energy Division's proposed procedures for reviewing and approving earnings claims, once the incentive mechanism is in place.¹⁹⁸ Comments were filed by NRDC, DRA, SCE, PG&E, TURN and jointly by SDG&E and SoCalGas.

8.4.1. Positions of the Parties

SDG&E, SoCalGas and PG&E recommend reinstating the Annual Earnings Assessment Proceedings (AEAPs) with formal procedures for review and approval of interim and final earnings claims. In particular, SDG&E and SoCalGas jointly argue that the AEAP process provides "all parties an opportunity to participate both substantively and procedurally in the application review process."¹⁹⁹ In addition, they argue that the procedure set forth in the ACR may compromise "data accuracy"²⁰⁰ and "fails to provide the same level of critical review to inform the Commission decision-making on whether the utilities have supported their claims for incentive payments."²⁰¹

PG&E argues that occasionally disputes require "an unbiased and experienced person to oversee a formal process to ensure that all parties have the opportunities to question the positions of others."²⁰² PG&E contends that in the

¹⁹⁸ *Assigned Commissioner's Ruling Soliciting Further Comment on Procedures for Review and Approval of Interim and Final Earnings Claims*, April 4, 2007.

¹⁹⁹ *Opening Comments of SDG&E and SoCalGas*, April 23, 2007, p. 3.

²⁰⁰ *Ibid.*

²⁰¹ *Ibid.*, p. 4.

²⁰² *Comments of PG&E*, April 23, 2007, p. 2.

past disputes have “dealt with tune-ups to the measurement protocols themselves”²⁰³ and that “[n]either a workshop that included interested stakeholders nor written comments as a result of those workshops provides sufficient opportunity or rigor to thoroughly examine the range of issues that could reasonably be in dispute.”²⁰⁴ SCE argues for allowing utilities to request an AEAP with its formal proceedings in the event of a dispute.

NRDC similarly argues for a more formal process along the lines of the AEAP for earnings claims made pursuant to the *Final* Performance Basis Report, asserting that “the proposal has Energy Division staff making all final decisions about the reports and studies without a specific process for addressing concerns raised by parties. Some amount of Commission oversight seems appropriate...”²⁰⁵

With regard to the method for being paid pursuant to the Final Performance Basis Report, DRA argues in favor of requiring the utilities to file either an application or an Advice Letter subject to General Order 96-B, Section 7.6.2 (which requires resolutions to be approved by the Commission). According to DRA, an application or Advice Letter requiring a resolution would “promote transparency and public participation in the process.”²⁰⁶ TURN supported this approach in its Reply Comments. DRA was also concerned with scheduling a specific timeline in order to have program results to inform

²⁰³ *Ibid.*

²⁰⁴ *Ibid.*, pp. 2-3.

²⁰⁵ *Opening Comments of NRDC*, April 23, 2007, p. 3.

²⁰⁶ *Comments of DRA*, April 23, 2007, p. 5.

program planning, using the same procedures it suggested for assessing penalties, and establishing a process evaluation mechanism.

NRDC and PG&E support DRA's suggestion for a timeline in their Reply Comments. NRDC and TURN also support a formal process for assessing penalties. In addition, SCE argues in favor of adding a step to allow the program implementers and administrators to review preliminary drafts in order to identify factual errors before drafts are issued publicly. PG&E agrees with this suggestion in its Reply Comments. PG&E also contends that there was a lack of stakeholder input in the proposed procedures for review and approval of interim and final earnings claims.

NRDC points out that the Attachment 1 proposal of the ACR is intended to replace steps 4 through 9 of Attachment 4 to the January 11, 2006 ALJ Ruling. However, Attachment 4 of that ALJ Ruling addresses Impact and Market Effects Studies, whereas the Attachment 1 proposal addresses only Verification and Performance Basis Reports. NRDC requests clarification that the Attachment 1 proposal of the ACR is intended as a review and approval process for impact evaluation studies as well as Verification and Performance Basis Reports. NRDC also notes that the procedures refer only to earnings claims, and do not reflect the fact that penalties may be assessed in interim or final claims.

DRA recommends that Energy Division's proposed process for a 60-day turnaround time for program administrators' written responses to staff final evaluation reports be shortened to 30 days given that administrators will have outlined their issues both in oral workshop and written comments. DRA expresses concerns about Energy Division granting approval to extend this deadline even further, as noted under this same step.

8.4.2. Discussion

The ACR recognized that “adoption of these procedures may result in some change to D.05-01-055 . . . , and to Attachment 4 to *Administrative Law Judge’s Ruling Adopting Protocols For Process and Review of Post-2005 Evaluation, Measurement and Verification (EM&V) Activities*, dated January 11, 2006.”²⁰⁷ The ACR was sent to the energy efficiency service list in this rulemaking. Those on that service list thereby had notice of any potential changes to prior Commission actions and an opportunity to comment on any possible changes. This notice and opportunity to comment addresses PG&E’s concern regarding lack of stakeholder input. The ACR was put out for comment precisely for the purpose of garnering stakeholder input. Parties provided useful and detailed input on the process set forth in the ACR. Therefore, we find that the procedures set forth in the ACR have had the benefit of stakeholder input.

In our view, the parties have failed to show why the procedures set forth in the ACR do not address parties’ concerns while achieving both efficiency and accuracy. The steps outlined in the ACR provide parties the ability to participate, both procedurally and substantively. Contrary to NRDC’s position, the ACR sets forth a specific and adequate process by which parties can submit questions, concerns and comments to both Energy Division and evaluation contractors. Conferences and the submission of written comments based on conferences, allow parties to participate in the process by raising and discussing issues. This takes place in formulating the several reports before they are finalized: the draft Verification Report, the draft final evaluation reports, and the

²⁰⁷ *Assigned Commissioner’s Ruling Soliciting Further Comment on Procedures for Review and Approval of Interim and Final Earnings Claims*, April 4, 2007, p. 4.

draft Final Performance Basis Report. Our belief is that any concerns the parties may have can be resolved through such a process. Regarding substantive concerns, the scope of comments is not limited in any respect by the Ruling. Parties are free to raise any and all substantive concerns they may have with the reports to both Energy Division and the evaluation contractors. Thus, the steps outlined in the ACR allow for both procedural and substantive involvement of the parties in the review and approval of interim and final earnings claims.

It is precisely the nature of, and the numerous opportunities for, the procedural and substantive participation of the parties that will help ensure the accuracy of report results. As discussed in the ACR, the procedures allow for a free exchange between all of the stakeholders and technical experts. In so doing, the procedures allow the opportunity to explore and resolve areas of potential disagreement amongst the stakeholders and technical experts. PG&E seems to argue that nothing short of cross-examination provides sufficient opportunity or rigor to address potential disputes. We disagree with the proposition that only cross-examination allows thorough analysis of these kinds of issues. Cross-examination does not provide for the multi-party give and take available in a conference, which we think is better suited for the kinds of disputes likely to arise here. Furthermore, the procedures require response to all written comments, ensuring, as noted in the Ruling, that all comments will be considered and dealt with in a reasonable manner. The mechanism allowing for parties to interact with evaluation contractors, through conferences and written comments, helps to ensure the accuracy of the results.

Overall, we think the procedures set forth in the ACR to be equally accurate and more efficient than any of the more formal processes suggested by the parties. Parties who have requested more formal procedures have not shown

why the procedures set forth in the ACR would not be equally accurate while being more efficient. Because the issues are of a technical nature, no party has shown why such issues are not just as well, if not better, suited to resolution by Energy Division with the assistance of outside consultants rather than an ALJ and the five Commissioners.

As noted in the ACR, “The goal of these proposed procedures is to determine the level of incentive payments by a process that is both efficient and accurate.”²⁰⁸ The idea behind the procedures is to create a mechanism in advance to determine the level of incentive payments. Having created such a mechanism there is no need for full Commission involvement to resolve issues, except to the extent required under General Order 96-B, 7.6.1, discussed below. Once Energy Division has issued a Final Verification Report or the Final Performance Basis Report, determining the level of earnings or penalties is strictly a matter of applying the formulas in this decision to the results outlined in those final reports. Accordingly, it will be a ministerial task for Energy Division to determine whether the utilities’ advice letters filed in response to these reports contain the correct calculation of earnings or penalties.

SCE argues for allowing utilities to request an AEAP with its formal procedures in the event of a dispute. As already discussed above, an AEAP is not necessary in light of the procedures outlined in the ACR.

PG&E raises the issue of an “unbiased and experienced” party to facilitate parties’ participation. As discussed in the ACR, D.05-01-055 marked a shift in the responsibility for overseeing EM&V studies, from the utilities to Commission

²⁰⁸ *Ibid.*, p. 2.

staff. The purpose of the shift was to help ensure unbiased results by having a neutral party overseeing the EM&V process. Commission staff provides a neutral, unbiased party to facilitate parties' participation. In addition, Commission staff, specifically Energy Division, will have access to the experience and expertise of evaluation contractors throughout the processes for review and approval of both interim and final earnings claims. The procedures set forth in the ACR address PG&E's concerns regarding having an unbiased and experienced party oversee the process.

With regard to the method for being paid pursuant to the Final Performance Basis Report, DRA suggests an application process or an advice letter requiring resolution in order to promote transparency and public participation. As discussed above, the steps outlined in the Ruling provide ample opportunity for public participation. Stakeholders in this process include, not only those on one of the Commission's energy efficiency service lists, but also any individual or organization who has "notified Energy Division of their interest [in] being informed of these meetings."²⁰⁹ Therefore, the procedures in the ACR allow for broad public participation. The procedures also allow for transparency through the various conferences and the requirement that all written comments to the various reports be addressed in the final versions of each report.

DRA argues for at least an Advice Letter process subject to General Order 96-B, Section 7.6.2, which requires resolutions to be approved by the

²⁰⁹ *Ibid.*, Attachment 1, fn. 5.

Commission. The current process allows for Energy Division disposition pursuant to General Order 96-B, 7.6.1 which states that:

An advice letter will be subject to Industry Division disposition even though its subject matter is technically complex, so long as a technically qualified person could determine objectively whether the proposed action has been authorized by the statutes or Commission orders cited in the advice letter. Whenever such determination requires more than ministerial action, the disposition of the advice letter on the merits will be by Commission resolution, as provided in General Rule 7.6.2. (Emphasis added.)

Where Energy Division disposition of utility earnings claims would be ministerial, a Commission resolution should not be required. As explained above, approval of claims should be ministerial because any substantive issues will already have been resolved through the procedures set forth. However, the current process still allows for Commission resolution under appropriate circumstances where Energy Division disposition would require “more than ministerial action.” If more than ministerial action is required than under General Order 96-B, 7.6.1, Energy Division will, of course, prepare a resolution for Commission approval.

SCE argues in favor of adding a step to allow the program implementers and administrators to review preliminary drafts in order to identify factual errors before drafts are issued publicly. As set forth in the ACR and discussed above, SCE, as well as the other utilities and stakeholders, will have various opportunities to address errors in the studies and reports. Therefore, extra steps allowing for program implementers and administrators to review preliminary drafts to identify errors prior to public release of the drafts is unnecessary.

In sum, we find the procedures outlined in the ACR to be reasonable and will adopt them, subject to certain clarifications. First, in response to NRDC's comments, we clarify that the procedures adopted in Attachment 7 are intended to establish a public and stakeholder review and input process for Energy Division consultants' evaluation reports (e.g., impact evaluation studies) as well as Energy Division's Verification and Performance Basis reports. Steps 1-4 under "Final Claim" in that attachment describes the process for reviewing and providing input on the consultants' evaluation reports.

In addition, we clarify that the 60-day turnaround time for program administrators' written responses to final evaluation reports is not pertinent to any earnings claims disputes but rather relevant to implementing the findings of evaluation reports. The procedures are now modified to make this clear. The 60-day period described in Step 5 under "Final Claims" of the ACR is not excessive and may be a practical timeframe for the program administrators to develop an action plan based on the evaluation results. We do, however, agree with DRA's concerns regarding delays getting EM&V on-track and in synch with the programs. We therefore grant Energy Division the authority to shorten the response timeframe on a case by case basis as needed. Step 5 under "Final Claims" of the ACR contained erroneous language in light of the process adopted in this decision.²¹⁰ Today's adopted procedure removes that language.

²¹⁰ Specifically, we delete the following sentence: "In this follow-up response to each report, administrators should note any concerns they have over specific report finding and indicate whether they agree with the final load impact estimates for the programs in question."

We also clarify in Attachment 7 that the adopted procedures apply to claims that involve either penalties or earnings, and establish the due dates for utility advice letters.

Finally, establishing where performance falls along the adopted penalty/earnings curve involves estimating load impacts, load shapes and (for calculating PEB) measure and program costs for an extensive number of programs and measures. In recognition that we may not have the resources to verify each parameter on an *ex post* basis for every program, our adopted EM&V protocols provide staff the flexibility to establish priorities for the EM&V efforts throughout the program cycle. In performing its EM&V duties, we clarify that staff or its evaluation contractors may utilize any or all of the following approaches in order to report an estimated PEB for those programs that do not receive an impact evaluation, as staff deems appropriate:

- Extrapolate findings from comparable programs to determine net resource benefits for programs that do not receive full impact evaluation; or
- Accept reported savings values for programs that do not receive impact evaluation; or
- Extrapolate savings findings from impact evaluations for comparable programs for some net resource benefit parameters and accept reported values for others; or
- Apply a discount factor to savings or costs from programs that do not receive impact evaluation based upon historic impact evaluation results for comparable programs.

Staff should describe the method(s) it uses to estimate PEB for those programs that do not receive an impact evaluation in the Final Performance Basis Report, which will be issued to obtain stakeholder input pursuant to the Attachment 7 procedures. In addition, Energy Division may need to prioritize resources for verifying measure installations and program costs over the

program cycle, and may, as circumstances warrant, report the results of completed verification tasks in the Final Verification and Performance Basis Report. If such circumstances arise, Energy Division should describe in each Verification Report the additional verification activities that will be performed and reported later in the program cycle.

9. Defining “What Counts” in Calculating Achieved Savings and Net Benefits

As we directed in D.05-04-051, the risk/reward shareholder incentive mechanism we adopt today will be applied to portfolio performance, rather than to the performance of each individual program. We determined that this portfolio-level approach was necessary “to encourage innovation and allow for some risk taking on pilot programs and/or measures in the portfolio.”²¹¹ All parties to this phase of the proceeding propose that the incentive mechanism be applied to a portfolio of programs; however, they differ with respect to what program costs and EM&V expenditures should be included in that portfolio. In other areas related to “what counts” there is agreement among the parties, such as the treatment of savings from low-income energy efficiency (LIEE) programs and Codes and Standards Advocacy programs. We discuss these and other related issues in the following sections.

9.1. Non-Resource Programs

Non-resource programs represent energy efficiency activities that do not focus on the displacement of supply-side resources at the time they are implemented (but may lead to that displacement over the longer-term, or

²¹¹ D.05-04-051, mimeo., p. 43.

enhance program participation overall). Therefore it is very difficult, and in some instances impossible, to reasonably estimate and verify the resource savings attributable to those programs. Non-Resource programs include Emerging Technologies Programs, Flex Your Power and other statewide marketing activities, general education, training and outreach programs and demonstration programs, such as Advanced Home Design.

The adopted EM&V protocols describe the difficulties in independently estimating the savings attributable to non-resource programs.²¹² For this reason, in almost all instances, EM&V efforts for these programs will focus on evaluating performance parameters other than resource benefits, at least until the first evaluations of their primary impacts can be completed. Because resource benefits will not be directly attributed to these programs over the 2006-2008 program cycle, SCE and SDG&E/SoCalGas recommend that the incentive mechanism apply only to the portfolio of resource programs. They propose that all costs associated with non-resource programs (including associated EM&V) be excluded from the calculation of PEB.²¹³ CE Council supports this approach.

TURN and DRA, on the other hand, recommend that all costs of the non-resource programs be included in the calculation of PEB, even though they do not directly contribute to the calculation of resource benefits. In DRA's view, these programs are an essential part of the portfolio to promote the achievement of program savings, and since their impacts will be reflected in the success of the

²¹² See *ALJ Ruling on EM&V Protocol Issues*, September 2, 2005, p. 12.

²¹³ SCE adds the following caveat: In the future, if measurable savings can be attributed to non-resource programs, both the costs and benefits of these programs would be included in calculating the MPS and PEB.

resource programs, their costs should be included as well. NRDC and PG&E support this approach in conjunction with providing the utility an opportunity to earn under PG&E's proposed performance-adder treatment. (See Section 11 below).

