Decision 10-01-023 January 21, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address the Gas Utilities' Incentive Mechanisms and the Treatment of Hedging Under Those Incentive Mechanisms.	Rulemaking 08-06-025 (Filed June 26, 2008)

DECISON FOR AN INCENTIVE FRAMEWORK TO MOTIVATE OPTIMAL USE OF NATURAL GAS HEDGING

TABLE OF CONTENTS

TABLE OF CONTENTS
(Cont'd)

Title **Page**

DECISON FOR AN INCENTIVE FRAMEWORK TO MOTIVATE OPTIMAL USE OF NATURAL GAS HEDGING

1. Summary

In this decision, we adopt an incentive framework for the effective utilization of natural gas price "hedging."[1] The following utilities are respondents: Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company, Southern California Gas Company (SoCalGas), and Southwest Gas Corporation (SWG) (collectively, the "utilities").

This rulemaking was initiated to examine the California gas utilities' gas cost incentive mechanisms and the treatment of hedging under those incentive mechanisms, pursuant to Decision 07-06-013. We examine the regulatory treatment currently in effect for natural gas hedging to determine if it should be modified to provide better incentives to manage costs prudently. Our goal is to adopt a regulatory treatment of hedging that provides flexibility to accommodate changing market conditions and risk factors over time.

We address whether, or to what extent, the costs or payouts from natural gas hedging plans should be incorporated into the utilities' existing gas procurement incentive mechanisms or whether other means should be utilized to ensure that utilities manage hedging in the best interests of customers.

The utilities' use of hedging has grown substantially in recent years. Through the 1990s, the monthly indices for natural gas prices were relatively

---

[1] As explained in further detail herein, hedging is a form of price insurance used to protect customers from excessive swings in natural gas prices.

stable, and measures to mitigate price volatility were of a lesser concern. Gas prices have exhibited greater volatility since the year 2000, however, with particularly large fluctuations in the winters of 2000-2001 and 2005-2006. Ratepayers have been required to bear all of the risks and payouts (if any) associated with the expanded use of winter hedging since 2005. We conclude that the utilities will have an incentive to hedge more cost-effectively, however, where they share in the financial consequences of hedging.

For PG&E, we adopt the provisions of the Proposed Settlement as presented in this proceeding. Consistent with the Settlement, we will allocate a share of PG&E's gas winter hedging transactions to its "Core Procurement Incentive Mechanism," (CPIM) thereby sharing hedging risks and rewards between ratepayers and shareholders.

For SoCalGas, we adopt a treatment that is not based upon any settlement, but that relies upon the underlying record developed in the proceeding. On that basis, we conclude that there should be some sharing of hedging risks and rewards between SoCalGas' shareholders and ratepayers, subject to limits on maximum shareholder risk. Accordingly, we allocate 25% of transactions from the SoCalGas' winter hedging program into its Gas Cost Incentive Mechanism (GCIM), providing sharing of risk and reward with ratepayers. The remaining 75% of winter hedging transactions will be charged or credited as applicable to ratepayers. For SWG, we shall not adopt any changes in its regulatory incentive program at this time given the limited nature of the SWG program for mitigating price risk, as explained further below.

In this decision, we address:

- the hedging guidelines and policies each utility uses, and whether statewide guidelines and policies should apply to all California gas utilities;

- whether hedging costs should be re-integrated into the utilities' existing procurement incentive mechanisms, and if so, how;
- whether a separate incentive mechanism should be designed for hedging costs relative to a market benchmark to encourage better management;
- the processes whereby the utilities' hedging activities should be monitored, reviewed, and/or approved by the Commission;
- whether exclusion of hedging cost recovery from the incentive mechanisms results in reduced risk to shareholders. If so, what, if any, changes should be adopted; and
- what timetable should apply for transitioning from current rules and processes to revised arrangements adopted herein.

2. Procedural Background

This rulemaking was instituted on June 26, 2008, to address the incentive treatment used for natural gas hedging. A scoping memo was issued September 17, 2008, setting a schedule for parties to present and to support their substantive positions and proposals through written comments. The parties actively participating in this proceeding were as follows:

1. The three largest natural gas utilities providing retail gas service in California: PG&E, SoCalGas, and SWG;
2. Southern California Edison Company (SCE) in its capacity as a wholesale customer of natural gas for generation of electricity for sale to its retail electric customers;
3. The Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN) representing consumer advocacy issues;
4. Shell Energy North America (Shell) representing competing gas marketer interest; and

5. Lodi Gas Storage, as a competing Independent Gas Storage Provider.

The record was developed through written comments and a workshop. No evidentiary hearings were conducted. Opening comments with parties' positions were filed October 3, 2008, with reply comments filed October 17, 2008. An Administrative Law Judge (ALJ) ruling was issued on October 27, 2008 setting the agenda and topics of discussion for the workshop held November 5, 2008.

The workshop was convened and a staff workshop report was served on parties and made a part of the record in the proceeding by ruling dated November 25, 2008. Comments on the workshop report were filed on December 9, 2008, with reply comments on December 19, 2008. By ALJ ruling dated January 15, 2009, additional information was solicited. Further comments in response to that ruling were filed on February 20, 2009, with reply comments filed on March 13, 2009.

A joint motion was filed on July 10, 2009, sponsored by DRA, TURN, and PG&E for approval of a Proposed Settlement.[2] The settlement agreement attached to the motion resolves all issues among the sponsoring parties with

---

[2] Because the Settlement contains confidential information about the parameters of the proposed hedging program, sponsors of the Settlement concurrently filed a joint motion for leave to file a confidential version of the Settlement under seal. Sponsors concurrently served on parties a public version of the Proposed Settlement with confidential information redacted. Protection of such confidential information is consistent with past Commission practice. If disclosed, the confidential hedging plan information could compromise PG&E's negotiating leverage. Accordingly, the joint

Footnote continued on next page

respect to the treatment of hedging costs for PG&E. The Settlement, however, does not address the treatment of hedging costs for SoCalGas or SWG. Comments in response to the motion for adoption of the settlement were filed by Shell and SCE, respectively, on August 10, 2009.

3. Framework for Addressing the Issues

As a starting point for addressing the issues, we explain our framework for review and analysis. The record in this proceeding has been developed through written comments and a technical workshop. No evidentiary hearings were held. The comments consist of separate proposals for hedging treatment applicable to each of the three utilities as well as a proposed settlement that is applicable only to PG&E.

In order to lay a proper foundation for evaluating the respective proposals, we start with a review of the role and significance of natural gas hedging as a tool within the larger context of providing reliable service at reasonable cost. Next, we proceed with an analysis of how different approaches to hedging cost recovery affect incentives for effective management of hedging as part of an overall gas procurement program. We consider parties' general arguments on a conceptual basis based on their pre-settlement positions. Based on these arguments, we reach certain general conclusions regarding the appropriate incentives applicable to natural gas hedging. Within this context, we then separately consider the particular incentive treatment applicable to each utility.

---

motion to file the confidential unredacted version of the Proposed Settlement under seal is hereby granted.

For PG&E, we consider this issue in the context of the proposed settlement that has been offered in relation to the record as a whole. For SoCalGas and SWG, we separately consider the appropriate incentive treatment apart from the proposed settlement.

Based on the regulatory treatment applied since 2005, the utility recovers its actual net costs of hedges (net of any gains) on a dollar-for-dollar basis from core customers up to its preapproved limits. For PG&E, based on the settlement approved in Decision (D.) 07-06-013, hedging plans are approved via expedited advice letter filing with the Energy Division. The Commission conducts no retroactive reasonableness review. The Energy Division conducts only compliance reviews at the beginning and end of each hedge season. For SoCalGas, hedging plans are approved via application filing.

Our goal is to achieve a regulatory framework that promotes ratepayers' best interests. In considering whether the status quo produces an appropriate alignment of ratepayer and shareholder interests, one consideration is to review past results of the utilities' use of hedging as a tool to protect ratepayers against extreme price volatility. In this regard, we note that the utilities have incurred net losses for hedges since 2005. In order to evaluate whether the existing system is working optimally, however, we cannot simply tabulate the gains or losses as a result of past hedging strategies. Since hedges are entered into based on uncertainty as to future gas prices, an after-the-fact assessment of hedging performance may not reveal whether the hedges were prudent at the time they were executed. Given the limitations inherent in relying on after-the-fact results to evaluate the effectiveness of hedging, we recognize the importance of management incentives to promote effective hedging.

3.1. The Role of the Proposed Settlement in Relation to the Whole Record

The settlement presented in this proceeding applies only to PG&E and is not offered as a proposal to resolve disputes relating to SoCalGas or SWG. Accordingly, we do not rely upon the Proposed Settlement as a basis to resolve issues relating to SoCalGas or SWG. We independently consider the merits of the record exclusive of the Settlement for purposes of resolving issues relating to SoCalGas and SWG.

Parties' pre-settlement arguments continue to apply in considering how to resolve issues relating to hedging incentives for SoCalGas and SWG. Accordingly, we review parties' pre-settlement positions: (1) to evaluate the reasonableness of the settlement position relating to hedging policies for PG&E only in relation to the whole record; and (2) as a basis to evaluate substantive proposals relating to hedging policy for SoCalGas and SWG apart from the settlement.

3.2. Uniformity Versus Utility-Specific Policies

One of the issues in this proceeding is whether, or to what extent, the Commission should establish uniform statewide hedging guidelines and policies for all California gas utilities. The Commission has established broad statewide energy policies applicable to all California energy utilities as articulated in the Energy Action Plan which identifies, among other goals, ensuring reliable long-term natural gas supplies at reasonable cost. Natural gas service is essential to every Californian's general welfare and to the health of California's economy.

We recognize that broad themes apply on an industry wide basis, and the policies we adopt are designed to promote broad consistency among the utilities where applicable. On the other hand, we appreciate that each utility faces different operational and market constraints. We recognize that differences exist in the incentive designs and hedging practices among the utilities, based for example, on location-specific variations in market or operational factors. Even though particular utilities' hedging strategies differ, there is still value in formulating broad regulatory goals on a consistent basis where fundamental principles of fairness and equity are involved.

We also recognize, however, that setting rigid statewide standards for hedging practices by all gas utilities would not be in the public interest. Whatever standards may be adopted must accommodate different conditions facing individual utilities. Mandating a one-size-fits-all approach to hedging would unduly constrain the utilities from responding to different conditions within their different service territories. Each utility takes different approaches to protect its customers from undue price volatility. PG&E and SoCalGas both utilize hedging, but under different guidelines and constraints. Each utility serves a different service territory and has access to different sources of supply subject to differing infrastructure constraints and conditions. SoCalGas has more storage inventory compared to PG&E. PG&E contracts for more interstate capacity relative to its summer capacity, while SoCalGas holds about the same amount of capacity throughout the year. Winter weather in SoCalGas' and San Diego Gas & Electric Company's (SDG&E) service territories is milder than in PG&E's service territory.[3] PG&E has spent almost three times more in hedging

---

[3] DRA Opening Comments dated October 3, 2008 at 2.

than SoCalGas in recent years, yet PG&E has fewer core customers to protect.[4] The colder winter weather is one possible explanation for some of PG&E's higher level of expenditures resulting in its core customers consuming more gas in the winter.

