JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the 2009 Integrated Energy Policy Report Natural Gas Procurement by Utilities	Docket No. 09-IEP-1J

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ORIGINAL

Reported by:
Peter Petty
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COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, IEPR Committee; Electricity and Natural Gas Committee

James Boyd, Vice Chairperson, Associate Member, IEPR Committee; Electricity and Natural Gas Committee

ADVISORS and STAFF PRESENT

Susan Brown, Advisor

Suzanne Korosec

Ruben Tavares

Lana Wong

ALSO PRESENT

Katie Elder
RW Beck

Herb Emmrich, Southern California Gas Company, San Diego Gas and Electric

Pam Taheri
Sacramento Municipal Utility District

Laird Dyer
Shell Energy North America

Marshall Clark
Natural Gas Services
Department of General Services

John Armato
Patrick Fox
Pacific Gas and Electric Company

Richard Meyers (via teleconference)
California Public Utilities Commission

Ray Welch
Navigant Consulting

ALSO PRESENT

Wendy Al-Mukda (via teleconference)

I N D E X

P R O C E E D I N G S

9:05 a.m.

MS. KOROSEC: Good morning. This is a joint workshop of the Energy Commission's Electricity and Natural Gas Committee and the Integrated Energy Policy Report Committee to look at the impacts of market prices on natural gas utilities' customers and ratepayers.

I'm Suzanne Korosec and I'm the lead for the Energy Commission's Integrated Energy Policy Report unit. As part of the IEPR, every two years the Energy Commission assesses California's natural gas system including supply, demand, prices and infrastructure.

In 2008 we saw very high natural gas prices, which have since dropped very dramatically. And as part of the natural gas analysis in the 2009 IEPR, the Energy Commission needs to better understand the impacts of this volatility.

Just a few housekeeping items before we get started. Restrooms are out the double doors and to your left. There's a snack room on the second floor at the top of the stairs in the atrium under the white awning.

And if there's an emergency and we need to evacuate the building for any reason, please follow the staff out to the Roosevelt Park across the street and wait there for the all-clear signal.

Today's workshop is being webcast. And for those listening in who wish to speak during the public comment period, the call-in number is 888-566-5914, and the passcode is IEPR.

I also want to remind parties that written comments are due by 5:00 p.m. on March 18th. Those can be submitted using the procedure that's in the workshop notice. Copies of that are available in the foyer out in the hall, and also online on our website.

So, with that I'll turn it over to Commissioner Byron and Commissioner Boyd for any opening comments.

PRESIDING MEMBER BYRON: Thank you, Ms. Korosec. Good morning, everyone. I'm Jeff Byron, and with me is Commissioner Boyd. And since we are both members of the Natural Gas and Electricity Committee, and the IEPR Committee, it makes it easy for us to hold a joint Committee workshop with ourselves.

Thank you all very much for coming today. I'm looking forward to hearing more about this, after having read a number of the presentations and delving into this issue a little bit more.

I think our plan is to go to about noon today. And I may need to step out at 11:00 for a few minutes.

Commissioner Boyd, any comments?

ASSOCIATE MEMBER BOYD: Thank you, Commissioner Byron. No, just that I look forward to the discussion today. I'm reflecting back on how many years I've been associated with the natural gas question in California, all the way back to the electricity crisis of yesteryear. And it's been an interesting subject, to say the least, but one that has fared better for us, as a state, than certainly electricity did.

So, hopefully we'll hear that the 2008 price escapade was a little anomaly, and we'll get back to more or less a civil and normal gas market in California, bolstered by the good practices of our gas procuring industries. And buoyed by the fact that we're moderately rich in storage, which has always provided a decent hedge for us in the state.

So, thank you, and look forward to what goes on. And I'll tough it out here when you step out of the room. Thank you.

MS. KOROSEC: All right, Ruben, I'll turn it over to you then.

MR. TAVARES: Good morning, Commissioners; good morning, everybody. My name is Ruben Tavares and I'm part of the staff of the Energy Commission.

March 10, 1999, exactly ten years ago, the price of natural gas on the Henry Hub was listed as $1.94 per mmBtu. A year later, 2000, it had increased to $2.76, again, March 10, 2000.

Two years later, March 10, 2001, it was selling on the spot market at $5.12 per mmBtu. However, by March 2002 it was down again in the $2.80 per mmBtu.

Since 2002, with a few exceptions, prices have climbed steadily to the $4, $5, $6 and $7 per mmBtu. More recently, over last year, natural gas price increase from $7 per mmBtu in early January 2008 to over $13 in July of the same year, last year. Since then prices have declined steadily and they are under the $4 per mmBtu today.

What would this volatility in natural gas prices mean for California consumers? Californians consume approximately 6.5 billion cubic feet of natural gas a day, or approximately 2.5 trillion cubic feet a year.

If we were to purchase all the gas at $4 per mmBtu it would cost consumers approximately $9.5 billion a year. At $7 per mmBtu the cost would increase to $16.5 billion. And at $13 per mmBtu it will cost a staggering $31 billion.

However, utilities and noncore customers do not purchase all their gas needs at one price. They procure gas at different prices through the year.

The purpose of this workshop is to learn how utilities and other state entities procure natural gas for core and noncore customers. Will the daily fluctuation in natural gas price affect those customer bills?

For this purpose today we have a series of presentations and a panel of experts to try to answer some of the questions. So, with that introduction, I would like to introduce Lana Wong. She is part of the staff of the Energy Commission, and she will make the first presentation. Lana.

MS. WONG: Hi, I'm Lana Wong with the Energy Commission. And I'm going to talk about the research that I did on how the utilities procure natural gas for their core residential customers.

And I've limited the research to core customers because the gas utilities have the responsibility to procure natural gas for their core customers while noncore customers typically procure their own natural gas. Plus the data was much more readily available on the core side of the business.

So last summer, a natural gas prices rose above $13 an mmBtu, the question was asked, what kind of exposure do customers have to these high natural gas prices.

There was some belief that customers may not be exposed to these high prices because they enter into long-term fixed-price contracts.

So I spoke with the CPUC, DRA and the gas utilities to try to get a sense of how the gas utilities procure natural gas. The message that I kept hearing was that, no, they don't enter into long-term fixed-price contracts. Those are a thing of the past.

That any long-term contract tends to be volume only, with prices tied to the index. And most purchases are short-term oriented. So that was the message that I kept hearing.

And then I looked at the details of the gas cost incentive mechanisms and the benchmark within the incentive mechanism. I found that that benchmark was short-term oriented; that it was tied to monthly and some daily indices. So I said, okay, there really is no incentive to enter into long-term fixed-price contracts.

So after getting that information I thought, okay, so what does the data show. So I pulled out data pertinent to California. So I pulled out PG&E's citygate and SoCal border average prices. And I looked at these indices, and I said, well, 2005 and 2008 you can see that we still had price spikes in those particular years similar to the Henry Hub prices that we just looked at. And I thought these indices could be viewed as a proxy for the benchmark.

So then the next step I focused on PG&E and SoCalGas, the two largest gas utilities. In April 2008 SoCalGas started to procure gas for San

Diego Gas and Electric. So I really just focused on PG&E and SoCalGas.

And so in this particular chart I said, well, really, the index, or PG&E's weighted average cost of gas is really tied to the index; that they tend to track one another very well. And the data is really highly correlated.

Then I also pulled out data for PG&E core procurement charge. And the procurement charge is the retail rate that is charged to customers. And it includes the weighted average cost of gas and other procurement-related fees.

And so when I looked at this, I said, okay, the procurement charge deviates more from the index. And when I looked at the details what I found is that, well, the procurement charge is an estimate, and eventually there's a true-up of actual cost to this estimate. And in subsequent months there may be costs that are rolled into the procurement charge due to under-collection or over-collection in the purchase gas account.

But, in general, when I looked at this data I said, really the procurement charge exhibits a similar price pattern and volatility as the index. So when we had prices spike in 2005 and 2008, the procurement charge moved right along with it.

So then to look at SoCalGas, I wasn't able to get the weighted average cost for SoCalGas. They consider that data confidential. But I was able to get their core procurement charge, and that was available on their website.

And so when I looked at this data, SoCalGas' procurement charge almost lays right on top of the SoCal border average bid week price. And so I said, to answer the original question, how are customers exposed to the prices in the market place, I just said, well, really in summary the prices and the volatility in the marketplace are passed on to customers. But the gas utilities do employ limited hedges.

And so as I've shown these charts to staff and our executive office, one of the often-heard comments was, hedging? what hedging?

So I know we have a number of speakers today who will talk about hedging and risk management activities. And that should help provide insight into those activities that are occurring at the utilities.

So that concludes my presentation. Are

there any questions?

(Pause.)

MR. TAVARES: Thank you very much, Lana. Next we have Herb Emmrich representing Southern California Gas and San Diego Gas and Electric. Henry.

ASSOCIATE MEMBER BOYD: While the speaker is coming to the microphone let me just point out to the audience, this is a workshop, this is not a formal hearing. The room is laid out with us sitting up here towering above you, but that's just a formality.

And I encourage you to ask questions or make any comments that you might want to make. We're trying to have a dialogue with all of you.

I would ask that if you have a question or comment that you just grab one of the microphones here in the front of the room and introduce yourself for the record.

But, again, this is not a formal hearing. This is a workshop and we'd like all the dialogue back and forth that you feel that you'd like to engage in. So, thank you.

MR. EMMRICH: Good morning, Commissioners and all the attendees here. My name is Herb Emmrich; I'm the Gas Demand Forecast Manager for Southern California Gas Company and San Diego Gas and Electric. We're the largest gas utility in the country serving over 6 million customers, and 1.3 million electric customers.

I tried to answer the questions that were given to us, to what extent are gas utilities and the ratepayers exposed to natural gas price structure issues. We have monthly pricing on the gas side, so core customers do experience that monthly price fluctuation as we set the commodity cost of gas for each month, based on the purchases and withdrawal from storage in the wintertime.

So, residential and core commercial industrial customers also have the option of signing up for level pay plan where they pay the same amount each month for their procurement bill. And they have a yearly true-up.

So if somebody wants to avoid the fluctuations month to month they can sign up for the level pay plan. And that's also available for core commercial customers that use less than 3000 therms per year.

The other option, of course, is core customers can go with an aggregator that will purchase the gas for them, according to their needs, if they want to have a fixed price portfolio or so on.

In addition, core ratepayer is also protected from most price spikes because we have a significant amount of storage and we do annual winter hedging, as approved by the CPUC.

SoCalGas has 75 bcf of storage for the core; 369 million cubic feet a day of injection; and over 2 bcf a day of withdrawal. We also have winter hedging of $2 per customer per month for the winter season.

And the positions we take on that are to make sure that customers don't experience the severe price spikes that we've had in the past. So we take options positions at a fairly high rate to protect the customers against that.

Currently SoCalGas and San Diego shareholders are not exposed to natural gas price fluctuations as long as the gas we purchase for core customers is no more than 2 percent above the benchmark that's established in the gas cost incentive mechanism. It's a monthly benchmark based on industry publications for the month.

What's important to us on this, it's a

known benchmark, so we know how we're going to be judging our purchases. And this aligns the utility shareholders' interest with the interests of the ratepayers. Also aligns us with the state's energy efficiency programs.

And this is a very important aspect of our incentive mechanism, that we're not exposed to the ups and downs of prices so that we can continue to support and fully implement all the energy efficiency programs that are so important for the state.

Just an example, 20 years ago the average core customer used about 800 therms a year. And all the energy efficiency programs, appliance standards, building standards have reduced that down to 500 therms. That's about a 35 percent reduction in usage. And we continue to strongly support all those energy efficiency programs.

I talk about storage and why is storage a hedge. If you look at this slide you see the purchases are flat. Every month we basically purchase the same amount of natural gas, about 1.1 bcf a day.

And if you look at the demand pattern,

the blue, in the summer the demand is around 650 to 700 million cubic feet a day. But in the wintertime it's much much higher.

So if you look at the little yellow bars, we inject gas in the summer months into storage to fill up that 79 bcf of storage. And we withdraw that gas in the wintertime when prices tend to be higher, mostly in December and January. So we avoid purchasing gas when the price is extremely high, to a large degree. About 35 percent of the winter demand is satisfied by storage withdrawals.

PRESIDING MEMBER BYRON: Mr. Emmrich, just if I may, a quick question. I mean this clearly is one of the abilities that we have in California that saves our bacon every year.

But, do any other states or regions have similar kind of storage capability as California?

MR. EMMRICH: Yes, you do. In the northern states you have extensive storage, especially in Michigan where it's extremely cold. And everywhere around the country you see that storage is added everywhere. Everybody's going into storage and doing what California has been a leader in.

PRESIDING MEMBER BYRON: Thank you.

MR. EMMRICH: We don't buy gas for noncore customers, but noncore customers can also take advantage of storage on our system. We have balancing services of 4.2 bcf. So during extreme price spikes, noncore customers can use storage that's in our system for balancing to avoid purchases during extreme price spikes.

We also have the unbundled storage program where on a transaction-based program that noncore customers have 47.9 bcf for storage Available to them that they can enter into contracts with SoCalGas, also to avoid having to have purchase gas when the price is extremely high.

We also reached an agreement with our customers on storage that we will be expanding storage by another 7 bcf in the next six years. Four bcf will go to the core and 3 bcf will go to the noncore. So this was a very good agreement, and all parties, including DRA and Edison, and all other noncore customers agreed to this proposal. And we will be expanding storage accordingly.

Noncore customers, of course, can hedge on their own. They can purchase their own gas through their own procurement department, or they can go with a marketer and purchase any kind of product that they want.

Or they can hedge it financially with NYMEX gas futures, options, puts, calls, whatever they want to do. They're free to do that. Or they can enter into contracts with producers to buy a fixed-price volume.

But generally the industry is about 70 to 80 percent based on monthly pricing. That's the standard in the industry.

PRESIDING MEMBER BYRON: So, does SoCalGas do any hedging on the NYMEX gas futures market?

MR. EMMRICH: Yes, we do hedging according to the approved plan that we negotiate with the CPUC with -- it includes TURN, it includes DRA and the energy division. And we get approval to hedge a certain amount of gas every winter. And that is outside of the gas cost incentive mechanism, so that we are -- the shareholders are not put at risk for that.

And the reason we did that is that we wanted to protect against extreme price spikes. It's not hedging done to moderate a monthly up and down. But if prices were to go to $15, $16, our customers will be protected against that.

PRESIDING MEMBER BYRON: So, if I may ask, last June when prices were up around the $14 range, about what percentage of your gas purchase was hedged out through NYMEX?

MR. EMMRICH: At that time -- we do not hedge in the summer, we only hedge in the winter.