The treatment of non-resource programs under today's adopted incentive mechanism should be consistent with their treatment at the start of the program cycle, when we assess whether or not the portfolio of proposed programs should be funded by ratepayers. Our policy rules for energy efficiency require that all portfolio costs, including those associated with non-resource programs, be included in our evaluation of whether the portfolio is cost-effectiveness from a net benefits perspective over the 3-year program cycle, with only one exception. We permit the exclusion of Emerging Technologies Program in recognition that the development and commercialization of new energy efficiency technologies may not contribute directly or indirectly to resource savings for several program cycles.²¹⁴

Excluding all non-resource program costs from the PEB, as SCE and SDG&E/SoCalGas recommend, would be inconsistent with the manner in which we evaluate portfolio performance for the purpose of committing ratepayer dollars. As our policy rules recognize, statewide marketing and outreach programs, upstream market transformation programs, information and education programs and other non-resource program activities will promote the achievement of program savings over the near- and long-term. Since their

²¹⁴ D.05-04-051, Attachment 3, Rules II.8 and IV.9.

impacts will be reflected in the success of the resource programs, their costs should be included as well.²¹⁵

Moreover, the approach suggested by SCE and SDG&E/SoCalGas would create a perverse incentive for the utility to “game” the classification of programs or the allocation of costs across programs in order to maximize the net benefits of those programs subject to the incentive mechanism (resource programs) relative to those that are not (non-resource programs). In addition, under this approach utility program administrators would be less motivated to make the non-resource programs as cost-efficient as possible, since those improvements would not impact the calculation of PEB and associated shareholder earnings.

For the above reasons, we will include both resource and non-resource program costs in the calculation of PEB, with the exception the Emerging Technologies Program. Those program costs, and related EM&V costs, will be excluded in the calculation of the PEB. We discuss in greater detail the treatment of the costs and benefits of one particular resource program, Codes and Standards Advocacy, in Section 9.3 below.

Finally, because energy efficiency funding is now authorized over 3-year program cycles and subject to a 10-year trajectory of increasingly aggressive savings goals, it is not in the interest of the utility to shortchange non-resource programs that can enhance portfolio savings performance over both the short-and long-term. In any event, the ability of utility program administrators

²¹⁵ D.05-04-051, Attachment 3, Rule II.7.

to unilaterally implement shifts in portfolio funding away from non-resource programs is restricted by our adopted fund-shifting rules.²¹⁶

9.2. EM&V

NRDC and the utilities propose to exclude from the calculation of PEB the vast majority of EM&V expenditures managed by Energy Division, arguing that the utilities do not have control over those efforts and therefore their earnings should not be contingent upon such dollar expenditures. We find no merit to this argument: EM&V is an integral cost of delivering reliable and verifiable energy efficiency savings, irrespective of who manages those efforts. Just because the utilities may not manage most of those funds, it does not follow that shareholders should be paid a larger share of portfolio net benefits by excluding EM&V costs.

In sum, all EM&V costs should be included in the evaluation of the performance of the energy efficiency portfolio and calculation of PEB, just as those costs are included on a prospective basis when ratepayers are asked to fund energy efficiency activities administered by the utilities. The limited exception we make to this rule is for EM&V directly related to the Emerging Technologies Program. For the reasons discussed above, this program will be excluded from the calculation of PEB. Therefore, it is reasonable to exclude expenditures on the associated EM&V activities from that calculation as well.

²¹⁶ See D.05-09-043, Table 8. For example, the utility must file an advice letter for any proposed fund shifting of more than 1% out of statewide marketing and outreach, emerging technologies, or codes and standards advocacy programs. An advice letter process is also triggered with shifts among program categories of over 25% on an annual basis. (See D.05-09-043, Table 8.)

9.3. Codes and Standards Advocacy

The treatment of savings from Codes and Standards (C&S) advocacy work was addressed at some length in D.05-09-043, and those determinations were reflected in parties' proposals for how C&S savings should "count" towards the MPS or PEB for the 2006-2008 program cycle. We review those determinations first, before addressing the counting issues.

9.3.1. Determinations in D.05-09-043

As discussed in D.05-09-043, one of the major accounting changes for post-2005 energy efficiency was to stop counting commitments and only count actual installations in evaluating portfolio performance. Based on this change and other considerations, we determined that utilities should be able to credit some portion of the savings attributable to pre-2006 codes and standards advocacy work towards savings goals during the transition (i.e., for program cycle 2006-2008). In particular, we recognized that this was appropriate because the baseline for the potentials studies underlying our savings goals did not consider the increase in appliance/new construction efficiency standards that were put in place near the start of the 2006-2008 program cycle. Now that the new standards are in place, this meant that those standards could actually work against the utilities with respect to their ability to tap that economic potential with other types of energy efficiency activities.²¹⁷

We also determined that only 50% of the GWh, MW and MTherm savings associated with pre-2006 advocacy work would be counted towards the 2006-2008 savings goals. We established this limit primarily because of certain

²¹⁷ See D.05-09-043, mimeo. pp.123-125.

inherent and potentially significant uncertainties associated with the approach taken to attribute savings to the pre-2006 work. For future C&S evaluation efforts, we directed staff to address how best to verify parameters used to develop the *ex ante* savings estimates as part of the EM&V protocols, which are now in place.

Because of transition issues²¹⁸, we also determined that the 2006-2008 PEB would not include the savings associated with the pre-2006 C&S programs in calculating earnings or portfolio cost-effectiveness. On a forward looking basis, we directed that savings from C&S advocacy work undertaken in 2006 and beyond would be counted when calculating either net resource benefits (“performance basis”) or cost-effectiveness (TRC or PAC tests).²¹⁹

9.3.2. Discussion

All parties commenting on this issue recommend that 50% of the savings attributed to pre-2006 C&S advocacy work count towards establishing whether the MPS has been met for the 2006-2008 cycle. They also recommend excluding these savings from the calculation of PEB. We find these recommendations to be fully consistent with our determinations in D.05-09-043, as discussed above, and will adopt them. As stated in that decision, for this purpose the C&S savings are to be *verified* (as opposed to *ex ante* estimates used for planning purposes).²²⁰ Energy Division’s EM&V contractors are in the process of verifying those savings

²¹⁸ Namely, because counting savings associated with this work towards PEB, upon which the risk/reward performance mechanism would be based, created a fundamental policy inconsistency with respect to the cessation of shareholder earnings during the program years when these pre-2006 investments were made. *Ibid.*, p. 130.

²¹⁹ *Ibid.*, pp. 132-133. See also Attachment 10 to D.05-09-043.

²²⁰ *Ibid.*, p. 132.

estimates, and Energy Division will be including the verified numbers in its Annual Verification Reports.

There is some disagreement, however, on how to treat the costs associated with 2006-2008 C&S advocacy work. PG&E, TURN, DRA and NRDC take the position that C&S advocacy costs should be booked in the program cycle in which they occur, whereas SDG&E and SoCalGas would apparently exclude those costs in calculating PEB – at least for the 2006-2008 program cycle. Although we recognize that there may be a significant lag between when the costs are incurred and when the savings are actually realized for this program, over time, these “lagged” streams of costs and benefits should tend to even out as they do for commitments to long-lead time projects, such as new construction. Moreover, if the costs of the C&S advocacy work are not reflected in the PEB at the time they occur, when should they be? SDG&E and SoCalGas provide no compelling reason to depart from our practice of including program costs and savings on an “actual” basis in determining portfolio performance for post-2005 energy efficiency. Therefore, we will include C&S advocacy costs as they are incurred in calculating the PEB under today’s adopted incentive mechanism.

There is one issue related to our determinations in D.05-09-043, however, that we cannot resolve today. We deferred consideration of whether savings from pre-2006 C&S advocacy work will also count towards the updated goals for 2009 and beyond, pending further consideration of the baseline issues discussed in that decision.²²¹ By ruling dated June 1, 2007, the Assigned Commissioner solicited comment from parties to this proceeding on whether and how to

²²¹ *Id.*

change utility energy savings goals through 2011.²²² Therefore, the baseline issues that may affect whether C&S advocacy work will count towards savings goals for the 2009-2011 cycle (and beyond) cannot be addressed until after the Commission has had an opportunity to consider comments in response to that ruling.

The Assigned Commissioner's June 1, 2007 ruling also solicits comment on whether we should reconsider what savings will count toward fulfillment of goals, including those associated with C&S advocacy, irrespective of whether the goals are modified.²²³ We will be considering these issues as we plan for the 2009-2011 program cycle. Until further order of the Commission, however, determinations we have made to date on these issues remain unchanged.

9.4. Savings from LIEE

The potential studies underlying our savings goals did not distinguish between measures/equipment installed under low-income energy efficiency (LIEE) versus non-low income energy efficiency (non-LIEE) programs.

Therefore, in D.04-09-060, we determined that the verified savings from LIEE programs should count towards meeting our energy efficiency goals.²²⁴

Accordingly, all parties agree that those savings should also count towards the MPS under the risk/reward incentive program, but not towards the PEB.

This means that LIEE savings will count when determining whether the utilities have met at least 85% of the savings goals (the MPS), and are thus are

²²² *Assigned Commissioner's Ruling Soliciting Questions on Whether and How to Change Utility Energy Savings Goals*, June 1, 2007.

²²³ *Ibid.*, pp. 3-4.

²²⁴ D.04-09-060, p. 134.

eligible to share a percentage of the net benefits (PEB) achieved at that level of performance or higher. Energy Division's Annual Verification Reports and Final Verification and Performance Report should reflect the results of the most recent LIEE load impact studies and any other completed Energy Division LIEE verification activities in reporting the savings for this purpose. However, in the calculation of the portfolio net benefits, to which the shared-savings rate(s) will apply, neither the savings nor the costs associated with LIEE programs will be included. Only the savings and the costs associated with the non-LIEE portfolio will be used to calculate the PEB net benefits and associated earnings under today's adopted incentive mechanism.

9.5. Augmented Funding for Programs During Program Cycle

The issues discussed above concerning "what counts" raise a corollary issue: How should we consider augmented program funding during the program cycle in the context of today's adopted incentive mechanism? We establish energy efficiency funding levels for each three-year program cycle after an extensive program planning and compliance process. During that process, we evaluate on a prospective basis the ability of portfolio activities to achieve the three-year savings goals cost-effectively with the funds authorized, with the input of all interested stakeholders and program advisory group members, including Commission staff. Therefore, we expect utility requests for funding augmentation once the Commission has approved funding levels and utility

program portfolios for a particular program cycle to be limited to extraordinary circumstances.²²⁵

In the 2009-2011 planning phase of this proceeding, parties have submitted specific recommendations for the treatment of savings and costs associated with energy efficiency funding augmentations during the funding cycle (referred to as “mid-cycle” funding augmentations). In a subsequent decision, we will address parties’ proposals and adopt policy rules that establish how to count savings and costs associated with mid-cycle funding augmentations in the context of today’s adopted incentive mechanism. We prefer to adopt a generic approach to this issue by adopting policy rules, rather than addressing these issues on a case-by-case basis for each mid-cycle funding augmentation request, as suggested in the Proposed Decision.

Nonetheless, we will need to carefully examine each request for LIEE program funding to ensure that it is properly classified as LIEE. As discussed below, there are implications associated with classifying a program as LIEE and augmenting its funding that now carry over to the risk/reward incentive mechanism adopted today.

One such example is the May 10, 2007 application filed by SCE for approval of a “change a light, change the world” compact fluorescent lamp (CFL) program. In this application, SCE requests \$22 million in augmented LIEE funding to achieve additional kWh and kW savings through the distribution of approximately one million CFLs to homes in low-income neighborhoods by

²²⁵ This expectation applies to requests for funding augmentation that would require either approval to increase revenue requirements or approval to carryover unspent funding authorized for an earlier program cycle.

December 31, 2008.²²⁶ If this augmentation is treated as an LIEE program, as SCE requests, then the additional program costs and savings will be handled in the manner described in Section 9.4 above. However, we need to consider this treatment on a case-by-case basis, because of the following implications.

If the proposed funding is approved as LIEE, then the utility is authorized to spend more ratepayer funds on activities that will make it easier for the utility to meet the MPS and become eligible for shared-savings. However, as discussed above, the net benefits (either positive or negative) associated with the program augmentation would not be reflected in the PEB calculation and subject to the earnings true-up process. Because LIEE programs are undertaken to meet equity as well as resource objectives, they provide energy efficiency measures and services at no cost to eligible, low-income households. LIEE programs are generally much less cost-effective relative to activities funded through non-LIEE energy efficiency programs (where participants are generally required to pay a significant portion of the measure installation cost), or not cost-effective at all. Therefore, as we review funding requests for energy efficiency, we must carefully and consistently distinguish between LIEE and non-LIEE programs. Otherwise, utilities could end up earning more than their authorized “share” of net benefits due to misclassification of programs as LIEE, which would not be fair to ratepayers.

10. Cost-Effectiveness Issues

We identified two issues related to how energy efficiency cost-effectiveness calculations should be performed in the scoping of Phase 1. The

²²⁶ See *Application for Approval of SCE’s “Change a Light, Change the World” Compact Fluorescent Lamp Program*, A.07-05-010, dated May 10, 2007.

first is whether shareholder incentive payments under today's adopted risk/reward incentive mechanism should be included (as a cost) in the energy efficiency tests of cost-effectiveness. The second is the manner in which "free rider" (or net-to-gross) adjustments should be applied in calculating the net benefits of the risk/reward incentive mechanism performance basis, an issue raised by Energy Division during the review of cost-effectiveness calculations for the 2006-2008 compliance filings.²²⁷ Both were discussed in comments and during workshops in this phase of the proceeding, and the positions of the parties are summarized in Attachment 3.

In addressing these issues, we will be referring to two cost-effectiveness tests adopted in our Policy Rules for energy efficiency and described in the Standard Practice Manual (SPM), which is also referenced in those rules.²²⁸ Therefore, by way of background, we provide a brief explanation of these two tests and how they are used in the context of energy efficiency.

The first is the "total resource cost" (TRC) test. As discussed in D.06-06-063, the TRC test is the measurement of net resource benefits of a program from the perspective of all ratepayers, and is produced by combining

²²⁷ See *Assigned Commissioner's Ruling and Scoping Memo and Notice of Phase 1 Workshops*, May 24, 2006, pp. 3, 7.

²²⁸ See D.05-04-051, Attachment 3, Rule IV.1. The most recent version of the SPM is published as the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, October 2001 (2001 SPM), and is posted on the Commission's website at <http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/em+and+v/index.htm>.

the net benefits of the programs to participants and non-participants.²²⁹ The benefits are the costs of the supply-side resources avoided or deferred. The costs included in the TRC test are all costs paid by both the utility and the participant, which encompass the costs of the measures/equipment installed and the costs incurred to start and administer the program.

The only costs that are not explicitly included in the SPM formulation of the TRC test are those incentives that are paid directly to participating customers to reduce the net expenditures of their own funds, so as to motivate their installation and retention of measures included in the program. As described in the SPM, such incentives are restricted to include only dollar benefits such as rebates or rate incentives (monthly bill credits). To prevent double counting of the dollar amount of these “rebate” incentives, they cannot be included as both a program administration cost and a participant cost.

In other words, since the SPM formulation includes these rebate incentives in the participant cost, they cannot also be included in the program administrators’ cost. Additionally, as the SPM discusses,²³⁰ these rebate incentive dollars can intuitively be thought of as canceling because they appear both as a cost to all ratepayers and as a benefit to participating ratepayers, or as “transfer payments” that cancel out when subtracting total cost from total benefit in calculating the net benefit of the program. Historically, for the reasons just mentioned, these dollar rebate payments have been excluded on both the benefit

²²⁹ “The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the *total costs of the program*, including both the participants’ and the utility’s cost.” 2001 SPM, p. 18, emphasis added.

²³⁰ 2001 SPM, p. 11, footnote 3.

and cost side of the TRC equation, and considered to be a transfer payment between participating and non-participating customers.²³¹ However, as discussed further below, the SPM formulas and definitions do not explicitly address how to account for these rebate incentive costs when there are free rider participants who receive them.

The second test is the “program administrator cost” (PAC) test of cost-effectiveness. Under this test the program benefits are the same as the TRC test, but costs are defined differently to include all the costs incurred by the program administrator, including all incentives and all other program costs that become revenue requirements. The PAC test does not include the costs incurred by the participating customer.

These two tests are used on a prospective basis in evaluating the projected cost-effectiveness of the utility’s proposed portfolio plans, as well as after-the-fact to assess the actual cost-effectiveness of the implemented portfolio. In addition, a weighted average of cost and benefit values for the TRC and PAC tests is used in the calculation of net benefits under the PEB formula adopted in D.05-04-051. More specifically, the TRC net benefit results are weighted by 2/3 and the PAC net benefit results are weighted by 1/3 to produce the PEB.²³²

²³¹ D.06-06-063, pp. 63, 68 and *ALJ Ruling Addressing Compliance Filings Pursuant to D.06-06-063*, December 21, 2006 (2006 ALJ Compliance Ruling), p. 6.

²³² For the Commission’s determination on PEB-related issues, see D.05-04-051, *mimeo.*, pp. 38-43, 60-64. See also *Administrative Law Judge’s Ruling on EM&V Protocol Issues*, September 2, 2005 in R.01-08-028, pp. 2-6, 14-15.

10.1. Treatment of Shareholder Incentive Costs in Cost-Effectiveness Tests

In D.04-10-059, we determined that shareholder incentives represent a true economic cost in the production of utility programs and should be included as a direct cost in the various Standard Practice Manual tests of cost-effectiveness, including the TRC test and the predecessor of the PAC test, the “Utility Cost” test.²³³ There appears to be no disagreement that this policy rule is still relevant today.

More specifically, in evaluating the cost-effectiveness of program plans submitted during the program planning cycle, or when conducting a cost-effectiveness review of portfolio performance in hindsight, the costs of shareholder incentives should be included in those calculations. As SCE points out, during the planning process those costs will need to be estimated, based on the projected performance of the portfolio. Similarly, until the final earnings claim is authorized for a particular program cycle, we will also need to estimate the total cost of shareholder incentives in evaluating portfolio cost-effectiveness for that cycle.