SWG utilizes a "Volatility Mitigation Program" (VMP) which involves fixed price contracts entered into for price mitigation to protect against extreme price increases. The VMP purchases are flowed through to customers, and thus have no impact on incentive rewards or penalties.[5]

The policies adopted in this decision thus take into account the fact that each utility faces different conditions, and allows the flexibility for each utility to utilize hedging tailored to its own circumstances.

4. The Role and Significance of Hedging in Managing Price Volatility

As a starting point for considering regulatory reforms, we identify the role and significance of hedging as a tool to manage price volatility. Next we consider, how hedging cost recovery currently works.

The potential for volatility in gas prices warrants serious consideration of measures to promote the appropriate use of hedging to protect against price

---

[4] According to PG&E's website, there are 4.2 million customers while SoCalGas has 5.1 million customers.

[5] In D.05-05-033, SWG was granted approval of a gas cost incentive mechanism (GCIM). In response to other utilities' requests that prompted D.05-10-015 and D.05-10-043, SWG stated that since it had recently begun operating under its first GCIM cycle, it had already implemented its hedging program for the 2005-2006 period and did not recommend suspending its program.

spikes. At the same time, the regulatory treatment of hedging costs should not be driven solely by short-term market conditions. Regulatory policies should accommodate different market conditions over time, during periods of market stability as well as where sharp price swings may be more likely.

We have repeatedly acknowledged that gas prices exhibit significant volatility, particularly with the devastating hurricanes that struck the Gulf Coast in 2005. For example, as stated in D.05-10-015:

> …Hurricane Katrina has had a major adverse impact on natural gas markets, contributing to significant increases in the price of natural gas throughout the United States…The problems caused by Hurricane Katrina have come on the heels of several years of sustained high gas prices. Prices for natural gas already had been on an upward trajectory since early 2002.

In D.06-08-027, in reviewing hedging plans for the 2006-2007 winter season, we found "evidence that natural gas markets have become increasingly volatile, which has increased the costs of and the risks associated with purchasing hedging instruments."

In D.07-06-027, the Commission stated:

> …natural gas prices have continued to remain both volatile and high in 2007 compared with historical averages and do not appear likely to return to historical experience any time soon.
>
> …The threat of price spikes this winter cannot be ruled out. Hence, prudence dictates that we act now to protect customers from further price run-ups by providing SoCalGas flexibility to respond quickly to the changes in the natural gas market instead of reacting to an unforeseen event. (D.07-06-027 at 4.)

By moderating the volatility in gas prices, hedging can promote the goal of reliable gas supplies at a reasonable cost, consistent with the Commission's

Energy Action Plan. Therefore, we consider hedging to be important as part of an overall utility strategy in providing reliable gas supplies at a reasonable cost.

Financial hedging is a form of insurance designed to protect customers from extreme natural gas price volatility. Hedging is implemented through financial instruments arranged between the utility and a counterparty to transfer certain price risks to the counterparty. Examples of hedging instruments may include:

- *Futures contracts* obligate a buyer (i.e., the utility) to take delivery and obligate the seller to provide delivery of a fixed amount of natural gas at a predetermined price at a specified location.
- *Call Options* give the purchaser the right, but not the obligation, to *purchase* a New York Mercantile Exchange (NYMEX) Henry Hub natural gas futures contract[6] at a predetermined fixed price (or "strike price") on or before a specific date (an "expiration date").
- *Put Options* give the purchaser the right, but not the obligation, to *sell* a NYMEX futures contracts at a predetermined fixed price on or before a specific date.
- *Basis Swaps* give the buyer the obligation to pay or receive the value difference between the purchase price and the settled spread between the NYMEX Henry Hub futures and a defined locational index.
- *Fixed Price Swaps* give the buyer the obligation to pay or receive the value difference between the purchase price and

[6] Henry Hub is a natural gas pipeline supply point located in Louisiana. Futures prices set at Henry Hub are generally considered to be the primary price set for the North American natural gas commodity market.

a natural gas index settlement price. It involves no up-front premium.

Hedge instruments transfer price risks associated with future price uncertainties at the time when gas supplies are actually delivered. Hedges, however, entail their own separate risk. Moreover, some hedging instruments entail greater risk than others, while offering the opportunity for greater savings. For example, "swaps" offer the potential to essentially pay below-market rates for gas, if commodity prices rise, but also entail the potential risk of greater loss compared to options, if commodity prices fall. Call options also do not provide for cost savings until the commodity price rises above the "strike price" of the option.

Hedges can lose value or expire worthless depending on their terms and market conditions. A utility may be required to provide collateral in form of a "margin call" to counterparties to mitigate default risk if a hedge loses value. For example, in D.06-11-006, the Commission authorized PG&E to issue short-term debt to finance margin calls on hedges that could result from declines in natural gas prices.[7] In authorizing this authority, the Commission expressed concern that such margin calls on gas hedges could reach as much as $900 million. As stated in D.06-11-006, if this were to occur, it could signal a possible large-scale failure of PG&E's hedging activities. PG&E's ratepayers might then have to pay $900 million more than the then-current market price of gas. In

[7] D.08-01-010, Ordering Paragraph (OP) 2.

order to monitor the process, the Commission required PG&E to provide notice when margin calls not offset by other hedges reached prescribed levels.[8]

Managing a hedging strategy successfully is a complex undertaking. Insufficient hedging may expose customers to undue risks of gas price spikes. On the other hand, a poorly managed hedging plan may cost more than its value as a protection against price volatility.

While hedging can mitigate volatility in wholesale market prices, it should be coordinated with other tools to manage overall price stability. On a longer term basis, infrastructure investment in pipeline transmission and storage facilities can reduce vulnerability to market price instability. The utility has discretion in managing its core gas supply portfolio price, and the core customer's gas utility bill.[9] For example, even if the wholesale market price for natural gas exhibits volatility, the utility may be able to mitigate the effects on its core supply portfolio to some extent through timing of storage injections and withdrawals.

Moreover, even where the utility experiences additional volatility in its core supply portfolio, the effects on customer retail bills may be mitigated

---

[8] PG&E was required to serve notice when margin calls not offset by other hedges reached $300 million, $600 million, $900 million, and each $300 million increment thereafter for the first time in each calendar quarter. Most recently, PG&E served notice that on November 13, 2009, margin calls subject to this notification requirement exceeded $600 million. The posting of collateral for margin calls, by itself, has no significant impact on the customer, other than the financing costs associated with posting cash or letters of credit. The financing costs on $600 million of collateral posted would, by themselves, have a negligible per-customer impact.

[9] See December 9, 2008 DRA Comments at 2.

through retail billing plans that average out month-to-month gas supply cost swings over a prescribed period. These plans smooth out the impact on bills due to both variations in physical energy consumption as well as changes in unit cost. The use of this bill payment option does not eliminate the ultimate effects of large price increases, but may in some instances allow the timing of bill payment to be smoothed out in a more manageable fashion. Such retail bill payment plans are not a substitute for hedging and do not provide the price mitigation that hedging offers.

4.1. Operation of the Incentive Mechanisms in Relation to Hedging Costs

We next review how procurement incentive mechanisms work in assigning both risks and benefits relating to gas hedging and commodity costs. Prior to 2005, utility costs and offsetting benefits from financial hedges were shared between customers and investors, along with commodity costs, as part of the utility gas procurement incentive mechanism. We briefly review how these incentive mechanisms work.

Procurement costs for the combined SoCalGas/SDG&E portfolio are recovered under the GCIM.[10] PG&E utilizes a similar CPIM. SoCalGas' GCIM is somewhat similar to PG&E's CPIM in structure and concept, but uses a more flexible metric which adjusts to account for the location of actual monthly purchases based on indices of gas prices at these various locations, and adjusts

---

[10] Since April 1, 2008, SoCalGas' Gas Acquisition Department has become responsible for supplying both its own core customers as well as those of SDG&E through a combined portfolio.

for actual storage activity. Such differences should be considered in developing guidelines and policies regarding hedging among the utilities.

SWG's GCIM is based on transportation, storage and gas commodity costs, and is relatively new compared to that of PG&E and SoCalGas. SWG's hedging activities were negotiated and integrated into SWG's regulatory regime upon its inception. SWG's hedging program does not change from year to year.

The incentive mechanisms measure gas purchasing performance by comparing actual performance against a benchmark cost of gas intended to emulate actual market conditions on a monthly basis. Any resulting difference is allocated as a net cost or savings between shareholders and ratepayers. A "dead band" around the benchmark delineates the range of costs or savings not subject to sharing by ratepayers and shareholders.

These incentive mechanisms replaced reasonableness reviews as a means to ensure the reasonableness of costs incurred on behalf of core customers. Under the previous era of reasonableness reviews, gas costs were passed through on a dollar-for-dollar basis subject to any disallowances for imprudent actions but with no recognition of superior management success in lowering costs. By contrast, the incentive mechanisms reward utility management for lowering gas costs, but also reduce utility earnings if costs exceed the benchmark. The incentive mechanisms eliminated hindsight reasonableness reviews, thereby reducing regulatory burdens and complexity. In this manner, the incentive mechanisms: (1) promote sound business decisions without micromanagement by regulators; (2) encourage innovative methods for improving performance; (3) allow flexibility to adjust to changing circumstances; and (4) preserve accountability for utility management.

DRA has monitored and evaluated the results of the incentive mechanisms for many years and has continuously and unequivocally concluded that both ratepayers and shareholders derive benefits under the incentive programs, as exemplified in its comments.

4.2. Exclusion of Winter Hedging from Incentive Mechanisms Since 2005

From the 1990s up until 2005, both the costs and payouts from winter hedging were fully included in the procurement incentive mechanisms. The Commission changed the treatment of hedging beginning in the fall of 2005, however, in response to petitions filed by the utilities. The utilities sought a change in the regulatory treatment of hedges in response to severe disruptions in natural gas supplies and resulting price volatility beginning in the summer of 2005.[11] In anticipation of significantly rising prices in the coming winter season, the utilities sought to increase hedging activity significantly. The utilities were concerned, however, that utility shareholders would be exposed to excessive risks if the costs of this significant expansion in hedging continued to be subject to risk sharing through the existing incentive mechanisms.

Consequently the utilities requested to modify their incentive mechanisms to expand the amount of winter hedging authorized and to assign 100% of those hedging costs to core customers. PG&E was the first to file such a request.[12] In the fall of 2005, SoCalGas and SDG&E filed a similar petition[13] to assign to core gas customers all costs and benefits of expanded hedging plans for the coming winter, as well as for gas hedging already incurred for the 2005-2006 winter. The utilities argued that without the modification, an expanded hedging program would entail too much risk for investors, and create a disincentive to hedge at a level needed to protect core ratepayers.

In October 2005, the Commission approved PG&E's request, assigning all costs and payouts from winter hedging to ratepayers, and approved a similar

---

[11] The disruption to natural gas supply production was caused largely by Hurricane Katrina-and to a lesser extent Hurricane Rita—which had a major adverse impact on natural gas prices beginning in late August 2005, creating the substantial possibility of further increases due to the loss of gas production.

[12] See PG&E Petition for Modification of D.04-01-047 in Rulemaking (R.) 02-06-041.

[13] See Petition to Modify D.02-06-023 and D.03-07-037.

arrangement for SoCalGas and SDG&E. In winter hedging plans approved since 2005, the Commission has continued to assign all winter hedging losses and gains 100% to core customers.[14]

We next consider whether the current treatment of hedging costs best serves ratepayers' interests, and whether reforms are warranted going forward.