PRESIDING MEMBER BYRON: I'm sorry, prior to that time how much was hedged? In other words, how much exposure did you have for those high prices?

MR. EMMRICH: We had full exposure at that time.

The other way that we hedge is that we have contracts with interstate pipelines all the way back to the basin. So if there are constraints on the pipeline system, we avoid that by having contracts on Transwestern, El Paso and Kern River, and also going into the Canadian -- western Canadian basin so that we avoid any constraints that might happen at the border.

And it also gives us an opportunity to diversify our purchases. And we have access to the very low cost Rockies Basin. We've increased that quite a bit in the last few years. And also to the San Juan Basin on El Paso and the Transwestern system.

We also have Canadian path gas which at this time it's a little bit more expensive, but the number one issue for us is reliability of supply. We want to have a diversified portfolio of sources, of pipelines, producing basins and producing companies. And we do that.

What option do utilities have for natural gas procurement and cost recovery? At this point we are judged based on the GCIM benchmark. The benchmark is the monthly prices that are published by natural gas intelligence inside FERC and so on. And we purchase gas monthly to try to beat that benchmark.

The reason we went to this monthly benchmark is previously we had long-term contracts, five-, six-year contracts at a fixed price. And when the market price, the daily price or the monthly price got below that, we had -- and disallowances by the regulatory commission. Because we didn't know how we were going to be judged. What is a standard for a long-term fixed-price contract? When do you know that this is the right time to fix that price?

And every time you do that you wind up being the loser on the utility side. Because you're always going to be second-guessed, Monday-morning quarterbacking. And what's important to us is to know what that benchmark is. We want to know how we're going to be judged, and we'll beat that benchmark. We've been very successful in beating the benchmark and creating benefits to core customers.

Interstate pipeline capacity costs are passed through. So we're required to hold at least average year demand capacity. We coordinate that with DRA and the energy division and TURN. If we want to buy additional capacity, we have a meeting with those groups; and we agree whether or not we should purchase more capacity and so on.

We actually have authority to hold capacity up to 120 percent of average year throughput.

Under the incentive mechanism we do have authority to hedge. And we have authority to enter into fixed-price contracts. But because we are judged monthly, we tend to have volume contracts going longer term. But the pricing of those volumes is based on the monthly index. That's how basically industries run, anyway.

We have monthly procurement activity coordination meetings with Commission Staff, DRA and energy division and TURN. So all the parties are at the table. And we reach agreement each month on what we're going to do and how we're going to purchase gas for our core customers. And it's been very successful.

PRESIDING MEMBER BYRON: Mr. Emmrich, these are obvious questions, I suppose. I guess most everybody here knows this, but are there any other -- these are procurement review groups, I take it?

MR. EMMRICH: Yes.

PRESIDING MEMBER BYRON: Are there any other participants than what you've listed here in the PRGs?

MR. EMMRICH: No, no. We don't buy for the noncore customers, so they're not party to that.

PRESIDING MEMBER BYRON: Okay. So TURN Is the only really outside consumer organization that's involved, correct?

MR. EMMRICH: Yes.

PRESIDING MEMBER BYRON: And they're compensated, I believe, to be there, is that correct?

MR. EMMRICH: If they participate in a proceeding, then they can ask the Commission to get compensation for that.

PRESIDING MEMBER BYRON: So the other way around is they probably don't participate if they're not being compensated?

MR. EMMRICH: Well, I don't want to assume what their motivation are. I assume their motivation is to protect core customers. So, I think they would do it even if they weren't compensated. They would find compensation somewhere else. But it's obviously important to have them on the team and to do this in concert with them.

PRESIDING MEMBER BYRON: Yeah, I don't mean to put you in a position to answer for TURN, but you did end you last comment by saying that this has been very successful. And so the measure of success that you're using is?

MR. EMMRICH: The measure of success is that we've been able to purchase gas at below benchmark prices. And we have avoided -- and disallowances. We don't have this constant contention on what the right policy is. So that's all been Avoided.

And our core customers are very happy. We're ranked number one and number two nationally as far as customer satisfaction. And so we're very proud of that. And that's mainly we've worked with our customers each and every day.

PRESIDING MEMBER BYRON: And one last question. How long has that process been in place?

MR. EMMRICH: Let's see, the GCIM, we are in year 14. We just finished year 14, we're actually in year 15.

PRESIDING MEMBER BYRON: All right, thank you.

MR. EMMRICH: Also, the GCIM costs are audited annually by DRA, and so we have to pass an audit. We don't get a free ride to say these are our costs and it's not checked on. It's audited annually.

So, we're allowed to recover all the costs as long as we're no more than 2 percent above the benchmark. And we have shareholder benefits if we are at least 1 percent below the benchmark.

This is just a map showing where we have interstate pipeline capacity. The San Juan Basin on Transwestern El Paso; on the Kern River pipeline to the Rockies Basin, which has been their cheapest basin. And I see PG&E is also going to get more access to that with their pipeline project.

And we also have access to the western Canadian Basin, going through PG&E's territory and GTN going to the Canadian border. And actually all the way up into the basin on Canadian pipelines.

What list mitigation strategies available to utilities in -- hedging. SoCalGas, San Diego gas procurement department uses storage as their main tool to mitigate price and volume risk. Purchases gas in the summer months when gas prices are usually low. Withdrawing gas from storage in the winter when prices are usually higher allows the utility to mitigate volume and prices.

The reason I said usually, it turns out this year the highest prices were in June -- I mean last year the highest prices were in June, and the lowest prices have been just recently. So it is still considered to be winter months.

So, of course, nobody anticipated the worldwide economic collapse, and the reduction industrial demand for gas, which has led to this price decline.

Another way we mitigate prices is hold interstate pipeline capacity on several different pipelines out of the access to supply basins. And we have that winter hedging program, which is approved by the PUC. And we can also do additional hedging outside of the GCM if we deem that to be appropriate.

This is just a brief description of the gas cost incentive mechanism. So if we purchase gas below the benchmark, at least 1 percent below the benchmark, then ratepayers get 75 percent of the benefit and shareholders 25. And if it's more than 5 percent below the benchmark, shareholders get 10 percent, and 90 percent to ratepayers.

And the total benefit is capped at 1.5 percent of actual commodity cost of gas. So that excludes all the transportation costs. It's only the commodity cost.

How the risk of hedging balanced against the benefits of hedging. Hedging allows utility lock-in certain volumes of gas at a set price using storage, futures or options.

And this is the thing, hedging doesn't mean you get lower gas costs. What you do is you avoid volatility. If the price locked in turns out to be lower than the fluctuating daily or monthly price, the utility and ratepayers both gain benefits. If the price locked in with the hedge turns out to be higher than the fluctuating daily or monthly price, we both lose.

Hedging cannot guarantee a gain or loss for the utility or ratepayers, but can only reduce price fluctuation, which is defined as risk. The value of reduced price fluctuation or risk is based on consumers list preference, such as choosing a fixed rate mortgage or a variable rate mortgage.

If the mortgage or customer gas bill is a large part of the consumer's budget, one would think that a fixed price option is desirable because consumer could probably not absorb the higher price risk.

This is a case with the preference of fixed rate mortgage as compared to variable rate mortgages.

If the monthly bill is small, such as the average monthly winter bill this year of $67, one would think the consumers are willing to absorb price fluctuation and avoid the cost of hedging. Hedging is not free. You have to pay for it. And that is an added cost that if you enter into long-term contracts you're going to pay for that, because the producer will then have to absorb that risk. And they will charge you a premium for absorbing that risk.

Fixed-price contracts are more expensive than monthly contracts because the seller has to recover the cost of hedging in offering the fixed-price option.

How do regulatory incentive mechanisms function in the overall procurement process. SoCalGas, San Diego GCIM has been very effective in -- ratepayer interest by providing a known benchmark that gives the utility incentive to buy reliable, low-cost gas supplies for core customers.

And here's an important point for us and all the other utilities. The GCIM has eliminated the contentious, (inaudible) process that wastes the time and money of the utility and the regulatory agency.

Now, over the 14 years of the GCIM we have saved gas costs of $763 million. So that's a large amount of money to be able to purchase gas below the benchmark. And usually the core assets that we have, when some of the storage assets are not being used by the core, we can rent those out to marketers to noncore customers on a monthly basis or longer term basis, and create more value for customers.

The active coordination with DRA, energy division and TURN has further aligned utility, ratepayer and regulatory interests to assure reliable, low-cost supplies to core customers.

The GCIM has motivated the utility to efficiently and effectively use core custom assets to reduce core ratepayer costs and shareholder earnings.

Thank you. I'm available for questions if you have any.

PRESIDING MEMBER BYRON: Mr. Emmrich, thank you very much. Just a couple of quick questions, I think. Thank you for answering one of them, and that would be how much the GCIM has resulted in savings for customers.

Can you give me a sense of how you can calculate that, what's the benchmark that you're using? Is it that month-to-month zero baseline that we're talking about?

MR. EMMRICH: Yes, the benchmark is the industry publication index at the point of purchase. So if we are buying gas on Transwestern in the San Juan Basin, there is a monthly index that's published. And if we beat that index by more than 1 percent, then we share those savings with the ratepayers and the shareholders.

PRESIDING MEMBER BYRON: And I agree, $763 million is a lot. Over 14 years, if you'll allow me some quick math, that's on the order of $50 to $60 million per year.

MR. EMMRICH: Yes.

PRESIDING MEMBER BYRON: Okay. But if I go back, you know, to the price of natural gas last June versus earlier in the year, and your utility hedged a fair amount of those costs, that would be on the order of billions of dollars in that short period of time, correct?

MR. EMMRICH: Not quite. We purchase about $3 billion worth of gas during the entire year. And because we purchase flat, we purchase the same amount each month, we avoid those kinds of problems.

PRESIDING MEMBER BYRON: Right, I'm sorry, you're right, I was using Mr. Tavares' statewide costing --

MR. EMMRICH: Yes.

PRESIDING MEMBER BYRON: -- of natural gas purchase.

MR. EMMRICH: But it would only be the purchases during that month that we had the highest exposure to. Not for the rest of the year. But if you were locked in at that time, let's say and the price was $13, and you thought, let's say $7 was a good price for long term, if you locked that in, right now the price at the California border is $3.

PRESIDING MEMBER BYRON: Right.

MR. EMMRICH: So you'd have been losing $4 each and every day times 1.1 bcf of gas. So that's a huge amount of money you'd be losing.

PRESIDING MEMBER BYRON: Well, Commissioner Boyd knows a lot more about these things than I do, but I'm going to go back to one of the points you made earlier and just kind of see if this reveals the thinking, or the philosophy here.

Where you'd indicated earlier if the monthly bill -- the monthly bill is such a small part of the consumer budget, you know, only $67, natural gas in the middle of winter.

So I guess I'd have to ask at what point would the bill have to be to make hedging worthwhile to customers? Maybe that's the wrong question, but my sense is that we're spreading this cost over such a large base of customers, even though the numbers are big, to the individual customer, that the exposure is rather small. Isn't that really the point that you were making there?

MR. EMMRICH: Yes, that is the point. I believe noncore customers that have large volumes of gas every month may not be able to absorb that kind of price fluctuation. But, of course, they have the ability to hedge themselves, if they want to do that. Or they can buy fixed-price contract from marketers that make those available to them.

So, we're looking out for the core customers and what we've found, over the long term, buying month to month, and having a monthly benchmark has been the lowest option, lowest-cost option for customers.

We have had the lowest (inaudible) for the last ten years, as far as I know. Nobody's been able to beat our (inaudible). So we're purchasing gas for core customers at a very low price.

We do purchase a lot of gas, so that gives us the ability to seek out the best deals. But in combination with the storage assets we have, we have had unparalleled success in reducing gas costs to our customers.

PRESIDING MEMBER BYRON: Very good. Mr. Emmrich, thank you for coming this morning.

MR. EMMRICH: Thank you.

MR. TAVARES: Thank you, Herb. We'll have an additional opportunity to ask more questions later on during the panel discussion.

Next we have Pam Taheri from Sacramento Municipal Utility District.

(Pause.)

MS. TAHERI: Good morning, Commissioners, and good morning, workshop participants. I'm Pam Taheri; I'm SMUD's risk manager. And I appreciate the opportunity to be able to give this presentation today.

I just want to go over some of the SMUD facts. We're the sixth largest municipal utility in the United States. And we serve over 600,000 customers, but for electric service only.

So, basically as far as gas is concerned, we're really more of a noncore faction. And we only buy gas as a fuel for generating the electricity.

As a municipal utility, we, in our interest, align 100 percent with our customers, because we are owned by our customers. And generally speaking, our goal is to try to provide reliable service at reasonable and stable rates.

Here's a little bit background in terms of our resource mix. If you look at our annual retail revenue is around 1.3 billion. And our annual power and gas budget is over 600 million. So as you can see, it's almost half of our annual retail revenue.

If you look at our supply mix for the resource, natural gas is a pretty big piece. It's over half. While we have hydro and we have quite a bit of renewable, and a little bit of others mixed in with it, obviously we have to do something in order to make sure that if we want price to be stable and predictable, we'll have to do something about procuring the natural gas that's necessary to support the generation for our system.

Here's a gas price chart. And as previous speakers has already mentioned, there's quite a bit of fluctuation in gas prices. We have two lines up here; one is Henry Hub and the other is PG&E citygate.

And it goes back to right in the middle of the crisis. As you can see, this is almost total peak, and then start coming down. And the two, for the most part, correlate fairly well.

And you can see where there's some huge spikes that goes up to about $12 and over. And, of course, too, you know, it fluctuates from 2 to 12, 13.

Gas hedging. The way we look at it is that, again, our objective is to try to increase financial certainty by stabilizing the costs. And the cost is really the price times the volume.

You know, previous speakers have talked about volume, it fluctuates. Well, you got to lock in that volume at a fixed price of some sort so that you go ahead and try to dampen that volatility and have certainty on the cost.

So the action taken is to reduce the open positions by locking in the price. For example, SMUD's gas volume averages about 120,000 mmBtu per day. But on a daily basis it could go somewhere swing up between 80,000 to 160,000 as a potential. So it could be quite a bit of daily fluctuation, although the average is pretty stable, with some seasonal fluctuation.

This is just to illustrate some of the points the earlier speakers have already talked about. If you look at it, this is the Henry Hub gas price going back to '99 all the way to the early part. So if you look at the volatility on a daily basis that's what it looks like.

And then there are two lines of different colors, and I hope you guys can differentiate the color. One is green, and the other is blue. Okay.

I hope everybody can hear me. But if you look at there, what I tried to have my staff plot is that this is representing the average of the 12 months. So the blue line is representing if you take 12 months and average it out, that's what it looks like.