TURN recommends that we also subtract out shareholder incentives when we apply the TRC and PAC tests in calculating the PEB under today’s adopted shared-savings mechanism. More specifically, TURN suggests that we “forecast shareholder incentives to obtain an estimated PEB....then calculate a new incentive number and use an iterative process to recalculate the PEB and

²³³ D.04-10-059, Attachment 6 Policy Rule II.10.

incentive until the numbers converge.”²³⁴ However, as noted in the Proposed Decision, it would be nonsensical to reduce the PEB based on some projection of shareholder incentives before the sharing rate is even applied. The whole purpose of the PEB is to establish the level of portfolio net benefits *before shareholder incentives are paid out*, so we can determine what those incentive levels should be. To subtract forecasted incentives out *before* applying the sharing rate is a circular proposition. It is akin to saying that we will share a quarter of a pie with you, but before we slice it into 4 pieces, we will first remove a quarter. We reject TURN’s recommendation, and continue to implement the PEB calculation utilized in previous incentive mechanisms by excluding incentive costs from the PEB net benefit calculation.

We will modify the Energy Efficiency Policy Manual, Version 3 to reflect this treatment of shareholder earnings in the prospective evaluation of energy efficiency portfolios, beginning with the 2009-2011 funding cycle.

10.2. Free-Rider Adjustments to TRC Costs-Application of the Net-to-Gross Ratio

In the context of energy efficiency programs, free riders are those program participants who would have undertaken the energy efficiency activity in the absence of the program. The net-to-gross or “NTG” ratio is the total number of participants that are *not* free riders, e.g., a ratio of 0.80 indicates that 20% of the participants are free riders. There is no dispute among parties that the NTG ratio should be applied to the benefit side of the TRC equation to remove the resource savings attributable to free riders, since free riders do not add benefits to the

²³⁴ TURN’s *Opening Comments on Proposed Decision Concerning Shareholder Incentives*, August 29, 2007, p. 12.

program.²³⁵ The SPM formulation explicitly defines the utility increased and decreased supply costs as net of free riders.²³⁶

However, there remains some disagreement among the parties about the impacts of free riders on the cost side of the TRC equation.

During the 2006-2008 portfolio planning process, Energy Division staff noticed that the utilities were also applying the NTG ratio to some components of TRC costs, and questioned the propriety of discounting any TRC costs in this manner. In their Phase 1 comments, the utilities and other parties point to a 1988 memo from members of the SPM working group that recommended a correction to adjust the “participant cost” component of the TRC by the NTG ratio. We refer to this memo, which is included in Attachment 9, as the “1988 SPM Correction Memo”.

The 1988 SPM Correction Memo acknowledges that some portion of the TRC costs would have been incurred anyway (by free riders that would have purchased the measure on their own without the program being available), and therefore those costs should be excluded from the TRC calculation, as are the savings attributed to free riders on the benefit side. By ruling dated December 21, 2006, the assigned ALJ observed that there appeared to be

²³⁵ There is also no dispute that the NTG ratio should be applied to the benefits side of the PAC equation. And since the PAC test does not include any of costs incurred by the participating customer, no one proposes that PAC costs should be adjusted by the NTG to remove free rider costs. Therefore, today’s decision focuses on how the NTG ratio should be applied to the cost-side of the TRC test.

²³⁶ The utility avoided cost and utility increased cost terms, UAC and UIC respectively of the TRC, PAC and Ratepayer Impact Measure tests are defined to be based upon net energy and demand. See *2001 SPM*, pp. 13, 18 and 23 for description and page 17 for net energy and demand formulas.

consensus on this issue, since all parties agreed during the workshops that the 1988 SPM Correction Memo is the applicable approach.²³⁷

However, based on our further review of the Phase 1 record and consultation with Energy Division, we conclude that while there was general consensus that the 1988 SPM Correction Memo permitted the application of the free rider adjustment (NTG ratio) to the participant cost term of the TRC test, the correction formulation left unaddressed the appropriateness of adjusting for free riders (i.e., reducing) the “rebate” incentives term (“INC”) paid to program participants.²³⁸ Even the most recent version of the SPM does not clarify this issue, as the term “PCN” that appears in the TRC formula is simply defined as “Net Participant Costs,” which does not indicate whether this means “net” of free riders, net of incentives, or both.

As indicated in Attachment 3, the joint summary documents filed in Phase 1 present the position of TURN, DRA and NRDC as recommending that only the free-rider “out of pocket costs” (net of any rebate incentives) be removed from the cost side of the equation and that the utility cost of rebate payments to free riders be retained in TRC costs. Based on the Attachment 3 summaries for the utilities, as well as the observations made by the ALJ in her December 2006 ruling, it appears that the utilities’ position is different. In particular, it appears that they would remove from the cost side of the TRC equation essentially all utility costs incurred on behalf of free riders, whether

²³⁷ See 2006 ALJ Compliance Ruling, pp. 10-11.

²³⁸ As discussed above, the SPM restricts this rebate incentive (“INC”) term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). See also our discussion of this term in D.06-06-063 with numerical examples at pp. 68-74. See also 2006 ALJ Compliance Ruling, pp. 6-8.

these represent direct install program costs or dollar rebates paid when free riders install the measure or equipment themselves.²³⁹

We clarify today how the NTG ratio is to be applied to the cost-side of the TRC equation. As described in the SPM and reiterated in D.06-06-063, the intent of the TRC test of cost-effectiveness is to capture “*all* costs associated with the energy efficiency activity, whether paid for out-of-pocket by program participants or by non-participants through the authorized revenue requirement that fund the programs.”²⁴⁰ Ratepayers, through the energy efficiency revenue requirements collected to fund these programs, incur a cost for free rider participants that must not be ignored in the formulation of the TRC test. Because the simplified numerical examples we presented in D.06-06-063 involved only one participant, the issue of how to fold in free rider considerations on the cost side of the TRC equation was never explicitly addressed in that decision.

In fact, the only time we have discussed in a Commission decision how to apply the NTG ratio to costs associated with energy efficiency programs was in 1992, in the very limited context of the DSM bidding pilots undertaken in the early 1990s. In that context, our objective was to ensure that doing so would not create “an advantage to bidders over the utility program even when the projects

²³⁹ *Ibid.*, pp. 12-13. As discussed in D.06-06-063, the TRC will fail to capture all costs only in the limited instance when the dollar rebate incentive to a participating customer exceeds the participants’ cost of purchasing and installing the measure. This “excess” rebate cost will not currently be captured by the TRC cost formulations, due to the treatment of these costs as a transfer payment in the SPM formulation. For this reason, we use the “dual test” of cost-effectiveness (PAC and TRC tests) in evaluating the cost-effectiveness of energy efficiency and utilize a weighted average of the PAC and TRC tests in calculating the PEB.

²⁴⁰ D.06-06-063, *mimeo.*, p. 67.

have identical total costs and benefits.”²⁴¹ Our determinations in D.92-12-050 were designed to achieve that specific objective, based on the record in that proceeding. However, in 1992 we did not consider how applying the NTG ratio to individual components of “participant costs” could impact the cost-effectiveness of different program delivery approaches (e.g., direct install versus rebate programs), that is, how such application could unduly advantage one approach over the other. It was not until the post-2005 portfolio plans were being developed and evaluated that Energy Division and its consultants brought these implications and questions concerning the 1998 SPM Correction Memo to our attention. Therefore, it is appropriate and important that we fully examine and resolve this issue in the context of post-2005 energy efficiency portfolio development and evaluation, and we do so today.

Without further clarification, the mathematical formulation of the 1988 SPM Correction Memo appears to create a free rider cost advantage to rebate programs relative to direct install programs, which should not occur if all else is equal. This is because this memo first displays the equation for TRC costs, which included at that time a “participant cost” (PC_t) term,²⁴² and then “suggest[s] renaming the participant cost as PCN to designate ‘Participant cost – net’.” (See Attachment 9.) That particular PC_t term has always been defined in the SPM as participant costs *before* receiving the dollar rebate incentive (cash rebate or bill credit) discussed above, which is represented as the “INC” term in SPM

²⁴¹ D.92-12-050, 47 CPUC 2d, p. 73.

²⁴² *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs (1987 SPM)*, December 1987, p. 29.

equations.²⁴³ Therefore, the 1988 SPM Correction Memo could be interpreted to mean that the NTG ratio is applied to the participants' out-of-pocket costs (after receiving a rebate incentive) as well as to the rebate incentive paid, up to the full cost of the measure or device.

This result means, as currently formulated in that memo, removal from TRC costs of all revenue requirements associated with paying free riders a rebate incentive. However, an equivalent financial incentive to the customer offered under a direct install program would not be removed. In other words, if instead of offering a cash rebate to the customer, the utility directly installs that same measure and requires a customer co-payment (such that the out-of-pocket cost to the customer is the same under either approach), the financial incentive to free rider participants would be *included* in the costs. This is because all of the direct install costs would appear in the "program administrative cost" (PRC) term.²⁴⁴ As indicated in Attachment 9, the 1988 SPM Correction Memo specifically

²⁴³ See 1987 SPM, p. Appendix C, p. C-6; See also 2001 SPM at p. 11, footnote 3, and p. 32.

²⁴⁴ See D.06-06-063, pp. 71-72 and Ordering Paragraph 15. The utilities recently filed a joint petition to modify D.06-06-063 with regard to our orders that certain costs be included in the administrative cost component of the TRC, and not be considered transfer payments. (See *Joint Petition of PG&E, SDG&E, and SCE for Modification of D.06-06-063*, May 31, 2007 in R.04-04-025 and also served on the parties to this rulemaking.) We do not address this issue in today's decision. Instead, we focus on how the NTG should be applied to TRC cost components within the context of the SPM and our determinations to date on the application of the TRC and PAC tests to various energy efficiency delivery approaches. Until further order by the Commission, our determinations in D.06-06-063 and the 2006 ALJ Compliance Ruling on how costs are to be accounted for under these tests remain unchanged.

prohibits applying the NTG ratio to the administrative cost component of TRC costs, since these are costs unrelated to participant expenditures.²⁴⁵

This means, all other things being equal, the 1988 SPM Correction Memo formulation would assign more costs to a direct install program than to a customer rebate program that is identical except for the delivery approach. As we stated in D.06-06-063, this type of inconsistency in cost-effectiveness results makes no sense, and is inconsistent with the intent of the TRC discussed above.²⁴⁶ It is not even clear that this was the intent of the authors of the 1988 memo, since the formula did not actually present a full restatement of all the equations (benefit and cost side) of the TRC test with explicit NTG ratios applied.

To clarify how the NTG ratio should in fact be applied, a transfer incentive (INC) recapture quantity will be added to the TRC cost equation presented in the 1988 SPM Correction Memo as follows:

TRC Costs = PRC + NTG*PC + UIC + (1.0-NTG)*INC, where:

PRC = program administrator program costs

PC = participant device costs (*before* INC is received)

UIC = (for fuel substitution programs) utility increase supply costs

NTG = net-to-gross ratio

INC = incentive costs, restricted to include only dollar benefits such as rebates or rate incentives (bill credits).

Adding this term to the TRC cost formulation will ensure that the removal of free rider costs does not also remove program costs that become ratepayer

²⁴⁵ The 1988 SPM Correction Memo utilizes the "UC" (for "utility administrative costs") term, which as been subsequently renamed "PRC" ("program administrator program costs") in more recent versions of the SPM. Therefore, we use the current PRC term in today's clarification.

²⁴⁶ See D.06-06-063, p. 72.

revenue requirements, consistent with the intent and purpose of this test.²⁴⁷ In doing so, it also serves to ensure that direct install programs and customer rebate programs are treated consistently when the measure cost, the customer financial incentive, program administration costs and the NTG ratio are the same under the two delivery approaches.²⁴⁸ This can be seen from the numerical examples presented in Attachment 9. This formulation is also fully consistent with the text description of the TRC test in the SPM, which recognizes that the “incentives” (INC) term will cancel from the benefit and cost side of the equation “*except for the differences in net and gross savings.*”²⁴⁹

In consultation with the assigned ALJ, and as soon as practicable, Energy Division should post this clarification to the SPM as a “2007 SPM Clarification” memo on the Commission’s website, together with the latest (2001) version of

²⁴⁷ As we note in Section 10, the SPM defines the “perspective” of this test as one of evaluating *program* cost-effectiveness, that is, looking at “the total costs of the program, including both the participants’ and the utility’s costs.” (2001 SPM, p. 18.) In its comments on the Proposed Decision, PG&E argues that we “erode” the concept of rebates by adding this clarification to the 1988 SPM Correction Memo. However, PG&E’s argument hinges on its characterization of the TRC test as one “designed to count the total incremental cost of energy efficiency measures to society as a whole (considering ratepayers and utilities collectively).” (*Comments of PG&E on Proposed Decision*, August 29, 2007, p. 8.) This is not the definition or perspective presented for this test in the SPM or in any Commission decision.

²⁴⁸ As discussed in D.06-06-063, there may be limited instances for program design purposes where the cash rebate to the customer exceeds the measure installation cost. Under these circumstances, the TRC results will be the same for both direct install and the rebate program (all other things being equal), given the transfer payment treatment of cash rebates in the SPM. However, the PAC test will favor the direct install program to reflect the lower revenue requirements associated with direct install under these circumstances. See D.06-06-063, p. 72.

²⁴⁹ 2001 SPM, p. 18. (emphasis added.)

the SPM. The utilities shall take steps immediately to ensure that all future cost-effectiveness calculations apply the NTG ratio as directed by this decision. This includes the accomplishments reported for 2006-2008 energy efficiency portfolios, effective immediately.

As directed in the 2006 ALJ Compliance Ruling, Energy Division shall confer with Energy and Environmental Economics (“E3”) and other technical expertise, as staff deems appropriate, to explore whether the naming of input values in the E3 calculator should be modified to better capture the SPM cost definitions and calculation methods, including the NTG ratio adjustments we clarify today. In addition, Energy Division may directly manage the development of the E3 calculator in the future, at its discretion, as part of this Commission’s overall quality assurance responsibilities for post-2005 energy efficiency.²⁵⁰

11. Performance-Based Incentives for Emerging Technologies and Information Programs

PG&E proposes separate performance-based incentives for emerging technologies and education and training programs, in recognition of the essential role they play in the total portfolio of programs. NRDC supports PG&E’s proposal in order to provide some earnings potential to balance the inclusion of these program costs in the PEB.

For the Emerging Technologies Program, PG&E proposes that shareholder earnings equal to five percent (5%) of Emerging Technology expenditures be awarded based on two performance thresholds. The first would be a “product introduction” threshold, which is met if the utility successfully moves a total of seven new technologies or products into the resource programs to generate

²⁵⁰ See D.05-01-055, Section 5.3.3.

savings (one new product in 2006, two new products in 2007 and four new products in 2008). The second is an “aggregate minimum expected savings” threshold of 150 MWh and 2,250 MTherm (for all seven products combined), or approximately 5 percent of PG&E’s three-year energy targets. The product threshold would apply as a condition for being eligible for earnings in the interim claims, and the aggregate minimum expected savings threshold would apply as part of the final true-up claim.

For the Education and Training Program, PG&E proposes milestones tied to the number of training sessions, energy audits and equipment tests that would trigger eligibility for five percent (5%) of the yearly program expenditures. The threshold would be 25% of the goals listed in its compliance filing for these activities for the program year.²⁵¹

Although informational, marketing, emerging technologies and other non-resource programs are an essential part of the portfolio, we agree with DRA and others that a separate incentive mechanism should not be established for non-resource programs. As DRA notes, doing so runs the risk of double-counting the savings benefits already attributable to resource programs for many of the non-resource activities that PG&E seeks to include (e.g., audits and training).²⁵² Moreover, our experience in the past with milestone-based incentive mechanisms reminds us of the difficulty in establishing mechanisms to reward the performance of non-resource programs. As SCE points out, a

²⁵¹ *PG&E’s Pre-Workshop Written Comments and Proposal on Energy efficiency Shareholder Risk/Reward Incentive Mechanism*, June 16, 2006, pp. 14-16.

²⁵² *DRA Proposed Risk/Return Shareholder Incentive Mechanism for Energy Efficiency Portfolios*, September 8, 2006, p. 26.

milestone-based mechanism can “eventually lead to a matter of interpretation either when developing how performance will be achieved for a particular milestone or deciding if performance was achieved.”²⁵³ Finally, our decision to not include emerging technologies program costs in the calculation of PEB addresses NRDC’s concerns about not having a performance adder mechanism for this program.

For these reasons, we do not adopt PG&E’s proposal. Energy Division does plan to undertake EM&V activities to assess the net resource benefits associated with audit programs, as indicated in the September 2, 2005 ruling on EM&V Protocols.²⁵⁴ Therefore, to the extent that the resource savings associated with utility audits are verified through staff EM&V efforts, they will be reported in the Final Performance Earnings Basis Report and included in the true-up calculation of PEB under the shareholder incentive mechanism we adopt today.