5. Should Hedging Risks and Benefits Be Shared by Utility Investors?

5.1. Parties' Positions Apart from the Settlement

We first address the general policy of whether winter hedging risks should be shared by utility investors, considering the underlying record apart from the Proposed Settlement. We reach general conclusions, based on this review, that some degree of risk sharing is appropriate. We next consider the specific application of this principle to each utility separately. For PG&E, we consider the Proposed Settlement as a basis for specific modification in risk sharing. For SoCalGas and SWG, we separately consider modifications based on the record apart from the Proposed Settlement.

Parties' pre-settlement positions apply generally to all of the gas utility respondents to this proceeding. Accordingly, review of the pre-settlement positions provides a framework: (1) with respect to PG&E, for assessing whether the settlement offers a reasonable resolution in light of the whole record, and (2) with respect to SoCalGas and SWG, whether parties' arguments have substantive merit (since the settlement only covers PG&E).

---

[14] See D.05-10-043, D.06-08-027, D.07-06-013, and D.07-12-019.

5.1.1. Utilities and TURN Pre-Settlement Proposal

In their pre-settlement proposal, the utilities support the status quo, with 100% of the risks and benefits of winter hedges assigned to the core ratepayers. TURN, in its pre-settlement position, also advocates maintaining 100% of winter hedging impacts outside the procurement incentive mechanism.

The utilities argue that the re-integration of winter hedging programs into their gas cost incentive mechanisms would create disincentives to hedge at a level that is appropriate to protect customers from possible price spikes in winter months when consumption is the greatest.

TURN agrees with the utilities that including hedging within the existing incentive mechanisms would disrupt the alignment between customers' and shareholders' interests. Because shareholders would face penalties for the costs of hedging, they would have the incentive to curtail the amount of hedging that would otherwise be performed absent such risk.

The utilities and TURN argue that the existing framework properly aligns the interests of ratepayers and shareholders, and that the objectives of hedging (i.e., limiting customer exposure to price risk) are distinct and potentially incompatible with the goals of gas cost minimization. They characterize hedging as a tool to reduce price volatility, but not the absolute level of costs.

The utilities maintain that gas cost minimization and hedging have diverging objectives that cannot be reconciled. TURN likewise argues that placing hedging within the gas cost procurement mechanism creates an inherent conflict between ratepayers and shareholders by penalizing investors when gas prices fall, thereby creating a disincentive to hedge.

TURN agrees with the utilities that integration of hedging into the existing procurement incentive mechanisms would not provide an incentive for optimal hedging. TURN argues that a tool such as hedging (designed to provide benefits only when commodity prices rise) is not compatible with an incentive that rewards utilities when prices decline. Hedging and commodity prices move in opposite directions. Thus, for example, in instances where hedging produces a gain due to a broader market commodity price rise, ratepayers would give up some hedging gain to shareholders in addition to paying a share of costs caused by higher commodity prices.

TURN thus argues that including hedging within the procurement incentive mechanism would break the alignment between shareholders' and customers' interests. Because utility shareholders would face penalties for the costs of hedging, TURN believes the utilities would have an incentive to curtail hedging, and would no longer be an impartial agent for ratepayers. TURN argues that forcing the utility to bear risk by including the effects of hedging within the procurement incentive mechanism will expose the utility to significant earnings volatility without an expectation of a positive return, thus negatively impacting the utility's credit rating, and making the cost of borrowing more expensive. TURN believes ratepayers could be subject to higher costs as a result.

The utilities also argue that gains and losses from hedging are primarily due to factors beyond their control (e.g., market fluctuations resulting from weather, macroeconomic trends, etc.). The utilities assert that the incentive mechanisms for gas commodity procurement costs are based on a factor over which the utilities can exert some control-its assets-whereas hedging strategies attempt to minimize market price volatility-an area outside of utility control, and not a reflection of the utility's acumen.

SoCalGas argues that if some or all of its winter hedging transactions were to be included within the GCIM, some sort of corresponding shareholder reward-or at least the potential for additional reward-might compensate somewhat for additional risk. SoCalGas suggests, as one possible approach, that the GCIM lower tolerance band (currently set at 1%) could be adjusted by an amount that roughly compensates for the amount of winter hedging options moved into the GCIM. By reducing the tolerance band, the utility could begin to share in GCIM savings earlier, and thereby receive some offsetting compensation for absorbing additional risks associated with winter hedges.

5.1.2. SoCalGas Separate Benchmark Proposal

Although SoCalGas and SDG&E support the status quo as their primary position, they believe a separate benchmark index could be developed in the event the Commission desires such treatment. SoCalGas believes that a separate performance benchmark could be designed to track winter hedges based upon fixed-price forward transactions using the average of the posted settlement price for the first five days of each transaction month—not the settlement month. For example, the benchmark for a December 2010 NYMEX futures contract entered into in August 2010 would be the average daily settlement prices for December 2010 NYMEX futures contracts for the first five trading days of August 2010.

Forward price transactions would include physical contracts, futures, and swaps, but exclude options. Because of their low probability of payoff and the limited availability of settlement prices, SoCalGas does not consider options as being conducive to benchmarking. Actual performance would be compared against the benchmark, with differences (either positive or negative) shared between customers and shareholders in the same way as for any other GCIM input. SoCalGas argues that the benchmark would provide an incentive to actively follow the markets and trading patterns in order to enter transactions at times when the prices are more favorable.

PG&E does not believe that a separate incentive mechanism can be designed that aligns customers' and shareholders' interests in a fair and economically efficient manner. PG&E cannot find any transparent benchmarks or published end-of-day quotes of forward prices (particularly longer-dated forwards published on a consistent basis) or option values with which to construct benchmarks for use in designing a hedging incentive mechanism. PG&E does not believe that SoCalGas' proposal for the use of Henry Hub NYMEX futures (even if deemed useful for SoCalGas) would be as effective for PG&E. PG&E is concerned about the locational hedge effectiveness of using (and being benchmarked against) only NYMEX futures to hedge supply basin price risks in western Canada and San Juan in the Four Corners region of New Mexico and Colorado.

SWG similarly believes that benchmarks for hedging transactions do not exist because transactions in futures markets are not sufficiently transparent. SWG relies on its competitive bidding process to ensure that it purchases hedging instruments at the lowest cost available at the time of purchase.

DRA opposes establishing a separate incentive mechanism limited to hedging costs alone, arguing that such an approach is patently flawed. DRA likewise believes that there are no readily available, transparent benchmarks that could be applied to index the performance of a hedging program through a separate incentive mechanism.

DRA objects to SocalGas' proposed benchmark based on a NYMEX futures contract. The NYMEX gas futures prices move minute-by-minute and many related financial instruments are traded privately and/or "over the counter." DRA argues that it would be poor policy to design a separate hedging benchmark that is unverifiable. Incentive mechanisms, by definition, incorporate some type of reward/penalty structure for the utility. DRA argues that absent a balanced and equitable utility incentive structure, dedication of resources to such a regulatory effort carries little to no value, because the proper utility incentive and accountability to prudently manage costs is never pursued.

Shell also objects to using fixed-price forward transactions based on a NYMEX futures contract as a benchmark to measure SoCalGas' hedging performance. Shell argues that such a benchmark would not provide accountability for utility management since the hedge purchase price would simply be measured against itself. (*See* Comments at p. 11.)

Shell also argues that the use of the NYMEX price at Henry Hub would not provide a meaningful benchmark for SoCalGas' performance given that Henry Hub is in Louisiana, not in California. The NYMEX price would need to be translated to the Southern California border price through a basis swap, according to Shell, in view of the substantial variation between the NYMEX price and California border prices.

5.1.3. DRA Pre-Settlement Proposal

DRA, in its pre-settlement proposal, argues that insulating investors from 100% of winter hedging risks does not provide an incentive to manage hedging in ratepayers' best interest. DRA argues that the utilities are not subject to accountability for the consequences of their hedging activities. DRA has referred to PG&E's hedging program as a "shopping spree" and that "there is no evidence such hedging behavior helps reduce gas costs for PG&E customers."[15] As its pre-settlement position, DRA proposed that all hedging costs be re-integrated into the existing gas cost incentive mechanisms.

DRA believes that the current deadband tolerances within the incentive mechanisms (equal to an amount of 2% above the commodity benchmark to 1% below the commodity benchmark) provide adequate flexibility for the utilities to conduct any hedging that each corporation determines to be appropriate. DRA suggests, however, that the existing incentive mechanisms could be modified to accommodate investors' added risks by expanding the tolerance bands to provide additional flexibility and an extra measure of protection in consideration of any perceived need by the utilities (and/or Commission) to increase the level of hedging activity.

If hedging costs are re-integrated into the existing incentive mechanisms, DRA believes that no Commission authorization of hedging plans would be needed, but that hedging gains or losses would simply be included within the utilities' actual procurement mechanisms, and measured relative to the benchmarks.

DRA argues that hedging should be discretionary rather than subject to Commission mandate. DRA would leave the responsibility with the utility as its strategy to hedge, subject to recovery within the incentive mechanism. DRA

[15] See R.04-01-025, DRA's Response to PG&E Petition to Modify D.04-01-047 and D.05-10-015, pp. 5, 7, filed May 26, 2006.

believes that this approach provides flexibility for the utilities to make prudent hedging decisions on a real time basis in conjunction with prevailing market conditions, and incorporates accountability for their discretionary decisions, providing the investor with a financial stake in the outcome of hedge transactions.

If the Commission retains winter hedging program costs outside the incentive mechanism structure, however, DRA believes that the current approval process (with some modification as explained below) is acceptable, in contrast to designing a separate hedging incentive mechanism (which DRA believes would offer no true accountability). If winter hedge program costs remain outside the incentive mechanism, DRA recommends that the utilities file an application or advice letter for plan approval, somewhat similar to the process used for interstate pipeline capacity approved in D.04-09-022.

If the utility obtains consensus with DRA and TURN as to the terms of its annual winter hedge program, then it would file for Commission approval of the plan by advice letter. If the utility is unable to obtain agreement with DRA and TURN as to a winter hedge program, the utility would file an application for approval of its plan. DRA intends to continue to audit all winter hedge plan costs and identify them separately in its annual audits of the incentive mechanisms.

5.1.4. Shell Proposal

Shell presented its proposals on hedging policies from its perspective as an independent marketer of natural gas. Shell argues that the existing regulatory process does not provide adequate assurance that hedging costs charged to ratepayers are reasonable. Shell believes that excluding the utilities' winter hedging plans from the incentive mechanisms relieves the utilities from any accountability for risks associated with hedge transactions. Shell claims that under the existing framework, the hedging programs have resulted in no tangible benefits to ratepayers.

Shell argues that the ability of DRA and TURN to assess utility hedging strategies and execution is limited, and that a more public and transparent process in the review of hedging costs is needed, with objective measures of performance. Shell proposes that a target be established to measure the volatility of the GCIM/CPIM benchmark price. Based on an annual assessment of the utility's performance in achieving a designated price volatility mitigation target, the utility would receive an award or incur a penalty in relation to its performance.

Shell proposes that the Commission establish a "portfolio price volatility target," expressed as a percentage of the procurement incentive mechanism's benchmark price volatility. This target would compare the volatility of the utility's gas purchases relative to the GCIM/CPIM benchmark price. Based on an annual assessment of the utility's performance in achieving the price volatility mitigation target, the utility would receive an award or incur a penalty in relation to its performance.