PRESIDING MEMBER BYRON: Ms. Taheri, I think you need to use the microphone, otherwise --

MS. TAHERI: Okay.

PRESIDING MEMBER BYRON: -- everybody on the webcast is going to be wondering what's going on.

MS. TAHERI: Okay. Sorry about that. This blue line here represents that 12-months period averaging this. And that's what visually, if you average that, that's what the price look like.

The green line here represents that if you bought that, a 12-month strip, at the beginning of that period, that's what the price look like. Since you're buying it as a strip, that's the same price. Look at the delta. Again, look at all these deltas.

So, in other words, for the longest time, since around, I'm guessing, 2001, '2, if you look at that delta it's quite substantial because it's almost like two bucks here. And then, again, all these periods showing that if you had bought a strip -- of course, that's only one of many procurement strategy, one to do is hedge it 12 months in advance, others use different strategy.

I just wanted to illustrate a point here, is that for all these period is looking pretty good. But, of course, as we all know, sometimes it could flip on you. Look at what happen on these other periods.

So, bottomline is I just want to use this to illustrate a point that when you do hedging it's really not meant to be a profit center. It is a cost center. Because you are transferring the risk to someone else.

Sometimes it looks like a winner, like these periods here. But that doesn't mean it's always going to hold like that, because there are other periods that are like this.

As far as hedging instruments concerned, we do physical, as well as financial. We do multi-year, as well as seasonal purchased. We do storage, as the previous speaker talked quite a bit about that already. We also use gas reserves.

In addition to that we also procure substantial amount of pipeline capacity to different path to further diversify our risk from different hubs. Because there are basis differentials.

Some of the key considerations and challenges. It's really one, the balance between price certainty and the cost of providing that certainty.

The collateral requirements to default risk, and then there's also accounting treatment and reporting. I'll go through this one-by-one, but I just want to mention that those are the things that we see as considerations and challenges.

As far as we're concerned it's really a policy issue, trying to balance between price certainty and costs.

For price certainty we're looking at it and say, if you look at a household and business, we all generally have a budget in mind. So we believe that for the most part having some level of predictability is preferred by many customers, if not most.

The economy of scale, though, to hedge that is that we find a few of our large customer, mostly the industrial ones that potentially could even be a national customer, have the ability to probably have an energy manager and hedge that independently.

However, for the most small commercial and residential customers we do not believe at this time they have the necessary capability.

In terms of cost, hedge, as I mentioned, has a cost. It's a risk transfer mechanism. It's like an insurance policy in some ways. Or like a, you know, a fixed cost for -- picking fixed interest rate for a house payment.

For insurance policy it's to limit the cost exposure. I mean I don't know about you, I know that when I was younger and didn't have much asset to protect I tend to take the cheapest one I can with a low deductible.

But as I get older and I have more asset to protect, I take a higher deductible so that I can protect more of my asset to limit that exposure.

Having said that, I buy the insurance every year. And I don't go back and ask for a refund when my car didn't crash and I didn't die that year.

(Laughter.)

MS. TAHERI: So the point I'm trying to make is it's not intended to represent the lowest cost alternative. Sometimes it turns out that way. And in those years we're all heroes. But there comes a point you have to pay the piper.

As far as the collateral requirements, it is a major issue, especially right now with the financial situation and the liquidity situation and the entire market.

We see that there could potentially be significant collateral and margin cost, okay, because of market to market with the forward positions with the counter-parties.

For example, we do some long-term hedging and mid-term hedging. So we do weekly settlement based on the forward curve. And then take a look at it. And to the extent that if prices -- of course, in this case we mostly do this, which is purchase, not sales.

But if prices, after we bought, went up, well, that's not so bad. Because then that means that we have to just to make sure that the counter-party, the one who has sold us the stuff, is creditworthy and only that half the money to pony up, so that we could be holding their cash.

But on the flip side, when prices go up, since we bought that, -- go down, and since we bought that position it has gone down, then we have to pony up the cash or find some other way to be able to manage that liquidity.

So here are some mitigation factors for collateral requirements. One of them is that we share our credit limits with our counter-parties. For example, if they have a AAA rating, we may give them more credit limit as compared to somebody who has less rating. But in no way we do a deal with people that are not creditworthy.

We use netting arrangements. For example, sometimes we buy and sometimes we sell certain things in terms of power. And there may be netting -- we do cross-commodity netting, as well, in terms of gas versus power.

Also, one of the key things that we use is actually counter-party diversification. Imagine if you only deals with one party and they turn out to be somebody who shall remain unnamed, they go belly up. Then we have not minimized our risk. So it's very important to be able to diversify the counter-parties among all good credit counter-parties.

Strong balance sheet obviously helps. And we also use letter of credit, we could use NYMEX transaction, although we don't. Others could.

But, again, using the letter of credit has a significant cost. We have experienced that recently when we went out and asked for a letter of credit.

First of all, the banks will only deal with you because we've been with you and had a business relationship long term for a long, long time.

And second of all, however unwilling we are, we're willing to do it with you, but at a really really expensive cost. So that's something to keep in mind, especially in today's market.

We also are very diligent in modeling and stress testing so we can stay ahead of the curve a little bit. To say, gee, prices look low today, but tomorrow it could be lower. What could the margin call look like. How are we going to provide that liquidity.

Default risk. A lot of the parties, as we know, have AAA, but that doesn't mean they won't slide. And these days when they slide it could be very fast.

So we have to look at the counter-party financial weaknesses and follow that pretty closely. And at the same time, the longer the duration of a transaction you do, the more time there is for them to deteriorate.

I mean they can get better, too, but if that's the case I don't know that we're too concerned about it. But if they do go down the tubes, it could be a major concern. Because what you thought you locked in the price and feel pretty good about it. And especially in a time when market has gone up. Then find out that they're not there because they've gone belly up.

Again, there's also market turbulence. That could drag down, even like a good bank could go bad if the market is very turbulent. And we've seen some of that and continue to see that.

So what do we do in terms of trying to mitigate some of the default risk? We're putting contractual protection in, for example, termination rights. We put in collateral requirements to make sure that any given time if prices have already gone up since we bought the contract, we're holding part of that as collateral so that at any given time if they default, and then we have the termination right, we can go back and replace in the market. We're not out the money too much.

We set limits. Again, it gets down to diversity. So that you're not doing too much with any party. And then we also, again, watch the credit all the time.

Something that I know this really give us a lot heartburn because there's a lot accounting rules and you have to be able to make everybody happy.

So there's the FASB, which is the financial accounting standards for it, and GASB is the government one. We have to make sure that we are not buying and selling pork belly to try to hedge our gas risk. To make sure that it truly is relevant to the business that we're in, and that there's a fair valuation and it's effectiveness is tested. Otherwise it could potentially have a significant impact on our income statement.

In addition to that we also try to use standard products. We do not come up with our own forward curve, but rather go to buy independent forward curve, so that we could say, okay, you know, it's not like SMUD always think that we're always in the money.

And we try to match it so that the hedge is as clean as we can make it, although sometimes that's not always practical.

If you have any questions I'll be happy to answer them.

Thank you.

ASSOCIATE MEMBER BOYD: I have only a comment. There's another industry I can think of right now that I wish followed your prudent approach to financing and hedging, but that's in a class of mortgaging 101, I guess.

MR. TAVARES: Thank you, Pam. We're going to move on next, and we have Laird Dyer from Shell Energy.

MR. DYER: Good morning. My name is Laird Dyer; I'm with Shell Energy North America out of our San Diego office. I appreciate this opportunity to speak to you this morning.

My comments are focused on the core side of procurement in California. Noncore customers tend to be sophisticated enough to be able to manage their own market exposures, so we won't dwell on them in this presentation.

So the first thing I'd like to do, though, is to characterize the natural gas market that we're living in right now.

It is a North American natural gas market with a connected grid out there. So, any perturbation in the market kind of emanates across the whole system.

We still remain, the prices still remain extremely volatile. For example, in 2008, just the so Cal border, we had a low price of 2.49, that was in October, and a high of 12.68 was witnessed in June. So over a four-month period we still have prices declined $10.

That occurred because of the combined impact of indigenous gas growth, mostly in the Barnett Shales, the Hanesville Shales, the shale area around the Gulf Coast, and the global economic turndown.

We're estimating we're over-supplied in this market, in the North American market, I'm just talking Canada and the United States, by about 6 bcf a day in a 73 bcf-a-day market.

That has led to the price collapse we've seen. Currently the market is trading below replacement cost. And we've seen, and continue to see, dramatic reductions in exploration activity. Rig count is currently down about 42 percent from its highs.

That, in time, will lead to a supply response that will set us up -- as I refer to it, we're loading the spring for the next price move-up once we get economic recovery.

What that means in the longer term, contrary to what you might hope for, we are going to see a lot more volatility and higher prices in this market.

PRESIDING MEMBER BYRON: Great. And when's that going to happen?

(Laughter.)

MR. DYER: 2011. You'll see the bottom this year. My opinion you'll see the bottom this year, and we might see a 2 -- on the NYMEX, maybe 2.50, as a spike down. I think it deserves somewhere around 3 or so. Replacement costs are somewhere, they're falling now but they're somewhere around 3.50 to $4.

So once we get below those, you just, you know, you're just tightening that spring and it'll come back.

With regard to price exposure there's really kind of two camps in California. You have the utilities on one side and then you have all the customers on the other.

Since the 1990s California's gas utilities procured under these incentive mechanisms. Those mechanisms were designed in a period of protracted gas-on-gas competition with deregulation in 1986.

You effectively had a contracting period where you would -- and I was involved with this when I was working with Amoco in a previous life -- you would sell gas on a contract, they had a DCQ and a max date. Typically 133, 125 percent.

So you withheld 25 percent or 33 percent of your gas from the market for peak day needs. With deregulation all that gas flooded the market. And it took us 15 years, 14 years to work that off.

And that shot across the bow occurred in the year 2000 when we hit $10 on the NYMEX. But these mechanisms were designed kind of in the middle of that, in the mid 90s, in a $2 gas environment, be a $3 gas environment. And we're just a buy market. That was the prevailing opinion.

So, performance under these mechanisms is measured against benchmarks, which are based on monthly prices. Did promote a short-term focus, did discourage supply portfolio development, and they discouraged price hedging, given shareholder exposures to the impacts. And we've heard much about that today.

As such, the utilities engaged in very little hedging within the mechanisms. And California's ratepayers, which is the other side of this equation, remained fully exposed to market prices and market price volatility.

That is illustrated in this plot. As you can tell, all I did is I took DRA data; combined their results that they report each year on the incentive mechanisms. I looked at PG&E and SoCalGas for this. I just combined the data on a weighted average basis.

You can see that prices overlap the benchmark price, actual prices overlapped the benchmark prices. Meaning that as consumers we're just tracking the market here.

And you can see the substantial monthly volatility, ranging anywhere from 50 percent up to we've seen highs of 90 percent. Meaning that there's dramatic month-to-month movement in prices.

With the increasing volatility in the

market after 2000, and then in response to hurricanes Katrina and Rita in 2005, California's gas utilities petitioned the Commission for authority to hedge outside of the mechanisms.

The utilities sought permission to hedge to defend against price spikes, to limit this hedging just to winter periods so it's three, maybe five months a year. Pass through all program costs to the customers. And impose strict confidentiality on their hedging strategies and transactions. The public does not get to see what they do.

I know it's nice to talk about $2 a customer as the cost of these things. In real terms in the first two years of these programs over $208 million was spent, an aggregate among the utilities.

In our view, this is Shell Energy, the winter hedging programs are ineffective and very expensive, and provide no tangible benefits to customers.

So in the current situation what are all the procurement options for the utilities, given their risk/reward structure of those mechanisms. They limit their -- they have limited procurement options basically. And their focus is on month-to-month market price gas.

And under these incentive structures the utilities remain financially indifferent to the market price of gas and to the volatility of gas prices.

All hedging activities are currently conducted outside of the incentive mechanisms under the CPUC-approved winter hedging programs.

One of the questions that was put to us is what are the benefits and risks of hedging. And it was pointed out hedging is not normally considered to be associated with gains or losses. It's a transfer of risk.

The current incentive mechanisms discourage hedging. Utility shareholders are exposed to financial losses if market prices fall below the hedge prices they enter into. So they don't do it.

But the question here is, is hedging an acceptable risk for ratepayers. We think it is. We think that through hedging ratepayers can see reduced price volatility, more stability, reduced exposure to price spikes, and we think if the incentive mechanisms are designed properly, may produce lower overall prices. If you motivate the utilities to buy low you may get some good outcomes.

There are a number of risk mitigation strategies out there available to the utilities. Of course, hedging, which is basically, you know, a mixed of fixed price, calls off, all sorts of options out there for you.

Storage. We take issue with the idea that it's simply just buy in the summer and withdraw in the winter. We think it needs to be combined with hedging, as well.

If you look at 2008 and the price spikes we had up and through the end of June, and I just did a quick back-of-the-envelope analysis looking at what SoCal injected every day versus the gas daily price, it would argue that their average price of gas in storage today, at the end of -- sorry, summer injection period, was $8.59, which does not compare favorably to a $3.-and-change gas market right now. So the presumption that summer prices are always cheaper is not a good one.

The utilities could also pursue peak load shaving opportunities having customers be paid not to -- or be compensated for turning their load off in peak periods.

A number of California municipals have pursued buying reserves in the ground. SMUD participated in that, for example, and I believe that it's been done through the SCPPA entity. They've bought reserves in the Rockies and in the Barnett Shales. That introduces a whole different set of risk structures. Now they're worried about what their reserves look like and what the production costs look like, and if their wells will survive. So it's a different risk structure.

The last thing, of course, is supply diversity. It's important as any end-use customer, any user that you have options. So you want to connect to at least three or more supply basins.

There are diminishing returns, though, once you get beyond that. If you have five, six or seven it's questionable whether you're getting much value in adding each of those individual incremental supply sources.

We believe that the current incentive structure mechanisms require modification. Today's gas market, unlike the one in 1990, is characterized by dramatic high prices and volatility.

There's an ongoing proceeding at the CPUC addressing the incentive structures. In that proceeding the CPUC has identified two procurement goals: Achieving low prices and price volatility mitigation.

We think that in order to align the interests of ratepayers and shareholders within those mechanisms they should be modified to capture shareholder exposures to hedging, to motivate the utilities' development and manage the supply portfolios, which requires an adjustment to the risk/reward profiles within the mechanisms.

Include all procurement activities within the incentive structure. And assess those activities against objective measures.

In doing so you'd introduce accountability and consequences to the utilities for their procurement actions.

We'd also like to see increased transparency. We don't get to see what goes on in the winter hedging program. Nobody does, but for TURN, DRA, I think maybe AGLET and the utilities. And the Commission.