12. Rate Recovery, Cost Allocation and Short-Term Rate and Bill Impacts

Pursuant to D.98-03-063, earnings authorized for energy efficiency are collected through electric distribution and gas transportation rates, and allocated to customer classes based on marginal cost allocation factors. We have applied this approach to rate recovery and cost allocation to earnings authorized for non-LIEE under mechanisms in place prior to 2002, as well as to earnings paid out under the performance adder incentive mechanism currently in place for LIEE.

²⁵³ *Post-Workshop Opening Comments of SCE*, September 29, 2006, p. 19.

²⁵⁴ *ALJ’s Ruling on EM&V Protocol Issues*, September 2, 2005, p. 6 and Appendix 1.

The issue of whether to change this practice was first raised by TURN in its direct testimony. In that submittal, TURN argues that it is unfair because the current approach for allocating shareholder incentive costs to customer classes would assign a greater proportion of incentive costs to residential customers than the percentage of the energy efficiency expenses they pay. Therefore, TURN recommends that “if the Commission is going to burden *any* ratepayers with these massive incentives, it should charge the incentives in proportion to energy efficiency expenditures....”²⁵⁵

Changes to our rate recovery and cost allocation procedures for shareholder incentives was not a topic identified in any of the scoping rulings for Phase 1, by workshop participants in their pre- and post-workshop filings, or by the Assigned Commissioner in her ruling identifying the issues for Phase 1 testimony and evidentiary hearings. It is therefore beyond the scope of Phase 1 to address such changes in today’s decision. We also agree with CLECA and others that cost allocation is an issue to be addressed only after proper notice is given to all potentially affected customers. It is also a complicated one, with multiple possible approaches for resolution and factual information on the impact on various customer classes that we must carefully consider.

Therefore, until further order by the Commission, we will continue to recover shareholder incentives (earnings) associated with energy efficiency activities through electric distribution or gas transportation rates, using the cost allocation methods adopted for that purpose. We encourage the Assigned Commissioner, in consultation with Energy Division staff, to consider how the

²⁵⁵ Exh. 66, p. 22.

cost allocation issue that TURN raises in its testimony may be raised for Commission consideration in the future, in the appropriate procedural forum and with proper notice to all interested parties.

As in the past, the rate changes required to recover positive earnings under the incentive mechanism shall be consolidated with the next scheduled change in the utility's electric distribution and gas transportation rates. However, as discussed in Section 8.2.2, any pay-back obligations that might arise in the final true-up claim will be booked against positive earnings in the next energy efficiency program cycle, and not be consolidated with other electric distribution or gas transportation rate changes for the next scheduled change.

More specifically, upon review and authorization of earnings for the interim or final earnings claim, SCE will record the authorized earnings in the distribution sub-account of the Base Revenue Requirement Balancing Account. The year-end balance recorded in this account will be recovered in SCE's annual Energy Resource Recovery Account forecast proceeding, where we consolidate authorized revenue requirement changes (including balancing account balances) for SCE into one rate change that is implemented on (or soon after) January 1st of each year.²⁵⁶

PG&E consolidates distribution rate changes each year by submitting Annual Gas True-up and Annual Electric True-up advice letters in the fall. This process sets PG&E's gas and electric rates on or soon after January 1st of each year. Accordingly, PG&E will include the electric revenue requirement and gas incentive amounts that are authorized for a particular interim or final earnings

²⁵⁶ The earnings claim (for electric energy efficiency only) is grossed up by the Franchise Fees and Uncollectible factor in effect at the time of collection.

claim in the next scheduled Annual Electric True-up and Annual Gas True-up advice letter. Similarly, SDG&E and SoCalGas will collect authorized shareholder earnings through the advice letter process they use to consolidate rate changes that become effective on or soon after January 1st of each year. These are the December Consolidated Filing to Implement Electric Rates and December Consolidated Gas Rate Changes advice letter filings.

At the direction of the assigned Commissioner and ALJ, the utilities prepared estimated rate and bill impacts associated with various scenarios of potential levels of shareholder incentives for energy efficiency.²⁵⁷ These projected rate and bill impacts reflect the immediate, short-term impacts associated with increasing funding requirements for shareholder incentives associated with 2006-2008 program accomplishments. They *do not* reflect the net impact on rates and bills of those programs (including shareholder incentives) over time.

The overall impact of energy efficiency programs – even with the payout of shareholder earnings – will be to *decrease* utility revenue requirements, customer rates and customer bills relative to the levels without the energy efficiency programs. This decrease occurs because the earnings paid out under a shared-savings mechanism, by definition, are a fraction of the verified net benefits to ratepayers, that is, the verified reductions in supply-side costs less energy efficiency portfolio costs. For example, as shown in Table 1 (in Section 1), earnings of \$323 million for the combined utilities will be paid out at 100%

²⁵⁷ July 13, 2007 e-mail ruling of assigned Commissioner Grueneich and ALJ Gottstein. See *PG&E, SDG&E and SoCalGas' Joint Response* and *SCE's Response* to this ruling, dated July 19, 2007.

achievement of the Commission's 2006-2008 savings goals, if and only if Energy Division verifies that the corresponding net benefits of \$2.7 billion will materialize. The return of \$2.4 billion on ratepayers' investment (ratepayers' "share" of net benefits) at this level of performance translates into reduced utility revenue requirements and lower bills for customers that far exceed the short-term rate and bill impacts associated with recovering the earnings as they are paid out.

The magnitude of these short-term rate and bill impacts depends upon the actual level of portfolio performance, the associated earnings rate and the earnings recovery schedule. The tables in Attachment 10 present bill impact analyses for the 2006-2008 portfolio performance at 100% of goal achievement assuming earnings rates of 5%, 10%, 15% and 20% under two alternative earnings payout scenarios. One scenario provides the annual impact spread evenly over three years and the other spreads that same impact over four years. Table 4 presents the impacts associated with an earnings rate of 15% and a three-year payout of earnings. These numbers represents the upper bound of impacts, given the earnings rates and earnings recovery schedule that we adopt today.

TABLE 4
Average Annual Rate Change and Bill Impact to Recover
Earnings Paid For Achieving 100% of 2006-2008 Savings Goals
(Upper Range of Short-Term Impacts)

	Average Bundled % Change	Average Residential % Change	Average Residential Increase per Month
SCE	0.51%	0.65%	\$0.58
PG&E	0.41%	0.49%	\$0.42
SDG&E	0.48%	0.66%	\$0.22
SoCalGas	0.69%	0.44%	\$0.09

As Table 4 indicates, the payout of shareholder earnings for 2006-2008 energy efficiency activities is estimated to increase average annual rates to all customers (“bundled change”) by no more than 0.41% to 0.69%, depending on the utility. The percentage change in annual residential rates is estimated at no more than 0.44% to 0.66%, which translates to average residential bill increases in the range of 9¢ to 58¢ per month, depending on the utility. Again, we emphasize that these are short-term rate and bill impacts because they do not reflect the much greater decreases in revenue requirements and customer bills that are resulting from the implementation of 2006-2008 energy efficiency activities.

13. Revisiting the Adopted Incentive Mechanism

As recommended by most parties, we establish today a schedule for revisiting the specific risk/reward mechanism we adopt today, after we have gained experience with its implementation. Specifically, we direct Energy

Division to prepare an evaluation report by February 1, 2011, so that we may consider any recommended modifications to today's adopted risk/reward incentive mechanism in time for the 2012-2014 program cycle. For this purpose, Energy Division may hire evaluation contractors. We authorize Energy Division to use 2009-2011 EM&V funds for this evaluation, and direct Energy Division to solicit stakeholder input in the scoping of the evaluation and in the review of the draft evaluation report(s). Energy Division should also consider today's incentive mechanism in the context of the implementation of greenhouse gas emissions caps and other mechanisms under Assembly Bill 32 and our Procurement Incentive Framework.²⁵⁸

14. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner, and Meg Gottstein is the assigned ALJ for Phase 1 of this proceeding.

15. Comments on Proposed Decision

The proposed decision of Assigned Commissioner Grueneich and ALJ Gottstein (Proposed Decision) in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on August 29, 2007 by the utilities, TURN, DRA, NRDC, California Center for Sustainable Energy, Pacific Energy Policy Center and CE Council. Reply comments were filed by the utilities, TURN, DRA and NRDC on September 4, 2007.

²⁵⁸ See D.06-02-032, *mimeo.*, pp. 34-35.

We have carefully reviewed the comments on the Proposed Decision and make clarifications and corrections in response to many of them.²⁵⁹ However, we do not alter the substantive determinations made in the Proposed Decision, with two exceptions. For the reasons discussed in Section 6.3, we conclude that the lower end of the range of supply-side comparable earnings calculations should be used as an upper bound to the earnings potential under today's adopted risk/reward incentive mechanism. We therefore lower the cap on both earnings and penalties from the \$500 million level recommended in the Proposed Decision (for all utilities combined, over each three-year program cycle), to \$450 million. The \$450 million combined cap is allocated to each utility as follows: PG&E--\$180 million; SCE--\$200 million; SDG&E-\$50 million and SoCalGas--\$20 million.

We also modify the Proposed Decision with respect to the treatment of mid-cycle funding augmentation. As discussed in Section 9.5, parties to the 2009-2011 planning phase of this proceeding have submitted specific recommendations for the treatment of savings and costs for funding augmentation that occurs during the funding cycle as part of our generic review of energy efficiency policy rules. Therefore, we will address this issue in a

²⁵⁹ The comments of Pacific Energy Policy Center urging us to adopt policies related to the review and approval of utility applications for new plant construction are beyond the scope of Phase 1, as are the comments of the California Center for Sustainable Energy on policies regarding third party programs and the role of the program advisory groups. We encourage the participation of these and other interested organizations in our proceedings, but they should be mindful of the scope of each proceeding (or Phase of proceeding being addressed in the decision) so that their participation can be meaningful.

subsequent Commission decision in that phase, rather than in today's Phase 1 decision.

On all other issues, we affirm the conclusions and determinations contained in the Proposed Decision.

In particular, we affirm the Proposed Decision's clarification of how free riders should be accounted for (i.e., how the NTG ratio should be applied) in the calculation of TRC costs. The utilities argue that if we do not adopt their preferred treatment of free riders with respect to the cost side of the TRC calculation – then we have inappropriately introduced a newly revised TRC computation and contradicted the Commission's findings in D.06-06-063, without an adequate opportunity to develop the record.²⁶⁰ Moreover, PG&E contends that unless we ignore or significantly limit free rider adjustments to savings benefits in the final true-up claim (or in the alternative lower the Commission's adopted goals and associated MPS levels), the "rules of the game are being changed mid-stream."²⁶¹

We disagree. With regard to the treatment of free riders on the cost side of the TRC test, the debate over how to apply NTG ratios to TRC costs has been going on for some time among the interested stakeholders, at least since the 2006-2008 planning process began. As discussed in the Proposed Decision (and reiterated today), neither the SPM, the 1988 SPM Correction Memo nor D.06-06-063 explicitly resolve this debate, which is why it was identified in the

²⁶⁰ As discussed in today's decision, the utilities prefer to apply the NTG ratio to program costs, a view that is not shared by any other party.

²⁶¹ *Comments of PG&E on Proposed Decision*, August 29, 2007, p. 6. See also *Opening Comments of SDG&E/SoCalGas on Proposed Decision*, August 29, 2007, pp. 2-5.

scoping ruling for resolution in this phase of the proceeding.²⁶² Today's decision provides the clarification requested by Energy Division and other stakeholders in order to remove any uncertainty over how these computations should be performed for calculating the PEB. The utilities as well as all other interested parties have been provided the opportunity to express their views and make specific recommendations on this issue.

We have reviewed the parties' comments and recommendations on how to apply the NTG ratio to the cost side of the TRC equation, and have carefully considered them in the context of the purpose of the TRC test. We see no merit to deferring this issue until a later date, as some parties suggest in their comments on the Proposed Decision. The utilities recommendation to exclude rebates paid to free riders from TRC costs would increase the PEB under the adopted incentive mechanism 67 cents for each dollar paid to free riders, with zero dollars of added benefit to ratepayers. Paying utility incentives on the dollars they pay to free riders is unreasonable, and today's decision appropriately rejects that proposal.

It is also unreasonable for the utilities to ask us to broaden the scope of Phase 1 in order to reverse our determinations on how to account for free riders in the calculation of portfolio savings benefits, just because NTG ratios may be higher (and net benefits correspondingly lower) on an *ex post* basis than they assumed in developing their portfolio plans.²⁶³ There are many parameters that

²⁶² See *Assigned Commissioner's Ruling and Scoping Memo and Notice of Phase 1 Workshops*, May 24, 2006, p. 7. See also May 9, 2006 Prehearing Conference RT at p. 56.

²⁶³ The scope of Phase 1 does not include revisiting these protocol issues or how the Commission's savings goals should be established, which are issues raised by PG&E's and SDG&E/SoCalGas comments on the Proposed Decision.

go into the calculation of PEB, some of which we have determined should be true-up (e.g., NTG ratios, portfolio costs and unit energy savings) in calculating the PEB and others that will be updated for prospective use only (i.e., to revise *ex ante* estimates for the subsequent program cycle). Since early 2005, the utilities have been on notice that the parameters used to evaluate near-term net savings, including NTG ratios, would be subject to true-up in calculating the PEB for each program cycle. The Commission made this very clear in D.05-04-051, issued on April 21, 2005, as did the September 2, 2005 ALJ ruling on related EM&V protocols.²⁶⁴ Moreover, incorporation of up-to-date NTG values into the current portfolios has been the subject of extensive discussion at Commission workshops, as well as program advisory group and peer review group meetings prior to and during the implementation of the 2006-2008 programs.²⁶⁵

In sum, the utilities cannot in good faith claim that risks associated with EM&V results – particularly NTG ratios – are “unforeseen expected evaluation risk.”²⁶⁶ They have had ample opportunity to adjust their portfolios in response to available data, and should be encouraged by Commission policies to minimize

²⁶⁴ See D.05-04-051, *mimeo.*, pp. 48-53 and *Administrative Law Judge’s Ruling on EM&V Protocol Issues*, September 2, 2005, Appendix 3. For the reasons discussed in D.05-04-051, the Commission did not require that the results of “persistence studies,” which evaluate the extent to which near-term savings from a program persist over time, be used to true-up the PEB for a particular program cycle. Rather, the Commission stated that those results would be used on a perspective basis only, that is, to inform updates to *ex ante* savings projections for future program cycles. The Commission also indicated its intent to revisit this policy and revise it at a future date, as appropriate, if the evidence indicated that the results of *ex post* persistence studies were significantly different from the *ex ante* estimates. (*Ibid*, pp. 52-53.)

²⁶⁵ *TURN Reply Comments on Proposed Decision*, September 4, 2007, p. 2. See also *DRA’s Reply Comments on Proposed Decision*, pp. 3-4.

expenditures on free riders by doing so. The Proposed Decision achieves this outcome.

The utilities also contend that adoption of per-unit penalty rates that are higher than any of the specific levels proposed by NRDC, TURN and DRA represent a violation of due process. However, they fail to point out that all parties had the opportunity to develop proposals for a fair balancing of risk/rewards under the incentive mechanism, and that the assigned ALJ specifically requested supplemental comments on the basis for the level of per unit penalty rates.²⁶⁷ In response, the utilities argued that the levels proposed by TURN, DRA and NRDC were arbitrary, not well reasoned, and failed to adequately balance the risks and rewards under the incentive mechanism.²⁶⁸ However, none of the utilities proposed an alternate basis for per-unit penalty rates for Commission consideration. Instead, they continued to argue that this type of penalty provision should be categorically rejected by the Commission.

It is now self-serving for the utilities to argue that we cannot adopt anything other than the per-unit penalty levels that these parties proposed. Moreover, none of the utilities recommended that the basis for per-unit penalty rates be subject to evidentiary hearings, when the Assigned Commissioner solicited comment on the need for further factual inquiry in this phase of the

²⁶⁶ *Comments of PG&E on Proposed Decision*, August 29, 2007, p. 7.

²⁶⁷ See *Administrative Law Judge's Ruling Memorializing Electronic Rulings on Phase 1 Requests for Information and Changes to Submittal Dates*, March 13, 2007, Attachment 2.

²⁶⁸ See *PG&E's Response to Parties' Proposed Incentive Mechanism Penalty Rate Explanation*, March 21, 2007; *Reply of SDG&E and SoCalGas to Response to ALJ Electronic Ruling*, March 21, 2007; *Reply Comments of SCE to the TURN/DRA/NRDC Submittal on Proposed Incentive Mechanism Rate Explanation*, March 21, 2007.

proceeding.²⁶⁹ In sum, we find no merit to their arguments that our decision violates their due process by not adopting the specific penalty rate levels that were presented in the context of other parties' overall risk/reward incentive design. Today's decision adopts per-unit penalties taking into consideration the per-unit penalty levels we have established for other preferred resources, the resulting balance of potential penalties with incentive rewards under the adopted incentive mechanism, and the full record developed on this issue. The utilities may object to our judgment on the appropriate balancing of these risks and rewards, but that does not constitute legal error.