Shell proposes a four-step process for calculating the volatility of market benchmark prices: (1) list monthly natural gas prices in a column; (2) take the natural logarithm of the ratio of each monthly price to its value in the preceding month; (3) calculate the standard deviation of this data set; and (4) multiply the resulting standard deviation by the square root of 12. The resulting number, expressed as a percent, represents the annual price volatility of the market benchmark. Shell believes that the same calculation can be applied to each utility's actual prices to determine the volatility of the utility's supply portfolio.

In this manner, the performance of the utility with respect to price volatility could be compared to an objective market measure.

Shell believes that the Commission should establish a targeted reduction in utility price volatility relative to the benchmark price volatility. Shell presumes that the specific figure or value for portfolio price volatility would be based on customer risk preferences. Until the Commission determines such values, as an interim measure, Shell proposes use of a volatility reduction target of 30%, representing hedging of 25% to 50% of each utility's portfolio (based on the range that SWG currently utilizes). Shell anticipates that the actual volatility value would be established based upon actual or projected customer preferences for price stability.

Shell supports the inclusion of all hedging costs and benefits within the gas cost incentive mechanism. In order to accommodate the inclusion of hedging, however, Shell proposes that the benchmark used to assess rewards or penalties under the incentive mechanism be modified to reflect "all utility procurement products, including hedges." The benchmark would thus include index prices representing fixed price contracts at each given location where the contracts are purchased. Shell proposes that the utility investor share in 15% of the gains and 2% of the losses related to utility procurement costs versus the benchmark, with no tolerance band. Under Shell's proposal, each utility's overall financial exposure for gas procurement, including hedging, would be limited to a gain of $38 million and a loss of $14 million. Shell believes that these percentages of sharing and caps will be sufficient to provide an incentive for the utilities to hedge.

Shell further argues that in order to ensure that utility hedging procurement is transparent and non-discriminatory, the Commission establish a protocol whereby a number of suppliers that meet credit and performance criteria can be qualified for any utility solicitation. Shell proposes that the utilities be required to rotate through suppliers over time on a non-discriminatory basis in order to maximize competitive opportunities among suppliers. Shell characterizes this proposal as an "open, transparent, and non-discriminatory hedge solicitation protocol" for each gas utility intended to mirror the electric utilities' hedge solicitation process. Shell argues that its proposal eliminates the need for a confidential hedge procurement plan and that core customers will be better served by an open process allowing for scrutiny of the utilities' hedging programs by "risk managers that are part of the solicitation process." (July 30 Shell Comments at 18-19.)

SoCalGas and PG&E oppose Shell's proposal to force the utilities to contract for a significant amount of fixed-price gas on a year-round basis. PG&E believes that a hedging strategy limited to the peak-demand winter months is best for its bundled core customers because it applies the appropriate price protection when high prices could coincide with high demand. PG&E argues that Shell's notion of year-round contracting for fixed-price gas has very little benefit to core customers during summer months when their usage and gas bills are generally low. SoCalGas states that while it would consider fixing the price of a portion of its core portfolio, if it could secure a very low price, it may very well consider such arrangements. SoCalGas, however, does not want to be forced into fixed price arrangements by a new mechanism that places an artificial and unwarranted premium on rate stasis.

DRA opposes Shell's proposal, arguing that there is no factual basis to establish the solicitation protocol proposed by Shell. Core purchases represent less than 50% of the gas sold in the California market, while the balance of gas supply is generally moved into the market by noncore customers and/or marketers/producers. DRA claims that Shell's proposal would create a double standard in the gas market – "full disclosure" of hedge products for utilities, and "no disclosure" for all other market participants (marketers, producers, large end-users, core aggregators, etc.).

5.2. Discussion

5.2.1. Introduction

In reviewing parties' positions, apart from the settlement, we are not persuaded that any single proposal optimizes the goals of protecting customers against price spikes while minimizing overall gas costs over time. We conclude that if all hedging costs and payouts were included with the GCIM/CPIM without limits, the resulting perception of risk could create a disincentive to hedge at an appropriate level. We also conclude, however, that the record supports a regulatory approach that holds the utility accountable for the consequences of its gas hedging while limiting investor risk exposure. The utility will have a greater interest in managing hedges effectively knowing that its shareholders will participate in the consequences.

We disagree with the claim that hedging and minimizing gas prices are inherently conflicting goals and that investors' and ratepayers' interests with respect to the use of hedging cannot be reconciled. These goals are not inherently conflicting, but are complementary, namely to minimize overall gas costs consistent with risk preferences. The formulation of a hedging plan should be based upon appropriate goals for balancing customer risk preferences utilizing hedging in a cost-effective manner. Even under the present incentive structure without a monetary award available, the utility still has a duty to customers to manage the hedge program effectively even though the goals of hedging are different than the goals of seeking to minimize gas costs. The utility manager is currently responsible for pursuing both of these goals in a balanced and coordinated manner, even though their specific objectives differ. Imposing a financial consequence on the utility for the results of its hedging program will not lessen the utility manager's existing responsibility to coordinate these goals in a balanced and effective manner. Moreover, financial incentives are only one factor in the design and execution of a hedging plan. In providing reliable and reasonably priced service to customers, prudent hedging will be based on all of the relevant factors, including the nature of the hedge instrument, market conditions, and the needs of customers. As such, we do not believe that including at least some portion of hedging costs within the gas cost procurement incentive mechanism results in incentive signals that are inherently incompatible or contradictory. By placing the utility at some risk for the consequences of the hedge plan after it has been adopted, the interests of the utility investors and ratepayers can be reasonably aligned.

5.2.2. Merits of Adopting a Separate Index Versus Uniform Risk Sharing

We conclude that the best design of an incentive mechanism is the one which is the simplest to administer, and the least vulnerable to gaming. Thus, we decline to adopt proposals for a separate performance index based on futures contracts or volatility targets. We conclude that providing for a uniform percentage of the sharing of gains and losses from hedges offers a much simpler and easier approach to administer while avoiding the difficulties involved with a separate index.

If the Commission were to establish predetermined indices for hedging, for example, by specifying fixed percentages of the supply portfolio to be hedged, or maximum limits on price variability, a system of incentives could be crafted based upon the degree to which the utility attained the targets. The appeal of such a mechanism is that it matches rewards or penalties more directly with hedging management performance. The drawback of such an approach, however, is that it is only as effective as the index or performance target that the Commission sets.

We conclude that the potential complexity involved the proper design, tracking, and verification of a separate index mechanism outweighs any advantages in improving the utility's hedging performance. For the Commission to engage in the sort of detailed oversight entailed in designing and monitoring such a mechanism would not be an efficient use of resources. SoCalGas' benchmark would still call for Commission pre-review and pre-approval of a hedging plan which could insulate SoCalGas from any future allegations of gaming the benchmark. Simply including the costs of hedging within the incentive mechanism relieves the Commission of the need for detailed review of hedging transactions after the fact.

Also, under the index proposed by SoCalGas, the utility would only bear the risk that hedge trades be executed at the 5-day average price. There would be no risk associated with how closely the hedge price compared to the benchmark price in the procurement mechanism. The SoCalGas proposed index also would not account for the use of options, thereby unduly restricting potential hedging strategies. The index would also likely limit hedging activities to a period covering only 12 months or less.

We likewise reject the Shell proposal for a "portfolio price volatility target." Shell provides insufficient information to calculate and integrate it into the existing mechanisms. The proposed changes would introduce more complexity and uncertainty which could pose greater risk and the potential for higher ratepayer costs.

We recognize that hedging has been used by electric utilities to minimize or mitigate the potential for high electric bills. In several decisions in 2002 and 2003, the Commission developed a framework for its electric rate volatility mitigation policy.[16] This policy is based on the Customer Risk Tolerance (CRT) guideline, which states that in any given 12-month period, the utilities should avoid having electric rates fluctuate from forecasted levels by more than one cent per kWh. The CRT target is subjective and based on Commission judgment. The Commission has never set a similar target for the utilities' gas programs, and we find insufficient basis to pursue developing a separate CRT target for purposes of a hedging benchmark here.[17]

Given the complexities involved in managing a hedging strategy, a preferable approach is one in which the utility manager has the flexibility to manage the hedging strategy on an ongoing basis without being constrained by a specific index that may not realistically measure the relevant performance results.

---

[16] D.02-10-062, D.02-12-074, D.03-12-062.

[17] In order to meet the CRT guideline, the utility was to monitor the expected volatility of the procurement portfolio by using the metric: "To Expiration Value at Risk" (TEVaR) initially set at 99%. Estimating the value of the TEVaR metric allows the utility to state, with 99% confidence, that rates will fluctuate over the next 12 months by no more than the TEVaR 99% value. Since then, the TEVaR was adjusted from 99% to 95%. (See D.07-12-052.)

5.2.3. Merits of Shell's Proposed Solicitation Process

We reject Shell's claim that utility hedge plans should be provided to third parties, including gas marketers. As stated in past decisions, the utility hedging plan is to remain confidential, presumably containing highly sensitive market information which, if released, could work toward the detriment of ratepayers. Many hedging instruments can be purchased in a liquid and transparent market, however, and DRA publishes an after-the-fact review of the utilities' performance. Shell fails to justify why utilities, buying gas for core customers, should be compelled to establish a transparent, non-discriminatory "full disclosure" solicitation protocol for hedge products, while the rest of the market would not be covered within this protocol.

Shell asserts that its proposed solicitation process will increase the range of potential products. The gas market is competitive with a vast range of products already available, and is capable of developing new products when there is a demand for them. Shell fails to quantify any ratepayer benefits of its proposed changes to the incentive mechanisms relative to the current incentive mechanisms.

5.2.4. Merits of Risk/Reward Sharing of Hedging Costs/Gains As Incentives to Management

We next consider the merits of adopting a risk/reward sharing between utility investors and core customers of both the costs and potential payouts from hedging transactions. When we eliminated hindsight reasonableness reviews for gas commodity costs back in the 1990s, we did so with the understanding that the utility would still bear financial responsibility for gas costs by the sharing in gains and losses relative to a performance benchmark. In this manner, we maintained a balance between accountability and risk tolerance associated with gas procurement. Up until 2005, this balance applied to costs incurred to hedge natural gas prices, as well as for natural gas commodity costs, themselves.

The dramatic increase in the use of hedging beginning in 2005 caused us to revise how hedging costs were treated at least for the immediate winter seasons at issue. While we excluded hedging costs from the gas procurement incentive mechanisms in that context, however, we did not reinstitute hindsight reasonableness reviews.

While the Commission has the authority to approve or modify the utilities' hedging plans prospectively, the process for Commission review and approval of hedging plans, however, has significant limitations. The hedging plans submitted for Commission approval do not provide assurance as to how the purchasing strategy will be optimal for ratepayers as time passes and circumstances change. Unlike a contract for a utility product or service, purchasing hedging instruments requires knowledge of future purchasing decisions that we cannot evaluate in advance. Therefore, the process for advance approval of utility hedging plans is not comparable to advance approval of a pipeline contract or a gas storage facility.

Consequently, utilities are subject to no retrospective reasonable reviews of their hedging strategies, but also are largely not held accountable for the consequences of hedging prospectively. Although we have allowed this modified treatment for winter hedging plans approved since 2005, we have not conducted a comprehensive analysis of its longer-term implications prior to this rulemaking.