We also think that if the mechanisms can be properly designed you can reduce the time and resources dedicated to oversight.

My last slide is kind of what we propose, it's a quick summary of what we proposed in the CPUC proceeding. We propose modifications to the mechanisms. We'd like to see those mechanisms leveraged and expanded to address not only price, but price volatility. Introducing a volatility reduction benchmark.

And we've also suggested that the risk/ reward profile in those mechanisms be altered. And that, in our minds, eliminates the need for the tolerance bands.

We also want to cap utility rewards and penalties. And require open and transparent hedge solicitation processes.

And that concludes my remarks. And there's the famous clamshell. I'm open for any questions.

PRESIDING MEMBER BYRON: Mr. Dyer, thank you. I always say thank god there's one commission in the state that is concerned about the cost to consumers. But that's not us. That's the Public Utilities Commission, at least with regard to the investor-owned utilities.

Have you had opportunity to express some of these recommendations to the PUC?

MR. DYER: Yes. The proceeding, the OIR proceeding has been going on since June 30th. I think we've had five or six submissions so far. We keep saying the same thing over and over again. We just hope somebody reads it.

PRESIDING MEMBER BYRON: And do you know what the schedule is for the close on that rulemaking?

MR. DYER: I do not, but there's another submission due this Friday the 13th, rather ominous.

PRESIDING MEMBER BYRON: So, a couple of questions in no particular order. You talked about increase in transparency of utility procurement activities. Why -- I mean, my understanding is that the reason these procurement strategies are confidential is in order to protect customers from, you know, some market manipulation that could be used.

You don't necessarily know what the procurement or hedging strategies are of the noncore customers that you deal with, do you?

MR. DYER: Actually there's two elements

to that fight, and I have to remember them. The first is that the utilities still procure from market participants. Just a limited number of them. And so those market participants are fairly sophisticated banks. They're just as capable as the entire market to do whatever manipulation you're concerned about. So you haven't really avoided the issue, you've just put it into a small capsule.

I'm sorry, it escapes me, the second point -- so if you might ask me your question again?

PRESIDING MEMBER BYRON: Well, just about increasing the transparency of utility procurement. I mean that might advantage the sellers but disadvantage the buyers, wouldn't it?

MR. DYER: Well, there -- I remember now, there are, for example, Southern California Edison and Southwest Gas, as you go out each year or periodically with long-term fixed-price and other product solicitations that are very public.

And they've been quite successful, they would argue, I guess, in their approach.

Again, though, even under the -- again, when you look at the winter hedging program, you are limiting the number of participants who bid or offer products under those solicitations. But they are sophisticated banks. They are big trading houses. And you just have to be in that group.

It doesn't preclude manipulation. It doesn't mean it goes away, it just limits who can do it.

And so we don't see the harm in having it more public. Plus we see the benefit of looking at what the utilities are doing. So we see that exposure being beneficial to the utilities.

You will get input from other folks with other ways to do it. We have no idea. We're not sure exactly what they buy in the winter, but we suspect they're out-of-the-money call options.

We would argue that maybe a better approach is to buy, fix the price at the money and buy post instead. It gives you a cap on some stuff. It also gives you the opportunity for a lower price. So there's other approaches that they may look at.

Once you get into kind of an oversight structure like that, with just the Commission or entities like TURN and DRA looking at it, you tend to get very static strategies, because then you have to explain why you're changing. And once you've got something set up, it's kind of very easy to keep going with the same strategy, change the strike prices and keep moving. Anything that requires explanation tends to be avoided.

PRESIDING MEMBER BYRON: Yeah, it's a very conservative industry.

MR. DYER: Yes. Change is not well accepted.

PRESIDING MEMBER BYRON: Another point you made was assessing all utility procurement against objective measures. Who would you propose would do that?

MR. DYER: Well, we actually want to use the existing benchmarks, expand the existing benchmarks. There are no good alternatives.

You can use some daily indices, they tend to be a little more volatile. We support using the existing benchmark structure. But you can also attach a volatility to that. You can just take monthly prices and attach a volatility to it.

And you could mandate a reduction in

volatility within a portfolio, meaning that you have to hedge a certain portion of the portfolio.

PRESIDING MEMBER BYRON: Let me ask one more. I see my fellow Commissioner may have a question, and maybe Ms. Brown does, too.

How would you suggest that we motivate utilities to develop and manage these different portfolios? I mean what -- the incentives, there's really no incentives in place for trying to keep shareholders whole, or trying to essentially mitigate some risk to customers in price fluctuations. But the reality is all costs are eventually absorbed by the customer.

So, how would we properly motivate utilities to look at these different options?

MR. DYER: It's really in the risk/reward structure within the mechanism. The concern right now and the reason they don't hedge is that they have unbounded exposure to an adverse outcome. And so you need to address that.

And we focused our comments in the OIR on that, largely. And what we suggest is that you skew the risk/reward profile. Make it favorable. For example, what we proposed is that they have exposure to 2 percent of the down side and 15 percent of the upside.

PRESIDING MEMBER BYRON: Instead of 1 percent of the downside?

MR. DYER: Yes. Well, right now it's unbounded. Their exposure to the downside is unbounded. What we're saying is -- is that okay?

PRESIDING MEMBER BYRON: Yes.

MR. DYER: Okay. We also want to cap those exposures. Thirty million on the upside and 6 million on the downside per year. So that there's nothing adverse.

But in that regard, by doing that what we hope to do is promote activity on their part. They have a favorable risk/reward profile. They use their expertise in procurement, risk analysis, fundamentals, and go forward and buy gas.

And we would argue in today's environment where gas is trading below its replacement costs, this is not a bad time to be buying long-term fixed-price gas. And we are getting a lot of inquiries within Shell from the muni world. California municipals are quite active in this market right now, buying five- and ten-year supplies at fixed prices.

Yes, there's risk involved with that,

but right now your risk/reward profile is quite favorable, and that's what you should be doing.

PRESIDING MEMBER BYRON: Okay, well, I'm reminded Mr. Buffett yesterday was correct in his remarks. He said a year ago that it's a good time to buy stock.

(Laughter.)

PRESIDING MEMBER BYRON: That market's dropped another 30 percent since he made that recommendation.

MR. DYER: I have a view on that, if you want it, too.

PRESIDING MEMBER BYRON: Commissioner?

ASSOCIATE MEMBER BOYD: Even he's not perfect. I just want to thank Mr. Dyer for his presentation, particularly the recommendation about increasing the transparency of the procurement activities.

Thank Commissioner Byron for asking the question, and for your lengthy answers on that subject, because now we have a lot of additional information in our record on that subject.

You did mention that very few people get to see a lot of this information. Perhaps this Commission. I just need to point out this

Commission's been on record for years as recommending that we need more transparency in the utility procurement area, period.

All Commissioners, since I've been here, have refused to sign the confidentiality agreements that would allow us access to this information. And some staff do have that access.

The organization needs to proceed. But we, too, have difficulties with the lack of transparency. So maybe your issues will get addressed better in the future. We've not had a lot of success.

MR. DYER: We're always hopeful.

ASSOCIATE MEMBER BOYD: But maybe we can keep at it. Thank you. I have no further comments.

PRESIDING MEMBER BYRON: Thank you, Mr. Dyer.

MR. TAVARES: Thank you, Mr. Dyer.

Next we have Marshall Clark. He is the person in charge of procurement of gas for General Services.

MR. CLARK: Good morning, Commissioners, audience. Okay, I'm going to have to -- I'm one of those people who has to move around, so this is going to be a discipline.

My name is Marshall Clark. I'm Manager of the Natural Gas Services program with the Department of General Services. For the record, I've been doing that for about 13 years, so I'm ingrained in my habits, whether they're right or wrong.

Let's see -- first of all, just a little background as to who we are. We're an element of the Department of General Services in the admin division, office of risk and insurance management. Appropriate title.

We are a nonmandated service program. This is important to point out because we have to go out and recruit our customers. They're not mandated to use our services. And likewise, if they don't like our services they can leave. That puts a very different dynamic on how we deal with our customers, because we're constantly at challenge from what they might want or what they might not like about what we're doing.

Our customers are the public sector in California. About 30 percent of our customers are the executive agencies of the state, the ones you traditionally think of as state government. But we also have the University of California, CSU, the community colleges, counties. Seventeen of the counties in the state buy their gas through our program. Cities and special districts, that's mostly wastewater treatment plants, but for instance, here in Sacramento the Regional Transit, the compressed gas for the buses is something that we purchase.

Only for core accounts. Most of the conversations today have talked about purchasing for core. We only purchase for noncore accounts greater than 250,000 therms per year through a single meter. So that gives us a very different dynamic, both in scale and the kinds of customers.

We have 135 different customers, 180 different accounts. Unlike the utilities that have talked today, this is a very different environment, as well, because we can literally get all of our customers in a single room.

We talk to every single one of our customers on a regular basis, have workshops and so forth. So there's a lot more communication. Simply because our audience is a much smaller group.

In terms of scale and scope, for this

year we're going to buy about 32 bcf. And the price changes on a regular basis, but right not we're estimating about $260 million for volume of business. In comparison, we're about probably two-thirds the size of SMUD in terms of our gas purchasing.

The next thing to talk about is how the customer base changes the strategy. For the public sector, the strategy for purchasing is dominated by the public sector budgeting process.

And this is different than things that you've heard from others today, if you think about how the public sector budgeting process works. For this fiscal year from July of 08 through June of '9, the budget was based, for natural gas for our customers, at least for the executive agency, it was based on a Department of Finance budget letter that would have been published -- remember this, fiscal year started in July of 08 -- the budget letter was published in August of 2007, projecting to the departments what they needed to budget for this current fiscal year.

Obviously when the budget prices are set well before even the beginning of the year, and don't have any flexibility during the year, that dominates how our customers think about natural gas. They have a certain amount to spend.

The biggest concern is price volatility. If you're stuck there with a budget that you can't change, the thing that frightens you the most is a price spike that's going to tear that budget apart.

Also, because of the public sector budgeting process they're concerned about how much they spend over the course of a whole year. What happens in any given month doesn't really matter, it is the annual total that they focus on. So their perspective is very different from month, rather than watching the price from month to month. What they're constantly watching is whether or not they've used up their annual appropriation for natural gas, and whether they can project that that's going to happen or not.

It's a very asymmetric point of view about natural gas. All of our customers would love to save money on their natural gas purchases. But there's a thing my customers, the folks I deal with, called the walk. You don't ever want to have to do the walk. And the walk is going down the hall to the chancellor's office or the warden's office or whoever and telling him that you have to take some money from program, the actual accomplishment of the department's mission, and use it to pay a gas bill that went above budget.

It's very asymmetric in the sense that they would very much like to have savings. But at least ten times more they don't want to go over that budget. So their constraints produce a different psychology in terms of what they would accept. Savings are secondary. Not exceeding the budget is primary.

I didn't put this together.

The right strategy constrains price volatility within the budgeted level of cost. And you've heard talk of benchmarks. We have a benchmark, but our benchmark is that price that's hard-wired into our customers' budget. It has advantages and disadvantages to know that.

What it does mean is that, for instance, we know that in a given year our customer's budget will be $8 on mmBtu delivered to their meter, then we know that if we can purchase gas below that, we will stay within their budget.

We also use a portfolio approach, rather than making a single big bet, we tend to buy a lot of purchases for our customers. We may have anywhere from 30 to 40 purchases made for a particular month. So, we're tending to buy like 1 or 2 percent of what a month might need ahead of time.

I should explain very quickly the way our procurement works. We have a contract with a gas supplier; the default is that the contractor will deliver all the gas to alert our customers. We have a full requirements customers of contracts, so that means all the volume will be delivered. And it will be delivered at a default price, which is the monthly bid week price for either northern California or southern California. So we have an automatic reliability, we will get the gas at the monthly price.

But then we go out and purchase, using that portfolio approach, forward purchases of gas, mostly on the futures market, mostly fixed price, but with some caps, some callers of a mixture of different approaches. And in terms of the length we go out as much as five years.

Some of our customers have contracts with us for as much as five years. But obviously, as a department, we can't buy gas for which we don't have a customer who's ready to take it.

So, our limit to how far we can buy in the future is how much the customers have contracted for and what their volumes that they've contracted with us for might be.

We have a risk management protocol. I don't know if this one made it into the slide handout, but a risk management protocol is simply the rules that you follow when you're going out to buy natural gas. Particularly when you're in a hedging kind of structure.

Some of the features of ours, we won't buy more than 75 percent ahead of time. We always will buy at least 25 percent on the monthly spot market.

That does a couple of things. One is it means that the monthly spot market is part of our portfolio. It's 25 percent of the portfolio automatically. When the prices are below what you had in the portfolio, you really welcome that 25 percent.

The other item is that there's a tremendous variation in volume with our customers. We do a lot of work to try to estimate volumes ahead of time, but we rarely get it right within a very tight tolerance. Usually within plus or minus 5 percent.

But by having 25 percent on the spot market we have a hedge against making a mistake about what our volumes might be needed. Remember, when you do futures purchases you're doing take-or-pay, which means that you committed to buy that gas whether you had a need for it or not. So you need to have a little cushion there to make suer that you've always got to use.

The purchases are always limited to actual usage. We never buy greater than what our customers will be using. The object here is simply to build in an absolute prohibition against any kind of speculation where someone is trying to essentially make a profit to buy down the cost of the gas. That's not allowed in our process.

We have a number of other different purchase constraints. I have to take certain purchases to my boss. We have a whole lot of review processes built in and so forth.

The other thing to add in is that as a program we find that some of our largest customers don't want to follow necessarily the portfolio of risk management that we're providing. They have other constraints.

A lot of times they have very large cogeneration units. For instance, UCD Med Center here in Sacramento has a very large cogeneration project. They have their own interest about how they want to buy gas.

And so we do what we call special purchasers. We allow the individual customers to come to us and direct us to make purchases just for them. Out of 135 customers about 20 do special purchases.

The thing that's interesting about special purchases is that it is a way that we understand how our customers are thinking about risk, and what they want to do, what they don't want to do. They are, in fact, even more, I would say, adventurous than we are.

Where we will make very small purchases for very limited periods of time, and build those up over time, the special purchases tend to be for larger amounts of the total gas that the customer needs. And they tend to run for longer periods of time. They value certainty very very much.

The last thing. The six rules I threw

in because this is something that we take to our customers. It wasn't meant for this workshop, but I included it.

The reason -- we do a lot of education of our customers. We have a very few customers that are very close to us that we have to keep. We spend a lot of time talking to them about what's happening in the gas market, what we're doing, why we're doing it and so forth.

That gives us the strength to be able to go out and do these things because we know we're clearly following what the customers have communicated.