In its comments on the Proposed Decision, DRA introduces for the first time in Phase 1 a proposal for structuring the earnings side of the incentive mechanism as a relatively continuous curve of graduated earnings rates for each 5% interval of goals achievement at or above the MPS. DRA presents two alternatives for the Commission's consideration in these comments: The first would start the shared-savings rate at 1.5% if the MPS is met (85% of goals), increasing as follows: 2.5% (90% of goals), 3.8% (95% of goals), 5.0% (100% of goals), 6.3% (105% of goals), 7.5% (110% of goals), 8.8% (115% of goals), 10% (120% of goals), 11.5% (125% of goals), 12.0% (130% of goals). The second alternative would have the same graduated rates between the MPS until 100% of goals are reached, but be higher once the goals are reached as follows: 9.0% (at 100% of goals), 9.5% (at 105% of goals), 10% (110% of goals), 10.5% (115% of goals), 11.0% (120% of goals), 11.5% (125% of goals) and 12% (130% of goals). DRA argues that these alternatives are preferable to the two-tiered earnings rate

²⁶⁹ *Assigned Commissioner's Ruling Soliciting Comment on the Need for Additional Factual Inquiry and Evidentiary Hearings in Phase 1*, February 28, 2007.

structure in the Proposed Decision because, in DRA's view, they would avoid any sharp discontinuities and the potential for creating "perverse incentives" associated with such discontinuities.²⁷⁰

DRA's newly proposed alternatives significantly reduce the earnings potential at all levels of performance relative to the Proposed Decision and our final decision today. For example, under both of DRA's alternatives, the resulting earnings curve produces an earnings level of \$24 million (for all three utilities combined, over the three-year program cycle) if the MPS is reached, i.e., at 85% of goal achievement. At 100% of goal achievement, Alternative #1 produces combined earnings of \$92 million, and Alternative #2 produces combined earnings of \$242 million (over the three-year cycle). Hence, DRA's proposal is as much a recommendation to reduce the earnings potential under the entire earnings side of the mechanism as it is to address a discontinuity problem.

We affirm the adoption of a simple tiered earnings rate, as adopted in the Proposed Decision and recommended by all parties to this proceeding during workshops and in their pre- and post-workshop comments, including DRA. A wholesale change to a continuous curve of earnings rates at this juncture could introduce incentives and implementation consequences that have not been adequately explored in this proceeding, due to its untimely introduction. The combination of the more simplified tier structure proposed by all parties (including DRA) throughout the course of this proceeding, coupled with our

²⁷⁰ *Comments of the DRA on Proposed Interim Decision*, August 29, 2007, pp. 8-9 and Appendix B.

adopted approach to establishing the “trigger” for the MPS and second earnings tiers, reflects the goal to keep the mechanism relatively simple to understand and implement, and at the same time addresses the discontinuity concerns associated with that simple structure. As discussed in Section 4.1, we rejected the proposal put forth by some parties (including DRA) to trigger the MPS and eligibility for the second tier earnings rate based on an “all or nothing” reliance on specific numerical values. Instead, we adopt a hybrid approach that motivates superior performance while reducing unnecessary pressure points.

For these reasons, we do not modify the two-tier structure adopted in the Proposed Decision. During our review in 2011 of the incentive design we adopt today, Energy Division should evaluate the advantages and disadvantages of alternatives should our experience with a two-tiered structure reveal that discontinuity problems are not sufficiently mitigated by today’s decision, and can be more effectively mitigated in other ways.

We also concur with the proposed decision’s conclusion that the “debt equivalence” debate over what impact power purchase agreements might have on the utility’s capital cost structure and return on equity is more properly addressed in our cost of capital proceedings, and not in this rulemaking. It is therefore reasonable, in our view, to include both “with” and “without” debt equivalence scenarios in developing a range of values for the supply-side comparable earnings calculation. DRA objects to this approach, arguing that because energy efficiency would avoid any risks (if any) associated with power purchase agreements, debt equivalence should not be included in establishing the range of values for supply-side comparable earnings. As PG&E points out, this manner of thinking about debt equivalence in the context of today’s decision fails to recognize the question that is being asked by supply-side comparability.

To the extent that a utility has fewer actual power purchase agreements due to energy efficiency programs, no party refutes the fact that there will also be less impact (if any) on the utility's capital cost structure and return on equity due to debt equivalence. However, DRA is responding to the wrong question: The one being asked by supply-side comparability is what would be the impact on the return on equity and associated earnings (if any), if those power purchase agreements were not displaced by energy efficiency programs.²⁷¹

In addition, DRA asserts that the proposed decision "accelerates earnings returns" relative to the asset life underlying the utilities' cost of capital and relative to the 12-year economic life for energy efficiency used in the calculation of supply-side comparable earnings. Therefore, DRA argues that the supply-side comparable earnings calculations should be lowered to "reflect the time value of money."²⁷² DRA's presentation of this new argument and assertion of facts in its opening comments on the proposed decision is untimely. DRA had ample opportunity to present them in its Phase 1 testimony, so that they could be examined during evidentiary hearings. In particular, DRA's argument rests on the assertion that the cost of equity is dependent upon a 30 year asset life. The record provides no support (or even exploration) of this and other factual assertions underlying DRA's assertion of "accelerated earnings returns." What the record does show, however, is that the time value of money is explicitly accounted for in the utilities' comparable earnings calculations. For

²⁷¹ See *Comments of DRA on Proposed Decision*, August 29, 2007, p. 3, footnote 11; Exh. 46, p. 14; *DRA Opening Brief*, June 18, 2007, p. 30; *Reply Brief of PG&E*, June 27, 2007, pp. 40-41.

²⁷² *Comments of DRA on Proposed Decision*, August 29, 2007, pp. 3-4.

those calculations, all earnings paid out for the supply-side resources avoided by energy efficiency are discounted to “time zero.”²⁷³ In this context, it is difficult to reconcile DRA’s assertion of accelerated earnings return, since the recovery period for energy efficiency earnings extends beyond time zero.

Finally, CE Council argues that the omission of references to *Bluefield*²⁷⁴ (or other Supreme Court cases on utility rate of return) represents a “major oversight.”²⁷⁵ We disagree. The use of utility returns on supply-side investments as one consideration in establishing a shared-savings rate does not provide a basis to connect *Bluefield* and related cases with the risk/reward incentive mechanism for energy efficiency. Even if such a basis could be established, the Commission is not bound to the use of any single formula or combination of formulae in determining rates. As the Court stated in *Bluefield*, “What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts.”²⁷⁶ As discussed in this decision, we have considered several methods, relevant facts and presentations before ultimately reaching today’s determinations.

Findings of Fact

1. Ensuring sustained and successful commitment to energy efficiency is best accomplished by moving away from a cost-of-service compliance regulatory

²⁷³ See, for example, Exh. 34B.

²⁷⁴ *Bluefield Water Works and Improvement Co. v. West Virginia Public Service Commission*, 262 U.S. 679, 692 (1923).

²⁷⁵ *CE Council Comments on Proposed Interim Decision*, August 29, 2007, p.4.

²⁷⁶ *Bluefield*, at 692.

framework, to one that creates a “win-win” alignment of shareholder and ratepayer interests.

2. The Commission has determined in previous decisions, consistent with the recommendations of the Energy Action Plan, that shareholder incentives for energy efficiency should be pursued in conjunction with other procurement policies.

3. The purpose and scope of Phase 1 is to develop a shareholder risk/reward incentive mechanism for energy efficiency consistent with the Commission’s determinations in D.05-04-051 on the following threshold incentive design issues:

- a) Energy efficiency performance will be evaluated based on overall portfolio achievements, rather than on the performance of each individual program;
- b) The metric for establishing a dollar value for energy efficiency performance (“performance earnings basis” or “PEB”) will represent the net benefits to ratepayers from their investment in energy efficiency;
- c) Shareholder earnings will represent some percentage (“earnings rate” or “shared-savings rate”) of the net benefits achieved by the energy efficiency portfolio;
- d) Before any of these earnings accrue, the portfolio must achieve a minimum threshold of GWh, MW and MTherm savings tied to the achievement of the Commission’s savings goals for energy efficiency; and
- e) The level of this minimum threshold (“minimum performance standard” or “MPS”) is to be determined in Phase 1 of this proceeding.

4. The MPS approach proposed by DRA, NRDC and TURN sets up an all-or-nothing trigger for allowing any earnings that relies too heavily on specific numeric values.

5. Under the DRA/NRDC/TURN approach, missing just one of the MW, GWh or MTherm goals by a small amount could mean that utilities forfeit the potential for any earnings on the portfolio, even if that portfolio produces sizeable net benefits to ratepayers and achieves or surpasses the savings goals for one or more of the other savings metrics.

6. The possibility of missing the MPS by falling short on one metric by a small margin is likely to motivate utility administrators in ways that do not make sense from the standpoint of optimizing portfolio performance.

7. SCE's proposal to base the MPS on a simple average of achievements (relative to goals) could result in the utility becoming eligible for earnings even if it has unacceptably under-performed in achieving one or more of the individual savings goals.

8. The hybrid approach recommended by PG&E, SDG&E/SoCalGas and CE Council represents an option that both provides the utility with some flexibility in achieving the MPS (through averaging) and ensures that poor performance is not rewarded by establishing individual floors for each savings metric.

9. The alternatives that DRA introduces for the first time in its comments on the Proposed Decision to reduce discontinuity of a 2-tiered earnings tier structure would also significantly reduce the earnings potential at all levels of performance relative to the Proposed Decision and today's final decision.

10. A wholesale change to a "continuous curve" of earnings rates (from a 2-tiered rate), as DRA proposes, could introduce incentives and implementation consequences that have not been adequately explored in this proceeding, due to DRA's untimely introduction of its new proposal.

11. The combination of the more simplified tier structure proposed by all parties (including DRA) throughout the course of this proceeding, coupled with

our adopted approach to establishing the “trigger” for the MPS and second earnings tier serves to mitigate the discontinuity problem that DRA proposes to address with a much more complicated (and untested) incentive structure.

12. An MPS of 85% recognizes the challenges that utilities face in achieving the savings goals and, when coupled with individual floors of 80% for each savings metric, also gives appropriate weight to the individual goals themselves.

13. An MPS of 85% also recognizes that the utilities’ success in achieving 85% to 100% of the savings goals creates a substantial return on ratepayers’ investment, even after shareholder earnings are paid. That return will continue to increase if the utilities reach beyond the MPS to meet and surpass the 2006-2008 savings goals.

14. Because SoCalGas is subject to a single goal (for MTherm savings), it has less flexibility than the other utilities in meeting an average MPS of 85%. Establishing an MPS for SoCalGas at the level of the individual floors adopted for the other three utilities (i.e., at 80%) treats all utilities consistently with respect to a minimum threshold of performance.

15. Protecting ratepayers against the risk of portfolio losses (negative net benefits) is not a sufficient penalty mechanism in the context of the Commission’s resource planning and procurement objectives, which focus on both achieving specific savings goals for energy efficiency and doing so cost-effectively.

16. In the context of those objectives, it is reasonable to combine a portfolio cost-effectiveness guarantee with per-unit penalty provisions that start when the utilities miss savings goals at a level of performance below the MPS.

17. Taking this approach is also consistent with the Commission’s introduction of per unit penalty provisions in other areas of resource

procurement, such as the procurement of renewable resources to meet the requirements of the Renewable Portfolio Standard. It also ensures that each end of the deadband, where penalties and rewards are triggered, is structured to reflect the dual objectives of cost-effectiveness and achieving verified MW, GWh and MTherm savings levels.

18. A penalty trigger of 65% of the savings goals strikes the appropriate balance between imposing financial penalties when savings performance is substandard and recognizing that there are significant net benefits created by the portfolio even when performance falls below that trigger.

19. The utilities have a reasonable opportunity to manage the risk of potential penalties under the penalty provisions adopted herein, given the unprecedented level of resources made available to them, the flexibility to use their authorized funding to “dig deeper” to achieve more savings even if the ratio of costs to savings increases in the process, their access to over ten years of completed EM&V studies and their ability to manage risks through portfolio diversification.

20. The calculation of either positive or negative net benefits produced by the energy efficiency portfolio should be based on the adopted PEB formula.

21. PG&E’s proposal for calculating negative net benefits under the cost-effectiveness guarantee is inconsistent with the definition of PEB adopted by the Commission in D.05-04-051.

22. PG&E’s proposal also produces a lower rate at which penalties would accrue compared to the PEB metric adopted for positive net benefits.

23. As a starting point, the per unit Tier 2 penalty rates that NRDC proposes will serve to balance overall risks with the reward side of the adopted incentive mechanism. However, the Tier 2 kWh penalty rate is still significantly lower

than the 5¢/kWh penalty imposed on utilities if they miss their Renewable Portfolio Standard requirement.

24. It is not reasonable to impose lower per unit kWh penalties for poor performance in energy efficiency relative to renewables, particularly since energy efficiency is “first in the loading order” under California’s resource procurement priorities.

25. NRDC’s Tier 2 kWh penalty rates should be increased from 4 cents to 5 cents per kWh, and the other per unit penalty rates adjusted upwards to reflect a comparable increase. This level of per unit penalties in conjunction with the cost-effectiveness guarantee and the “reward” side of the mechanism produce a reasonable balance of potential earnings and penalties on either side of the deadband.

26. All parties have been afforded the opportunity to develop proposals for a fair balancing of risk/rewards under the incentive mechanism in this phase of the proceeding. The utilities’ showings on this issue argue that the levels proposed by TURN, DRA and NRDC were arbitrary, not well reasoned, and failed to adequately balance the risks and rewards under the incentive mechanism. Instead of presenting alternative levels for Commission consideration or recommending that the basis for per-unit penalty rates be subject to evidentiary hearing, the utilities chose to argue for the categorical rejection of per-unit penalty provisions by the Commission. It is now self-serving for the utilities to argue that we cannot adopt anything other than the per-unit penalty levels that these parties proposed.

27. The risk/reward mechanism’s financial penalties are intended to compensate ratepayers for their reduced benefits or increased costs on a pre-tax basis as a result of the utilities’ substandard performance.

28. Making the per unit and cost-effectiveness guarantee penalties additive, as NRDC and DRA recommend, results in penalties that would pay ratepayers back more than their full investment in energy efficiency.

29. Presenting parties' proposals for shared-savings rates as a ratio of earnings to portfolio costs fails to recognize that the sharing rate and associated earnings are not tied to those costs, but rather to the much larger dollar value of avoided supply-side costs. Comparing those dollar earnings instead to the net benefits created by the energy efficiency portfolio is consistent with the yardstick established in D.03-10-057.

30. Under any of the parties' proposals for earnings levels in this proceeding, achievement of the 2006-2008 savings goals is expected to produce an extraordinary monetary return to ratepayers – on the order of a 107% to 132% return on their investment. This level of achievement is also expected to create an unprecedented level of net resource benefits to all Californians – on the order of \$2.7 billion.

31. Utility investors are attracted by opportunities to earn returns, and absent energy efficiency incentives, utilities only earn on supply-side investments. Recognition of this fundamental disincentive to energy efficiency has been expressed in prior Commission energy efficiency decisions, the federal Energy Policy Act of 1992, California's 2003 Energy Action Plan, the National Action Plan for Energy Efficiency and in the Commission's 2006 Procurement Incentive Framework decision, D.06-02-063.

32. No party to this proceeding presented convincing evidence to dispute that this fundamental disincentive exists in today's regulatory environment, now that investor-owned utilities have been returned to the role of managing both supply-and demand-side resource procurement on behalf of their ratepayers.

33. Funding of energy efficiency through a non-bypassable charge on distribution rates does not change the fact that California investor-owned utilities face a risk of bypass today, that expenditures on cost-effective energy efficiency results in initial rate increases, and that higher rates increase the risk of bypass.

34. No party to this proceeding presented convincing evidence to overturn the finding made by this Commission in 1993 concerning the short-term rate impacts associated with energy efficiency, which also serve to bias utilities towards supply-side options.

35. The purpose of a comparable earnings analysis is to provide a numerical benchmark for addressing these biases that favor supply-side resources, and not to prove or disprove the tautology of zero foregone shareholder earnings posed by DRA and TURN in this proceeding.

36. A comparable earnings benchmark recognizes that utilities as decision makers make day-to-day decisions on how to direct their resources and personnel that regulators cannot directly control or mandate.

37. Without an energy efficiency incentive, given the focus of investors and utility management on increasing shareholder value, utilities will on balance be more inclined to devote scarce resources to procurements on which they will earn a return, and not on meeting or exceeding the Commission's energy efficiency goals, or maximizing ratepayer net benefits in the process.

38. Knowing how much investors would have earned on supply-side procurements, if not for energy efficiency, is useful information: It helps the Commission to consider, among other factors, what level of earnings potential will be sufficient to overcome the biases in favor of supply-side resource procurement and achieve the policy objectives for energy efficiency.

39. The Commission has previously rejected recommendations to establish the earnings potential under a shared-savings incentive mechanism by relying on historical evidence of utility management interest, by reducing earnings to reflect claims of utility bias *towards* energy efficiency (relative to supply-side resources), or by reducing earnings to a minimal management fee.

40. As recognized in D.94-10-059, comparisons of the risk/reward profile for demand-side and supply-side resources are difficult to make, given the differing performance, earnings and investment characteristics of these resources. In addition to who funds the initial investment, there are multiple dimensions to the relative risk between supply- and demand-side resources (and that are changing over time), including (1) how shareholder earnings vary with project performance and (2) who bears the risk of non-cost effective investments.