We have now considered the longer-term implications in this rulemaking. As a result, we conclude that the hedging treatment that has been approved for each winter season since 2005 should not be institutionalized as a permanent policy. The utility's hedging strategies should be based upon a balance of risks and rewards, with accountability for the consequences of management's hedging activity. The utilities don't want investors to be harmed by bearing downside risks of hedging, but the consequence is that core customers bear the entire downside risk. Utilities should share in the financial consequences for their hedging strategies, but subject to limits on the maximum risk exposure. The proper balance lies somewhere between the extremes proposed by opposing parties.

We thus reject the utilities' proposals simply to continue the status quo. Insulating investors from all risks of winter hedging programs without accountability does not promote the proper incentives for prudent hedging. At the same time, given the magnitude of potential risks involved, DRA's proposal to include all hedging costs within the procurement incentive mechanisms is not practical. Likewise, the proposal of Shell also fails to provide a satisfactory solution.

In characterizing the incentives (or disincentives) resulting from the inclusion of hedging within the procurement incentive mechanism, opposing parties selectively highlight only certain effects while downplaying or ignoring other relevant effects. DRA, for example, emphasizes the utility's lack of incentive to be cost-effective. DRA thus seeks to limit hedging only to what is truly needed to protect core customers. DRA, however, does not adequately address the potential of its proposal to cause the utilities to curtail hedging to the point where ratepayers may not be adequately protected against price spikes.

The utilities and TURN emphasize the risks of hedging when addressing the effects on investors, but emphasize the benefits of hedging when addressing the effects on core ratepayers. The fact is that hedging can potentially result in negative and beneficial effects to both investors and ratepayers. SoCalGas has argued that in most years, the investors would realize lower earnings if required to absorb hedge risks. Such hedging losses, however, would also produce higher bills for customers in most years. The same adjustment that would lower shareholder earnings would also reduce any shared cost savings that customers would otherwise realize.

It is unduly one-sided simply to focus on the potential hedging losses to investors without recognizing potential hedging losses imposed on ratepayers. Similarly, if the results of hedging are shared, any successes from hedging would yield benefits to investors as well as to customers.

In periods where hedging produces beneficial effects, those benefits can accrue to both customers and investors to the extent that both share in price variations through the GCIM/CPIM. Under the GCIM/CPIM, the investor is at risk for a share of the variance between the gas commodity price and a designated benchmark (subject to dead-band tolerances). If a hedge narrows that variance, investors' net earnings volatility attributable to commodity prices would correspondingly be mitigated to that extent.

In comments on the Proposed Decision, TURN observes that different time horizons apply in accounting for earnings or loss with respect to: (1) the multi-year duration between potential payouts from hedge instruments and (2) the 12-month cycle associated with earnings under the GCIM. TURN observes that in most years, hedges will result in the recording of a loss (since unexpected price swings do not typically occur every year). By contrast, most offsetting hedging gains may be expected to occur beyond a given 12-month GCIM period, and over intermittent intervals, due to the unpredictable nature of hedges. Consequently, TURN argues that assigning risk of hedging to the GCIM creates a disincentive to hedge at an appropriate level because of these differences in the timing of earnings-or-loss recognition.

We recognize that timing differences exist with respect to multi-year, intermittent hedging payouts versus annual GCIM adjustments. We are not persuaded, however, that such differences necessarily lead to a disincentive to hedge in ratepayers' interest. This argument implies that a utility manager focuses on the consequences of hedging exclusively within the 12-month time horizon used for calculating GCIM awards or penalties. We find no reason to believe that a utility manager makes decisions with such tunnel vision, based solely upon impacts during a 12-month regulatory cycle while ignoring effects due to hedging payouts that may occur beyond the current 12-month GCIM cycle.

A prudent manager would not ignore future earnings potential from hedging payouts in subsequent years merely due to the regulatory artifact of calculating GCIM earnings adjustments at 12-month intervals. While GCIM rewards or penalties are calculated annually, the GCIM process, itself, remains in effect continuously through multiple annual regulatory cycles. It is reasonable to expect a utility manager to be influenced by the full range of consequences from hedging decisions (both positive and negative), even if some consequences are expected to occur during later GCIM cycles. Some hedging effects may be beneficial to the investor, and others may entail potential negative consequences. Management incentives will be informed by the full range of expected future hedging impacts.

Nonetheless, to the extent that concern remains regarding potential negative incentive influences due to timing differences relating to the multi-year nature of hedging payouts, we have addressed this concern by including only 25% of winter hedging transactions in the GCIM. By adopting this limitation on shareholder risk during any 12-month GCIM cycle, we mitigate potential disincentive effects, as noted by TURN. In this way, the potential magnitude of earnings variations is mitigated, compared with allocating 100% of winter hedging transactions to the GCIM. The utility manager will still have incentives to exercise more careful attention to hedging, knowing that management actions may affect utility earnings. Our adopted approach is an improvement over proposals to shield the utility from any financial consequences of the management of winter hedges, while mitigating potential disincentives to hedge at an appropriate level.

The primary goal of utility hedging should not be to realize speculative profits, but rather, to manage price risk so as to promote stability in retail core customers' gas rates, and to protect customers against excessive price swings. TURN claims that the Proposed Decision does not differentiate between "speculative" versus "insurance" hedging. TURN claims that the whole idea of "managing" hedging positions implies an active market participation that is more akin to speculation rather than insurance. We disagree with inferences that establishing incentives for the prudent "managing" of hedging positions somehow implies the use of hedging mainly for speculation, rather than as a form of insurance. There is no reason to equate hedging as a form of insurance with passive management inaction. A prudent utility manager makes a variety of discretionary choices in management of hedging. While particular choices may differ depending on whether the hedges are for speculation or for use as insurance, the utility remains responsible to manage the hedges proactively. The incentives that we adopt promote the prudent management of hedging, and are fully consistent with the use of hedging as insurance to protect ratepayers against price spikes.

In considering incentives and disincentives for hedging, we conclude that any adopted treatment should provide a balance between opportunities to share gains and responsibilities for bearing losses. While some sharing of risk is appropriate to provide the proper incentive to hedge effectively, too much risk exposure could create a distortion in the incentive to hedge at a level conducive to protecting ratepayers from excessive price volatility.

We are not persuaded, however, that placing the utility investor at *any* risk for winter hedging would cause curtailment of hedging below what is needed to protect core customers. The claim that added risk creates a disincentive to hedge begs the question of what level of hedging is optimal to protect core customers. While the utility should have the incentive to hedge at the appropriate level to protect the ratepayer, no party has provided empirical analysis to establish that "appropriate" level.

There is a trade-off between the value of hedging against price risk versus the costs of hedging. The value of hedging is a function of risk aversion and preference for stability and predictability. The customer benefits only as long as hedging provides an offsetting value in the form of reduced volatility in retail bills. At the point where the additional value of enhanced price stability is less than the incremental cost of hedging, no further hedging would be beneficial for the customer.

In D.07-06-013, the Commission contemplated that PG&E would arrange for a market survey of the risk preferences of its core gas customers. The goal was to determine the dollar amount core customers might be willing to spend on hedging to mitigate the impacts of commodity price volatility.[18] TURN supported considering the results of that customer risk preference study in this proceeding. By ruling dated September 17, 2008, in this proceeding, it was determined that the PG&E risk preference study might provide useful information in this proceeding.

The PG&E risk preference study has not been formally presented for review in this proceeding. Under the terms of the Proposed Settlement offered, the Commission would not set a predetermined hedging amount based on risk preference. Yet, since the Settlement only applies to PG&E, the question remains as to whether a study of customer risk preferences should be performed for SoCalGas, and if not, how the Commission would determine if a presumed "disincentive" to hedge might adversely impact customers.

SoCalGas expresses skepticism that a survey of customer risk tolerance would provide useful hedging guidance. SoCalGas believes that the risk tolerance of any individual customer will likely depend upon a host of variables, and that group behavior may be even more complex and subject to external variables that can change quickly.

SoCalGas did not formally assess customer risk tolerance when it designed its recent winter hedging programs, but its hedging strategy was based on what

[18] See D.07-06-013 at 11.

it believed was a reasonable and prudent approach to hedging for its core customers.[19] Therefore, SoCalGas is asking the Commission to rely upon the utility to guess as to customer risk preferences, while imposing no financial accountability for a wrong guess.

We appreciate the difficulties and limitations involved in conducting and interpreting an empirical survey of customer risk preferences in relation to the cost of winter hedging. Nonetheless, absent empirical data quantifying customers' risk preferences, the utilities cannot demonstrate with certainty how changes in incentives to hedge may affect customers.[20]

In the absence of evidence measuring customers' risk preferences, the utility investors' own risk preferences provide some objective indicator of whether a hedging strategy reflects careful attention to its cost-effectiveness. If a utility manager is more cautious about entering into a hedge knowing that investors might be at some risk, that cautious stance may also provide more assurance that any hedges charged to ratepayers have been more carefully considered by the utility.

The assignment of some risk and reward creates an incentive for the utility to manage its hedging more cost-effectively. The Commission has repeatedly expressed support for mechanisms that provide an incentive for utilities to

---

19 See February 20, 2009 SoCalGas Comments at 4.

20 PG&E provided an illustrative analysis showing how customer tolerance for price variances provides a model for establishing hedging parameters, and no actual empirical study was presented.

manage costs effectively through exposure to risks as well as opportunities for rewards.[21]

In comments on the Proposed Decision, TURN states that it is more appropriate for the Commission--rather than utility managers--to determine appropriate customer risk preferences for SoCalGas hedging targets. In the alternative, TURN states that the Commission should set a minimum hedge target for SoCalGas, as TURN discusses in reference to the PG&E Settlement. TURN, however, offers no specific proposals as to customer risk preference parameters that could be used to determine Commission-mandated hedging targets for SoCalGas. TURN also offers no insights as to how to overcome the practical difficulties involved in producing a valid customer risk preference study which might form a basis for Commission-mandated risk preference parameters or hedging targets. Likewise, no other party has offered such evidence. Consequently, we find no basis for the adoption of a Commission-mandated hedging target for SoCalGas in this rulemaking. In any event, while we do not mandate specific hedging targets, we emphasize that SoCalGas continues to be responsible for managing its hedging program in a manner consistent with its ongoing obligation to provide reliable customer service at just and reasonable rates.

We recognize that that the results of hedging are, to some extent, outside of utility management control, but driven by market forces. Nonetheless, the utility can control certain aspects of its hedging strategy, such as formulating

---

[21] D.02-06-023, D.02-08-070, and D.04-01-047.

overall risk preference goals, integrating hedging with other means of mitigating risk, and adjusting hedging positions in response to changing conditions. The utility can exert control over the degree of risk relative to benefits by proper selection and management of hedging instruments. Assigning risk sharing incentives therefore will motivate the utility to do a better job of managing those aspects of hedging over which it does have some control.

6. Adopted Treatment of Hedging Incentives for Specific Utilities

Based on the general principles discussed above, we conclude that some sharing of risks and rewards from hedging transactions is appropriate for PG&E and SoCalGas. Because SWG relies on fixed price contracts, but does not actively engage in changing of hedging strategies, we do not impose any change on SWG's existing recovery mechanisms. We next turn to the adoption of specific amounts of risk sharing that should be applied with respect to hedging costs, starting with PG&E.