The six rules is something that we give out in our workshop and talk about. I won't go through each one of them, but there are a couple of them, I think, that are germane.

The first one, ultimately it's about risk, actual prices paid are the consequential outcome of choices made about risk. And that's whether you know that you're making a choice about a risk or not. Whether you do or not, it's there.

The second point, you cannot make risk disappear. You can, however, change the type of risk that you face. This was mentioned earlier when Pam was talking about insurance.

You take the risk of having a multi, tens of thousands, hundred thousand dollar AXA, which you can accept. Then you have the other side, you change it into a risk of paying $1500 a month for car insurance. The risk is that you will pay $1500 and won't have an accident. But that risk is a lot more acceptable than the risk of a possible $100,000 exposure or liability in a car accident.

Skipping down here, number 4. This is my own statement. Anybody who wants to argue it is welcome to. There's two basic strategies.

One of them is that you simply try to buy at a discount against the price. If you've got a big enough volume you can command some kind of market discount.

The good thing is that you've always made a saving against that benchmark that you got a discount against. On the other hand, when the market goes up, you go with it, just a little bit behind, but you're still up.

The other choice, the one that our program uses, is that we buy at target; our benchmark is the customer's ability to have that meet their budget. There is a risk to that, and we're in that risk right now. My price to my customers is above the market, but it's below their budget. And that's what they care about. So they can accept that for the protection that we give them against the price spikes.

I'll leave that last one, people who can consistently beat the market tend to leave public sector employment. I have to keep reminding my customers that if I was as good as they wanted me to be, I probably wouldn't be here.

(Laughter.)

MR. CLARK: With that, I conclude. If there are any questions?

MS. BROWN: I had a couple of questions, Marshall. Nice to see you again.

MR. CLARK: Nice to see you, Susan.

MS. BROWN: It's been awhile. I gather from your comments that hedging is not something that you depend on for very much of your total portfolio, is that correct?

MR. CLARK: Well, we can go up to 75 percent --

MS. BROWN: Oh, really?

MR. CLARK: -- from now until June, we

have 75 percent of our expected volumes already purchased. It is a function of a couple of things. More than anything else, what our budget for our customers are, what the market is doing.

If the market is above our customer's budget there's not much point in locking in a loss for them, even though we will buy slightly at that time. When the market is below their budget that's when we buy. And if it is well below their budget, again we'll go right up to the 75 percent limit that we're allowed.

MS. BROWN: Are you doing month-ahead pricing, or month-ahead hedging, or do you tend to look at longer term periods?

MR. CLARK: We do across the spectrum. As I said, our customers have contracts. Some of our customers and therefore some of our volume goes out right now to June of 2014. And we have bought all the way out to June of 2014.

How much we buy out in those longer periods, it's less than say 10 percent out in that last year.

But mostly we are buying in the next anywhere from six to 18 to 24 months. That's where most of our purchases are occurring.

MS. BROWN: So you don't rely to any great extent on long-term fixed-price contracts?

MR. CLARK: Not to a -- if you mean like more than say 20 or 30 percent, no.

MS. BROWN: Thank you. It seems like, again, you mentioned this several times, the driver's really your bottomline budget --

MR. CLARK: It dominates.

MS. BROWN: Very different than what we heard from some of the other speakers today.

MR. CLARK: Well, it's nice to have a budget, a benchmark number to work against. Sometimes it's an inconvenience, sometimes it's a great thing. But it takes out one of the variables in the equation.

MS. BROWN: Well, thank you very much.

MR. CLARK: Certainly.

PRESIDING MEMBER BYRON: Mr. Clark, I would -- thank you very much for being here -- I would assume that the private sector works against budgets, as well. I mean the same problem you characterized for your agency exists in a private sector companies, as well.

MR. CLARK: I don't have direct experience, but I've speculated that the public sector is different. Our budget is so hard-wired, if you will.

In the private sector I suspect there are hard-wired budgets, but there's also the issue, I think, of competition. If I were in the private sector I wouldn't want my natural gas to cost me more than it costs my competitor. I would always be interested in staying competitive with the rest of my industry. And that is a different driver than what my customers have.

PRESIDING MEMBER BYRON: So let me explore that one a little bit further around this issue of confidentiality. Are your hedging strategies confidential? Do they --

MR. CLARK: No. I'm in the public sector.

PRESIDING MEMBER BYRON: Do they need to be confidential, though? Do you feel you're giving up some information as a buyer? That disadvantages you.

MR. CLARK: Well, we share this information with our customers. In terms of the market, our program is about a 1.3 percent of all the gas used in California. That's a whole lot, and that's not very much in terms of what's going on out in the market. I think we would never see the impact of a purchase that we made on the day's trading one way or the other. It's just -- it's so much bigger than we are.

PRESIDING MEMBER BYRON: Well, thank you.

Commissioner, questions?

ASSOCIATE MEMBER BOYD: Just thank you, Marshall. Good to see you again. Marshall is one of the folks that spent a lot of time in conference room with us during the fun years of the gas/electricity crisis. Good to see you again.

MR. CLARK: Thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Clark.

MR. TAVARES: Thank you, Marshall.

Next I think we're going to go to PG&E. I don't think they have -- they don't have a presentation, but they wanted to make some comments?

MR. ARMATO: Correct.

MR. TAVARES: Okay, that would be Mr. John Armato.

MR. ARMATO: Good morning,

Commissioners, and good morning, participants. I apologize for not having a prepared presentation. But much of what I wanted to say would have been covered by the SoCalGas presentation anyway.

Let me just give you a little bit of background. PG&E, as you know, is a combined natural gas and electric utility. PG&E does provide natural gas services to the core market and also the noncore market.

Most noncore customers, as was already previously indicated, are fairly sophisticated. They buy their own natural gas supplies. They have available to them storage services in PG&E service territory, offered both by PG&E and also two third-party storage providers.

And I suspect that they also engage in hedging when and if they feel it's necessary.

By the way, I work for the core gas supply side of PG&E. So my remarks are basically regarding the core natural gas procurement activities.

The average annual load of our department is about 800 million cubic feet a day. In the wintertime that kicks up quite a bit because we're serving the, you know, the core heating load. So it's over 2 bcf in the winter.

In the summer it drops down to about 500 million cubic feet a day.

We meet core load basically by buying gas. In Canada we have pipeline capacity access all the way to the Alberta Basin. We also have access to the U.S. southwest, mainly the San Juan Basin.

We buy gas in the basins and transport it to California. We also buy gas at downstream points if it's advantageous to do so.

Historically we've purchased about 60 percent of our gas supplies from Canada. And about 40 percent from the U.S. southwest.

Basically PG&E takes a wedding-cake approach to building its supply portfolio. The base layer is composed of multiyear and multimonth contracts. These are all priced, however, on published monthly gas indices. This represents up to 70 or 75 percent of our portfolio, depending on the time of the year.

The second layer i the monthly baseload. These supplies are purchased during the month for delivery in the subsequent month, the prompt month. And then, again, these are priced based on the monthly indices.

The third layer in the wintertime is storage withdrawal. We can provide up to 20 percent of core load in the wintertime through storage withdrawals.

And finally, the top layer, the last layer on the top of the cake, if you will, is our swing spot supplies. These are typically no more than 5 to 8 percent of our supply portfolio. And these are based on daily prices, either daily indices or fixed prices.

We do buy gas under our core procurement incentive mechanism, and that provides a means for cost recovery. And as SoCalGas already explained, the benchmark is basically comprised of a basket of monthly price indices.

Why monthly? Because that's what the market uses. It provides transparency for both the buyer and the seller. And it's also a very clear measurement or benchmark that the regulators can use in order to judge our costs.

A little bit about pricing. PG&E's policy is to avoid multimonth fixed pricing for physical gas contracts for a couple of reasons. One, of course our core gas customers' price is tied to the monthly indices through the CPIM.

Two, it reflects the CPUC policy that customer prices should generally follow the market. And three, fixed price contracts that, you know, in this day and age they would certainly subject PG&E to increased contract default and credit risks.

A little bit about hedging. PG&E does engage in hedging. I think our policy is to protect against price spikes, particularly in monthly indexes during future months, future winter periods.

Our purpose for hedging is not to reduce customer costs, but to mitigate the risks associated with high prices during these periods.

PG&E, like SoCalGas, has an approved, CPUC-approved hedging plan. These plans are established and executed in collaboration with the DRA and TURN. We hedge with financial instruments, not physical deals. We have swaps that create fixed positions. We all use call options to create price caps.

We do have storage. Our storage, however, is limited to about half, less than half of what SoCal has. So we have far less flexibility in our storage. Therefore, for PG&E storage is generally for reliability. However, storage does protect against spikes in the daily and monthly prices.

One thing I want to say about customer risk tolerances. If you're not aware, PG&E has engaged in the services, in fact we hired a vendor, to survey our customers. And basically ask them some questions that would help determine their actual customer risk tolerance.

Unfortunately, the timing doesn't help this group here. We don't have the results yet. The survey is finished; it's completed. The vendor is currently going through the survey and finalizing its report. I haven't seen or heard any preliminary data from this, so I have nothing to report.

I did, however, in preparation for this workshop, I did, however, take a look at something that PG&E has some data on. And that is our customer inquiries. PG&E receives a number of phone calls every month from customers requesting more information about all sorts of things.

But there are also quite a number of questions about bill costs. And I took a look at the data over the last three winters and the last two summers. And there is a pattern. And that is PG&E receives much more bill inquiries in the wintertime than it does in the summertime.

In fact, when I looked at the inquiries that PG&E received last summer when gas prices were, as we know, upwards of $12, and compared those to inquiries during the previous summer when gas prices were about $4. There was no difference.

So I'll just plant this seed. I'm a little concerned that this Commission and a lot of people are very concerned about the effect of gas price variability on core customers. I'm not sure PG&E's core customers really feel those effects. They're more concerned, and they have more questions and more issues when their bills go up because they're using more energy.

You know, to me it's an indication that temperatures and customer usage is a far more important element than gas prices. That's not to say that there are customers that don't desire or are not, you know, interested in fixing the price of gas.

And for those customers, like PG&E, we

do have a balanced payment plan, where customers can elect that plan and basically spend an even amount throughout the year on their individual monthly bills.

Customers in our service territory can also avail themselves to the core aggregation services. Core aggregators can fix the price. And I am aware that some of them do offer that to our customers. So that's another avenue that our core customers can choose if they're eligible and if they're very interested in, again, having a fixed portfolio price.

That's about it. I think everything else was previously covered. I'm available for questions.

PRESIDING MEMBER BYRON: Mr. Armato, thank you for being here. It's too bad you don't have the survey results, I think that would be interesting. And this Commission would be interested in seeing those, as I suspect would the Public Utilities Commission.

This balanced payment plan, can you give us a sense of how many customers, core customers, participate in that?

MR. ARMATO: Not very many. The

interest is pretty low --

PRESIDING MEMBER BYRON: Which would, I think, support your point that they're not too concerned about these prices.

MR. ARMATO: They don't seem to be. Out of our 4.2 million customers, there are approximately I think it's 350,000 customers, about 350,000 customers have signed up for the balanced payment plan.

PRESIDING MEMBER BYRON: And can you reveal, are those primarily low-income customers?

MR. ARMATO: I don't know. I don't know the breakdown.

PRESIDING MEMBER BYRON: I'm just curious, how much fluctuation do you see in gas demand amongst your core customers year-on-year, say December-to-December kind of comparison? I would imagine it's all temperature-related, correct?

MR. ARMATO: Definitely temperature-related.

PRESIDING MEMBER BYRON: Are you seeing any general growth or, would like to say, energy efficiency improvements in gas use that's causing a reduced demand?

MR. ARMATO: We're not seeing much, if any, growth. I think a lot of customers are conserving. It's hard to say what attempts are being made to conserve, but I think it's quite clear that customers are conserving.

PRESIDING MEMBER BYRON: I have a very simplistic question. Given that year to year it doesn't fluctuate very much, and your customer base is not going anywhere, why don't you look at making long-term purchases, particularly at a time like now, for natural gas? I mean many-year purchases going forward. Is there any advantage to your customers if you were to do something like that?

MR. ARMATO: I assume you're asking about maybe long-term purchases based on a fixed price?

PRESIDING MEMBER BYRON: Right. I mean we just heard General Services talk about 75 percent.

MR. ARMATO: Um-hum.

PRESIDING MEMBER BYRON: That kind of purchase.

MR. ARMATO: Well, there's always room for regret. For instance, --

(Laughter.)

MR. ARMATO: -- had we purchased last summer fixed price gas at $12, and here today gas is, you know, $3.50, $4, I think a lot of customers and our regulators would not be too happy with that.

Again, I think the whole marketplace is really geared toward these short-term purchases. And long term for us is a year. But we do price that at the monthly index for a couple of reasons.

One, it's PUC public policy. Two, that's how we get reimbursed through the CPIM. If we were to go out and sign up for fixed price, we got supplies, we would be taking a risk, the shareholders would be taking a risk. So would the ratepayers.

PRESIDING MEMBER BYRON: And how much of the state's gas purchase does your company represent on an annualized basis? GSA said they were about 1.5 percent, I believe.

MR. ARMATO: You know, I don't know the answer to that.

PRESIDING MEMBER BYRON: What I'm driving at is that you're obviously -- you're probably a very large purchaser of gas for core customers. And if you were to stretch out these purchase periods, other than the way the market's currently set up on a monthly basis, wouldn't that help moderate these tremendous fluctuations that we see in the price of natural gas, as well?

MR. ARMATO: We do take a portfolio approach. We do try and spread out our purchases. However, no, we don't go out beyond a year particularly.

I'm not sure how that would really help, to tell you the truth. I don't see how that might moderate the prices.

PRESIDING MEMBER BYRON: I misunderstood you, when you were describing your wedding cake.

MR. ARMATO: Yes.

PRESIDING MEMBER BYRON: The annual purchases, were that up to 30 percent?

MR. ARMATO: No, sir. They were up to 70 to 75 percent.

PRESIDING MEMBER BYRON: Okay.

MR. ARMATO: But they're multimonth and annual purchases. The base layer of the wedding cake is composed of multimonth and annual purchases.

PRESIDING MEMBER BYRON: Okay, so I

can't break those out, then. Any other questions?

MR. ARMATO: It's probably more -- it's definitely more multimonth than annual. But I don't have that breakdown.

PRESIDING MEMBER BYRON: Mr. Armato, thank you.

MR. ARMATO: Thank you.

ASSOCIATE MEMBER BOYD: Yes, thank you.

MR. TAVARES: Thank you, Mr. Armato.

Commissioners, we're scheduled for a short break so that the panel will all get together here. Would you like to take a break for about ten minutes, and then come back? Or do you want to proceed?