41. The argument that supply-side comparable earnings are not relevant because ratepayers (not shareholders) put up the initial capital for energy efficiency ignores these multiple dimensions to risk. This same argument was rejected by the Commission in the proceedings leading up to D.94-10-059 as a rationale for either discontinuing shareholder incentives altogether or for reducing the earnings potential to minimal levels.

42. Ratepayers “invest” in both supply-side and energy efficiency resources, irrespective of who puts up the initial capital. The only difference is that for steel-in-the-ground investments (generation, transmission, distribution), ratepayers have to pay not only the cost of the facilities, but also the financing costs (debt service and return-on-equity and associated taxes) to compensate those that put up the initial capital.

43. In contrast, since energy efficiency expenditures are expensed and reflected in rates immediately, energy efficiency saves ratepayers substantial

financing costs. Those cost savings are magnified by the fact that a dollar of energy efficiency can displace far more than a dollar of supply-side investment to meet the same GWh, MW and MTherm energy needs.

44. The critical question in establishing the earnings potential under a shared-savings incentive mechanism is not “who puts up the capital” for energy efficiency, but rather, “how can we ensure that the potential return on ratepayers’ investment in energy efficiency is actually realized.”

45. Decoupling addresses a financial “lost revenues” penalty for pursuing energy efficiency – it does not make energy efficiency the preferred resource from a shareholder, investment community or utility management perspective.

46. Decoupling was in place in California and several other states prior to electric industry restructuring, and then resurrected in 2001 in California during the electric crisis.

47. The Commission’s reinstatement of a decoupling mechanism in 2001 is not a reason to ignore earlier Commission findings on the existence of significant disincentives to energy efficiency or policy determinations since the energy crisis to address those disincentives.

48. TURN’s and DRA’s conclusion that changes in the way energy efficiency programs are funded since the mid-1990s have removed a critical disincentive to energy efficiency is not logical or supported by the record. Ensuring that customers leaving the utility system cannot avoid paying their fair share of energy efficiency funding does not change the fact that expenditures on cost-effective energy efficiency can increase the risk of bypass (e.g., through community choice aggregation) by initially increasing rates.

49. No party has refuted the finding the Commission made in 1993 that, “[e]ven though energy efficiency may have a higher ratepayer and societal value,

other options (e.g., inter-utility power purchases) may have a higher private value to utilities because they generally do not initially increase rates.”

50. Two recent national studies (the July 2006 National Action Plan for Energy Efficiency and the US DOE March 2007 Report to the United States Congress) corroborate that fundamental disincentives to utility pursuit of energy efficiency persist today.

51. DRA’s justification for a 3% sharing rate based on the management fees earned by mutual fund portfolio managers suffers from two major shortcomings. First, DRA provides no references or evidence to support its assertion that mutual fund manager fees range from \$0.75 to \$4.50 per \$100 dollars. Second, DRA makes an “apples-to-oranges” comparison by comparing its proposed sharing rate (% of net benefits) to a fee calculation based on total portfolio value.

52. Comparing the earnings rate under a risk/reward incentive mechanism with fees earned by mutual fund managers fails to acknowledge that mutual fund managers would probably demand considerably more than the single-digit fees DRA calculates if they (1) earned only in proportion to portfolio gains, as measured over a multi-year period, and (2) were also required to pay penalties for missing targets and for losses on their clients’ investment.

53. DRA’s claim that a 3% shared-savings rate is sufficient to motivate utility behavior is premised on a Management Bonus Model that calculates a very high employee bonus “equivalent” associated with \$81 million in earnings over three years. This calculation substantially overstates the level of equivalent bonus by basing the calculation on a limited subset of utility employees and on “base” salary that does not include other salary and non-salary benefits.

54. DRA’s Management Bonus Model is premised on the assumption that the utilities’ short-term bonus compensation plans are sufficient to motivate

California investor-owned utilities to aggressively pursue energy efficiency. This premise is unsupported in theory and unproven in practice.

55. When corrected for the limited scope of employees considered in the Management Bonus Model, DRA's proposed 3% shared-savings rate (\$81 million at 100% of savings goals) would result in an organization-wide employee "bonus" that would be virtually imperceptible.

56. DRA and CE Council's comparisons to energy efficiency incentive levels offered in other states fail to address the characteristics of individual states that may make them have greater or lesser relevance for California policy makers.

57. In assessing the nine other states' energy efficiency incentives presented in its testimony, DRA does not evaluate numerous important factors that are essential to a valid comparison to California. These factors include: (1) the level of savings goals (if any) established for the utilities in other states and what entities established them, (2) differences in retail sales, energy efficiency budgets and expenditure levels, or whether the investor-owned utilities in the other states had the option of investing in supply-side resources rather than energy efficiency programs, (3) whether verification efforts, if they were in place, were conducted *ex post* (post installation) and independently of the utility in question, or (4) whether other states' incentive mechanisms included financial penalties, as did all the proposals in this proceeding.

58. The nine states listed in DRA's testimony represent vastly different utilities, in different service areas, with different economic determinants of the power marketplace and the energy efficiency market there, as well as critical institutional differences.

59. DRA's analysis of other states' incentive rates ignores the relevance of electric industry restructuring on the ACEEE survey results. It reflects where

most of those states have ended up after the decline in energy efficiency and associated incentives that accompanied restructuring in the mid-1990s.

60. A survey of other state's energy efficiency incentive rates would have looked much different if DRA had considered the incentive rates in place prior to electric restructuring, when investor-owned utilities across the country managed resource portfolios as the California investor-owned utilities do again today.

61. DRA's analysis also ignores the higher end of the range of incentive levels that can be observed from the ACEEE survey for Nevada and Arizona – even though several key variables (e.g., expected rate of population growth) make Nevada and Arizona potentially the most comparable to California.

62. DRA's assertion that less financial incentive is needed to improve performance in California relative to other states because California's programs are more mature than in those states is not founded in basic economic theory or logic.

63. TURN's proposal to benchmark the earnings potential under a shared-savings energy efficiency incentive mechanism to the dollar incentive rewards received by utilities under various non-DSM PBR mechanisms suffers from the following flaws:

- a) TURN's analysis is restricted to the absolute dollar amount earned under non-DSM mechanisms, and does not discuss what each mechanism is designed to achieve or the value of success to ratepayers.
- b) TURN's comparison looks at the achieved results under the various non-DSM PBR mechanisms, whereas it is the potential results for energy efficiency that is established by the shared-savings rates and reflected in parties' proposals.
- c) TURN's analysis does not discuss the maximum penalty provisions under those mechanisms, or the thresholds of

performance established before either penalties or rewards can be earned.

- d) TURN's analysis lacks reasonable criteria for deciding what PBR mechanisms to include in the benchmark and appears to exclude some that could be relevant.

64. A statistical analysis to correlate historical energy efficiency incentive levels with performance would be extremely difficult (if not impossible) to perform due to the numerous variables that have affected portfolio performance as well as differences in how energy efficiency performance has been defined-since the early 1990s.

65. TURN presents figures in its opening brief to support its argument that utility spending and utility savings do not correlate to the higher incentive levels provided by D.94-10-059. TURN's figures are problematic in many ways, including their failure to reflect many other variables that affect performance.

66. As discussed in this decision and D.03-10-057, the Commission has established funding levels for energy efficiency over the years taking a variety of factors into consideration. Therefore, it is not reasonable to conclude that because budgets and spending levels do not appear to be correlated with incentive levels, higher incentive levels are no more effective than lower incentive levels.

67. As the Commission noted in D.03-10-057, the lack of correlation between incentives and spending levels, for whatever reason, does not mean that the incentive mechanism has not produced sizable net benefits to ratepayers.

68. SDG&E presented a figure on the record that suggests a positive correlation between incentive levels and the production of savings at the highest efficiencies (or lowest total costs). Unlike the figures that appear in TURN's

brief, this figure was produced in sworn testimony (by SDG&E) and subject to cross-examination.

69. Due to the fundamental differences in reporting and measurement practices, as well as very different purposes and incentive structures over the last 15 years, it would be difficult to draw definitive conclusions from graphing historical data on incentives and savings or net benefits, even if a more comprehensive graphing of data was available.

70. These differences include the fact that “commitments” were counted in reporting savings achievements during some of the last 15 years, while in others they were not. In addition, in most of the years between 1990 and 2005 savings were not subject to *ex post* verification. Because of these and other differences, the MWh achievements (and other metrics based on those achievements) depicted in TURN’s graphs are not directly comparable.

71. The inferences made by DRA and TURN from historical data when incentive levels were capped at 7% of efficiency program budgets ignore the fundamental differences in the role of utilities in energy efficiency and resource procurement, as well as the changes in Commission policy on energy efficiency over the last 15 years.

72. Given the history of energy efficiency described in this and prior Commission decisions, it is unreasonable to infer that the incentive levels adopted during restructuring or during the peak of the energy crisis in 2001 are appropriate for the risk/reward incentive mechanism adopted today.

73. No party presented alternate base case assumptions for the average energy efficiency measure lives and the split between “utility build-utility buy” scenarios used by the utilities in this proceeding. Based on the record and

review of utility procurement plans, these assumptions are reasonable for the purpose today of estimating a comparable supply-side earnings benchmark.

74. DRA's proposal to update specific base case assumptions for supply-side comparability calculations at each earnings claim is based on an incorrect premise that these calculations serve as a "model" that directly produces earnings rates. Moreover, under this approach the applicable earnings rates could change at each earnings claim, introducing an unreasonable amount of uncertainty over the design parameters of the mechanism, litigation and associated delays in the earnings recovery process.

75. TURN's alternative-use-of-funds analysis assumes that the utility would make it a practice to raise money in the capital markets to cover supply-side investments that it does not need to make, in order retain those funds so that they could be used for alternative investments.

76. This assumption is not supported by either common sense or by the factual record in this proceeding: Utilities do not plan to have more cash than is needed for the plant and equipment that they will be building (or for working cash requirements), and carefully manage their cash reserves accordingly. They also do not sell shares or issue debt to raise cash for a capital investment they do not need to make, such as the supply-side resources that energy efficiency is planned to defer or displace. Therefore, it does not follow that the utility has "alternate uses" for equity on a dollar-for-dollar basis that was not needed for supply-side resources due to energy efficiency, as TURN's analysis assumes.

77. Utilities use profits from the capital investments and utility operations that they do undertake for a variety of purposes, including the pay-out of dividends to investors or stock repurchases via their holding companies. It does not follow

that these profits and uses originate from cash available to the utility because energy efficiency has displaced the need to make supply-side investments.

78. TURN's assertion that a utility's net income will increase as a result of lower capital expenditures defies a basic tenet of cost of service ratemaking: When capital expenditures are lower, by definition rate base is lower and so too is net income, all else remaining equal.

79. TURN's alternative-use-of-funds analysis presents a fundamental contradiction to another position TURN advocates in this proceeding, namely, that the "right" answer to a calculation of foregone shareholder earnings is likely to be zero. If shareholders are no worse off when energy efficiency displaces supply-side resources because they take their investment funds elsewhere to earn a comparable return, it does not follow that the utility can use those funds for the alternative investments that TURN describes in its testimony.

80. TURN's assertion made in comments on the Proposed Decision that the alternative-use-of-funds analysis somehow changes when one looks at overall cash management techniques is not supported by the record.

81. The theory of utility behavior that TURN proposes in this proceeding lacks the support of a factual record and a persuasive conceptual rationale, as did TURN's predecessor economic and financial theories on the same issues in prior energy efficiency proceedings.

82. Calculating comparable supply-side earnings based on "comparable performance", as the utilities propose, is consistent with the purpose and prior application of this benchmark in California. In contrast, NRDC's proposal to base these calculations on "comparable costs" lacks both precedent and a persuasive conceptual rationale.

83. There are persuasive arguments on both sides of two methodological disputes concerning the calculation of supply-side comparable earnings. These are: (1) whether debt equivalence should be imputed for power purchases in the utilities' comparable earnings calculations, and (2) whether some portion of avoided CCGT capacity should be displaced with lower-cost CTs.

84. These disputed issues are more appropriately addressed in cost-of-capital proceedings (for debt equivalence policies and calculations) or resource planning/avoided cost proceedings (for the CCGT versus CT avoided cost question). Rather than attempt to resolve these issues in today's decision, it is reasonable to acknowledge that they create a range of possible outcomes around the base case assumptions for the purpose of calculating comparable earnings.

85. Imputing debt equivalence to power purchases and assuming avoided generation capacity based exclusively on CCGT costs produces the upper range of supply-side comparable earnings estimates, which is approximately \$700 million for all utilities combined over the 2006-2008 program cycle.

86. Removing debt equivalence and substituting 24% of avoided CCGT costs with CT capacity costs as TURN recommends produces the lower range of the calculations, which is approximately \$450 million for all four utilities combined over the 2006-2008 program cycle.

87. DRA's objection to including debt equivalence in establishing the upper range of values for supply-side comparable earnings fails to recognize the question that is being asked by supply-side comparability: What would be the impact on the return on equity and associated earnings (if any) if those power purchase agreements were not displaced by energy efficiency programs.

88. DRA's comments on the Proposed Decision concerning how the time value of money should be reflected in considering supply-side comparability are

untimely. The argument that supply-side earnings should be lowered to reflect “accelerated earnings returns” afforded to energy efficiency rests on factual assertions that are unexamined (and therefore unsupported) by the record, including the assertion that the cost of equity is dependent upon a 30 year asset life.

89. The record shows that the time value of money is explicitly accounted for in the utilities’ comparable earnings calculations. For those calculations, all earnings paid out for the supply-side resources avoided by energy efficiency are discounted to “time zero.” In this context, it is difficult to reconcile DRA’s assertion of accelerated return, since the recovery period for energy efficiency earnings extends beyond time zero.

90. The supply-side comparability benchmark should not be separated by fuel or type of program activity, but rather should serve as a general numerical guide for setting the appropriate share of the combined net benefits from electric and natural gas efficiency programs.

91. Including only the earnings from the electric supply-side resources foregone, and none from any gas supply-side resources foregone, avoids the need to debate the size of gas supply-side resource investments, about which there is no record.

92. Establishing the level of earnings for a shareholder risk/reward incentive mechanism is ultimately a judgment call that the Commission must make, and not a precise science. In making this judgment, consideration should be given to the following:

- (a) What level of earnings will balance the level of potential penalties under the mechanism and offset existing financial and regulatory biases in favor of supply-side procurement.

- (b) What level of earnings potential will provide a clear signal to utility investors and shareholders that achieving and exceeding the Commission's savings goals (and maximizing ratepayer net benefits in the process) will create meaningful and sustainable shareholder value.
- (c) Differences in the risk/reward profiles of utility resource choices in applying the comparable earnings benchmark to the incentive mechanism.
- (d) The level of performance expected in return for higher and higher earnings potential.
- (e) What is "fair" to ratepayers in terms of the return on their investment in energy efficiency.

93. Although it is challenging to compare the different (and changing) risk/reward profiles among utility resource choices, we can observe the following:

- (a) Since the energy crisis, utilities must now manage supply-side resources to meet resource adequacy requirements subject to the risk of significant financial penalties. With the passage of Senate Bill 1368, utilities also now face the risk of non-compliance for any long-term supply-side procurement that does not meet the GHG performance standard required by that statute.
- (b) Although its implementation is several years out into the future, the statewide GHG emissions cap pursuant to Assembly Bill 32 will further increase the financial risks associated with any supply-side resource procurement that increases GHG emissions.
- (c) These developments serve to increase the risks associated with procuring at least certain types of supply-side resources and, in turn, reduce the relative risks of energy efficiency in the context of utility resource portfolio management, even if the impact of these changes cannot be quantified.
- (d) Working in the other direction is the fundamental disincentive to energy efficiency relative to "steel-in-the-

ground” supply-side investments of any type (renewables or non-renewable generation, transmission and distribution) due to the fact that utilities only earn on supply-side investments under current regulatory practices.

- (e) In addition, unlike supply-side procurements (including purchased power) cost-effective energy efficiency investments will increase rates in the short-term, even though it will minimize revenue requirements and customer bills overtime. This is because energy efficiency, by definition, reduces the sales volume over which fixed costs can be recovered.
- (f) Energy efficiency is also not as readily “deployed” as supply-side resources, since it involves customer-side appliance changes, arrangements with manufacturers and distributors, etc. Hence, even when the portfolio funding is authorized, there is more uncertainty as to the actual deployment results of energy efficiency than for supply-side resources. In addition, energy efficiency requires independent verification of load impacts that extends beyond program implementation. These attributes introduce uncertainty and performance risks to shareholders that are not shared by supply-side choices.
- (g) Although ratepayers put up 100% of the investment capital for energy efficiency programs, shareholders are at risk under the adopted incentive mechanism for losses to that capital and face sizable per-unit penalties for substandard performance of the portfolio. Unlike a rate-based plant, shareholder earnings will vary in direct proportion to performance (i.e., realized net benefits), even when factors entirely beyond the utility’s management control affect that performance.
- (h) At the same time, the utilities now have over 15 years of experience in implementing energy efficiency and over 10 years of EM&V study results available to them. They also have the authorization and funding to conduct meaningful process and market penetration studies to assist them in managing these uncertainties during the program cycle. In

addition, applying the risk/return incentive mechanism to the entire portfolio of programs, rather than on a program-specific approach, will serve to decrease the absolute level of potential penalties as well as the probability of falling into the penalty range.