6.1. Adopted Treatment for PG&E

With respect to PG&E, we conclude that the Proposed Settlement offers a reasonable outcome, consistent with our determination that the utility should bear some financial consequences for hedging. We likewise conclude that the settlement's proposed risk sharing of hedging transactions is reasonable. We accordingly adopt the settlement for purposes of a hedging incentive policy for PG&E, as outlined below.

A motion for adoption of the Proposed Settlement was jointly filed on July 10, 2009, by DRA, TURN, and PG&E. The parties jointly filed a motion to file under seal a confidential unredacted version of the Proposed Settlement which describes detailed parameters of the proposed hedge program. We grant the motion to file the confidential version of the Proposed Settlement under seal, consistent with our past policy recognizing that customers' interests are protected by not disclosing confidential information that could compromise the effectiveness the utility's bargaining position in the procurement of gas.

6.1.1. Sponsoring Parties' Positions Based on the Proposed Settlement

The key provisions of the Proposed Settlement call for the following treatment of hedging transactions:

- 80% of net realized gains or losses and associated transaction costs will be included in the CPIM Commodity Benchmark. Net hedging losses (inclusive of net option premium outlays) are added to the Commodity Benchmark. Net hedgings gains (inclusive of net option premium outlays) are subtracted from the Commodity Benchmark.
- 100% of the net hedging realized gains or losses and associated transaction costs will be included in the Cost side of CPIM. Net hedging losses (inclusive of net option premium outlays) are added to the Costs. Net hedging gains (inclusive of net option premium outlays) are subtracted from the Costs.
- The CPIM sharing mechanism will be modified such that total shareholders earnings will be capped solely at 1.5 percent of annual gas commodity costs. The hard dollar cap of $25 million on shareholder gains is removed effective November 1, 2009.
- All other aspects of customer/shareholder sharing above and below the CPIM dead-band under the current CPIM mechanism remain the same.
- The winter hedge portfolio design and implementation is left to the discretion of PG&E.
- PG&E will have a combination of storage, physical fixed-price contracts, and financial instruments to cover the targeted core portfolio customer average forecast demand.

6.1.2. Other Parties' Responses to the Proposed Settlement

Shell and SoCalGas each filed a response to the Proposed Settlement. In its response to the Settlement, Shell expresses opposition, arguing that the Settlement fails to address or resolve most of the key issues in this proceeding. Shell argues that the Settlement would not mitigate gas price volatility, would not adequately balance risks and rewards between ratepayers and shareholders, and would not provide increased transparency regarding PG&E's hedge solicitation process.

Shell disputes sponsoring parties' claim that the Settlement will "ensure that PG&E [takes] proactive steps to mitigate gas rate volatility." (Joint Motion at 8.) Shell points to its proposal to establish a "portfolio price volatility target," expressed as a percentage of the utility's benchmark price volatility, as discussed above. Shell believes that the target must provide a meaningful opportunity for (and impose an enforceable obligation upon) PG&E to manage price risk and mitigate price volatility in its core portfolio.

Shell further argues that the Proposed Settlement exposes the shareholder to little or no risk based on the level of winter hedging likely to be undertaken and based on the operation of the CPIM. Shell provided calculations to show that even if PG&E hedged 70% of its winter core demand, PG&E shareholder exposure for hedging under the CPIM would be no more than $1.1 million. Shell believes this calculation likely overstates the risk exposure since it assumes extreme conditions in effect in the immediate aftermath of Hurricane Rita and

Katrina. Shell also notes PG&E's comments that allocating as much as 25% of the net costs of hedges to PG&E's CPIM would "not directly remedy the lack of alignment between customer and shareholder interests."[22]

SCE also filed a response to the Settlement. SCE continues to disagree conceptually with the treatment of hedging in the Proposed Settlement. SCE does not oppose the Settlement, however, as long as the Commission is clear that the provisions of the Settlement do not apply to any other gas utility. Because SCE does not interact in PG&E's service territory in a significant way, SCE does not believe it would be directly affected by the Settlement. Conceptually, however, SCE continues to believe that hedging and gas cost minimization (which is the current objective of the procurement incentive mechanism) constitute different and potentially contradictory objectives. SCE believes that combining these functions within a single incentive mechanism could produce unintended conflicts of interest.

6.1.3. Discussion

Under Rule 12.1(d) of the Commission's Rules of Practice and Procedure, we will not approve settlements, whether contested or not, unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest. In reviewing a settlement, we consider individual provisions, but we do not base our conclusion on whether an isolated provision is, in and of itself, the optimal outcome. Instead, we determine whether the settlement, as a

---

[22] See PG&E comments filed February 20, 2009, on a Ruling Soliciting Further Information Regarding Hedging Issues," at p. 5.

whole, is in the public interest. Since the Proposed Settlement here is not sponsored by all parties, we also weigh objections or concerns raised by other parties.

In this rulemaking, our responsibility is to establish policy in a manner that serves the public interest. As the starting point for evaluating the PG&E Settlement, we are guided by an overarching responsibility to establish policies that promote the public interest. In considering the Settlement, therefore, we must determine whether it represents the broad public interests. In this regard, we note that the parties sponsoring the Settlement include not just a utility, but also DRA and TURN, both of whom represent the interests of core ratepayers.

In reviewing the Settlement, we also look to prior precedents. In D.88-12-083 for example, we approved a settlement proposed by PG&E and Commission staff that resolved issues relating to the Diablo Canyon Nuclear Power Plant that was vigorously opposed by other parties.[23] In that instance, the Commission stated that in a settlement affecting all PG&E customers, the factors used by the courts in approving class action settlements provided appropriate criteria for evaluating the Diablo Canyon settlement. The Commission stated:

> …When a class action settlement is submitted for approval, the role of the court is to hold a hearing on the fairness of the proposed settlement…
>
> In order to determine whether the settlement is fair, adequate, and reasonable, the court will balance various factors which may include some or all of the following: the strength of applicant's

---

[23] *Re Pacific Gas and Electric Company* (1988) D.88-12-083, 30 CPUC2d 189 ("*Diablo Canyon*").

> case; the risk, expense, complexity, and likely duration of further litigation; the amount offered in settlement; the extent to which discovery has been completed so that the opposing parties can gauge the strength and weakness of all parties; the stage of the proceedings; the experience and views of counsel; the presence of a governmental participant; and the reaction of class members to the proposed settlement. [Citations omitted.] In addition, other factors to consider are whether the settlement negotiations were at arm's length and without collusion; whether the major issues are addressed in the settlement; whether segments of the class are treated differently in the settlement; and the adequacy of representation. [Citations omitted.][24]

We apply similar principles in reviewing and approving the Proposed Settlement here. We will only approve the settlement if it assists us in carrying out our responsibility to resolve the identified issues in a manner that best serves the public interest.

We conclude that the Proposed Settlement is reasonable in light of the record as a whole, resulting in an outcome that holds the utility financially responsible for the consequences of its hedging activities, but limits the extent of investor risk exposure. The balanced outcome in the Settlement is consistent with our general analysis of the relevant goals, constraints, and considerations that guide our policies relating to cost recovery and incentive treatment for hedging. The compromise reached in the Settlement strikes a reasonable balance, providing some incentive to hedge prudently while also avoiding the

---

[24] *Id.* at 222.

risk of large losses that could act as a disincentive to hedge at levels warranted to protect the ratepayer.

Under the terms of the Settlement, PG&E will no longer be required to seek formal Commission approval of its hedging plans, but must report to DRA and TURN on the total amount of hedge coverage in accordance with Section C.3 of the Settlement.

We are not persuaded by the objections raised by Shell in its opposition. Shell contends that nothing in the Settlement requires PG&E to reduce its gas price volatility, and does not make PG&E accountable for mitigating customer exposure to gas price volatility. Shell contends that the Settlement appears to enable PG&E to replicate the hedging approach that it undertook in all of its winter hedging plans since 2005, and does not impose an enforceable obligation upon PG&E to reduce price volatility.

In criticizing the Settlement, however, Shell does not give due recognition to the risk sharing effects of the Settlement in providing an incentive for PG&E to manage its hedging program more effectively than it has in the past. The incentive mechanism rewards PG&E if hedges produce positive results and requires PG&E to share in losses if hedges produce negative results. To this extent, the interests of ratepayers and shareholders are aligned.

Shell is correct that the Settlement does not impose a specific volatility target for PG&E to meet. But by relying on financial incentives to encourage sound management, it is not necessary to mandate a specific volatility target. Moreover, no party in the proceeding, including Shell, provided empirical analysis to quantify a specific volatility target figure for PG&E. Accordingly, the Settlement provides a workable solution that does not require picking some mandated figure as a volatility target.

Shell also argues that the level of risk exposure in the Settlement is not sufficient to impose added accountability on PG&E with respect to its hedging activities. We disagree. We conclude the proposed risk sharing balances the offsetting considerations of avoiding an excessive risk of loss so as to create a disincentive to hedge, while maintaining some degree of accountability for hedging results.

The Proposed Settlement, by its own terms, was to apply to winter hedge transactions executed by PG&E on or after November 1, 2009, for CPIM years beginning on or after November 1, 2010. Since this order will take effect subsequent to November 1, 2009, we adopt the Settlement, amended to apply to winter hedge transactions executed beginning on the effective date of this decision. In other respects, the term and notice provisions of the Settlement will apply, as set forth in Section C thereof, for an initial period of seven years, with a possible extension for two more years.

6.2. Adopted Treatment for SoCalGas/SDG&E

For SoCalGas/SDG&E,[25] we adopt an incentive treatment for hedging that is not based on the Settlement, but rather is based on the record apart from the Settlement. As discussed in Section 5 above, we conclude that some degree of risk sharing is warranted for SoCalGas hedging. The record in the proceeding, apart from the Settlement, supports certain common principles that apply to SoCalGas' incentives as well as to those of PG&E. Thus, while we adopt somewhat different measures for SoCalGas, in terms of the specific sharing of

---

[25] References to SoCalGas also include applicability to SDG&E by implication.

hedging risks and benefits compared with PG&E, we conclude that similar general considerations apply to both PG&E and SoCalGas with respect to the treatment of incentives.

As with PG&E, we conclude that some level of financial accountability should apply to SoCalGas for the consequences of its hedging. At the same time, we conclude that placing all hedging costs and gains within the GCIM could expose the investor to excessive risk, as illustrated in the calculations below.

The following tabulation shows the effects on the GCIM reward of including versus excluding winter hedging costs and gains from the GCIM based on hedging costs over the period from 2002-2003 through 2007-2008:

GCIM Year	Annual Period	SoCalGas Total Annual Hedging Costs Included[26]	SoCalGas Winter Hedging Costs Excluded (Nov-Mar)	SoCalGas Recorded Rewards	SoCalGas Rewards if all Winter Hedging Costs Included
9	2002-2003	$6,081,264		$6,318,811	
10	2003-2004	$9,962,197		$2,364,577	
11	2004-2005	$4,986,226		$2,508,339	
12	2005-2006		$24,569,211	$9,803,589	$3,661,287
13	2006-2007		$21,438,774	$8,953,993	$3,594,300
14	2007-2008		$19,968,928	$6,521,684	$1,529,452

These hypothetical calculations illustrate how the GCIM reward would have been impacted if all SoCalGas hedging costs had been included within the GCIM after 2005.[27] We conclude that utility investors' risk exposure should be limited to avoid creating an undue disincentive to hedge at an appropriate level for core ratepayers. Under the current process, however, there is no affirmative financial incentive to hedge at an appropriate level, and to make sure that hedging is neither too limited nor excessively costly.