PRESIDING MEMBER BYRON: I think we're in agreement for a ten-minute break, Mr. Tavares.

MR. TAVARES: Okay.

PRESIDING MEMBER BYRON: Okay.

MR. TAVARES: We'll have a break.

PRESIDING MEMBER BYRON: Thank you.

(Brief recess.)

MR. TAVARES: We're going to continue now. We're going to have a panel discussion. In addition to the speakers this morning, we have another two persons. One is joining us by telephone, that's Richard Meyers from the California Public Utilities Commission. Richard, are you there?

MR. MEYERS: I am.

MR. TAVARES: Okay, welcome.

MR. MEYERS: Thanks.

MR. TAVARES: We also have Ray Welch. He's from Navigant Consulting. He's actually an Associate Director from Navigant. He actually spent 14 years at PG&E in the natural gas market.

So, with that, I will have Lana and Katie Elder, from RW Beck, moderate the panel. And go ahead.

MS. ELDER: We're back. So, welcome to the game show portion of our schedule today. We have a lovely set of panelists, some of whom you've heard from already, Commissioners. But, we thought we'd give the two that you haven't heard from yet just a chance to make a couple of comments. Ray Welch from Navigant Consulting; and then we'll go to Rich Meyers off on our ethernet here.

So, if you'd like to make a couple comments here, Ray, go right ahead.

MR. WELCH: Thank you very much.

PRESIDING MEMBER BYRON: Go ahead; make sure that your green light is on on your microphone button. Okay, thank you.

MR. WELCH: It is, so are we live here?

MR. SPEAKER: No.

MR. WELCH: Great. You can't hear it?

PRESIDING MEMBER BYRON: Just bring it a little closer and we'll be able to hear you.

MR. WELCH: How's that? Is that better? Okay, great.

First, I appreciate the opportunity to participate on the panel today. As Ruben said, I was portfolio manager for PG&E for a core gas group for ten years.

And so when I learned just the other day that this panel was convening, and there was a potential for my participation, I jumped at the chance. So I really appreciate being brought up today.

I guess through my experience and market observations over the years I think that in the long run reducing demand is the way to approach cost reductions rather than hedging.

I mean, hedging to reduce costs is chasing a will'o'the wisp from my perspective.

Hedging, as an impulse to sidestep the market is a misguided impulse. The costs are what they are. We're all part of the dynamic that is the market.

I think a lot of the comments that we've seen so far reflect my sentiments on this issue, that there really isn't any way to sidestep the market in the long run, any more than we can sidestep, for example, the climate crisis.

It's simply something that is part of -- it's environmental, and we're part of that environment. And the notion that we can hedge to reduce costs, I know that seems to be part of the CPUC mandate in the OIR, is, I think, kind of phobic, really. That's the word I would use for it.

And there's really nothing to be done for it. We're all part of this market. It's a dynamic where our actions or inactions feed into the totality of the picture.

I have a little thing here just to kind of quaintly put it: Hedging and expecting to beat the market is kind of like getting married and expecting to continue to play the field.

(Laughter.)

MR. WELCH: It's a compelling fantasy,

but it's bound to produce heartbreak if acted upon.

MR. DYER: It's worth a try, though, isn't it?

(Laughter.)

MR. WELCH: So hedging is about risk reduction, it's about specific risk reduction. It's about risk that's been thought through beforehand and accepted beforehand. It's not about the risk of prices going up necessarily. It's about a more targeted sort of thing.

The DGS, for example, has a budget it's trying to manage, too. And so if it can manage to buy its gas below that target, it's happy with that, in advance, even though they might be offside with the market when the actual time of delivery comes.

But that's a thought-through and valid, I think, risk management objective. And I think, in a lot of cases, hedging and risk management are sort of not really thought through to that level where there's a concrete objective. And it gets -- the objectives get sort of meshed in with market performance. And I think that's a real mistake.

I think the distinction between your objective and market performance has to be very very clear; that those two things should not be conflated because it will lead to confusion, second guessing, public policy problems and ultimately disappointment, because you can't beat the market. The market, in the long run, is what it is, and we're all part of it.

MS. ELDER: Rich Meyers, have you got anything you'd like to throw in here?

MR. MEYERS: I'd just like to say that I think from the energy division's point of view and I think the Commission's, in general, point of view is that the gas cost incentive mechanisms have worked quite well over the time period that they've been in place.

And I think they've certainly worked quite well compared to the kind of regulatory framework we had prior to the incentive mechanisms being in place.

And I've been involved with natural gas issues for I guess close to 20 years now. I can remember the period when we did conduct reasonableness reviews and I think not only were the reasonableness reviews that we did conduct quite contentious and took a long time, and took up a lot of resources for both the utilities and the Commission.

But once, I think, the incentive mechanisms began to be implemented it not only reduced the time spent on reviewing utility gas purchases, but it resulted in lower gas costs.

And so I think it was beneficial from that viewpoint, as well. I mean especially when you look at the comparison of the utilities' gas costs, when there is a reasonableness review framework in place versus the cost compared to market prices once the incentive mechanisms were in place, I think the incentive mechanism framework is a far better framework overall than what we had before.

And I think that's basically just what I'd like to say.

MS. ELDER: Thanks. I thought what we'd do is kind of go around. I know a couple people, in their remarks, answered this question, but I thought it would be good to see if we could get all the panelists to share this little bit of information.

And that is how much gas do you buy. So

I'll start way down there with Herb.

MR. EMMRICH: Is this microphone on?

MS. ELDER: I think that's the one that goes to the -- there's one that goes to the webcast and one that goes to the room. So you have to sort of make sure you talk into both.

MR. EMMRICH: We purchase 1.1 bcf of gas a day on average. And in the wintertime would be 10 percent more.

MS. ELDER: So SoCal's buying 1.1 bcf a day in the summertime, and maybe 10 percent more than that in the winter.

MR. EMMRICH: If it's a cold year.

MS. ELDER: If it's cold, yeah, yeah, yeah. Okay, great, thanks.

Pam.

MS. TAHERI: We do about 40 bcf a year. That's just as comparison to yours is how much a day.

MS. ELDER: And I thought earlier, I thought you'd said about 80 a day, maybe up to 120 mm cf's per day?

MS. TAHERI: Is averaging about 120.

MS. ELDER: Great. And Laird's selling gas, so --

MR. DYER: We buy it, too. We're obligated to purchase, they're called Shell Rocky Mountain Productions, our producer entity in the Rockies. We buy about 350 million a day from them. And then we trade with that volume included about 2.1 bcf a day in the west.

MS. ELDER: In the west. And can you break that down, how about being for just California?

MR. DYER: Gee, we don't think of it that way. I would be guessing at the number, but maybe half a b a day, --

MS. ELDER: Okay.

MR. DYER: -- little bit better than that.

MS. ELDER: Thanks. And, Marshall, tell us again how much. I think you mentioned it earlier, but I've forgotten already.

MR. CLARK: About 32 bcf a year; in terms of the daily flow, between 80 and 100 mmBtu.

MS. ELDER: Between 80 and 100 mmBtu a day.

MR. CLARK: Yeah.

MS. ELDER: Great.

MR. CLARK: A thousand mmBtu.

MS. ELDER: I would leave off those three zeroes.

(Laughter.)

MS. ELDER: And I think John mentioned earlier, what, 800 mm cf per day?

MR. ARMATO: I did. On an average annual basis about 800 a day for the core portfolio. In the wintertime that averages about a little over 2 bcf. But in the summertime it drops down to about 480, 490.

MS. ELDER: So, I'm too not quick enough to add all those numbers together, but I'm thinking, just in a ballpark term, so that we've probably got represented here close to half the California market?

MR. EMMRICH: Well, SoCalGas is about 18 percent for the core.

MS. ELDER: So another question I thought maybe it would be good to all answer would be to talk a little bit about customer bills. And what kind of bill size does your customer see in terms of maybe an average bill size. What kind of dollars would they see typically, just to kind of put it in perspective.

MR. EMMRICH: Well, in the summertime

it's about $30; in the wintertime, this year it's $67. But in some years it's been over $100 in the wintertime.

MS. TAHERI: We average about $70 per month, that's for electric.

MS. ELDER: For electric service about $70 per month.

MR. DYER: -- my first is the one I get on my house. It's about $400, 13.4 therms, 1205 in mmBtu.

MS. ELDER: That was your last household bill?

MR. DYER: My February bill, yes.

MS. ELDER: Your February bill. Okay.

MR. CLARK: Finally one that I get the big numbers. Our customers average, I think, for the whole group, about three-quarters of a million dollars a year.

Ranges all the way up -- I have one customer that's spending, oh, about 2.2 million a month. And it goes all the way down to Yosemite Community College, which I think my house bill is bigger.

MS. ELDER: Okay.

MR. ARMATO: And, Katie, for PG&E it's

about what SoCalGas' customers pay. One difference is although SoCalGas has more core customers, I think we have a greater variability in the load. We serve 58 counties in California, everywhere from the desert to the mountains to the coastal areas. And we probably do have customers that maybe, on average, have a higher usage than some of the SoCal customers.

MS. ELDER: So you're going to have much wider variability among the use of those customers, and therefore in their bills.

MR. ARMATO: I would expect that, yes.

MS. ELDER: Because of the climate variation across the service area.

Sort of in that same direction John talked earlier about balanced billing and had some numbers in mind about how many customers are using the balanced billing service. But I thought the Commissioners would be interested in hearing that data for the rest of you folks.

MR. EMMRICH: SoCalGas, we have about 4 percent of customers choose the level pay plan. So it's a very small amount.

MS. TAHERI: I actually don't know that.

MR. DYER: It's not pertinent to this,

but I have opinions on it.

(Laughter.)

MS. ELDER: Well, tell us your opinion, Laird.

MR. DYER: Number one, the level pay plans -- that's hard to say -- the LPPs, they do a couple things that we're not particularly thrilled about.

First of all, they don't address the underlying portfolio, volatility in the underlying portfolio. Secondly, they mute cost signals to customers, which I think we all agree is something, the customers that see price signals. And they mute not only price, but usage. So if you have a demand responsiveness program they negatively impact those, as well.

And last, you're not going to get everybody in the state, every customer, to go, yeah, okay, I'll go for a level pay plan.

So the utilities are still faced with, you know, if the Commission is true in its objective of launching volatility mitigation, the utilities still have to deal with that.

MS. ELDER: So your view would be the level playing plans, or balanced billing plans, aren't really a substitute for a comprehensive hedging program.

MR. DYER: I think they're a great idea, they're kind of fun, but it mutes too many signals, and they don't really solve underlying problems.

MS. ELDER: Marshall, how do your folks deal with that?

MR. CLARK: We don't have any level --

MS. ELDER: They really can't.

MR. CLARK: -- plan for it. With a $260 million a year business I have zero working capital. So, everything settles every month.

MS. ELDER: And I think John had said about 350,000 out of, was it 4 million?

MR. ARMATO: Yeah, out of about 4.2 million customers, a very small percentage.

MS. ELDER: So that's going to be what, maybe 6 or 7 percent --

MR. ARMATO: Close to 5, yeah.

MR. WELCH: Katie, if I may?

MS. ELDER: Yeah, please, Ray.

MR. WELCH: I think the idea of pricing is a really interesting one to maybe talk about a little bit. Because I think that's a primary policy issue that the state might want to influence and have an opinion about.

To what extent do they want price signals to reach a population and make them responsible to make decisions about their own energy usage.

Because anything that we're talking about here today, whether it's a balanced payment program or hedging, we'll mute that signal. I mean that's the whole point is to take the volatility out and not let that signal get through to the consumer.

From my point of view, just speaking as an individual citizen, not as a gas person or a hedging person, but just somebody who gets a bill, I'm really interested in how much my bill is. I'm not particularly interested in having to develop a measurable percentage of my life in figuring it out.

I want to understand what the bill is and its relationship to my usage. And I do recognize that the usage component is the one thing that I can control. I can turn my thermostat down. I can cook differently. I can rearrange my living patterns. But I can't control the price.

So to complicate my life with a bunch of choices about, you know, portfolios and involve me in the public policy machinations of whether we should be hedging or not, from a consumer point of view, I think, is really expecting a lot of a consumer. It's really putting a burden on them that they don't want.

MR. MEYERS: This is Richard Meyers to follow up on Ray's point. The California utilities change their prices every month to allow customers to see what the changes are in the price that they're paying so that they can make their decisions about how much they want to use.

And this wasn't always the case. This is only been -- this began to be the case, I think, in like the early 1990s or mid 1990s.

Before that, the natural gas procurement price was set for a year, or even two, I believe. And so it was only the case that the natural gas procurement price that the customer saw changed every month beginning about the early to mid 1990s, so that customers could see what the variation in price actually was.

MR. WELCH: Now, that being said,

there's a lot of problems with trying to get that price signal to the consumer. Because it's always after the fact. You're always seeing your bill two months after the prices have happened. So it's very very difficult to adjust your behavior in real time.

And I'm also very sensitive to the idea that -- hedging to me is a good tool to use to mitigate those kinds of bill situations -- I'll avoid the word price, but I'll say bill situations -- for particularly low-income people where it's going to force them that month to choose between food and fuel.

That seems like a legitimate public policy sort of approach for hedging to me, to make sure that bill doesn't put somebody in that position.

But just to mitigate volatility for the sake of mitigating volatility seems very abstract, theoretical and ultimately sort of pointless.

MS. ELDER: I know Herb wants to jump in here.

MR. EMMRICH: Yes. We do believe that the pricing or the monthly change --

MR. MEYERS: I'm having a hard time

hearing Herb.

MR. EMMRICH: Is this better, Richard?

MR. MEYERS: Yeah, thanks.

MR. EMMRICH: We do believe that the monthly price signal is very important. And if you look at the electric side, they're talking about critical peak pricing which is going by the hour in order to give customers the incentive to reduce their usage.

We have monthly metering and we have monthly pricing, and the industry, on the gas side, is a monthly industry basically for probably 80 percent of the volumes.

So I think we are in tune with that. We certainly don't want to go to daily pricing, but because we do have storage and we can draw on that to even it out.

But the monthly pricing is important to us and it's also important for energy efficiency that the customers get the right signal that it's more expensive to use gas in the wintertime than in the summer. And that we can conserve pipeline capacity and storage capacity and so on.

MS. ELDER: John talked earlier about kind of the bill responses -- or, I'm sorry, the customer inquiries, I'm not using the right terminology, from core customers and how that varied over the course of the year.

I'm just wondering what SoCal's seeing on that front, what's it hearing from its customers?

MR. EMMRICH: Well, obviously when it gets cold and the bills go up, we get increased calls through the call center that we have to respond to. We have more high-bill complaints and so on.