94. Using supply-side comparable earnings as a benchmark creates the sustainable “clear signal” we are looking for on the earnings side of the incentive mechanism. However, based on observations of the relative risk/reward profiles that energy efficiency earnings and other considerations, it is reasonable to apply the supply-side earnings comparability calculations very conservatively to the adopted incentive mechanism, i.e., by establishing the lower end of the range of values as an upper bound for energy efficiency earnings potential.

95. Establishing supply-side comparable earnings as an upper bound means that earnings on energy efficiency will approach supply-side earnings at a level of superior performance, that is, performance that is significantly greater than the forecasted level of savings or net benefits expected from the authorized energy efficiency portfolio. Using the supply-side comparability benchmark in conjunction with achievement of superior performance is consistent with the Commission’s discussion of the role of financial incentives in D.06-02-032.

96. The tiered earnings rates adopted in today’s decision strikes a reasonable balance among the following considerations: (1) Creating meaningful and sustainable shareholder value for superior achievement in achieving cost-effectiveness and verified GWh, MW and MTherm savings levels, (2) recognizing that the Commission-adopted savings goals are aggressive (yet achievable), (3) recognizing the different risk/reward profiles of energy efficiency and supply-side resource options, (4) adopting a percentage of sharing that is fair to

ratepayers and (5) reasonably balancing the penalty side of the risk/reward incentive curve.

97. Today's adopted shared-savings mechanism is consistent with Section 111(a)(8) of the federal Energy Policy Act of 1992, but based on a broader set of factors than the profitability guideline articulated in that section.

98. It is appropriate to consider a broader set of factors in establishing the earnings potential for a shared-savings incentive mechanism, given (1) the complexity and diversity in our ratemaking treatment of both supply-side and demand-side resources and (2) the context for energy efficiency today under the Commission's procurement incentive framework and related climate change policies.

99. TURN's proposal for a higher kW incentive rate is premised on the assumption that kW savings are not properly valued in avoided cost calculations, a premise that is not reasonable based on the avoided costs adopted after careful deliberations in R.04-04-025.

100. The approach adopted today for the recovery of earnings should send a message to the utility to continue to pursue cost-effective energy savings as quickly and aggressively as possible throughout the program cycle. It should also provide the utility with an opportunity to learn from market and EM&V feedback so that it can make up during the program cycle for lower accomplishments in a single program year.

101. The Single-Year approach to evaluating interim earnings claims does not accomplish either of these objectives and, in fact, could encourage a utility to slow down or shut down programs because either the annual goals have been met before the end of the calendar or there is no possibility to achieve the annual goals.

102. The Cumulative-Program-Cycle approach introduces significant forecasting error into calculations of savings achievements and PEB because those calculations include forecasts of future program participation that were made at the start of the program cycle.

103. By considering the achievements of the previous year as well as the current year, the Cumulative-To-Date approach will encourage continuous effort and improvements in response to feedback throughout the program cycle. Moreover, this approach does not introduce the forecasting error associated with the Cumulative-Program-Cycle method.

104. The Cumulative-to-Date basis is the most reasonable approach for evaluating interim earnings claims and should be adopted.

105. Unlike the shared-saving mechanisms adopted prior to the energy crisis, today's adopted mechanism defines successful performance in terms of dual objectives: The achievement of a specific levels of GWh, MW or MTherm savings while maximizing ratepayer net benefits in the process.

106. Key design parameters, such as the MPS and deadband range, reflect the need for energy efficiency to produce more than positive net benefits. Energy efficiency also needs to produce sizable GWh, MW and MTherm savings that resource planners can depend upon now and in the future.

107. If the true-up adjustment in the final claim does not fully reflect the final EM&V results, then these key design parameters lose their meaning. Under the true-up approach proposed by the utilities the MPS or deadband range could end up being anywhere. This is because utilities could end up keeping the earnings they received in the interim claims even if they only actually achieved energy savings within the deadband or in the penalty range, based on the final EM&V results.

108. The true-up approach proposed by SCE and SDG&E/SoCalGas would result in a skewed treatment of load impact forecasting errors: If those errors work to the benefit of shareholders, the earnings are adjusted so that the actual earnings rate is never lower than the adopted rate. However, if forecasting errors work to the detriment of shareholders, they would be ignored, and shareholders would actually earn at a shared-savings rate that is higher than the one adopted.

109. An approach that fails to true-up savings and net benefit accomplishments based on the results of final load impact studies creates a perverse incentive for utility managers to promote exaggerated savings assumptions during the planning process.

110. The possibility of refunding earnings already claimed may present certain problems for the utilities with respect to financial reporting. However, these problems are effectively addressed in today's decision by 1) limiting payout of initial claim(s) and 2) deducting any over-collections from future earnings claims, as suggested by PG&E and others in this proceeding.

111. An unrestricted true-up process provides the proper incentive for utility managers and staff to support the most accurate estimates of energy savings as possible and serves to ensure that ratepayers share the net benefits from their investment with shareholders only when the MPS is actually achieved and at precisely the adopted shared-savings rates – no more, no less.

112. To reduce the effect of load-impact forecasting errors on the final true-up claim, it is reasonable to hold back 30% of the earnings progress payments calculated in each interim claim.

113. The adopted schedule for earnings recovery paces the earnings claims so that there is only one claim per calendar year, and ties the claims to only those reports that were intended to be a basis for incentive payments.

114. Moving the first interim claim to the second year of the program cycle makes moot any need for the lower first-year MPS or threshold savings requirement proposed by PG&E and SCE.

115. PG&E's proposal to base the MPS for the interim claims on its ramp-up compliance filing targets, rather than Commission-adopted annual savings goals, could introduce significant gaming of ramp-up targets in future compliance filings.

116. PG&E's concerns that it will forego earnings because of a "slower start" at the beginning of a program cycle only occurs under the single-year basis approach that PG&E has proposed in this proceeding. Under the Cumulative-to-Date approach adopted in this decision, those efforts will be fully reflected over the program cycle in subsequent claims.

117. The MPS should not change from one interim claim to another and should be based on the Commission-adopted annual and cumulative savings goals.

118. There is no guarantee that Energy Division's schedule for completing EM&V reports will never be delayed, based on unforeseen circumstances. However, ratepayer interests are best served if the payout of earnings (or imposition of penalties) occurs only after the installations, program costs and (for the final claim) load impacts have been verified by Commission staff and its contractors.

119. Under the earnings recovery schedule adopted for the pre-1998 shared-savings mechanism, earnings recovery was extended to up to 10 years

after program implementation, pending completion of persistence and retention studies. In addition, the EM&V reports managed by the utilities at that time, and resulting earnings claims, were subject to litigation that could cause substantial delays in earnings recovery. In that context, the Commission allowed for the calculation of interest (using the 90-day commercial paper rate) on delayed earnings recovery. EM&V responsibilities for post-2005 programs and the claim review and approval process adopted today do not share these characteristics.

120. The procedures for the review and approval of interim and final earnings claims, set forth in the April 4, 2007 ACR, have had the benefit of stakeholder input.

121. With the clarification adopted in this decision and reflected in Attachment 7, the procedures set forth in the ACR address parties' concerns while achieving both efficiency and accuracy.

122. The steps outlined in the ACR and set forth in Attachment 7 provide parties the ability to participate in the review of evaluation studies, both procedurally and substantively, by setting forth a specific and adequate process by which parties can submit questions, concerns and comments to both Energy Division and evaluation contractors.

123. The multi-party give and take available under the procedures established by the ACR and set forth in Attachment 7 is better suited than cross-examination for the kinds of disputes likely to arise with regard to evaluation study results.

124. The procedures set forth in Attachment 7 provide for a neutral and unbiased party (Energy Division) to facilitate parties' participation. They allow for broad public participation through various conferences. The requirement that all written comments to the various reports be addressed in the final versions of each report also provides for a transparent process.

125. The procedures set forth in the ACR will be equally accurate and more efficient than any of the more formal processes suggested by the parties.

126. Once Energy Division has issued a Final Verification Report or the Final Performance Basis Report, determining the level of earnings or penalties is strictly a matter of applying the formulas in this decision to the results outlined in those final reports. Accordingly, it will be a ministerial task for Energy Division to determine whether the utilities' advice letters filed in response to these reports contain the correct calculation of earnings or penalties.

127. The advice letter procedures under General Order 96-B allow for Commission resolution under appropriate circumstances where Energy Division disposition would require more than ministerial action.

128. Establishing where performance falls along the adopted penalty/earnings curve involves estimating load impacts, load shapes and (for calculating PEB) measure and program costs for an extensive number of programs and measures.

129. The adopted EM&V protocols provide staff the flexibility to establish priorities for the EM&V efforts throughout the program cycle, in recognition that the Commission may not have the resources to verify each parameter on an *ex post* basis for every program.

130. Excluding all non-resource program costs from the PEB, as some parties recommend, would be inconsistent with the manner in which we evaluate portfolio performance for the purpose of committing ratepayer dollars.

131. This approach would also create a perverse incentive for the utility to game the classification of programs or the allocation of costs across programs in order to maximize the net benefits of those programs subject to the incentive mechanism (resource programs) relative to those that are not (non-resource

programs). Moreover, utility program administrators would be less motivated to make the non-resource programs as cost-efficient as possible if costs were excluded from the PEB, since those improvements would not impact the calculations of shareholder earnings.

132. Since the impacts of statewide marketing and outreach programs, upstream market transformation programs, information and education programs and other non-resource program activities will promote the achievement of program savings over the near- and long-term, and their impacts will be reflected in the success of the resource programs, their costs should be included in the PEB as well.

133. Including non-resource program costs in the PEB should not result in the short-changing of these programs by utility program managers, as some parties suggest, for the following reasons:

- a) Since energy efficiency funding is now authorized over 3-year program cycles and subject to a 10-year trajectory of increasingly aggressive savings goals, it is not in the interest of the utility to shortchange non-resource programs that can enhance portfolio savings performance over both the short- and long-term.
- b) The ability of utility program managers to unilaterally implement shifts in portfolio funding away from non-resource programs is restricted under the Commission's adopted fund-shifting rules.

134. EM&V is an integral cost of delivering reliable and verifiable energy efficiency savings, irrespective of who manages those efforts. Although the utilities may not manage most of those funds, it does not follow that shareholders should be paid a larger share of portfolio net benefits by excluding EM&V costs.

135. Including in the calculation of PEB all resource and non-resource program costs and all associated EM&V, with the exception of the Emerging Technologies Program is fully consistent with the Commission's energy efficiency policy rules on how to evaluate portfolio cost-effectiveness on a prospective basis.

136. Counting 50% of the savings attributed to pre-2006 C&S advocacy work towards establishing whether the MPS has been met for the 2006-2008 cycle, and excluding those savings from the PEB, is fully consistent with the Commission's determinations in D.05-09-043.

137. Although there may be a significant lag between when the costs for C&S advocacy programs are incurred and when the savings are actually realized, over time these streams of costs and benefits should tend to even out as they do for commitments to long-lead time projects such as new construction.

138. SDG&E and SoCalGas propose to exclude C&S costs from PEB at the time they occur, but do not indicate when those costs will ever be counted. Moreover, they do not provide a compelling reason to depart from the adopted practice of including program costs and savings on an actual basis in determining portfolio performance for post-2005 energy efficiency.

139. The baseline issues that may affect whether C&S advocacy work will count towards savings goals for the 2009-2011 cycle (and beyond) cannot be addressed until after the Commission has had an opportunity to consider comments in response to the Assigned Commissioner's June 1, 2007 ruling.

140. The potential studies underlying the Commission's savings goals did not distinguish between measures installed under low-income energy efficiency (LIEE) versus non-LIEE programs.

141. Consistent with the Commission direction in D.04-09-060, verified savings from LIEE programs should count towards the MPS under the risk/reward incentive mechanism, but not towards the PEB.

142. The Commission establishes funding levels for each three-year program cycle after an extensive program planning and compliance process, in which portfolio cost-effectiveness and the ability to achieve the three-year savings goals with the funds authorized are evaluated on a prospective basis with the input of all interested stakeholders and program advisory group members, including Commission staff.

143. Utility requests for funding augmentation once the Commission has approved funding levels and the utility program portfolios for a particular program cycle should be limited to extraordinary circumstances.

144. Specific proposals for the treatment of savings and costs associated with mid-cycle funding augmentations are being addressed in the 2009-2011 Portfolio Planning Phase of this proceeding .

145. There are implications associated with classifying a program as LIEE and augmenting its funding that carry over to the risk/reward incentive mechanism adopted today. If programs are misclassified as LIEE, the utilities could end up earning more than their authorized share of net benefits.

146. Shareholder incentives represent a true economic cost in the production of utility programs.

147. The costs of shareholder incentives should be included in calculations when evaluating the cost-effectiveness of program plans submitted during the program planning cycle, or when conducting a cost-effectiveness review of portfolio performance in hindsight.

148. TURN's proposal to subtract forecasted incentives out *before* applying the sharing rate is a circular proposition. It is akin to saying that we will share a quarter of a pie with you, but before we slice it into 4 pieces, we will first remove a quarter.

149. Because the simplified numerical examples presented in D.06-06-063 involved only one participant, the issue of how to fold in free rider considerations on the cost side of the TRC equation was never explicitly addressed.

150. The 1988 SPM Correction Memo formulation prohibits applying the NTG ratio to the administrative cost component of TRC costs, since these are costs unrelated to participant expenditures.

151. Parties to this proceeding disagree on whether the "rebate" incentives term ("INC") paid to free rider program participants should be adjusted by the NTG ratio.

152. As currently formulated in the 1988 SPM Correction Memo, the cost equation would remove from TRC costs all revenue requirements associated with paying free riders a rebate incentive. However, an equivalent financial incentive to the customer offered under a direct install program would not be removed.

153. All other things being equal, this means that the 1988 SPM Correction Memo formulation would assign more costs to a direct install program than to a customer rebate program that is identical except for the delivery approach.

154. Adding a transfer incentive (INC) recapture quantity to the 1988 SPM Correction Memo will ensure that the removal of free rider participant costs does not also remove program costs that become ratepayer revenue requirements.

155. Clarifying the formulation of TRC costs in this way serves to ensure that direct install programs and customer rebate programs are treated consistently when the measure cost, the customer financial incentive, program administrative costs and the NTG ratio are the same under the two delivery approaches.

156. This clarification is consistent with the text description of the TRC test in the SPM, which recognizes that the incentives (INC) term will cancel from the benefit and cost side of the equation “except for the differences in net and gross savings.”

157. The utilities’ recommendation to exclude rebates paid to free riders from TRC costs would increase the PEB under the adopted incentive mechanism 67 cents for each dollar paid to free riders, with zero dollars of added benefit to ratepayers. It is not reasonable to pay utility incentives on the dollars they pay to free riders.

158. The utilities have been put on notice well before the 2006-2008 program cycle began that PEB parameters associated with load impacts, particularly NTG ratios, would be trued-up based on *ex post* studies in each program cycle. Assertions that a true-up of these parameters in the final earnings claim represents unforeseen evaluation risk are therefore without merit. The utilities have had ample opportunity to adjust their portfolios in response to available data, and should be encouraged by Commission policies to minimize expenditures on free riders by doing so. Today’s decision achieves this outcome

159. Directing Energy Division to work with Energy and Environmental Economics (“E3”) and other technical expertise on the E3 calculator or to manage the development of that calculator, as Energy Division deems appropriate, is consistent with the post-2005 administrative structure adopted in D.05-01-055.

Under that structure, this Commission is responsible for overall quality assurance and policy oversight responsibilities for energy efficiency.

160. Establishing a separate milestone-based incentive mechanism for certain non-resource programs, as PG&E recommends, runs the risk of double-counting the savings benefits already attributable to resource programs.

161. Our past experience with milestone-based incentive mechanisms corroborates the concerns expressed by SCE over the difficulty in establishing reasonable milestones and determining if performance is achieved.

162. Excluding emerging technologies program costs in the calculation of PEB addresses NRDC's concerns about not having a performance adder mechanism for this program.

163. To the extent that resource savings associated with utility audits are verified through staff EM&V efforts, they should be reported in the Final Performance Earnings Basis Report and included in the true-up calculation of PEB.

164. Changes to Commission rate recovery and cost allocation procedures for shareholder incentives was not a topic identified in any of the scoping rulings for Phase 1, by workshop participants in their pre- and post-workshop filings, or by the Assigned Commissioner in her ruling identifying the issues for Phase 1 testimony and evidentiary hearings. This issue was first raised in TURN's direct testimony.

165. Changes to cost allocation should be addressed only after proper notice is given to all potentially affected customers. In making any such changes, the Commission should consider a variety of possible approaches as well as factual information on the impacts for various customer classes.

166. As discussed in this decision, recovery of shareholder earnings in rates creates short-term rate and bill impacts that do not reflect the overall impact on rates and bills of energy efficiency programs (including shareholder incentives) over time.

167. The overall impact of energy efficiency programs – even with the payout of shareholder earnings – will be to decrease utility revenue requirements, customer rates and bills relative to the levels without energy efficiency programs.

168. The magnitude of these short-term rate and bill impacts depends upon the actual level of portfolio performance, the associated earnings rate and the earnings recovery schedule.