---

[26] As reported in SoCalGas' annual GCIM proceeding, Application (A.) 03-06-021, A.04-06-025, and A.05-06-030, respectively.

[27] The calculations are based on costs actually incurred, without speculating as to how utility hedging behavior may have changed if different incentives had applied.

Although the utilities oppose bearing any risk associated with hedging, the fact remains that hedging costs were included in the GCIM/CPIM prior to 2005. Even though hedging costs were at a more modest level then, the utilities did engage in some hedging, and bore a shared of the risks and rewards of hedging. Yet, no utility has claimed that the hedges executed before 2005 were imprudent as a result of a perceived disincentive to hedge. Including hedging costs within the incentive mechanisms did not lead the utilities to refrain from hedging at all.

SoCalGas' categorical opposition to sharing any gains or losses from winter hedging as an incentive to promote better performance is also at odds with other statements extolling the merits of incentives. In the omnibus gas proceeding (A.06-08-026), SoCalGas argued that an incentive mechanism can make a difference in how well the utility manages. In seeking approval of an incentive award for interruptible access charge revenue, SoCalGas argued that without a financial incentive, utility employees would not apply "the same level of vigor and innovation" in the marketing, discounting, and promoting interruptible access rights.[28] We believe that in the case of gas hedging, the utility is likely to pursue more vigor and innovation if there are financial consequences resulting from how well the hedging program is managed.

The policy of insulating the investor from 100% of winter hedging gains and losses was adopted in response to specific short-term risks of price spikes in view of Hurricane Katrina and Rita. While markets continue to be subject to

---

[28] See D.07-12-019, *mimeo.* at 88.

future uncertainty, the specific market conditions today are different than in 2005 when we modified the GCIM/CPIM to exclude winter hedging. At that time, the concern was to protect ratepayers from rapidly escalating natural gas prices as a result of temporary supply disruptions caused by Hurricane Katrina. Over time, however, natural gas prices can move dramatically downward as well as upward, or may remain flat. We acknowledge the utilities' concerns regarding the need to limit investor risks while allowing flexibility to hedge sufficiently to protect ratepayers. On the other hand, the treatment of winter hedging plans, and their associated gains and losses, adopted since 2005 in anticipation of potentially extreme short-term price spikes is not necessarily suitable for purposes of a more lasting approach for promoting appropriate hedging.

We conclude that an appropriate incentive should be provided by holding SoCalGas financially responsible for some share of its hedging activities. Identifying an appropriate share of hedging risk and reward requires some degree of judgment, as there is no bright line test that can precisely delineate an exact allocation which is optimal. Previously in R.04-01-025 proceeding where we considered how to allocate hedging plan risks for the 2006-2007 winter season, DRA had suggested an allocation of risk whereby 25% of each utility's hedges would be included in its procurement incentive mechanism, with the remaining 75% to be allocated outside of the incentive mechanism. While declining to adopt such an approach for the 2006-2007 winter season due to an insufficient record, the Commission noted that this alternative may deserve additional consideration in the design of a permanent hedging ratemaking mechanism for the treatment of hedging plans.[29]

In this proceeding, we have now given additional consideration to this alternative. By ALJ Ruling dated January 15, 2009, parties were directed to address the potential impacts of including 25% of hedging transactions within the procurement incentive mechanism, with ratepayers bearing the remainder. In consideration of the record developed on this issue, including 25% of hedging costs and gains within the GCIM is a reasonable incentive approach for purposes of SoCalGas.

SoCalGas produced calculations showing how the GCIM would have been impacted if theoretically a maximum of 25% of winter hedging transactions had been included within the GCIM over the three years of 2005-2006 through 2007-2008.[30] SoCalGas calculated that shareholder awards would have been impacted as follows:

[29] See D.06-08-027 at 15.

[30] See SoCalGas Comments dated February 20, 2009, Attachment B, reproduced in Appendix B of this Decision. SoCalGas produced these calculations in response to the ALJ Ruling dated January 15, 2009. As noted by SoCalGas, the calculations do not consider how hedging strategies and outcomes might have been affected if the revised risk sharing had applied at the time.

Annual Period	Hedging Gain ($ in Millions) (Loss)	GCIM Award ($ in Millions) Reduction
2005-2006	($24.6)	($1.54)
2006-2007	($21.4)	($1.34)
2007-2008	($20.0)	($1.25)
Cumulative Total		($4.13)

For SDG&E, the totals are:

Annual Period	Hedging Gain ($ in Millions) (Loss)	GCIM Award ($ in Millions) Reduction
2005-2006	($6.8)	($0.4)
2006-2007	($23.0)	($0.8)
2007-2008	($3.5)	($0.2)
Cumulative Total		($1.4)

These calculations illustrate that although a 25% share of hedging costs are included in the GCIM, the actual reduction in the GGIM award would be more modest.

Depending on market conditions over time, however, any actual losses would vary, and the investor could also experience hedging gains in some years. In the interest of caution, however, we conclude that investors should not be placed at risk for the effects of including 100% of hedging costs in the GCIM. As noted above, exposing the investor to excessive levels of risk for hedging could act as a disincentive to hedge at levels needed to protect customers. At the same time, however, for the reasons discussed above, we are not inclined to continue to shield the investor from 100% of the risks resulting from winter hedging.

We conclude that 25% of hedging costs and gains represents a reasonable share of hedging transactions to include in the GCIM. The resulting impacts on investor risk should be modest enough to avoid potential disincentives to hedge at appropriate levels, but sufficient to encourage cost-effective management of hedges. The tolerance bands within the GCIM serve to mitigate the investor's risk exposure, in conjunction with the utilities own discretionary decision whether and to what extent to undertake any hedging.

We thus shall adopt a 25% allocation of winter hedges to the GCIM to replace the current regulatory policy of assigning 0% of winter hedging gains and losses to utility investors. The percentage allocation of each hedge instrument shall be applied in a consistent manner. This requirement will preclude the selective allocation of high-risk hedge instruments differently than lower risk instruments.

Without bearing any risk, the utility investor is financially indifferent to the success or failure of the hedging program, whereas the ratepayer has a significant financial stake in the program. Assigning a uniform 25% share of such gains/losses and improving/offsetting savings to the GCIM provides a reasonable balancing of ratepayer and shareholder interests.

We recognize that our adopted approach does not produce a precise matching of investor allocation of costs or benefits of hedging with the quality of utility management of hedging. Depending on market conditions, the utility may receive hedging gains as a result of external events over which it has little or no control. Likewise, the utility may absorb added costs as a result of hedging losses where market prices decline unexpectedly. Nonetheless, the sharing of risks and gains will provide some level of heightened motivation for the utility manager to devote more resources to effective management of hedges over time. Moreover, our adopted approach has the advantage of simplicity and ease of administration. The proposals for index-specific hedging incentive mechanisms, as discussed above, lack this advantage.

SoCalGas proposes certain administrative modifications to help streamline the existing application process, specifically: (1) preauthorization to file winter hedging plans under seal; (2) adoption of a standardized protective order for winter hedging plans; (3) adoption of standardized deadlines for winter hedge applications, responses, and prehearing conferences (if needed); and (4) adoption of procedures that would enable utilities to proceed with their applications earlier, such a true-up to reflect March 31 storage levels and natural gas prices, and other relevant conditions. Since we will be relying upon the incentive mechanism to motivate the utility to manage its hedge program in a cost-effective manner, we will no longer require SoCalGas to file annual applications for Commission approval of a hedging plan. We shall, however, require SoCalGas to continue existing practices in providing ongoing hedging transaction information to DRA, TURN, and the Energy Division. All future winter hedging transactions executed by SoCalGas shall be subject to DRA monitoring and review within the GCIM through the same process applied to other transactions under the GCIM, consistent with existing DRA audit and report procedures. SoCalGas shall cooperate fully with DRA's review process.

6.3. Treatment for SWG

SWG's GCIM is a relatively new program. SWG's hedging activities were integrated into its GCIM upon its inception. Because of its use of storage assets and the modest size of its market, SWG's hedging is comprised of volumelimited purchases of physical, fixed-price supplies. In the GCM, the cost of these supplies is passed through to customers without any incentives or penalties. After a vetting with the DRA, the hedged volumes were established at a percentage of forecasted annual demand. SWG acquires these volumes through a regimented program over time for each annual period.

SWG opposes any revision that would assign a share of hedging gains or losses to investors. SWG supports continuation of the existing program of assigning all hedging gains/losses to ratepayers. SWG suggests a revision to its GCIM and hedging program to include the use of fixed-for-floating index swaps. SWG also suggests reexamining the percentage of its purchases currently included in its hedging program. SWG believes that it may be desirable to increase the hedged percentage to somewhere between 25 and 50% to align with hedging activities in its Arizona and Nevada jurisdictions where about 50% of the portfolio is hedged.

DRA opposes the changes suggested by SWG, arguing they are beyond the stated scope of the Order Instituting Rulemaking (OIR). The OIR states, "This rulemaking is not intended to be a broad reexamination of the utilities' gas incentive mechanisms. Each year these incentive mechanisms go through an application process where there is an opportunity to propose modifications."[31] DRA argues that SWG's proposed changes should be developed and addressed in an appropriate proceeding, but they are not within the scope of this rulemaking.

---

[31] See OIR at 22-23.

Given the fact that the SWG's GCIM is relatively new and its hedging is limited to utilization of fixed price contracts, we find no need to change the SWG incentive mechanism at this time. We agree with DRA that changes in SWG's California program to include the use of index swaps or to mandate the amount of hedging to be utilized are issues beyond the scope of this proceeding. Such changes do not relate to the issue of incentives that should be adopted to motivate effective management of hedges.

7. Fixed Price Tariff Option to Reduce Price Volatility

As an alternative way to providing customers with price volatility protection, another possible proposal discussed by parties was to develop a fixed price tariff that could be offered on an optional basis. A version of this concept had previously been offered by SoCalGas over 10 years ago in A.96-03-060. The Commission issued D.96-08-037 which remanded SoCalGas' proposed fixed price option and a related level pay plan to the assigned ALJ for further proceedings. In D.97-04-029, the Commission approved the level pay plan but rejected SoCalGas' proposed fixed price plan.

Under its original proposal, SoCalGas would conduct a quarterly pre-registration process to determine the likely level of hedges needed to be purchased, and then set a proposed fixed price for customers (based on one of three load variability patterns). Customers would then have 48 hours to accept the proposed load-specific rate for the succeeding 12 months. Any usage over

150% of the customer's peak consumption month for the previous 24-month period would be billed at standard tariff rates.[32]

Although that proposal for a fixed price plan was rejected by the Commission, DRA suggested that a similar approach could possibly be reconsidered, allowing customers to choose among pricing plans based on their own risk preference. The previous proposal caused concern that the utilities would profit from a higher fixed price. The proposal would have offered the choice initially for commercial customers. DRA suggested that a revised version of the earlier proposal now could include a different portfolio for different customers.

SoCalGas acknowledges the theoretical appeal of an optional tariff program that allows customers a choice of payment options. Customers who value the stability offered by hedging could receive it; while customers who do not place the same value on price stability would not be required to pay for hedging. SoCalGas states that it would not be opposed to proposing a revised fixed-price option via advice letter filing, application, or in a later phase of this proceeding, but expresses certain caveats regarding such an approach.

SoCalGas raises concerns as to the logistics of establishing a quarterly pre-registration process and accepting elections from its 6.3 million core residential customers. SoCalGas believes that the logistical challenges of such an undertaking would be much greater than the challenges anticipated in the 1996 version of the proposal. SoCalGas also raises concerns as to the potential for

---

32 See D.97-04-029, *mimeo*. at 2-3.

increased customer service staffing that would be needed to run the program, and whether charging customers for the increased staffing would make the costs of such a program unattractive to customers.

SoCalGas also questions whether a fixed price program really offers much more benefit to customers than is already available through its tariff option known as the "Level Pay Plan" (LPP) which is available to its residential and master-meter core customers and smaller C&I customers. Under the LPP, monthly gas bills are calculated based on forecasted average annual consumption and costs over a 12-month period, with billing adjustments every six months to minimize the accumulation of large variances between the amounts billed versus owed. The LPP averaging process is intended to enable core customers to smooth out the variations between monthly gas bills.

SoCalGas contends that for the vast majority of its core customers, bill stability which is already available through the LPP, may be much more important than the ability to fix a commodity price for a particular period of time, such as 12 months. Yet, less than 5% of SoCalGas customers currently avail themselves of the LPP. SoCalGas believes, however, that the availability of the LPP could be emphasized even more than is already being done.

Customers' interest in paying for a fixed price option also would depend upon how much of a premium such fixed price protection would cost. SoCalGas observes that forward natural gas premiums can be substantial. For example, as of February 20, 2009, NYMEX prices for March 2010 were trading at a 45% premium to March 2009 NYMEX prices.

DRA questioned the goals of the hedging programs, and suggested that retail bill volatility can be addressed through the utilities' tariff option such as the LPP noted above.

7.1. Discussion

We conclude that the concept of an optional fixed price tariff raises more questions than it resolves, and the potential difficulties with implementing such an option outweigh its potential advantages. Among the issues raised by the fixed price tariff option are: (1) what conditions a customer would have to meet to qualify for this option (e.g., minimum term commitment), (2) effects on customers' ability to switch to core aggregation, (3) estimating the separate demand for different portfolio risk characteristics, and (4) Commission oversight requirements, etc. Moreover, this option would still leave unresolved the question of what level of hedging is appropriate for the fixed price portfolio, and what degree of price risk would be appropriate for customers.

We agree that some of the benefits of a fixed price tariff may be realized through the existing LPP billing plan. Increased efforts toward making customers aware of the availability of the LPP plan may be helpful in maximizing the potential usefulness of this program as a tool in mitigating volatility in customers' bills.

We further conclude, however, that the LPP does not substitute for the potential protections and benefits of price stability available through an effective hedging program. The LPP is merely a means of deferring the timing of a core customer's retail bill payment, but has no effect on mitigating the volatility of the underlying supply portfolio costs, themselves. Therefore we conclude that an effective hedging program is still of value, as part of a broader program which can include the LPP option.

8. Comments on the Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311 and Rule 14.2(a) of the Commission's

Rules of Practice and Procedure. Comments were filed on January 11, 2010 and reply comments were filed on January 19, 2010. We have considered the comments in finalizing this decision.

9. Assignment of Proceeding

John A. Bohn is the assigned Commissioner and Thomas R. Pulsifer is the assigned ALJ.

Findings of Fact

1. Financial hedging is a form of price insurance that, when managed properly, can provide a degree of protection to core customers from excessive natural gas price volatility.

2. By moderating the volatility in gas prices, financial hedging can help promote the goal of reliable gas supplies at a reasonable cost, consistent with the Commission's Energy Action Plan.

3. Managing a successful hedging strategy for the benefit of core customers is a complex undertaking. Insufficient hedging may expose customers to risks of price spikes, whereas excessive hedging may not be cost-effective relative to any perceived benefits realized.

4. Rather than a Commission-mandated program for hedging, the most effective regulatory treatment of hedging is to leave hedging strategies to the expertise of the utility, but also incorporate a system of incentives to hold the utility financially accountable for its decisions.

5. The extent to which a hedging program should be implemented depends, in part, on core customer risk preferences, and the cost and terms of hedges in relation to the degree of price volatility protection desired by customers.

6. Parties did not provide empirical evidence in this proceeding to quantify core customers' risk preferences in relation to the cost of hedging.

7. Prior to 2005, utility costs and offsetting benefits from financial hedges were shared between customers and investors, along with commodity costs, as part of the utility gas procurement incentive mechanism.

8. Beginning in 2005, the gas utilities substantially increased their use of hedging in response to severe natural gas supply disruptions which had a major adverse impact on natural gas markets, contributing to significant volatility in the price of natural gas.

9. The Commission adopted modifications to the utilities' gas cost incentive mechanisms beginning in 2005, to exclude all losses and gains relating to winter hedging, in order to encourage a significant expansion in the utilities' winter-season hedging compared with prior years. Consequently, core customers were assigned 100% of both the risks and payouts associated with winter hedges.

10. By assigning all risks and benefits of winter hedging to core customers, the Commission sought to eliminate disincentives for the utility to hedge in view of investor risk. Insufficient hedging could leave core customers unprotected against potential price spikes.

11. The Commission has continued to exclude all winter hedging costs and payouts from the utility gas cost procurement incentive mechanisms, recognizing that the merits of continuing such treatment as a policy matter would be examined in this rulemaking.

12. With all costs and benefits of hedging excluded from the gas cost incentive mechanisms, the utility receives no financial reward for superior performance of its hedge program, and incurs no financial loss as a result of ineffective management of its hedge program.

13. Insulating utility investors from all risks of winter hedging programs without accountability does not promote the proper incentives for vigorous and innovative management of hedging.

14. The goal of hedging is to limit the volatility of wholesale gas cost procured by the utility, which is different than the goal of minimizing overall gas commodity costs. These goals are complimentary, and can be harmonized over time to seek to minimize overall gas costs consistent with properly defined customer risk preferences.

15. Although the results of hedging are to a significant extent, outside of utility management control, the utility can control certain aspects of its hedging strategy, such as assessing overall risk preferences, selecting appropriate hedging instruments, integrating hedging with other means of mitigating risk, and adjusting its hedging positions in response to changing conditions.

16. To the extent that hedging results are partially within management control, the sharing of risks and rewards from hedging can help to enhance the utility's motivation to manage its hedging program in a cost-effective manner.

17. The potential complexity involved in the proper design, tracking, and verification of a separate index mechanism outweighs any advantages in improving the utility's hedging performance. For the Commission to engage in the sort of detailed oversight entailed in designing and monitoring such a mechanism would not be an efficient use of resources.

18. PG&E entered into a Settlement Agreement with DRA and TURN, with the provisions incorporated in Appendix A of this decision. The Settlement would place a portion of hedging transactions at risk through inclusion in the CPIM, with the remaining hedging costs or gains assigned to core customers.

19. The Settlement Agreement maintains the integrity of the CPIM while providing an incentive to minimize costs.

20. The Settlement is reasonable in light of the record as a whole, resulting in an outcome that holds the utility financially responsible for the consequences of its hedging activities, but limits the extent of investor risk exposure.

Conclusions of Law

1. The Proposed Settlement entered into by PG&E, DRA, and TURN is reasonable in light of the whole record, consistent with the law, and in the public interest.

2. The Settlement is consistent with the relevant goals, constraints, and considerations that guide Commission policies relating to cost recovery and incentive treatment for hedging.

3. Although the Proposed Settlement was contested, no objections were raised which justify a denial of the settlement.

4. The sharing of hedging gains and losses as proposed in the PG&E Settlement provides a reasonable balance between the goals of holding the utility financially responsible for its hedging activities while limiting potential investor risks to avoid creating a disincentive to hedge at levels appropriate to protect ratepayers.

5. The utility should not be placed in a position where the purchasing of hedging instruments to protect core customers could result in large financial penalties for utility shareholders. Correspondingly, the utility should not be insulated from all financial consequences of its hedging program.

6. Since the Proposed Settlement only applies to PG&E, the Settlement does not provide a basis for adopting conditions on the treatment of hedging costs for any other utility.

7. The record in the proceeding, apart from the Settlement, supports certain common principles that apply to SoCalGas as well as to PG&E, and similar general considerations apply to both PG&E and SoCalGas with respect to incentives for hedging.

8. The record in this proceeding supports holding SoCalGas/SDG&E financially responsible for some share of winter hedging transactions while placing reasonable limits on the maximum risk exposure.

9. Placing SoCalGas/SDG&E at risk by inclusion of 25% of all winter hedging transactions within the GCIM would provide an incentive to manage hedging in a cost-effective manner, while avoiding excessive investor risks that could otherwise create a disincentive to hedge at an appropriate level.

10. The existing SWG incentive program does not warrant any change at this time since the SWG's GCIM is relatively new, and SWG currently only utilizes long-term contracts to mitigate price swings. A change in the incentive risk sharing percentage would not have a significant effect on SWG current practices to manage price risk.

11. The concept of an optional fixed price tariff raises more questions than it resolves, and the potential difficulties with implementing such an option outweigh its potential advantages.

12. The new provisions for the treatment of hedging transactions adopted in this decision shall take effect immediately.

O R D E R

IT IS ORDERED that:

1. The Proposed Settlement, incorporated as set forth in Appendix A of this decision, is hereby approved. The motion to file under seal the confidential

version of the Proposed Settlement is granted. The provisions of the Settlement shall apply solely to Pacific Gas and Electric Company.

2. Pacific Gas and Electric Company shall modify its treatment of net realized gains and losses in accordance with the provisions of the adopted Settlement.

3. The requirement for Pacific Gas and Electric Company to seek formal Commission authority for annual hedge plans is discontinued, but Pacific Gas and Electric Company shall continue to apprise the Division of Ratepayer Advocates and The Utility Reform Network of its hedge plans in accordance with Section C.3 of the Settlement.

4. The treatment of the net hedging gains, losses, and benefits attributable to the Southern California Gas Company/San Diego Gas & Electric Company winter hedging program is hereby modified as follows: A ratio of 25% of all winter hedging net gains and losses attributable to that winter hedging program shall be included within the Gas Cost Incentive Mechanism. The remaining 75% of winter hedging gains and losses attributable to the winter hedging program shall be directly allocated to core customers. The remaining structure of the Gas Cost Incentive Mechanism will continue in place.

5. Southern California Gas Company/San Diego Gas & Electric Company will no longer be required to seek formal Commission approval of annual hedge plans, but must continue to follow existing requirements to apprise Division of Ratepayer Advocates, The Utility Reform Network, and the Energy Division of its hedging activities.

6. All future winter hedging transactions executed by Southern California Gas Company/San Diego Gas & Electric Company shall be subject to Division of Ratepayer Advocates monitoring and review within the Gas Cost Incentive Mechanism through the same process applied to other transactions under the

Gas Cost Incentive Mechanism, consistent with existing Division of Ratepayer Advocate audit and report procedures. Southern California Gas Company shall cooperate fully with the Division of Ratepayer Advocate's review process.

7. No change shall be made in the existing treatment of the Southwest Gas Corporation program to control the volatility of natural gas costs.

8. The proposals of Shell Energy North America for modifications in the program for natural gas hedging shall not be adopted.

9. Rulemaking 08-06-025 is closed.

This order is effective today.

Dated January 21, 2010, in San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
Commissioners