But it's basically the level of the bill; it's not just the gas price. If the gas price is high and it's a warm winter, you don't get those calls --

MS. ELDER: Right, --

MR. EMMRICH: -- gas bill. It's like --

MS. ELDER: -- and so what I think I heard from both, you know, the big gas utilities, is that customers are calling about their bill and they're not necessarily, in the context of that phone call, mentioning the price. It's not clear if they're really not paying attention to the price, or if they're -- do they know the price and are just not mentioning it, or do they not even really know the price?

MR. EMMRICH: Well, I've worked for The Gas Company, and when I get my bill I look at the bill.

(Laughter.)

MS. ELDER: You and I are different, though.

MR. ARMATO: For PG&E customers I think what we've experienced is that customers sometimes don't even distinguish between the electric portion and the gas portion of their bills. They just look at the bottomline, and they say, why is my bill so high.

MS. ELDER: And Pam's nodding her head. She's got the same experience with electric customers for SMUD, I'll bet.

MS. TAHERI: Yeah. Usually it's like a hot summer day, like a couple years ago when it was 110 degrees for a number of days. And then our summer prices is also -- we have like two seasonal prices on the electric. So that's when we get the calls.

But, again, as an individual I would agree with some of the other panelists' observations, which is I look at my bill. If it's small enough I'm not going to pay attention. And I work in this industry. If it's big, then I'm going to start digging into it.

MS. ELDER: Marshall, did you have something you wanted to jump in on?

MR. CLARK: Well, just again, our situation is somewhat peculiar. But we publish on the 5th of every month, once we've got the bid week price, we send each customer a price sheet that shows them what their price for that month will be by the 5th of the month.

That's primarily for the cogeneration operators who want to use that input to decide how they're going to run their cogen plants.

But we give them that price ahead of time. And in that same sheet we always send them a whole year. It's both the actual to-date, and a projected for the rest of the year, using just the future curve for the market price.

And down in the bottom-right there's a number that says, based on today's information we project that your total bill for the year will be such-and-such. And, of course, that changes every month.

But what we see from our customers is

that as long as that number stays below their budget, we never hear from them. The minute it starts edging above their budget, we hear from them constantly.

So, again, it's they're matching the information they get to their own benchmark. And as long as it's staying below the benchmark they don't care.

MS. ELDER: That reminded me of a point, I think that you made earlier, Marshall, is that you're really managing your gas procurement expense to budget. And other folks, I think, are managing to different benchmarks, if you will.

I don't mean to imply that the benchmark that's in the incentive mechanisms. But I think it might be the case that SMUD, perhaps, is managing more for rates and rate stability. Is that a fair characterization, Pam, or am I overstating it?

MS. TAHERI: On an overall basis that's absolutely true. We manage to the rates. In our situation it's similar to the DGS program. But what we do is actually we know that our fuel budget, and the wholesale size, the one that swings the most.

And as we all know, the gas price and electric price track pretty closely for the most part, unless it's a really wet or dry year.

But having said that, what we do is when we go into setting the budget cycle we pretty much have to lock in most of our open positions. So that we could then say, okay, we know what our budget is, and it's not going to be changing too substantially.

During the year we also have to worry about the volumetric risk, and also the price risk associated with hydro, because we also, as I indicated earlier in my presentation, a pretty substantial piece of our portfolio is based on hydro. So if you have a dry year, you got to also manage that, as well.

So, we do try to lock in most of the position by the time we set the budget.

MS. ELDER: One of the kinds of gas buyers that we didn't get onto the panel for you, and I'll sort of try to substitute for them real quickly, is we didn't get anybody who actually is just a merchant generator who's buying natural gas to fuel a single, or maybe a handful of power projects.

It turns out that I advise those folks quite a lot. And most of those folks are actually way different than any of these folks here on your panel in that they really are buying gas on the day market. And they don't give a rip what the price is, as long as the price of gas tracks the price of electricity.

Because they won't know until maybe a couple of days or the day before that they have to go out and buy the gas, whether they're going to get dispatched on that day.

And so what they're trying to manage is the link between the electric price and the gas price. So, a totally different issue. Laird may have some more experience of selling gas to those people.

MR. DYER: Well, I agree with you. I mean they are basically a processing plant. They're taking one form of energy and converting it to another. And it's a (inaudible) of their own, which is --

MS. ELDER: Right, right.

MR. DYER: -- and they don't want to hedge, because they're making a bet on where the true prices are.

MS. ELDER: And their banks that finance them don't want them to hedge, because the bank doesn't want that risk transferred to them.

MR. DYER: We have had folks, though, that will hedge both ends. Will hedge against price and the power price, lock in a margin --

Now, they do take some unit contingent risk with that. So we tend not to like doing that with entities of one unit. But when they have, you know, may have three or four, that's not a bad approach, as well, for at least a portion.

So we see that among the municipals.

MS. ELDER: And similarly, the municipals, we've got SMUD here, but we didn't get some of the smaller municipals like Palo Alto. Was down working with Palo Alto a couple weeks ago. One of the things I heard was that customers were upset in terms of the response back to the utility, feedback back to the utility, that natural gas prices had fallen since last summer, but the prices on their bills weren't dropping.

So, maybe some confusion there between it's the fact that it's winter, that consumption's higher so the bill is higher. But some of them may have actually, maybe in Palo Alto, paid attention to summertime prices versus winter prices. They're smarter in Palo Alto there than the rest of us.

MR. DYER: Well, they actually run a three-year program in Palo Alto. They buy --

MS. ELDER: They have a laddering program.

MR. DYER: Yes. And so their city council actually likes increase in prices because it makes their purchase price look good. And summer prices could fall. Of course, they've locked in, you know, $8, and it's $3, and they're like, well, you guys don't know what you're doing.

So it's really difficult to try -- people think there are gains and losses when hedging. And that's the underlying problem.

MS. ELDER: Well, Pam talked about that some when she talked about there are years that you look like a hero, and there are years you look like a dunce.

Maybe could you expand on that just a little bit, what we're getting at there?

MS. TAHERI: Well, that depend on when you retire.

MR. DYER: Well, yeah.

MS. TAHERI: Yeah. If you do a laddering program obviously there are good years, there are bad years. And it shows very much. Right now doesn't look so good because we also do some laddering program. But who's to say, tomorrow something could happen and prices go back up.

So, a lot of it is that you have to take your -- recognizing that there is a price. And then it's a policy issue in terms of, you know, what is that risk appetite. It's the stability versus, there's a certain amount of price that you have to pay.

MS. ELDER: Laird, yeah.

MR. DYER: Underlying all of this, and I don't want to be presumption that, you know, we're just price takers in this marketplace. I reject that outright.

There are many tools available to us in the marketplace to assess our risk. There's obviously fundamental analysis just looking at the flows of gas. And you can make -- there's some pretty astounding things going on in southern California right now, as the prices in the middle of 2006, that paint a very bearish picture for prices in southern California going forward.

Then you also apply to that some technical analysis. And between the two you can make some pretty decent calls. That's how we make our living. Our job is to -- we're not only, you know, not only market, but we're a trade shop. So we spec in this market.

And so we make big bets at times based on our fundamental technical view. And, you know, it's our money on the line.

And so I don't adopt the -- just, you know, prices are what they are. Yes, the market is what the market is. But you can defend and you can be aggressive at times. And today's the day to be aggressive, frankly. Just the way the market's set up right now.

MS. ELDER: And we should be aggressive because prices are low?

MR. DYER: Well, they're below the replacement costs.

MS. ELDER: Below the replacement costs.

MR. DYER: And that should always be a signal to you to be, gee, I should be thinking about buying long-term gas.

Now, frankly, the market is very

contangled right now, meaning that the prices are -- it's quite a steep slope. But through the summer when we start getting some LNG, and that may change.

Nonetheless, we should be prepared to be long-term buyers.

MR. WELCH: Could I jump in?

MS. ELDER: Well, -

MR. FOX: Just a real quick question for those on the phone. I am Patrick Fox from PG&E. Earlier I thought you speculated that the market was going down to $2.

MR. DYER: Yeah.

MR. FOX: So wouldn't it be better to wait then, and buy your long-term at $2 versus today's?

MR. DYER: Well, you have an investment portfolio. I've never picked the bottom in my life, ever. So what you do is you look for the appropriate risk/reward profile.

And I would now and say, gee, we're at $3,80 on the NYMEX right now, 2.50 might be the bottom, it's $1.30 downside. We've seen $13 and $15 on the upside.

My risk/reward profile tells me I should be a buyer here. Now, I might have to live through $2.50, having bought $3.50 gas. But I'd be pretty happy about that four or five years from now.

MS. ELDER: And there's that issue of regret and how much regret you're willing to bear as part of your risk/reward profile.

MR. DYER: Making an informed choice.

MS. ELDER: Ray wanted to jump in here.

MR. WELCH: Yeah, I would agree with Laird to the extent that there is information available that somebody who's competent in the market can analyze and make use of and take the risk, that analysis, and put their money on the line.

And that is probably -- that's definitely appropriate for an organization like Shell. Whether it's an appropriate response or an appropriate activity for an investor-owned utility that's regulated, that has this larger public policy sort of overlay to it, I think that's a different question.

There are many different risks that apply to that kind of decisionmaking that are external to the gas market. The most spectacular one, of course, right now is the credit meltdown.

And so that could have a really really -- it's an unknown and extremely strong effect on gas prices going forward for a long time to come. It could depress them for quite a bit.

I'm not saying that it will. I'm just saying that's a risk. So, to put my money on $4 or $3 or $2.80 is something of a risk.

And if I'm concerned about market performance, and even despite the fact that we have all disavowed market performance as a real measure of the effect of hedging, we still keep coming back to it in this conversation. So, it's always there.

So getting in at $3, $2.80 is perhaps not going to play out against the market as people would, you know, down the road ultimately would have liked to have had happen.

MS. ELDER: It seems like there's a question, and you're sort of getting to it, Ray, a little bit. And that is, you know, we all agree the market's volatile. We can put the graph up and we can look at what the monthly index has done over the last umpteen years. And we can see that it's jumped all over the place, in this last year, we've experienced extraordinary swing between the $13 and -- or $12.something, high $12s in June and July, and back down to the $3s now, maybe.

But the question, one question is who's best equipped, or who do we want to manage that volatility for us. And I don't know the answer. I think that different people would probably answer that differently. But Laird's got an answer, I can tell.

(Laughter.)

MR. DYER: With that introduction, I would submit that gas procurement or gas purchase should be a core competency of the utility, given who they represent.

And to suggest that it's not or is not necessary, or that they're just going to follow the market, I think, is incorrect. I think -- I would argue that I think the best model is the SMUD model.

Have the utilities report back to the citizens. And if they don't do a good job, and they gouge you on prices, well, you get a school out of it, or more paved roads, or more police officers. At least the benefit returns back to the community.

So I think it's a better model than the IOU model, frankly, for California. It's proven to be so, so far.

MS. ELDER: And interestingly, I'm hoping that John Armato is sitting there snickering because he may well remember that I personally had that argument with Gordon Smith at PG&E about 1990 or 1991. And I lost.

(Laughter.)

MS. ELDER: And procurement was set up to be done according to an index where we filed a short-term index and the utility minimized its risk because there was no upside for the utility in being a gas purchaser.

And John may have a different -- something different he wants to add to that.

MR. ARMATO: No, I'm not sure I really want to add to that. It's just a, it's a question of risk. And who's going to bear the brunt of that risk.

And every time there's a hedge put on, or every time there's a fixed-price long-term gas contract that has been purchased, that really does represent a huge risk to the utility shareholders.

So perhaps until such time as that is

resolved, then the situation is just going to be status quo.

MS. ELDER: So I know that there's a proceeding that's going on at the PUC. And we didn't really want to, you know, go into the guts of that proceeding.

But let me just test whether or not this is a fair characterization. Is it correct that proceeding's really looking at hedging and how hedging should be incorporated or should not be incorporated into the mechanism? It's not really looking at the question of the mechanism, itself, is that right?

MR. DYER: I think that it would be characterized -- the CPUC has two procurement goals. They identify volatility and mitigation in the OIR. On top of, I would think, that their long-standing low-cost procurement goal.

And so it's addressing how do we incorporate this new objective within the existing framework, or what do we do differently. I think it's that wide open of a question. It doesn't presuppose that it has to be involved, included within the mechanism. It can be kind of anywhere.

So, we think it can be included in the

mechanism, but that's just our opinion.

MS. ELDER: And then Pam has to live and breathe it every day.

MS. TAHERI: I think it really gets down to our customers. We don't have a pass-through mechanism. So we have to live with whatever it is that we do as a result. We hedge significantly.

But, as I say, depending on where the prices turn out, I mean our customer has enjoyed very stable and low rates for many years because of that particular strategy.

But to the extent, if it turn out that the deals are not as favorable as compared to the spot, like it is now, it could very well that our customer could have a different perspective now. And if that is the case, I'm sure we will hear about it.

And it's possible that we could be potentially, and I'm not taking a SMUD position in saying this, it's possible depending on what our customers' reactions are. It could potentially change our strategy going forward. Although I'm not predicting that at this time.

MR. EMMRICH: Well, of course, we are actively participating in the proceeding, but it's, you know, if it ain't broke why fix it. We've got a proven track record that by buying monthly we've got the lowest rank and the lowest cost of gas every year, and over the last 14 years.

So, there is always room for improvement. We have an open mind. If somebody can show us how that benefits customers, the cost of the hedging doesn't out-weigh the benefits, then we have an open mind to that.

But right now we feel very comfortable with the incentive mechanism we have, that monthly price signals that you have, and the customer satisfaction that we have. Customers are satisfied with what we are doing for them.

MS. ELDER: Any focus group work with customers? I'm just curious what we know about what customers are actually looking at on their bills.

What I'm thinking, I'm actually working on a rate case in Utah where the local utility has got evidence from survey that customers aren't looking at the third tier of the electric rate. And so they're not even looking at it.

Pam's going, yeah, my customers don't

look at it, either. Because Pam and I don't look at it, nor SMUD customers.

MR. EMMRICH: Well, we keep in contact with customers all the time. And we do have focus groups and so on to respond to customers' needs. That has not been a big demand at this point in time.

Of course, if we go to $15 gas prices, that all would change. But we don't see that in the medium- to long-term, especially with LNG coming on big-time in this coming year. And next year.

So the delivered price of LNG is probably going to put a lid on gas prices in the $4 to $5 range.

ASSOCIATE MEMBER BOYD: Katie, could I ask a question --

MS. ELDER: Yes, sorry, please jump in.

ASSOCIATE MEMBER BOYD: -- of the group. This is very interesting, but I'm just wondering what the role of storage in California has been with regard to all this discussion of California having, in the past, and kind of atypical, having had pretty decent storage.

And then I want to reflect on what I

think was an experience during the electricity crisis. There were actually people telling the then-governor that we have to go buy into the gas business just like you've had to do with electricity. It's really the gas business that's driving this electricity crisis.

And many of us had to look at that situation and come back and say, you know, there's really a better market in the gas world. And, you know, we think you should leave it alone and let it play out.

But the observation, and Marshall may remember this, is that at that point in time, during that alleged crisis, storage was way under-utilized. And it's kind of like it seemed that one year that after restructuring of the electricity industry, gas folks didn't put gas in the ground like they historically had.

And after that year, no matter what the price was in the summer, everybody's, you know, chucking it back in there, filling up storage.

So, what role does storage play in this situation in California, and what we're seeing in this discussion about hedging in the market and price volatility?

MS. ELDER: I know, Herb talked about that earlier, so I'm thinking he might want to expand on that a little bit.

MR. EMMRICH: Well, from our perspective, of course all these crises and so on have motivated us to increase storage. We had 90 bcf of storage; we now have 131. And we're expanding another seven. We'll have 138 bcf of storage.

There's all kinds of storage coming on in northern California, private sector development. PG&E, I believe, is buying into some of that storage. And nationally. So with that goal moderate some of the pricing that we're -- price swings we've had before.

And also LNG is coming online. And with LNG, we'll again have a moderation of those volatile prices that we've had in the past.

It's essential that the customers put that gas in storage and not bet on a warm winter, as was done in that 2000/2001 period. Reliability is the number one issue, and you got to get that gas in storage to be able to withdraw it in the wintertime. And customers have learned that lesson.

We've been chocked full of storage every year since then. And we are again this year.

MS. ELDER: Laird's going to jump in here.

MR. DYER: From a market standpoint storage development has nothing to do with reliability. It's driven by volatility. It's a valuation process. You develop storage because you want to take advantage of volatility. Kind of the short answer.

And we'll see continued storage development as long as there's perceived volatility in the marketplace.

And I wouldn't hang your hat too heavy on LNG coming here in big volumes for too long. Probably in the near term, given the economic environment, this is a great dumping ground because we have storage. It's a place to hide it. So, this summer should be, we should be swamped with it.

And there's some new facilities coming on line, and the (inaudible) are quite busy up there. But after 2010 there's nothing on the drawing boards.

And if the economies recover you'll see

that soaked up by the Asian economies, again. And they'll pay $18, $19 a mmBtu before like they haver done in the past.

And today that they're even considering delivering it to the U.S. shores for $3 and $4 tells you how dire it is out there. I love to throw that word in there.

So, LNG, the U.S. is going to be in near term -- two years ago we had a very warm winter. They dumped LNG. Here we got 3 bcf a day into the U.S. through the summer. The last two winters have been a lot colder. We're a half a bcf a day right now, injection, of importation of LNG into the United States. And it's been that way for a good year and a half.

We will see a ramp-up here, but I wouldn't hang your hat on it, that it's going to protect us from everything. The shales will actually do that in time.

ASSOCIATE MEMBER BOYD: Yeah, I was going to say that this isn't a gas supply workshop, but it does seem to me that gas shale is pretty well move your doubt any discussions of bringing LNG into California from new facilities.

And the fact that there was reference by

Herb to LNG in California made me think that those folks in Costa Azul must be planning to send some of it into California. Whereas heretofore we've never quite known where that gas might go.

MS. ELDER: I do happen to know that staff is going to come back with a workshop on the supply --

ASSOCIATE MEMBER BOYD: Oh, I --

MS. ELDER: -- and LNG -- Marshall, you were looking like you want to add something. Did I misread that?

MR. CLARK: Storage, our business model we don't use it, so that's not my pigeon.

MS. ELDER: So the folks that you're buying gas for, let me make sure I interpreted this correctly. Is what you're saying that the folks that you're buying gas for are really not using storage as part of their portfolio?

MR. CLARK: Correct.

MS. ELDER: Correct. Okay. Interesting. John, did you want to say something about storage and how it fits into PG&E's core portfolio?

MR. ARMATO: As I mentioned before, we wish we had more storage. I do agree with Laird that, you know, volatility -- storage developers depend on volatility. That's really what drives the development of storage.

However, storage can dampen volatility to some extent. And, again, whereas SoCal seems to be flush with storage, our storage for the core is quite limited in northern California.

We have gone out and purchased some third-party storage beyond what just PG&E holds. So we have been able to do that just recently.

MS. ELDER: Herb talked about 138 bcf of storage. Is that just for the core or is that total?

MR. EMMRICH: That's total.

MS. ELDER: That's total. And the core share that was 98 --

MR. EMMRICH: 79.

MS. ELDER: 79, 79. For PG&E there's maybe, what, 36?

MR. ARMATO: No. For PG&E core it's about 32.

MS. ELDER: 32 for the core. Okay.

MR. ARMATO: Plus we have a lot less withdrawal capability during the winter.

MS. ELDER: Right, right. SoCal can

meet a huge portion of its demand with withdrawals from storage. And PG&E can't quite to that.

MR. ARMATO: That's correct.

MR. EMMRICH: Yeah, just to reiterate that we purchase flat basically 1.1 bcf a day every day of the year. In the wintertime we just withdraw the gas from storage. We don't increase purchases in the winter unless it being an extremely cold winter, then we would have to purchase more.

MS. ELDER: And so you're purchasing that 1.1 bcf a day. And so in a month when demand is lower than that, or days when demand is lower than that, the difference between demand and that 1.1 is what you're injecting into storage.

MR. EMMRICH: That's right.

MR. WELCH: Well, I think there's an interesting distinction that's being drawn here, which is, you know, the market motivates people to take certain actions on a private level like storage developers are motivated by price volatility to take advantage of that. Because they see the commodity is basically something that is a profit center for them. They can make some money off that.

For a utility, if they have access to more of that developed storage that's a benefit that the market provides them. But their real focus is not on whether it's expensive or inexpensive. Their real focus is on making sure that nobody runs out of gas in the middle of the winter.

And the price effects are not trivial by any means, they're important. But they're certainly secondary. I think it's a corollary to something that Marshall was saying earlier. It's that you don't want to have to explain why you ran out of gas, you know. You'd much rather explain why gas is $10.

MR. FOX: And ideally neither of those situations.

(Laughter.)

MS. ELDER: Right, ideally neither of those situations arises.

If we could imagine Lana's graph back up there. I don't have a magic wand to wave and make it go up there, but somebody else may, while I sort of stall here.

One of the graphs that she had was the monthly index. Yeah, that one will do, close enough.

If you look at that graph and you think about a hedging program, I think one of the other pieces of analysis -- oh, I get a pointer. Now I'm really dangerous.

One of the other points that she made was when you looked at what core customers were actually paying, it actually looked a lot like this graph. The ups and the downs, the way COGs tend to move with the index.

And that's what we'd expect, given the way the benchmark, the incentive program is set up, which is telling me, just go out and buy monthly spot gas.

The question is, and this might be a good closing question since it's 11:55. Unless the Commissioners have got more questions that they want to ask.

But here's my goofy question: And that is if someone were to implement a, quote-unquote, effective hedging program, how would that graph look different. In other words, would it look different and what would it look like. Any thoughts?

In other words, would we see kind of the peaks and valleys kind of disappear a little bit?

MR. DYER: It would naturally take those out. You'd see the trend should still be -- if it's an upward trend, you should maintain the upward trend.

MS. ELDER: The upward trend. So it would --

MR. DYER: You're going to reflect the market.

MS. ELDER: It would sort of even it out?

MR. DYER: Well, you know, California adopted the interline principle that -- and I remember Dan Fessler saying this was market-to-market, you know, I'm going to get this price. You're going to get that price.

You will take the peaks and troughs out of the thing.

MR. FOX: And I think it's important to remember that when you hedge you're not trying to lower your cost. You're trying to decrease the variability, --

MS. ELDER: The volatility.

MR. FOX: -- the size of the distribution. Correct. And so we are not looking, or anyone hedging is not looking to lower their average cost. The mean will stay the same with your different financial instruments. You're looking to decrease that distribution.

MS. ELDER: And that's --

MR. MEYERS: In fact, --

MS. ELDER: -- that Ray was talking --

MR. MEYERS: -- what I believe is going to happen under a hedging program is that you might have a slight dampening of those peaks and valleys, but the overall costs are going to be higher.

MS. ELDER: Because of the cost of implementing the hedging program, is that what you're getting at, Rich?

MR. MEYERS: Yeah.

MS. ELDER: So when you add that heading program onto your cost of gas, we've taken out the peaks and valleys, but your total cost will be higher because as Marshall pointed out, there ain't no free lunch. You got to pay for hedging program somewhere. You have to pay somebody else to take away that risk, right?

MR. MEYERS: And I think the PUC has

used the hedging program, at least currently, as more of an insurance program against unexpectedly high gas prices.

And so I think the expectation is that you'd put money into this to prevent an extremely high price blowout. But you're going to end up paying some money in order to do that.

So you're effectively adding onto your expected gas cost.

MS. ELDER: I see lots of heads nodding. Does anybody want to amplify on that?

MR. DYER: I would like to say, I always like to think that I have control. It's a human condition. So I think, yes, you're transferring risk, you have to pay to do that.

But there are lots of ways to do it out there, and I still think that, at least in everything I do for myself, personally, I try to mitigate my volatility.

I'm willing to pay some money for that. But I also think if I manage it right the cost to do that can be minimal.

And I also like the idea of thinking that I can win. You have to go in that way.

MS. ELDER: You have to go in that way,

okay. Any closing thoughts anybody wants to add. We're getting to 11:58. My job is to wrap this up by noon unless I'm otherwise instructed.

PRESIDING MEMBER BYRON: Ms. Elder, let me interrupt for just one moment in the event -- I've got two cards here from folks that are on the phone, and they have some questions. If they're still with us, they've been very patient.

The order I received them -- is Wendy Al-Mukda on the phone?

MS. AL-MUKDA: Hi, yes, I'm on the phone, but actually I don't. It was very interesting presentations, thanks.

PRESIDING MEMBER BYRON: Okay, good. Any other -- thank you for joining us. The other one that I have is Mr. Ron Perry.

THE OPERATOR: He has disconnected.

PRESIDING MEMBER BYRON: Okay. Sorry for the interruption. Wanted to make sure that if there was anyone on the phone they had opportunity to comment.

MS. ELDER: Good.

ASSOCIATE MEMBER BOYD: I'll make one observation. I was intrigued with the discussion about price transparency and letting the customers make decisions predicated on getting a real price versus price averaging or any other approach that's taken short of just, you know, aid to the really poor people and support there.

And being a SMUD customer, and a lifetime Sacramentan, recently -- well, some time back you changed your billing and you started telling us not only, you know, what our use was for the billing period, but what our neighborhood is doing and what the best person in the neighborhood is doing.

(Laughter.)

PRESIDING MEMBER BYRON: Did you get a smiley face on your bill?

ASSOCIATE MEMBER BOYD: Yeah, and I know we're an atypical audience, but, you know, I guess Pavlov was right. That incented me to engage in competition more than I ever thought I would in terms of, by god, I'm going to knock that down. I should be below the average of the neighborhood, et cetera, et cetera. And I've succeeded, too.

But there's something interesting in that approach. And what influence will have on people. There are some people who will never pay any attention, but I'll bet you there's more people who would. Lesson learned for me today.

MS. TAHERI: Thank you, Commissioner, for that comment. I certainly will pass that along.

As you've -- very much into customer engagement and we're ramping that up. And because we're looking at different ways in anticipation of when we have the AMI, you know. With all this information pushing out to our customer in terms of real-time pricing, how is that going to impact and influence their behavior in terms of when would be a good time maybe to do the laundry, or what-have-you.

But, competition. I mean I know, if I knew all my neighbors doing better than me, considering I'm supposed to be SMUD's risk manager, --

(Laughter.)

MS. TAHERI: -- certainly that's going to have more impact in terms of my personal usage patterns as compared to the bill. Thank you.

ASSOCIATE MEMBER BOYD: I have one other message for you to deliver to your management. Will you quit hiring so many of our employees.

MS. TAHERI: This is the second time

I've heard that today. I will certainly pass that on.

ASSOCIATE MEMBER BOYD: Ah, very good. It hurts.

PRESIDING MEMBER BYRON: Well, so maybe I'll take a moment to add, as well, this has been a very interesting discussion. I appreciate all of you and those that made presentations and stayed for this panel.

Of course, the debate will continue, I suspect. Mr. Welch indicated you can't beat the market; and Mr. Dyer indicating that you can and you should be trying, at least, to beat the market all the time.

And Mr. Emmrich and others indicating that everything's working fine. So, you know, why do we have to do anything about it.

The PUC, of course, will continue to take this up, and I'm glad they are taking it up. I'd like to also thank our colleague, Mr. Meyers, from the PUC to be able to join us by phone.

But there are some potential policy recommendations that we can make from this. And I'll be discussing them with Commissioner Boyd, those ideas.

We are interested, of course, in trying to improve the level of service to the customers, as well as reducing their costs. The volatility of the price of natural gas will continue to be a concern. Certainly this last year was extraordinary in what happened.

So, we'll put our heads together, Commissioner, and we'll do our best to predict the future, as well, I suppose.

I'm kidding, of course.

ASSOCIATE MEMBER BOYD: Yeah, very good. We're not very good at that.

PRESIDING MEMBER BYRON: We're not very good at that. Ms. Elder, why don't you close us out here.

MS. ELDER: Well, do any of the panel have a last comment they'd like to make, recognizing it's 12:03?

(Laughter.)

MS. ELDER: Herb would like to.

MR. EMMRICH: Well, I think I've been remiss, Commissioners, not thanking Lana Wong for the excellent and comprehensive staff paper. We had some contact, exchange of emails, and she did an outstanding job. And I want to express my appreciation on behalf of SoCalGas and San Diego Gas and Electric.

MS. ELDER: Yeah, rah, Lana. Anybody else?

MR. FOX: I mean again PG&E would echo that. We appreciate the ability to take part in these conversations. We care about our customers, their costs, the variability they see in pricing. And we're committed to working with customer groups and different Commissions to better that.

MS. ELDER: Pam.

MS. TAHERI: On behalf of SMUD we just want to appreciate that you guys are really great customers. The bill keeps getting paid, so we really appreciate that.

(Laughter.)

MS. ELDER: And with that I think we're done. Thanks to everyone for coming and for participating and tolerating my questions.

ASSOCIATE MEMBER BOYD: Thank you, all, very very much.

(Whereupon, at 12:08 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

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PETER PETTY