169. Based on the bill and rate impacts prepared using a range of assumptions for these parameters, the payout of shareholder earnings for 2006-2008 energy efficiency activities is estimated to result in:

- a) A short-term increase in average annual rates to all customers of no more than 0.41% to 0.69%, depending on the utility.
- b) A short-term increase in annual residential rates of no more than 0.44% to 0.66%, which translates to average residential bill increases in the range of 9¢ to 58¢ per month, depending on the utility.
- c) Net decreases overall in bills and rates due to the much greater decreases in revenue requirement and customer bills that are resulting from the implementation of 2006-2008 energy efficiency activities

170. Instead of addressing the factual or methodological issues for establishing a relevant benchmark for shared-savings, WEM argues in its opening brief against adopting any amount of shareholder incentives for energy efficiency in this proceeding. WEM also argues for third party administration of

energy efficiency programs, a proposal that has been decided in prior decisions and is not the subject of this proceeding.

Conclusions of Law

1. The fundamental regulatory and financial biases against energy efficiency (in favor of supply-side resources) identified in D.93-09-078 also exist under the current regulatory framework, in which utilities have returned to their traditional role as resource portfolio managers.

2. It is unreasonable to base the earnings potential under a shared-savings incentive mechanism on the alternate benchmarks presented by DRA and TURN in this proceeding.

3. In the context of other considerations, supply-side comparability provides a relevant numerical benchmark for conservatively establishing the upper bound of earnings potential under a risk/reward shareholder incentive mechanism for energy efficiency.

4. Today's decision creates incentives of sufficient level to ensure that utility investors and managers view energy efficiency as a core part of the utility's regulated operations that can generate meaningful earnings for its shareholders. At the same time the adopted incentive mechanism protects ratepayers' financial investment and ensures that program savings are real and verified.

5. Today's decision achieves a "win-win" alignment of shareholder and ratepayer interests in the following ways:

- a) The level of potential earnings under the adopted incentive mechanism represents a meaningful opportunity to earn for utility shareholders based on consideration of supply-side comparability and other factors.
- b) However, earnings to shareholders accrue only when utility portfolio managers produce positive net benefits (savings minus costs) for ratepayers.

- c) These earnings begin to accrue only as the utilities reach to meet and surpass the Commission's kWh, kW and therm savings goals.
- d) Earnings are greatest when savings performance is superior, not just "expected."
- e) All calculations of the net benefits and kW, kWh and therm achievements are independently verified by the Commission's Energy Division and its evaluation, measurement and verification (EM&V) contractors, based on adopted EM&V protocols.
- f) Ratepayers receive the vast majority of realized savings, since they pay for all of the energy efficiency portfolio costs.
- g) The shareholder "reward" side of the incentive mechanism is balanced by the risk of financial penalties for substandard performance in achieving the Commission's per kW, kWh and therm savings goals.
- h) Ratepayers are protected against financial losses on their investment in energy efficiency. If portfolio costs exceed the verified savings from that portfolio, shareholders are obligated to pay ratepayers back dollar-for-dollar for those negative net benefits.
- i) The overall level of potential earnings and penalties is capped in a manner that symmetrically limits both ratepayers' and shareholders' exposure to risks, while still encouraging superior performance.

6. The use of utility returns on supply-side investments as one consideration in establishing a shared-savings rate does not provide a basis to connect *Bluefield* and related cases with the risk/reward incentive mechanism for energy efficiency. Even if such a basis could be established, the Commission is not bound to the use of any single formula or combination of formulae in determining rates. We have considered several methods, relevant facts and presentations before ultimately reaching today's determinations.

7. Today's adopted schedule for earnings claims represents a reasonable balancing of various considerations, namely, the need to ensure that claims and payments are linked directly to EM&V results while providing ongoing incentives to the utilities throughout the program cycle and recognizing the resource limitations and competing priorities for staff time.

8. As circumstances warrant, the assigned ALJ should be permitted to modify the earnings recovery schedule set forth in Attachment 6, in consultation with Energy Division and the assigned Commissioner. For reasons discussed in today's decision, no interest should accrue on delayed payments of either earnings or penalties.

9. The procedures for review and approval of earnings claims set forth in Attachment 7 are reasonable and should be adopted.

10. As it deems appropriate, Commission staff should have the discretion to use any of the approaches discussed in this decision when reporting on estimated PEB for those programs that do not receive an impact evaluation.

11. The clarifications in cost-effectiveness calculations discussed in today's decision ensure consistent application of the SPM and our determinations in D.06-06-063, and should be effective immediately.

12. PG&E's proposal for performance adder incentive mechanisms should not be adopted.

13. It is reasonable to establish per-unit penalty rates that are higher than the per-unit rates proposed in this proceeding based on our consideration of per-unit penalty levels established for other preferred resources, the resulting balance of potential penalties with incentive rewards under the adopted incentive mechanism, and the full record developed on this issue.

14. Until further order by the Commission, shareholder earnings associated with energy efficiency activities should continue to be collected through electric distribution and gas transportation rates, using the cost allocation methods adopted for that purpose.

15. The rate changes required to recover positive earnings under the adopted incentive mechanism should be consolidated with the next scheduled change in the utility's electric distribution and gas transportation rates.

16. Any pay-back obligations that might arise in the final true-up claim should be booked against positive earnings in the next energy efficiency program cycle, and not be consolidated with other electric distribution or gas transportation rate changes for the next scheduled change.

17. The Commission should revisit today's adopted risk/reward incentive mechanism after gaining experience with its implementation.

18. The opening brief of Women Energy Matters (WEM) goes beyond the scope of Phase 1 and the Assigned Commissioner's Ruling dated March 26, 2007, which clearly defined the issues that were to be included in evidentiary hearings and addressed in the briefs.

19. In order to implement the regulatory framework for post-2005 energy efficiency as expeditiously as possible, this decision should be made effective today.

INTERIM ORDER

IT IS ORDERED that:

1. The energy efficiency risk/reward incentive mechanism described in this decision is adopted for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E)

and Southern California Gas Company (SoCalGas), collectively referred to as “the utilities.” Today’s adopted incentive mechanism applies to the energy efficiency programs funded for the 2006-2008 program cycle and for subsequent program cycles until further Commission notice.

2. The adopted risk/reward shareholder incentive mechanism is structured as follows:

- a) To be eligible for earnings, SDG&E, PG&E and SCE shall meet the following minimum performance standard (MPS) for the energy efficiency portfolio as a whole:
 - (1) Achieve a minimum of 85% of the Commission-adopted savings goals, based on a simple average of the percentage of each individual gigawatt-hour (GWh), megawatt (MW) and, as applicable, million therm (MTherm) goal they achieve, *and also*
 - (2) Meet a minimum of 80% of the goal for each individual savings metric.
- b) SoCalGas shall meet the MPS and be eligible for earnings if it achieves a minimum of 80% of the MTherm savings goal.
- c) Once the utility meets the MPS, earnings shall be calculated as a percentage (sharing rate) of the “performance earnings basis” (PEB) metric defined in Decision (D.) 04-10-059, as follows:
 - (1) Portfolio net benefits calculated using the Total Resource Cost test of cost-effectiveness are weighted by two-thirds, and
 - (2) Portfolio net benefits calculated using the Program Administrator Cost test of cost-effectiveness are weighted by one-third.
- d) Program savings and costs shall be counted in determining whether the MPS is met and in calculating the PEB, as follows:
 - (1) Savings from low-income energy efficiency (LIEE) programs shall count towards determining whether the utilities have met their MPS, but neither LIEE program

costs nor savings shall be included in the calculation of the PEB under today's adopted incentive mechanism.

- (2) With the exception of the Emerging Technologies Program and LIEE, all energy efficiency portfolio costs including associated evaluation, measurement and verification (EM&V) shall be included in the calculation of PEB.
 - (3) Fifty (50) percent of verified savings from pre-2006 Codes and Standards Advocacy Programs shall count towards the MPS for the 2006-2008 program cycle.
 - (4) Consideration of whether savings from pre-2006 Codes and Standards Advocacy Programs shall also count towards the goals for 2009 and beyond is deferred until further consideration of the baseline issues discussed in D.05-09-043 and responses to the Assigned Commissioner's June 1, 2007 ruling in this proceeding.
- e) If the utility has met the MPS, a first tier sharing rate of 9% shall apply. If the utility has met 100% of the savings goals, a second tier sharing rate of 12% shall apply, up to the earnings cap adopted for each utility.
- (1) If the MPS is met, each individual savings metric must be no less than 5% below the second tier threshold to be considered within that tier based on the three-metric average.
- f) Penalties shall begin to accrue if portfolio performance for any single savings metric (GWh, MW or MTherm) falls to or below 65% of the savings goal for that metric. If this occurs, the larger of the following penalty provisions apply up to the penalty cap adopted for each utility:
- (1) 5¢/kWh, 45¢/therm and \$25/kW per unit penalties applied to each unit below the savings goal, or (if larger):
 - (2) Dollar-for-dollar payback of negative net benefits ("cost-effectiveness guarantee"), where negative net benefits are calculated based on the PEB formula adopted in D.04-10-059.

- g) Total earnings and penalties are capped for the four utilities combined at \$450 million over each three-year program cycle, beginning with the 2006-2008 program cycle. The \$450 million combined cap is allocated to each utility as follows: PG&E--\$180 million; SCE--\$200 million; SDG&E--\$50 million and SoCalGas--\$20 million.

3. Utility requests for funding augmentation once the Commission has approved funding levels and the utility program portfolios for a particular program cycle are expected to be limited to extraordinary circumstances. The Commission shall address the treatment of savings and costs associated with mid-cycle funding augmentations on a generic basis in a subsequent decision in this proceeding, after reviewing and considering the proposals submitted in the 2009-2011 Portfolio Planning phase. As discussed in this decision, each request for LIEE program funding shall be carefully examined to ensure that the request is properly classified as LIEE.

4. Earnings (or penalties) under today's adopted incentive mechanism shall be paid as follows:

- a) There shall be two "progress payment" interim earnings claims and one final true-up claim for each three-year program cycle. They shall be linked to Energy Division's Verification and Performance Basis Reports as described in this decision and in Attachment 6.
- b) Interim claims shall be evaluated on a "Cumulative-to-Date" basis, which counts the verified achievements from program year(s) in determining whether the MPS is met in each subsequent interim claim.
- c) Thirty (30) percent of the earnings calculated for each interim claim shall be "held back" until the final true-up claim, in order to minimize the risk of overpaying the utilities in their interim claims.

5. The procedures for submitting, reviewing and approving claims set forth in Attachment 7 are adopted. These procedures augment and substitute for Attachment 4 to Administrative Law Judges' Ruling Adopting Protocols for Process and Review of Post-2005 Evaluation, Measurement and Verification Activities, dated January 11, 2006.

6. D.05-01-055 shall be modified as follows:

- a) The text on page 109 of D.05-01-055 (mimeo.) that begins with "The forum for this review may be..." shall be modified as follows (additions are indicated in italics.)

"The forum for review may be this rulemaking, a pending Commission proceeding (e.g., the AEAP) or a future Commission proceeding in which resource planning assumptions are being developed. *It may involve conferences with stakeholders, workshops or other review procedures.* The appropriate forum *and procedures* for this review will be established by Assigned Commissioner's ruling *or by Commission decision.*"

- b) The paragraph beginning with "If disputes concerning the study filings" on page 111 of D.05-01-055 (mimeo.) is deleted in its entirety, and replaced with the following new paragraph:

"It is premature to adopt an automatic placeholder for alternative dispute resolution in today's decision, and NRDC and other members of the *Reaching New Heights* Coalition recommend. Instead, we will consider this issue in the broader context of our EM&V procedures in a subsequent decision, after further consultation with Energy Division and after obtaining further input from interested parties."

7. No additional customer notice need be provided pursuant to General Rule 4.2 of General Order 96-B for the compliance advice letter filings required under the procedures adopted in Attachment 7.

8. The utilities shall submit the compliance advice letters as directed in Attachment 7, the timing of which shall be tied to the issuance dates of Energy Division's Verification and Performance Basis Reports. Should circumstances warrant, the assigned Administrative Law Judge may modify the schedule for Energy Division's reports set forth in Attachment 6, in consultation with Energy Division and the assigned Commissioner.

9. In performing its EM&V duties, Energy Division staff or its evaluation contractors may utilize any or all of the following approaches in order to report an estimated PEB for those programs that do not receive an impact evaluation, as staff deems appropriate:

- a) Extrapolate findings from comparable programs to determine net resource benefits for programs that do not receive full impact evaluation; or
- b) Accept reported savings values for programs that do not receive impact evaluation; or
- c) Extrapolate savings findings from impact evaluations for comparable programs for some net resource benefit parameters and accept reported values for others; or
- d) Apply a discount factor to savings or costs from programs that do not receive impact evaluation based upon historic impact evaluation results for comparable programs.

Energy Division shall describe the method(s) it uses to estimate PEB for those programs that do not receive an impact evaluation in its Final Performance Basis Report, which shall be issued to obtain stakeholder input pursuant to the Attachment 7 procedures. As discussed in this decision, Energy Division may need to prioritize resources for verifying measure installations and program costs over the program cycle, and may, as circumstances warrant, report the results of completed verification tasks in the Final Verification and Performance Basis Report. If such circumstances arise, Energy Division shall describe in each

Verification Report the additional verification activities that will be performed and reported later in the program cycle.

10. The costs of shareholder incentives shall be included in calculations when (1) evaluating the cost-effectiveness of program plans submitted during the program planning cycle (on a projected basis), or (2) conducting a cost-effectiveness review of portfolio performance in hindsight. These costs shall not be included in the calculation of PEB.

11. The Energy Efficiency Policy Manual, Version 3 presented in Decision 05-04-51, Attachment 3, shall be modified as follows:

- a) Add after the first sentence (ending in "eligibility for ratepayer funds") of paragraph IV.6 the following sentence:

"This prospective showing of cost-effectiveness shall include the costs for shareholder incentives that are projected to be paid for portfolio performance under the energy efficiency risk/reward incentive mechanism in effect at that time."

12. Energy Division shall post to the Commission's website The Energy Efficiency Policy Manual, Version 3 with the modification adopted today, as soon as practicable.

13. The clarifications on how to apply net-to-gross adjustments for free riders presented in today's decision and illustrated numerically in Attachment 9 are adopted. In consultation with the assigned Administrative Law Judge, and as soon as practicable, Energy Division shall post the clarification to the Standard Practice Manual described in Section 10.2 as a "2007 Standard Performance Manual Clarification" memo on the Commission's website, together with the latest (2001) version of the Standard Performance Manual.

14. The utilities shall take immediate steps to ensure that all future cost-effectiveness calculations apply the free-rider adjustment ("net-to-gross ratio") as

directed by this decision. This shall include accomplishments reported for the 2006-2008 energy efficiency portfolios, effective immediately.

15. Energy Division shall confer with Energy and Environmental Economics (E3) and other technical expertise, as staff deems appropriate, to explore whether the naming of input values in the E3 calculator should be modified to better capture the Standard Practice Manual cost definitions and calculation methods, including the net-to-gross ratio adjustments clarified by today's decision. As discussed in this decision, Energy Division may directly manage the development of the E3 calculator in the future, at its discretion.

16. Until further notice by this Commission, all rate changes required to recover positive earnings under the adopted risk/reward shareholder incentive mechanism shall be consolidated with the next scheduled change in the utility's electric distribution or gas transportation rates. As discussed in Section 8.2.2, any pay-back obligations that might arise in the final true-up claim shall be booked against positive earnings in the next energy efficiency program cycle, and not be consolidated with other electric distribution or gas transportation rate changes for the next scheduled change.

- a) Upon review and authorization of earnings for the interim or final earnings claim, SCE shall record the authorized earnings in the distribution sub-account of the Base Revenue Requirement Balancing Account. The year-end balance recorded in this account shall be recovered in SCE's annual Energy Resource Recovery Account forecast proceeding, where we consolidate authorized revenue requirement changes (including balancing account balances) for SCE into one rate change that is implemented on or soon after January 1st of each year.
- b) PG&E shall include the electric revenue requirement and gas incentive amounts that are authorized for a particular interim or final earnings claim in the next scheduled Annual Electric

True-up and Annual Gas True-up advice letter. These consolidated rate changes are implemented on or soon after January 1st of each year.

- c) SDG&E and SoCalGas shall also collect authorized shareholder earnings through the advice letter process they use to consolidate rate changes that become effective on or soon after January 1st of each year. These are the December Consolidated Filing to Implement Electric Rates and December Consolidated Gas Rate Changes advice letter filings.

Energy Division shall prepare an evaluation report on today's adopted risk/reward incentive mechanism by February 1, 2011, so that the Commission may consider any recommended modifications to the mechanism in time for the 2012-2014 program cycle. In its report, Energy Division shall evaluate the advantages and disadvantages of alternative tier structures should the experience with a two-tiered structure indicate that discontinuity problems are significant, even with the hybrid approach we adopt today for the MPS and second tier trigger, and can be mitigated more effectively in other ways. Energy Division shall use 2009-2011 EM&V funds for this evaluation, and may hire evaluation contractors as it deems appropriate. Energy Division shall solicit stakeholder input in the scoping of the evaluation and in the review of the draft evaluation report(s).

17. For good cause, the Assigned Commissioner or Administrative Law Judge may modify the dates for utility submittals or Energy Division reports required by today's decision.

This order is effective today.

Dated September 20, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners